of IPM analysis presented herein. Therefore, since IPM is a more definitive measure of DSM's value as a resource than are simple screening tests, and is capable of screening out non-cost-effective measures, we chose this "liberal" approach to passing DSM measures to the next step.

Finally, **achievable potential** is an estimate of the portion of economic potential that could actually be captured by programs over a number of years of sustained program effort. We will discuss our derivations of technical and economic potential in this section, and detail achievable potential in subsequent sections.

To determine DSM potential, it is also necessary to estimate measure applicability factors, saturation factors, and avoided costs. Applicability factors, varying from 0 to 1, determine the engineering feasibility of implementing a measure in a particular end-use. For instance, the applicability factor for a compact fluorescent light (CFL) would represent the percentage of inefficient incandescent light bulbs that could feasibly be upgraded to CFLs from a purely technical perspective (accounting for the fact that due to their size and performance characteristics, CFLs cannot universally be used to replace all incandescent bulbs).

Another factor used to determine technical potential was installed saturation factor. The installed saturation factor refers to the percentage of the market or sub-sector where the measure has already been implemented. We used historical GRU data from the 1994 GRU study, as well as regional and national averages, to develop installed saturations by technology type.

The technical potential of a measure is then determined by multiplying the savings factor, applicability factor, and saturation factor by the technology type load (from the results of Step 1). For example, the energy technical potential calculation for residential CFLs is as follows:

Measure: CFLs	
Technology Type Load	122.3 GWh
% Savings Factor	X 0.75
Applicability Factor	X 0.60
1 - Saturation Factor	X (1 - 0.14)
Technical Potential	47.5 GWh

CFLs are a part of the incandescent technology type in the residential lighting end-use. The maximum introduction of this measure would reduce overall annual load in this technology type and end use by 47.5 GWh. From this new baseline of 75 GWh (or 122.3 GWh minus 47.5 GWh), any additional measures would have similar percentage reductions according to their savings, applicability, and saturation characteristics. In this measure-by-measure fashion, we estimated the total technical potential for the full range of DSM measures. Measures were considered in order of descending TRC benefit-cost ratios (see below). Note that for measures that achieve savings in the same way and which would be redundant if installed together, the most cost-effective option has been selected. For instance, because "exterior shades" and "shade screens" achieve essentially the same objective, only the more cost-effective (exterior shades) is considered. To remove the other measure from the analysis, its applicability factor has been set to zero. Of course, ultimate implementation of such a program may permit a variety of technologies to be used to accommodate customer preferences and market acceptance of various measures.

To determine economic potential, we used the same methodology, but only allowed those measures passing the TRC test to be selected. As noted above, we allowed measures with a TRC benefit-cost ratio of greater than or equal to 0.5 to be included in the estimates of economic potential. This is in contrast to typical practice, which allows only those measures with a benefit-cost ratio of greater than or equal to 1.0. Please see further description of cost-effectiveness analysis below.

The TRC test measures the net costs of a DSM program as a resource option based on the total costs of the program, including both the utility's and participant's costs.[18] Generally, the TRC test measures the ratio of a measure's benefits (kWh and kW savings x avoided costs) versus a measure's incremental costs plus any program administrative costs. Because it is difficult to credibly assign program costs to specific measures, all program administrative costs were ignored for the measure-by-measure screening (such costs were later included in the analysis of the DSM programs.)

To calculate TRC cost-effectiveness, the costs of a DSM technology are compared to GRU's avoided costs of generation and capacity. Avoided costs are the expenses GRU would have incurred had it generated or purchased electricity in lieu of a DSM program. These avoided costs were taken from GRU Strategic Planning's Inter-office Communication from August 31, 2005. We weighted the Winter Peak, Summer Peak and Off Peak savings per kWh by the number of hours to created one yearly avoided cost per kWh. As per GRU's original avoided costs documents, we then used a discount rate of 6.75% to convert the avoided cost into a Net Present Value (NPV) to correspond to the life of a measure. Similarly, we converted the 2012 avoided capital cost of $2,360.50/kW to a Net Present Value. We then used the Net Present Value for kWh and kW savings to determine the Total Resource Cost (TRC) benefit-cost ratio of a measure. That is, the net present value of all avoided energy and capacity costs divided by the incremental costs of the measure. GRU's avoided cost table is included in Attachment 3. Note that some of these assumptions have been modified or updated based on ICF's analysis for the purposes of the IPM runs. The results include:

- Out of 76 measures for existing residential homes, 28 had a TRC>=1.
- An additional nine measures had a TRC>=0.50, making them marginally cost-effective.

[18] California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects, October 2001

- Out of 22 new construction residential measures, 5 had a TRC>=1. An additional two measures had a TRC>=0.50, deeming them marginally cost-effective.
- Out of 116 commercial measures and 10 building types, equaling 1,160 total applications, 522 applications had a TRC>=1.
- An additional 89 commercial applications had a TRC>=0.50, deeming them marginally cost-effective.

The list of all measures screened and the cost-effectiveness results are provided in Attachment 3. Figures 3-16 through 3-21 illustrate technical and economic potential in the residential and commercial sectors.

Figure 3-16
GRU Residential Technical and Economic Energy Potential by End-use (Excludes Losses)

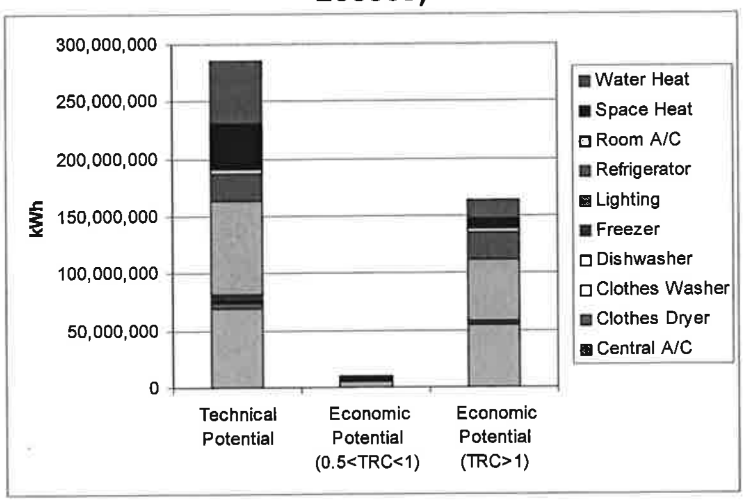

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Figure 3-17
GRU Residential Technical and Economic Demand Potential by End-use (Excludes Losses)

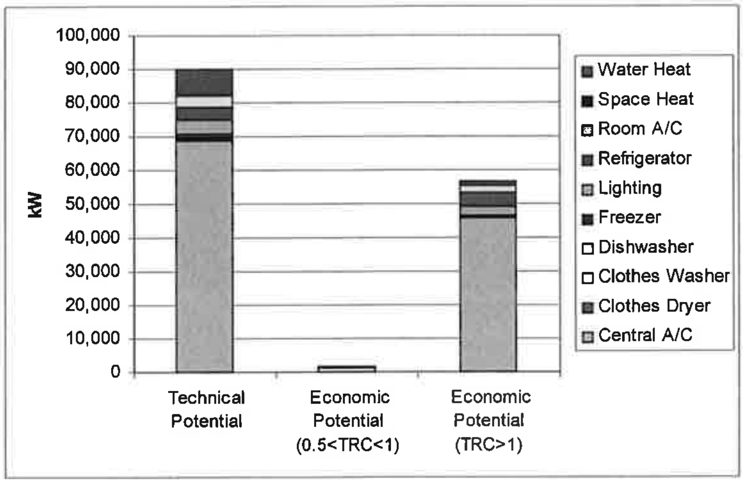

Figure 3-18
GRU Commercial Technical and Economic Energy Potential by Sub-sector (Excludes Losses)

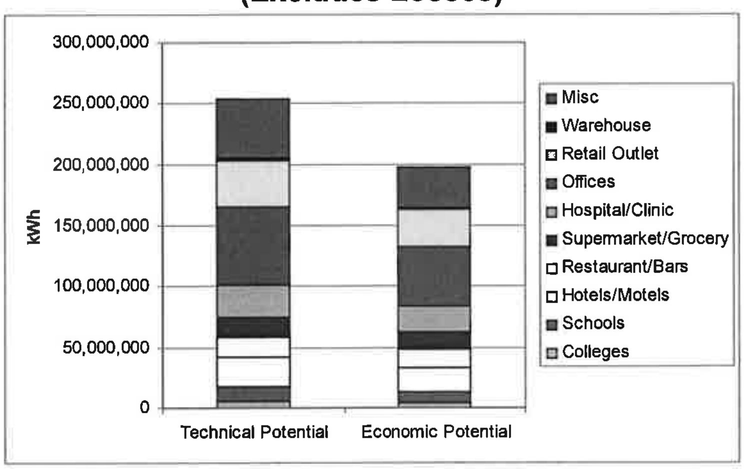

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Figure 3-19
GRU Commercial Technical and Economic Demand Potential by Sub-sector (Excludes Losses)

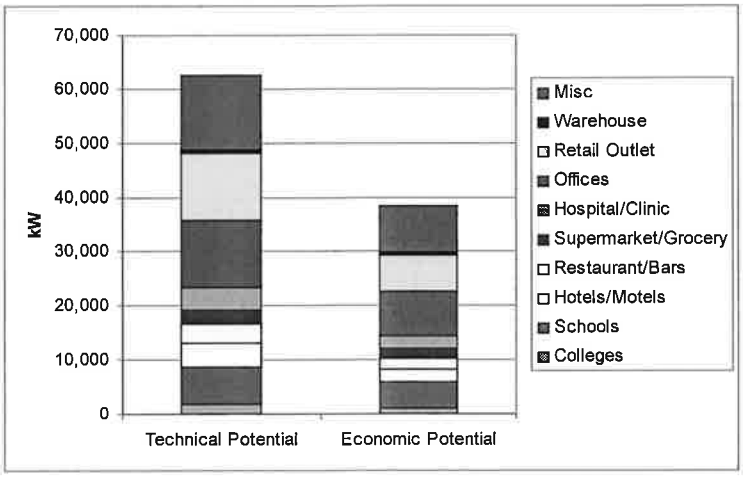

Figure 3-20
GRU Commercial Technical and Economic Energy Potential by End-use (Excludes Losses)

