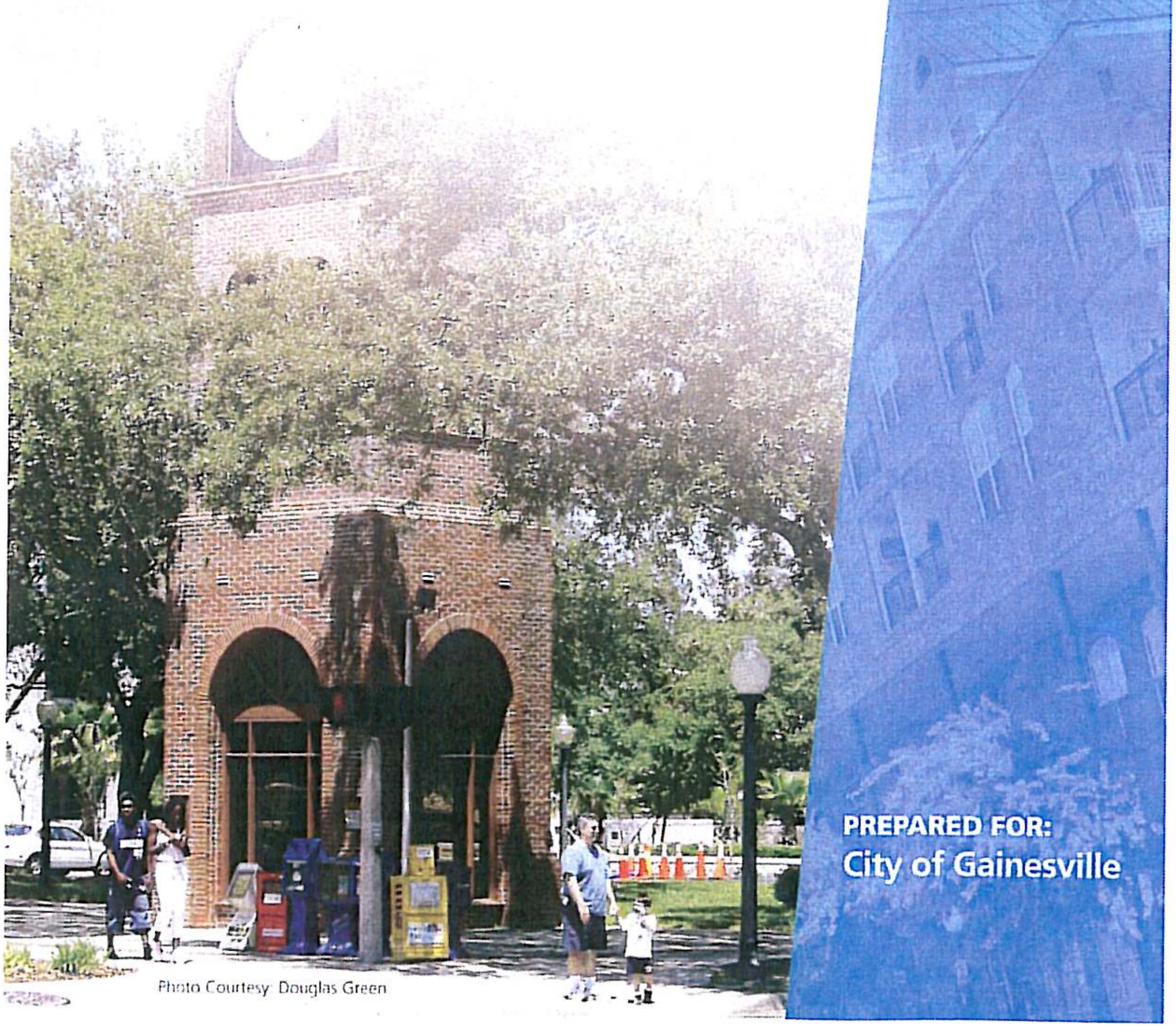
City of Gainesville

City of Gainesville Electricity Supply Needs

(RFP No. 2005-147)

March 1, 2006



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PREPARED FOR:
City of Gainesville

ICF CONSULTING

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EXECUTIVE SUMMARY
CITY OF GAINESVILLE ELECTRICITY SUPPLY NEEDS

INTRODUCTION

This Executive Summary is organized into eight sections. The first section discusses the four options examined and the sensitivity analysis approach used to examine selected economic uncertainties. Note, by contract, ICF was limited to examining "up to" four options which had to be specified before the completion of the DSM and other analyses to meet the timeline established by the City of Gainesville.

The second section discusses qualitative risks associated with the four options. The third section discusses scaling the size of the supply options and adjusting them for greater biomass use. The fourth section discusses the "maximum" DSM option, especially the amount of MW and MWh savings over time. The fifth section discusses the impacts of the four options on GRU's electric revenue requirements which determine average electric rates. The sixth section discusses emission and health impacts including CO_2 emissions. The seventh section discusses socio-economic and job impacts.

The eighth section presents a summary of ICF conclusions which the reader may want to read first. ICF does not identify a best option since value judgments regarding trade-offs are required. Rather, ICF provides the information for the City of Gainesville to support their decision.

FOUR OPTIONS AND SENSITIVITY ANALYSIS

After consultation with the City with respect to which options to analyze, ICF examined the following four resource options: (1) the construction by 2011[1] of a 220 MW Circulating Fluidized Bed Combustion plant (CFB) capable of using coal, petroleum coke and up to 30 MW of biomass without major degradation of plant performance[2]; (2) the construction of a 220 MW Integrated Gasification Combined Cycle (IGCC) with similar fuel and on-line date characteristics; (3) a 75 MW biomass only plant also on-line by 2011 with "maximum" Demand Side Management (DSM), where "maximum" DSM is defined as the economic choice among 19 programs under the most adverse supply side circumstances – i.e., high natural gas prices and high CO_2 allowance prices; and (4) Maximum DSM where DSM programs are implemented in 2006.

[1] The analysis assumes the supply options come on-line by 2011, but in fact, there is a chance even with a clear near-term decision the supply options may only be on-line by 2012. Thus, in some cases, revenue requirements are reported as of 2012, e.g., 2012 to 2025 instead of 2011 to 2025.

[2] Solid fuel options are allowed to increase biomass use in the modeling but at the cost of a large capacity derate and higher heat rates, i.e., lower thermal efficiency. See Chapter Four.

This analysis explicitly examined for each of the options, a base case plus 35 additional future scenarios which results in 144 combinations of scenarios and options (4x36). The analysis in each case was conducted for 20 years starting in 2006 resulting in 2,880 years of data (20x144). The goal of this sensitivity analysis was to explicitly examine selected economic uncertainties. ICF also supplemented these cases with several other sensitivities "off" the Base case where we found the Base case also reflected well the average across the 36 cases.

Most scenarios represent future economic conditions that will differ from historic conditions in that:

- **CO_2 Emission Regulations** – Currently, CO_2 emissions are not regulated in Florida or on a federal basis. In contrast, two thirds of the scenarios examined assume CO_2 emission regulations will be in place after 2010 based on ICF's expectation that such regulations are likely[3].

- **Slower Electricity Demand Growth Before DSM** – Electricity demand growth before DSM is forecast to be less than historical levels for both GRU and Florida. For example, the Base Case forecast growth rate is 2.1 percent per year, and is two thirds the ten year rolling average growth rate between 1985 and 2005. A high case is also examined, but this case also assumes a slowing in demand growth before DSM.

- **Higher Natural Gas Prices** – In 2005, annual average Henry Hub, Louisiana natural gas prices were $8.37/MMBtu which was an all time record high price. The Base Case delivered natural gas price is $6.10/MMBtu in 2003$. In comparison, however, the ten year 1995 – 2004 average price was $4.21/MMBtu (2003$). This forecast of long term high natural gas prices is expected to strongly affect decisions across the power grid. The higher real natural gas prices will compound the effect of general inflation to the extent GRU ratepayers are sensitive to both real and nominal effects. For example, general inflation alone would cause gas prices to double over the study horizon from the long term average. Also, the year to year volatility would likely increase as base prices increase. Lastly, GRU consumers also consume natural gas directly increasing the effect of high natural gas prices.

- **Solid Fuel Choice and Prices** – GRU is assumed to have much greater flexibility in its solid fuel choices for any new plant compared to what Deerhaven 2 has had historically. Delivered coal/solid fuel prices are forecast to be at or below recent levels, favoring solid fuel options all else equal. This low to steady price is reinforced by: (1) the use of low cost petroleum coke at approximately 45 percent of the total fuel input, (2) increased fuel flexibility due to flue gas desulfurization and use of newer

[3] This can be thought of as a two-thirds chance CO_2 regulations will be in place since each of the 36 cases is treated as equally likely.

combustion technologies, and (3) the availability of biomass combined with the ability to use it. The study did not fully examine an all petroleum coke option and this could further lower solid fuel prices since petroleum coke is the fuel option with the lowest delivered price. This option was not examined since it might not be technically feasible and/or petroleum coke supply may not be sufficiently available to achieve these high levels.

- **Financing Costs** – ICF examined only one financing scenario with very low financing costs for GRU compared to most U.S. utilities. This reflects current conditions at GRU which does not pay income tax and can issue tax free bonds for options to primarily meet its own needs. While this is not a change, the generation options considered here have a much higher capital investment cost on a $/kW basis than the last round of new power plant capacity ordered by GRU. Thus, the financing advantages are more significant.

If one takes a different view of likely economic and regulatory uncertainties, the results of this analysis can differ. For example, if one believes natural gas prices will return to or be closer to historical levels, solid fuel options can be less attractive.

QUALITATIVE RISKS

Some of the options examined represent in some cases significant changes for GRU and/or involve difficult to quantify risks for the City of Gainesville (see Exhibit ES-1):

- **DSM** – The DSM program examined here involves levels of expenditures, expertise, and performance that the most advanced municipal utilities (e.g., Austin, Texas) have taken roughly 10 years to achieve. The City of Gainesville is not at these levels at this time, and failure to achieve these reductions can lead to faster than expected load growth (net of DSM) and greater reliance on purchase power and/or "last minute" peaking units. Thus, special attention is directed to ICF's forecast of purchase power prices.

- **Local Biomass** – The local biomass option has not been fully explored by GRU since none of its current generation capacity can use biomass. There are significant economic and technical uncertainties regarding biomass transportation, delivered cost, fuel variability and quality, plant reliability, and the potential for CO_2 regulations to enhance the relative economics of this option which is considered a zero CO_2 emission option.

- **IGCC** – IGCC is a very advanced generation technology with significant perceived risks even when using conventional fossil fuels (e.g., coal and petroleum coke). There are also additional perceived risks related to the use of high levels of biomass. There are also significant issues with respect to actual capital costs after factoring in these risks. ICF's extra contingencies for these risks are described in Chapter 4 as are alternative views on the costs of IGCC. One area where these risks could manifest themselves would be during construction contracting. Accordingly, if the City of Gainesville pursues IGCC, it should consider pursuing during the contracting stage two options (e.g., CFB and IGCC) to verify cost estimates and assess risks. Also, the specifications and associated costs for use of biomass should be explored in detail[4]. Another area where risks could manifest themselves would be during debt financing. ICF assumes that 80 percent of all investments are debt financed and that financing costs will be the same for IGCC as for other GRU options. This assumption was made because of the potential availability of federal loan guarantees which are made available to address these concerns. ICF does not believe cash grants will be available in any significant amount for defraying IGCC costs since the programs providing the most funding have expired. In light of the results discussed below which indicate IGCC is the least cost option, these issues are particularly salient.

Exhibit ES-1
Potential Revenue Requirements Risks

Option	Potential Economic Risks – Modeled	Qualitative Risks
CFB	Low Gas Prices, High CO_2	
IGCC	Low Gas Prices, High CO_2	Capital Costs and Operations
Biomass	Delivered Costs, Low CO_2	Operations
Maximum DSM	High Purchase Power Costs and Volatility	Implementation

Accordingly, ICF recommends that the City factor into its decision making these qualitative risk issues.

SCALING AND BIOMASS DESIGN ISSUES

While ICF did not examine the effects of changing the size of the options, it did analyze the capital cost effects of scaling the options. ICF found the CFB to be much more scalable than the IGCC or NGCC (Natural Gas Combined Cycle) in terms of decreasing the size. For example, decreasing the CFB option from 220 MW to 75 MW increases the per kilowatt capital cost by 8 percent, but increases the IGCC cost by 57 percent (see Exhibit ES-2). Thus, while CFB may be scalable, IGCC is much less scalable.

The costs of allowing for 100 percent biomass use in a CFB are shown. A 220 MW CFB capable of burning 100 percent biomass costs 7 percent more than a CFB which experiences major capacity derates as the biomass share increases from 15 percent to 100 percent. The modeling does not allow for this redesign option, but allows the plant to use 100 percent biomass with derates if economic on a discounted cash flow basis. Conversely, if the 75 MW biomass plant is modified in a relatively low cost manner, it could use coal and petroleum coke and achieve higher capacity than 75 MW.

[4] ICF assumes a spare gasifier but not a dedicated biomass gasifier.

Exhibit ES-2
Comparison of Selected Power Station Technologies (2003$/kW) – GRU[1]

Size (MW)	SCPC		CFB		IGCC		CFB (100% Biomass)		NGCC	
	GF[2]	BF[3]	GF[2]	BF[3]	GF[2]	BF[3]	GF[2]	BF[3]	GF[2]	BF[3]
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]Project contingency fees are included in costs. They are 6, 8, 10, and 20% for NGCC, CFBV, SCPC, and IGCC, respectively.
[2]GF = Greenfield
[3]BF = Brownfield

MAXIMUM DSM OPTION

The Maximum DSM option had lower costs than the generation options examined. The average DSM cost was approximately $23/MWh in real 2003 dollars. In contrast, generation options were typically $40/MWh to $55MWh. The costs of DSM were primarily payments to encourage end users to use more electricity efficient equipment or building stock than they otherwise would. Since these programs generally concentrate on replacement of existing equipment as they gradually age, and the programs require development lead time, they ramp up gradually over time.

By 2025, DSM had decreased reserve requirements by 88 MW or about eleven percent (see Exhibit ES-3)[5]. DSM did not delay the need for new capacity resources beyond 2011 since the effects were concentrated at the end of the horizon, but DSM did decrease the amount of capacity needed in all years (see Exhibits ES-4 and ES-5).

[5] In the High Demand Case, 2025 reserve requirements are 913 MW versus 798 MW in the Base Case. Thus, 88 MW would be 10 percent in this case, unless more savings were achieved.

Exhibit ES-3
Maximum DSM Effects on GRU Supply and Peak Demand Balance (MW) – Base Case Demand Growth

Year	Before DSM				DSM Effects	After DSM		
	Peak Demand	Peak Demand Plus Reserve Require-ments	Existing Capacity Net of Retire-ments[1]	Deficit/ Surplus Relative to Existing Capacity	Decrease in Peak Demand	Peak Demand	Peak Demand Plus Reserve Requirements	Deficit/ Surplus Relative to Existing Capacity
2006	470	541	611	71	4	466	536	75
2007	483	555	611	56	6	477	549	62
2008	495	569	611	42	7	488	561	50
2009	508	584	611	27	11	497	572	39
2010	520	598	602	4	15	505	580	22
2011	532	612	579	-32	21	511	588	-9
2012	544	626	579	-46	27	517	594	-15
2013	556	639	579	-60	34	522	600	-21
2014	569	654	579	-75	42	527	607	-27
2015	580	667	579	-88	49	531	611	-31
2016	592	681	579	-102	54	538	619	-40
2017	603	693	579	-115	59	544	625	-47
2018	614	706	551	-155	65	549	631	-80
2019	625	719	537	-182	72	553	636	-100
2020	636	731	537	-195	79	557	641	-104
2021	648	745	537	-209	81	567	652	-116
2022	659	758	537	-221	83	576	663	-126
2023	671	772	454	-318	84	587	674	-221
2024	683	785	454	-332	86	597	686	-232
2025	694	798	454	-344	88	606	696	-243

[1]15% reserve margin.

Exhibit ES-4
Maximum DSM Effects on GRU Supply and Demand Balance – Base Case

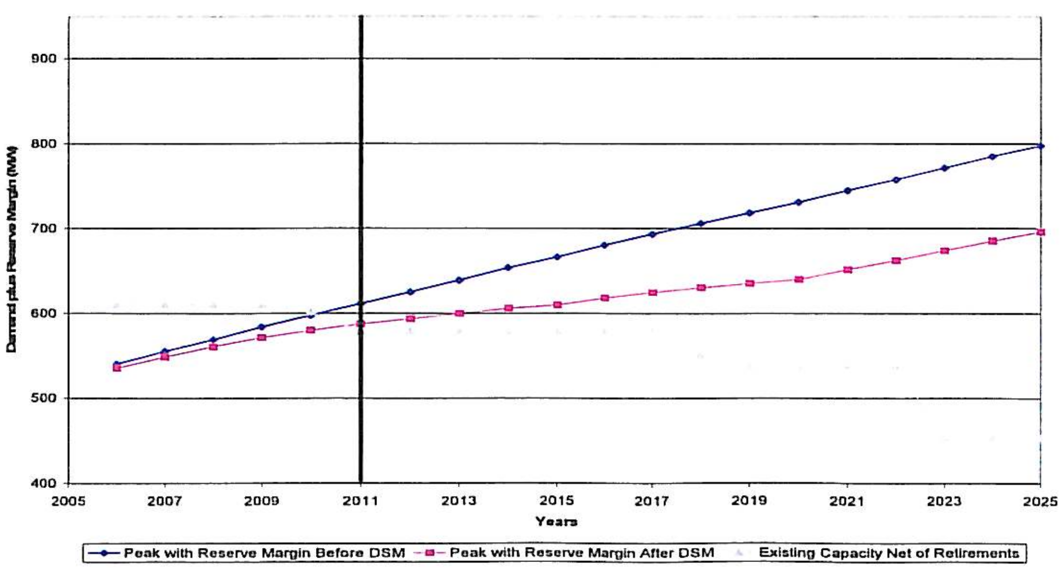
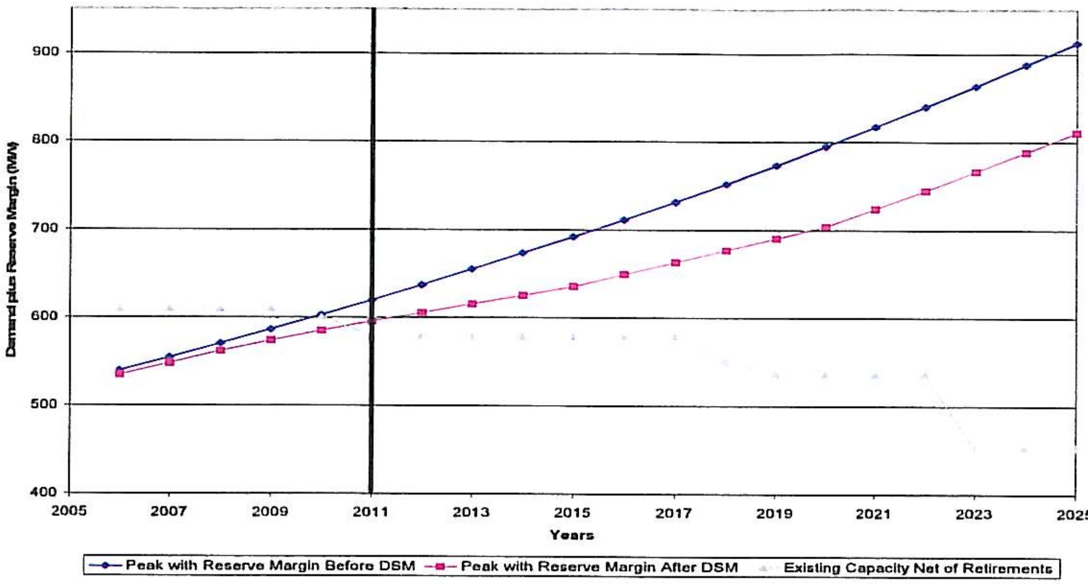


Exhibit ES-5
Maximum DSM Effects on GRU Supply and Demand Balance – High Demand Case



Total generation requirements in MWh decreased on an average approximately 0.13 BkWh per year (see Exhibit ES-6). In comparison, a 220 MW baseload plant produces 1.6 BkWh and on average GRU's current electrical energy needs are 2.7 BkWh. Thus, on an energy basis savings are on average 5 percent of GRU requirements.

Exhibit ES-6
Maximum DSM

Year	Decrease in MW Peak Demand	Decrease in MWh Demand (000)	Annual Incremental DSM Costs (2003$/millions)	Annual Costs (2003 $/MWh)
2006	4	12	0.3	22.8
2007	6	16	0.4	22.8
2008	7	21	0.5	22.8
2009	11	31	0.7	22.8
2010	15	45	1.0	22.8
2011	21	61	1.4	22.8
2012	27	80	1.8	22.8
2013	34	100	2.3	22.8
2014	42	121	2.8	22.8
2015	49	143	3.3	22.8
2016	54	157	3.6	22.8
2017	59	172	3.9	22.8
2018	65	189	4.3	22.9
2019	72	207	4.7	22.9
2020	79	227	5.2	22.9
2021	81	232	5.3	22.9
2022	83	238	5.5	22.9
2023	84	243	5.6	22.9
2024	86	249	5.7	22.9
2025	88	254	5.8	22.9

None of the four options meet the long-term reserve capacity needs of GRU through 2025, though under the CFB and IGCC options, new capacity is not needed until approximately ten years after the plants came on-line. GRU is assumed to make up the difference with the construction of simple cycle combustion turbines (see Exhibit ES-7). These plants are suited for peaking needs, have relatively quick construction and permitting lead times, and very low capital investment costs[6]. The ability to import capacity counting towards reserve requirements is assumed to be limited as discussed elsewhere in the report[7], and hence, incremental needs are met through combustion turbines. The largest combustion turbine construction requirement is in the Maximum DSM case at 249 MW. This is because this option provides the least local generation capacity among the four. Lastly, more capacity is required for the two large solid fuel options than the DSM options since at the end of the horizon when CO_2 allowance costs are the highest they choose based on economic considerations to use more biomass than 30 MW and accept a capacity derate and lower thermal efficiency.

[6] However, they have high variable costs.
[7] Electrical energy import potential, however, is very substantial.

Exhibit ES-7
Base Case GRU Capacity Expansion – 2006 – 2025 (MW)

Resource Type	Option			
	CFB	IGCC	Biomass Maximum DSM	Maximum DSM
CFB	220	--	--	--
IGCC	--	220	--	--
Biomass Only CFB	--	--	75	--
Peaking Combustion Turbine	159	141	174	249
Capacity Import – 2025	29	29	29	29
DSM – 2025	--	--	88	88
Total	408	390	366	366

While potential capacity imports and exports for super peak summer supply is assumed to be very limited (i.e., MW for reserve margin), the electrical energy import and export consequences (i.e., MWh) of the four options are very different. For example, in 2012, under the CFB option, exports are 701,000 MWh versus under Maximum DSM imports are 748,000 MWh, a difference of 1,449,000 MWh (see Exhibit ES-8). This difference equals approximately two-thirds of GRU's total 2006 energy requirements, and hence, is a very large amount. Also, since it occurs early in the study horizon, it has a larger effect on the NPV. This significant difference in net imports decreases over time and by 2025 the difference is 820,000 MWh and GRU imports under all options. This difference narrows as DSM ramps up and demand growth catches up with the solid fuel additions. The large imports expose GRU to the risks of high costs due to high natural gas and wholesale power prices, while the large exports expose GRU to low revenues and/or avoided costs due to low natural gas prices, and hence, low wholesale power prices.

Exhibit ES-8
Base Case Net Imports (000 MWh)

Year	CFB	IGCC	Biomass Maximum DSM	Maximum DSM
2006	+148	+148	+137	+137
2007	+156	+156	+141	+141
2008	+163	+163	+145	+145
2009	+185	+185	+157	+157
2010	+275	+275	+230	+230
2011	-715	-760	+245	+738
2012	-701	-745	+238	+748
2013	-687	-729	+231	+758
2014	-665	-700	+196	+703
2015	-642	-670	+161	+647
2016	-365	-455	+206	+711
2017	-207	-309	+264	+780
2018	-118	-210	+338	+857
2019	-67	-143	+433	+941
2020	-38	-97	+554	+1,034
2021	+63	-7	+596	+1,080
2022	+163	+84	+641	+1,128
2023	+264	+174	+689	+1,178
2024	+364	+265	+741	+1,230
2025	+465	+355	+797	+1,285
Average 2006 – 2025	-98	-151	+357	+731

- means export
+ means import

Over the 20 year period, under Maximum DSM, 27 percent of total GRU needs are met via imports (see Exhibit ES-9). Under Biomass Maximum DSM, this amount falls in half. Under the IGCC and CFB options on average GRU exports 4 to 6 percent of total supply.

Exhibit ES-9
GRU Generation – Base Case (000 MWh)

Option	2006 – 2025 Cumulative				
	Solid Fuel[1]	Natural Gas	DSM	Net Imports	Net Total
CFB	52,329	3,126	-	-1,959	53,496
IGCC	53,557	3,110	-	-3,020	53,647
Biomass – Maximum DSM	39,762	3,581	2,799	7,139	53,282
Maximum DSM	31,863	4,156	2,799	14,628	53,447

[1]Includes petroleum coke, coal, nuclear biomass, and landfill.

GRU REVENUE REQUIREMENTS

Revenue requirements are important since average rates are proportional to revenue requirements[8]. Revenue requirements equal the costs to GRU including surpluses provided to the City. ICF includes two components of revenue requirements (see Exhibit ES-10):

- **Cash Going Forward Production Related Costs** – Cash going forward production costs include fuel, allowance costs, variable and fixed non-fuel O&M, incremental capital costs, allowance allocation, import costs and export revenues. These are the part of total GRU revenue requirements that vary between cases. Since additional revenue requirements exist, this measure understates the percent change in total revenue requirements.

- **Other Electric Revenue Requirements** – Other electric revenue requirements include transmission, distribution, G&A and other electric costs, many of which are assumed constant, regardless of the resource choice. These costs account for roughly a third of the total electric revenue requirements. These requirements assume that the funds provided by GRU to the City of Gainesville are constant across cases.

- **Total Electric** – This adds the above two components together.

Reporting Periods

ICF analyzed the 20 year period 2006 – 2025[9]. However, two other periods are also reported:

- **2012 – 2025** – This is the period when the options become available[10], and hence, the period that the City can most affect by its decisions today. Not only are the generation options assumed to have a long lead time coming on-line only by 2012, but most DSM savings also occur after 2012 and thereafter. 2006 – 2011 should not be affected in a significant way by Commission decisions among the resource options.

- **2012 – 2020** – One might imagine that by 2015, the City could make a new decision that would be on-line by 2021. In this scenario, the City would have ten years to gather more information including three during which it could gauge which the effects of the resources coming on-line in 2011. Furthermore, the post-2020 period is especially uncertain.

[8] GRU is estimating rate impacts.
[9] A longer period can be analyzed by extrapolating from the last years of analyses, e.g., 2026 – 2030 can be based on 2020 – 2025. Furthermore, capital cost recovery was assumed extended by 2025.
[10] Even though the modeling has supply options on-line by 2011, it is questionable whether this could in fact be achieved. Thus, 2012 may be a more conservative period for reporting purposes.

Exhibit ES-10
Base Case Revenue Requirements (Nominal MM $)

Year	Revenue Requirements Fixed Across Cases[2]	Average Base Case Cash Going Forward Costs – Four Options[3]	Total Electric
2006	79	98	177
2007	80	101	181
2008	82	104	186
2009	83	113	197
2010	84	135	219
2011	84	134	218
2012	87	142	229
2013	91	150	241
2014	94	159	253
2015	96	169	265
2016	99	180	279
2017	102	193	295
2018	105	206	311
2019	108	220	328
2020	111	236	347
2021	115	251	366
2022	118	267	386
2023	122	285	407
2024	126	304	430
2025	131	324	454
Total Undiscounted Cumulative	1,998	3,770	5,768
Average 2006 – 2025	100	188	288
NPV 2006 - 2025[1]	1,151	2,038	3,189
NPV 2012 - 2025[1]	1,013	2,017	3,030
NPV 2012 - 2020[1]	687	1,257	1,943

[1]Nominal discount rate. Net Present Value or NPV as of first year, i.e., 2006, or 2012.
[2]Includes transmission and distribution expenses, G&A, general fund transfer, system and load dispatch expenses, nuclear decommissioning and fuel disposal costs, debt service, and capital expenditures.
[3]SO_2, NO_x and Hg allocations are not included. Therefore, revenue requirements may be understated. However, this will not affect the results.

Revenue Requirements – Expected Values

All four options have expected NPV (Net Present Value) revenue requirements within approximately five to seven percent of each other with IGCC having the lowest cost and the other three options very tightly bunched together. In order to achieve the potential IGCC savings, Gainesville would have to accept the perceived risks of the IGCC option. Key aspects of the results vis~a~vis revenue requirements include:

- IGCC has the lowest costs on a NPV basis among the four options by 6 to 7 percent over the 2006 to 2025 period in the Base Case (see ES-11). The results are very similar whether one relies on the single Base Case or the simple average of the 36 cases (see ES-12)[11]. The IGCC has lower emission allowance costs for CO_2, NO_x, SO_2, Hg, lower capital costs, and

[11] In other words, the base is a good estimate of the mean of the distribution.

lower fuel costs due to higher thermal efficiency. This advantage is not huge but persistent across cases. In dollar terms, the NPV of revenue requirements of the IGCC are $163 to $204 million lower than the alternatives.

Exhibit ES-11
Revenue Requirements – Single Base Case[2] (Nominal MM$)

Option	NPV 2006 - 2025[1]	Incremental NPV	% Incremental NPV
IGCC	2,935	--	--
CFB	3,099	+164	+6
Biomass Maximum DSM	3,107	+172	+6
Maximum DSM	3,139	+204	+7

[1]5.5 percent nominal discount rate.
[2]Base Demand, Base Fuel, Base CO_2, Base Biomass.

Exhibit ES-12
NPV Revenue Requirements – Average Across All 36 Cases (Nominal MM$)

Option	NPV 2006 – 2025[1]	Incremental NPV	% Incremental NPV
IGCC	3,055	--	--
CFB	3,218	+163	+5
Maximum DSM	3,236	+181	+6
Biomass Maximum DSM	3,247	+192	+6

[1]5.5 percent nominal discount rate.

- ICF also examined a sensitivity case in which the IGCC capital costs for GRU and the rest of the grid were increased. This case is otherwise comparable to the single Base Case. In the case of GRU, the costs were increased by $534/kW in real 2003 dollars or about 25 percent. This reflects the higher end of available IGCC capital cost estimates. This raised the NPV of the IGCC option, but only by two percent and IGCC was still preferred in terms of having the lowest NPV of revenue requirements (see Exhibit ES-13). The impacts of higher IGCC capital costs were muted by GRU's very low financing costs. If there are operational problems, especially for biomass, or financing problems not mitigated by federal loan guarantees, the cost increases could be larger.

Exhibit ES-13
IGCC Sensitivity – NPV Revenue Requirements – 2006 – 2025 (Nominal MM$)

Case	NPV
Base Case	2,935
High IGCC Capital Cost - +$534/kW over Base Case	2,981 (+46)

- Very large amounts of coal-fired IGCC generation capacity is also built grid-wide (see Exhibit ES-14), especially when utilities expect CO_2 controls. This reflects economic decision making in the modeling. In the Base Case, 38,000 MW of IGCC are forecast to be built nearly equal to current FRCC (Florida Regional Coordination Council) peak demand. Thus, even if GRU does not build a coal plant, it may be able to benefit from IGCC by buying solid fuel (primarily coal) power in the wholesale power spot market. If the market place is not as forthcoming as forecast in terms of new coal generation additions, the costs could increase for the options which most increase reliance on power purchases from other wholesale suppliers.

Exhibit ES-14

Grid-Wide[1] New Power Plant Construction – Cumulative MW – 2006 – 2025

Case[2]	Coal/Solid Fuel				Nuclear	Natural Gas Total			Biomass	Other/ Renewable[3]	Total
	SCPC	IGCC	CFB	Total		Combined Cycle	Combustion Turbine	Total			
Base	194	37,845	--	38,039	10,543	15,151	11,001	26,152	--	619	75,353
Base No CO_2	21,096	32,936	--	54,032	7,543	2,285	12,180	14,465	--	557	76,597
Base High CO_2	--	17,970	--	17,970	10,543	37,423	8,718	46,141	90	619	75,363
Base Low Gas	--	--	--	--	7,543	57,128	8,513	65,641	--	555	73,739

[1]Florida and Southern Company
[2]Maximum DSM
[3]Other includes DSM, Landfill Gas, Solar, and Wind.

- The other three options, CFB, Maximum DSM and biomass, Maximum DSM had similar costs which were within one percent of each other over the 2006 to 2025 period on a Net Present Value basis (NPV)[12, 13].

- CFB has higher costs than IGCC but is the most proven solid fuel technology examined. Again, there is the trade off between risk and potential IGCC savings.

- The Maximum DSM option has a reasonable expected net present value of revenue requirements. This reflects two factors. First, DSM is very cost effective if it can be achieved. DSM costs are approximately $23/MWh versus approximately $40-$55/MWh for the generation options. In fact, DSM is so cost effective most of the options would be picked under Base Case conditions and can be an economic component of a combined supply and demand strategy. Second, Maximum DSM requires that the remaining large need for power be obtained via a combination of purchase and local peaking units. Maximum DSM also exposes GRU to greater reliance on purchase power costs and the risks of less than effective implementation of DSM. These effects are muted on an expected basis since GRU is able to purchase coal power from other utilities in many hours since the modeling shows a strong reversal of recent Florida trends from all gas to all coal construction. If coal power plant construction is less than forecast, e.g., there is a mixture of coal and gas or gas continues to predominate, the Maximum DSM option can be more costly.

- The Biomass with Maximum DSM option has similar results to the Maximum DSM but with less exposure to power imports. This is because Biomass and expected purchase power costs are similar.

One perspective on these results is derived by comparing the four options on a back-of-the-envelope average $/MWh basis. The IGCC and CFB options provide approximately 1.64 million MWh at $40/MWh, and $49/MWh, respectively (see Exhibit ES-15). These average cost estimates are discussed more in Chapter Four. This indicates that the IGCC option should be the lower cost of the two options and save over $100 million on a NPV basis[14], which is consistent with the modeling results. The two DSM options require an additional 0.95 – 1.51 million MWh to be purchased from other utilities relative to the 220 MW CFB and IGCC options. The model forecasts wholesale power prices at $53/MWh in the Base Case[15] (see Exhibit ES-16). The DSM costs much less at $23/MWh than generation options. However, on a weighted average basis, these

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[12] NPV is discounted for the time value or money.

[13] These results are somewhat different from the interim results. At that time, all options were within 8 percent of each other, but the order was different. This was not due to major input changes, but due to quality assurance and quality control checks which required retirements in the application of the assumptions. A narrower range among the option was anticipated in the presentation to Gainesville on February 15, 2006 as a result of initial Q/A, Q/C.

[14] $9/MWh times 1.64 million equals $15 million per year starting in 2011. Even after discounting to 2006, this still is above $100 million.

[15] Note, the biomass cost of $55/MWh happens to be very similar to the purchase power cost.

options are $51/MWh and should cost some what more than the CFB which they do. These back-of-the-envelope calculations are shown for expositional purposes only as the actual calculations are much more complex and vary yearly.

Exhibit ES-15
Base Case – 2006 – 2025 – Simplified Back-of-the-Envelope Calculations

Option	Self-Supply		Purchase		Average
	Option Average Costs ($/MWh)	Average MWh Provided (million)	Incremental Purchase Power Costs ($/MWh)	Average MWh Purchased (Million)	Average Costs ($/MWh)
IGCC	40[4]	1.64	NA	NA	40
CFB	49[4]	1.64[1]	NA	NA	49
DSM	23[3]	0.13	53	1.51	51
Biomass	55[4]	0.56[2]	NA	NA	NA
Biomass/DSM	49[6]	0.69[3]	53	0.95	51

[1]220 MW, 8,760 hours, 0.85 capacity factor.
[2]75 MW, 8,760 hours, 0.85 capacity factor.
[3]0.56 plus 0.13
[4]See Chapter Four
[5]See Chapter 3
[6]Weighted average

Exhibit ES-16
Average Realized Wholesale Power Import Price to GRU (2003$/MWh) – 2012 – 2025 Average

Case	Case			
	CFB	IGCC	Biomass Maximum DSM	Maximum DSM
Base	61	65	53[1]	53[1]

[1]The lower average realized prices primarily reflect greater purchases off-peak when prices are lower than for the 20 MW options.

REVENUE REQUIREMENTS – SENSITIVITY TO WHOLESALE POWER MARKET CONDITIONS

There are two major sources of wholesale price volatility. The first is shortages at the summer peak where the alternative can in the extreme be rolling blackouts and prices can spike to very high levels. If the City decides not to move forward with any of the generation options identified, it should begin planning to add combustion turbines very soon thereafter[16].

The second is fuel price volatility which is much greater for coal than natural gas. Over the last ten years, the standard deviation of delivered annual utility natural gas prices (a statistical measure of variability year-to-year) was 27 times higher than for coal (see Exhibits ES-17 and ES-18). Utility delivered natural gas prices were highly correlated with commodity natural gas prices at Henry Hub, Louisiana, the industry marker

[16] See end of Chapter 1. This needs to move quickly is heightened by the effects of a problem at a key GRU transformer.

location. While some coal prices on a spot commodity basis show higher volatility than delivered coal prices, this is still less than for natural gas prices and does not necessarily mean delivered utility coal prices will be volatile for the CFB or IGCC options (see Exhibit ES-18). This reflects many factors as discussed in Chapter Five.

Exhibit ES-17
Delivered Utility Fuel Price Volatility Compared to Henry Hub Natural Gas Prices – U.S. Average

Year	Nominal$/MMBtu		
	Coal – U.S. Average Delivered Utility Cost[1]	**Gas – U.S. Average Delivered Utility Cost[1]**	**Henry Hub Spot Gas Price[2]**
1995	1.32	1.98	1.72
1996	1.29	2.64	2.81
1997	1.27	2.76	2.48
1998	1.25	2.38	2.08
1999	1.22	2.57	2.29
2000	1.20	4.30	4.70
2001	1.23	4.49	3.70
2002	1.26	3.56	3.02
2003	1.28	5.39	5.46
2004	1.36	5.96	5.90
Average	1.27	3.60	3.42
Standard Deviation	0.05	1.37	1.47
Correlation Coefficient with Henry Hub	21%	97%	--

[1]Source: EIA Electric Power Annual Table 4.5
[2]Source: Platts' Gas Daily. Prices from 1995 onwards are volume-weighted averages.

Exhibit ES-18
Coal Price Volatility Greatly Dampened by Relative Stability in Transportation Costs and Contracting Prices

Year	Spot Coal Prices[1] (Nominal$/MMBtu)		Average Delivered Coal Costs to Utilities (Nominal$/MMBtu)	
	PRB	Central Appalachia 1% Sulfur	GRU[2]	U.S.[3]
1995	0.27	0.87	1.73	1.32
1996	0.23	1.05	1.66	1.29
1997	0.25	1.02	1.66	1.27
1998	0.26	1.08	1.66	1.25
1999	0.27	1.02	1.66	1.22
2000	0.26	0.99	1.62	1.20
2001	0.57	1.72	1.88	1.23
2002	0.35	1.17	2.06	1.26
2003	0.36	1.40	2.04	1.28
2004	0.36	2.27	2.03	1.36
Standard Deviation	0.10	0.43	0.18	0.05
Correlation with Gas Prices	0.37	0.73	0.59	0.21

[1] Source: Coal Outlook
[2] Source: A Review of Florida Electric Utility 2005 Ten-Year Site Plans, prepared by the Florida Public Service Commission, Division of Economic Regulation, December 2005, p.48
[3] Source: EIA AEO 2005

In order to understand some of the risks of relying on purchases from the wholesale power markets, several additional sensitivities were run in which no new coal or nuclear builds were permitted (see ES-19). As a result, practically all new plants are natural gas-fired. This changes the wholesale marketplace from a heavily coal to a heavily natural gas reliant market. Put another way, this assumption returns the wholesale market to its current situation in which gas and oil dominate the margin. The CFB option is compared to the Maximum DSM option to highlight the two extreme situations vis~a~vis imports and exports of power. Maximum DSM relies the most on spot power imports and the CFB relies heavily on exports in the near-term and minimizes imports among the options[17]. As new coal power plants are replaced with new natural gas power plants and natural gas prices rise, the CFB option's NPV revenue requirements steadily fall from $3,099 million in the Base Case to $2,812 million. This is because export revenues rise as do the avoided costs of imports. Conversely, the Maximum DSM revenue requirements rise from a NPV of $3,139 million or very close to the CFB to $3,514 million or 25 percent above the CFB option. While a 25 percent disparity is unlikely except for a year or short period, it does illustrate the sensitivity of options to alternative wholesale market conditions.