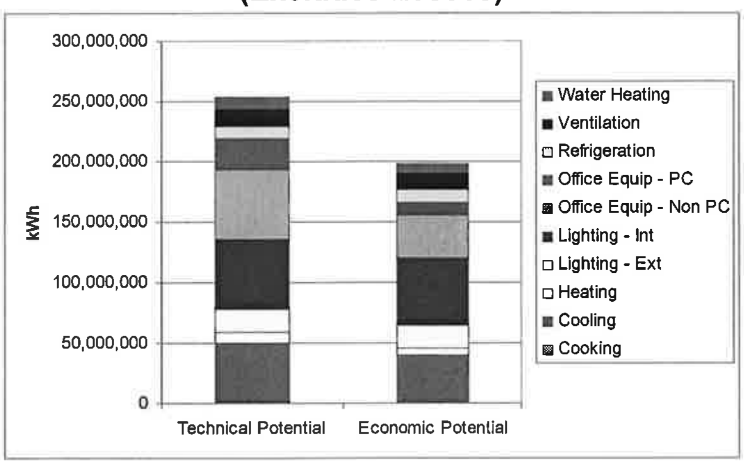

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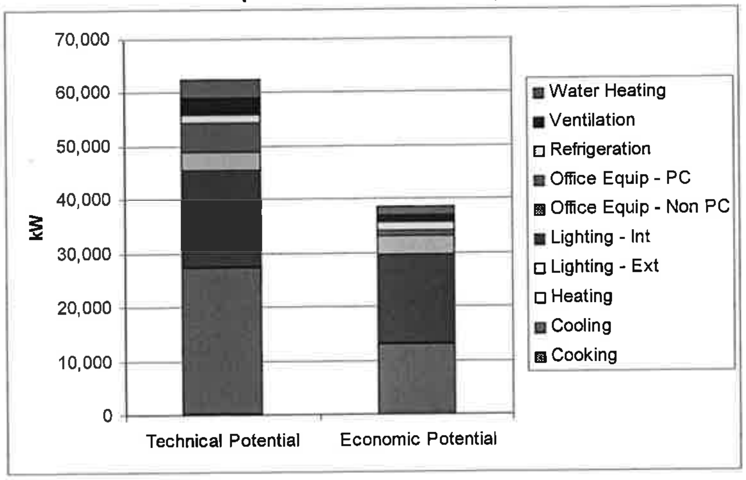
Figure 3-21
GRU Commercial Technical and Economic Demand Potential by End-use (Excludes Losses)



Step 5. Bundling of Measures into Programs

Once we were able to determine technical and economic potential for each measure, we bundled measures together to form potential programs. These programs were designed to capture all of the market or achievable potential identified for the region. The programs represent a more realistic view of how the potential could actually be captured through specific activities. Our methodology in bundling programs results from what would be feasible for the GRU service territory, as well as from our experience in implementation of energy efficiency programs across the country. Most programs consisted of measures that were cost-effective (with a TRC>=1). A few programs, including Home Performance with ENERGY STAR (Existing Homes), included some measures that were marginally cost-effective (with a TRC between 0.5 and 1). The marginally cost-effective program components were separated from the cost-effective components so as to ensure that otherwise cost-effective programs were not entirely discarded due to a few less cost-effective measures. Below, in Figure 3-22, is an example of how measures were bundled together into programs.

Figure 3-22
Example of Program Bundling

Measures	Program
Compact fluorescent lamps	Residential CFL Program
Energy Star Refrigerators	Residential Appliances
Energy Star Clothes Dryer	
Energy Star Clothes Washer	
Energy Star Dishwasher	

Many of the programs relate to lighting and cooling end-uses, where the potential for efficiency improvements is typically high. The programs include:

Residential Programs

- CFLs – Replaces incandescent bulbs with compact fluorescent lamps.
- Fridge/Freezer Buyback – Provides payment for the transportation and disposal cost of older, inefficient second refrigerators and freezers.
- Home Performance with ENERGY STAR - Implements high efficiency residential measures in existing homes such as equipment and insulation for central and room A/C use, and may include low-income focused components
- Comprehensive Water Heating – Implements high efficiency measures such as equipment and tank / pipe wraps for water heating use.
- Solar Water Heater – Provides incentives for the purchase of a solar water heater system.
- Appliances – Provides incentives for the purchase of ENERGY STAR or other high efficiency appliances, including clothes washers and dryers, dishwashers, and refrigerators / freezers.
- A/C Rebate, Weatherization, and A/C Tune-Up Program – Similar to the Home Performance Program, this program implements high efficiency measures for central and room A/C use, and may also include low-income components
- A/C Direct Load Control – In exchange for A/C cycling during peak periods, GRU will provide payments to participating customers.
- Water Heating Direct Load Control – In exchange for water heater cycling during peak periods, GRU will provide payments to participating customers.
- ENERGY STAR Home – Provides incentives for high efficiency measures in new homes, and expands the reach of the current Gainesville ENERGY STAR Homes Program.

Commercial Programs

- Cooling – Provides incentives for high efficiency equipment such as packaged rooftop air conditioners and other measures for cooling use across all sub-sectors.
- Exterior Lighting - Provides incentives for high efficiency exterior lighting and other measures for exterior lighting use across all sub-sectors.
- Interior Lighting - Provides incentives for high efficiency equipment such as T8 lamps and other measures (such as lighting controls) for interior lighting use across all sub-sectors.
- Office Equipment - Provides incentives for high efficiency equipment, such as computers, monitors, and printers, across all sub-sectors.
- Grocery and Restaurant Refrigeration - Provides incentives for high efficiency equipment and other measures for cooling use in the grocery and restaurant sub-sectors.

- Ventilation - Provides incentives for high efficiency equipment and other measures for ventilation use across all sub-sectors.
- Water Heating - Provides incentives for high efficiency equipment and other measures for water heating use across all sub-sectors.

Step 6. Estimation of DSM Program Penetration

DSM program penetration determines the percentage of economic potential that becomes achievable. Achievable potential is typically defined as the amount of cost-effective energy efficiency improvement expected to be captured as the result of specific program actions, over and above the efficiency improvements attributable to normal consumer and market behavior and existing conservation policies and programs. Achievable potential differs from technical and economic potential in that it is time-dependent. That is, in reality, it takes some amount of time to change consumer purchasing decisions and increase the installed saturations of efficiency measures.

For this study, we typically assumed that a total of 85% of current economic potential could be captured over the time horizon of this study. While it is certainly the case that the actual potential achieved will vary by program and is in part a function of external factors such as fuel prices, along with the nature of incentives etc., such a simplifying assumption is necessary given the schedule and scope of this study. In ICF's experience, this assumption is at the upper end of the range used in similar studies across the country.

Annual impact is derived using a straightforward mathematical function designed to simulate the growth of energy-efficient market share over time. The function incorporates initial market share, a maximum market share, and a parameter that represents the speed at which the DSM measures gain market share.

For this study, the difference between achievable potential and naturally occurring conservation is market potential. Below, in Figure 3-23, market potential is the area between the achievable potential and naturally occurring curves. This is the amount of additional conservation that could occur due to DSM programs.

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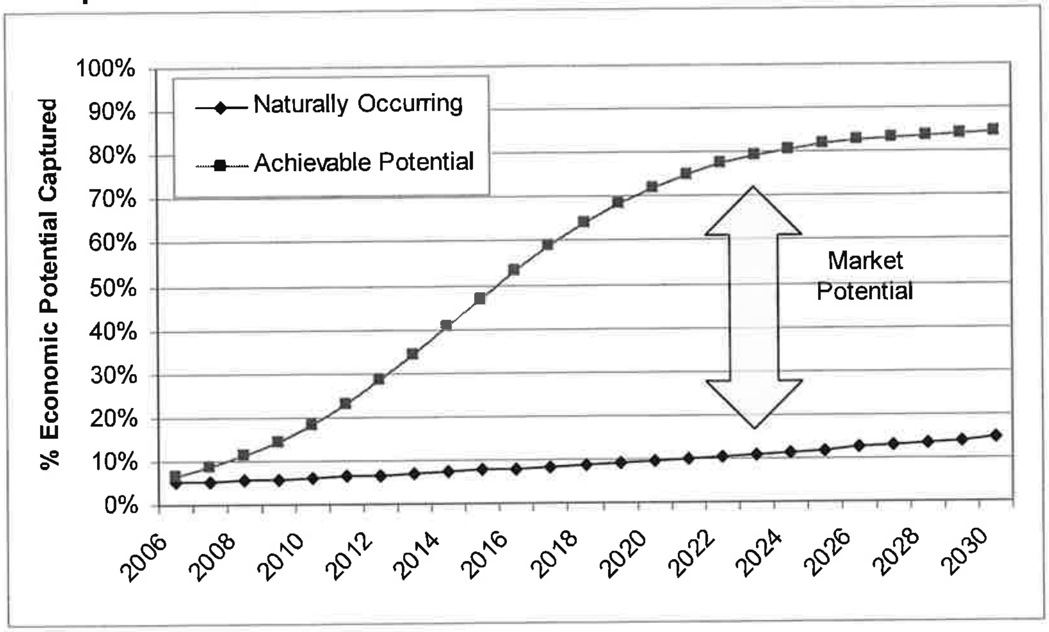
Figure 3-23
Comparison of Market Potential with Naturally Occurring Conservation



Of course, the ramp-up rate is in part a function of the aggressiveness of the programs, especially the level of incentive paid to end-users. Determination of the precise level of incentive is somewhat of an art form, involving consideration of the customer's payback criteria, availability of alternatives, newness of the technology to the market, impact of free-riders (end-users who would install the measure even in the absence of the program but to whom we still pay an incentive) and other factors. For the purposes of this study, we assume that GRU would pay an incentive equal to full incremental cost of the efficient measure relative to the inefficient alternative. When combined with consideration of the somewhat limited existing market infrastructure available to support DSM programs in Gainesville (e.g., contractors, stocks of efficient equipment, energy auditing companies, etc.) the ramp-up rates assumed in this study are believed to be aggressive, especially when compared with the experience of other utilities. Of course, with large scale programs, this infrastructure can be expected to grow rapidly to keep pace with demand.

We further assume that program marketing, administration, and other costs are equivalent to approximately 50% of the incentives paid to customers, although for certain programs such as load control we developed a more detailed profile of programs costs and incentive levels based on program experience in Florida. Cost assumptions for all programs and for the suite of programs as a whole were also benchmarked against experience elsewhere.

Note that the City of Gainesville has certain DSM program delivery options available to it that investor-owned utilities do not. For example, instead of the "market-based"

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approach assumed herein where customers and trade allies are provided incentives for efficiency upgrades, the City could, in the extreme, simply change building codes to require the higher levels of efficiency. However, for the purposes of this study we have assumed a market based approach (instead of mandates) for all programs. If the City were to pursue a "mandates" approach, program expenses could likely be reduced, but perhaps at the cost of considerable constituent dissatisfaction.

As with the DSM load impacts, certain of these assumptions are being refined and should be considered "draft."

Summary statistics for each of the draft programs are provided in Figure 3-24, with more detailed program impacts and annual results provided in Attachment 3. The captions for the tables and graphs in this report note whether impacts are at the "customer meter" level, excluding losses, or if transmission and distribution losses are included. The additional value of these programs in avoiding transmission and distribution losses (approximately 7%) and generating system reserve requirements (approximately 15%) is reflected in the IPM modeling runs. Please note that due to revisions of these draft program costs and potentials, the values shown in the below table have been updated after the completion of the IPM modeling runs. For the final report, the IPM runs will reflect the updated program costs and impacts as shown below.