[17] IGCC has a similar effect.

Exhibit ES-19
Sensitivity to Wholesale Power Market Conditions - NPV Revenue Requirements 2006 - 2025[1] – Selected Cases and Options

Scenario	Option	
	CFB	Maximum DSM
Base	3,099	3,139
Base – No Coal or Nuclear Builds[3]	3,016	3,112
Base – No Coal or Nuclear Builds – High Gas Price[3]	2,939	3,217
Base – No Coal or Nuclear Builds – Extremely High Gas Price[2,3]	2,812	3,514

[1]5.4% Nominal discount rate
[2]Two standard deviation increase in gas prices over Base Case with historical standard scaled for higher mean gas prices. Much more likely for one year than on average for period.
[3]Otherwise Base conditions.

The exposure to power market conditions can also hurt CFB although to a lesser degree (see Exhibit ES-20). If natural gas prices are low, then Maximum DSM becomes preferred over CFB in terms of lower NPV of revenue requirements reversing the Base Case relationship which is close but slightly favorable to CFB. Instead of being 1 percent more costly, under the low gas price case, Maximum DSM becomes 3 percent less costly.

Exhibit ES-20
Sensitivity to Wholesale Market Conditions – NPV Revenue Requirements (Nominal MM$)

Case	Option	
	CFB	Maximum DSM
Base Case	3,099	3,139
Low Gas[1]	3,060	2,974
Low Gas High CO_2[1]	3,488	3,359

[1]Otherwise, Base conditions.

Expected Revenue Requirements – Alternative Measures

The NPV of revenue requirements are also shown for different time periods (see Exhibits ES-21 through ES-24). While the ranking does not change, (i.e., IGCC still has lowest cost) the percent difference does. Instead of the range being 6 percent between the best and worst NPV among the four options, the difference is 9 percent over the shortest of the three periods – i.e., 2012 – 2020. Similarly, for 2012 to 2025, the difference between IGCC and the highest NPV option increases from 6 to 8 percent. Lastly, the increases are larger when measured off the portion of GRU revenue requirements which vary across the options ignoring the fixed portion. Here, the difference is 10 to 15 percent versus 6 to 9 percent.

Exhibit ES-21
Revenue Requirements – NPV[1] (Nominal MM$) – Average Across All Cases – Different Time Periods

Period	Option			
	CFB	IGCC	Biomass Maximum DSM	Maximum DSM
2006 – 2025	3,218	3,055	3,247	3,236
2012 – 2025	3,064	2,857	3,103	3,094
2012 – 2020	1,962	1,823	2,002	1,989

[1]Nominal discount rate of 5.4 percent. As of the first year of that period, i.e., 2006 or 2012. Includes generation going forward production costs only.

Exhibit ES-22
Revenue Requirements (Nominal MM$) – Change From Least Cost Case[1] – Average Across All Cases – Different Time Periods

Period	Option			
	CFB	IGCC	Biomass Maximum DSM	Maximum DSM
2006 – 2025	+163	--	+192	+181
2012 – 2025	+208	--	+246	+237
2012 – 2020	+139	--	+180	+166

[1]Nominal discount rate of 5.4 percent. Includes generation going forward production costs only.

Exhibit ES-23
Revenue Requirements – Ranking in Different Time Periods

Period	Option			
	CFB	IGCC	Biomass Maximum DSM	Maximum DSM
2006 – 2025	#2	#1	#4	#3
2012 – 2025	#2	#1	#4	#3
2012 – 2020	#2	#1	#4	#3

[1]Use of existing plants, purchase power, new CTs. Includes generation going forward production costs only.

Exhibit ES-24
Revenue Requirements – Difference Between Best and Worst Option (%) – Average All Cases – Different Time periods and measures of Revenue Requirements

Period	Selected Generation Production[2]	Total Revenue Requirement[3]
2006 – 2025	10	6
2012 – 2025	13	8
2012 – 2020	15	9

[1]Nominal discount rate of 5.4 percent.
[2]Includes generation going forward production costs only.
[3]Includes revenue requirements which are fixed across cases

STANDARD DEVIATION - REVENUE REQUIREMENTS

The Maximum DSM option has the highest variability in outcomes as measured by the standard deviation of NPV of revenue across the 36 cases (see Exhibit ES-25). One interpretation of this statistic is that there is 95 percent chance of the Maximum DSM result being plus or minus \$516 million on an expected value of \$3,236 million. This higher variability is due to the effect of wholesale market conditions on this option. However, the extent of the higher variability is only moderate at 8 to 11 percent measured off the average of the cases (i.e., the ratio of the standard deviation to the average) versus 6 to 9 percent for the other options (see Exhibit ES-26).

Exhibit ES-25
Long-Term Variability

Period	Standard Deviation of NPV for all 36 Scenarios (millions NPV)			
	CFB	IGCC	Bio-DSM	DSM Only
2006 – 2025	202	174	205	258
2012 – 2025	268	235	262	327
2012 – 2020	137	112	132	178

Exhibit ES-26
Long-Term Variability

Period	Standard Deviation of NPV for all 36 Scenarios (%)			
	CFB	IGCC	Bio-DSM	DSM Only
2006 – 2025	6	6	6	8
2012 – 2025	9	8	8	11
2012 – 2020	7	6	7	9

Revenue Requirements – No CO_2 Regulations

The analysis assumes that significant CO_2 emission regulations will likely be imposed (see Exhibit ES-27). In the Base Case by 2025, CO_2 allowance costs reach \$22/ton in real dollars. However, the effects on revenue requirements are muted by allocation of allowances to fossil generators as discussed in Chapter Six.

Exhibit ES-27
CO_2 Allowance Price Forecast (2003\$/ton)[1]

Year	Low Case	Base Case	High Case
2010	0	0	15.5
2016	0	7.7	24
2020	0	13.4	26.4
2025	0	21.7	30
Average 2010 – 2025	0	10.7	24.0

[1]Gross, not net of allocation. See later section on allocations.

The absence of CO_2 regulations lowers revenue requirements for all options and IGCC is still the least cost option (see Exhibits ES-28 and ES-29). However, assuming no CO_2 regulations decreases the gap between the IGCC option and the other three options since it is the least CO_2 intensive. This closing of the gap is largest for Maximum DSM which relies on imported coal. Also, imported coal has less attractive biomass options than the other three GRU generation options which rely on

Gainesville's biomass supply and plant design flexibility[18]. Thus, the options with the lowest local direct CO_2 effects are most adversely affected by CO_2 regulations since they rely on imported CO_2 intensive coal generation with less biomass options than local plants.

Exhibit ES-28
Revenue Requirements No CO_2 (Nominal MM\$)[1] – Average of All 12 No CO_2 Cases (Change From Average of all 36 Cases)

Period	CFB	IGCC	Biomass Maximum DSM	Maximum DSM
2006 – 2025	3,046 (-172)	2,931 (-124)	3,061 (-186)	2,986 (-250)
2012 – 2025	2,834	2,689	2,856	2,764
2012 – 2020	1,867	1,767	1,891	1,825

[1]Includes generation going forward production costs only.

Exhibit ES-29
Revenue Requirements - Change From Least Cost Option – Average of All 12 No CO_2 Cases (Nominal MM\$)[1]

Period	CFB	IGCC	Biomass Maximum DSM	Maximum DSM
2006 – 2025	+115	--	+130	+55
2012 – 2025	+145	--	+167	+75
2012 – 2020	+100	--	+124	+58

[1]Includes generation going forward production costs only.

AIR EMISSIONS AND HEALTH IMPACTS

Except for CO_2, GRU air emissions will be lower than current levels under all options due to forthcoming controls at the existing Deerhaven 2 coal-fired power plant, and the tight emission controls for all new generation options required by law.

Among the options, local GRU emissions are lower for the Maximum DSM and Biomass Maximum DSM options (see Exhibit ES-30). However, this difference is significantly muted by GRU purchases of coal power off system, and hence, higher emissions elsewhere.

Exhibit ES-30
Cumulative Local GRU Emissions – 2006 – 2025 – Average Across 36 Cases

Option	CO_2 (MM Tons)	SO_2 (1,000 Tons)	NO_x (1,000 Tons)	HG (Ton)
CFB	45	49	38	1
IGCC	43	48	33	1
Biomass DSM	29	40	32	1
DSM	30	40	32	1

MM=millions

[18] GRU options can switch to 100 percent biomass if the economics favors such a change and large shifts to biomass occur in the modeling at the GRU plants near the end of the horizon even at the costs of derates, and higher heat rates.

CO_2

Between 2006 and 2025, the Biomass Maximum DSM and Maximum DSM options have lower local CO_2 emissions by approximately 31 to 35 percent, or 13 to 16 million tons lower than the IGCC and the CFB options on a cumulative basis (see Exhibit ES-31). These are the least CO_2-intensive options locally since they do not directly involve new fossil generation assets beyond peakers. However, the CO_2 emissions grid-wide are only 2 to 8 million tons lower due to power imports. The Maximum DSM only lowers grid CO_2 emissions 2 million tons or 0.03 percent over 20 years relative to the IGCC due to heavy use of coal power imports.

Exhibit ES-31
CO_2 Emissions (million tons) – Average Across 36 Cases – 2006 – 2025 – Cumulative

Source	Option			
	CFB	IGCC	Biomass Maximum DSM	Maximum DSM
GRU	45	43	29	30
Total Grid[1]	7,567	7,565	7,559	7,563

[1]Florida plus Southern Company region.

SO_2

Today, GRU emits 7,000 tons per year of SO_2 and the County still complies with $PM_{2.5}$ standards. GRU's SO_2 emissions average 2,000 to 2,500 tons per year under the four options, and hence, will be two-thirds below current levels[19]. This is because new options are highly controlled for all pollutants except CO_2 for which post-combustion controls do not exist, and are not expected to become practical. $PM_{2.5}$ can result from emissions of SO_2 and NO_x and is a health concern. However, local air quality is better than 75 percent of U.S. monitoring locations in terms of $PM_{2.5}$ and is fully expected to meet $PM_{2.5}$ standards which are set to protect health with an adequate margin of safety under all the options.

Exhibit ES-32
SO_2 Emissions (cumulative thousand tons) – Average Across 36 Scenarios – 2006 – 2025[2]

Source	Option			
	CFB	IGCC	Biomass Maximum DSM	Maximum DSM
GRU	49	48	40 – 44[3]	40
Total Grid[1]	12,383	12,381	12,379	12,380

[1]Florida plus Southern Company region.
[2]Note, a large portion of the total emissions of SO2 are in the 2006-2010 period before Deerhaven 2 retrofits are complete. This also applies to NO_x.
[3]See discussion in text.

Between 2006 and 2025, cumulative GRU SO_2 emissions are eight to nine thousand tons lower for the Maximum DSM option (see Exhibit ES-32) compared to IGCC and

[19] Even lower during the post-70% period.

CFB. On an annual basis this is 400 to 450 tons per year lower which is very small. GRU will continue to comply with $PM_{2.5}$ standards under the highest emitting option (CFB). This decrease does not account for SO_2 emissions from non-GRU plants associated with GRU's increased imports of wholesale power. Accounting for grid-wide SO_2 emissions lowers the difference in SO_2 emissions to one to three thousand cumulative tons for Maximum DSM.

The Biomass and Maximum DSM could have SO_2 emissions intermediate between the CFB and IGCC on the one hand, and Maximum DSM on the other hand. The plant could control the SO_2 associated with biomass via use of limestone, but it may not be required or may not find it economic to do so.

The estimated health damage cost of $PM_{2.5}$ shows a range of potential effects from not material to material reflecting uncertainty in the effects especially at low concentrations. Furthermore, if Gainesville consistently acted on the effects of residual emissions or other externalities, this could lead to major changes in many areas of Gainesville life outside of power since there are many activities that do not violate the law, but have external effects on society.

NOx

GRU currently emits approximately 4,000 tons per year of NO_x, and hence, the cumulative 20 year difference in NO_x emissions across the options of 6,000 tons is small in comparison (see Exhibit ES-33). Furthermore, as noted for SO_2, which can also be a $PM_{2.5}$ precursor, the GRU area is in compliance with ozone, NO_x and $PM_{2.5}$ limits and will remain in compliance regardless of the option. Between 2006 and 2025, cumulative NO_x emissions are one to six thousand tons lower for the DSM options. This is 50 to 300 tons per year lower, a small difference (compared to 4,000 tons of emissions per year today). Also, grid-wide NO_x emissions actually increase slightly for the DSM options compared to IGCC due to imports of more NO_x intensive electricity.

Exhibit ES-33
NO_x Emissions (thousand tons) – Average Across 36 Scenarios – 2006 – 2025 Cumulative

Source	Option			
	CFB	IGCC	Biomass Maximum DSM	Maximum DSM
GRU	38	33	32	32
Total Grid[1]	3,758	3,753	3,754	3,754

[1]Florida plus Southern Company region.

Hg

Between 2006 and 2025, cumulative mercury (Hg) emissions are about one ton for all options (see Exhibit ES-34).

Exhibit ES-34
Hg Emissions (cumulative tons) – Average Across 36 Scenarios – 2006 – 2025

Source	Option			
	CFB	IGCC	Biomass Maximum DSM	Maximum DSM
GRU	1	1	1	1
Total Grid[1]	150.07	150.12	150.10	150.10

[1]Florida plus Southern Company region.

This analysis did not factor in the emission impacts of preventing open burning of biomass (e.g., particulates, NO_x, SO_2) which might be avoided if one of the three generation options is chosen. Emissions could be lower since any of the three options would be GRU's first capable of using biomass.

SOCIOECONOMIC IMPACTS

Chapter 7 presents the socioeconomic impacts modeled for the four resource options. The main impacts of these options appear to be the potential for job creation in the local economy. The total number of jobs estimated for these options are summarized in the Exhibit below.

Exhibit ES-35
Jobs

Option	Construction Jobs – Total[1]	Operations Jobs – Total[1]	Total Job Years[2]	Total Job Equivalents[3]
CFB	1,858	192	**13,192**	**388**
IGCC	1,759	165	**11,986**	**353**
Biomass + DSM – High[4]	672[5]	470[5]	**18,288**	**569**
Max DSM only[6]	---	---	**1,500**	**75**

[1]Total includes jobs directly required for construction and operation of the various plant options, as well as their multiplier impacts (indirect and induced jobs).
[2]Assumes 4 years during construction and 30 years of operations for the generation options and 20 years for DSM.
[3] Expressed as total number of continuous jobs available for the entire period of the analysis.
[4] High includes all jobs needed for the entire biomass supply, including those in neighboring counties.
[5] Includes construction and operations jobs for biomass plant only. Does not include DSM operation jobs.
[6]DSM option does not entail construction of any power plant. Hence the jobs created by this option should be interpreted as jobs in the local economy for all the DSM programs modeled in IPM.
See Chapter 7 for more details on the DSM option as well definitions of the types of jobs modeled.

All four generation options modeled have the potential to create significant local jobs in Alachua County, especially the Biomass + Maximum DSM option (see Exhibit ES-36). Jobs created during the construction phase are expected to be temporary because they will be available for four years during the construction of the plant. Jobs created by the operation and maintenance of the plant options will be permanent with long-term economic benefits for the local Alachua economy. The 220-MW CFB and the 220-MW

IGCC plant options are expected to require similar investments, thereby creating employment opportunities that are quite similar (about 13,200 job years or 390 job equivalents under the CFB option compared to about 12,000 job years or 350 job equivalents under the IGCC option). The 75-MW biomass plant option will require less investments during the construction phase thereby creating fewer temporary construction jobs. However, the biomass technologies are more labor intensive than the other conventional coal technologies. Therefore, running the 75-MW biomass plant is expected to require more O&M labor, thereby creating more full time jobs in the local economy (470 jobs in Alachua and surrounding counties for biomass, as opposed to 192 and 165 jobs for the CFB and IGCC plant options, respectively). Finally, the DSM option by itself is expected to create fewer jobs over the entire life of the program. The program will create about 1,500 job years or 75 job equivalents in Alachua County during 2006 to 2025.

CONCLUSIONS

A summary of the results of this analysis is shown in see Exhibit ES-36.

Expected Revenue Requirements – IGCC

Revenue requirements are important because average GRU rate payer bills will be proportional to the revenue requirements. IGCC has the lowest expected revenue requirements compared to the other three options on the order of six percent for the 2006 to 2026 period on a net present value basis, and a slightly higher percentage discount for other periods. IGCC is also preferred gird wide in most of the modeling scenarios. The other three options, CFB, Maximum DSM and Maximum DSM with Biomass, have revenue requirements that are very similar to each other. This is in part because under Maximum DSM GRU imports power from other new coal power plants built in Florida, i.e., coal by wire.

Exhibit ES-36
Summary Results

Criterion	Options			
	CFB	**IGCC**	**Biomass Maximum DSM**	**Maximum DSM**
Expected Revenue Requirements	Essentially Tied for Second	Best	Essentially Tied for Second	Essentially Tied for Second
Performance/Capital Cost/Financing Risk	Low	Medium High	Medium High	Medium High
Risk Due to Exposure to High Wholesale Market Prices/High Oil and Gas Prices	Low	Low	High	Highest
Risk Due to Exposure to Low Gas Prices	Medium	Medium	Low	Low
Variability of Revenue Requirements	Low	Low	Low	Medium
Local CO_2 Emissions	High	Medium High	Low	Low
Grid CO_2 Emissions	Medium	Medium	Medium	Medium
Local NO_x, SO_2 Emissions	Low	Lower	Lower to Lowest	Lowest
Health Effects	Comply with Ambient Standards	Comply with Ambient Standards	Comply with Ambient Standards	Comply with Ambient Standards
SocioEconomic Jobs	High	High	High	Medium

This IGCC advantage reflects several considerations including lower capital costs, higher thermal efficiency, lower fuel cost in $/MWh and lower emission costs. However, there are risks that this new advanced technology will have performance issues, higher than expected costs or financing challenges. There is only one operating IGCC utility plant in the country which received significant subsidies, though there are other IGCC plants in the industrial sector or abroad or that were operating in the past in the U.S. as demonstration projects. Also, there are several proposed IGCC projects including a second one in Florida and several in the Midwest.

To the extent that IGCC risks not explicitly estimated in the scenario analysis eliminate the advantage of this option (e.g., IGCC construction cost and operational risks, financing risks), expected or average revenue requirements effectively cannot be used to distinguish the options. Remaining differences are too small given the uncertainties in the study. Even if the IGCC risks are ignored, the six percent advantage of IGCC is not large since the standard deviation of revenue requirements is typically equal to or greater than the IGCC advantage. Lastly, the IGCC option scales poorly as the size of the option decreases compared to CFB. To the extent an intermediate size option is being considered, this hurts the IGCC option.

Revenue Requirements, Power Imports and Risks

The CFB and IGCC have the least exposure to reliance on wholesale power imports and hence less exposure to high oil and natural gas prices. These prices can be very volatile and increases are compounded by the fact that many consumers use both natural gas and oil directly as well as electricity[20].

Exposure to risks of high oil and natural gas prices is proportional to GRU imports of power. For example, GRU is a net power importer on average between 2006 and 2025 under the Maximum DSM option, and by 2025 imports equal 66 percent of GRU's 2006 expected electric generation requirements. Over the full twenty year period, 27 percent of GRU energy requirements are from imports under Maximum DSM. This is in spite of building 249 MW of peaking combustion turbines. In contrast, in the CFB and IGCC options, on average GRU is an exporter of power. Over the 2006 to 2025 period exports are 4 to 6 percent of total MWh requirements.

This risk becomes most apparent in scenarios in which future grid wide construction of new power plants is not primarily coal-fired – i.e., continues to be natural gas fired. In a high natural gas price case in which there is no coal or nuclear builds, Maximum DSM has nine percent higher NPV of revenue requirements compared to CFB.

To a certain extent, the CFB and IGCC options expose GRU to the opposite risk: low natural gas prices. This is in addition to exposure to high CO_2 allowance prices. For example, under a scenario of low natural gas prices, and high CO_2 allowance prices, CFB is 4 percent more costly than Maximum DSM versus one percent lower in the Base Case.

Also, the variability of the Maximum DSM case is the highest measured in terms of the standard deviation of revenue requirements over the full horizon. The standard deviation of this option is two percent higher than the other three options. This is due to the greater effects of changing wholesale power market conditions when GRU is very reliant on power imports. However, some of the risks are not fully reflected in the modeling. For example, in high natural gas price scenarios, Florida utilities are assumed to switch from nearly 100% new natural gas power plant construction to majority coal power plant construction, especially in 2010-2020. While this 180 degree shift in capacity expansion to coal may be economic, it may not fully happen. Hence, qualitative consideration needs to be given to these risks.

DSM

Even though Maximum DSM option has higher revenue requirements than IGCC, DSM had the least costs per MWh saved among all the options studied. The three generation options on average had twice the costs of DSM per MWh. This makes DSM attractive even under base case supply side assumptions if the implementation challenges can be overcome. To achieve the full level of DSM savings requires a large

[20] The economy is also tied to some extent to oil market conditions.

and fast improvement in DSM programs in Gainesville. These savings can be linked with supply side options as evidenced in the Maximum DSM biomass option. Put another way, the overall Maximum DSM option had higher costs than the IGCC option because of the high costs of power imports not because of the costs of the DSM programs, and most MWh under this option actually come from power imports, not DSM.

CO_2 EMISSIONS

CO_2 emissions are not currently regulated, but ICF expects that there is a two-thirds chance that in the future, CO_2 regulations will be imposed. CO_2 emissions are highest when measured locally for the CFB option at 45 million cumulative tons over twenty years. Local CO_2 emissions are 4 percent lower under the IGCC option due to its higher thermal efficiency (i.e., lower CO_2 per MWh) and 33 to 35 percent lower for the Maximum DSM and Maximum DSM and Biomass options.

The difference in CO_2 emissions between the options is less when grid wide CO_2 emissions are considered. Maximum DSM has four million tons less grid wide CO_2 emissions than CFB versus 15 million tons less for local emissions. Grid wide differences in CO_2 emissions are less since under Maximum DSM GRU relies more on fossil power imports.

CO_2 emission impacts on the environment are the same regardless of location of emission. The potential impacts of CO_2 are not local, but global warming. IGCC technology is the only fossil-fueled generation technology that could potentially involve CO_2 capture, but carbon capture and sequestration were not included in the estimation of IGCC costs and emissions in this study, and is likely to be substantially less practical in Florida than other places in the US. Furthermore, these costs are very high and carbon sequestration for utility applications has never been implemented.

The effects of CO_2 emission regulations on the CFB, and IGCC options are also muted by the ability to switch to greater levels of biomass (a zero CO_2 option) if CO_2 emission allowance costs rise enough. The model makes this decision accounting for the costs of lower plant performance. These costs could be further mitigated if the design of the plants is adjusted up front for greater biomass use than 30 MW or 14 percent as discussed in Chapter Four.

SO_2, NO_X, AND HG EMISSIONS AND $PM_{2.5}$ AMBIENT CONDITIONS

Emissions of regulated pollutants, SO_2, NO_x and mercury (Hg) will be lower under all options than current emission levels. This is because of the forthcoming retrofit of pollution controls on the existing Deerhaven 2 coal power plant combined with current and future and legal requirements which mandate extremely tight emission controls on the emissions at any new plant.

The GRU area has relatively low concentrations for $PM_{2.5}$, which are well within ambient standards and lower than 75% of the country's monitoring location. Even with possible tightening of $PM_{2.5}$ standards, the GRU area complies and is expected to continue to comply with these standards. These standards are designed to protect public health with an adequate margin of safety.

The expert estimates of the externality costs of residual emissions range from not material to large with a factor of ten variation underlining the lack of agreement or uncertainty on these issues, especially regarding the impacts of low concentration.

SOCIOECONOMIC IMPACTS/JOBS

The largest local job increases are associated with the generation options. Biomass+ maximum DSM has the largest effects if one includes the jobs for biomass supply, even those in neighboring counties. DSM has less local job impacts.

REMAINDER OF REPORT

The remainder of the report is organized as follows:

- Chapter Two – Demand Growth Before DSM
- Chapter Three – DSM
- Chapter Four – Generation Options and Financing Cost
- Chapter Five – Fuel
- Chapter Six – Emissions and Health
- Chapter Seven – Socioeconomic Impacts
- Chapter Eight – Detailed Results

CHAPTER ONE
APPROACH, OPTIONS, AND METRICS

OBJECTIVE OF STUDY

ICF Consulting was engaged to provide the City of Gainesville independent consultation on options for meeting the electrical supply needs of the Gainesville community. The goal is to provide the information needed to support a decision by the City including evaluation of potential trade offs on such issues as revenue requirement impacts, revenue requirement uncertainty, environmental impacts, health impacts, etc. The range of resource options covers both the demand and supply side.

RESOURCE OPTIONS ANALYZED

Under its contract, ICF was engaged to examine four electricity options, one of which was pre-specified. After consultation with the City Commission and interested members of the Gainesville community, the following four options were chosen for analysis[21]:

- **220 MW CFB Flexible Solid Fuel Plant** – Under this option, GRU builds a Circulating Fluidized Bed Combustion (CFB)[22] power plant likely coming on-line in 2012. This plant is capable of using coal, petroleum coke, and up to 30 MW (approximately 14 percent) of biomass. The 30 MW level for biomass usage prevents major effects on the plant's performance, e.g., deterioration of plant capacity, thermal efficiency, etc. during very high biomass usage. The plant could use even greater biomass, though the plant's performance could be adversely affected[23]. ICF provides some scoping level assessments of the derates and the steps that can be undertaken to ameliorate them in a later chapter. The CFB option is the same as the GRU IRP choice whose analysis is required under ICF's contract[24].

- **220 MW IGCC Flexible Solid Fuel Plant** – Under this option, GRU builds an Integrated Gasification Combined Cycle (IGCC) solid fuel power plant capable of gasifying and using coal, petroleum coke, and biomass. This

[21] Under each option, the utility can purchase or sell power on the wholesale market subject to existing transmission limits and/or add combustion turbines as needed to assure reliable operation and compliance with the reserve margin obligations of the utility.
[22] This option is sometimes referred to as FBC.
[23] The plant is allowed to increase its use of biomass above 30 MW but incurs significant loss of performance, e.g., output derates.
[24] The current GRU coal power plant uses pulverized coal power plant technology. Approximately 315,000 MW of such power plants are operating in the U.S. with roughly 10 million MW years of operating experience. The current Deerhaven coal unit has a capacity of approximately 220 MW which is similar to the capacity level of the proposed plant. CFB is a more recent solid fuel technology which is more flexible with respect to solid fuel choice compared to pulverized coal power plant technology, though it has higher capital costs.

plant uses very advanced coal-fired generation technology similar to Tampa Electric's Polk power plant. Polk is the country's only operating utility IGCC, though others are under active consideration and some are used in the U.S. industrial sector and abroad. The size of the plant was chosen not only to be comparable to the CFB plant, but also because smaller plants exhibit large diseconomies of scale. This plant is very well suited for petroleum coke use and there has been some small scale biomass testing in the U.S. on this technology. The advantages and disadvantages of this technology are discussed in a later chapter.

- **"Maximum" DSM** – Under this option, a set of DSM programs are specified which are economic under very adverse supply side conditions. Namely, we identify DSM options which are economic under very high fuel and CO_2 allowance prices. Residual incremental power needs are met via a least cost combination of existing GRU plants, short-term wholesale power purchases, and the construction of peaking plants, i.e., combustion turbines. Even so, this option is a minimal generation investment option.

- **75 MW Biomass Plant Plus Maximum DSM** – Under this option, Maximum DSM is combined with a 75 MW biomass plant. This plant would have a similar technology as the 220 MW CFB plant, and would theoretically be able to use multiple solid fuel options. However, in this study, the plant would only be able to use biomass. The size of the biomass plant was chosen to be smaller than the 220 MW plant, and hence, involves less generation capital investment. The 75 MW size was chosen based on a number of considerations including: (1) other biomass plant sizes including a 75 MW plant in Florida, (2) biomass availability which is limited and uncertain, and which could create transportation problems, (3) economies of scale which favor at least moderate size, and (4) the desire to significantly distinguish this option from the 220 MW solid fuel options which can use biomass.

OTHER SUPPLY SIDE RESOURCE OPTIONS CONSIDERED

ICF also considered alternative power supply options. The review of the consideration of the options provides insight into our decision making *vis~a~vis* our recommendations to the City. The options considered, but not chosen included:

- **220 MW Natural Gas Combined Cycle** – Under this alternative option, GRU would build a natural gas-fired combined cycle power plant. This plant would use a technology similar to GRU's last major power plant addition. This option was almost included and it was "a close call" as to whether it should be in the "final four" because it had several attractive features including:[25]

- **Lower CO_2 Emissions** – This option allows for consideration of the lowest level of CO_2 emissions consistent with fossil fuel use. The likely CO_2 emissions of the CFB on fossil fuel is approximately 1.5 million tons per year, compared to 1.3 million tons for the IGCC, and 0.9 million tons for the combined cycle. CO_2 emissions are considered zero for the DSM and biomass options.

- **Lower Regulated Emissions and Possible Health Impacts** – The natural gas-fired combined cycle plant has the lowest SO_2, NO_x, and Hg emissions, and hence, minimizes possible local health impacts of any option involving fossil fuel.

- **Lower Capital Costs** – The size of the combined cycle capital investment is much lower at only approximately $150 million versus approximately $450 to $550 million for the solid fuel options. The lower capital costs can be a huge advantage offsetting higher fuel costs, especially if the current phase of high oil and natural gas prices ends faster than expected. Thus, while the current high fuel costs may appear to make the natural gas option a "straw man", the lower capital costs combined with environmental and health considerations make the gas option a real option that the City may prefer.

- **Financial Advantage of Municipal Utilities** – If electric power including the capital component will have to be purchased at open market prices from entities without the financing advantages of municipals, the financial advantage of municipal utilities available to GRU would be lost. Municipal utilities are exempt from paying income tax and can issue tax free bonds. Thus, a GRU combined cycle would have lower financing cost than purchasing power from other combined cycles.

- **Flexibility and Options for Deferring Decisions** – Once the combined cycle comes on-line, it can be converted to an IGCC and provided a solid fuel option – e.g., biomass, coal, petroleum coke, etc. Thus, the decision on solid fuel can be deferred, e.g., until CO_2 regulations are imposed, additional information as available about the future course of natural gas prices, etc., demand growth uncertainty is resolved, etc.

- **Proven Technology** – There is little technology risk perceived by the financial community and little fuel risk in terms of delivery.

[25] Our understanding is that the natural gas combined cycle option is under review in a parallel GRU process.

- **Financial Community Receptivity** – The financial community is currently involved in financing new combined cycles today. There will be no major issues regarding potential downgrades in bond rating associated with technology risk. Florida is adding 7,000 MW of gas-fired combined cycles (i.e., under construction, permitted, under study, or on hold), and in the U.S., approximately 100,000 MW are planned, permitted, under construction, or under study.

- **Economic Size** – The smallest sized combined cycle using the current Frame 7FA technology, the most prevalent advanced high efficiency combined cycle technology, is approximately 220 MW[26]. Thus, a natural gas plant with a size similar to the CFBC is feasible and, in fact, close to optimal in terms of capital cost economies of scale.

- **Flexibility and Electricity Demand Growth** – Unless GRU's electricity demand growth slows, 220 MW represents 12 to 16 years of growth in peak demand. Thus, a smaller plant would require frequent decisions, while the 220 MW size is not so large as to preclude decisions in ten years or so for a new plant with different technology.

- **Supercritical Pulverized Coal Power Plant (SCPC)** – Nearly all U.S. coal plants are designed to use pulverized coal. Supercritical plants are designed to increase the plant's thermal efficiency (compared to the more typical sub-critical pulverized coal plant) by having the water in the water wall tubes at temperatures and pressures above the critical fluid to gas change in phase point[27]. The SCPC plant is highly controlled for sulfur dioxide (SO_2), nitrogen, oxides (NO_x), and mercury (Hg). Beyond the technical description, this type of coal plant is actively being considered by other utilities and is modeled as an option for other southeastern U.S. utilities. This plant has lower per unit capital cost than other GRU solid fuel options especially assuming a much larger plant can be built and the power delivered, e.g., 800 MW versus the 220 MW size being considered. However, this plant type is less flexible in the fuel that can be used, especially regarding petroleum coke and biomass. The SCPC option was rejected for this study for a number of reasons discussed in a later chapter including the desire to consider GRU-only options, i.e., not consider a jointly owned SCPC power plant.

- **Peaking Combustion Turbine Natural Gas-Fired Power Plant** – This plant is similar to a combined cycle except it has lower thermal efficiency

[26] The actual optimal size in terms of available equipment is likely to be closer to 250 MW. A Frame G is larger at approximately 365 – 385 MW.
[27] Put another way, there are four leading coal technologies: pulverized subcritical, pulverized supercritical, CFB, and IGCC.

and lower capital costs. Since GRU's financing costs are so low, the annual control costs of this option are very low for GRU. Also, this plant has a shorter lead time than other plants. This option is provided both to GRU and to other southeastern utilities in the modeling. Since its per MWh production cost is much higher than the combined cycle, and hence, while it helps meet the companies' need for reserve capacity to handle its peak requirements, it provides little to address the GRU's need for electrical energy. This must be produced by other plants or imported.

- **Power Purchases and Sales Reflecting Short-Term Market Conditions** – Wholesale power import and export options are modeled in each hour as are capacity or reliability transactions for the peak. Together with the construction of new combustion turbine peakers, power exchanges are the default supply options for GRU. The modeling assumes that the current physical limitations on the power grid will remain. Furthermore, such limits cannot be violated. Thus, under any scenario where it is economic to purchase power, the model will do so as needed and vice versa. The smaller the capacity of the resource option for GRU, the greater the potential reliance on spot wholesale power purchases. Today, spot off-system power is primarily oil and natural gas-fired. A critical issue is whether this will continue or will sufficient coal be built to provide lower cost wholesale power costs.

  Florida has much less merchant power plant capacity than other U.S. regions due to state law which greatly restricts the construction of merchant plants without contracts to utilities. Merchant plants are defined here as power plants not dedicated via contract or ownership to a utility buyer. Thus, one important dimension of relying on spot market purchases is that while electrical energy may be available from multiple suppliers in most hours, it may be difficult to obtain on short notice capacity for reserve margin requirements (i.e., for the summer super peak period) even though physically ICF estimates approximately 30 MW can be imported to GRU. This adds to the risk associated with waiting to make decisions regarding securing enough capacity for reserve margin. This risk is not fully captured in the modeling which assumes GRU always meets its reserve margin because it is difficult to measure the leverage of sellers when faced with buyers unable to meet their peak needs. The importance of meeting the reserve margin requirement is highlighted by the fact reserve margin requirements must be met for a given demand growth level either by added supply or effectively forced conversion of part of the City's electricity supply to interruptible status[28]. This interruption would most likely be during the peak air conditioning season and in the extreme could raise numerous issues including public health concerns.

[28] Failure to meet reserve margins not only exposes GRU to reliability risks, but also exposes other utilities sharing the grid to such risks. Not only might the state of Florida act to force utilities to meet reserve requirements, the Federal government under the 2005 Energy Policy Act is expected to promulgate sanctions for entities violating reserve levels.

- **Central Station Solar Thermal** – This option was rejected since there is too little Florida experience with the central station solar and its cost is very high, especially considering back-up costs to cover the utility's reliability needs when the solar plants output is less than the plant's rated maximum and the low capacity factors of such plants in Florida relative to other prime U.S. locations – e.g., the U.S. desert Southwest. See Chapter Four for more information.

- **Nuclear** – This option was rejected since nuclear power plants are way too large and complex for GRU. We decided after consultation with the City to not consider jointly owned power plants. However, we provide discussion of this option. Furthermore, it is less likely that near-term jointly owned nuclear plant options will be available relative to large jointly owned pulverized coal plants due to permitting, regulatory, and financing uncertainties and the very long lead times for such plants.

- **Wind** – Wind was rejected for Florida due to the lack of prime wind resources.

FLORIDA GENERATION ADDITIONS

Florida utilities are in the process of adding new plants which can be relevant as a point of comparison and because of their effects on wholesale power market prices. Put another way, other entities are also facing similar issues. Among the units under construction or recently added, nearly all use natural gas combined cycle or simple cycle technology (see Exhibit 1-1). These plants generally reflect decisions made before or early in the recent period of very high natural gas prices which started in 2000.

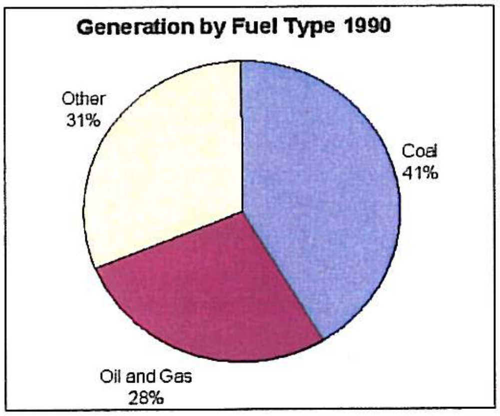
Exhibit 1-1
Recently Operational and Firmly Planned Capacity is Almost Exclusively Natural Gas-Fired

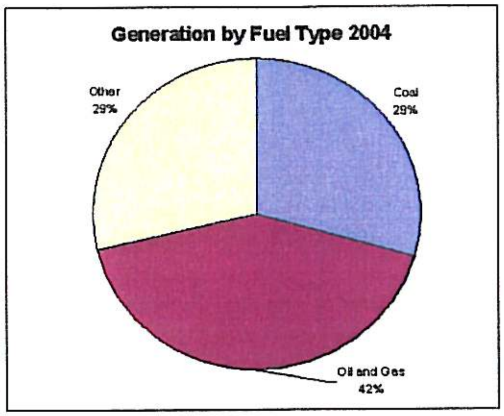
Model Region	Plant Name	Unit Name	Capacity Type	Retrofit Size	On-Line Date
Florida Power & Light	Fort Myers Expansion	Generator: 3	Combustion Turbine	340	6/1/2003
Florida Power & Light	Sanford Expansion	Generator: 2	Combined Cycle	1,116	6/15/2003
Florida Power & Light	Lake Worth Generation	Generator: 1	Combustion Turbine	212	12/1/2004
Florida Power & Light	Martin Expansion	Generator: 2	Combined Cycle	547	6/1/2005
Florida Power & Light	Manatee	Generator: 3	Combined Cycle	1,100	6/1/2005
Florida Power & Light	Okeelanta Cogeneration[1]		Steam Turbine - Agricultural Crop Byproducts/Straw/Energy Crops	65	5/1/2006
Florida Power & Light	Stock Island[1]		Combustion Turbine	42	6/1/2006
Florida Power & Light	Turkey Point[1]		Combined Cycle	1,150	6/1/2007
Florida Power & Light - SUB-TOTAL				4,572	
Jacksonville Electric	Brandy Branch	Generator: 2	Combined Cycle	570	5/1/2005
Orlando Utilities CO	Stanton Energy Center	Generator: 1	Combined Cycle	633	10/1/2003
Progress Energy	Hines Energy Comp	Generator: 1	Combined Cycle	554	12/1/2003
Progress Energy	Hines Energy Comp	Generator: 2	Combined Cycle	500	12/1/2005
Progress Energy - SUB-TOTAL				1,054	
Tampa Electric CO	Gannon	Generator: 1	Combined Cycle	750	6/1/2003
Tampa Electric CO	Osprey Energy Center	Generator: 1	Combined Cycle - Cogen	530	5/1/2004
Tampa Electric CO	Gannon	Generator: 2	Combined Cycle	1,125	6/1/2004
Tampa Electric CO - SUB-TOTAL				2,405	
GRAND TOTAL				9,234	

As a result of this trend of building natural gas combined cycles, the share of oil and gas in Florida's generation mix has risen from 28 to 42 percent between 1990 and 2004 (see Exhibit 1-2). This is significant because wholesale spot sales and purchases by GRU will reflect the costs of the marginal not average source of supply which will be almost always oil and natural gas-fueled power plants. Oil and natural gas plants are the marginal or incremental sources since their variable costs are by far the highest and are the price setting source in nearly all on-peak hours[29]. In order to reliably access sources of baseload power, one must undertake the obligation of investing in or long-term contracting for such power. Alternatively, one may benefit if others build large amounts of coal or nuclear, have extra to sell in some hours, and compete to sell such power. As discussed elsewhere, this happens in some scenarios.

[29] On-peak is Monday – Friday, 6 AM – 11 PM.

Exhibit 1-2
State of Florida – Energy Generation by Fuel Type – 1990 and 2004 – Shows Very Large Increase in Oil and Gas Generation





Source: A Review of Florida Electric Utility 2005 Ten-Year Site Plans, prepared by the Florida Public Service Commission, Division of Economic Regulation, December 2005, page 11

More recently, announced new power plant projects in Florida show a much greater interest in coal (see Exhibits 1-3 and 1-4). Whereas none of the recent additions have been coal-fired, nearly half of the announced future planned generation capacity in Florida is coal-fired. This very large and very recent increase in the reliance on coal among planned projects is mirrored in many parts of the U.S. Among the announced coal plants are:

- Stanton IGCC – This proposed IGCC coal plant is jointly being pursued by the Orlando Municipal Utility and Southern Company.
- Seminole
- Jacksonville FMPA
- JEA CFB

None of the plants have actually broken ground. A critical issue in this study is the future of the wholesale power market in Florida and the extent to which will be coal or oil/gas driven. It should also be noted that none of the existing plants using combined cycle technology have chosen to retrofit gasification technology either in Florida or elsewhere.

Exhibit 1-3
FRCC Announced Builds[1]

Company	Plant	Planned Capacity	Fuel Type	Type of Plant	On-line Date
Hillsborough Co	Hills Co. Resource Recovery Facility	17	Garbage	Resource Recovery Facility	N/A
Florida Power & Light[2]	West County Energy Center 2 Units	2,200	Gas	Combined Cycle	2009, 2010
Southern Co.	Demonstration Project at Stanton	285	Coal	Integrated Gasification Combined Cycle	2010
Seminole Electric	Unit 3 at Palatka	750	Coal	Pulverized/ Conventional	2012
JEA/FMPA	Coal Project	800	Coal	Conventional	2012
Gainesville Regional Util.	Deerhaven expansion	220	Coal	Coal Fluidized Bed/Biomass/ Other	2011[3]
Progress Energy	Hines Unit 5	540	Gas	Combined Cycle	2009
Seminole Electric	Unknown – 2 units	364	Gas	CC	2008, 2009
Pasco Co	Pasco Co. Resource Recovery Facility	20	Garbage	RRF	N/A
Palm Beach Co	Palm Beach Co Resource Recovery Facility	28	Garbage	RRF	2010
JEA	Circulating Fluidized Bed	250	Coal	CFB	2013
Progress Energy	Hines Unit 6	540	Gas	CC	2010
Progress Energy	Central Florida Nuclear	N/A	Nuclear	Nuclear	2015
Progress Energy	Unknown CC	536	Gas	CC	2012
Tampa Electric Co	Undetermined	502	Gas	CC	2013
Seminole Electric	Unknown – 3 Units	546	Gas	CC	2013, 2014
Progress Energy	Unknown CCs – 2 Units	1,072	Gas	CC	2013, 2014
JEA/Biomass Industries Group	Unknown – 2 Units	240	E-grass	Biomass	N/A

[1]Revised by ICF to reflect cancellation of the SW St. Lucie coal units and announcement of two 1,100 MW of combined cycles at West County.
[2]Revised by ICF. 2012 may be most likely.
Source: Florida's Energy Plan, Department of Environmental Protection 1/17/06 page 20
[3]Provided for information purposes only. Model will choose builds by scenario for non-GRU power companies (Source: Energy Velocity).

Exhibit 1-4
FRCC Announced Builds Summary

Type	Planned Capacity
Coal	4005
Gas / Other	4405
Total	8410

NEW POWER PLANTS AND MODELING ANALYSIS

In the modeling analysis, the construction of new power plants by other utilities will be determined by the model, unless the plant is already under construction or otherwise determined to be a firm addition. Therefore, in each scenario, new power plants will reflect the economics facing utilities and the assumption they are trying to minimize costs. The reason we have decided not to base capacity expansion for other entities on announcements is that nationwide, most planned projects do not come to fruition or are substantially delayed. This is critical, especially for a 20-year study. If utilities do not respond economically, wholesale power costs will be higher than forecast.

SENSITIVITY ANALYSIS

ICF analyzed the performance of the four resource options using a large amount of sensitivity analysis to account for the largest economic and regulatory uncertainties facing Gainesville. These include:

- **Fossil Fuel Prices** – ICF analyzed Base, Low, and High fuel price scenarios where the focus is on future long-term natural gas prices. Natural gas prices have risen greatly since 2000 and especially since 2004 along with oil prices and are highly uncertain. Coal issues will also be addressed including the effect of having multiple sources for coal and the option to use petroleum coke and biomass. These important issues are discussed in the fuel chapter.

- **CO_2 Emission Regulations** – ICF analyzed Base, Low, and High CO_2 emission allowance prices and associated emission allowance allocations. ICF considers CO_2 to be the key uncertainty *vis~a~vis* future air emission regulations. Furthermore, the range of possible CO_2 emission levels is especially broad across the four resource options examined in detail. This contrasts with other air emissions (e.g., SO_2, NO_x, Hg) in which the range across options is very narrow, i.e., total GRU emission levels are very similar. CO_2 is a greenhouse gas and is not currently regulated in the U.S. and the nature of potential future programs is highly uncertain. Regulations exist in some developed countries and there is significant potential that future controls will be enacted. ICF recognizes that regardless of the regulations, CO_2 emissions will be a key issue for the Gainesville community.

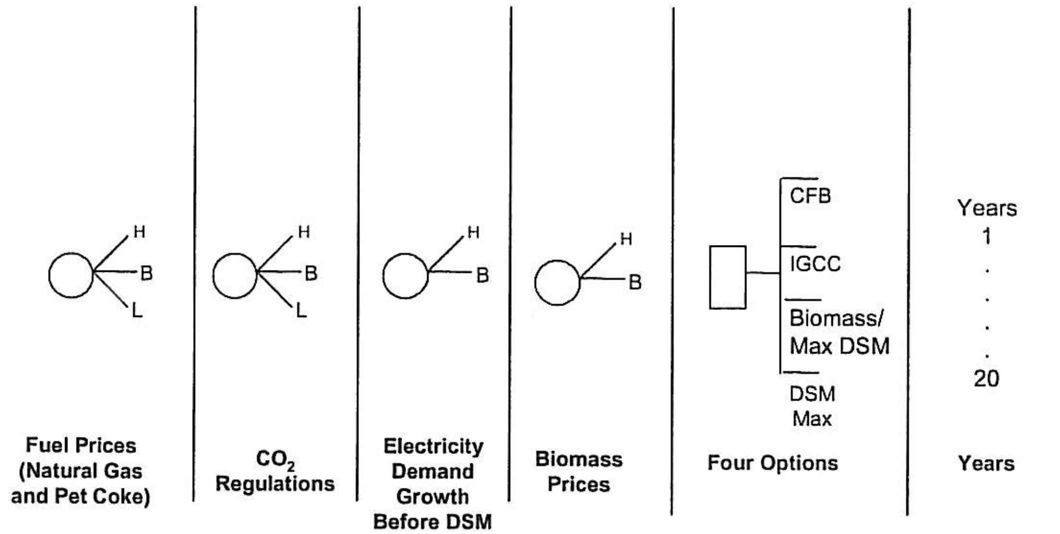
- **Electricity Demand Growth Before DSM** – ICF analyzes Base and High electricity demand growth before DSM. Both scenarios assume growth will be below historical levels (i.e., below the ten year rolling average historical level), and hence, this partly explains the lack of a Low case. Furthermore, each of the two electricity demand projections is further decreased by incremental DSM choices in the DSM scenario. ICF believes the GRU Base Case projection of electricity demand growth is conservative and this too contributed to having only two demand growth levels before DSM scenarios. Lastly, the decision not to add a third case also reflects the need to limit the number of scenarios to a manageable level.

- **Biomass Fuel Prices** – ICF analyzes Base and High cost biomass price scenarios. ICF believes the risks of higher than expected costs of using biomass are greater than lower than expected costs. Furthermore, there is the need to limit the number of scenarios, and hence, we are not examining a Low case. Lastly, all generation options have the ability to use biomass, and hence, there is a thorough examination of biomass which ICF considers the key renewable generation option for Gainesville. Accordingly, ICF did not analyze a third biomass price trajectory.

As a result, there are 36 scenarios reflecting 3 fuel price cases, 3 CO_2 price cases, 2 electricity demand before DSM cases, and two biomass cases (3 x 3 x 2 x 2 = 36). For example, base fossil fuel prices, base CO_2 regulations, base demand growth before DSM, and base biomass prices would be one scenario, etc. In addition for each scenario, we will examine each of the four options. This results in 144 scenario/option combinations and 2,880 years worth of modeling analysis (2,880 = 20 x 144). See Exhibit 1-5.

ICF has not assigned probabilities to each of the outcomes. Rather, to simplify the analysis, we are treating each scenario as equally likely. Thus, the probability of each case is effectively one divided by 36 or 2.8 percent.

Exhibit 1-5
The Scope of the Analysis is at Its Maximum Involving 2,880[1] Years of Analysis



[1]3 x 3 x 2 x 2 x 4 x 20 = 2,880
H = High, B = Base, L = Low

It is worth mentioning that ICF considered and rejected two additional options that use more complex decision analysis approaches including assigning explicit probabilities to each scenario. In these approaches, all generation decisions were delayed by five years such that no new generation resource would come on-line until 2016 or 2017[30]. In spite of being rejected, these options are useful in conceptualizing the challenges facing the City of Gainesville. These two options were:

- **Maximum DSM/ Delay Generation Decisions 5 years[31]/ Make Decisions Assuming 100% Resolution of Uncertainty – Include Biomass 75 MW Plant as One of the Generation Options** – This alternative is graphically summarized in Exhibit 1-6[32]. The decisions for today would be: (1) solid fuel CFB coming on line 2011/2012, (2) solid fuel IGCC coming on line 2011/2012, (3) 75 MW biomass plant on-line 2011/2012, and (4) waiting, pursuing Maximum DSM, and then making a decision among the three generation options at a future date (2011/2012) with that unit coming on-line 2016/2017. This analysis would use the simplifying assumption that uncertainties are fully and completely resolved

[30] Of course, combustion turbines would have to be built or reliability purchases be made to meet reserve requirements. All estimates expect such requirements by 2011.
[31] Hence, generation additions would be delayed ten years or more due to the large lead time for siting, permitting, designing, contracting, financing, and testing new power plants.
[32] Graphically, uncertainties are represented as circles and decisions as squares. The expected values of the options across various metrics are still evaluated, but after the resolution of uncertainty, the optimal decisions are taken for each state of the world. This can have a greater or lesser value depending on the exact circumstances.

by 2011/2012, and at that time the best decision is made for the state of the world at that time.

- **Maximum DSM/ Delay Generation Decisions 5 years/ Make Decisions Assuming 100% Resolution of Uncertainty – Include 220 MW Natural Gas Combined Cycle as One of the Generation Options** – This alternative is graphically summarized in Exhibit 1-7. It is the same as the above option except that the natural gas combined cycle option replaces the 75 MW biomass plant.

There are several advantages of this type of approach. First, the benefit of waiting is explicitly taken into account since in each state of the world the best option is chosen lowering costs or improving performance on other metrics. Second, the cost of waiting is also explicitly estimated. In the interim, the extra five years of exposure to wholesale power market fluctuations is captured as demand grows and an increasing share of GRU power supply is bought from other utilities' power plants. The cost of waiting also includes the challenge of making reliability purchases of peaking capacity from other utilities and/or rushing to build combustion turbines. To illustrate this point, by 2017, GRU electricity demand could be as much as 26 to 43 percent higher than expected 2006 levels.[33]

The disadvantages of this formal alternative delay analysis are several and ultimately this approach was rejected. First, while learning occurs over time about the future state of the world, 100% resolution of uncertainty is clearly an overstatement made for analytic convenience. One certainty is that uncertainty will not be fully resolved. Furthermore, agreeing on the degree to which uncertainty is resolved is very difficult. Second, it is more complicated to understand and describe this approach and requires explicit quantitative probability assessments to fully implement. Third, this option is not directly comparable to the up-front options which reflect uncertainty. Fourth, some aspects of the risks of relying on the spot markets are hard to characterize. This is especially regarding reliability purchases in a state which formally discourages merchant plants[34]. This discourages the existence of extra capacity available to meet demand during peak periods.

[33] 26 percent corresponds to 2.1 percent growth over 11 years and 43 percent corresponds to 3.3 percent which equals historic growth rates. At the high case demand rate of 2.8 percent, growth would be 35 percent. All of these increases would be mitigated by DSM, and hence, the estimates are "as much as".

[34] Florida law prohibits merchant uncontracted plants with steam capacity in excess of 75 MW.

Exhibit 1-6
Alternative Approach to Analyzing Options – Delay and Then Build Biomass Plant

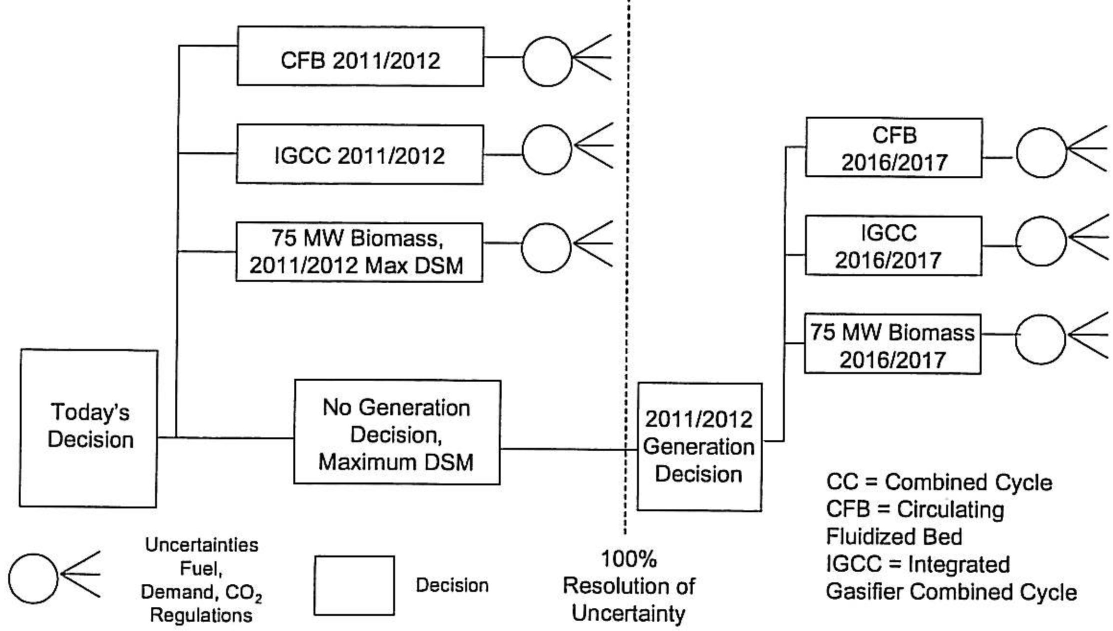
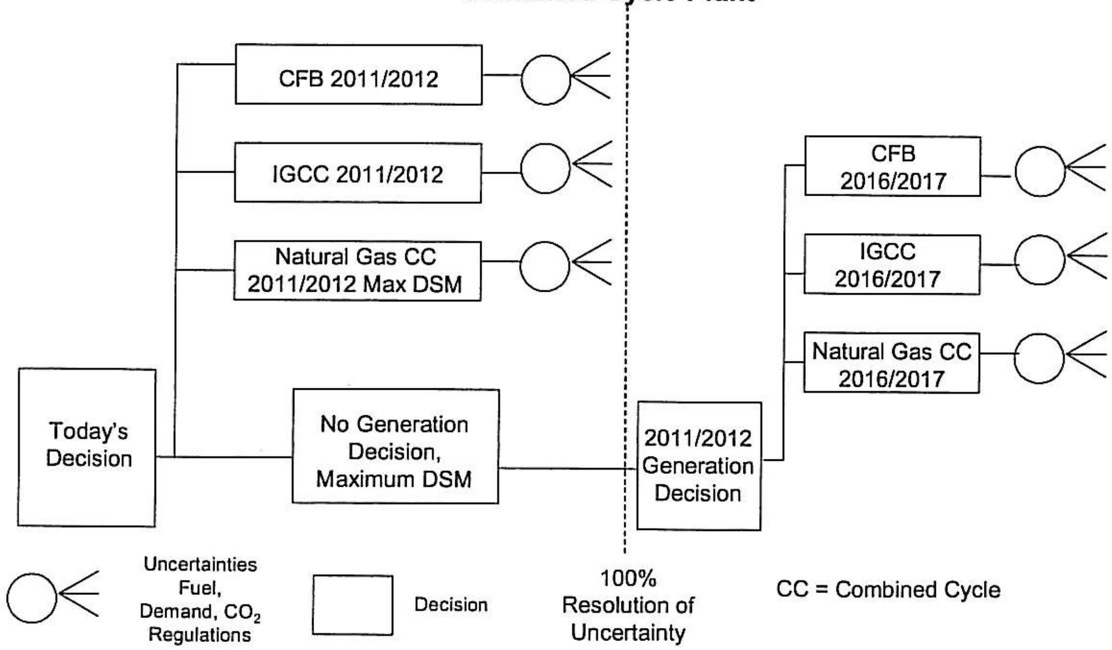


Exhibit 1-7
Alternative Approach to Analyzing Options – Delay and Then Build Natural Gas Combined Cycle Plant



METRICS

The goal of the study is to provide an assessment of the four options that will allow the City of Gainesville to make decisions regarding future supply options. Each option was evaluated according to a range of metrics including:

- Revenue Requirements – Average
- Revenue Requirements – Long-term Variability
- Revenue Requirements – Annual Fluctuations
- Residual Emissions and Health/Environmental Impacts – CO_2, SO_2, NO_x, Hg, resulting $PM_{2.5}$
- Capital Costs
- Local Socio-Economic Impacts
- Technological and Implementation Risk

ANALYTIC APPROACH

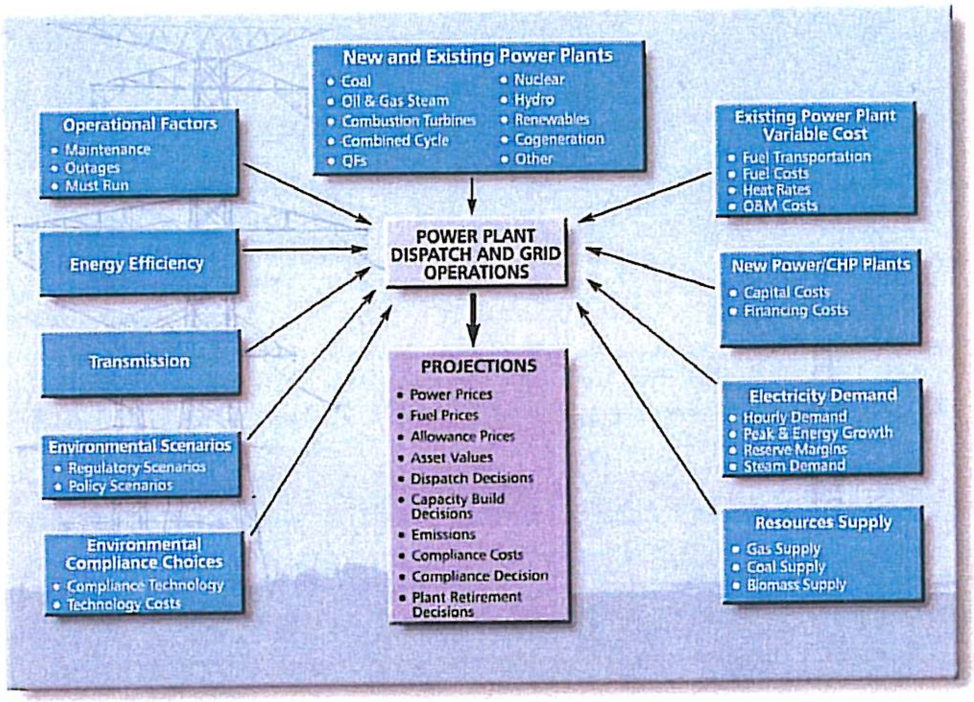
The overall analytic approach is for GRU and other utilities to make decisions which minimize costs given that one of the four options has been chosen. This is the commonly accepted analytic approach to studies considering the range of both demand and supply side options. This analysis requires a very large number of calculations that can only be done using a computer model. ICF chose to use its IPM® model, while GRU uses AEGIS, a different proprietary computer model. Both models minimize production costs including allowance costs. ICF's IPM® model is widely accepted in both the private and public sector and has undergone extensive review since it is the main tool used by the U.S. EPA.

ICF's Integrated Resource Planning (IRP) and forward short-term power market assessment will be derived utilizing the Integrated Planning Model (IPM®). The model simultaneously, for all selected regions including a GRU region, solves the following parameters consistent with a least cost solution (Exhibit 1-8):

- Power plant dispatch
- Fuel use, emissions, and environmental compliance
- Capacity expansion, mothballing, and retirement – except for GRU where we will specify four options
- Inter-regional transmission flows

- Hourly spot electrical energy prices
- Annual spot pure capacity prices which can heuristically be allocated to super peak demand hours

Exhibit 1-8
The IPM® Modeling Framework Analyzes Supply and Demand Resources on Equal Footing



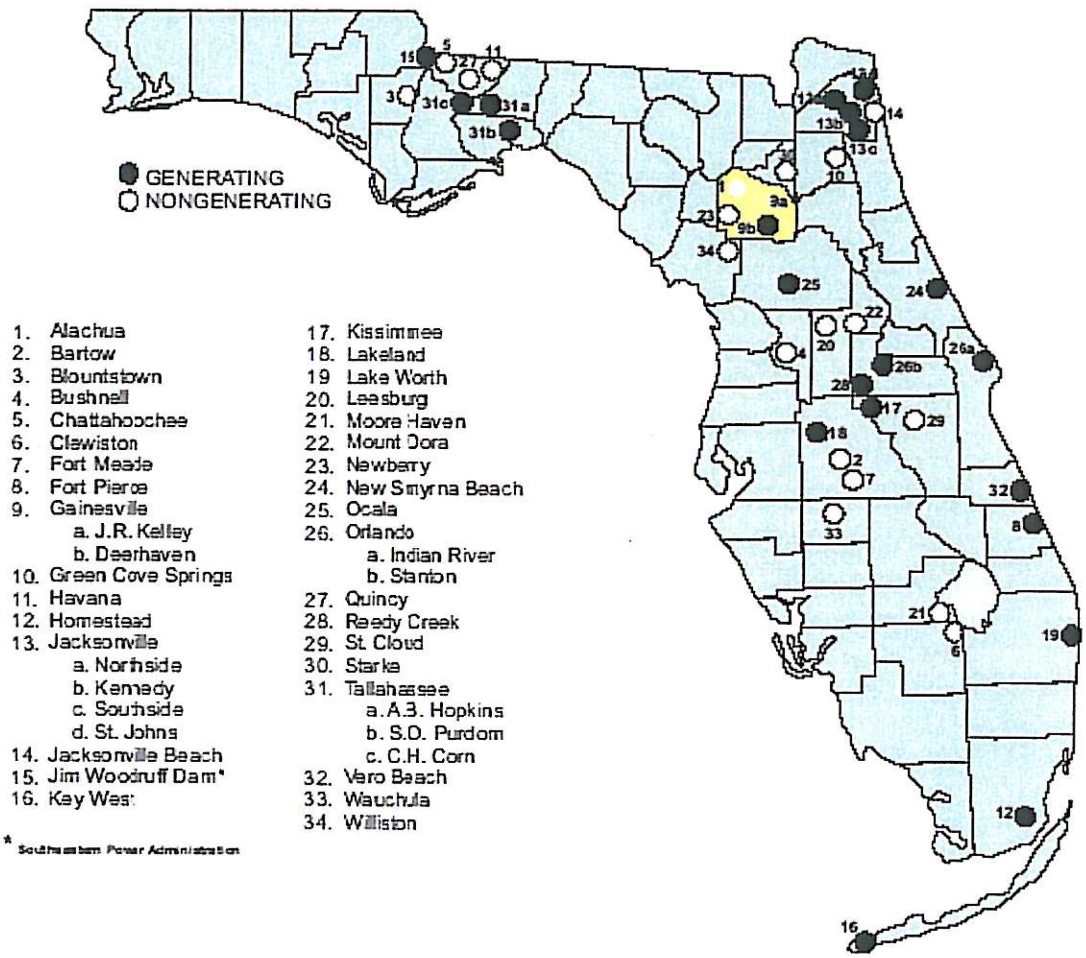
The IPM® modeling will cover not only GRU, but also the rest of the Florida Regional Coordinating Council (FRCC) and regions north of Florida in the Southern Company region covering Georgia, Alabama, and parts of Mississippi and Panhandle Florida. Florida will be disaggregated into nine zones including GRU as one of the zones (Exhibit 1-9). Transmission flows will be determined by the model. Transmission limits for non-firm (i.e., economy energy) and firm capacity are shown below (see Exhibits 1-10 and 1-11). GRU's import capability for non-firm energy is substantial. At the extreme, GRU could import 2.3 BkWh. In comparison, its 2006 energy requirements are approximately 2.2 BkWh.[35]

On the other hand, ICF AC[36] load flow modeling has identified significant firm import and export limits associated with the Deerhaven 230/138 kV transformer. A failure of

[35] While GRU's need to block power is much less today, it is larger over time due to demand growth.
[36] AC = Alternating Current; PowerWorld Load Flow Model

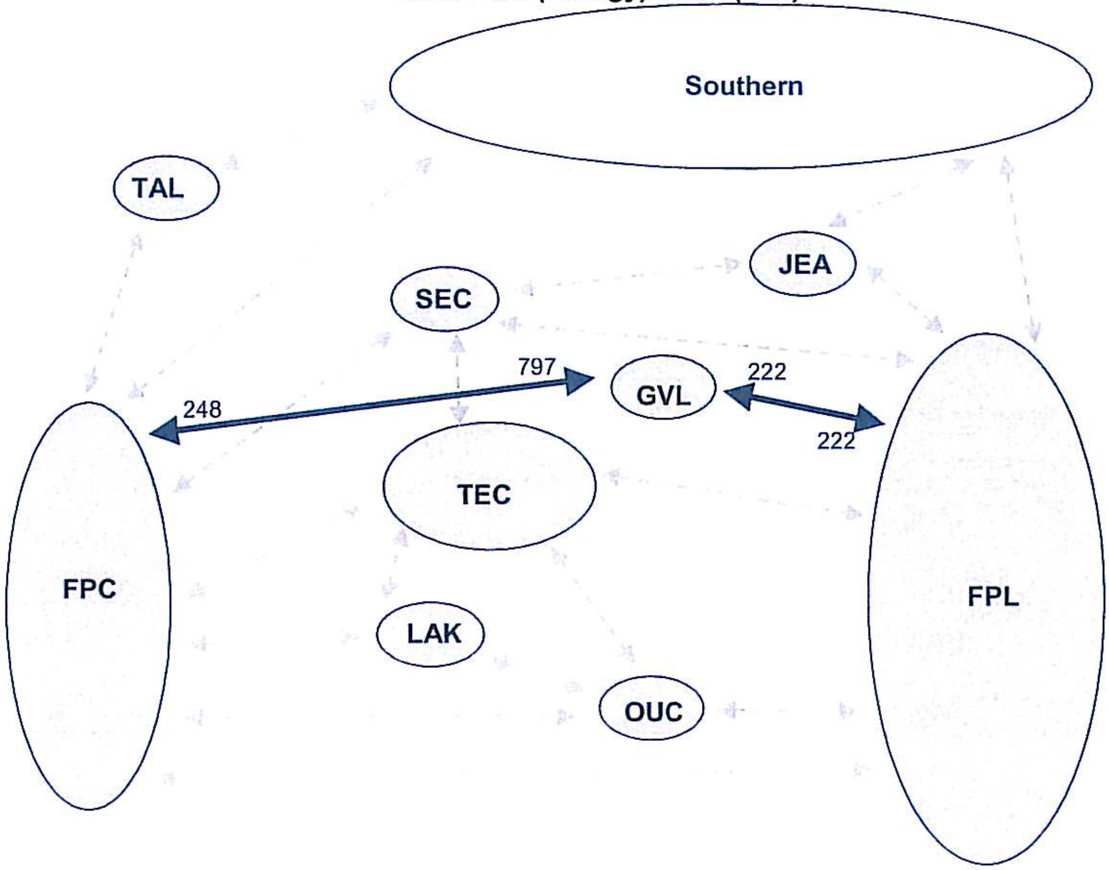
this system element threatens the Parker to Archer Road 230 kV transmission line, and hence, firm flows need to be restricted to account for this potential problem[37].

Exhibit 1-9
FRCC Region Will be Modeled Along With Neighboring Areas Accounting for Wholesale Transactions



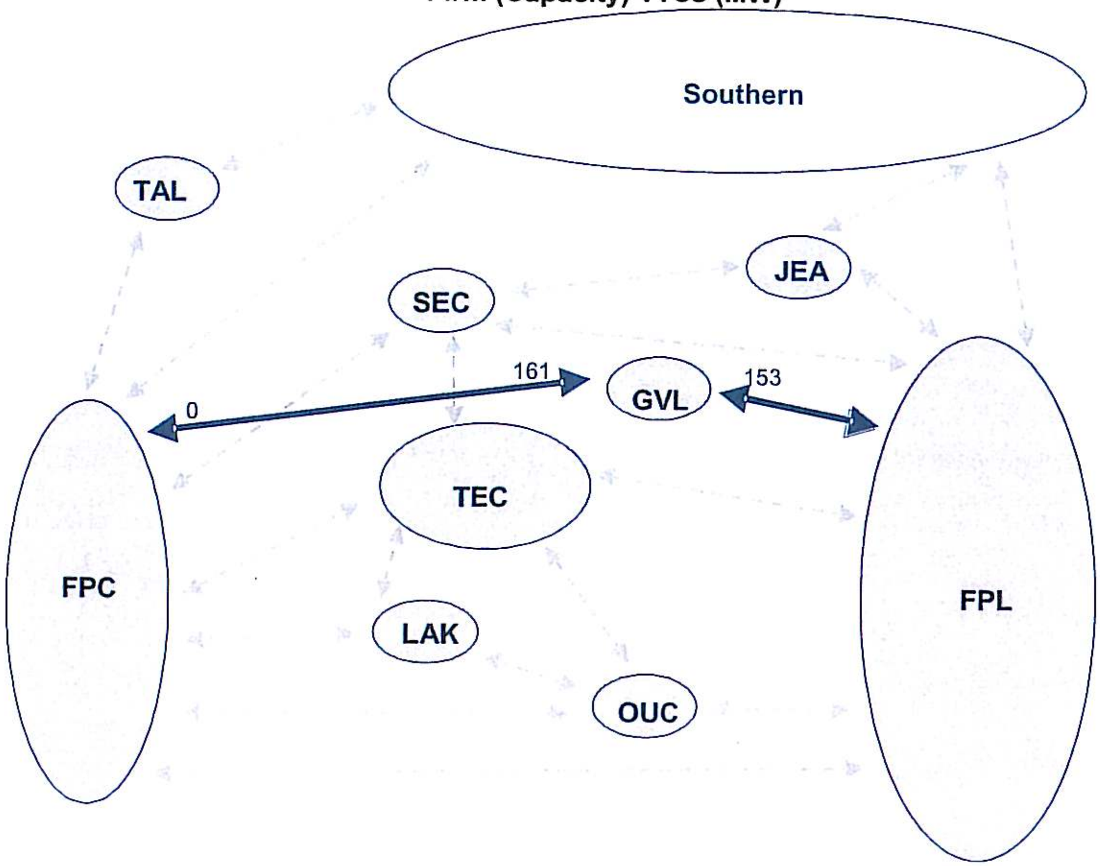
[37] An upgrade to this transformer could increase the firm import limit to approximately 150 MW. This was not modeled. In the current situation of exposure to a contingency that greatly limits external sales, the 15 percent reserve margin should be considered as especially binding and special care should be exercised to maintain sufficient generation capability.

Exhibit 1-10
Non-Firm (Energy) TTCs (MW)



GVL Non-Firm Simultaneous TTCs: Imports = 260 MW; Exports = 490 MW

Exhibit 1-11
Firm (Capacity) TTCs (MW)



GVL Firm Simultaneous TTCs: Imports = 30 MW; Exports = 0

CHAPTER TWO
DEMAND GROWTH BEFORE ADDITIONAL DEMAND SIDE MANAGEMENT PROGRAM IMPLEMENTATION

The demand growth forecast before additional DSM is very important. If electricity demand is less than expected, costly investments can and should be deferred. On the other hand, if demand is greater than expected, the City could be exposed to a higher than expected reliance on purchasing power from a few sellers in the wholesale power market and the need to quickly make decisions regarding the imperative of meeting reserve requirements.

This chapter discusses demand growth projections before additional DSM beyond the levels already planned by GRU. The next chapter separately addresses DSM. This chapter is organized into four sections. The first discusses historical electricity demand growth. The second briefly discusses electricity demand forecasting accuracy. The third presents the forecast demand growth rates used in this study. The fourth discusses GRU's supply and demand balance.

DEMAND GROWTH BEFORE ADDITIONAL DSM

Electricity demand growth for GRU has been 3.3 percent per year on a ten year rolling average basis through 2004. The ten year average including 2005 for which only limited demand data is available is 3.2 percent. These rates are above the U.S. average of approximately 2.5 percent per year for peak demand. GRU's growth is also very close to the FRCC average (Florida Regional Coordinating Council) which covers most of the state (see Exhibits 2-1, 2-2, and 2-3). Florida's electricity demand growth rate is the fastest among large states.

Exhibit 2-1
Historical Peak Electricity Demand Growth (%) Ten Year Rolling Average – Slowing Demand Growth

Ten Year Rolling Average	GRU	FRCC
1994-2004	3.3	3.5
1995-2005	3.2	3.2
2000-2004	2.9	2.8
2001-2005	2.7	2.6
2002-2004	2.6	2.5
2002-2005	2.5	2.3

Source: GRU 2005 Ten-Year Site Plan Submitted to the Florida Public Service Commission, April 2005 and NERC ES&D.

GRU has been growing at 3.2 to 3.3 percent per year which means electricity demand doubles approximately every 22 to 23 years. The ten year rolling average estimate of 3.3 percent is the simple average of 10 ten year periods, e.g., 1984 – 1994, 1985 – 1995, etc. The rolling average tends to correct for weather variation which can strongly affect peak demand growth.

Exhibit 2-2
GRU Electricity Demand Growth History – Ten Year Rolling Averages – Peak Demand

Year	Average (%)
1995 – 2005	2.56
1994 – 2004	2.70
1993 – 2003	2.09
1992 – 2002	3.07
1991 – 2001	3.25
1990 – 2000	3.37
1989 – 1999	3.54
1988 – 1998	3.45
1987 – 1997	3.28
1986 – 1996	3.90
1985 – 1995	3.50

Year	Average (%)
1984 – 1994	3.94
1983 – 1993	NA
1982 – 1992	NA
1981 – 1991	NA
1980 – 1990	NA
1979 – 1989	NA
Average 1985 – 2005	3.16
Average 1981 – 2001	NA
Average 1991 – 2005	2.74

Exhibit 2-3
FRCC Electricity Demand Growth History – Ten Year Rolling Averages – Electrical Energy

Year	Average (%)
1995 – 2005	2.34
1994 – 2004	2.56
1993 – 2003	2.12
1992 – 2002	2.89
1991 – 2001	3.09
1990 – 2000	3.15
1989 – 1999	2.97
1988 – 1998	3.96
1987 – 1997	3.24
1986 – 1996	4.30
1985 – 1995	4.69

Year	Average (%)
1984 – 1994	4.96
1983 – 1993	4.86
1982 – 1992	5.50
1981 – 1991	4.57
1980 – 1990	4.01
1979 – 1989	5.25
Average 1985 – 2005	3.21
Average 1981 – 2001	4.12
Average 2000 – 2005	2.69

In this context, the historical GRU electricity demand growth reflects several aspects of the Gainesville community including:

- **GRU Service Area Population Growth** – Population growth has been 2.2 percent per year between 1995 and 2004.
- **Residential Customers** – The number of residential customers has been growing at 3.0 percent per year between 1995 and 2004.
- **Commercial Customers** – The number of commercial customers has been growing at 2.6 percent per year between 1995 and 2004.

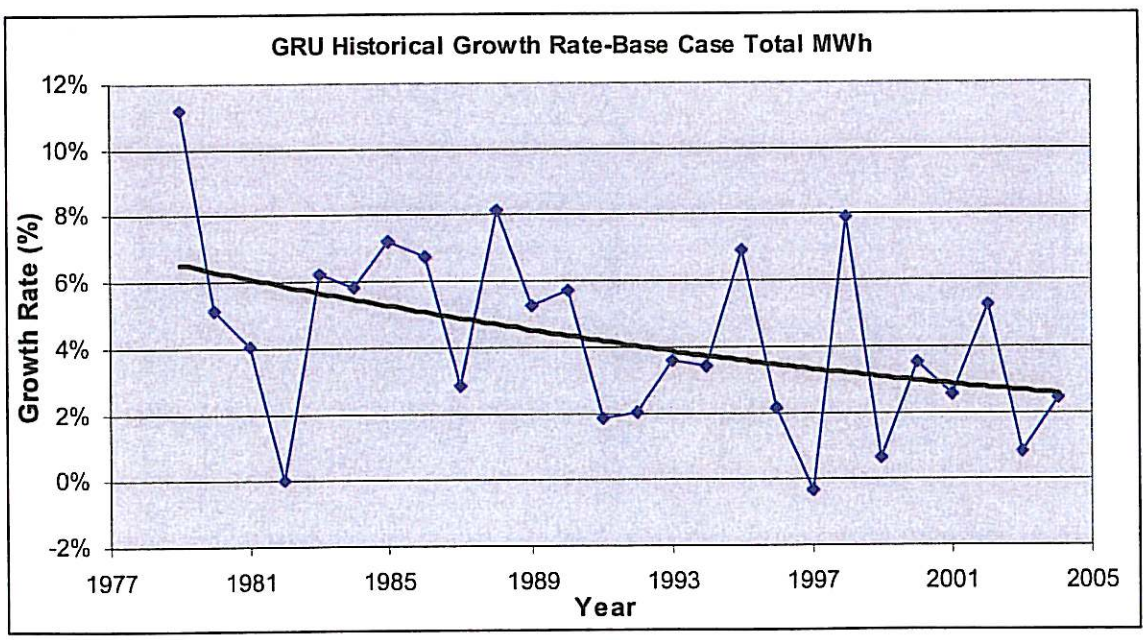
- **Residential and Commercial Sales** – Together, the commercial and residential sectors account for 88 percent of total ultimate customers sales by GRU, and hence, their strong growth explains most of the total growth in demand.

- **Retail versus Wholesale** – 13 percent of the total growth in net peak demand between 1995 and 2004 has been from wholesale sales with the remainder from retail sales. Thus, retail sales are the most important factor explaining growth.

More recently, GRU electricity demand growth appears slower. The five ten year periods ending in 2001 – 2005 show 2.7 percent annual growth, and the three ten year averages for the 2003 to 2005 period show 2.5 percent growth. This recent demand growth trend continues to match closely FRCC-wide demand growth which has also been slowing.

Between 2000 and 2004, GRU peak demand grew in total only 1 percent (see Exhibit 2-7). In 2005, peak demand grew 4.8 percent. However, the year-by-year trend also shows demand growth slowing though it also appears to be bottoming out around two percent which is GRU's projection (see Exhibit 2-4).

Exhibit 2-4



This slowing in demand growth in recent years seems to be related to slowing in population growth and income growth though they may be a temporary post-9/11 2001 recession phenomenon.