Figure 3-24
Potential Programs Savings and Costs (Generator Level, Includes 7% Losses)

Program	2025 Cumulative Annual MW Savings	2025 Cumulative Annual MWh Savings	Program Cost $ / Coincident kW	Program Cost $ / Non-Coincident kW
Residential CFL Program	1.89	35,479	$1,548.04	$161.45
Residential Fridge/Freezer Buyback	1.55	8,680	$411.23	$365.67
Home Performance with Energy Star (Marginally Cost-Effective Measures)	0.30	1,502	$4,754.72	$3,611.24
Home Performance with Energy Star (Cost-Effective Measures)	10.75	12,794	$464.30	$350.31
Comprehensive Water Heating Program	1.25	12,769	$2,071.29	$656.39
Residential Solar Water Heater	1.12	8,005	$23,511.48	$7,450.80
Residential Appliance	2.64	15,285	$6,444.27	$5,511.75
Residential A/C Rebate, Weatherization, & A/C Tune-Up Program (Marginally Cost-Effective	0.70	3,505	$4,754.72	$3,611.24
Residential A/C Rebate, Weatherization, & A/C Tune-Up Program (Cost-Effective Measures)	25.08	29,853	$464.30	$350.31
Residential A/C Direct Load Control	5.36	161	$90.44	$90.44
Residential Water Heating Direct Load Control	0.76	61	$891.71	$891.71
Energy Star Homes	0.27	570	$453.88	$342.44
Commercial Cooling	9.71	29,559	$1,543.37	$1,543.37
Commercial Lighting - Exterior	0.22	14,231	$15,763.43	$788.17
Commercial Lighting - Interior	12.21	41,554	$1,412.10	$1,277.08
Commercial Office Equipment	3.33	34,072	$1,039.65	$955.65
Grocery and Restaurant Refrigeration Program	1.12	8,125	$995.58	$928.05
Commercial Ventilation	1.05	10,217	$1,279.64	$1,279.64
Commercial Water Heating	1.06	5,624	$1,433.07	$1,133.30
Total	**80.38**	**272,043**	**$1,434.40**	**$955.85**

Supply curves provide a useful framework for understanding how much DSM is available at varying levels of cost. For example, Figure 3-25 is a supply curve for 2025 based on the programs developed above. This curve includes all transmission and distribution losses as well as full program incentive and administrative costs. It reveals that there is approximately 45 MW of achievable DSM load reduction available at an annualized or levelized cost of less than $100 per coincident kW. This potential increases to nearly 80 MW if the acceptable cost level is increased to $600 per coincident kW. Figure 3-26 reveals the programs and numbers corresponding to this curve. Note that for direct load control programs, the cited cost represents only initial installation of equipment and does not include ongoing incentive payments to maintain participation in the program.

Figure 3-25
Total Program Potential Coincident Peak Demand Supply Curve (Including 7% Losses)

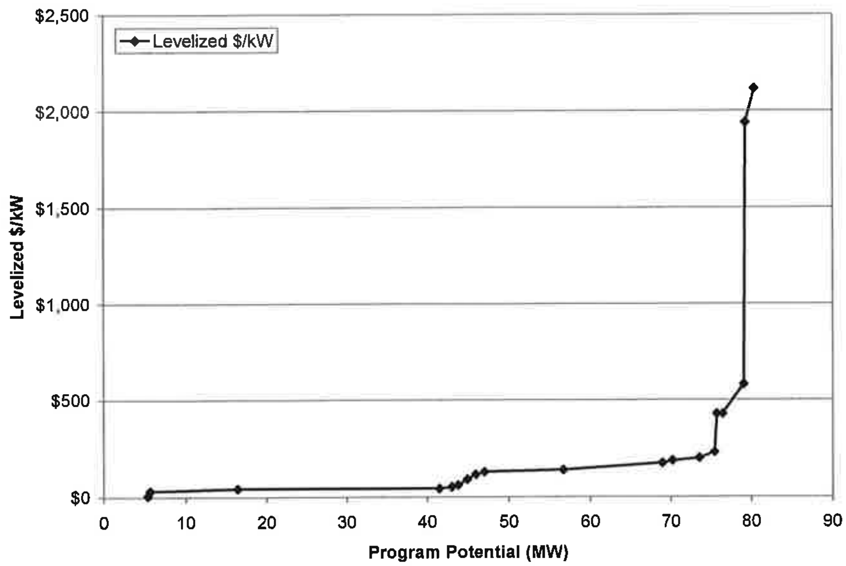


Figure 3-26
DSM Program Supply Curve (Including 7% Losses)

Program	Cumulative MW	Annualized $/Coincident kW
Residential A/C Direct Load Control	5.4	$6.06
Energy Star Homes	5.6	$30.41
Home Performance with Energy Star (Cost-Effective Measures)	16.4	$41.75
Residential A/C Rebate, Weatherization, & A/C Tune-Up Program (Cost-Effective Measures)	41.5	$41.75
Residential Fridge/Freezer Buyback	43.0	$50.60
Residential Water Heating Direct Load Control	43.8	$59.74
Grocery and Restaurant Refrigeration Program	44.9	$89.51
Commercial Ventilation	45.9	$115.05
Commercial Water Heating	47.0	$128.85
Commercial Cooling	56.7	$138.77
Commercial Lighting - Interior	68.9	$173.74
Comprehensive Water Heating Program	70.2	$186.23
Commercial Office Equipment	73.5	$199.45
Residential CFL Program	75.4	$229.33
Home Performance with Energy Star (Marginally Cost-Effective Measures)	75.7	$427.51
Residential A/C Rebate, Weatherization, & A/C Tune-Up Program (Marginally Cost-Effective	76.4	$427.51
Residential Appliance	79.0	$579.42
Commercial Lighting - Exterior	79.3	$1,939.46
Residential Solar Water Heater	80.4	$2,113.96

In Figures 3-27 and 3-28, we illustrate total residential DSM market potential over time by measure for all cost-effective measures (TRC>=0.5). These curves show the ramp-up of programs to capture available economic potential over the planning horizon. For energy reductions, compact fluorescent lamps make the single largest contribution to DSM potential. However, because of residential electricity usage patterns, CFLs make a much smaller contribution to peak demand potential. Peak demand opportunities are made up largely of central air conditioning measures, including high-efficiency air conditioners and building envelope improvements.

Figure 3-27
Residential Energy Market Potential by Measure (Excluding Losses)

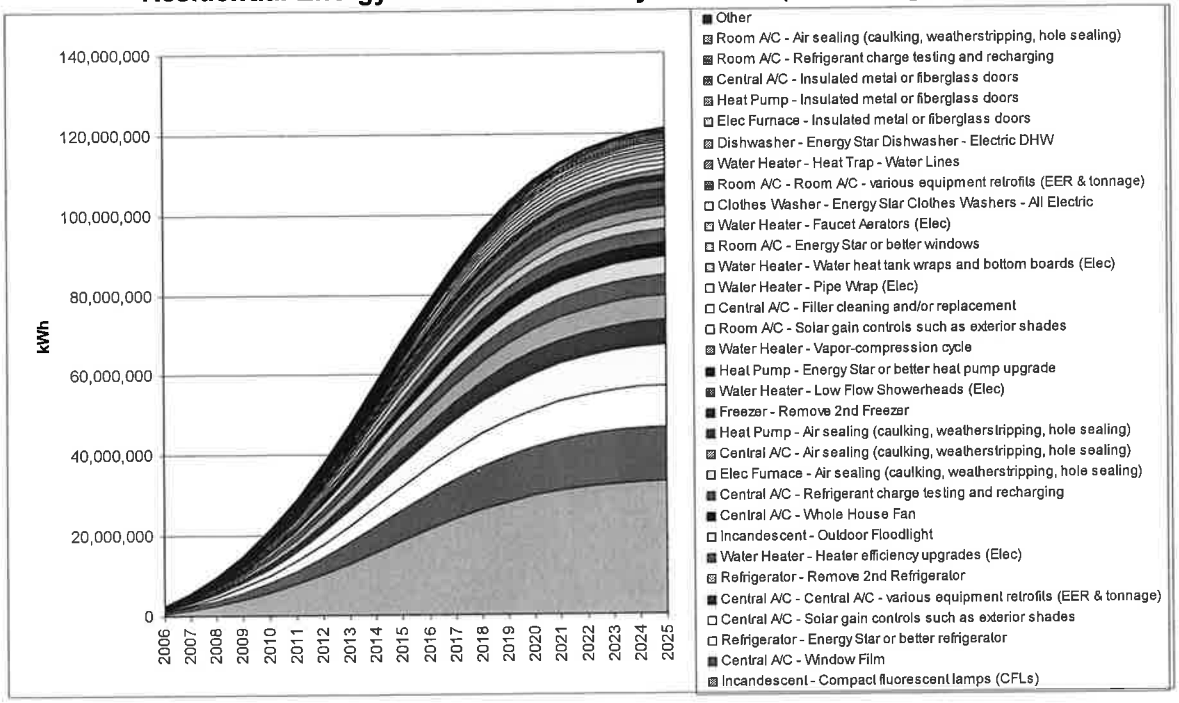
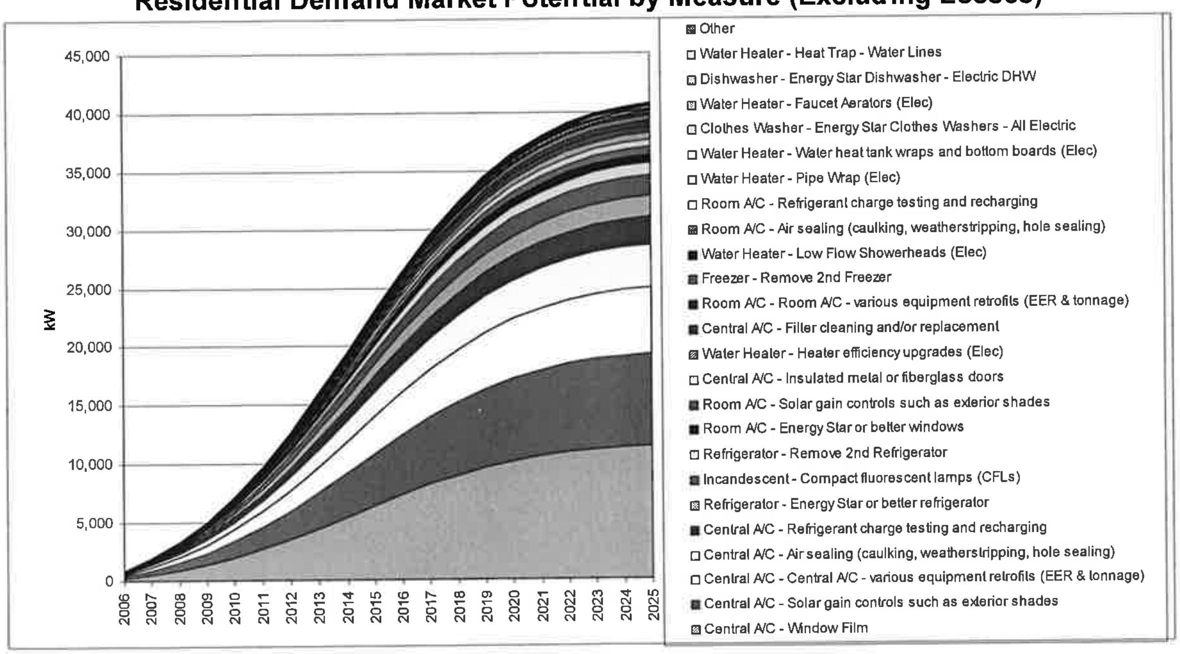


Figure 3-28
Residential Demand Market Potential by Measure (Excluding Losses)



Step 7. Comparisons with Other Utilities

As discussed later, several of the programs were either not picked by IPM (they were not cost competitive with the supply-side and other DSM alternatives even given the assumptions of high CO2 and high fuel prices) or their implementation was delayed until closer to the time that the capacity is needed. However, those that were picked still comprise a very aggressive DSM portfolio. The disposition of each program, showing its start date if it was selected, is provided in Figure 3-29.