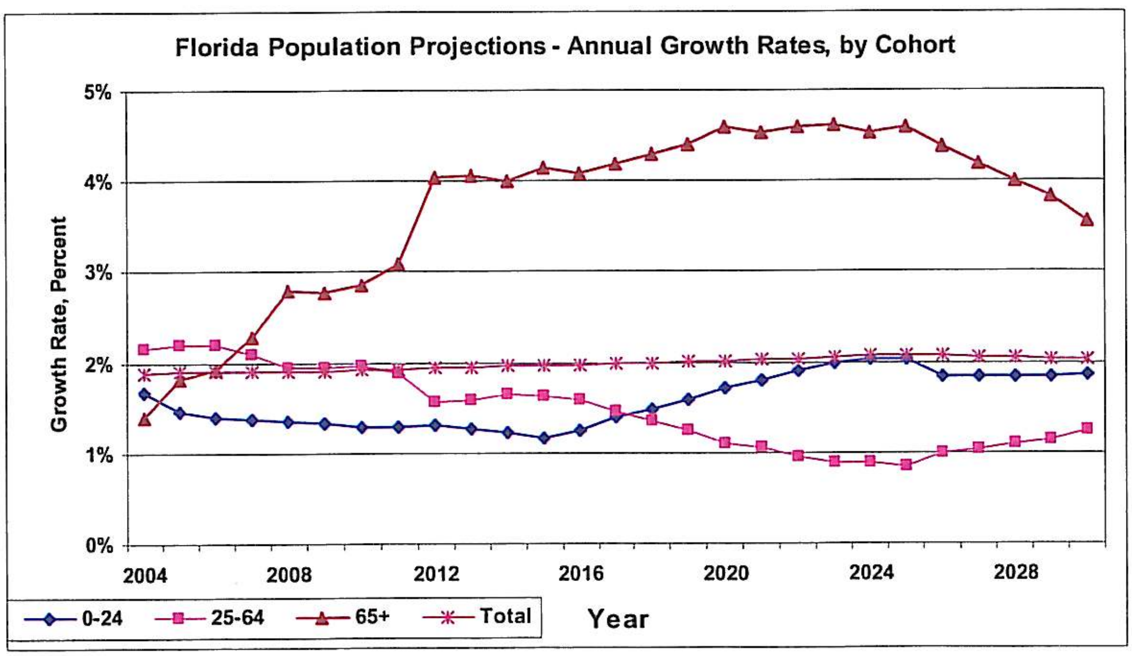
Exhibit 2-5
There Also Seems to be Modest Slowing in Key Drivers

	Personal Income Growth (%)	Population Growth (%)
Ten-Year Rolling Average – 1984 – 2002	3.6	1.8
Ten-Year Rolling Average 1989 – 2003	3.4	1.7
Ten-Year Rolling Average 1991 – 2003	3.3	1.5

Source: Bureau of Economic Analysis.

Exhibit 2-5 shows projected growth rates in population for different cohorts in Florida and supports the view that population growth will return to the longer term trend and the decline in demand growth is slowing. As has been discussed in several forums, the aging of the US population is expected to have a more severe impact on Florida than many other states. The graph below (Exhibit 2-6) shows that, while the growth rate of the overall population in Florida is expected to hold steady at around 2 percent, different cohorts are expected to grow at rates significantly different from the overall population growth rate.

Exhibit 2-6



Source: U.S. Census Bureau Population Projection data.

Exhibit 2-7
GRU Historical Demand

Year	Summer Peak Demand (MW)	Net Energy for Load (GWh)
1995	361	1648
1996	365	1659
1997	373	1661
1998	396	1779
1999	419	1798
2000	425	1868
2001	409	1882
2002	433	2008
2003	417	2015
2004	432	2049
2005	465	2122
Annual Average Growth Rate (%)[1]		
1995 – 2004	2.02%	2.45%
1995 – 2005	2.56%	2.56%
Period	**Summer Peak Demand Growth Rate (%)**	**Net Energy for Load Growth Rate (%)**
1995-2000	3.3%	2.55%
1999-2005	1.75%	2.8%

[1]These growth estimates do not correct for weather variation which strongly affects peak demand. Thus, rolling averages are preferred.
Source: GRU 2005 Ten-Year Site Plan Submitted to the Florida Public Service Commission, April 2005 and GRU provided 2005 update for peak demand.

ELECTRICITY DEMAND GROWTH PROJECTIONS

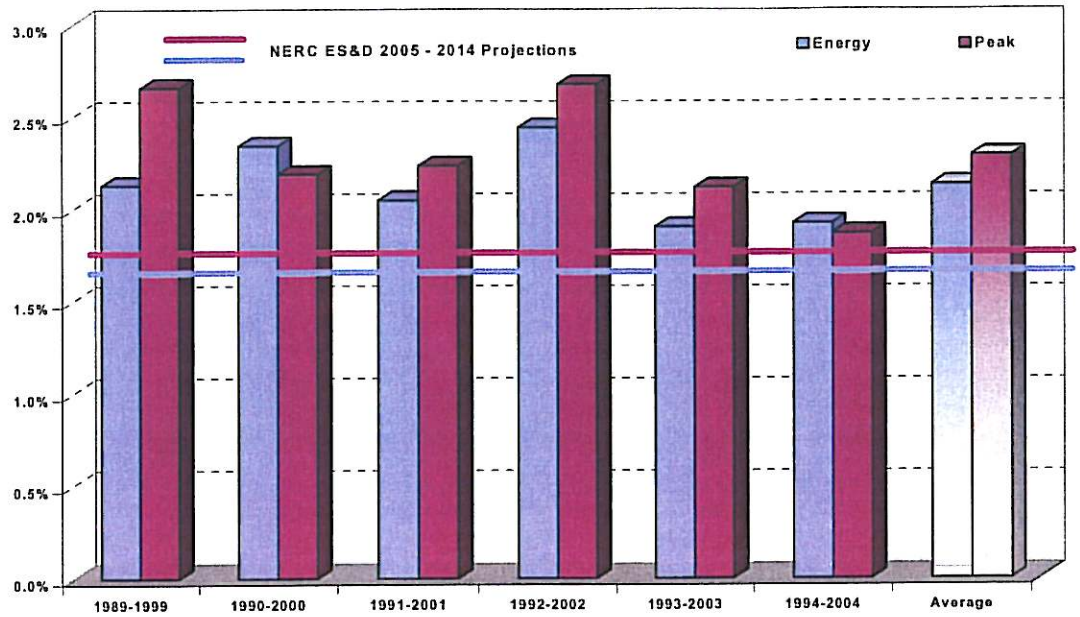
Electricity demand growth projections by the U.S. and Florida utility industry tend to be too low compared to actual historical growth (see Exhibit s 2-8 and 2-9). The causes of this under-forecasting are not fully understood, however, nationally it is a broad based phenomenon extending over nearly two decades. This has contributed to our view that the GRU forecast is reasonable to conservatively low.

Exhibit 2-8
Total Retail Energy Sales – Historical Forecast Accuracy – Significant Under Forecasting

Utility	Average Forecast Error (%)
Progress Energy Florida	-0.43
Florida Power & Light Company	-1.25
Gulf Power Company	-0.78
Tampa Electric Company	-0.73
Gainesville Regional Utilities	-1.00
JEA	-0.36
City of Lakeland	1.04
City of Tallahassee	0.31
Seminole Electric Cooperative	-0.47
Weighted Average (2000-2004) -2005 TYSP	-0.41
Weighted Average (1999-2003) -2004 TYSP	-0.72
Weighted Average (1998-2002) -2003 TYSP	-1.69

Source: A Review of Florida Electric Utility 2005 Ten Year Site Plans, prepared by the Florida Public Service Commission, Division of Economic Regulation, December 2005, page 19.

Exhibit 2-9
Demand Growth Across the US Has Been Above Industry Projections



FORECASTS OF DEMAND GROWTH BEFORE ADDITIONAL DSM

ICF has adopted the demand forecast of GRU and FRCC as its Base Case (see Exhibit 2-10). The high case for these entities reflect a weighting of historical growth and utility forecast. In 2006-2010, the estimate is a weighting of 75% historical GRU 10 year rolling average and 25% GRU 2005-2014 annual average forecast rate (AAGR); 2011-2020: 50% historical GRU 10 year rolling average and 50% GRU 2005-2014 AAGR; 2021 and thereafter : 25% historical GRU 10 year rolling average and 75% GRU 2005-2014 AAGR.

Exhibit 2-10
Forecast Electricity Demand Growth (%)

Scenario	GRU[1]	FRCC[2]
Low	NA	NA
Base	2.1	2.5
High[3]	2.8	3.1

[1]GRU's 2005 Electric System Forecast 2006-2024.
[2]FRCC 2004 Regional Load and Resources Plan, July 2004 (2004-2013 annual average)
[3]High demand scenario is a combination of historical and forecast.

GRU SUPPLY AND DEMAND BALANCE

In 2006, GRU's peak demand is forecast to be 470 MW. In 2005, actual peak demand was 465 MW. This requires GRU to have 541 MW which is 470 MW times one plus the required reserve margin of 15 percent. Reserves are required in large part because in the industry standard practice involves peak demand forecasts that assume average summer conditions, not the conditions of hotter than average summer. Also, in the industry, generation capacity is specified assuming no unexpected outages or problems even though they are very common if not ubiquitous.

Current GRU supply equals 611 MW providing a reserve margin of 30 percent. By 2012, under the base case demand growth, reserve requirements will be 626 MW and GRU supply 579 which accounts for planned retirement of Kelly #7. Thus, GRU will need more resources, supply or demand (see Exhibits 2-11 and 2-12).

By 2023, current supply less retirements is approximately 454 MW (see Exhibit 2-13). At that time, reserve requirements will be 772 MW. Firm capacity import limits are estimated by ICF to be approximately 300 MW. Thus, even if imports are available, GRU will not be able to meet its needs without more local resources.

Exhibit 2-11
GRU Supply & Demand (MW) – Base Case Demand Growth

Year	Peak Demand	Reserve Requirements[1]	Existing Supply Net of Retirements With no New Builds	Surplus (Deficit)
2006	470	541	611	71
2007	483	555	611	56
2008	495	569	611	42
2009	508	584	611	27
2010	520	598	602[2]	4
2011	532	612	579	-32
2012	544	626	579	-46
2013	556	639	579	-60
2014	569	654	579	-75
2015	580	667	579	-88
2016	592	681	579	-102
2017	603	693	579	-115
2018	614	706	551	-155
2019	625	719	537	-182
2020	636	731	537	-195
2021	648	745	537	-209
2022	659	758	537	-221
2023	671	772	454	-318
2024	683	785	454	-332
2025	694	798	454	-344

[1]Reserve margin requirement of 15 percent.
[2]Accounts for 8 MW of capacity penalty for Deerhaven 3

Exhibit 2-12
GRU Supply & Demand (MW) – High Demand Growth

Year	Peak Demand	Reserve Requirements[1]	Existing Supply Net of Retirements With no New Builds	Surplus (Deficit)
2006	470	541	611	71
2007	483	556	611	55
2008	497	571	611	40
2009	511	587	611	24
2010	525	604	602[2]	-1
2011	540	621	579	-41
2012	555	638	579	-59
2013	570	656	579	-76
2014	586	674	579	-95
2015	603	693	579	-114
2016	619	712	579	-134
2017	637	732	579	-154
2018	655	753	551	-202
2019	673	774	537	-237
2020	692	796	537	-259
2021	711	818	537	-281
2022	731	841	537	-304
2023	752	864	454	-411
2024	773	889	454	-435
2025	794	913	454	-460

[1]15 percent reserve margin.
[2]Accounts for 8 MW of capacity penalty for Deerhaven 3.

Exhibit 2-13
GRU Expected Retirements (2011 – 2025)

Plant Name	Unit No.	Unit Type	Primary Fuel	Expected Retirement Month/Year	Summer Net Capability (MW)
J.R. Kelly	7	ST	NG	8/2011	23
J.R. Kelly	3	GT	NG	2019	14
J.R. Kelly	2	GT	NG	2018	14
J.R. Kelly	1	GT	NG	2018	14
Deerhaven	1	ST	NG	2023	83
SW Landfill	1	IC	LFG	12/2009	0.65
SW Landfill	2	IC	LFG	12/2015	0.65
TOTAL					149.3

Source: GRU 2005 Ten-Year Site Plan submitted to the Florida Public Service Commission, April 2005.

Another perspective on demand growth is that in the near-term, at 2.1 percent peak demand growth, which is the GRU forecast growth rate, 12 MW of capacity requirements are added each year. At 3.3 percent growth per year, the ten year rolling average growth rate, GRU's demand grows 18 MW per year. Due to compound growth, the following is required:

- Between 2006 and 2012, the first year a new unit can reliably be brought on line, GRU generation requirements growth equals 74 MW, all else equal. This assumes that the GRU grows at the forecast growth rate of 2.1 percent.

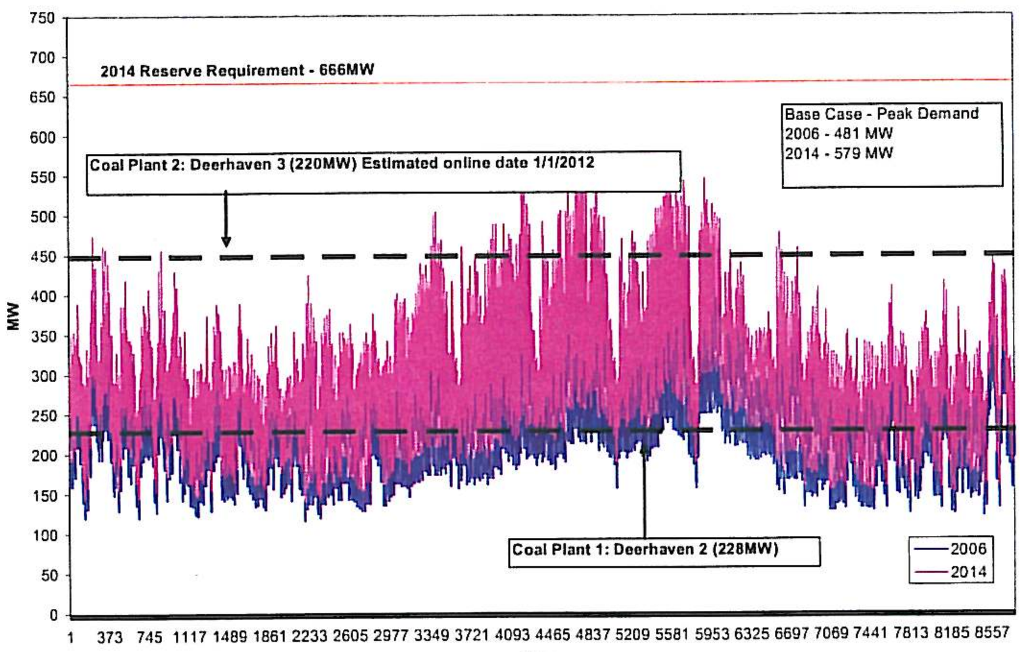
- At the historical annual growth rate of 3.3 percent, GRU requires an additional 120 MW between 2006 and 2012.

Thus, there is large potential growth in demand given the size of the plants being considered, especially if incremental DSM does not greatly decrease growth.

To illustrate the supply and demand situation facing Gainesville, a stack of two solid fuel plants is compared to: (1) hourly demand in 2006, (2) hourly demand in 2014, and (3) the 2014 reserve requirement of 666 MW (see Exhibit 2-14). As can be seen, by 2014, hourly demand in the summer exceeds the capacity of the two solid fuel plants and the reserve capacity requirement is well above this level.

This does not mean that new generation is required. However, the modeling calculates the cost consequences of growing hourly electrical energy and reserve requirements.

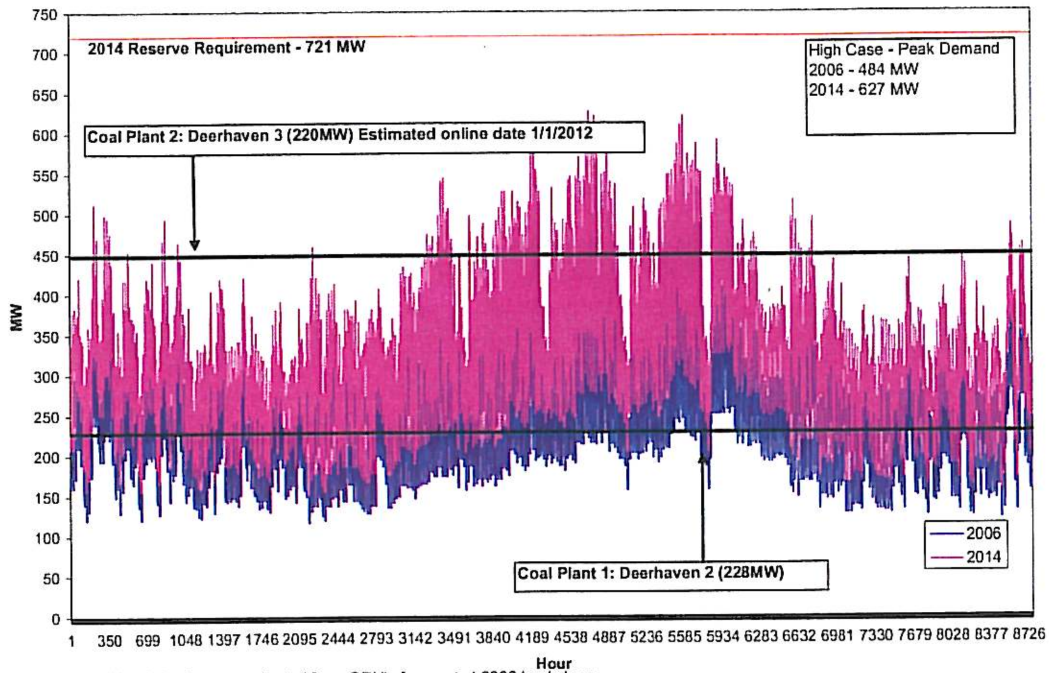
Exhibit 2-14
2006 and 2014 Base Demand Compared to Illustrative Potential Supply Stack



Source: Hourly load curves adjusted from GRU's forecasted 2006 load shape.

A similar graphic shows the effect of the high growth case (see Exhibits 2-15, 2-16, and 2-17) where demand grows at 2.8 percent per year. In this example, the capacity requirements in excess of the two solid fuel plants is 773 MW (721 – 228 – 220).

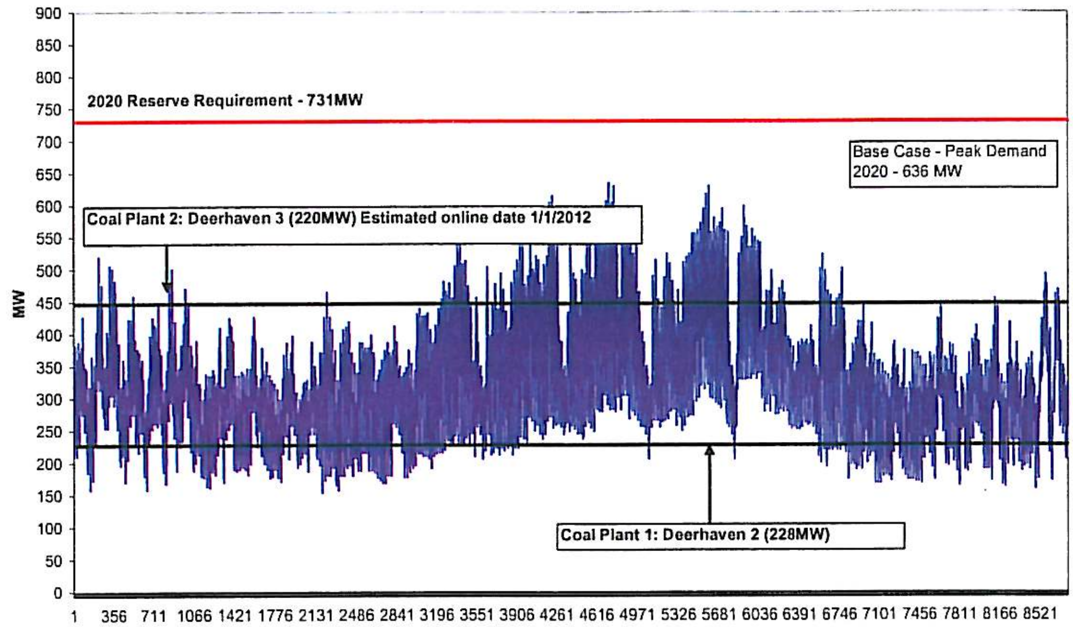
Exhibit 2-15
2006 and 2014 High Demand Case With Illustrative Potential Supply Stack



Source: Hourly load curves adjusted from GRU's forecasted 2006 load shape.

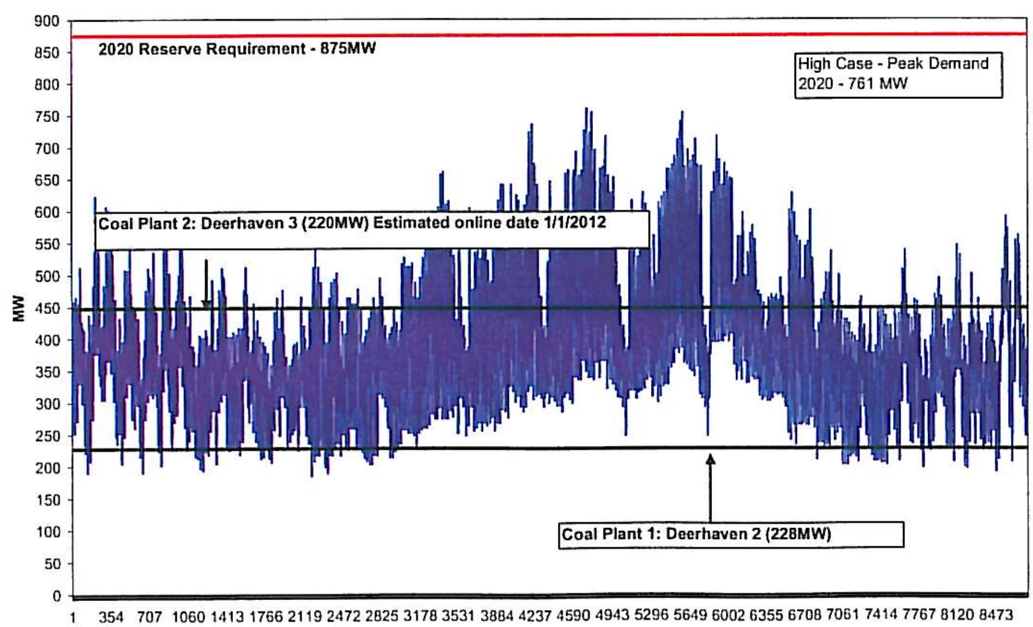
In 2020, cumulating demand growth raises the extent to which the second solid fuel unit is used on an hourly demand and capacity requirements.

Exhibit 2-16
2020 Base Demand Case With Illustrative Potential Supply Stack



Source: Hourly load curves adjusted from GRU's forecasted 2006 load shape.

Exhibit 2-17
2020 High Demand Case With Illustrative Potential Supply Stack



Source: Hourly load curves adjusted from GRU's forecasted 2006 load shape.

CHAPTER THREE
DEMAND SIDE MANAGEMENT

DSM Options Overview

To analyze the benefits of demand-side management (DSM) programs, we characterized a broad range of potential DSM programs and performed an integrated analysis alongside the supply-side options using the Integrated Planning Model (IPM). IPM was allowed to pick the most economic DSM programs as an alternative way to meet future electricity demand and reserve margin requirements. This analysis allows us to draw some important conclusions:

- Many of the potential DSM programs are less costly than the supply-side alternatives, with levelized average costs of only $23/MWh.

- Under base case load growth, these DSM options are capable of significantly deferring growth in capacity and generation requirements. The "Maximum DSM" scenario, which chooses all DSM programs which are economic assuming high natural gas prices and high CO_2 prices, provides an additional 48.99 non-coincident MW of capacity (30.66 coincident peak MW savings) by 2015 and 88.40 non-coincident MW (55.85 coincident peak MW) by 2025 (including reserve margins.) However, under the high load growth case the Maximum DSM scenario can only defer the need for capacity one year, from 2010 until 2011.

Note: Even under Base Case assumptions (i.e. not using the high CO2 and high fuel costs), the same combination of DSM programs was selected as being cost-effective.

- The Maximum DSM scenario results in GRU's annual spending on DSM doubling after two years, and growing to almost four times current levels within 10 years (approximately $7.0M/yr)[38].

- The Maximum DSM programs would cut GRU's annual load growth by approximately 43% by 2015.

- The incremental annual DSM program expenditures equate to an additional $13.11 per customer immediately, increasing to an additional $52 per customer in nine years.

- The Maximum DSM level of expenditure and load reduction is comparable to that achieved by Austin Energy, and as such would require

[38] All dollars are in expressed in 2003 dollars

Gainesville to become a national leader in DSM program implementation.

- Significant short-term investments in the DSM infrastructure of both GRU and the community would be necessary to achieve these reductions.

Exhibit 3-1 summarizes key statistics for all the 19 potential DSM programs analyzed, and shows their capital cost in dollars per non-coincident peak kW to range between \$90[39]/kW (for A/C direct load control) and \$5,133/kW (for solar water heaters). Note that direct load control programs for residential A/C and hot water have additional ongoing non-capital program costs included only in the annualized \$/kW-yr cost Exhibit s below.

Exhibit 3-2 summarizes the load impacts for the 15 DSM programs that were chosen at some point in the planning horizon, and details the rise in coincident peak MW reduction from these programs from 4.41 MW in 2008 to 55.85 MW in 2025 including reserve margin contributions. Exhibit 3-3 provides similar data for the annual energy or MWh reductions.

Exhibits 3-4 through 3-7 detail the impact of the Maximum DSM case programs on: Annual Costs, Reserve Margin Requirements, Base Case Demand Growth, and High Case Demand Growth respectively.

The remainder of this Chapter details our methodology for determining the magnitude and cost of the DSM programs, and illustrates how the results compare to those of other utilities.

[39] For an equitable comparison, the DLC cost should also reflect additional charges for incentives paid to customers and ongoing operations, maintenance, and switch replacement costs.

Exhibit 3-1
ICF Analyzed 19 DSM Programs

ICF Identifier Option – Gainesville DSM	Option Name	Capital Costs (2003$/kW)	CCR (%)	Life [40]	Capital and Other Costs Transformed to Yearly Payment (2003$/kW-yr)	Reserve Margin Contribution Factor (%, Coincidence Factor x 1.15)	Capacity Factor (%)
DSM 1	Residential CFL Program	161.45	14.81	8	23.92	12	32.6
DSM 2	Residential Fridge/Freezer Buyback	396.52	12.30	10	48.79	102	77.1
DSM 3	Home Performance with ENERGY STAR (Marginally Cost-Effective Measures)	1,511.65	8.99	15	135.92	87	--
DSM 4	Home Performance with ENERGY STAR (Cost-Effective Measures)	339.23	8.99	15	30.50	87	16
DSM 5	Comprehensive Water Heating Program	720.84	8.99	15	64.81	36	40.8
DSM 6	Residential Solar Water Heater	5,133.23	8.99	15	461.54	36	--
DSM 7	Residential Appliance	1,469.31	8.99	15	132.11	98	75.3
DSM 8	Residential A/C Rebate, Weatherization, & A/C Tune-Up Program (Marginally Cost-Effective Measures)	1,511.65	8.99	15	135.92	87	--
DSM 9	Residential A/C Rebate, Weatherization, & A/C Tune-Up Program (Cost-Effective Measures)	339.23	8.99	15	30.50	87	16
DSM 10	Residential A/C Direct Load Control	90.44	6.70	25	28.31[41]	115	0.3
DSM 11	Residential Water Heating Direct Load Control	891.71	6.70	25	162.78[42]	115	--
DSM 12	ENERGY STAR Homes	334.32	6.70	25	22.40	87	16.0
DSM 13	Commercial Cooling	825.09	8.99	15	74.19	115	22.9
DSM 14	Commercial Lighting – Exterior	788.17	12.30	10	96.97	6	51.6
DSM 15	Commercial Lighting – Interior	1,460.73	12.30	10	179.72	104	60.9
DSM 16	Commercial Office Equipment	1,387.00	19.18	4	266.09	106	77.0
DSM 17	Grocery and Restaurant Refrigeration Program	1,346.67	8.99	15	121.08	107	77.9
DSM 18	Commercial Ventilation	2,803.56	8.99	15	252.07	115	72.7
DSM 19	Commercial Water Heating	1,864.86	8.99	15	167.67	91	74.7

[40] DSM program impacts do reflect the life of the various measures installed, and are therefore inclusive of vintaging effects.
[41] Includes ongoing annual cost of 22.25 (2003$/kW-yr)
[42] Includes ongoing annual cost of 103.05 (2003$/kW-yr)

Exhibit 3-2
DSM Choice Under High Gas and CO_2 Prices – Cumulative Non-Coincident Peak MW[1] Savings

ICF Identifier Option – Gainesville DSM	Option Name	First Year On-Line	2006	2008	2009	2010	2011	2013	2015	2020	2025
DSM1	Residential CFL Program	2006	0.79	1.35	2.07	2.95	4.00	6.55	9.42	14.96	16.74
DSM 2	Residential Fridge/Freezer Buyback	2006	0.08	0.13	0.20	0.28	0.38	0.63	0.90	1.44	1.61
DSM 3	Home Performance with ENERGY STAR (Marginally Cost-Effective Measures)	Does Not Choose	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DSM 4	Home Performance with ENERGY STAR (Cost-Effective Measures)	2006	0.57	0.97	1.48	2.11	2.86	4.70	6.75	10.72	11.99
DSM 5	Comprehensive Water Heating Program	2006	0.19	0.33	0.50	0.72	0.98	1.60	2.30	3.65	4.09
DSM 6	Residential Solar Water Heater	Does Not Choose	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DSM 7	Residential Appliance	2006	0.10	0.18	0.27	0.38	0.52	0.86	1.23	1.95	2.19
DSM 8	Residential A/C Rebate, Weatherization, & A/C Tune-Up Program (Marginally Cost-Effective Measures)	Does Not Choose	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DSM 9	Residential A/C Rebate, Weatherization, & A/C Tune-Up Program (Cost-Effective Measures)	2006	1.32	2.26	3.45	4.93	6.68	10.96	15.75	25.01	27.98
DSM 10	Residential A/C Direct Load Control	2020	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.16	1.37
DSM 11	Residential Water Heating Direct Load Control	Does Not Choose	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DSM 12	ENERGY STAR Homes	2006	0.02	0.03	0.04	0.06	0.08	0.13	0.19	0.30	0.33
DSM 13	Commercial Cooling	2006	0.18	0.30	0.46	0.65	0.88	1.45	2.08	3.31	3.70
DSM 14	Commercial Lighting – Exterior	2006	0.14	0.25	0.38	0.54	0.73	1.20	1.72	2.74	3.06
DSM 15	Commercial Lighting – Interior	2006	0.48	0.82	1.25	1.78	2.41	3.96	5.68	9.03	10.10
DSM 16	Commercial Office Equipment	2006	0.12	0.20	0.31	0.44	0.60	0.98	1.41	2.23	2.50
DSM 17	Grocery and Restaurant Refrigeration Program	2006	0.04	0.07	0.10	0.15	0.20	0.33	0.47	0.74	0.83
DSM 18	Commercial Ventilation	2006	0.03	0.06	0.09	0.13	0.18	0.29	0.42	0.66	0.74
DSM 19	Commercial Water Heating	2006	0.06	0.10	0.15	0.21	0.28	0.46	0.66	1.05	1.18
	TOTAL		4.12	7.04	10.75	15.32	20.79	34.08	48.99	78.96	88.40

[1]MW at coincident peak.

Exhibit 3-3
DSM Choice Under High Gas and CO_2 Prices – Cumulative Annual MWh Savings

ICF Identifier Option – Gainesville DSM	Option Name	First Year On-Line	2006	2008	2009	2010	2011	2013	2015	2020	2025
DSM1	Residential CFL Program	2006	2,260	3,865	5,901	8,413	11,416	18,717	26,902	42,725	47,792
DSM 2	Residential Fridge/Freezer Buyback	2006	514	878	1,341	1,911	2,594	4,252	6,112	9,706	10,858
DSM 3	Home Performance with ENERGY STAR (Marginally Cost-Effective Measures)	Does Not Choose	-	-	-	-	-	-	-	-	-
DSM 4	Home Performance with ENERGY STAR (Cost-Effective Measures)	2006	795	1,359	2,075	2,959	4,015	6,582	9,460	15,025	16,807
DSM 5	Comprehensive Water Heating Program	2006	691	1,181	1,804	2,572	3,489	5,721	8,223	13,059	14,608
DSM 6	Residential Solar Water Heater	Does Not Choose	-	-	-	-	-	-	-	-	-
DSM 7	Residential Appliance	2006	682	1,166	1,780	2,538	3,444	5,646	8,115	12,889	14,417
DSM 8	Residential A/C Rebate, Weatherization, & A/C Tune-Up Program (Marginally Cost-Effective Measures)	Does Not Choose	-	-	-	-	-	-	-	-	-
DSM 9	Residential A/C Rebate, Weatherization, & A/C Tune-Up Program (Cost-Effective Measures)	2006	1,855	3,172	4,842	6,903	9,368	15,358	22,074	35,057	39,215
DSM 10	Residential A/C Direct Load Control	2020	-	-	-	-	-	-	-	31	36
DSM 11	Residential Water Heating Direct Load Control	Does Not Choose	-	-	-	-	-	-	-	-	-
DSM 12	ENERGY STAR Homes	2006	22	38	57	82	111	182	262	416	465
DSM 13	Commercial Cooling	2006	351	601	917	1,307	1,774	2,908	4,180	6,639	7,426
DSM 14	Commercial Lighting – Exterior	2006	655	1,120	1,709	2,437	3,307	5,421	7,792	12,374	13,842
DSM 15	Commercial Lighting – Interior	2006	2,548	4,358	6,653	9,484	12,870	21,100	30,327	48,165	53,877
DSM 16	Commercial Office Equipment	2006	797	1,363	2,081	2,967	4,027	6,602	9,489	15,070	16,857
DSM 17	Grocery and Restaurant Refrigeration Program	2006	268	459	700	998	1,355	2,221	3,192	5,070	5,671
DSM 18	Commercial Ventilation	2006	223	381	581	829	1,124	1,843	2,649	4,208	4,707
DSM 19	Commercial Water Heating	2006	364	623	951	1,356	1,841	3,018	4,337	6,888	7,705
	TOTAL (in GWh)		12.0	20.6	31.4	44.8	60.7	99.6	143.1	227.3	254.3

Exhibit 3-4
DSM Choice Under High Gas and CO_2 Prices – Annual Costs (in $000)

ICF Identifier Option – Gainesville DSM	Option Name	First Year On-Line	2006	2008	2009	2010	2011	2013	2015	2020	2025
DSM1	Residential CFL Program	2006	128	91	115	142	170	413	463	895	286
DSM 2	Residential Fridge/Freezer Buyback	2006	30	21	27	34	40	97	109	211	68
DSM 3	Home Performance with ENERGY STAR (Marginally Cost-Effective Measures)	Does Not Choose	0	0	0	0	0	0	0	0	0
DSM 4	Home Performance with ENERGY STAR (Cost-Effective Measures)	2006	192	137	173	214	256	621	697	1,347	431
DSM 5	Comprehensive Water Heating Program	2006	139	99	125	155	185	450	505	975	312
DSM 6	Residential Solar Water Heater	Does Not Choose	0	0	0	0	0	0	0	0	0
DSM 7	Residential Appliance	2006	152	108	137	169	202	491	550	1,063	341
DSM 8	Residential A/C Rebate, Weatherization, & A/C Tune-Up Program (Marginally Cost-Effective Measures)	Does Not Choose	0	0	0	0	0	0	0	0	0
DSM 9	Residential A/C Rebate, Weatherization, & A/C Tune-Up Program (Cost-Effective Measures)	2006	449	319	404	499	596	1,450	1,625	3,142	1,006
DSM 10	Residential A/C Direct Load Control	2020	0	0	0	0	0	0	0	492	88
DSM 11	Residential Water Heating Direct Load Control	Does Not Choose	0	0	0	0	0	0	0	0	0
DSM 12	ENERGY STAR Homes	2006	5	4	5	6	7	17	19	37	12
DSM 13	Commercial Cooling	2006	144	103	130	161	192	467	523	1,011	324
DSM 14	Commercial Lighting – Exterior	2006	114	81	103	127	152	369	413	799	256
DSM 15	Commercial Lighting – Interior	2006	698	495	628	775	927	2,253	2,526	4,884	1,564
DSM 16	Commercial Office Equipment	2006	164	116	148	182	218	529	594	1,148	368
DSM 17	Grocery and Restaurant Refrigeration Program	2006	53	38	48	59	70	171	192	371	119
DSM 18	Commercial Ventilation	2006	98	70	88	109	130	317	355	686	220
DSM 19	Commercial Water Heating	2006	104	74	94	115	138	335	376	727	233
	TOTAL/AVERAGE		2,471	1,754	2,225	2,746	3,283	7,980	8,947	17,787	5,627

Exhibit 3-5
Comparison of GRU Demand Before and After DSM Chosen – Base Case Demand Growth (MW)

Year	Before DSM		After DSM		Change	
	Peak Demand	Peak Demand Plus Reserve Requirements	Peak Demand	Peak Demand Plus Reserve Requirements	Peak Demand	Peak Demand Plus Reserve Requirements
2006	470	541	466	536	4	5
2007	483	555	477	549	6	6
2008	495	569	488	561	7	8
2009	508	584	497	572	11	12
2010	520	598	505	580	15	18
2011	532	612	511	588	21	24
2012	544	626	517	594	27	32
2013	556	639	522	600	34	39
2014	569	654	527	607	42	48
2015	580	667	531	611	49	56
2016	592	681	538	619	54	62
2017	603	693	544	625	59	68
2018	614	706	549	631	65	75
2019	625	719	553	636	72	83
2020	636	731	557	641	79	91
2021	648	745	567	652	81	93
2022	659	758	576	663	83	95
2023	671	772	587	674	84	97
2024	683	785	597	686	86	99
2025	694	798	606	696	88	102

Exhibit 3-6
Comparison of GRU Demand Before and After DSM Chosen – Base Case Demand Growth (GWh)

Year	Before DSM Energy (GWh)	After DSM Energy (GWh)	Change in Energy (GWh)
2006	2,177	2,165	12
2007	2,233	2,217	16
2008	2,291	2,270	21
2009	2,349	2,318	31
2010	2,407	2,362	45
2011	2,460	2,399	61
2012	2,514	2,434	80
2013	2,570	2,470	100
2014	2,627	2,506	121
2015	2,679	2,536	143
2016	2,732	2,572	160
2017	2,783	2,606	177
2018	2,833	2,639	194
2019	2,883	2,673	210
2020	2,933	2,706	227
2021	2,984	2,751	233
2022	3,036	2,798	238
2023	3,088	2,845	243
2024	3,140	2,891	249
2025	3,193	2,939	254

Exhibit 3-7
GRU Supply and Demand Balance – High Case Demand Growth

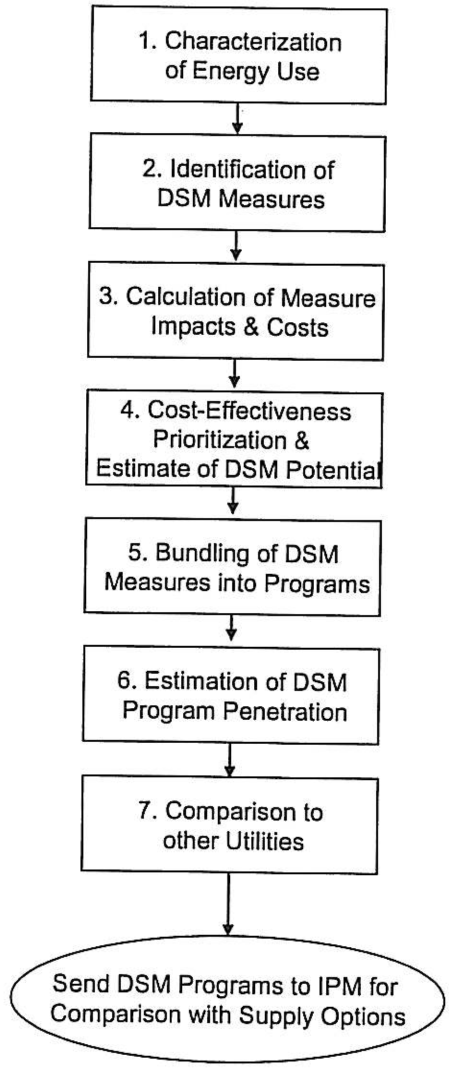
Year	Assuming No New Capacity Construction			Before DSM		After Maximum DSM	
	Existing Capacity	Retire-ments	Net Capacity	Peak Demand Plus Reserve Require-ments	Deficit Surplus	Peak Demand Plus Reserve Require-ments	Deficit Surplus
2006	611		611	541	71	536	75
2007	611		611	556	55	549	62
2008	611		611	571	40	563	48
2009	611		611	587	24	575	36
2010	611	9[1]	602	604	-1	586	16
2011	611	23	579	621	-41	597	-17
2012	611		579	638	-59	606	-27
2013	611		579	656	-76	617	-37
2014	611		579	674	-95	626	-47
2015	611		579	693	-114	637	-57
2016	611	1	579	712	-134	650	-72
2017	611		579	732	-154	664	-85
2018	611	28	551	753	-202	678	-127
2019	611	14	537	774	-237	691	-155
2020	611		537	796	-259	705	-168
2021	611		537	818	-281	725	-188
2022	611		537	841	-304	746	-209
2023	611	83	454	864	-411	767	-313
2024	611		454	889	-435	789	-335
2025	611		454	913	-460	812	-358

[1]Accounts for 8 MW of capacity penalty for Deerhaven 3.

Summary of DSM Analysis Methodology

The primary goal of the DSM analysis is to characterize a wide range of potential DSM programs in a manner consistent with supply-side alternatives such that an "apples-to-apples" comparison can be made by IPM. Therefore, the primary output of the DSM analysis is an assessment of the amount and timing of load reductions (kW and MWh) that can be achieved in the GRU service territory, along with the cost of such reductions. In addition the analysis supports the assessment of DSM impacts on emissions, jobs, and average GRU rate levels as discussed elsewhere in this report. The basic methodology is outlined in Exhibit 3-8.

Exhibit 3-8
Overview of DSM Analysis Methodology



Each step in this process is summarized briefly below. The remainder of this section discusses each step, its assumptions, and its results in more detail.

Step 1. Characterization of Energy Use. In order to understand which technologies are most applicable to the customers of GRU, it is first necessary to understand how electricity is currently being used in the community. Therefore, this step estimates how much energy is being used by a range of customer types (e.g. offices, schools, residences) for a variety of end-uses (e.g. lighting, air-conditioning).

Step 2. Identification of DSM Measures. Informed by the results of Step 1, a list of approximately 125 potential DSM measures was developed using data from previous GRU studies, community input, experiences of other utilities, ICF experience, and other sources.

Step 3. Calculation of DSM Measure Impacts and Costs. For each of the DSM measures, an estimate of the cost of installation and maintenance was developed, along with the impact on electricity summer peak demand (kW) and annual energy (kWh.) For weather-sensitive measures, ICF performed approximately 1,280 residential energy simulation runs and 2,112 commercial runs using the Department of Energy's DOE-2 software to determine specific impacts under Gainesville's unique weather conditions.

Step 4. Cost-Effectiveness Prioritization and Estimation of DSM Potential. Based on the costs and impacts, a "Supply Curve" for DSM, showing how many Megawatts of DSM reduction are available at varying cost levels was developed. The measures were then prioritized based on their potential cost-effectiveness (under the TRC test) and an estimate of the amount of cost-effective DSM was developed.

Step 5. Bundling of Measures into Programs. Since DSM measures (e.g., attic insulation) are rarely delivered alone, but are typically packaged into programs with other measures to achieve economies of scale, measures passing the cost-effectiveness screening were grouped into programs for further analysis. This process resulted in 12 residential and seven commercial programs.

Step 6. Estimation of DSM Program Penetration. The estimated participation rate of GRU customers in the DSM programs was developed based upon the market size, growth rate, economics of the technologies, and related factors. Total program impacts and costs were also developed. Note that these impacts are over and above GRU's currently proposed DSM programs.

Step 7. Comparison to Other Utilities. The relative magnitude of the DSM programs (both in terms of dollars and load reduction) was compared to other utilities, including Austin Energy and an illustration of the relative aggressiveness of the potential portfolio of DSM programs was provided.

All the DSM Programs were then passed to IPM for integrated analysis alongside the supply-side options and evaluation of economic, rate, and emissions impacts.

Note that this process does not attempt to define in final detail the complete nature of the potential DSM programs, and that many decisions about qualifying technologies, how to deliver the programs, and removal of barriers would need to be made if the programs were to be implemented. Similarly, the analysis does not attempt to analyze the universe of technologies that might have some value in the programs in the future, even if their impact would be small. Nor does this analysis reveal whether these programs are a "good idea" or not, since a variety of policy issues, such as impact of the programs on average rate levels, equity between customers, perspectives on future markets for fuels and energy, emissions, and other issues need to be resolved to answer this question.

The process does, however, characterize the amount and cost of DSM that is reliably achievable with aggressive funding and cost-effectiveness assumptions. It permits a robust comparison with the supply-side options, and lays the foundation for an assessment of the trade-offs between various policy considerations.

Step 1. Characterization of Energy Use

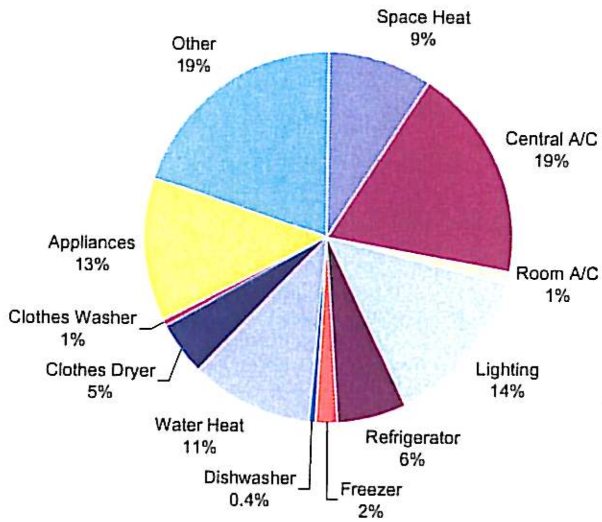
To establish a baseline profile of energy consumption by building type and end-use, we utilized data from GRU's ten-year plan, GRU's 1994-1995 DSM Study, and from the Energy Information Administration (EIA)[43]. This type of detailed end-use characterization is important since in many cases DSM potential is estimated as a percentage reduction in the energy currently used by a particular technology or end-use.

Total residential electricity sales were taken from EIA 2004 Form 861 data, and confirmed by the GRU 2005 Ten-Year Site Plan (Site Plan). The residential load of 878 GWh was segmented by end-use using EIA Annual Energy Outlook data to maintain consistency with our methodology for the commercial sector and to utilize the most recent available information. This end use segmentation is summarized in Exhibit 3-9[44]. End-use data were further segmented by technology type based on the GRU DSM Study, EIA data, and best judgment.

[43] End use segmentations and electricity intensities from EIA RECS, CBECS, and Annual Energy Outlook 2004.

[44] Data for the end-use consumption Exhibit s is provided in the Appendix

Exhibit 3-9
GRU Residential Electricity Load (MWh Share) by End-use



Total commercial electricity sales were also taken from EIA 2004 Form 861 data. The commercial load of 764 GWh was segmented by sub-sector according to the GRU DSM Study. Within each sub-sector, load was segmented by end-use according to building-specific end-use splits from EIA Annual Energy Outlook data (see Exhibit 3-10). End-use load was then further segmented by technology type.

A segmentation of residential and commercial peak demand, excluding losses and wholesale demand, was provided by GRU in comments received February 17, 2006. Total residential coincident peak demand was equal to 213 MW. We used regional load shapes in combination with the end-use electricity sales segmentation described above to assess the relative contributions of each end-use to the total residential sector peak demand. Commercial peak demand was equal to 171 MW, and was segmented by building type according to segmentations available in the 1994-1995 GRU DSM Study. As in the residential sector, the relative contributions of each end use to peak demand in each sub-sector were derived using region-specific load shapes and the electricity sales segmentation described above.

Exhibit 3-10
Share of Commercial Load (MWh) by Sub-sector and End-use

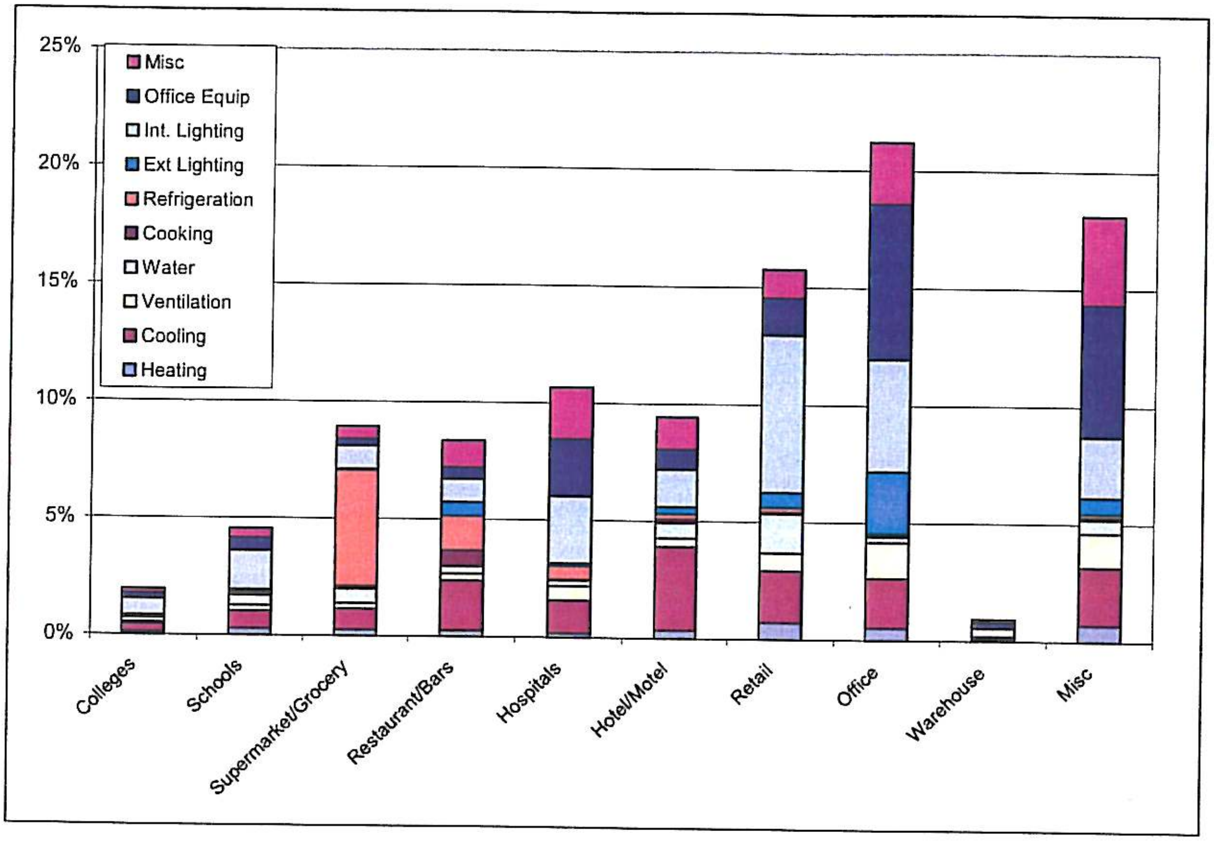
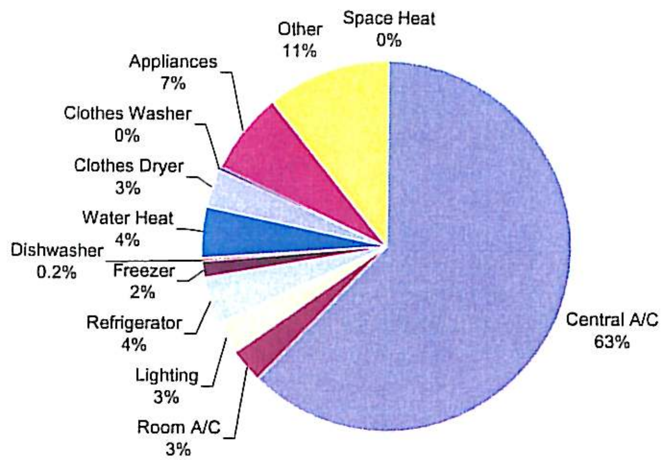


Exhibit 3-11
GRU Residential Peak Demand Share by End-use



To determine typical residential household electricity consumption for weather-sensitive end-uses, we referred to the EIA's 2001 Residential Energy Consumption Survey. The finest level of geographic resolution available from this data set is for the state of Florida, which we assumed to be indicative of average end-use consumption per household in Gainesville. As necessary, we made appropriate adjustments for Gainesville where specific data (such as the saturation of gas water heating) were known. In the commercial sector, end-use consumption per square foot was taken from the EIA's 1999 Commercial Building Energy Consumption Survey data. The values for end-use consumption were taken from the South Census Region survey tables as the best available representation of Gainesville load.

In the residential sector, electricity consumption is dominated by the central air conditioning, lighting, water heating, and appliance end-uses (Exhibit s 3-11 and 3-13). Because of Gainesville's warm climate, air conditioning is the single largest energy consuming end-use. Central air conditioning represents an even greater share of overall residential peak electricity demand and will be a primary target of the DSM technologies selected.

In the commercial sector, the office and retail building types make up the largest shares of overall electricity consumption and peak demand. Within these building types, cooling, lighting, and office equipment make up the largest shares (Exhibits 3-12 and 3-14). As is the case in the residential sector, peak demand more heavily favors cooling loads, which are at their peak coincident with the system peak.

Exhibit 3-12
GRU Commercial Peak Demand by Sub-sector and End-use

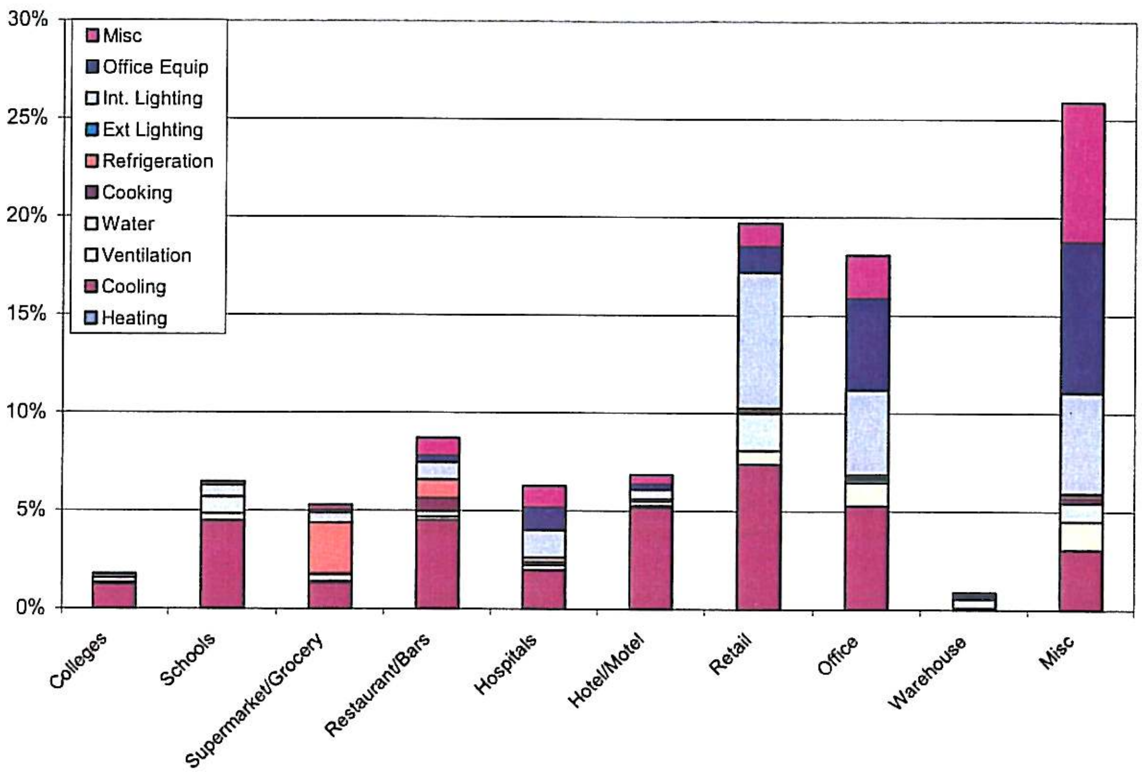


Exhibit 3-13
GRU Residential End-use Consumption

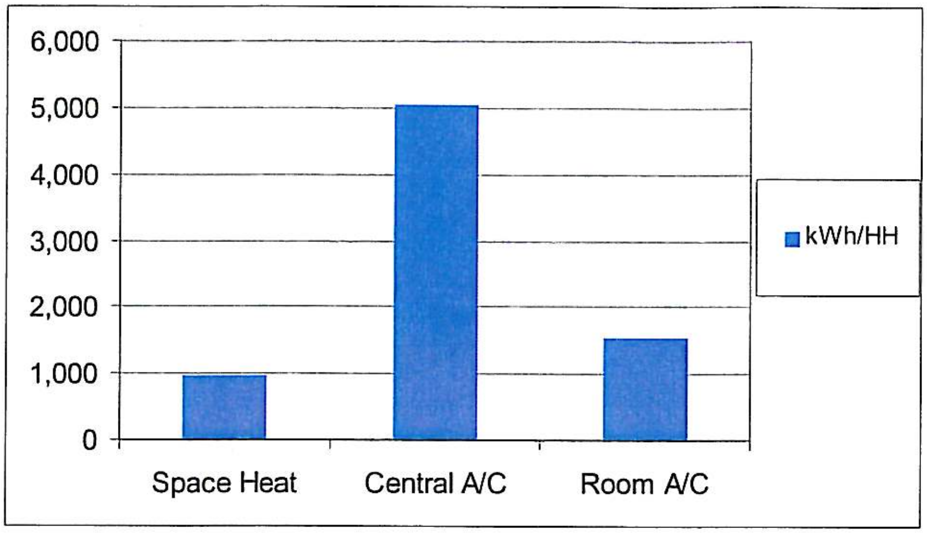
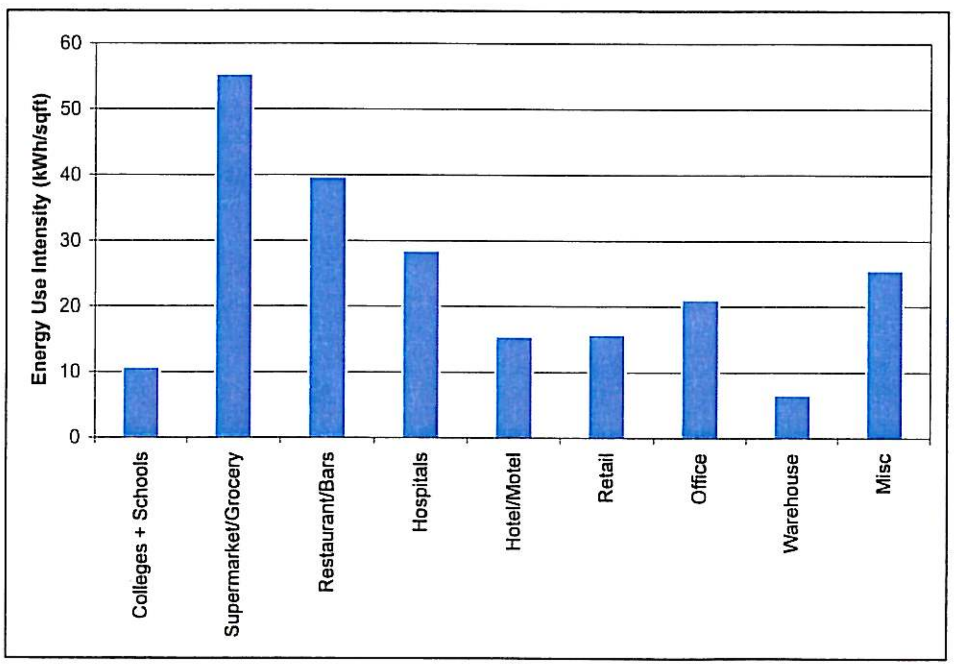


Exhibit 3-14
GRU Commercial Sub-sector Consumption Intensity



Step 2. Identification of DSM Measures

Initial Screening measures were taken from: the 1994 GRU Demand Side Management Base Planning Study, review of the DSM programs of other utilities, community suggestions (although not all suggested measures were necessarily included), as well as additions from ICF's own database of energy efficiency measures. Note that due to the comparative lack of industrial customers a comprehensive list of industrial DSM measures and niche technologies (e.g. combined heat and power) was not evaluated. This is not to suggest that there is not potential for such measures, perhaps as an element of a "custom rebate" program, but rather to recognize their limited applicability given the customer base.

The list of measures is provided in Exhibit 3-15. While perhaps not inclusive of all measures that could possibly be incorporated in GRU DSM programs over the planning horizon, the list provides a good representation of the applicable technologies and the potential for DSM.

Step 3. Calculation of DSM Measure Impacts and Costs

Because the data from the 1994 GRU DSM Study are in some cases somewhat dated, we updated energy savings and cost assumptions based on contemporary sources. Specifically, we used the 2004-2005 Database for Energy Efficiency Resources (DEER) Version 2.01 for updated cost information and savings information for non-weather-sensitive measures. DEER is a comprehensive and nationally-used measure database jointly developed by the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC). We screened all measures for applicability and feasibility to the GRU service territory and to the residential and commercial sectors. Data elements associated with each measure include: incremental capital, installation, and O&M costs; the effective useful measure life; and per unit energy and demand savings. For the commercial sector, energy impacts were specified for each individual building type.

In addition, weather-sensitive measures (such as high-efficiency air conditioning and home weatherization) required evaluation based on Gainesville's own unique weather patterns and building construction practices. To determine the demand and energy impact of these measures, the Department of Energy's DOE-2.1E software was used. This software takes data about the size, construction, and equipment characteristics of buildings and uses local weather to estimate energy use and the impact of specific energy efficiency upgrades.

Exhibit 3-15
DSM Measures Included in the Screening Process

MEASURES	
Air sealing (caulking, weatherstripping, hole sealing)	Instanteous Water Heater <=200 MBTUH
Anti-sweat (humidistat) controls	Insulated metal or fiberglass doors
Attic Radiant Barriers (Elec)	Landscape Shading
Attic, roof, wall, perimeter, knee wall, underfloor insulation	LCD monitor
Automatic OA reduction control	LED Exit Signs
Ceiling Fan	Load Control - AC
Central A/C - various equipment retrofits (EER & tonnage)	Load Control - Electric WH
Chiller economizers (water side), or air side economizers	Low Flow Showerheads
Circulation Pump Timelocks	Low Flow Showerheads (Elec)
Compact flourescent lamp (modular)	Motion Detectors
Compact fluorescent lamps (CFLs)	Network power management enabling - monitor
Compressor VSD retrofit	Night covers for display cases
Convection Oven	Nighttime shutdown - printers
Cool (reflective) rooftops	Occupancy sensors for 4' fluorescent
Cool Storage	Occupancy sensors for 8' fluorescent
CV to VAV conversion	Optimize chilled water and condenser water setting
Demand defrost electric	Outdoor Floodlight
Demand hot gas defrost	Outdoor lighting controls for fluorescent (photocell/timeclock)
Duct Insulation	Outdoor lighting controls for HID (photocell/timeclock)
Duct Sealing	Outdoor lighting controls for incandescent (photocell/timeclock)
Efficiency compressor motor retrofit	Perimeter dimming for 4' fluorescent
Efficient Infrared Griddle	Perimeter dimming for 8' fluorescent
Energy management controls	Pipe Insulation
Energy Star Clothes Washers - All Electric	Pipe Wrap (Elec)
Energy Star Dishwasher - Electric DHW	Power Burner Fryer
Energy Star or better clothes dryer (Elec)	Power Burner Oven
Energy Star or better freezer	Power management enabling - copier
Energy Star or better heat pump upgrade	Power management enabling - monitor
Energy Star or better refrigerator	Power management enabling - PC
Energy Star or better windows	Premium-efficiency motors
Evaporator fan controller for MT walk-ins	Programmable Thermostat
External hardware control - monitors	Reducing minimum outside air requirements
External hardware control - printers	Reflective Roof Coatings
Faucet Aerator	Reflectors for 4' fluorescent
Faucet Aerators (Elec)	Reflectors for 8' fluorescent
Filter cleaning and/or replacement	Refrigerant charge testing and recharging
Floating head pressure controls	Refrigeration commissioning
Furnace upgrades	Remove 2nd Freezer
Ground Source Heat Pump	Remove 2nd Refrigerator
Ground Source Heat Pump - Elec Resis Heater	Room A/C - various equipment retrofits (EER & tonnage)
Heat Pipe Enhanced DX	Shade Screens
Heat Pump - Load Control	Shell insulation upgrades
Heat Pump - Maintenance	Shell insulation upgrades (Wall and Slab, Elec)
Heat Pump WH - Add On	Solar control glazing
Heat Pump WH - Integral	Solar gain controls such as exterior shades
Heat Recovery Water Heater	Solar Water Heater
Heat Trap - Water Lines	Strip curtains for walk-ins
Heater efficiency upgrade	T8 lamps with electronic ballasts (2L4')
High-efficiency chillers	T8 lamps with electronic ballasts (2L4')
High-efficiency fan motors	T8 lamps with electronic ballasts (2L8')
High-efficiency packaged DX A/C	Tank Insulation
High-intensity discharge lamps (incandescent to hi-pres sodium)	Tank temperature setback (Elec)
High-intensity discharge lamps (incandescent to metal halide)	Two speed Central AC
High-intensity discharge lamps (mercury vapor to hi-pres sodium)	Two speed Heat Pump
Improved maintenance and diagnostics	Two speed Heat Pump - Elec Resis Heater
Infiltration Reduction	Unoccupied OA reduction
Infrared Conveyor Oven	Vapor-compression cycle
Infrared Fryer	Variable-speed drives
Installation of low-E glass or multiple glazed windows	Water heat tank wraps and bottom boards (Elec)
Installation of nighttime pre-cooling controls and systems	Whole House Fan
Installation of outside air reset controls	Window Film
Installation of wall, roof, or ceiling insulation	Window treatment

For the residential segment, analysis was conducted to determine the impact of energy efficiency upgrades on both existing home stock and new homes separately, reflecting the fact that existing homes often have significantly poorer energy performance than new homes. For the commercial segment, analysis included the six primary building types that make up a majority of the buildings located in the Gainesville region. The DOE-2 analysis uses Typical Meteorological Year (TMY2) weather data.

Each of the building types have a baseline determined by a typical set of architectural characteristics (e.g. foundation type, number of stories, conditioned floor area, window to floor area ratio), and a single set of energy-related characteristics (e.g. wall insulation, attic insulation, equipment efficiency, window U-value and SHGC). For a full set of characteristics modeled, see Attachment 3.

Step 4. Cost-Effectiveness Prioritization and Estimation of DSM Potential

DSM potential studies typically address three different concepts of "potential." First, **technical potential** quantifies the savings that could be realized if energy efficiency measures were applied in all technically feasible instances, regardless of cost. As is typical for such an analysis, we estimated technical potential assuming that this change-out occurs immediately. Technical potential is therefore useful as a broad gauge of the economy's inefficiency in the territory of interest.

Economic potential is the subset of technical potential that is cost-effective from a chosen benefit-cost perspective. For this initial screening we applied the Total Resource Cost or (TRC) test perspective as the primary measure. However, this is not to assert that the TRC perspective is necessarily the lone criterion which should be applied to establish "cost-effectiveness," nor to dismiss the value of other tests, such as the Ratepayer Impact Measure (RIM) test. However, to avoid prematurely screening out potential DSM measures before they can be analyzed alongside supply-side options in IPM, and consistent with the Commission's directives favoring DSM, the TRC test was used.

As with technical potential, economic potential assumes that all relevant energy efficiency improvements occur instantaneously. For this study, we have further subdivided economic potential into measures that are cost-effective (with a TRC>=1) or marginally cost-effective (with a TRC between 0.5 and 1). That is, measures failing the TRC test, but with a benefit cost ratio greater than 0.5 were treated as "passing" for the purposes of this analysis. This was done to recognize that there is uncertainty in the screening of the measures, and that some of the screening assumptions (such as avoided costs) were by necessity based on previous GRU analyses and not the results 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.[45] 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 $2,306.50/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 11 measures had a TRC>=0.50, making them marginally cost-effective.
- Out of 22 new construction residential measures, five 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, 537 applications had a TRC>=1.
- An additional 85 commercial applications had a TRC>=0.50, deeming them marginally cost-effective.

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

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

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

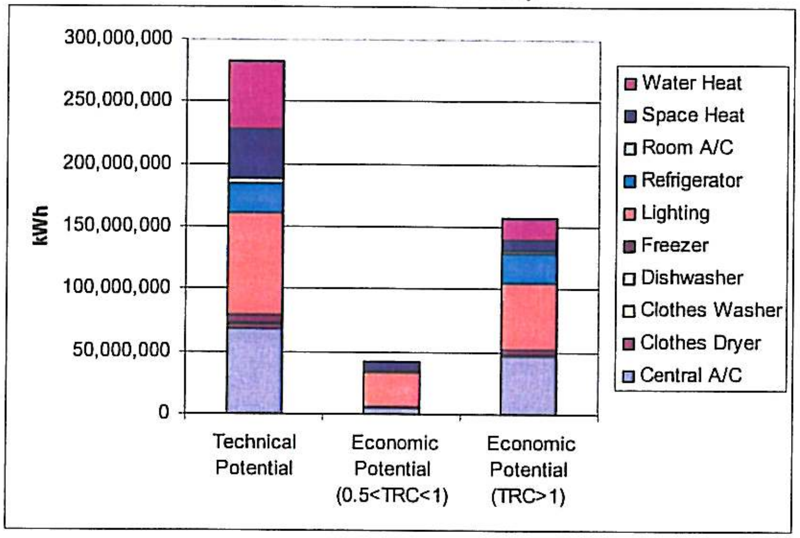


Exhibit 3-17
GRU Residential Technical and Economic Demand Potential by End-use (Excludes Losses)

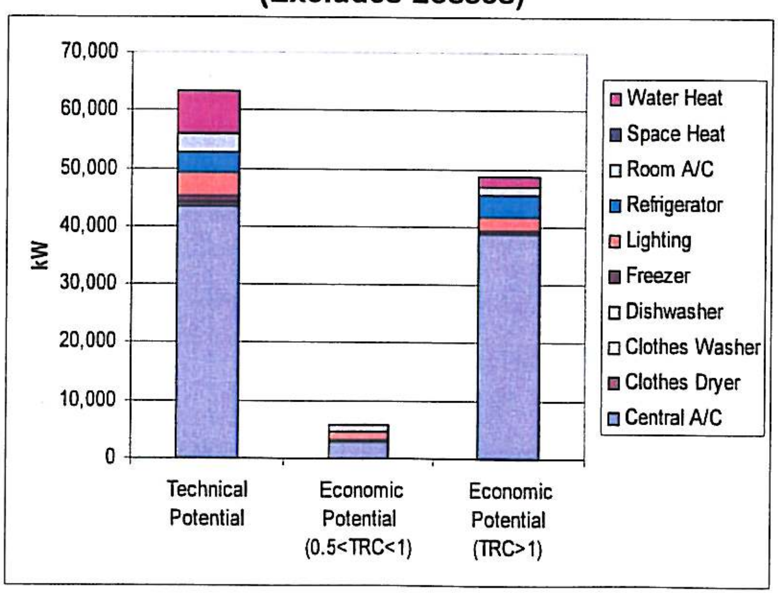


Exhibit 3-18
GRU Commercial Technical and Economic Energy Potential by Sub-sector (Excludes Losses)

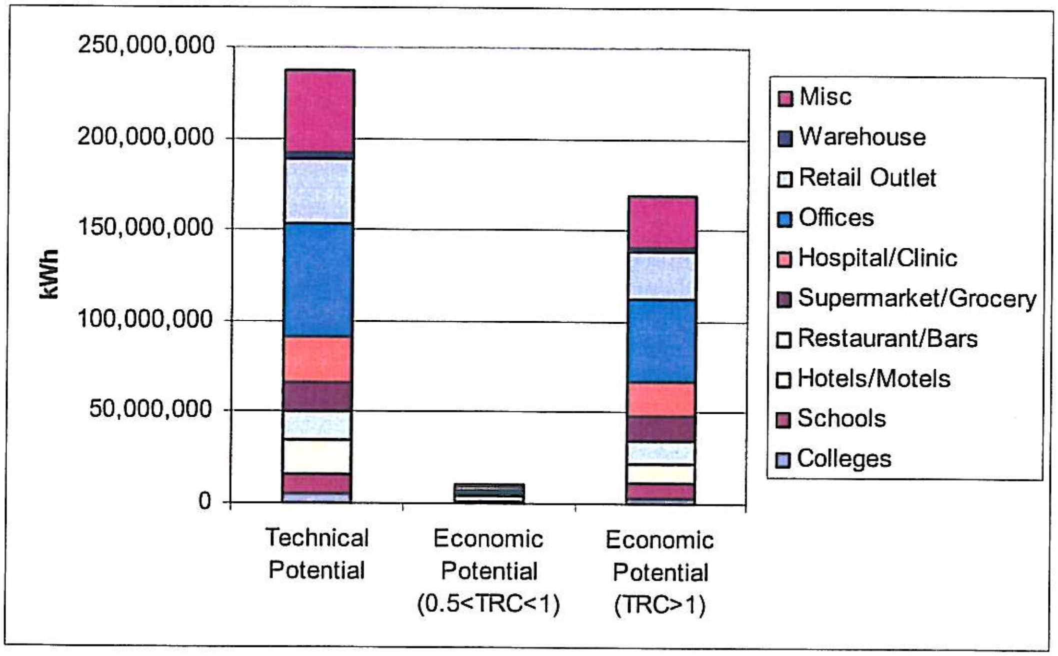


Exhibit 3-19
GRU Commercial Technical and Economic Demand Potential by Sub-sector (Excludes Losses)

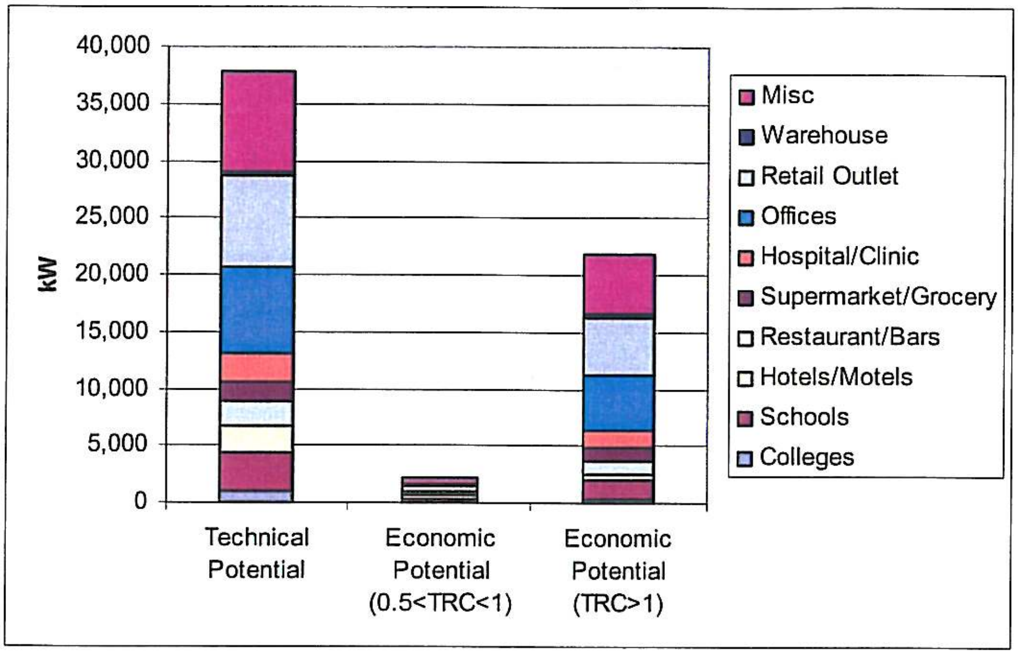


Exhibit 3-20
GRU Commercial Technical and Economic Energy Potential by End-use (Excludes Losses)

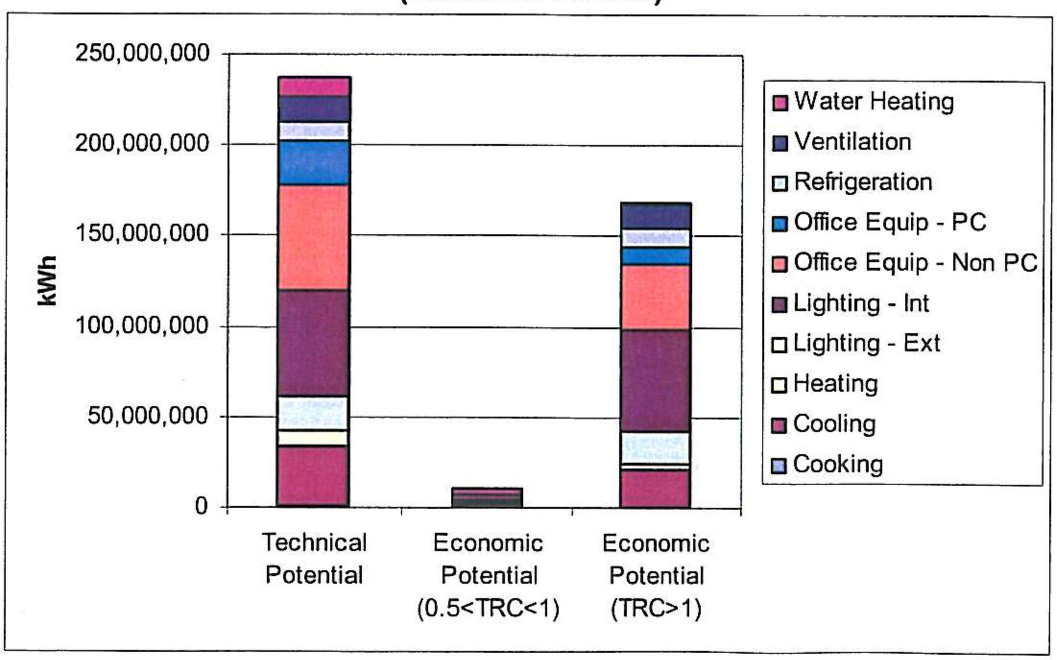
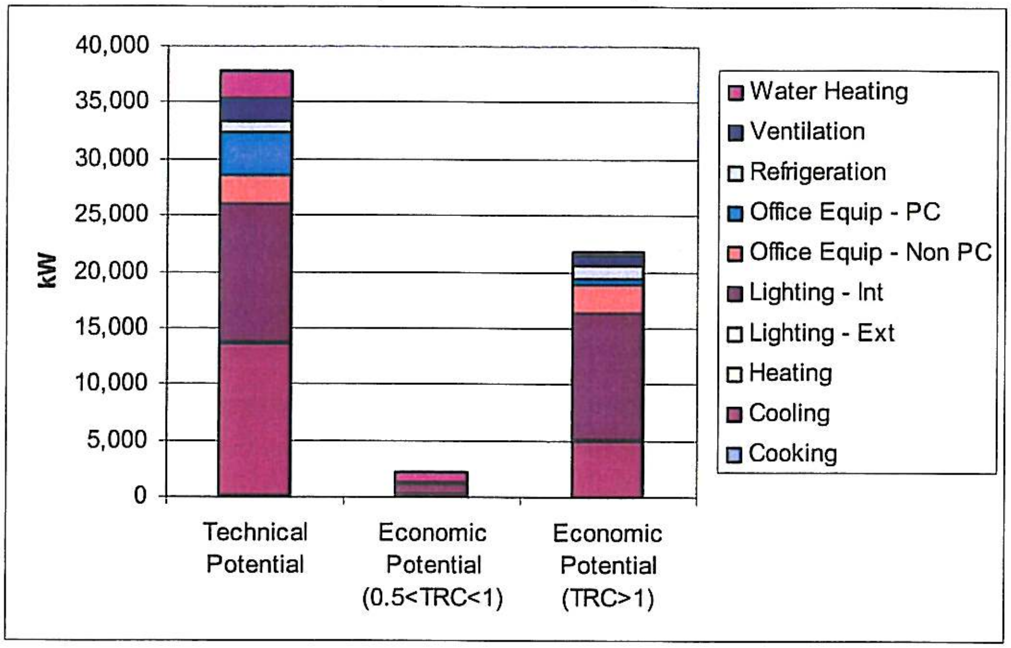


Exhibit 3-21
GRU Commercial Technical and Economic Demand Potential by End-use (Excludes Losses)



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 Exhibit 3-22, is an example of how measures were bundled together into programs.