Figure 3-29
Disposition of Potential DSM Programs After Analysis in IPM (Maximum DSM Case)

	Program	Year of First Implementation
1	Residential CFL Program	2006
2	Residential Fridge/Freezer Buyback	2006
3	Home Performance with Energy Star (Marginally Cost-Effective Measures)	Not selected
4	Home Performance with Energy Star (Cost-Effective Measures)	2006
5	Comprehensive Water Heating Program	2006
6	Residential Solar Water Heater	Not selected
7	Residential Appliance	2006
8	Residential A/C Rebate, Weatherization, & A/C Tune-Up Program (Marginally Cost-Effective Measures)	Not selected
9	Residential A/C Rebate, Weatherization, & A/C Tune-Up Program (Cost-Effective Measures)	2006
10	Residential A/C Direct Load Control	2006
11	Residential Water Heating Direct Load Control	2011
12	Energy Star Homes	2015
13	Commercial Cooling	2006
14	Commercial Lighting - Exterior	2015
15	Commercial Lighting - Interior	2006
16	Commercial Office Equipment	2006
17	Grocery and Restaurant Refrigeration Program	2006
18	Commercial Ventilation	2006
19	Commercial Water Heating	2006

If GRU were to implement all of these "Maximum DSM" case programs as scheduled above, the annual impacts would be as summarized in Figure 3-30.

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Figure 3-30
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Year	kW Saved							Annual Real $ on DSM			
	GRU Planned	IPM Additions	Total Ann DSM kW	Percent Increase	Cumulative Ann. kW(1)	DSM kW as % Peak kW Growth	DSM kW as % 2006 Peak kW	GRU Planned	IPM Additions	Total DSM Budget	Percent Increase
2006	595	1,501	2,096	352%	2,096	n/a	0.4%	1,860,783	$1,276,249	$3,137,032	169%
2007	605	1,806	2,411	399%	4,506	23.9%	0.9%	1,860,783	$1,535,675	$3,396,458	183%
2008	609	2,348	2,957	486%	7,463	28.7%	1.6%	1,860,783	$1,996,424	$3,857,207	207%
2009	613	2,978	3,591	586%	11,054	34.1%	2.3%	1,860,783	$2,532,419	$4,393,202	236%
2010	617	3,675	4,292	696%	15,345	39.9%	3.2%	1,860,783	$3,124,769	$4,985,552	268%
2011	621	4,410	5,031	810%	20,376	45.8%	4.2%	1,860,783	$3,750,418	$5,611,201	302%
2012	621	5,087	5,707	920%	26,083	50.9%	5.4%	1,860,783	$4,326,137	$6,186,920	332%
2013	458	5,639	6,097	1331%	32,180	53.3%	6.7%	1,860,783	$4,795,729	$6,656,512	358%
2014	458	5,983	6,441	1406%	38,622	55.1%	8.0%	1,860,783	$5,088,922	$6,949,705	373%
2015	458	6,068	6,526	1425%	45,147	54.7%	9.4%	1,860,783	$5,160,731	$7,021,514	377%
2016	458	5,881	6,339	1384%	51,487	52.1%	10.7%	1,860,783	$4,995,993	$6,856,776	368%
2017	458	5,431	5,889	1286%	57,376	47.4%	11.9%	1,860,783	$4,615,187	$6,475,970	348%
2018	458	4,807	5,265	1149%	62,641	41.5%	13.0%	1,860,783	$4,083,862	$5,944,645	319%
2019	458	4,088	4,546	992%	67,187	35.1%	14.0%	1,860,783	$3,470,579	$5,331,362	287%
2020	458	3,349	3,807	831%	70,994	28.8%	14.8%	1,860,783	$2,840,889	$4,701,672	253%
2021	458	2,649	3,107	678%	74,101	23.0%	15.4%	1,860,783	$2,244,133	$4,104,916	221%
2022	458	2,023	2,481	542%	76,581	18.0%	15.9%	1,860,783	$1,710,256	$3,571,039	192%
2023	458	1,485	1,943	424%	78,525	13.8%	16.3%	1,860,783	$1,252,267	$3,113,050	167%
2024	458	1,038	1,496	326%	80,020	10.4%	16.6%	1,860,783	$871,124	$2,731,907	147%
Cumulative	9,776	70,244									

Note: GRU budget is a placeholder number pending further information
(1) GRU kW additions not retired for equity in comparion to other utilities. GRU additions are included in current base load forecast, IPM additions reduce the load forecast

In this scenario:

- GRU's annual spending on DSM would double after two years, and grow to almost four times current levels within 10 years (approximately $7.0M/yr)[19]
- Annual kW reductions from DSM would increase from approximately 600 kW/yr resulting from current programs to 6,526 kW/yr including the additional programs in 10 years
- DSM programs would cut GRU's annual load growth by approximately 55% in Year nine
- The incremental annual DSM program expenditures equate to an additional $15/customer immediately, increasing to an additional $60 per customer in nine years.

In order to assess the likelihood that GRU could achieve such levels (and setting aside the policy considerations that will help determine if GRU *should* achieve such levels) some comparisons to other utilities are helpful. Of course, this is not to suggest that we should revise our estimates simply because other utilities have achieved more or less DSM than presented here. The experience of other utilities is not used as a constraint in this study, but rather to inform decision-makers of the relative successes of others who have made similar decisions.

First, we review the estimates of program potential developed for other utilities and compare them to the estimates developed herein. Second, we review the actual

[19] All dollars are in expressed in 2003 dollars

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spending and load impacts and results of other utilities compare them to the projections above.

Review of Other Potential Studies

To identify if ICF's methodology has generated estimates of the potential for DSM that are significantly different from the estimates that would result from alternate methodologies, a review of other studies of DSM potential was made (Figure 3-31). These studies included[20]:

Figure 3-31
Other DSM Potential Studies Reviewed

Study Name	Authoring Organization	Year	Region
An Economic Analysis of Achievable New Demand-Side Management Opportunities in Utah	Tellus Institute	2001	Utah
BC Hydro Conservation Potential Review 2002 Summary Report	BC Hydro	2003	British Columbia
BC Hydro Conservation Potential Review 2002 Summary Report	BC Hydro	2003	British Columbia
California Statewide Commercial Sector Energy Efficiency Potential Study	Kema-Xenergy, Inc.	2002	California
California Statewide Residential Sector Energy Efficiency Potential Study	Kema-Xenergy, Inc.	2003	California
Electricity Consumption and the Potential for Electric Energy Savings in the Manufacturing Sector	ACEEE	1994	U.S.
Energy Efficiency and Conservation Measure Resource Assessment for the Residential, Commercial, Industrial and Agricultural Sectors	Ecotope, Inc. ACEEE, and Tellus Institute	2003	Oregon
Energy Efficiency and Economic Development in Illinois	ACEEE	1998	Illinois
Energy Efficiency and Renewable Energy Resource Development Potential in New York State	New York State Energy Research and Development Authority (NYSERDA)	2003	New York
Estimates of the Achievable Potential for Energy Efficiency Improvements in U.S. Residences	Tellus Institute	1993	U.S.
Independent Assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwest Connecticut Region - Final Report	GDS Associates and Quantum Consulting	2004	Connecticut
Repowering the Midwest: The Clean Energy Development Plan for the Heartland	Synapse Energy Economics	2001	IL, IN, IA, MI, MN, NE, ND, OH, SD
Selecting Targets for Market Transformation Programs: A National Analysis	ACEEE	1998	U.S.
Selecting Targets for New Market Transformation Initiatives in the Northwest	ACEEE	1998	Oregon, Washington
The New Mother Lode: The Potential for More Efficient Electricity Use in the Southwest	Southwest Energy Efficiency Project	2002	AZ, CO, NV, NM, UT, WY
The Potential for Energy Efficiency in the State of Iowa	Oak Ridge National Laboratory (ORNL)	2001	Iowa
The Remaining Electric Energy Efficiency Opportunities	RLW Analytics, Inc.	2001	Mass.
Vermont Department of Public Service Electric and Economic Impacts of Maximum Achievable Statewide Efficiency Savings 2003-2012	Optimal Energy	2002	Vermont

Great care must be exercised in comparing estimates of DSM potential for a wide variety of reasons, including: weather zone, assumptions about avoided costs and cost-effectiveness, nature of the customer base, assumptions about the aggressiveness of utility programs, time frame of the analysis, definition of metrics, and other factors. Figure 3-32 provides the potential estimates from these other studies and compares them to the estimates for Gainesville (in italics).

[20] ICF did not include any of its own DSM potential studies so that the sample would not be skewed.

Figure 3-32
DRAFT Comparison of DSM Potential Studies (% of Class Peak MW that can be saved with DSM over time)

	Technical Potential	Economic Potential	Achievable Potential	
			Aggressive Assumptions	Typical Assumptions
Residential Sector	21%-36%	18%-26%	11%-35%	2%-7.9%
Max DSM Scenario for Gainesville	***37%***	***21%***	***18%***	
Commercial Sector	18%-41%	13%-35%	6.3%-36%	3.6%-9%
Max DSM Scenario for Gainesville	***25%***	***15%***	***12%***	

Despite the limitations associated with comparing studies for different regions and with different assumptions, it appears that the estimates of Achievable Potential for GRU (18% of residential and 12% of commercial peak demand over 20 years) are within the range of reasonableness, but tending towards the upper end of that range, especially in the residential sector.

Review of Actual Spending

GRU's 2005 and planned 2006 DSM impacts and expenditures prior to the implementation of any potential additional programs are set forth in Figures 3-33 through 3-35. Figure 3-36 sets forth the annual DSM expenditures and customer counts for a range of other states and utilities active in DSM. The spending in these states ranges between $7.17 and $47.89 per customer per year. Progress Energy Florida and FPL are spending approximately $41.66 and $31.74 respectively.

In comparison, GRU currently spends $21.75/customer/year on DSM (Note: Figure under review), and the potential new programs increase over nine years to $59.48/customer/year combining for a very aggressive (and perhaps unequaled) $81.23/customer/year.

Of special interest is the comparison to Austin Energy (AE), which is widely recognized as a leader in DSM and is spending approximately $64.50/customer/year on its programs. While AE is approximately four times the size of GRU and its programs are not all directly comparable, and although there are significant differences between the service territories, it is interesting to note that implementing the potential programs above would require a similar per customer expenditure.

Further, AE historically reduces peak demand by 35-40 MW a year with mature programs. The potential GRU programs above reduce demand by approximately 6 MW/year when mature. Given GRU's relative size, it seems appropriate to conclude (based both on expenditure levels and MW reduction) that in order to successfully implement the potential programs GRU will need to develop DSM delivery capabilities (and a local DSM infrastructure) on par with that of AE's, though on a smaller scale.

In summary, while the estimates of potential DSM program impacts appear reasonable, the new programs would require:

1. Significant additional research and analysis to develop complete program designs, qualifying equipment, and processes, along with integration with GRU's existing programs
2. Significant investment in GRU's own DSM delivery capabilities, to include software tools, personnel, and specialized expertise
3. A ramp-up time of several years to develop the local DSM infrastructure and other support systems, and
4. Strong support from the Commission, the University, and the community at large to help overcome local market barriers

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Figure 3-33
GRU DSM Program Budget 2005 (DRAFT)

	Sector	Program	Incentives paid to customers	Marketing & Advertising	GRU Admin. Costs	Other Costs	Total Costs	# Participating Customers
Ongoing	Residential	Conservation Surveys	N/A			(4)		2,271
		Self-Audit Materials	N/A					N/A
		New Construction Consultation	Comb. w/ existing					N/A
		Green Builder Program	$ -	$ 6,504				0
		Customer Consultation (1)	$ 17,800		$ 452,917		$ 1,004,861	89
		Low-Income Weatherization	$ 1,750					7
		Solar Water Heating Rebates	$ 1,410					4
		Solar Electric Interconnection and Buyback	$ 0			(5)		2
		Gas Water Heating Rebate	$ 5,800					29
		Gas Heating Rebate	$ 3,300	$ 40,447	$ 230,888		$ 559,085	11
		Gas Dryer Rebate	$ 600					12
		Gas New Construction Rebate	$ 278,050					775
		Customer Information	N/A	(2)	(3)		(6)	
	Commercial	Conservation Surveys	N/A					191
		Commercial Lighting Service	N/A		$ 30,236			161
		Solar Water Heating Rebates	$ -					0
		Solar Electric Interconnection and Buyback	$ 117					4
		Gas Air-Conditioning Rebate	$ -	$ 174,482		$ 215,868		0
		Gas Dehumindification Rebate	$ -					0
		Gas Water Heating Rebate	$ -					0
		Infra-red Scanning Service	N/A		$ 3,140			10
		Business Partners Workshops	$ 2,000					52
		Customer Information	N/A					N/A
New		Higher Efficiency Central A/C Rebate	$ 26,945	(7)		(8)		109
		Higher Efficiency Room A/C Rebate	$ 300					3
		Central A/C Maintenance Rebate	$ 28,490					518
		Heat Recovery Unit Rebate	$ 155					1
		Heat Pipe Enhanced A/C Rebate	$ 285					3
		Reflective Roof Coating Rebate	$ 140					2
		Duct Leakage Repair Pilot Program	$ 42,322					99
	TOTAL		$ 409,464	$ 221,433	$ 717,181	$ 215,868	$ 1,563,940	4,353

Notes:
(1) $17,800 Retail Equivalent
(2) $40,447 Residential and Commercial Natural Gas Advertising and Marketing
(3) $230,888 Natural Gas Marketing O & M
(4) $452,917 Commercial Conservation Services O & M
(5) $1,004,861 GRU does not have activity based costing so this number is a total conservation services number.
(6) $559,085 This is the total Gas Marketing number.
(7) $174,482 Electric Conservation Advertising and Marketing
(8) $215,868 1/2 of Large Account Marketing O & M
NB: Investigating whether these cost are already, or should be modified to be, inclusive of Indirect Overheads

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Figure 3-34
GRU DSM Program Budget 2006 (DRAFT)

	Sector	Program	Incentives paid to customers	Marketing & Advertising	GRU Admin. Costs	Other Costs	Total Costs	# Participating Customers
Current	Residential	Conservation Surveys	N/A			(4)		2,385
		Self-Audit Materials	N/A					N/A
		New Construction Consultation	Combined w/ existing					N/A
		Green Builder Program	N/A	$ 5,000	$ 594,382		$ 1,225,066	0
		Customer Consultation (1)	$ 18,000					90
		Low-Income Weatherization	$ 6,000					24
		Solar Water Heating Rebates	$ 3,500					10
		Solar Electric Interconnection and Buyback	$ -			(5)		2
		Gas Water Heating Rebate	$ 14,000					70
		Gas Heating Rebate	$ 12,000	$ 41,523	$ 242,694		$ 635,717	40
		Gas Dryer Rebate	$ 500					10
		Gas New Construction Rebate	$ 300,000					857
		Customer Information	N/A	(2)	(3)		(6)	N/A
	Commercial	Conservation Surveys	N/A					210
		Commercial Lighting Service	N/A		$ 38,237			170
		Solar Water Heating Rebates	$ -					0
		Solar Electric Interconnection and Buyback	$ 33					4
		Gas Air-Conditioning Rebate	$ 5,000	$ 201,690		$ 249,836		2
		Gas Dehumindification Rebate	$ 5,000					2
		Gas Water Heating Rebate	$ 15,000					30
		Infra-red Scanning Service	N/A		$ 4,600			11
		Business Partners Workshops	$ 2,000					60
		Customer Information	N/A					N/A
Planned		High Efficiency Central A/C Rebate 13 SEER	$ 16,250	(7)		(8)		65
		High Efficiency Central A/C Rebate 15-16 SEER	$ 4,375					35
		High Efficiency Central A/C Rebate 17 SEER	$ 3,150					15
		High Efficiency Central A/C Rebate 18> SEER	$ 3,250					10
		Higher Efficiency Room A/C Rebate	$ 1,500					10
		Central A/C Maintenance Rebate	$ 38,500					700
		Heat Recovery Unit Rebate	$ 465					3
		Heat Pipe Enhanced A/C Rebate	$ 475					5
		Reflective Roof Coating Rebate	$ 3,500					50
		Duct Leakage Repair Pilot Program	$ 6,800					34
	TOTAL		$ 459,298	$ 248,213	$ 879,913	$ 249,836	$ 1,860,783	4,904

Notes:
(1) $18,000 Retail Equivalent
(2) $41,523 Residential and Commercial Natural Gas Advertising and Marketing
(3) $242,694 Natural Gas Marketing O & M
(4) $594,382 Commercial Conservation Services O & M
(5) $1,225,066 GRU does not have activity based costing so this number is a total conservation services number.
(6) $635,717 This is the total Gas Marketing number.
(7) $201,690 Electric Conservation Advertising and Marketing
(8) $249,836 1/2 of Large Account Marketing O & M
NB: Investigating whether these cost are already, or should be modified to be, inclusive of Indirect Overheads

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Figure 3-35
GRU DSM Program Peak kW Impact (DRAFT)

	Residential Programs																		Commercial Programs												
Year	Walk-thru Audit	Action Check	Gas Water Heat	Gas Space Heat	Gas New Construction	Florida Fix	Low-Income Gas Ext.	Gas Cooling Rebate	HRU Rebate	Duct Leak Pilot	Solar Water Heat	Low-Income Cinsult	Central AC Rebate	Room AC Rebate	Duct Repair Rebate	Heat Pipe Rebate	Reflect Roof Coat Rebate	AC Maint Rebate	Walk thru Audit	Detailed Audit	CLS Audit	CLS Contract	Perf. Pmt Incentive	Gas WH Rebate	Gas Cooling Rebate	Thermal Storage Rebate	HRU Rebate	Window Shade Rebate	New Bldg BERS	PV Demo Project	TOTAL
1996	5	80	40	0	209	5	0	0	0	0	0	0	0	0	0	0	0	0	136	27	22	28	0	0	0	0	0	0	0	3	**555**
1997	3	60	41	0	252	15	0	0	0	0	4	0	0	0	0	0	0	0	70	3	19	21	0	0	0	0	0	0	0	0	**489**
1998	0	53	32	0	247	13	0	0	0	0	4	0	0	0	0	0	0	0	72	0	22	32	0	0	0	0	0	0	0	0	**475**
1999	7	51	28	0	300	0	0	0	0	0	0	0	0	0	0	0	0	0	69	0	21	37	0	0	0	0	0	0	0	0	**514**
2000	3	63	20	0	267	9	0	0	0	0	1	0	0	0	0	0	0	0	155	0	33	46	0	2	0	0	0	0	0	0	**599**
2001	0	58	21	0	271	10	0	0	0	0	4	0	0	0	0	0	0	0	119	0	20	28	0	0	0	0	0	0	0	0	**531**
2002	0	36	16	0	314	9	0	0	0	0	6	0	0	0	0	0	0	0	104	0	21	29	0	0	0	0	0	0	0	0	**535**
2003	0	58	16	0	266	12	0	0	0	0	3	0	0	0	0	0	0	0	104	0	18	26	0	0	0	0	0	0	0	0	**502**
2004	0	66	6	0	194	15	0	0	0	0	4	0	0	0	0	0	0	0	139	0	12	17	0	0	0	0	0	0	0	1	**454**
2005	0	68	5	0	160	11	0	0	4	25	4	0	100	6	0	1	3	10	137	0	19	29	0	1	0	0	3	0	0	0	**586**
2006	0	72	5	0	160	11	0	0	4	0	4	0	100	12	13	1	5	15	137	0	19	29	5	1	0	0	3	0	0	0	**595**
2007	0	76	5	0	160	11	0	0	4	0	4	0	100	18	13	1	5	15	137	0	19	29	5	1	0	0	3	0	0	0	**605**
2008	0	80	5	0	160	11	0	0	4	0	4	0	100	18	13	1	5	15	137	0	19	29	5	1	0	0	3	0	0	0	**609**
2009	0	84	5	0	160	11	0	0	4	0	4	0	100	18	13	1	5	15	137	0	19	29	5	1	0	0	3	0	0	0	**613**
2010	0	88	5	0	160	11	0	0	4	0	4	0	100	18	13	1	5	15	137	0	19	29	5	1	0	0	3	0	0	0	**617**
2011	0	92	5	0	160	11	0	0	4	0	4	0	100	18	13	1	5	15	137	0	19	29	5	1	0	0	3	0	0	0	**621**
2012	0	92	5	0	160	11	0	0	4	0	4	0	100	18	13	1	5	15	137	0	19	29	5	1	0	0	3	0	0	0	**621**
2013	0	92	5	0	160	11	0	0	0	0	4	0	0	0	0	0	0	0	137	0	19	29	0	1	0	0	0	0	0	0	**458**
2014	0	92	5	0	160	11	0	0	0	0	4	0	0	0	0	0	0	0	137	0	19	29	0	1	0	0	0	0	0	0	**458**
2015	0	92	5	0	160	11	0	0	0	0	4	0	0	0	0	0	0	0	137	0	19	29	0	1	0	0	0	0	0	0	**458**
2016	0	92	5	0	160	11	0	0	0	0	4	0	0	0	0	0	0	0	137	0	19	29	0	1	0	0	0	0	0	0	**458**
2017	0	92	5	0	160	11	0	0	0	0	4	0	0	0	0	0	0	0	137	0	19	29	0	1	0	0	0	0	0	0	**458**
2018	0	92	5	0	160	11	0	0	0	0	4	0	0	0	0	0	0	0	137	0	19	29	0	1	0	0	0	0	0	0	**458**
2019	0	92	5	0	160	11	0	0	0	0	4	0	0	0	0	0	0	0	137	0	19	29	0	1	0	0	0	0	0	0	**458**
2020	0	92	5	0	160	11	0	0	0	0	4	0	0	0	0	0	0	0	137	0	19	29	0	1	0	0	0	0	0	0	**458**
2021	0	92	5	0	160	11	0	0	0	0	4	0	0	0	0	0	0	0	137	0	19	29	0	1	0	0	0	0	0	0	**458**
2022	0	92	5	0	160	11	0	0	0	0	4	0	0	0	0	0	0	0	137	0	19	29	0	1	0	0	0	0	0	0	**458**
2023	0	92	5	0	160	11	0	0	0	0	4	0	0	0	0	0	0	0	137	0	19	29	0	1	0	0	0	0	0	0	**458**
2024	0	92	5	0	160	11	0	0	0	0	4	0	0	0	0	0	0	0	137	0	19	29	0	1	0	0	0	0	0	0	**458**

Figure 3-36
Comparison of Maximum DSM Scenario Spending with Other Utilities.