Exhibit 3-22
Example of Program Bundling

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

Many of the programs relate to lighting and cooling end-uses, where the potential for efficiency improvements is typically high. Note that because this study is a broad effort to gauge the extent of the total DSM resource, we generally have not dealt with specific issues of program design or delivery. For instance, we have not specifically addressed how programs might be designed to minimize free ridership. However, because we have estimated the extent of savings that would occur in the absence of programs (and have included in the program costs the payment of incentives to customers who would install the measures even without the programs) the "achievable potential" estimates are net of free riders. 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. We assumed 65% energy and 82% demand savings, based on GRU and Florida Solar Energy Center (FSEC) data. We also assumed a $1900 installation cost (inclusive of the 30% federal tax credit), net of annual operations and maintenance (O&M) costs.
- Appliances – Provides incentives for the purchase of ENERGY STAR or other high efficiency appliances, including clothes washers and refrigerators.
- 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 Homes – 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 cooling equipment, including packaged air conditioner units and chillers 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

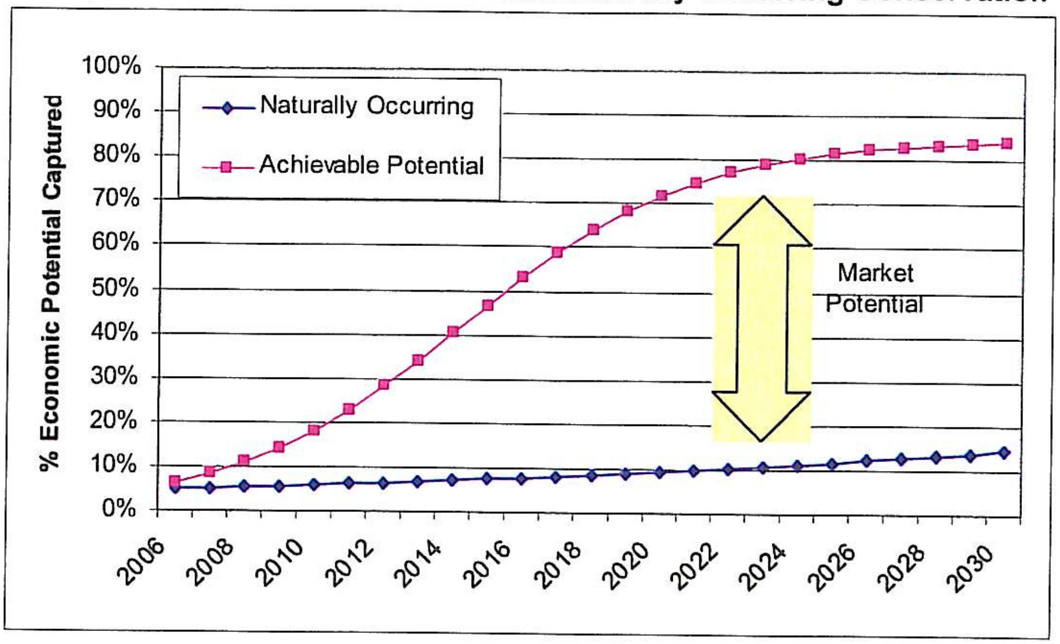
DSM program penetration determines the percentage of economic potential that becomes achievable. Achievable potential is typically defined as the amount of cost-effective energy efficiency improvement expected to be captured as the result of specific program actions, over and above the efficiency improvements 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, 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 Exhibit 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.

Exhibit 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. However, for the commercial cooling program, which subsidizes the purchase of large pieces of cooling equipment, we have assumed the program will pay an incentive equal to 50% of the full incremental cost. 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) 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. However, 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. A complete detailing of proposed load control program assumptions and costs is in the appendix.

The cost structure we have assumed reflects that of a portfolio of programs focused on direct financial incentives for efficient equipment. For highly aggressive efforts focused on DSM resource acquisition, this is typically the primary direct means by which to achieve savings targets. However, for other program portfolios including a higher proportion of education, engineering services, and other informational offerings, the cost profile will be considerably different. These types of programs also provide critical services to end-use customers and result in reduced energy consumption, but do not entail considerable subsidy of equipment purchases. In such a scenario, "administrative" costs, including the costs of providing these services, will by definition be in excess of 50% of incentive costs. Notably, GRU's current portfolio of DSM programs consists more of engineering and information services than incentives. Because of this DSM portfolio structure, "administrative" costs are currently a much higher percentage of incentives than we have assumed for our future DSM case.

Also, we have assumed for the purposes of the modeling that the ratio of program costs to incentive dollars is constant over the life of the program. In implementation, it is likely that start-up and infrastructure development costs will be higher in the first one to three years of the programs. While this has little effect on the cost-effectiveness of the programs and we believe that the program costs over their lifetime are sufficient to elicit the savings projected, it should be noted that it may desirable to accelerate certain expenditures during the start-up phase. Therefore, costs in 2006-2008 may be higher that projected here (and somewhat lower in the following years).

Summary statistics for each of the draft programs are provided in Exhibit 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.

Exhibit 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	1.75	47,787	$1,548.04	$161.45
Residential Fridge/Freezer Buyback	1.43	10,864	$445.92	$396.52
Home Performance with Energy Star (Marginally Cost-Effective Measures)	0.96	1,825	$1,990.31	$1,511.65
Home Performance with Energy Star (Cost-Effective Measures)	9.05	16,824	$449.62	$339.23
Comprehensive Water Heating Program	1.30	14,637	$2,274.64	$720.84
Residential Solar Water Heater	1.01	11,383	$16,198.24	$5,133.23
Residential Appliance	1.87	14,416	$1,717.90	$1,469.31
Residential A/C Rebate, Weatherization, & A/C Tune-Up Program (Marginally Cost-Effective	2.23	4,257	$1,990.31	$1,511.65
Residential A/C Rebate, Weatherization, & A/C Tune-Up Program (Cost-Effective Measures)	21.11	39,256	$449.62	$339.23
Residential A/C Direct Load Control	4.95	0	$90.44	$90.44
Residential Water Heating Direct Load Control	0.70	0	$891.71	$891.71
Energy Star Homes	0.25	466	$443.11	$334.32
Commercial Cooling	3.70	7,400	$825.09	$825.09
Commercial Lighting - Exterior	0.15	13,842	$15,763.43	$788.17
Commercial Lighting - Interior	9.13	53,836	$1,615.17	$1,460.73
Commercial Office Equipment	2.30	16,861	$1,508.93	$1,387.00
Grocery and Restaurant Refrigeration Program	0.77	5,672	$1,444.65	$1,346.67
Commercial Ventilation	0.74	4,712	$2,803.56	$2,803.56
Commercial Water Heating	0.93	7,705	$2,358.12	$1,864.86
Total	**64.32**	**271,743**	**$1,181.17**	**$784.49**

Supply curves provide a useful framework for understanding how much DSM is available at varying levels of cost. For example, Exhibit 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 65 MW if the acceptable cost level is increased to $300 per coincident kW. Exhibit 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.

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

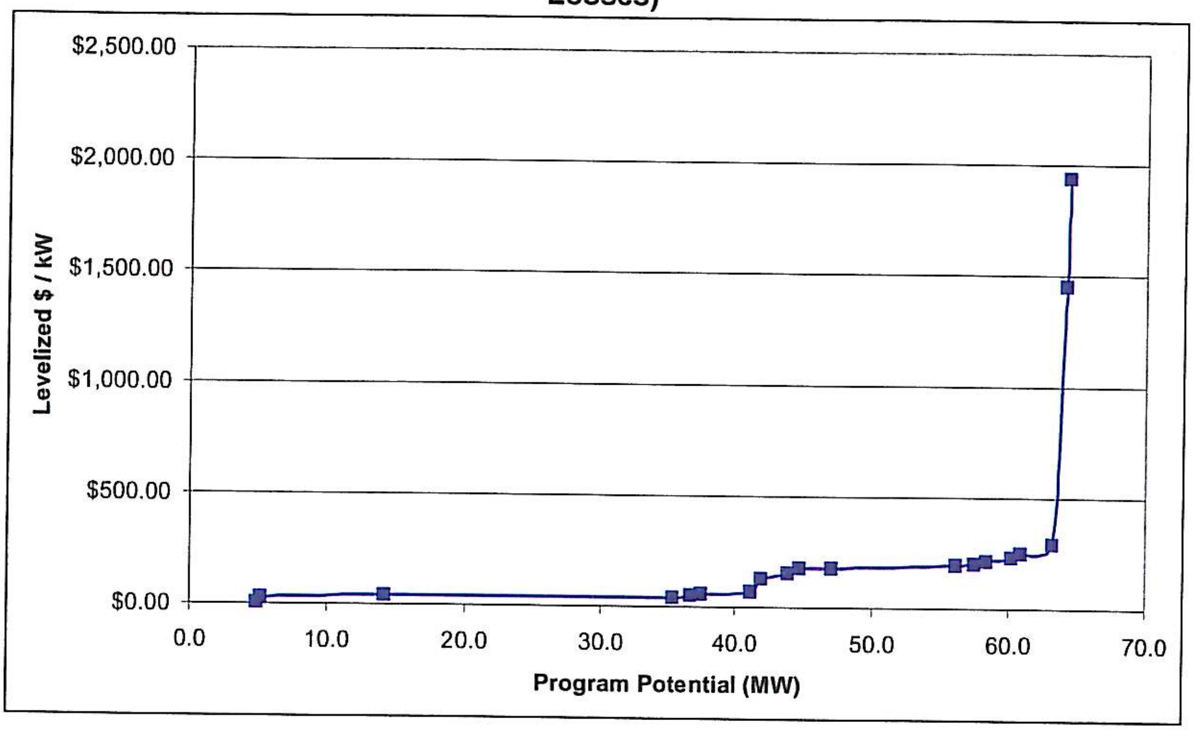


Exhibit 3-26
DSM Program Supply Curve (Including 7% Losses)

Program	Cumulative MW	Annualized $/Coincident kW
Residential A/C Direct Load Control	4.9	$6.06
Energy Star Homes	5.2	$29.68
Home Performance with Energy Star (Cost-Effective Measures)	14.2	$40.43
Residential A/C Rebate, Weatherization, & A/C Tune-Up Program (Cost-Effective Measures)	35.4	$40.43
Residential Fridge/Freezer Buyback	36.8	$54.86
Residential Water Heating Direct Load Control	37.5	$59.74
Commercial Cooling	41.2	$74.19
Grocery and Restaurant Refrigeration Program	42.0	$129.89
Residential Appliance	43.8	$154.46
Home Performance with Energy Star (Marginally Cost-Effective Measures)	44.8	$178.95
Residential A/C Rebate, Weatherization, & A/C Tune-Up Program (Marginally Cost-Effective	47.0	$178.95
Commercial Lighting - Interior	56.1	$198.72
Comprehensive Water Heating Program	57.4	$204.52
Commercial Water Heating	58.4	$212.02
Residential CFL Program	60.1	$229.33
Commercial Ventilation	60.9	$252.07
Commercial Office Equipment	63.2	$289.48
Residential Solar Water Heater	64.2	$1,456.41
Commercial Lighting - Exterior	64.3	$1,939.46

In Exhibits 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 (CFLs) 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.

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

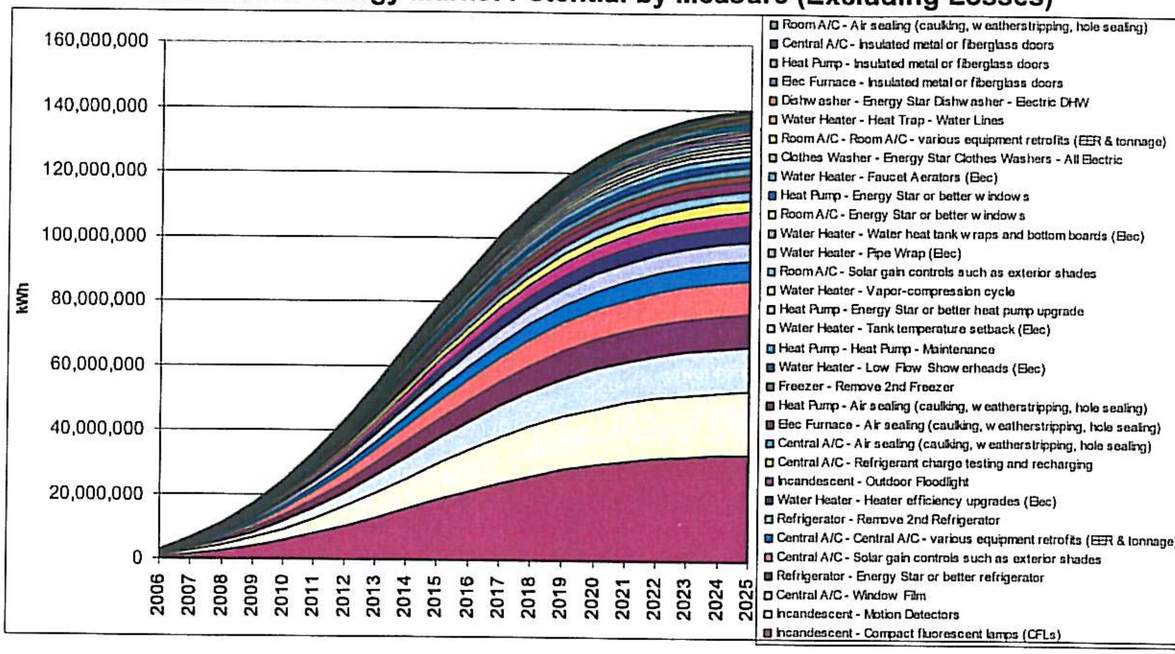
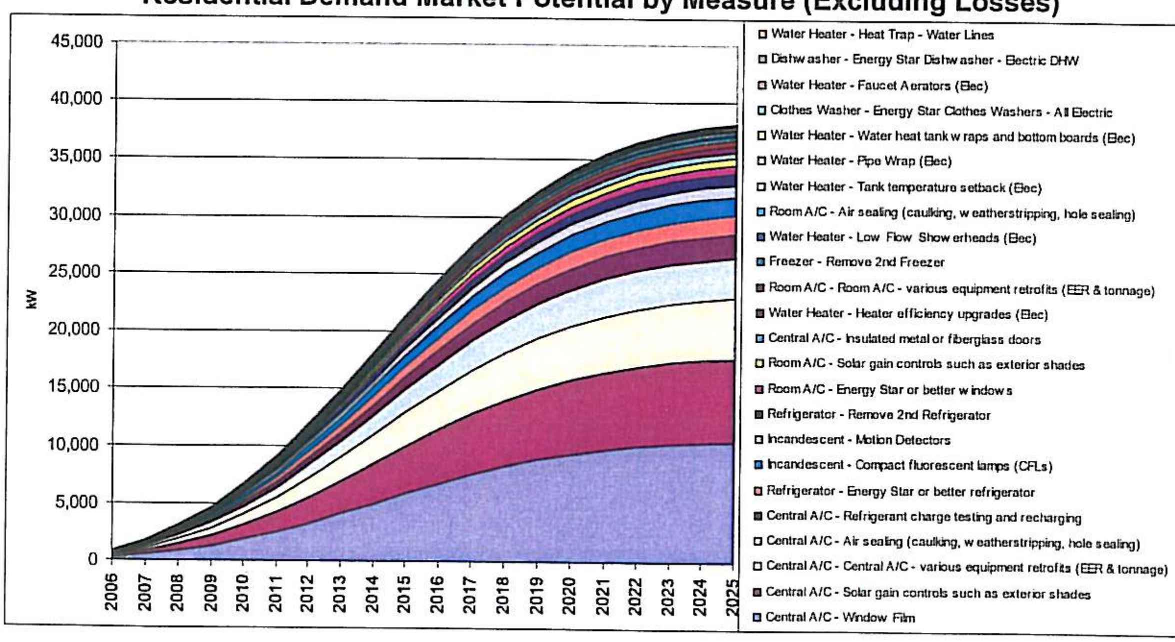


Exhibit 3-28
Residential Demand Market Potential by Measure (Excluding Losses)



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 CO_2 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 Exhibit 3-29.

Exhibit 3-29
Dispositions 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)	Does not build
4	Home Performance with Energy Star (Cost-Effective Measures)	2006
5	Comprehensive Water Heating Program	2006
6	Residential Solar Water Heater	Does not build
7	Residential Appliance	2006
8	Residential A/C Rebate, Weatherization, & A/C Tune-Up Program (Marginally Cost-Effective Measures)	Does not build
9	Residential A/C Rebate, Weatherization, & A/C Tune-Up Program (Cost-Effective Measures)	2006
10	Residential A/C Direct Load Control	2020
11	Residential Water Heating Direct Load Control	Does not build
12	Energy Star Homes	2006
13	Commercial Cooling	2006
14	Commercial Lighting - Exterior	2006
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 Exhibit 3-30.

Exhibit 3-30
DRAFT Summary of DSM Potential Programs

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	1,169	1,764	297%	1,764	n/a	0.4%	1,812,929	$1,121,471	$2,934,400	162%
2007	605	1,407	2,012	333%	3,776	19.9%	0.8%	1,812,929	$1,349,434	$3,162,363	174%
2008	609	1,829	2,438	401%	6,214	23.6%	1.3%	1,812,929	$1,754,306	$3,567,235	197%
2009	613	2,321	2,933	479%	9,148	27.9%	1.9%	1,812,929	$2,225,298	$4,038,227	223%
2010	617	2,863	3,480	564%	12,628	32.4%	2.6%	1,812,929	$2,745,810	$4,558,739	251%
2011	621	3,423	4,044	652%	16,672	36.8%	3.5%	1,812,929	$3,282,768	$5,095,697	281%
2012	621	3,948	4,569	736%	21,240	40.8%	4.4%	1,812,929	$3,786,061	$5,598,990	309%
2013	458	4,374	4,832	1055%	26,072	42.2%	5.4%	1,812,929	$4,194,078	$6,007,006	331%
2014	458	4,637	5,095	1112%	31,167	43.6%	6.5%	1,812,929	$4,446,331	$6,259,260	345%
2015	458	4,693	5,151	1124%	36,318	43.2%	7.6%	1,812,929	$4,500,180	$6,313,109	348%
2016	458	4,531	4,989	1089%	41,307	41.0%	8.6%	1,812,929	$4,344,650	$6,157,578	340%
2017	458	4,176	4,634	1012%	45,941	37.3%	9.6%	1,812,929	$4,004,232	$5,817,160	321%
2018	458	3,682	4,140	904%	50,080	32.6%	10.4%	1,812,929	$3,530,538	$5,343,467	295%
2019	458	3,114	3,572	780%	53,653	27.6%	11.2%	1,812,929	$2,986,381	$4,799,310	265%
2020	458	2,640	3,098	676%	56,751	23.4%	11.8%	1,812,929	$2,441,962	$4,254,890	235%
2021	458	2,114	2,573	562%	59,324	19.0%	12.3%	1,812,929	$1,921,859	$3,734,788	206%
2022	458	1,666	2,124	464%	61,447	15.4%	12.8%	1,812,929	$1,461,923	$3,274,851	181%
2023	458	1,295	1,753	383%	63,200	12.4%	13.1%	1,812,929	$1,072,460	$2,885,389	159%
2024	458	1,001	1,459	319%	64,660	10.1%	13.4%	1,812,929	$753,753	$2,566,682	142%
Cumulative	9,776	54,884									

Note: GRU budget was provided for 2006 only. The extension of these costs into future years was done for illustrative purposes by ICF
(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 three years, and grow to almost 3.5 times current levels within 10 years (approximately $6.3M/yr)[46].
- Annual kW reductions from DSM would increase from approximately 600 kW/yr from current programs to 5,095 kW/yr from additional programs in 10 years.
- DSM programs would cut GRU's annual load growth by approximately 43% in Year 9.
- The incremental annual DSM program expenditures equate to an additional $13/customer immediately, increasing to an additional $53 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

[46] All dollars are in expressed in 2003 dollars

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 (Exhibit 3-31). These studies included[47]:

Exhibit 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. Exhibit 3-32 provides the potential estimates from these other studies and compares them to the estimates for Gainesville (in italics).

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

Exhibit 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	***28%***	***24%***	***16%***	
Commercial Sector	18%-41%	13%-35%	6.3%-36%	3.6%-9%
Max DSM Scenario for Gainesville	***15%***	***10%***	***7%***	

Despite the limitations associated with comparing studies for different regions and with different assumptions, it appears that the estimates of Achievable Potential for GRU (16% of residential and 7% 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 Exhibits 3-33 through 3-35. Exhibit 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 $21.19/customer/year on DSM[48], and the potential new programs increase over nine years to $51.97/customer/year combining for a very aggressive (and perhaps unequaled) $73.16/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 5

[48] Note that although GRU's current DSM expenditures overall appear large relative to the amount of direct incentives paid to customers, this may be in large part due to the way GRU does its accounting and delivers its programs. For example, GRU provides services such as audits and construction consultation for free using in-house staff. As such, it appears in the accounting as administrative costs. Other utilities will often classify this same expenditure as a customer incentive, especially when a third party is used to deliver the program. ICF has not attempted through this study to evaluate the quality of delivery or cost levels associated with GRU's programs.

MW/year at their peak. 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.

Exhibit 3-33
GRU DSM Program Budget 2005

	Sector	Program	Incentives paid to customers	Marketing & Advertising	GRU Admin. Costs	Other Costs	Total Costs	# Participating Customers
Ongoing	Residential	Conservation Surveys	Free	$ -		-		2,271
		Self-Audit Materials	Free	$ -		$ -		N/A
		New Construction Consultation	Free	$ -		$ -		N/A
		Green Builder Program	$ -	$ 6,504		$ -		0
		Customer Consultation (1)	Free	$ -	$ 452,917	$ -	$ 987,061	89
		Low-Income Weatherization	$ 1,750	$ -		$ -		7
		Solar Water Heating Rebates	$ 1,410	$ -		$ -		4
		Solar Electric Interconnection and Buyback	$ 0	$ -		-		2
		Gas Water Heating Rebate	$ 5,800			$ -		29
		Gas Heating Rebate	$ 3,300			$ -		11
		Gas Dryer Rebate	$ 600	$ 40,447	$ 230,888	$ -	$ 559,085	12
		Gas New Construction Rebate	$ 278,050			$ -		775
		Customer Information	Free	(2)	(3)		(6)	
	Commercial	Conservation Surveys	Free		$ -		$ -	191
		Commercial Lighting Service	For Fee		$ 30,236		$ -	161
		Solar Water Heating Rebates	$ -		$ -		$ -	0
		Solar Electric Interconnection and Buyback	$ 117		$ -		$ -	4
		Gas Air-Conditioning Rebate	$ -		$ -		$ -	0
		Gas Dehumindification Rebate	$ -	$ 174,482	$ -	$ 215,868	$ -	0
		Gas Water Heating Rebate	$ -		$ -		$ -	0
		Infra-red Scanning Service	For Fee		$ 3,140		$ -	10
		Business Partners Workshops	$ 2,000		$ -		$ -	52
		Customer Information	Free		$ -		$ -	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		$ 391,664	$ 221,433	$ 717,181	$ 215,873	$ 1,546,140	4,353

Notes:

(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

Exhibit 3-34
GRU DSM Program Budget 2006

	Sector	Program	Incentives paid to customers	Marketing & Advertising	GRU Admin. Costs	Other Costs	Total Costs	# Participating Customers
Current	Residential	Conservation Surveys	Free	$ -		(4)		2,385
		Self-Audit Materials	Free	$ -				N/A
		New Construction Consultation	Free	$ -				N/A
		Green Builder Program	$ -	$ 5,000				0
		Customer Consultation (1)	Free	$ -	$ 587,962		$ 1,177,189	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					40
		Gas Dryer Rebate	$ 500	$ 41,523	$ 242,717		$ 635,740	10
		Gas New Construction Rebate	$ 300,000					857
		Customer Information	Free	(2)	(3)		(6)	N/A
	Commercial	Conservation Surveys	Free					210
		Commercial Lighting Service	For Fee		$ 38,237			170
		Solar Water Heating Rebates	$ -					0
		Solar Electric Interconnection and Buyback	$ 99					4
		Gas Air-Conditioning Rebate	$ 5,000					2
		Gas Dehumindification Rebate	$ 5,000	$ 201,690		$ 249,836		2
		Gas Water Heating Rebate	$ 15,000					30
		Infra-red Scanning Service	For Fee		$ 4,600			11
		Business Partners Workshops	$ 2,000					60
		Customer Information	Free					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		$ 441,364	$ 248,213	$ 873,516	$ 249,836	$ 1,812,929	4,904

Notes:
(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

Exhibit 3-35
GRU DSM Program Peak kW Impact

Year	Residential Programs																		Commercial Programs												
	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

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Exhibit 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	1,812,929	$ 21.19
GRU POTENTIAL (Yr. 9)	85,559	4,446,331	$ 51.97
GRU TOTAL	**85,559**	**6,259,260**	**$ 73.16**

An Aside on Solar Water Heating, Co-Generation, and Photovoltaics

ICF's evaluation of DSM options included explicit consideration of solar water heating, distributed generation, and PV.

Solar Water Heaters

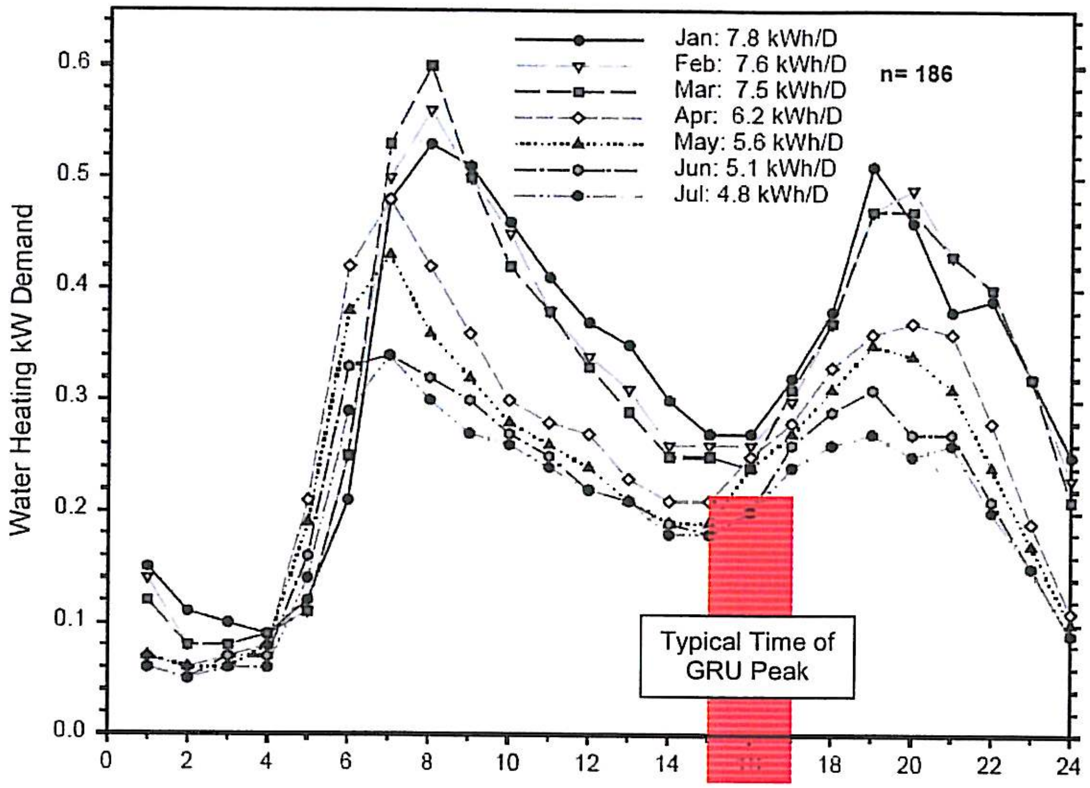
ICF included solar water heaters (SWH) as one of the measures included the initial screening and calculated the cost-effectiveness of SWH just as was done for the other measures. ICF concluded that SWH were not cost-effective using either the TRC or RIM test for any reasonable range of assumptions, with TRC benefit cost ratios ranging between 0.37 and 0.68. Despite this, ICF created a SWH Program in the same manner described above for the other measures and passed it to IPM for evaluation, which also found it to be more expensive than the supply-side options. The primary assumptions driving this result are: the peak kW saved, the annual kWh saved, and the system cost.

After review of available data from other programs, including those of JEA and Lakeland[49], ICF assumed that the typical residence in Gainesville, if retrofitted with a solar water heater would save 0.22 kW on peak. The primary reason for this comparatively small peak kW savings is that very little water is being heated during the summer system peak. Exhibit 3-37 shows the daily load of a typical electric hot water heater in central Florida based on a sample of 171 electric water heaters metered in a study by the Florida Solar Energy Center and Florida Power Corporation[50]. As suggested by this Exhibit, the average electric water heater in this study (based on an average household size of 2.8 persons) was drawing between 0.2 and 0.25 kW. This study also found that the average water heater was consuming only 2,325 kWh a year. Using these numbers as a baseline, ICF then applied savings factors of 65% of energy and 82% of kW. These savings factors were corroborated by a variety of sources and are consistent with the ranges articulated by FSEC. Given this, we believe the savings estimates we assumed (a savings of 0.22 kW and 1,466 kWh) to be reasonable, and perhaps even aggressive for the average Gainesville household (which has an average of 2.5 occupants).

[49] Lakeland assumes 0.2kW summer peak savings and 1,570 kWh. JEA has reported savings of as high as 0.5kW for a family of 4.

[50] *Factors Influencing Water Heater Energy Use and Peak Demand in a Large Scale Residential Monitoring Study* by John Masiello (Florida Power Corporation) and Danny Parker (Florida Solar Energy Center)

Exhibit 3-37
Measured Electric Hot Water Heater Load by Month



ICF assumed the installed cost of a SWH to be $1,720 and the annual maintenance cost to be $60, both of which are well within the range (and perhaps towards the low end) of costs reported by other utilities and FSEC.

ICF recognizes that these results are less favorable to SWH than those commonly reported, but believes there are a variety of Florida-specific factors (such as the increased level of the supply water temperature in the summer and the resultant reduced need to heat the water) which credibly explain the results.

This is not to deny that there may be specific instances where SWH is cost-effective, especially in large households. ICF has not recommended as a part of this study that GRU terminate or modify its existing program, recognizing that niche applications of SWH may have benefits to the system. ICF's goal in this study was to characterize the costs and benefits of programs believed to have sufficient applicability and scale to become a meaningful resource option for GRU, hence ICF's focus on the broader base of homes, including homes with fewer occupants. It should be noted that savings would have to be approximately triple (other factors being equal) those found here if a solar water heater program were to have a chance of being selected in place of the supply side options.

Distributed Cogeneration Systems

Distributed co-generation systems (systems that typically use a gas turbine or engine to produce electricity and then recover the heat from that process for another need (such as water heating or a manufacturing process) can indeed be cost effective. Although their economics are a function of the cost of natural gas and the rate charged for back-up power by the utility (among other items) their primary barrier to widespread implementation is that only a small subset of customers have loads that are suited to co-generation. That is, without a heat load these options are very rarely cost-effective for the customer under almost any assumptions. Customers most likely to have cost-effective co-generation applications typically exhibit:

- Operating hours in excess of 4,000 hours per year (i.e. at least a two-shift operation)
- Heat requirements in the form of steam or hot water
- Electricity requirements that are coincident with heat requirements, and
- Electric load between 50% and 250% of the heat load

Given this, the primary targets for co-generation are customers who have large, consistent heat loads such as laundries, heated swimming pools, hotels, hospitals, and certain industrial processes. While space heating loads make co-generation more attractive in the northern U.S., it cost-effectiveness is diminished in Florida's warm climate.

The smallest systems start at around 50 kW and cost around $70,000; the economics start to become more favorable as sizes increase to 1MW costing approximately $1 million.

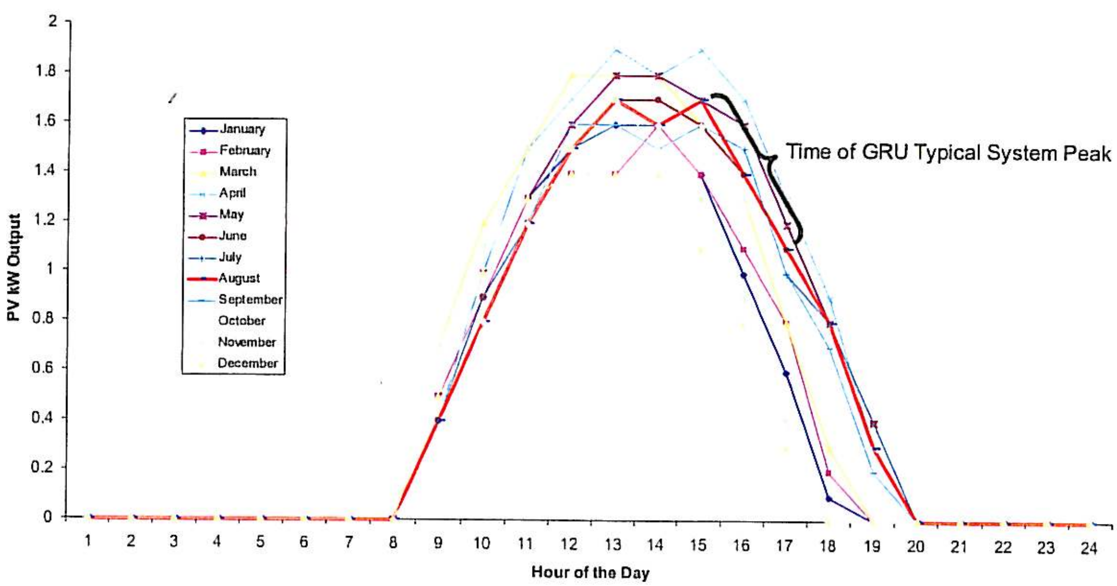
Recognizing that GRU has very few industrial or large commercial customers, and after a review of GRU's top 50 customers and based in part on conversations with GRU staff, ICF came to the opinion that, while potentially cost effective in certain applications, it is not likely that co-generation will become widespread in Gainesville with or without a program from GRU and it was dropped from further analysis. As noted elsewhere, ICF recommends that if GRU proceeds with its additional DSM programs, it accommodate such niche technologies with a standard offer program that pays incentives based on the measured kW and kWh reduced. Therefore, co-generation would not be precluded from participation in GRU programs.

Photovoltaics

As with solar hot water heaters, ICF included an analysis of small scale photovoltaic panels (PV) in its screening of DSM measures. The TRC benefit cost ratio given the mid-range assumptions about cost and energy savings is 0.33, suggesting that the cost of a PV system is not offset by the generation savings it provides. Given that this does not exceed even the 0.5 threshold for passing the measure to the IPM analysis, PV programs were not evaluated further.

The primary assumptions driving this conclusion are the cost of the PV system and the demand and energy savings. Consider the following example: a system capable of meeting the needs of an extremely efficient new house or perhaps 50% of the needs of a typical house might provide 1.9 kW of non-coincident AC power (3.2kW DC power) and produce electricity as represented in Exhibit 3-38. As shown in this Exhibit, the system may be expected to produce between 1.1 and 1.7 kW of peak demand reduction coincident with GRU's system peak. The annual energy production of this system is approximately 4,486 kWh.

Exhibit 3-38
Hourly Production of PV Power – Gainesville, FL[51]



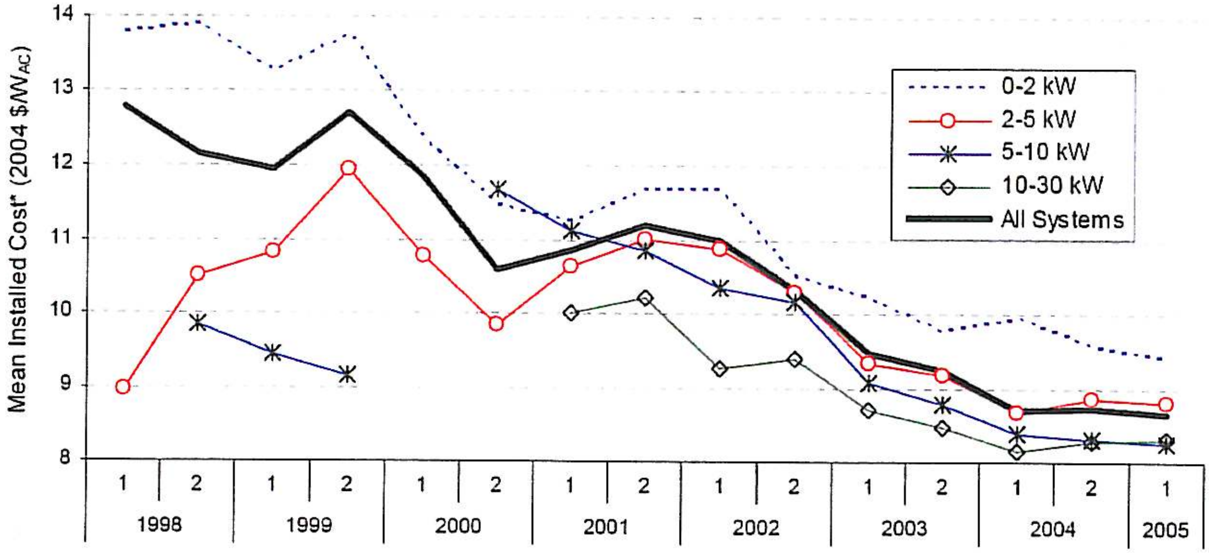
Estimates of the cost of PV system vary widely, especially if one attempts to incorporate potential future declines in costs due to commercialization of emerging technologies. However, several utilities and FSEC suggest that such a system should cost in the range of $13,200 after available tax credits ($8 per non-coincident AC watt less the $2,000 tax credit).

This cost is consistent with, indeed lower than, that found in a recent study of 17,889 PV systems installed in California between 1998 and 2005[52]. The cost of these systems over time is illustrated in Figure 3-39.

[51] Distribution developed using FSEC's Clean Power Estimator assuming a 3.2 kW DC PV system and 30 degree southward tilt.

[52] *Letting the Sun Shine on Solar Costs: An Empirical Investigation of Photovoltaic Cost Trends in California*. Ryan Wiser, Mark Bolinger, Peter Cappers, and Robert Margolis Environmental Energy Technologies Division. Lawrence Berkeley National Laboratory, January 2006.

Exhibit 3-39
Average Installed Cost Over Time in the California Energy Commission PV Program



*Within each system size bin, we excluded any 6-month period that contained fewer than 5 applications. This impacted only the 2 largest bins (>5 kW).

As suggested by the figure, in 2005 the average pre-rebate installed cost of PV systems in the 0-2 kW range is approximately $9.5/watt (2004 dollars), and for 2-5 kW systems is approximately $8.9/watt. ICF's assumption of $8/watt for a 1.9 kW system clearly gives PV the benefit of the doubt.

But even with these assumptions, the TRC benefit cost ratio of PV is 0.33. Although costs are expected to decline in future years, it would take an additional cost reduction of approximately 57% for PV to approach cost-effectiveness even assuming that program administrative and promotional costs are zero.

Put another way, the annualized cost of the PV system is approximately $884/year[53] or approximately $160/MWh (including credits for line losses and reserve margin contribution.) This compares to the cost of the DSM programs that passed the screening with an average of $24/MWh and the supply side options ranging between $40 and $55/MWh.

For these reasons, PV is not expected to become a viable large scale generating resource for GRU in the near future.

[53] Assumes a generous 25 year PV system life, no maintenance costs, and GRU's very low financing costs resulting in a annual capital charge rate of 6.7%.

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[54] 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)[55]. 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[56]. 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 has performed adequately. CFB technology has improved over time and other utilities in the country near the U.S. Gulf are choosing this

[54] 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.
[55] Actual reserve margin contribution is a fraction of rated maximum output, typically 5 to 30 percent.
[56] The capital costs in Florida may also be affected by the need to withstand hurricane conditions.

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[57]. 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:

- **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

[57] 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.

performance consistency. Since few solid fuel plants have been added in the U.S. in recent years, this is especially useful[58]. 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[59].

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).

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

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[60]:

- 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.

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 (see Exhibits 4-1 through 4-3). The economies of

[60] 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.

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.

Exhibit 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.

Exhibit 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.

Exhibit 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[61] for a greenfield plant, and $1,469/kW for a brownfield site with a pre-existing plant (see Exhibit 4-3). 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 for utilities other than 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 of higher biomass use (see Exhibit 4-4). 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

[61] 2003 dollars unless otherwise noted.

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

Exhibit 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[62]. 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.

Finally, in developing our scoping level capital cost estimates (shown in Exhibits 4-1, 4-2, 4-3) for CFB and IGCC technologies, ICF has drawn upon a number of technical sources. While prepared at a line item level of detail, for the illustrative purposes here we break down the cost estimates into 3 main categories: i) major equipment, ii) installation and labor, and iii) owner's costs.

For the IGCC, the major equipment costs can be further disaggregated into power island costs and gasification components. We used pricing from *The 2004-05 Gas Turbine World Handbook* for our power island costs. We used the Parson's Power Group report "M*arket Based Advanced Coal Power Systems*" to develop costs for our gasification equipment as well as installation and labor cost. Owner's costs, which include utility interconnections, plant startup, spare parts, site development, financing costs, etc. comes from ICF expertise. We regionalize the installation and labor costs

[62] 1 x 1 configuration will actually have a size closer to 250-265 MW.

with factors from Reed Construction's *Means Construction Cost Indexes, 2005.* Furthermore the plant capacity used in our estimates is on stated on a summer peak basis for Florida. Data for summer peak is based on a 30-year average obtained from the *National Climatic Data Center.*

Costs for the CFB technology has been scaled from cost estimates of two coal-fired facilities currently under construction. These are XCEL's Comanche III and Mid-American's Council Bluffs 4 facilities. These raw estimates were scaled down in size and also in technology using EPRI's *Technical Assessment Guide.* As with the IGCC we regionalize the installation and labor costs using factors derived from Reed Construction's *Means Construction Cost Indexes, 2005.*

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 (see Exhibits 4-5 and 4-6). ICF also accepts GRU's position it will be able to achieve 80 percent leverage which is higher than for most investor owned utilities.