Location	Customers	DSM Expenditure	$/Customer
TX	10,300,000	$ 73,900,000	$ 7.17
OR	1,700,000	$ 22,500,000	$ 13.24
ME	790,000	$ 13,600,000	$ 17.22
NY	8,200,000	$ 150,000,000	$ 18.29
CA	10,600,000	$ 230,000,000	$ 21.70
WI	2,700,000	$ 62,300,000	$ 23.07
NH	660,000	$ 20,200,000	$ 30.61
RI	470,000	$ 15,200,000	$ 32.34
CT	1,600,000	$ 61,100,000	$ 38.19
VT	330,000	$ 13,200,000	$ 40.00
MA	2,900,000	$ 135,100,000	$ 46.59
NJ	3,700,000	$ 177,200,000	$ 47.89
Average			**$ 28.03**
Florida Regulated Utilities (2003$)			
FPL	4,120,000	$ 151,354,540	$ 36.74
Gulf	394,772	$ 6,710,375	$ 17.00
Progress	1,511,000	$ 62,943,509	$ 41.66
TECO	620,000	$ 17,253,491	$ 27.83
FPUC	92,000	$ 392,653	$ 4.27
City of Austin	359,526	$ 23,190,000	$ 64.50
GRU CURRENT*	85,559	1,860,783	$ 21.75
GRU POTENTIAL (Yr. 9)	85,559	5,088,922	$ 59.48
GRU TOTAL	**85,559**	**6,949,705**	**$ 81.23**

* Estimates of current GRU spend on DSM and allocations under review

CHAPTER FOUR
GENERATION OPTIONS AND FINANCING COSTS

INTRODUCTION

This chapter discusses the generation options analyzed in this study for GRU and for other utilities in the region. As discussed in Chapter One, ICF considered a range of solid fuel, natural gas, and renewables before settling, after consultation with and direction from the City of Gainesville on three generation options plus a scenario involving maximum DSM[21] only.

One of the distinguishing characteristics of Gainesville's generation situation relates to renewables. Unlike several other areas in the U.S., Florida's local wind resources are not attractive for generation even with federal subsidies. This is significant since approximately half of all capacity additions this year in the U.S. are wind power (measured at maximum output)[22]. Also, solar conditions are not as attractive as the most attractive areas of the country such as the U.S. desert southwest. This combined with the high costs of central solar thermal stations makes solar very costly[23]. However, the Gainesville area has significant potential biomass which is considered a zero CO_2 emission source and for which there are some limited federal subsidies. At this time, GRU has no biomass generation capability. All generation options considered in this study have biomass capability to some degree. If chosen, these supply options would help clarify biomass supply uncertainties as discussed in the next chapter.

OPTIONS CHOSEN

The generation options chosen to be examined in this study were:

- **Generation Option #1 - Solid Fuel CFB** – We examined the GRU proposed 220 MW CFB plant with the capability to use coal, petroleum coke and a limited amount of biomass (30 MW). This option was specified in the GRU IRP. CFB tends to be modestly more expensive per kilowatt compared to the dominant coal power plant technology, pulverized coal, but has greater fuel sourcing flexibility. The plant is highly controlled for all major emissions except CO_2 for which practical controls do not exist. CFB technology is newer than pulverized coal technology which is the technology used at Deerhaven 2 and nearly all U.S. coal-fired power plants. Jacksonville, Florida has a CFB plant burning Central Appalachian coal. The Jacksonville plant has had some technical issues but overall

[21] GRU can supplement these options in the model with a peaking combustion turbine option and the ability to buy and sell wholesale power on a spot basis.
[22] Actual reserve margin contribution is a fraction of rated maximum output, typically 5 to 30 percent.
[23] The capital costs in Florida may also be affected by the need to withstand hurricane conditions.

has performed adequately. CFB technology has improved over time and other utilities in the country near the U.S. Gulf are choosing this technology because of the ability to access low cost petroleum coke produced by oil refineries. We also conducted scoping level assessments of alternative CFB sizes. There also was some scoping level examination of the consequences of using greater amounts of biomass than 30 MW. Increasing use of biomass above 30 MW is technically feasible, but has economic consequences.

- **Generation Option #2 - Solid Fuel IGCC** – We examined a 220 MW IGCC power plant. The 220 MW size was chosen to be comparable to the CFB and because smaller size plants exhibit very large diseconomies of scale compared to other solid fuel technologies. IGCC is a very new technology, and hence, has greater risk and technical requirements. A clear plan on how to handle these risks will be necessary as early as the start of the project's financing. Accordingly, a significant focused commitment to this type of project is required and careful consideration should be given to the staffing, financing, management, and decision making issues involved (e.g., the need to potentially make decisions about unexpected events such as supplemental investments, staff costs, etc.), as well as the utility's other commitments.

  Only one U.S. utility plant is operating with IGCC technology in part because this technology became available during the period when nearly all new U.S. plants were natural gas-fired. In addition to the Florida utility IGCC, the Delaware City IGCC uses petroleum coke to primarily supply power to an industrial sector plant. There are international IGCC plants in Japan, Spain, and the Netherlands. Several U.S. utilities are planning to add IGCC both in Florida and in the Midwest, though none have yet broken ground. In the past, large federal subsidies were provided to IGCCs. Current programs offer potential loan guarantees, but no large direct subsidies. While ICF assumes no subsidies, it did not raise the financing costs for IGCC on the assumption that loan guarantees would be forthcoming for a part of the debt issuance.

  The advantages of IGCC technology include:

  - IGCC has the lowest emissions of SO_2, NO_x, Hg, and particulates of any coal or solid fuel technology. This is because the synthetic gas must be cleaned on-site in order to burn it in the plant's combined cycle. It should be noted that the extent of the emission decreases relative to other new plants is limited since no new plant can be built without substantial controls on SO_2, NO_x, and Hg emissions. At the same time, this is an issue to be evaluated by the City.

- IGCC has higher thermal efficiency than other coal plants on the order of ten percent. This decreases CO_2 emissions per MWh and lowers fuel costs.

- IGCC is fuel flexible compared to pulverized coal plants. It is expected that biomass and petroleum coke can be used although the experience with petroleum coke is far greater than for biomass and very large use of biomass could affect design and costs.

- IGCC has the potential to capture CO_2 which could then be sequestered. Other coal plant technologies do not offer this potential. CO_2 capture is not being done anywhere at this time and Florida is a poor candidate relative to other states to find underground conditions suitable for receiving and storing CO_2. Even so, Gainesville could contribute to the advancement of this new solid fuel technology.

- **Generation Option #3 - Biomass Only 75 MW Plant** – All of the generation options examined in detail have some biomass capability. However, we also examined a 75 MW CFB that uses only biomass, though as a technical matter, it would be designed to use other solid fuels as well. If this plant were switched to a blend of pet coke and coal, its output and thermal efficiency could be increased if some flexibility is built into the plant, (e.g., an oversized generator). It may be possible to raise the output of this plant close to approximately 90 to 100 MW on coal or petroleum coke. This was a contributing factor to choosing the size to be examined in this option. 90 to 100 MW is approximately intermediate in size compared to the GRU IRP 220 MW option. This smaller size has a cost if in the end the same amount of capacity is needed, i.e., more similar plants are built at a later date. On a per kW basis, a 75 MW CFB is about 8 percent more expensive than a 220 MW CFB. This could raise the costs of having 220 MW of CFB approximately by $35 million[24]. Many other biomass plants use stoker technology. These plants can have lower thermal efficiencies, and higher emissions and less flexibility to efficiently use higher Btu solid fuels like petroleum coke and coal. This is discussed later.

OTHER GENERATION OPTIONS

In addition, several other generation options were considered beyond those selected including:

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[24] 220/75 times 172 million for a brownfield CFB equals $505 million. A 220 MW plant is $470 million. If both need to be designed for 100% biomass use without performance degradation, this cost increase due to diseconomies of scale could be slightly higher.

- **Other Generation Option #1 - Solid Fuel Super Critical Pulverized Coal (SCPC)** – We examined an SCPC option. After reviewing several SCPC size ranges, we focused on a 800 MW plant. SCPC was examined in part to compare across solid fuel technologies to ensure cost and performance consistency. Since few solid fuel plants have been added in the U.S. in recent years, this is especially useful[25]. The specification of an SCPC is also for use in the modeling exercise. Other utilities are forecast by the model to add capacity under the different scenarios and these utilities can consider very large coal plants such as IGCC and SCPC. We also wanted to provide some perspective on the option to jointly own a larger coal plant of this type since this is likely to be an option in the jointly owned arena.

- **Other Generation Option #2 - Natural Gas Combined Cycle** – ICF examined a combined cycle, and in what ICF considers a close call made by the City Commission on February 2, 2005, the decision was not to include it in the final set, but rather include the 75 MW biomass with maximum DSM option. Even though the natural gas fired combined cycle was not one of the four options chosen, it is an option that is available to other utilities in the modeling exercise. This plant is also a component of the IGCC and provides comparability across this technology and IGCC. This is useful in light of uncertainties on the cost of IGCC including the potential need for extra set asides for contingencies beyond those included in our estimates or greater operational guarantees from manufacturers which effectively raises costs.

- **Other Generation Option #3 - Natural Gas Peaking Combustion Turbine** – This is an option available to GRU and other utilities in the modeling exercise. In the case of GRU, combustion turbines may be needed in the later years of the study to ensure that GRU meets its reserve requirements. Peaking combustion turbines compete with power imports in this regard.

- **Other Generation Option #4 - Nuclear** – This is an option available to other utilities, albeit at a later date than for other generation options.

- **Other Generation Option #4 - Solar Thermal** – This was an option that was considered but found to not be economic or proven enough in Florida to be a major option for GRU. Solar thermal central station plants exist in the desert southwest and/or have been recently announced[26].

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[25] Only approximately five coal plants are under construction in the U.S. Over the last fifteen years almost none have been added.
[26] A 30-50 MW solar thermal power plant in Nevada is being contracted for at this time.

ICF relies on a number of sources for its estimates including confidential discussions with developers, manufacturers and utilities. Since so few plants are under construction, there are no public databases of actual plants which can be used to document these estimates. Furthermore, available public estimates are difficult to use since the data is often limited (e.g., what is included, what fuel and pollution controls are assumed, design and site differences).

CAPITAL COSTS – SOLID FUEL AND NATURAL GAS POWER PLANTS

ICF estimates the capital costs in 2003$ of the key options for GRU to be approximately[27]:

- 220 MW CFB – $470 million
- 220 MW IGCC – $445 million
- 75 MW CFB – $170 million

These estimates assume that the plant is on a site with an existing unit or units and is referred to in this regard as a brownfield plant. Plants at new sites are referred to as a Greenfield plant. These estimates are an attempt to estimate total costs including interest during construction, transmission hook-up costs, fuel, generation, and pollution control equipment, installation, construction, testing, financing charges, etc. General inflation can have a noticeable effect on these costs. At 2.25 percent general inflation, 2012 costs would be 22 percent higher.

As a point of comparison, a 220 MW share of a jointly-owned brownfield 800 MW SCPC plant would cost approximately $300 million or $145 to $170 million less before added transmission costs. ICF believes extra transmission costs beyond those included in the $300 million could be significant if the purchase is greater than 100-150 MW. Furthermore, siting new lines could be a challenge.

ICF also estimates that a 220 MW natural gas combined cycle would cost approximately $115 million. Thus, solid fuel options have higher capital cost in dollars per kilowatt compared to those of natural gas power plants by factors of approximately four. As noted, there is some added uncertainty on the capital costs for the solid fuel plants since few such power plants have been built in the U.S. in recent years. Furthermore, the demand for these plants appears poised to increase significantly and could raise capital costs as buyers compete for scarce resources. The higher capital costs apply to all three solid fuel technologies including CFB, IGCC, and the supercritical pulverized coal (SCPC) plant.

[27] ICF believes that actual costs are plus or minus 5 to 10 percent and of the estimates provided, the level of precision is not commensurate with the number of significant digits shown, but the estimates are shown at 3 to 4 significant digits to facilitate comparison.

Capital costs are only one component of costs. The solid fuel plants are still potentially attractive because they also have lower fuel costs or fuel options with lower price volatility. Fuel costs are discussed in the next chapter.

There are significant economies of scale involved in generation in terms of $/kW capital costs both with respect to the size of the plant and the presence of pre-existing generation units on the site. The economies of scale are the largest for the IGCC and CFB options compared to the SCPC. The economies of scale are especially large for the IGCC as its size is increased from 75 MW to 220 MW. This is associated with sizing the plant closer to the industry standard which is based on the Frame 7 combustion turbine component of the plant.

Lastly, the capital costs among solid fuels can be expected to vary as the share of biomass increases. This is driven primarily by the lower energy density of biomass fuels.

Figure 4-1
Comparison of Selected Power Station Technologies (2003$/kW) – GRU[3]

Size (MW)	SCPC		CFB		IGCC		CFB (100% Biomass)		NGCC	
	GF[1]	BF[2]	GF[1]	BF[2]	GF[1]	BF[2]	GF[1]	BF[2]	GF[1]	BF[2]
800	1,503	1,353	1,568	1,411	1,698	1,529	1,716	1,545	426	383
500	1,747	1,572	1,822	1,640	1,974	1,777	1,960	1,764	470	423
220	1,991	1,792	2,372	2,135	2,250	2,025	2,548	2,293	588	529
75	2,072	1,865	2,555	2,300	3,538	3,184	2,745	2,470	925	832

[1]GF = Greenfield
[2]BF = brownfield
[3]Project contingency fees are included in costs. They are 6, 8, 10, and 20% for NGCC, CFB, SCPC, and IGCC, respectively.

Figure 4-2
Comparison of Selected Power Station Technologies (2003$ million) - GRU

Size (MW)	SCPC		CFB		IGCC		CFB (100% Biomass)		NGCC	
	GF[1]	BF[2]	GF[1]	BF[2]	GF[1]	BF[2]	GF[1]	BF[2]	GF[1]	BF[2]
800	1,202	1,082	1,254	1,129	1,359	1,223	1,373	1,236	340	306
500	874	786	911	820	987	888	980	882	235	211
220	438	394	522	470	495	445	561	505	129	116
75	155	140	192	172	265	239	206	185	69	62

[1]GF = Greenfield
[2]BF = brownfield

The costs for similar plants for other utilities are higher due to higher financing costs relative to GRU.

Figure 4-3
Comparison of Selected Power Station Technologies – Utilities Other Than GRU[3] (2003$)

Size (MW)	SCPC ($/kW)		CFB ($/kW)		IGCC ($/kW)		CFB (100% Biomass) ($/kW)		NGCC ($/kW)	
	GF[1]	BF[2]	GF[1]	BF[2]	GF[1]	BF[2]	GF[1]	BF[2]	GF[1]	BF[2]
800	1,632	1,469	1,702	1,532	1,844	1,660	1,864	1,677	432	391
500	1,897	1,707	1,978	1,781	2,144	1,929	2,129	1,916	480	432
220	2,162	1,946	2,575	2,318	2,443	2,199	2,767	2,490	601	541
75	2,250	2,025	2,774	2,497	3,842	3,458	2,981	2,682	945	850

[1]GF = Greenfield
[2]BF = Brownfield
[3]Other utilities have higher interest during construction costs.

SCPC OPTION

As noted, the least costly solid fuel option on a $/kW basis would be at a large, 800 MW super critical pulverized coal plant. This plant type also has modestly more cost data available relative to other options. ICF estimates that such a plant would cost $1,632/kW[28] for a greenfield plant, and $1,469/kW for a brownfield site with a pre-existing plant. This estimate is for utilities other than GRU; the difference is higher interest during construction for non-municipal utilities.

This would only be feasible for Gainesville if it were jointly owned with other companies. This option has $25/kW for electricity transmission which may not be enough depending on where a jointly owned plant was located. This option was not considered among the four Gainesville options. This reflected several reasons including the difficulty in using biomass at such a plant, and to a lesser extent, petroleum coke, and the City's desire to have a plant locally sited and well suited to its load. If the City rejects the three solid fuel options, it should be aware that jointly owned solid fuel plant options are expected to be available to the City.

CFB OPTION

ICF estimates that the 220 MW GRU CFB plant would cost $2,318/kW versus $1,469/kW for the 800 MW SCPC. This increase in per kilowatt cost is mostly due to the plant's smaller size and to lesser extent due to the use of a different technology. Note, however, the CFB plant is very flexible in its fuel use options and is designed to use up to 13.6 percent biomass without need for major upgrades or derating of plant performance.

ICF estimates that the 220 MW CFB's capital investment costs would increase by approximately $35 million if it were adapted to 100 percent biomass use. Conversely, the plant's performance could be allowed to deteriorate in exchange for the advantages

[28] 2003 dollars unless otherwise noted.

of higher biomass use (see Figure 4-___). The challenges with biomass derives from several factors notably the lower energy density due to higher water content of wet biomass, fuel quality variability, the impacts of biomass transportation on surrounding areas. and deterioration of stored biomass material over time which lowers its heat content. Since biomass can be expected to be 30 to 50 percent water, its energy density is less by 50 to 60 percent than other solid fuels:

- **Wet Biomass** – 12 MMBtu/ton
- **Central Appalachian Coal** – 24 - 25 MMBtu/ton
- **Petroleum Coke** – 28 MMBtu/ton

This requires a larger facility including a larger boiler to handle the biomass at very high levels of total fuel input.

Figure 4-4
Effects on 220 MW CFB of 100% Biomass

Parameter	Value
Capital Cost for Retrofits	$20 million
Capacity Penalty	30%
Heat Rate Penalty	+3,500 Btu/kWh[1]

[1] 10,500 Btu/kWh to 14,000 Btu/kWh

IGCC OPTION

A third solid fuel option is the Integrated Gasification Combined Cycle (IGCC). At large sizes (i.e., 800 MW), this plant has the highest capital costs per kilowatt of the three solid fuel options. However, it scales down well to the 220 MW level since that is close to the size of a Frame 7 combined cycle[29]. The IGCC's capital costs only rise 32 percent on a per kilowatt basis versus 51 percent for a CFB or a SCPC. However, at sizes smaller than 220 MW, the cost per kilowatt escalates most rapidly for an IGCC since the smaller combustion turbines are more costly per kilowatt. Specifically, at 75 MW, LM6000 turbines are assumed to be used and cost escalation of a per kilowatt basis from 220 MW to 75 MW is 57 percent versus 8 percent for CFB, and 4 percent for SCPC.

As noted, the IGCC is the most recent solid fuel technology. The coal is gasified; the resulting gas is treated and is then burned in a gas-fired combined cycle power plant. Only one U.S. utility plant is operating an IGCC and it is located in Florida at the Polk power plant near Tampa. The Orlando utility has agreed to build such a plant with Southern Company, one of the largest power companies in the country. Others are actively considering this option.

[29] 1 x 1 configuration will actually have a size closer to 250-265 MW.

FINANCING COSTS OVERVIEW

As a municipal utility the financing costs of the options supply and demand are expected to be lower than for other entities due to the lack of income tax and the ability to issue fax free municipal bonds. ICF also accepts GRU's position it will be able to achieve 80 percent leverage which is higher than for most investor owned utilities.

Figure 4-5
Financing Assumptions

Parameter	GRU[1]	Other Market Participants[2]
Debt Share	80	50
Equity Share	20	50
Total	100%	100%
Debt Rate (%)	4.48%[4]	9.25%[5]
Equity Rate (%)	9%[3]	11%[6]
Income Tax Rate	0	38.6%

[1]GRU builds limited to specified options. Recovery of and on capital may be available to City of Gainesville.
[2]Assumes all new options are built as regulated rate base power plants.
[3]Customer Discount Rate; Source: GRU IRP (2003)
[4]Tax-Exempt Interest Rate; Source: GRU IRP (2003)
[5]Taxable Debt Interest Rate; Source: GRU IRP (2003)
[6]IOU Return on Equity; Source: GRU IRP (2003)

Figure 4-6
Key FRCC New Unit Financing Cost Assumptions

	GRU	Other Market Participants
Financing Costs		
Debt/Equity Ratio (%)[1]	80/20	50/50
Debt Rate (%)[1]	4.48	9.25
After Tax Return on Equity (%)[1]	9.0	11.0
Income Taxes (%)	0	38. 6
Other Taxes (%)[2]	0.3	1.04
General Inflation Rate (%)[3]	2.25	2.25
Levelized Real Capital Charge Rate (%)		
Base-Load Plants	5.5	10.4
Intermediate/Peaking Plants	5.8	10.7

[1]Assuming 2.25 percent inflation
[2]Includes property taxes as well as insurance costs of 0.3% for all the sub-regions.
[3]Levelized capital charge rate estimates the charges including recovery of and on capital, taxes, and levelizes these charges across the lifetime of the project. The modeling uses a real capital charge rate to be consistent with all other values which are all real.

OTHER COST AND PERFORMANCE PARAMETERS AND LEVELIZED COSTS

Additional generation cost and performance assumptions are presented below.