Exhibit 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)

Exhibit 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 in Exhibits 4-7, 4-8, and 4-9.

Exhibit 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.

Exhibit 4-8
Key Plant Performance Assumptions

Parameter	Treatment -- Base Case				
New Power Plant Builds Heat Rate[1] (Btu/kWh)	Combined Cycle	Combustion Turbine	SCPC	IGCC	FBC
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.

Exhibit 4-9
Key Plant Performance Assumptions

<table>
<tr><th>Parameter</th><th colspan="3">Treatment Base Case</th></tr>
<tr><td>Existing Power Plant Constraints (%)</td><td colspan="2"><u>Availability</u></td><td><u>Minimum Turndown (%)</u></td></tr>
<tr><td>Coal Steam</td><td colspan="2">84 – 88</td><td>40</td></tr>
<tr><td>Oil/Gas Steam</td><td colspan="2">76 – 85</td><td>25</td></tr>
<tr><td>Combined Cycle</td><td colspan="2">92</td><td>50</td></tr>
<tr><td>Variable O&M (2003$/MWh) Range[1]</td><td><u>CC</u>
2.5 – 8.7</td><td><u>CT</u>
2.2 – 9.0</td><td><u>O/G Steam</u>
0.7 – 3.2</td></tr>
</table>

[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 as shown in Exhibits 4-10 and 4-11.

Exhibit 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

Exhibit 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 is 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 on the spot market, the annual fuel bill for GRU would be approximately $140 million[63].

[63] 465 MW times 0.55 load factor times 8,760 hours per year times $9/MMBtu times 7,000 Btu/kWh.

Conversely, if the entire fuel bill were met via petroleum coke, GRU's 2005 fuel bill would have been approximately $20 million[64]. These illustrative extremes result in fuel costs of 6 cents/kWh versus 0.9 cents/kWh for natural gas and petroleum coke based generation, respectively. Another perspective is that with inflation over the 30 year lifetime of a plant, the capital costs range roughly between $180 million to $600 million, but the cumulative fuel costs are roughly $6.3 billion to $1 billion for natural gas and petroleum coke, respectively[65]. These examples are illustrative only, but help introduce the topic and emphasize the importance of fuel choice and prices for the costs of electric service.

FUEL TYPES ANALYZED

ICF analyzed the following fuel options, many of which the GRU option could choose among:

- **Coal** – ICF examined coal from four regions: (1) Central Appalachian 1-1.5% sulfur coal, similar to the coal currently used by GRU at Deerhaven, except the sulfur content is slightly higher, (2) Illinois Basin which typically has 2-3% sulfur coal, (3) Wyoming Powder River Basin which has less than 1 percent sulfur coal, and (4) coal imports from the southern hemisphere (e.g., Columbia, South Africa, Australia). Since all the new power plant options have controls to decrease SO_2 emissions, and are flexible with respect to the coal quality, a wider range of coal types can be considered than just Central Appalachia. ICF expects Illinois Basin coal to be the least expensive source of coal on a delivered per MMBtu basis due in part to recent price increases in Central Appalachian coal.

- **Petroleum Coke** – Petroleum coke is a by-product of petroleum refining and has high energy density and sulfur content. The price of petroleum coke is typically very low, on a per Btu basis for plants near refining centers in the U.S. Gulf, because few plants can readily use this type of fuel. The use of significant quantities of petroleum coke requires not only sulfur dioxide emissions control, but also flexible coal generation technology such as IGCC and CFB. Thus, the demand for petroleum coke has been limited and commodity prices have been very low. ICF estimates that this source is likely to be the lowest cost fossil fuel available to the plant.

- **Petroleum Coke/Coal Blend – 50%/50%** – This blend is considered as a conservative assessment of the capability of the proposed plants to use petroleum coke. Put another way, on a delivered dollar per Btu basis, petroleum coke is the least cost fuel, but there may be challenges in obtaining and/or using 100% petroleum coke. The effect of these

[64] 465 MW times 0.55 load factor times 8,760 hours per year times $1/MMBtu times 10,000 Btu/kWh.
[65] All numbers are in nominal dollars.

challenges is being reflected in this study by limiting the low end of solid fuel costs by limiting the use of petroleum coke to a coal-petroleum coke blend which raises fuel costs for the CFB and IGCC. This blend is based on Illinois Basin coal which is expected to have a lower delivered cost relative to Central Appalachian coal.

- **Petroleum Coke/Coal/Biomass Blend** – 43%:43%:14% Biomass

- **Natural Gas** – While none of the four options considered use natural gas, natural gas is used by Kelly and other GRU power plants. Also, natural gas is used grid wide in Florida and is an important price setting source for short term purchase power.

- **Oil** – While less important as an option for GRU, Florida uses more oil in electricity generation than any other state. Residual fuel oil 1% sulfur is used Florida grid-wide and is an important price setting source for short term purchase power.

- **Biomass** – ICF has developed assessments of biomass supply using various studies. The four main types of biomass are agricultural crops, agricultural wastes, urban wood wastes and forest residue.

NATURAL GAS VERSUS COAL PRICES

A critical issue facing the City of Gainesville and other utilities is the extent to which the recent increases in oil and natural gas prices that started in 2000 will continue. Recently, natural gas prices have hit all-time record highs (see Exhibits 5-1, 5-2, and 5-3). In 2005, Henry Hub, Louisiana gas prices, the principal marker price for U.S. natural gas, reached $8.37/MMBtu versus a ten year average of $3.42/MMBtu. 2005 natural gas prices are more than three standard deviations higher than the ten year average indicating that it is likely that the underlying distribution of likely gas prices has shifted upward (three standard deviation events have less than a one percent chance under often used statistical assumptions). This is clearly not just related to the recent hurricanes Katrina and Rita. Since 2000, in every year, natural gas prices have been higher than the highest price in the 1990s.

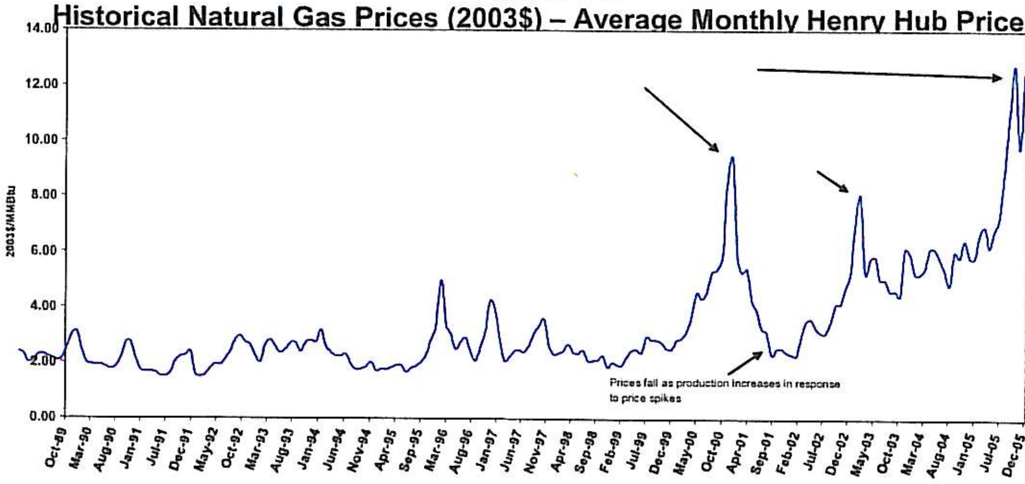
The principal cause of these rising natural gas prices has been increasing demand for the two premium fossil fuels: oil and natural gas. Oil competes closely with natural gas in the U.S. and internationally. There is a very strong correlation between oil and gas prices year-by-year, and hence, the resolution of future natural gas price uncertainty is tied to critical international issues affecting world oil markets. Also, there has been a huge increase in the amount of North American electric generation capacity which uses natural gas increasing the pressure on natural gas prices. As noted, recent additions at Gainesville and elsewhere in Florida have almost exclusively been natural gas-fired.

Exhibit 5-1
Annual Natural Gas Prices Hit a Record in 2005

Year	Henry Hub Price (nominal$/MMBtu)
1995	1.72
1996	2.81
1997	2.48
1998	2.08
1999	2.29
2000	4.70
2001	3.70
2002	3.02
2003	5.46
2004	5.90
2005	8.37
Average 1995 – 2004[1]	3.42
Standard Deviation 1995 – 2004[1]	1.47

[1]Both average and standard deviation would be higher if 2005 was included in the calculations.
Source: Platts' Gas Daily. Prices from 1995 onwards are volume-weighted averages

Exhibit 5-2
Historical Natural Gas Prices (2003$) – Average Monthly Henry Hub Prices



Source: Natural Gas Week & Platts' Gas Daily
January 2006

Exhibit 5-3
Henry Hub Natural Gas Prices

Year	Henry Hub Price (2003$/MMBtu)
1995	1.99
1996	3.19
1997	2.76
1998	2.29
1999	2.49
2000	4.99
2001	3.84
2002	3.08
2003	5.46
2004	5.75
2005	7.98
Average 1995 – 2004[1]	3.58
Standard Deviation 1995 – 2004[1]	1.36

[1]Both average and standard deviation would be higher if 2005 was included in the calculations.
Source: Platts' Gas Daily. Prices from 1995 onwards are volume-weighted averages

Between 1995 and 2005, GRU delivered natural gas prices were $4.28/MMBtu versus $1.84/MMBtu for delivered coal prices. Thus, on average, delivered natural gas cost $2.44/MMBtu more for GRU (see Exhibits 5-4 and 5-5). ICF's forecasts shows this gap will widen, especially when factoring in general economy-wide inflation. The increase in the premium is due to two factors. First, ICF forecasts that natural gas prices will be much higher than over the last ten yeas, though not as high in real terms as 2005. Second, even after inflation, delivered solid fuel costs are not expected to increase, at least before factoring in emission costs. This is in part due to the ability to switch from Central Appalachian coal to other solid fuels such as a blend of petroleum coke and Illinois Basin coal. This is also due to relative stability in delivered coal prices.

Exhibit 5-4
ICF Base Case Delivered Fuel Price Forecasts (Nominal $/MMBtu)

Period	Period Type	Delivered Natural Gas	Delivered Coal[1]	Natural Gas Price Premium
1995 – 2005[2]	Historical	4.28	1.84	+2.44
2011 – 2025[3]	Forecasts	9.18	2.16	+7.02

[1]50% Pet Coke – 50% Illinois Basin coal.
[2]Source: GRU 2005 Ten Year Site Plan, April 2005.
[3]Source: ICF

Exhibit 5-5
ICF Base Case Delivered Fuel Price Forecasts (2003 $/MMBtu)

Period	Period Type	Delivered Natural Gas	Delivered Coal[1]	Natural Gas Price Premium
1995 – 2005[2]	Historical	4.45	1.94	+2.51
2011 – 2025[3]	Forecasts	6.49	1.53	4.96

[1]50% Pet Coke – 50% Illinois Basin coal.
[2]Source: GRU 2005 Ten Year Site Plan, April 2005.
[3]Source: ICF

ICF forecasts for natural gas prices are much higher than used in GRU's IRP in the period 2007 – 2014 (see Exhibits 5-6 and 5-7).

Exhibit 5-6
Delivered Natural Gas Price Forecasts (Nominal$/MMBtu) – ICF versus GRU IRP

Year	Data	ICF Base Case	GRU – IRP
2007	Forecast	10.16	6.08
2008	Forecast	8.77	5.70
2009	Forecast	8.13	5.64
2010	Forecast	7.48	5.57
2011	Forecast	7.74	5.70
2012	Forecast	7.73	5.94
2013	Forecast	8.01	6.20
2014	Forecast	8.08	6.53
2015	Forecast	8.19	NA
2016	Forecast	8.23	NA
2017	Forecast	8.12	NA
2018	Forecast	8.64	NA
2019	Forecast	9.11	NA
2020	Forecast	9.59	NA
2021	Forecast	10.02	NA
2022	Forecast	10.51	NA
2023	Forecast	10.82	NA
2024	Forecast	11.28	NA
2025	Forecast	11.62	NA
1995 – 2005 Average	Historical	4.28	4.28
2006 – 2010 Average	Forecast	8.91	5.90
2011 – 2025 Average	Forecast	9.18	

Source: ICF

Exhibit 5-7
Delivered Natural Gas Price Forecasts (Real 2003$/MMBtu)

Year	Data	ICF Base Case	GRU – IRP
2007	Forecast	9.26	5.56
2008	Forecast	7.82	5.10
2009	Forecast	7.09	4.94
2010	Forecast	6.38	4.77
2011	Forecast	6.45	4.77
2012	Forecast	6.30	4.86
2013	Forecast	6.39	4.96
2014	Forecast	6.30	5.11
2015	Forecast	6.25	NA
2016	Forecast	6.14	NA
2017	Forecast	5.92	NA
2018	Forecast	6.17	NA
2019	Forecast	6.36	NA
2020	Forecast	6.55	NA
2021	Forecast	6.69	NA
2022	Forecast	6.86	NA
2023	Forecast	6.91	NA
2024	Forecast	7.04	NA
2025	Forecast	7.09	NA
1995 – 2005 Average	Historical	4.45	4.45
2006 – 2010 Average	Forecast	7.98	5.29
2011 – 2025 Average	Forecast	6.49	

Source: ICF

ICF has a greater forecast gas-coal price differential than GRU (see Exhibits 5-8 and 5-9).

Exhibit 5-8
Delivered Coal[1] Gas Price Differential (Nominal $/MMBtu)

Year	Data	ICF Base Case	GRU - IRP
1995	Historical	-.60	-.60
1996	Historical	-1.71	-1.71
1997	Historical	-1.64	-1.64
1998	Historical	-1.21	-1.21
1999	Historical	-1.20	-1.20
2000	Historical	-2.91	-2.91
2001	Historical	-3.03	-3.03
2002	Historical	-1.76	-1.76
2003	Historical	-3.76	-3.76
2004	Historical	-4.12	-4.12
2005	Historical	-4.91	-4.91
2006	Forecast	-8.43	-3.55
2007	Forecast	-8.53	-3.5
2008	Forecast	-7.10	-3.08
2009	Forecast	-6.42	-2.97
2010	Forecast	-5.72	-2.96
2011	Forecast	-5.94	-3.02
2012	Forecast	-5.89	-3.17
2013	Forecast	-6.12	-3.32
2014	Forecast	-6.14	-3.57
2015	Forecast	-6.20	NA
2016	Forecast	-6.19	NA
2017	Forecast	-6.03	NA
2018	Forecast	-6.50	NA
2019	Forecast	-6.91	NA
2020	Forecast	-7.34	NA
2021	Forecast	-7.71	NA
2022	Forecast	-8.13	NA
2023	Forecast	-8.38	NA
2024	Forecast	-8.76	NA
2025	Forecast	-9.04	NA

[1] Blended coal (50% Illinois Basin and 50% Pet Coke).
Source: ICF

Exhibit 5-9
Delivered Coal[1] Gas Price Differential (Real 2003 $/MMBtu)

Year	Data	ICF Base Case	GRU - IRP
1995	Historical	-0.69	-0.69
1996	Historical	-1.94	-1.94
1997	Historical	-1.83	-1.83
1998	Historical	-1.33	-1.33
1999	Historical	-1.30	-1.30
2000	Historical	-3.09	-3.09
2001	Historical	-3.15	-3.15
2002	Historical	-1.80	-1.80
2003	Historical	-3.76	-3.76
2004	Historical	-4.03	-4.03
2005	Historical	-4.70	-4.70
2006	Forecast	-7.89	-3.32
2007	Forecast	-7.77	-3.20
2008	Forecast	-6.33	-2.76
2009	Forecast	-5.59	-2.60
2010	Forecast	-4.87	-2.54
2011	Forecast	-4.94	-2.53
2012	Forecast	-4.79	-2.59
2013	Forecast	-4.88	-2.65
2014	Forecast	-4.78	-2.79
2015	Forecast	-4.73	NA
2016	Forecast	-4.61	NA
2017	Forecast	-4.39	NA
2018	Forecast	-4.64	NA
2019	Forecast	-4.82	NA
2020	Forecast	-5.01	NA
2021	Forecast	-5.14	NA
2022	Forecast	-5.31	NA
2023	Forecast	-5.35	NA
2024	Forecast	-5.47	NA
2025	Forecast	-5.52	NA

[1] Blended coal (50% Illinois Basin and 50% Pet Coke). Delivered to GRU.
Source: ICF

YEAR-TO-YEAR VOLATILITY IN FUEL PRICES

Natural gas prices are especially uncertain compared to coal not only on a long-term basis but also year-to-year. This is associated not only with the volatility of spot natural gas markets, but also due to the differences in the purchasing practices between solid fuels and natural gas. Generally a large portion of solid fuel costs on a delivered basis are transportation costs which do not fluctuate significantly, and which are purchased on long tern contract. Solid fuel commodities are also purchased on multi-year contracts where term purchases exchange price stability, and long-term commitments for prices lower than spot prices. Also, because there are so many options within the category of solid fuel, especially as plants retrofit or install pollution controls that on a delivered basis there is less volatility than on a commodity basis. This is because if one fuel source becomes more expensive, buyers with flexible equipment can switch to other regions or types of solid fuel.

In contrast, natural gas is generally purchased at spot due to uncertainties on the amount to be used, the difficulty in storing the fuel, the premiums needed to guarantee a fixed price, and the high costs of financially hedging the price of natural gas especially the need to effectively maintain margins.

Over the last five years, spot coal prices have risen significantly especially for Central Appalachian coal of the type historically used by GRU. Also, 2005 prices were higher than, or as high as 2004 prices depending on the type of coal. Also, there is some correlation between spot coal and natural gas prices (see Exhibits 5-10 and 5-11). However, the variability of delivered coal prices is much less than spot commodity prices at the minemouth. For example, the U.S. average standard deviation for delivered coal prices is 5 percent versus 43 percent for spot Central Appalachian low sulfur coal prices. This again is due to term commodity and rail contracting, the stability of rail costs and the ability to switch among coal types.

Exhibit 5-10
Coal Price Volatility Greatly Dampened by Relative Stability in Transportation Costs and Contracting Prices

Year	Spot Coal Prices[1] (Nominal$/MMBtu)		Average Delivered Coal Costs to Utilities (Nominal$/MMBtu)	
	PRB	Central Appalachia 1% Sulfur	GRU[2]	U.S.[3]
1995	0.27	0.87	1.73	1.32
1996	0.23	1.05	1.66	1.29
1997	0.25	1.02	1.66	1.27
1998	0.26	1.08	1.66	1.25
1999	0.27	1.02	1.66	1.22
2000	0.26	0.99	1.62	1.20
2001	0.57	1.72	1.88	1.23
2002	0.35	1.17	2.06	1.26
2003	0.36	1.40	2.04	1.28
2004	0.36	2.27	2.03	1.36
Standard Deviation	0.10	0.43	0.18	0.05
Correlation with Gas Prices	0.37	0.73	0.59	0.21

[1] Source: Coal Outlook
[2] Source: A Review of Florida Electric Utility 2005 Ten-Year Site Plans, prepared by the Florida Public Service Commission, Division of Economic Regulation, December 2005, p.48
[3] Source: EIA AEO 2005

The difference in the volatility in U.S. utility average delivered natural gas prices and U.S. delivered coal prices is much larger than the difference between spot and delivered coal. U.S. average delivered gas price volatility (i.e., standard deviation) exceeds U.S.

average delivered coal price variability by a factor of 27 (see Exhibit 5-11). Thus, reliance on natural gas or wholesale spot power which is driven by gas and oil prices means high year-to-year variation relative to coal.

Exhibit 5-11
Delivered Utility Fuel Price Volatility – U.S. Average

Year	Nominal$/MMBtu		
	Coal – U.S. Average Delivered Utility Cost[1]	Gas – U.S. Average Delivered Utility Cost[1]	Henry Hub Spot Gas Price[2]
1995	1.32	1.98	1.72
1996	1.29	2.64	2.81
1997	1.27	2.76	2.48
1998	1.25	2.38	2.08
1999	1.22	2.57	2.29
2000	1.20	4.30	4.70
2001	1.23	4.49	3.70
2002	1.26	3.56	3.02
2003	1.28	5.39	5.46
2004	1.36	5.96	5.90
Average	1.27	3.60	3.42
Standard Deviation	0.05	1.37	1.47
Correlation Coefficient with Henry Hub	21%	97%	--

[1]Source: EIA Electric Power Annual Table 4.5
[2]Source: Platts' Gas Daily. Prices from 1995 onwards are volume-weighted averages.

As noted, fuel contracting differences make coal prices much less volatile (see Exhibit 5-12).

Exhibit 5-12
Fuel Purchasing and Contracting

Parameter	Coal	Natural Gas
Commodity Contract Type	3 - 5 Year[1]	Spot
Transportation Contract Type	10 Year	10 Year
Financial Hedging	No	No

[1]Price fixed for five years on average.

DELIVERED SOLID FUEL FORECAST – BLENDED PET COKE, COAL, AND BIOMASS

Several solid fuel blends are shown in Exhibits 5-13 through 5-16 in real and nominal dollars. The model decides what bland to use including all biomass.

Exhibit 5-13
50% Illinois Basin Coal & 50% Pet Coke (Nominal $)

Year	50% Illinois Basin-50% Pet Coke		Transportation		Delivered[1]	
	$/ton	$/MMBtu	$/ton	$/MMBtu	$/ton	$/MMBtu
2011	23.6	0.98	19.9	0.82	43.5	1.80
2012	24.1	1.00	20.3	0.84	44.4	1.84
2013	24.8	1.03	20.8	0.86	45.6	1.89
2014	25.5	1.06	21.2	0.88	46.8	1.94
2015	26.3	1.09	21.7	0.90	48.0	1.99
2016	27.1	1.12	22.2	0.92	49.3	2.04
2017	27.9	1.15	22.7	0.94	50.6	2.09
2018	28.7	1.18	23.2	0.96	52.0	2.14
2019	29.6	1.22	23.7	0.98	53.3	2.20
2020	30.5	1.25	24.3	1.00	54.8	2.25
2021	31.5	1.29	24.8	1.03	56.3	2.31
2022	32.5	1.33	25.4	1.05	57.8	2.38
2023	33.5	1.37	25.9	1.07	59.4	2.44
2024	34.6	1.41	26.5	1.10	61.1	2.51
2025	35.7	1.45	27.1	1.12	62.8	2.57
Average	29.1	1.19	23.3	0.96	52.4	2.16

[1] Delivered prices may not be the sum of commodity and transportation prices due to independent rounding
Source: ICF

Exhibit 5-14
50% Illinois Basin Coal & 50% Pet Coke (2003 $)

Year	50% Illinois Basin-50% Pet Coke		Transportation		Delivered[1]	
	$/ton	$/MMBtu	$/ton	$/MMBtu	$/ton	$/MMBtu
2011	19.70	0.82	16.56	0.68	36.26	1.50
2012	19.63	0.81	16.56	0.68	36.19	1.50
2013	19.77	0.82	16.56	0.68	36.33	1.50
2014	19.93	0.82	16.56	0.68	36.49	1.51
2015	20.08	0.83	16.56	0.68	36.64	1.51
2016	20.24	0.84	16.56	0.68	36.80	1.52
2017	20.38	0.84	16.56	0.68	36.93	1.52
2018	20.51	0.84	16.56	0.68	37.07	1.53
2019	20.66	0.85	16.56	0.68	37.22	1.53
2020	20.81	0.85	16.56	0.68	37.37	1.54
2021	21.00	0.86	16.56	0.68	37.55	1.54
2022	21.19	0.87	16.56	0.68	37.75	1.55
2023	21.38	0.87	16.56	0.68	37.94	1.56
2024	21.58	0.88	16.56	0.68	38.14	1.56
2025	21.79	0.89	16.56	0.68	38.35	1.57
Average	20.58	0.85	16.56	0.68	37.14	1.53

[1] Delivered prices may not be the sum of commodity and transportation prices due to independent rounding
Source: ICF

Exhibit 5-15
14% Biomass, 43% Illinois Basin Coal & 43% Pet Coke (Nominal $)

Year	50% Illinois Basin-50% Pet Coke		Transportation		Delivered[1]	
	$/ton	$/MMBtu	$/ton	$/MMBtu	$/ton	$/MMBtu
2011	23.27	1.02	18.97	0.82	42.25	1.83
2012	23.71	1.03	19.40	0.83	43.12	1.87
2013	24.41	1.06	19.84	0.85	44.25	1.92
2014	25.12	1.09	20.29	0.87	45.41	1.97
2015	25.86	1.12	20.74	0.89	46.60	2.02
2016	26.63	1.16	21.21	0.91	47.84	2.07
2017	27.39	1.19	21.69	0.93	49.08	2.12
2018	28.18	1.22	22.17	0.95	50.35	2.17
2019	28.99	1.25	22.67	0.98	51.67	2.23
2020	29.83	1.29	23.18	1.00	53.01	2.28
2021	30.75	1.32	23.70	1.02	54.45	2.34
2022	31.69	1.36	24.24	1.04	55.93	2.40
2023	32.67	1.40	24.78	1.07	57.45	2.47
2024	33.68	1.44	25.34	1.09	59.02	2.53
2025	34.73	1.49	25.91	1.11	60.64	2.60
Average	28.46	1.23	22.28	0.96	50.74	2.19

[1] Delivered prices may not be the sum of commodity and transportation prices due to independent rounding
Source: ICF

Exhibit 5-16
14% Biomass, 43% Illinois Basin Coal & 43% Pet Coke (2003 $)

Year	50% Illinois Basin-50% Pet Coke		Transportation		Delivered[1]	
	$/ton	$/MMBtu	$/ton	$/MMBtu	$/ton	$/MMBtu
2011	19.41	0.85	15.82	0.68	35.23	1.53
2012	19.34	0.84	15.82	0.68	35.16	1.52
2013	19.46	0.85	15.82	0.68	35.29	1.53
2014	19.60	0.85	15.82	0.68	35.42	1.53
2015	19.73	0.86	15.82	0.68	35.55	1.54
2016	19.87	0.86	15.82	0.68	35.69	1.54
2017	19.99	0.87	15.82	0.68	35.81	1.55
2018	20.11	0.87	15.82	0.68	35.93	1.55
2019	20.23	0.87	15.82	0.68	36.06	1.55
2020	20.36	0.88	15.82	0.68	36.18	1.56
2021	20.52	0.88	15.82	0.68	36.34	1.56
2022	20.69	0.89	15.82	0.68	36.51	1.57
2023	20.86	0.89	15.82	0.68	36.68	1.58
2024	21.03	0.90	15.82	0.68	36.85	1.58
2025	21.21	0.91	15.82	0.68	37.03	1.59
Average	20.16	0.87	15.82	0.68	35.98	1.55

[1] Delivered prices may not be the sum of commodity and transportation prices due to independent rounding
Source: ICF

COAL PRICE FORECAST

Coal prices have risen in the spot markets on a commodity basis – i.e., at or near the mine. This increase has been especially pronounced in the Central Appalachian coal fields that have been the traditional source of coal for Gainesville. This increase has been driven by higher demand for coal which in turn has in part been driven by higher oil and natural gas prices. There also has been rising international demand for US coal. However, these increases have still left coal at a very large discount to natural gas prices. For example, over the last several months, the highest coal prices in the country on a commodity basis have been approximately $2/MMBtu for the premium coal types versus gas prices ten dollars per million Btu.

Gainesville will no longer be captive to premium grades of Central Appalachian coal. All the new solid fuel generation options under consideration will include flue gas desulphurization equipment. Accordingly, Gainesville can explore other coal alternatives from other regions of the country. For example, Midwestern coal can be produced closer to $1-1.25/MMBtu, and Wyoming PRB coal is often produced under $0.5/MMBtu at the mine.

U.S. coal resources are measured in many decades of current consumption. Only China produces more coal than the U.S. ICF forecasts show nominal prices of the least cost options to be at or below recent historical levels. Not including general inflation results in much lower coal prices (see Exhibits 5-17 and 5-18).

Exhibit 5-17
Delivered[2] Solid Fossil Fuel Prices (Nominal$/MMBtu)

Solid Fossil Fuel Type	2011 – 2025
Central Appalachia	2.88
PRB	2.81
Illinois Basin	2.69
Imported Coal	3.01
Petroleum Coke	1.63
Biomass	2.37
Weighted Average[1]	2.55

[1]Ten percent biomass, ten percent pet coke, 80 percent average of delivered Illinois Basin coal costs.
[2]Delivered to GRU.
Source: ICF

Exhibit 5-18
Delivered[2] Solid Fossil Fuel Prices (2003$/MMBtu)

Solid Fossil Fuel Type	2011 – 2025
Central Appalachia	2.05
PRB	2.00
Illinois Basin	1.91
Imported Coal	2.13
Petroleum Coke	1.15
Biomass	1.69
Weighted Average[1]	1.81

[1]Ten percent biomass, ten percent pet coke, 80 percent average of delivered Illinois Basin coal costs.
[2]Delivered to GRU.
Source: ICF

ICF average forecasts for a blend of Illinois coal and petroleum coke are below GRU forecasts (see Exhibit 5-19 and 5-20).

Exhibit 5-19
Delivered to GRU Coal/Petroleum Coke 50:50 Blend – ICF versus GRU Costs (Nominal $/MMBtu)

Year	Data	ICF Base Case[1]	GRU[2]
2007	Forecast	1.63	2.58
2008	Forecast	1.67	2.62
2009	Forecast	1.71	2.67
2010	Forecast	1.76	2.61
2011	Forecast	1.80	2.68
2012	Forecast	1.84	2.77
2013	Forecast	1.89	2.88
2014	Forecast	1.94	2.96
2015	Forecast	1.99	NA
2016	Forecast	2.04	NA
2017	Forecast	2.09	NA
2018	Forecast	2.14	NA
2019	Forecast	2.20	NA
2020	Forecast	2.25	NA
2021	Forecast	2.35	NA
2022	Forecast	2.38	NA
2023	Forecast	2.44	NA
2024	Forecast	2.51	NA
2025	Forecast	2.58	NA
1995 – 2005 Average	Historical	1.84	1.84
2006 – 2010 Average	Forecast	1.67	2.69
2011 – 2025 Average	Forecast	2.16	NA

[1]Blended coal (50% Illinois Basin and 50% Pet Coke); Source: ICF.
[2]Central Appalachia 0.7% sulfur coal. Source: GRU 2005 Ten Year Site Plan, April 2005.

Exhibit 5-20
Delivered to GRU Coal and Petroleum Coke 50:50 Blend – ICF versus GRU Costs (2003 $/MMBtu)

Year	Data	ICF Base Case[1]	GRU[2]
2007	Forecast	1.49	2.36
2008	Forecast	1.49	2.34
2009	Forecast	1.50	2.34
2010	Forecast	1.51	2.23
2011	Forecast	1.51	2.24
2012	Forecast	1.51	2.27
2013	Forecast	1.51	2.31
2014	Forecast	1.52	2.32
2015	Forecast	1.52	NA
2016	Forecast	1.53	NA
2017	Forecast	1.53	NA
2018	Forecast	1.53	NA
2019	Forecast	1.54	NA
2020	Forecast	1.54	NA
2021	Forecast	1.54	NA
2022	Forecast	1.55	NA
2023	Forecast	1.56	NA
2024	Forecast	1.57	NA
2025	Forecast	1.58	NA
1995 – 2005 Average	Historical	-	-
2006 – 2010 Average	Forecast	1.50	2.32
2011 – 2025 Average	Forecast	1.54	2.27

[1]Blended coal (50% Illinois Basin and 50% Pet Coke); Source: ICF.
[2]Central Appalachia 0.7% sulfur coal. Source: GRU 2005 Ten Year Site Plan, April 2005.

ICF forecasts for several coals, Illinois Basin 3% sulfur, Central Appalachia medium low sulfur coal, and Wyoming Powder River Basin (PRB) low sulfur sub-bituminous coal are shown in Exhibits 5-21 through 5-26.

Exhibit 5-21
Illinois Basin Coal (Nominal $)

Year	Illinois Basin - 3% Sulfur		Transportation		Delivered[1]	
	$/ton	$/MMBtu	$/ton	$/MMBtu	$/ton	$/MMBtu
2011	28.57	1.30	22.95	1.04	51.52	2.34
2012	28.60	1.30	23.47	1.07	52.07	2.37
2013	29.17	1.33	24.00	1.09	53.17	2.42
2014	29.76	1.35	24.54	1.12	54.30	2.47
2015	30.35	1.38	25.09	1.14	55.44	2.52
2016	30.96	1.41	25.66	1.17	56.62	2.57
2017	31.51	1.43	26.23	1.19	57.74	2.62
2018	32.06	1.46	26.82	1.22	58.88	2.68
2019	32.63	1.48	27.43	1.25	60.06	2.73
2020	33.20	1.51	28.04	1.27	61.24	2.78
2021	33.88	1.54	28.67	1.30	62.55	2.84
2022	34.58	1.57	29.32	1.33	63.89	2.90
2023	35.29	1.60	29.98	1.36	65.26	2.97
2024	36.01	1.64	30.65	1.39	66.66	3.03
2025	36.75	1.67	31.34	1.42	68.09	3.09
Average	32.22	1.46	26.95	1.22	59.17	2.69

[1]Delivered prices may not be the sum of commodity and transportation prices due to independent rounding.
Source: ICF

Exhibit 5-22
Illinois Basin Coal (2003 $)

Year	Illinois Basin - 3% Sulfur		Transportation		Delivered[1]	
	$/ton	$/MMBtu	$/ton	$/MMBtu	$/ton	$/MMBtu
2011	23.82	1.08	19.14	0.87	42.96	1.95
2012	23.32	1.06	19.14	0.87	42.46	1.93
2013	23.26	1.06	19.14	0.87	42.41	1.93
2014	23.21	1.06	19.14	0.87	42.35	1.93
2015	23.15	1.05	19.14	0.87	42.29	1.92
2016	23.10	1.05	19.14	0.87	42.24	1.92
2017	22.99	1.05	19.14	0.87	42.13	1.91
2018	22.88	1.04	19.14	0.87	42.02	1.91
2019	22.77	1.04	19.14	0.87	41.91	1.91
2020	22.66	1.03	19.14	0.87	41.80	1.90
2021	22.62	1.03	19.14	0.87	41.75	1.90
2022	22.57	1.03	19.14	0.87	41.71	1.90
2023	22.53	1.02	19.14	0.87	41.67	1.89
2024	22.48	1.02	19.14	0.87	41.62	1.89
2025	22.44	1.02	19.14	0.87	41.58	1.89
Average	22.92	1.04	19.14	0.87	42.06	1.91

[1]Delivered prices may not be the sum of commodity and transportation prices due to independent rounding.
Source: ICF

Exhibit 5-23
Central Appalachia U.S. Coal – Medium Low Sulfur (Nominal $)

Year	1.0% to 1.5% Sulfur, Central Appalachia – Minemouth Cost		Transportation Cost		Delivered[1]	
	$/ton	$/MMBtu	$/ton	$/MMBtu	$/ton	$/MMBtu
2011	49.03	1.95	19.18	0.77	68.19	2.73
2012	51.39	2.06	19.46	0.78	70.85	2.83
2013	53.61	2.14	19.75	0.79	73.36	2.93
2014	55.92	2.24	20.05	0.81	75.99	3.04
2015	58.36	2.33	20.36	0.81	78.71	3.15
2016	60.88	2.44	20.66	0.82	81.54	3.26
2017	63.74	2.55	20.97	0.85	84.70	3.40
2018	66.73	2.68	21.27	0.85	88.02	3.52
2019	69.88	2.79	21.59	0.86	91.48	3.67
2020	73.16	2.93	21.92	0.88	95.09	3.81
2021	76.54	3.07	22.25	0.89	98.75	3.96
2022	80.08	3.21	22.58	0.91	102.56	4.11
2023	83.78	3.36	22.91	0.92	106.51	4.27
2024	87.65	3.52	23.25	0.94	110.62	4.44
2025	91.70	3.68	23.60	0.95	114.88	4.61
Average	68.16	2.73	21.32	0.86	89.42	3.58

[1] Delivered prices may not be the sum of commodity and transportation prices due to independent rounding
Source: ICF

Exhibit 5-24
Central Appalachia U.S. Coal – Medium Low Sulfur (2003 $)

Year	1.0% to 1.5% Sulfur, Central Appalachia – Minemouth Cost		Transportation Cost		Delivered[1]	
	$/ton	$/MMBtu	$/ton	$/MMBtu	$/ton	$/MMBtu
2011	40.88	1.63	15.99	0.64	56.86	2.28
2012	41.91	1.68	15.87	0.64	57.78	2.31
2013	42.76	1.71	15.75	0.63	58.51	2.34
2014	43.62	1.75	15.64	0.63	59.27	2.37
2015	44.52	1.78	15.53	0.62	60.04	2.40
2016	45.42	1.82	15.41	0.61	60.83	2.43
2017	46.51	1.86	15.30	0.62	61.80	2.48
2018	47.62	1.91	15.18	0.61	62.81	2.51
2019	48.77	1.95	15.07	0.60	63.84	2.56
2020	49.93	2.00	14.96	0.60	64.90	2.60
2021	51.09	2.05	14.85	0.60	65.92	2.64
2022	52.27	2.10	14.74	0.59	66.95	2.68
2023	53.49	2.14	14.63	0.59	68.00	2.73
2024	54.73	2.20	14.52	0.58	69.07	2.77
2025	56.00	2.25	14.41	0.58	70.15	2.82
Average	47.97	1.92	15.19	0.61	63.12	2.53

[1] Delivered prices may not be the sum of commodity and transportation prices due to independent rounding
Source: ICF

Exhibit 5-25
Powder River Basin Wyoming (PRB) (Nominal $)

Year	PRB Minemouth		Transportation		Delivered[1]	
	$/ton	$/MMBtu	$/ton	$/MMBtu	$/ton	$/MMBtu
2011	8.90	0.50	35.68	2.03	44.59	2.53
2012	9.10	0.53	36.21	2.06	45.32	2.58
2013	9.24	0.53	36.75	2.09	46.02	2.61
2014	9.40	0.53	37.31	2.12	46.72	2.65
2015	9.56	0.54	37.87	2.15	47.43	2.69
2016	9.70	0.55	38.44	2.18	48.15	2.73
2017	9.80	0.55	39.02	2.22	48.82	2.77
2018	9.89	0.56	39.60	2.24	49.50	2.82
2019	10.00	0.57	40.19	2.29	50.20	2.85
2020	10.10	0.57	40.80	2.31	50.89	2.89
2021	10.21	0.58	41.42	2.35	51.61	2.93
2022	10.32	0.59	42.04	2.38	52.34	2.97
2023	10.43	0.59	42.67	2.42	53.08	3.01
2024	10.55	0.60	43.31	2.46	53.83	3.06
2025	10.66	0.61	43.96	2.49	54.59	3.10
Average	9.86	0.56	39.69	2.25	49.54	2.81

[1] Delivered prices may not be the sum of commodity and transportation prices due to independent rounding
Source: ICF

Exhibit 5-26
Powder River Basin Wyoming (PRB) (2003 $)

Year	PRB Minemouth		Transportation		Delivered[1]	
	$/ton	$/MMBtu	$/ton	$/MMBtu	$/ton	$/MMBtu
2011	7.42	0.42	29.75	1.69	37.18	2.11
2012	7.42	0.43	29.53	1.68	36.96	2.10
2013	7.37	0.42	29.31	1.67	36.7	2.08
2014	7.33	0.41	29.1	1.65	36.44	2.07
2015	7.29	0.41	28.89	1.64	36.18	2.05
2016	7.24	0.41	28.68	1.63	35.92	2.04
2017	7.15	0.4	28.47	1.62	35.62	2.02
2018	7.06	0.4	28.26	1.6	35.32	2.01
2019	6.98	0.4	28.05	1.6	35.03	1.99
2020	6.89	0.39	27.85	1.58	34.73	1.97
2021	6.81	0.39	27.65	1.57	34.45	1.95
2022	6.74	0.38	27.44	1.56	34.17	1.94
2023	6.66	0.38	27.24	1.55	33.89	1.92
2024	6.59	0.37	27.05	1.53	33.61	1.91
2025	6.51	0.37	26.85	1.52	33.34	1.89
Average	7.03	0.40	28.27	1.61	35.30	2.00

[1] Delivered prices may not be the sum of commodity and transportation prices due to independent rounding
Source: ICF

PETROLEUM COKE PRICE FORECAST

Over the last ten years, spot petroleum coke prices have averaged approximately $15/ton or $0.55/MMBtu measured in the U.S. Gulf. They have almost never been above $20/ton, and generally have fluctuated between $10 and $20/ton. There is increasing potential for production of petroleum coke since coke production increases as the quality of crude oil declines. At the same time, we expect other power companies to also consider petroleum coke in their design of solid fuel plants. Thus, ICF's forecasts balance these two developments (see Exhibit 5-27 and 5-28).