Figure 4-7
Key New Power Plant Fixed Cost Assumptions

Fixed O&M (2003$/kW)[1]	
CC[2]	15.4/29.2
Cogen / CT / LM6000	27.0/6.3/10.8
Coal[3]	36.6
IGCC[4]	52.4
Nuclear	100.0

[1]Fixed O&M for CT includes only labor, owner/operator G&A, and operator fees. For coal and cogen we have included major maintenance costs in fixed O&M due its base load mode of operation.
[2] We allow CCs to cycle on/off or to operate as base load with minimum levels available at off peak times. When in base load we include LTSA fees in fixed and track LTSA fees in variable production costs when cycling on/off.
[3] Reflects a supercritical boiler burning bituminous coal with wet scrubbing for sulfur removal, and SCR.
[4] Reflects IGCC units burning bituminous coal. IGCC are run only baseloaded and thus LTSA fees are considered as a fixed cost

Figure 4-8
Key Plant Performance Assumptions

Parameter	Treatment -- Base Case				
New Power Plant Builds	Combined Cycle	Combustion Turbine	SCPC	IGCC	FBC
Heat Rate[1] (Btu/kWh)					
2000-2004[6]	7,100	10,825	N/A	N/A	N/A
2005	7,100	10,778	N/A	N/A	N/A
2010[5]	6,800	10,547	9,312	N/A	9,950
2015	6,672	10,321	9,110	8,602	9,950
2020	6,553	10,101	9,670	7,908	9,950
Variable O&M[2,3,4,7] (2003$/MWh)	2.8	7.5	3.0	2.0	2.61
Minimum Turndown (%)	50	0	50	50	50
Availability (%)	92.0	92.0	90.0	90.0	90.0

[1] ISO, HHV, degraded, full load.
[2] Values specified correspond to an 83 percent, 5 percent, and 83 percent for combined cycles, combustion turbines and coal/IGCC respectively.
[3] Inversely correlated with capacity factor. This is due to two factors: (i) as dispatch moves from baseload to mid-merit, the number of starts increase; (ii) the cost per start is spread over less MWh in the mid-merit/cycling mode. Note, CC's VOM are for the 7FA machines.
[4] Simple and combined cycle unit O&M is assumed to increase over time as G/Fb and H type technology becomes available. G-tech machines are estimated to have an approximately 20 percent higher LTSA Fee.
[5] By 2010, G-technology is assumed commercially available. Improved efficiency results in approximately 3% lower heat rates over 7FA turbines, or approximately 6,800 Btu/kWh.
[6] To ensure dispatch consistency among the 7FA combined cycle fleet, all are modeled with a 7,100 heat rate.
[7] The VOM for coal reflects consumables and startup fuel. Consumables include water, limestone, ammonia, chemicals, and ash removable.

Figure 4-9
Key Plant Performance Assumptions

Parameter	Treatment Base Case		
Existing Power Plant Constraints (%)	Availability		Minimum Turndown (%)
Coal Steam	84 – 88		40
Oil/Gas Steam	76 – 85		25
Combined Cycle	92		50
Variable O&M (2003$/MWh) Range[1]	CC	CT	O/G Steam
	2.5 – 8.7	2.2 – 9.0	0.7 – 3.2

[1] Inversely correlated with capacity factor. This is due to two factors: (i) as dispatch moves from baseload to mid-merit, the number of starts increase; (ii) the cost per start is spread over less MWh in the mid-merit/cycling mode. Note, CC's VOM are for the 7FA machines and represent CC units in turndown mode of operation.

LEVELIZED ICF COST ESTIMATES

ICF calculated levelized average costs for the options considered.

Figure 4-10
Average Generation Cost – 2010 – 2025 Average – Illustrative Summary of Impacts of Assumptions – IPM® Modeling Analysis Will be More Comprehensive – Base Case ($/MWh)

Unit	SCPC	NGCC	NGCC High Gas Case	CFB Co-Bio	CFB All Bio	IGCC Co-Bio	Solar Thermal	Nuclear
Year Built	2012	2012	2012	2012	2012	2012	2012	2012
Size (MW)	800	220	220	220	75	220	50	1000
Capital Charge Rate	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%
Capital Cost (2003$/kW)*	$1,353	$529	$529	$2,135	$2,470	$2,025	$3,740	$3,100
FO&M (2003$/kW-yr)	$36.60	$15.40	$15.40	$71.00	$76.00	$52.40	$50.00	$100.00
VO&M (2003$/MWh)	$2.99	$2.34	$2.34	$2.61	$2.61	$1.96	$0.00	$2.00
Heat Rate (Btu/kWh)	9312	6800	6800	10494	13860	8602	0	10000
Cap Factor	85%	85%	85%	85%	85%	85%	20%	90%
NOx % Reduction	94%	98%	98%	94%	98%	98%	0%	0%
SO2 % Reduction	95%	0%	0%	98%	95%	98%	0%	0%
Hg % Reduction	90%	0%	0%	95%	95%	95%	0%	0%
CO2 % Reduction	0%	0%	0%	0%	0%	0%	0%	0%
NOx Content of Fuel (lb/MMBtu)	1.00	1.00	1.00	1.00	1.00	1.00	0	0
SO2 Content of Fuel (lb/MMBtu)	5.45	0.00	0.00	5.57	0.08	5.57	0	0
Hg Content of Fuel (lb/Tbtu)	9.83	0.00	0.00	13.12	0.00	13.12	0	0
CO2 Content of Fuel (lb/MMBtu)	205.30	117.08	117.08	184.73	0.00	184.73	0	0
Average Fuel Price (2003$/MMBtu)	$1.91	$6.10	$11.34	$1.41	$1.67	$1.41	$0.00	$0.50
Fuel Expense (2003$/MWh)	$17.8	$41.5	$77.1	$14.8	$23.1	$12.1	$0.0	$5.0
Annual NOx Allowance Price (2003$/ton)	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500
Ozone Season NOx Allowance Price (2003$/ton)	$2,500	$2,500	$2,500	$2,500	$2,500	$2,500	$2,500	$2,500
Annual NOx Charge (2003$/MWh)	$0.42	$0.10	$0.10	$0.47	$0.21	$0.13	$0.00	$0.00
Ozone Season NOx Charge (2003$/MWh)	$0.29	$0.07	$0.07	$0.33	$0.15	$0.09	$0.00	$0.00
SO2 Allowance Price (2003$/ton)	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500
SO2 Charge ($/MWh)	$1.90	$0.00	$0.00	$0.88	$0.04	$0.72	$0.00	$0.00
Hg Allowance Price (2003$/lb)	$35,000	$35,000	$35,000	$35,000	$35,000	$35,000	$35,000	$35,000
Hg Charge ($/MWh)	$0.32	$0.00	$0.00	$0.24	$0.00	$0.20	$0.00	$0.00
CO2 Allowance Price (2003$/ton)**	$4.40	-$4.70	-$4.70	$4.40	$10.00	$3.70	$10.00	$10.00
CO2 Charge ($/MWh)	$4.21	-$1.87	-$1.87	$4.26	$0.00	$2.94	$0.00	$0.00
Fixed (2003$/kw-yr)	$111.02	$44.50	$44.50	$188.43	$211.85	$163.78	$255.70	$270.50
Fixed (2003$/MWh)	$14.91	$5.98	$5.98	$25.31	$28.45	$22.00	$145.95	$34.31
Variable (2003$/MWh)	$2.99	$2.34	$2.34	$2.61	$2.61	$1.96	$0.00	$2.00
Fuel Expense (2003$/MWh)	$17.80	$41.48	$77.11	$14.81	$23.10	$12.14	$0.00	$5.00
Emissions Expense (2003$/MWh)	$7.14	($1.70)	($1.70)	$6.18	$0.39	$4.07	$0.00	$0.00
Subtotal (2003$/MWh)	$42.84	$48.10	$83.73	$48.91	$54.56	$40.17	$145.95	$41.31
REPI ($/MWh)***	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$18.00	$0.00
Total (2003$/MWh)	$42.84	$48.10	$83.73	$48.91	$54.56	$40.17	$127.95	$41.31

Notes:
*Capital cost assuming brownfield construction for conventional units
**Allowance Allocation taken into account for SCPC, NGCC, CFB Co-Bio, and IGCC Co-Bio units
***REPI taken into account for biomass options in biomass supply curves

ICF COMPARED TO GRU IRP ASSUMPTIONS

Figure 4-11
Key New Power Plant Cost Assumptions[1]

Capacity Types	ICF	GRU[2]	EIA[3,4]
All-In Capital Cost – CC/Cogen (2003$/kW)			
2006	$626	$588	NA
2010	$601	$588	$558
2015	$571	$588	$558
2025	$517	$588	$558
All-In Capital Cost – CT (2003$/kW)			
2006	$393	$527	NA
2010	$377	$527	$374
2015	$359	$527	$374
2025	$325	$527	$374
All-In Capital Cost – CFB (2003$/kW)			
2006	NA	--	NA
2010	$2,135	$1,785	NA
2015	$2,082	$1,785	NA
2025	$1,980	$1,785	NA
All-In Capital Cost – SCPC (2003$/kW)			
2006	NA	NA	NA
2010	$1,503	NA	$1,213
2015	$1,466	NA	$1,213
2025	$1,394	NA	$1,213
All-In Capital Cost – IGCC (2003$/kW)			
2006	NA	NA	NA
2010	$2,025	$2,402	$1,402
2015	$1,954	$2,402	$1,402
2025	$1,820	$2,402	$1,402
All-In Capital Cost – Nuclear (2003$/kW)			
2006	NA	NA	NA
2010	N A	NA	NA
2015	$2,931	NA	$1,957
2025	$2,931	NA	$1,957

[1]All costs represent Greenfield costs except CFB and IGCC costs which represent brownfield.
[2]"Technology Reports for Resource Planning," prepared by Black & Veatch for Gainesville Regional Utilities, 12/2005.
[3]Energy Information Administration," Assumptions to the Annual Energy Outlook," 2005.
[4]EIA costs do not include owner's costs such as IDC, land fees, spare pars, etc.
Note: $/kW are summer kW. Summer capacity can be much lower than winter kW. All-in refers to hook-up, IDC, fees, etc.

CHAPTER FIVE
FUEL

INTRODUCTION

There are several distinguishing characteristics of Gainesville's fuel situation:

- **Coal** – No coal is produced in either Florida or Georgia, and historically, Florida has had relatively high delivered coal costs due to the distance to the Central Appalachian coal fields in West Virginia and Kentucky. Furthermore, until the installation of the recently approved flue gas desulfurization equipment for Deerhaven 2, Gainesville must use premium, very low sulfur coal. Nonetheless, delivered coal prices have been much less lower than delivered natural gas and oil prices, the two principal alternative fuels used in Florida. Furthermore, this requirement to use very low sulfur coal is relaxing for Deerhaven 2 and will not be in place for any future coal power plant. Thus, coal supply needs to be reconsidered in terms of regional sourcing and coal characteristics. In light of the significant diversity of U.S. coal sources, this is a significant positive development in terms of lowered delivered coal costs, especially over the long-term.

- **Petroleum Coke** – Gainesville is located near the U.S. Gulf, the major U.S. source of petroleum coke. This is an advantageous fuel source heretofore unavailable to GRU. As a technical matter, all three generation options can use this fuel source.

- **Coal Transportation** – Coal has been delivered by rail under a long-term contract expected to last until 2019. Accordingly, the transportation component of delivered coal costs are both relatively large and stable.

- **Natural Gas** – Natural gas is delivered by the FGT pipeline. Delivery costs are a small portion of total delivered gas costs.

- **Biomass** – Gainesville has not been able to use local biomass resources, but significant quantities are likely to be available and economic, especially under possible future CO_2 emission regulations.

IMPORTANCE OF FUEL

The importance of fuel can be gauged by some highly illustrative extreme examples. If GRU were to rely on natural gas for all its fuel needs for 2005 and bought all of its fuel