Petroleum coke is expected to be delivered by rail, most likely from Jacksonville.

Exhibit 5-27
Petroleum Coke (Nominal $)

Year	Pet Coke Jacksonville, FL		Transportation		Delivered[1]	
	$/ton	$/MMBtu	$/ton	$/MMBtu	$/ton	$/MMBtu
2011	18.69	0.67	16.77	0.60	35.46	1.27
2012	19.53	0.70	17.14	0.61	36.68	1.31
2013	20.41	0.73	17.53	0.63	37.94	1.36
2014	21.33	0.76	17.92	0.64	39.25	1.40
2015	22.29	0.80	18.33	0.65	40.62	1.45
2016	23.29	0.83	18.74	0.67	42.03	1.50
2017	24.34	0.87	19.16	0.68	43.50	1.55
2018	25.44	0.91	19.59	0.70	45.03	1.61
2019	26.58	0.95	20.03	0.72	46.61	1.66
2020	27.78	0.99	20.48	0.73	48.26	1.72
2021	29.03	1.04	20.94	0.75	49.97	1.78
2022	30.34	1.08	21.41	0.76	51.75	1.85
2023	31.70	1.13	21.90	0.78	53.60	1.91
2024	33.13	1.18	22.39	0.80	55.52	1.98
2025	34.62	1.24	22.89	0.82	57.51	2.05
Average	25.90	0.93	19.68	0.70	45.6	1.63

[1] Delivered prices may not be the sum of commodity and transportation prices due to independent rounding
Source: ICF

Exhibit 5-28
Petroleum Coke (2003 $)

Year	Pet Coke Jacksonville, FL		Transportation		Delivered[1]	
	$/ton	$/MMBtu	$/ton	$/MMBtu	$/ton	$/MMBtu
2011	15.59	0.56	13.98	0.50	29.57	1.06
2012	15.93	0.57	13.98	0.50	29.91	1.07
2013	16.28	0.58	13.98	0.50	30.26	1.08
2014	16.64	0.59	13.98	0.50	30.62	1.09
2015	17.00	0.61	13.98	0.50	30.98	1.11
2016	17.38	0.62	13.98	0.50	31.36	1.12
2017	17.76	0.63	13.98	0.50	31.74	1.13
2018	18.15	0.65	13.98	0.50	32.13	1.15
2019	18.55	0.66	13.98	0.50	32.53	1.16
2020	18.96	0.68	13.98	0.50	32.94	1.18
2021	19.38	0.69	13.98	0.50	33.36	1.19
2022	19.80	0.71	13.98	0.50	33.78	1.21
2023	20.24	0.72	13.98	0.50	34.22	1.22
2024	20.68	0.74	13.98	0.50	34.66	1.24
2025	21.14	0.75	13.98	0.50	35.12	1.25
Average	18.23	0.65	13.98	0.50	32.21	1.15

[1] Delivered prices may not be the sum of commodity and transportation prices due to independent rounding
Source: ICF

BIOMASS FORECAST

Biomass Supply Curve Methodology

Biomass as a fuel source for generation was evaluated for several of the generation options considered in this analysis. Biomass has the advantage of generally being considered as having net-zero CO_2 emissions, and significantly reduced emissions of SO_2 and Hg, while still having NO_X emissions associated with its combustion. There are generally four sources of biomass that are considered feedstocks for combustion in a CFB plant – either in stand-alone or co-firing applications, or for gasification in an IGCC. These resources are urban wood waste, agricultural residues, forestry residues and agricultural crops. In developing our supply curves for biomass, ICF relied on the four existing sources of data described below.

Sources of Data

- **[ORNL]** ORNL Biomass Feedstock Availability by ORNL Staff (1999)
- **[P&C]** Biomass Options for GRU – Part II by Post & Cunilio (2003)
- **[B&V]** Supplemental Study of Generating Alternatives by Black & Veatch (2004)
- **[EIA]** Annual Energy Outlook 2006 Biomass Supply Curves by Zia Haq (2006)

Summary of Biomass Data

All sources agreed that urban wood waste is likely to be the least expensive, but most variable category of biomass. There was less agreement over the cost and availability of the other categories of biomass, which include agricultural residues, forestry residues, and energy crops. There was also disagreement over assumptions for key parameters constraining biomass use. P&C restricted their analysis to a 25 mile radius around the Deerhaven plant; B&V disagreed, stating that "it is common for biomass facilities to source supplies from as much as 100 miles away from the facility." B&V also revised the expected heat content of many sources of biomass noted by P&C in order to take into account the significant moisture content of biomass, and included new possible fuel sources, such as corn stover. The supply curve generated by EIA's analysis was similar to B&V's, except with a more pessimistic view of energy crop availability. ORNL's analysis matched up similarly with EIA. Additionally, none of the sources considered rail as a means of transporting biomass to the plant, and none of the sources took into consideration the Renewable Energy Production Incentive, which may be available to certain categories of biomass. Because of these differences, two cases were created to test the effects that different parameters may have on the supply of biomass to the Deerhaven plant. The parameters for these cases, along with a brief explanation of each, are listed below (see Exhibit 5-29).

Base Case and High Case Parameters

Exhibit 5-29
Biomass Scenario Parameters

Parameter	Base Case	High Case
Radius of Eligible Biomass from Plant	50 Miles	35 Miles
Rail Loading/Unloading to Plant	No	Yes
Renewable Energy Production Incentive	Yes	No
Assumed Moisture Content	30%	50%
Energy Crop Potential	Optimistic	Pessimistic

Radius of Eligible Biomass from Plant – This parameter sets the distance, in miles, that is considered eligible to supply the plant with biomass. A larger radius allows for an exponentially greater amount of biomass availability, and so this parameter has a great influence on the estimated shape of the biomass supply curve. Additionally, this parameter allows for the standardization of regional sources of data, such as the EIA and ORNL supply curves, into the same land area as studied by P&C and B&V.

Rail Loading/Unload to Plant – Delivering large quantities of biomass by truck may not be feasible, or at the least extremely problematic, in densely populated urban areas. This parameter simulates the cost of collecting and shipping biomass to the plant by rail, at a central collection point, instead of entirely by 75 or 100 ton truck. Assuming a standard rail charge of $4 per ton, and an average wet biomass heat content of 8.5 MMBtu per ton, this parameter effectively increases the cost of delivering biomass for the High Case by $0.47 per MMBtu.

Renewable Energy Production Incentive (REPI) – This parameter models the effect that the REPI, recently extended under the Energy Policy Act of 2005, may have on the availability and price of biomass supplies near the plant. Because of uncertainty about the funding for this incentive and the partial eligibility of biomass, the effects of the REPI are discounted to approximately $2.70 per MWh, which is then incorporated into the Base Case supply curve as a decrease in cost of approximately $0.25 per MMBtu. Full details on this calculation can be found in Attachment 5.

Assumed Moisture Content – Many sources of biomass, especially the low cost urban wood waste category, vary in moisture content, and this variability can increase the price of the fuel depending on how much processing and drying is to be conducted before consumption. This parameter effectively sets a moisture content penalty for the High Case, in order to capture the uncertainty surrounding the true heating value of the biomass likely to be consumed by the plant.

Energy Crop Potential – Currently there is little consensus on the economic potential for biomass to be grown as a crop. To capture the different points of view on this issue, two separate forecasts were created for the Base Case and the High Case supply curves to model optimistic and pessimistic views of the price and availability of biomass energy crops. Greater detail of these forecasts can be found in the Attachment.

Biomass Supply Curve Results

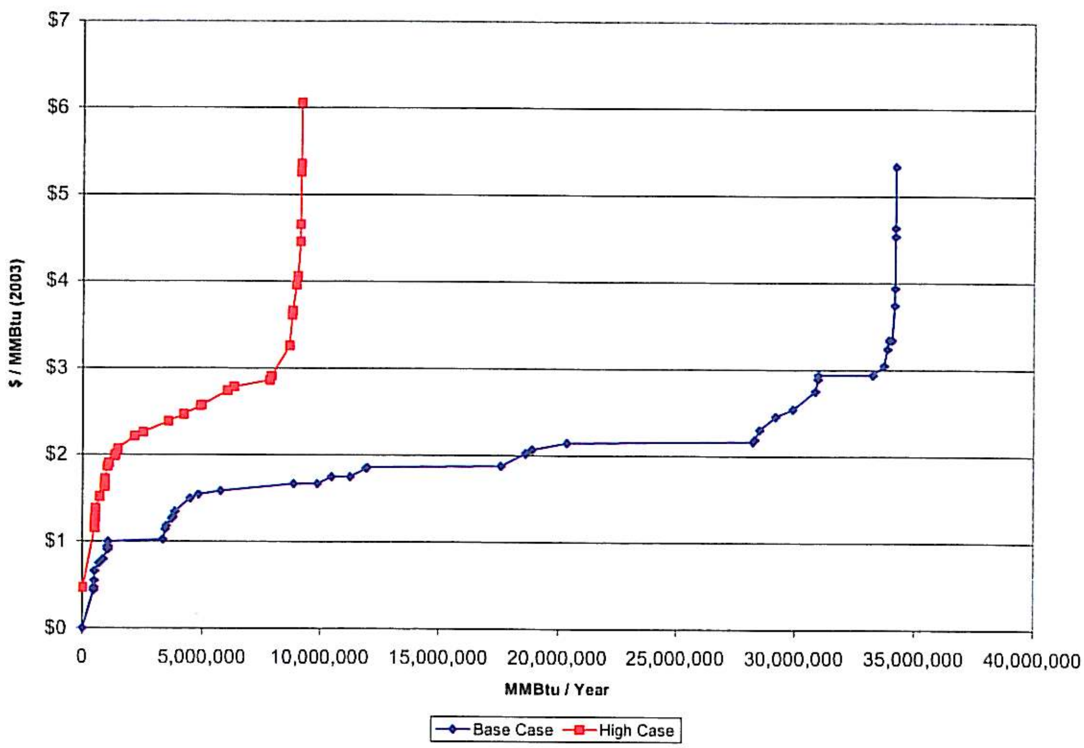
A summary table and a graphical representation of the biomass curves follow below (see Exhibits 5-30 and 5-31).

Exhibit 5-30
Biomass Supply Curves Summary Table

Base Case			High Case		
$ / MMBtu	MMBtu	Capacity Supported (MW)*	$ / MMBtu	MMBtu	Capacity Supported (MW)*
$1.19	3,492,779	47	$1.19	496,539	7
$1.67	9,870,326	133	$1.67	911,279	12
$2.07	18,898,334	254	$2.07	1,455,818	20
$2.47	29,171,977	392	$2.47	4,210,282	57
$5.36	34,190,556	459	$5.36	9,145,372	123

*Assuming a heat rate of 10,000 btu / kwh and 85% capacity factor

Exhibit 5-31
Biomass Supply Curves Graph



NATURAL GAS PRICE FORECAST

ICF forecasts show a larger gap between natural gas and coal than GRU (see Exhibits 5-32, 5-33, and 5-34).

Exhibit 5-32
Henry Hub 4P Natural Gas Price Forecast[1]

Year	2003$/MMBtu	Nominal$/MMBtu
2006	8.95	9.60
2007	8.87	9.73
2008	7.43	8.34
2009	6.71	7.70
2010	5.99	7.02
2011	6.06	7.27
2012	5.91	7.25
2013	6.00	7.52
2014	5.91	7.58
2015	5.86	7.68
2016	5.75	7.71
2017	5.53	7.58
2018	5.77	8.09
2019	5.97	8.55
2020	6.15	9.01
2021	6.30	9.44
2022	6.47	9.91
2023	6.52	10.21
2024	6.65	10.65
2025	6.70	10.98
Average	6.48	8.59

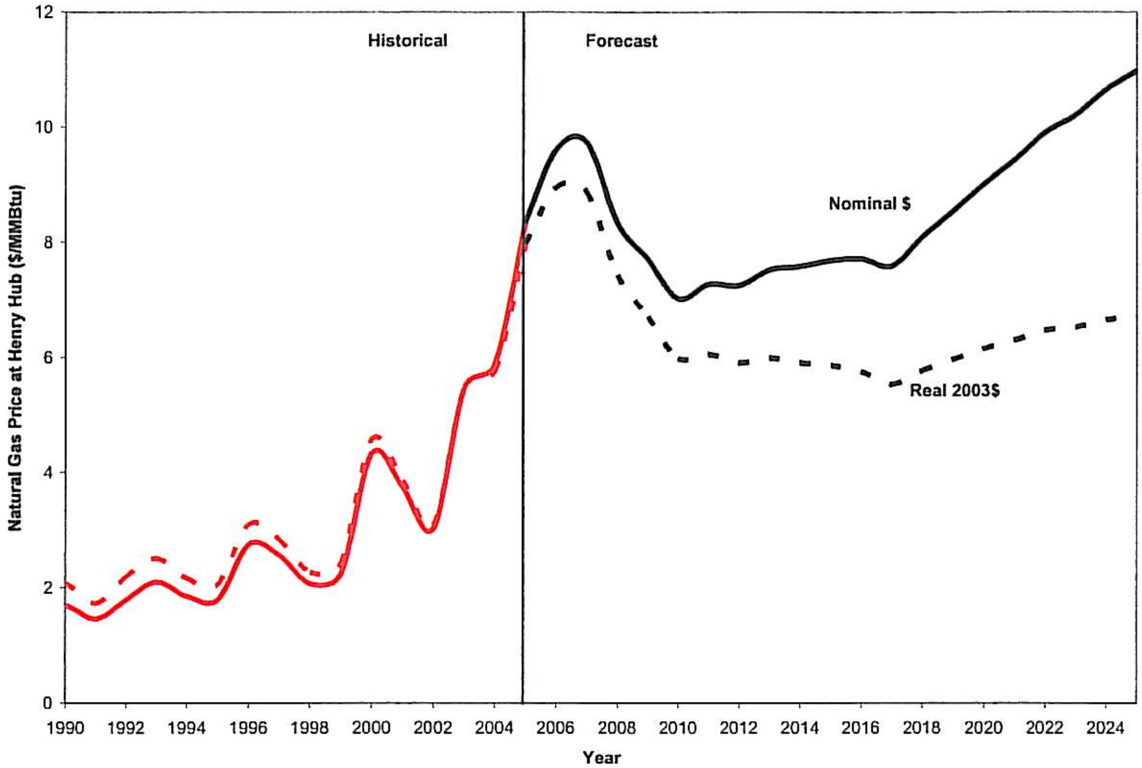
[1] Near-term 2006-2008 forecast is derived from NYMEX natural gas futures. 2006 price is an average of historical prices for January 2006 and the calendar futures for 2006 traded on 1/5/2006. 2007 is a calendar year average of the futures traded for 2007 on 1/5/2006. 2008 is a six-month rolling average of the futures traded for 2008 between 7/5/2005 and 1/5/2006. 2009 is an average of 2008 and 2010; 2010 returns to the fundamentals gas forecast.
Source: ICF

Exhibit 5-33
Forecast Fuel Prices – 2011 – 2014 (Nominal $/MMBtu)

Source	Delivered Natural Gas	Delivered Coal[1]	Gas Premium
ICF Base Case	7.89	1.87	+6.02
GRU IRP	6.09	2.82	+3.27

[1] Blended coal (50% Illinois Basin and 50% Pet Coke).

Exhibit 5-34
Henry Hub Natural Gas Price Projection ($/MMBtu) – Base Case CO_2



Source: Natural Gas Week and Gas Daily (Historical); ICF (Forecast)

Long Term Uncertainties

The future price of these fuels, especially for oil and natural gas are considered highly uncertain. Hence, these fuels are analyzed in base, low and high price sensitivity cases (see Exhibit 5-35).

Exhibit 5-35
Henry Hub Natural Gas Prices – 2010 – 2025 (2003$/MMBtu)

Scenario	Low	Base	High
CO_2	4.50	6.1	7.50
NO CO_2	4.00	5.56	7.00

Source: ICF

OIL PRICE FORECAST

ICF's forecast of crude oil prices is lower than current price levels (see Exhibit 5-36).

Exhibit 5-36
ICF WTI Crude Forecast (2003$/Bbl)

Year	2003 $/Bbl	Nominal $/Bbl
2006	51.87	54.23
2007	51.40	54.95
2008	50.94	55.68
2009	50.47	56.41
2010	50.00	57.15
2011	49.54	57.89
2012	49.07	58.63
2013	48.14	58.81
2014	47.20	58.97
2015	46.27	59.10
2016	46.85	61.19
2017	47.49	63.43
2018	48.14	65.73
2019	48.78	68.11
2020	49.43	70.56
2021	50.05	73.07
2022	50.68	75.65
2023	51.31	78.31
2024	51.94	81.05
2025	52.57	83.88

Source: ICF

Historically, crude and distillate oil prices have traded above natural gas and 1 percent residual at parity or below on a per MMBtu basis. ICF forecasts this will continue (see Exhibits 5-37 and 5-39).

Exhibit 5-37
Oil/Gas Relationship (Oil Divided by Gas Price)

Year	Data Type	Relationship to Gas Price – Henry Hub, Louisiana – 1.0 Equals Parity in $/MMBtu		
		Crude West Texas Intermediate Marker WTI[1]	Distillate #2 U.S. Gulf[2]	Residual 1% Sulfur U.S. Gulf[3]
1995	Historical	1.85	2.04	1.36
1996	Historical	1.36	1.54	0.98
1997	Historical	1.43	1.6	1.04
1998	Historical	1.19	1.37	0.92
1999	Historical	1.45	1.54	1.05
2000	Historical	1.12	1.27	0.87
2001	Historical	1.21	1.38	0.91
2002	Historical	1.49	1.61	1.17
2003	Historical	0.98	1.08	0.81
2004	Historical	1.21	1.37	0.72
2005	Historical	1.17	1.45	0.78
2006	Forecast[4]	1.00	1.27	0.68

[1] Shown for illustration purposes as crude is not a fuel since it must be refined. 5.80 MMBtu/bbl
[2] 5.825 MMBtu/bbl.
[3] 6.287 MMBtu/bbl.
[4] Futures data for 2006-2008 from NYMEX traded on 1/6/2006.

Exhibit 5-38
Delivered Oil Price Forecast – Gainesville, FL

Oil Type	Year	Commodity Price (2003$/ Bbl)	Transportation (2003$/ Bbl)	Delivered Price (2003$/ Bbl)[1]	Delivered Price (2003$/ MMBtu)	Delivered Price (Nominal$/ MMBtu)[2]
0.05% Sulphur Distillate (Gainesville, FL)	2006	66.40	5.88	72.28	12.41	12.86
	2010	61.07	6.06	67.12	11.52	12.90
	2015	55.48	6.28	61.76	10.60	13.11
	2020	59.15	6.51	65.66	11.27	15.40
	2025	62.81	6.76	69.56	11.94	18.03
1% Sulphur Residual (Gainesville, FL)	2006	38.50	7.78	46.27	7.26	7.72
	2010	35.31	8.01	43.32	6.80	8.21
	2015	33.01	8.31	41.32	6.48	9.06
	2020	34.23	8.62	42.85	6.72	10.94
	2025	35.73	8.94	44.66	7.01	13.24
1.5% Sulphur Residual (Gainesville, FL)	2006	36.98	7.78	44.75	7.02	7.48
	2010	33.73	8.01	41.74	6.55	7.96
	2015	31.32	8.31	39.63	6.22	8.79
	2020	32.68	8.62	41.30	6.48	10.70
	2025	34.35	8.94	43.29	6.79	13.02
3% Sulphur Residual (Gainesville, FL)	2006	32.41	7.78	40.19	6.30	6.77
	2010	28.97	8.01	36.98	5.80	7.21
	2015	26.26	8.31	34.56	5.42	8.00
	2020	28.04	8.62	36.66	5.75	9.97
	2025	30.23	8.94	39.17	6.14	12.38

[1] Delivered price may not be the exact sum of the Commodity Price and Transportation due to rounding.
[2] Spreads between Commodity price and WTI Spot price are not subject to dollar inflation rates. Therefore, Nominal Commodity Price = (Real WTI Spot Price + Real Transportation Cost)/ Dollar Inflation Factor ± WTI-Commodity Price Spread
Source: ICF

Exhibit 5-39
Oil/Gas Relationship

Year	Data Type	Relationship to Gas Price – Henry Hub, Louisiana		
		Crude WTI	Distillate #2 U.S. Gulf	Residual 1% Sulfur U.S.
2007	Forecast	1.00	1.19	0.65
2008	Forecast	1.18	1.41	0.77
2009	Forecast	1.30	1.55	0.84
2010	Forecast	1.44	1.75	0.94
2011	Forecast	1.41	1.71	0.92
2012	Forecast	1.43	1.71	0.93
2013	Forecast	1.38	1.65	0.91
2014	Forecast	1.38	1.64	0.90
2015	Forecast	1.36	1.63	0.90
2016	Forecast	1.40	1.68	0.92
2017	Forecast	1.48	1.77	0.97
2018	Forecast	1.44	1.71	0.93
2019	Forecast	1.41	1.68	0.90
2020	Forecast	1.39	1.65	0.89
2021	Forecast	1.37	1.63	0.87
2022	Forecast	1.35	1.61	0.86
2023	Forecast	1.36	1.62	0.86
2024	Forecast	1.35	1.60	0.85
2025	Forecast	1.35	1.61	0.85
Average Historical (1995-2005)		1.31	1.48	0.96
Average Forecast (2006-2009)		1.12	1.36	0.74
Average Forecast (2010-2025)		1.39	1.66	0.90

Source: ICF

CHAPTER SIX
ENVIRONMENTAL AND HEALTH

This chapter discusses environmental regulatory and health issues. The chapter is divided into two sections. The first discusses environmental regulatory assumptions, and the second discusses health impacts with emphasis on PM 2.5.

AIR EMISSION RATES

Exhibit 6-1
Illustrative Power Plant Emissions (tons/year)

Emission Type`	Existing Coal Plant[1]		Power Plant Options – Illustrative				
	Deerhaven #2 – 2005	Deerhaven #2 After Controls	CCFB[2]	IGCC[2]	Natural Gas Combined Cycle	Biomass	Solar
SO_2	6,934	859	1,083	888	0	NA	0
NO_x	3,989	1,080	516	141	105	77	0
CO_2	1.6 MM	1.6 MM	1.6 MM	1.3 MM	0.6 MM	0	0
Hg	.07	.06	.01	.01	0	0	0

[1]Shown for comparison purposes only.
2 Assumes 220 MW capacity, of which 30 MW is co-fired with biomass

Exhibit 6-2
Direct Power Plant Emission Rates (lbs/MMBtu)

Emission Type	Plant Options						
	Current GRU Coal Plant1,2,4	Current GRU Coal Plant After Retrofits2,4,6	CCFB3,4,5	IGCC3,4,5	Gas Combined Cycle3	Biomass	Solar
SO_2	1.0	0.12 (90% reduction from current levels)	95% reduction from fuel input	98% reduction from fuel input	0	0.08	0
NO_x	0.5	0.07	0.15	0.02	0.02	0.02	0
CO_2	205 (bit. Coal)	205 (bit. Coal) to 212 (subbit. Coal)	205 (bit. Coal) to 225 (pet coke)	205 (bit. Coal) to 225 (pet coke)	117	0 (assumed CO_2 neutral)	0
Hg	12% from fuel content	90% from fuel input	90% from fuel input	90% from fuel input	0	0.57	0
PM 2.5	NA	NA	NA	NA	NA	NA	NA

[1]Deerhaven 2
[2]Shown for comparison and expositional purposes only
[3]NO_X controls assumed are as follows: SNCR for CFB and SCR for IGCC and combined cycle.
[4]SO_2 and Hg emission rates for CFB, IGCC and the existing coal units are dependent on the contents of sulfur and mercury in the coals burned and are therefore presented here as percentage reductions from fuel input rather than absolute rates.
[5]CO_2 emissions are fuel dependent, so a range is presented here. CO_2 contents are derived from US EPA's "Inventory of U.S. Greenhouse gas Emissions and Sinks: 1990-2000", Annex A for pet coke and from EIA's "Carbon Dioxide Emission Factors for Coal" for various coal types.
[6]Target rates and reduction factors provided by GRU.

ENVIRONMENTAL REGULATIONS – POSSIBLE CO_2 CONTROLS

Exhibit 6-3
Applicable CO_2 Emission Allowance Prices (2003$/Ton CO_2)

Year	Data Type	ICF Base Case
2010	Forecast	--
2011	Forecast	1
2012	Forecast	3
2013	Forecast	4
2014	Forecast	5
2015	Forecast	6
2016	Forecast	8
2017	Forecast	9
2018	Forecast	11
2019	Forecast	12
2020	Forecast	13
Average	Forecast	7

Note: CO_2 = Carbon Dioxide. This is the likely price for CO_2 allowance facing GRU plants and not necessarily the externality value.
Note: No federal or state allowance costs were applicable to GRU on a historical basis and no legislation or regulation currently exists which will require the imposition of such a cost on GRU.

While no federal CO_2 regulation is currently in place in the U.S., increasing pressure from the grassroots and state government levels, as well as implementation of CO_2 policies in foreign countries, is likely to result in future federal CO_2 regulation. Massachusetts and New Hampshire have already promulgated CO_2 regulations at the state level. The Regional Greenhouse Gas initiative (RGGI) is examining a regional CO_2 cap and trade program over 7-9 states in the Northeast. Canada and Europe are moving ahead with programs aimed at participating in the Kyoto Protocol process.

For the Base Case analysis, ICF assumed a CO_2 price trajectory that reflects a range of US domestic CO_2 policy proposals that have been discussed including those endorsed by Senator Bingaman (National Commission on Energy Policy), Senator Carper, Senators McCain and Lieberman. Along with the caps specified under these proposals, ICF has analyzed the impact of reduction offsets on the costs of complying with such programs. The resulting Base Case CO_2 trajectory reflects one potential probability weighted outcome that reflects the shift from a very mild cap in the near-term to an increasingly tighter cap as domestic and international policy moves ahead with CO_2 regulation. In this policy scenario, prices start at $0/ton in 2010 and rise to over $13/ton by 2020 (see Exhibit 6-3).

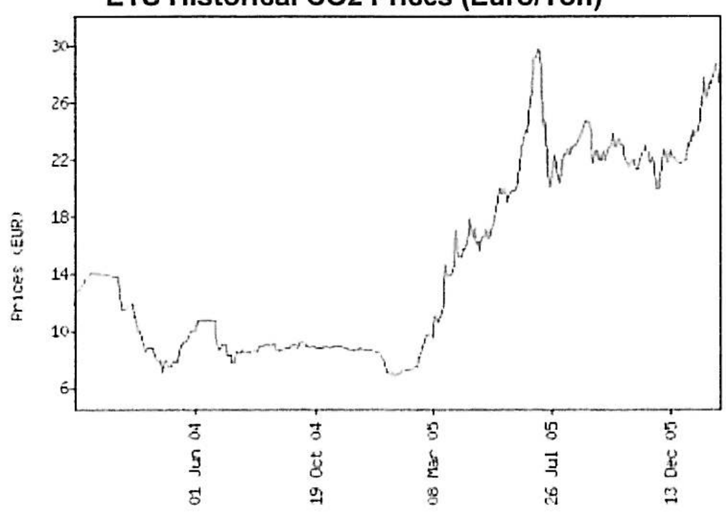
In addition, ICF analyzed a High CO_2 Case where prices are assumed to start at $15/ton CO_2 in 2010 and reach over $26/ton by 2020 (see Exhibit 6-4). This policy reflects a non-probability weighted scenario where CO_2 policy with limited allowance of offsets starts in 2010.

Exhibit 6-4
CO_2 Price Forecast (2003 $/Ton)

Year	Low Case	Base Case	High Case
2010	0	0	15.5
2016	0	7.7	24
2020	0	13.4	26.4
2025	0	21.7	30
Average 2010-2025	0	10.7	24.0

CO_2 prices in the European Trading Scheme has been trading at relatively high prices recently with allowance prices initially falling in the 8 - 10 Euro/ton ($9.50 - $12/ton[66]) CO_2 range, and since the summer of 2005, trading in the 20 - 30 Euro/ton ($24 - $36) range (see Exhibit 6-5). We agree with many analysts in regarding current ETS prices as overvalued with the expectation to fall back into the 5-15 Euro/ton range once the Clean Development Mechanism (CDM) becomes more institutionalized and efficient, and allowances from Russia and the Ukraine become available on the market. The CDM allows relatively inexpensive offsets from developing countries to be used and counted towards a county's Kyoto obligation, while a large excess of allowances from the Former Soviet Union is also expected to push prices down.

Exhibit 6-5
ETS Historical CO2 Prices (Euro/Ton)[67]



Allocation-Adjusted CO_2 Allowance Prices

It is likely that generating units will receive some allowance allocation to offset the impacts of a potential future national CO_2 program. Since no program currently exists, the cost of compliance with such a program, including an allowance allocation, is highly uncertain. In order to capture a range of potential uncertainties associated with a future CO_2 allocation mechanism, two potential scenarios have been examined, each

[66] Assumes $1.20/Euro
[67] Source – evolution Markets, LLC

associated with one of the CO_2 prices stream forecasts described above. The impact of these allocation methods is shown in the table below as allocation-adjusted CO_2 allowance prices.

The method assumed for the purposes of this example allocates allowances to generators on an output basis (lb./MWh) at the average system rate for affected fossil units that results from ICF's Expected Case CO_2 price trajectory (see Exhibit 6-7). This results in the same $/MWh allocation for all fossil units. Units that receive some amount of allocation but whose CO_2 emission rates (on a lb./MWh basis) are higher than the system average will be short allowances and face a positive adjusted CO_2 price lower than the pre-allocation price. Units with an average rate less than the system average will receive an over-allocation and have excess allowances and therefore face a negative allocation-adjusted CO_2 price. Allowances would be allocated based on a unit's rolling share of the total generation of affected units over a three-year period.

In the Base Case it is assumed that 25% of the total allowance budget will be withheld from allocation and auctioned or sold to emitting sources with the proceeds used to support efficiency measures, renewable development, consumer rebate programs, etc. at the state level. This is similar to what has been proposed for the Regional Greenhouse Gas Initiative (RGGI) program in the Northeast US. For the High CO_2 Case, 50% of the total allowance budget is assumed to be auctioned. The system fossil emission rates for both the Base and High CO_2 policies are shown in Exhibit 6-6 below. Rates decline over time as a fixed or declining cap is divided among increasing fossil (gas & coal) generation. Rates under the High CO_2 case are slightly lower as the cap is tighter.

Exhibit 6-6
CO_2 Allowance Price – ICF versus GRU
(2003 $/Ton)

Source	Allowance Price ($/ton)	After Adjustment for Allocation[2]
GRU	13.21[1]	0
ICF – Base Case – 2010 – 2020	7	1.7 – 2.7
ICF – High Case – 2010 – 2020	21.8	5.8 – 9.1

[1]Average of $0, $12.4, $27.3/ton CO_2 derived from $0, $45.36, $100 per ton of carbon.
[2]100% coal mix; IGCC and CCFB

Exhibit 6-7
CO_2 Emission Allowance Allocation Rates (lbs/MWh)

Year	Low CO_2	Base CO_2	High CO_2
2006	**0**	**0**	**0**
2007	0	0	0
2008	0	0	0
2009	0	0	0
2010	0	1,749	1,717
2011	0	1,727	1,693
2012	0	1,706	1,670
2013	0	1,684	1,646
2014	0	1,663	1,622
2015	0	1,641	1,598
2016	0	1,620	1,574
2017	0	1,602	1,555
2018	0	1,585	1,537
2019	0	1,567	1,519
2020	0	1,550	1,500
2021	0	1,537	1,485
2022	0	1,523	1,470
2023	0	1,510	1,455
2024	0	1,497	1,440
2025	0	1,484	1,425

EMISSION REGULATIONS – CURRENTLY REGULATED AIR EMISSIONS

Exhibit 6-8
Key Federal Environmental Related Assumptions Overview

Parameter	Treatment
SO_2 Regulations	Phase II Acid Rain; CAIR begins in 2010, with second phase in 2015. Affected units (see map on following slide) exchange 2 allowances for every ton emitted between 2010 and 2014 and 2.86 allowances starting in 2015
NO_x Regulations	SIP Call through 2008; CAIR ozone and annual programs begin in 2009 with second phase cuts in 2015 for affected states
Mercury Regulations	National cap and trade program based on CAMR: 34 ton limit in 2010, 15 ton limit in 2018
CO_2 Regulations	ICF "Expected Case" price trajectory plus low and high CO_2 trajectories

Exhibit 6-9
Allowance Price Forecast (2003 $/Ton)

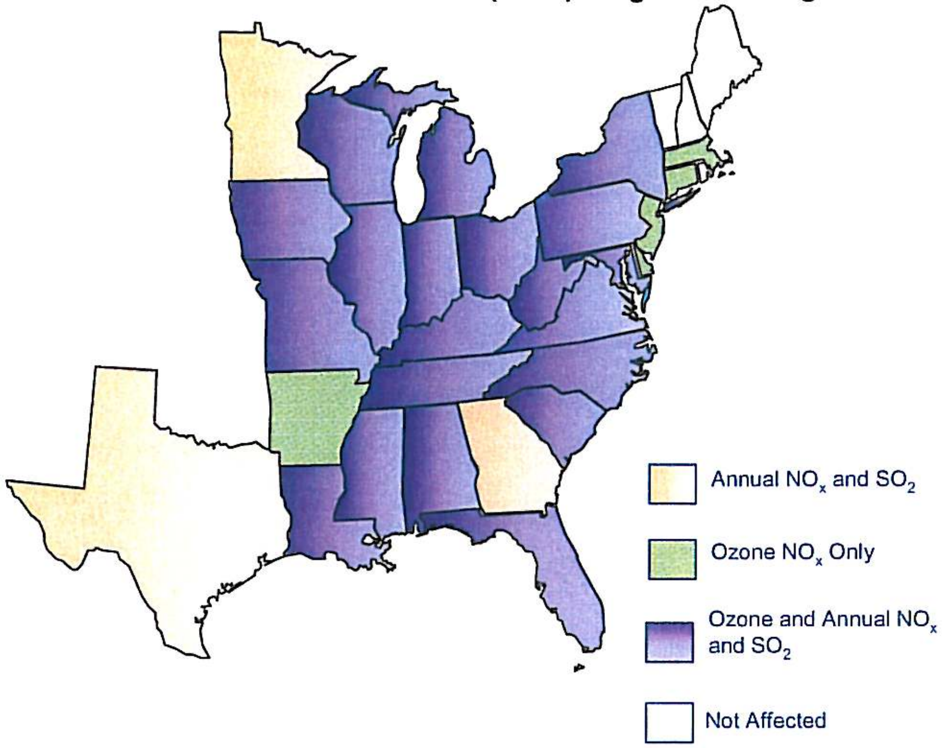
Year	Title IV SO_2 Pre-2010	Title IV SO_2 Post-2010	SIP/CAIR Ozone NO_X	CAIR Annual NO_X	Mercury ($/lb)	CO_2
2011 – 2025 Average	1,500	500	3,000	1,500	30,000	10

Key Environmental Assumptions

There is uncertainty regarding the exact form and timing of future environmental regulations. However ICF has incorporated an expected scenario covering regulations for the three pollutants of SO_2, NO_x, and H_g. The air regulatory structure for the Base Case is representative of the timing, scope and stringency likely to be realized under a regulated or legislated future. While it remains uncertain as to how NO_X, SO_2, and mercury $(Hg)_2$ will be constrained over the next decade, the reductions included here are within the range of those proposed by both EPA and legislators.

The Expected Case includes NO_X and SO_2 emission reduction targets consistent with those specified in EPA's recently announced (March 10th) and likely to be implemented Clean Air Interstate Rule (CAIR) (see Exhibit 6-10). The Hg component assumes that EPA is successful in implementing a national Hg trading program announced on March 15th in place of a unit-by-unit MACT regulation.

Exhibit 6-10
Clean Air Interstate Rule (CAIR) Program Coverage



As the SO_2 and annual NO_x components of CAIR target $PM_{2.5}$ non-attainment while the ozone season NO_x program addresses 8-hour ozone non-attainment, the coverage of CAIR is different for the different components.

- The annual NO_x and SO_2 program covers 23 states + DC.
- The ozone season NO_x program covers 25 states + DC.

As discussed earlier, while CO_2 is not currently part of the nationally regulated pollutant landscape, pressure for the inclusion of this pollutant is building. The Base Case includes a price trajectory, based on probability-weighted outcomes of three recent carbon proposals in the US Congress, including those by Senator McCain, Senator Carper and the National Center for Energy Policy (NCEP) proposal supported by Senator Bingaman. In addition, a High CO_2 scenario, which represents a non-probability weighted and relatively stringent CO_2 policy is also analyzed. Analogous to the SO_2 allowance policy, we assume that some portion of CO_2 allowances will be allocated. The effect of this will be an offset in some of the costs of this policy.

6.2 Potential Public Health Impacts

In this section, we build on prior analyses and findings by various parties related to GRU's planned CFB energy project that are relevant to its public health impacts, compile and analyze new information from the available literature, and identify and describe the potential public health impacts of the four power options – CFB, IGCC, DSM/biomass, and DSM/power purchase.[68] Where possible, we attempt to quantify factors related to health impacts. Given the available information and the project schedule and resources, however, many key factors remain unquantifiable. Thus, consistent with our original proposal, much of this public health impact analysis is qualitative and descriptive in nature.

Ideally, one would perform a comprehensive quantitative risk assessment that would support numerical estimates of the possible health impacts (for example, numbers of predicted cases of illness, numbers of predicted premature deaths) associated with each of the options. This kind of analysis would require sophisticated and expensive air modeling, exposure assessment, and exposure-response modeling, and possibly economic modeling to monetize the predicted health damages. Such quantitative modeling would not, however, eliminate uncertainties about the results; in fact, the uncertainties would remain quite large, due to significant questions about model completeness, algorithm formulation, and the input data used.

6.2.1 Scope of Analysis

To be fully comprehensive, there are numerous kinds of emissions, residuals, activities, and life cycle steps associated with the four power options that would need to be considered in a public health impact assessment. For example, in addition to air emissions, there are also wastewaters (e.g., cooling water, scrubber water) and solid wastes generated, and there are activities such as fuel transport and handling that can produce various emissions and also have accident potential. Moreover, a full life cycle assessment could entail consideration of a broader range of potential impacts, such as those related to fuel extraction and processing, as well as those related to manufacture and disposal of products used as part of energy efficiency and conservation activities (e.g., energy-efficient lamps and appliances, home insulation materials). A number of these kinds of potential impacts on public health have been considered in prior studies performed by GRU (2003, 2004a,b), local agencies (ACEPD 2004), citizen groups (EPAC 2005), and others (Numark 2005).

After an initial review of prior studies related to potential health impacts of GRU's planned CFB project and various alternatives, we decided to focus this analysis on airborne fine particulate matter (also referred to as $PM_{2.5}$) resulting from power plant stack emissions for the four options. There are four main reasons for this focus.

- Recent exhaustive studies and regulatory decisions by US EPA demonstrate the relative importance of $PM_{2.5}$ in assessment of public

[68] The four power options are described in detail earlier in this report; see Chapter 1 for more information.

health impacts of air pollutants (US EPA 2005a,b, US EPA 2006). Given current knowledge and risk assessment methods, impacts of $PM_{2.5}$ exposures are likely to dominate any numerical estimates of the human health impacts of air pollutants associated with power plant emissions (largely because $PM_{2.5}$ exposure has consistently been shown to have the strongest relationship to mortality impacts). For example, in the regulatory impact analysis for the 2005 Clean Air Interstate Rule (CAIR), the estimated health benefits associated with reduced $PM_{2.5}$ exposures are over 100 times greater than the benefits associated with reduced ozone exposures (US EPA 2005b).

- Based on our review of the prior studies related to the GRU planned CFB project, exposure to airborne $PM_{2.5}$ appears to be a primary public health concern of local agencies and groups. For example, the county Environmental Protection Department's technical review document focused on air quality and greenhouse gas impacts, and the department's only recommendation for new monitoring was for $PM_{2.5}$ (ACEPD 2004). In its technical review, the Environmental Protection Advisory Committee (EPAC) said that "the most serious adverse air pollution effects are from fine particles emitted directly from the stacks (primary particulate matter) and those produced in the atmosphere from sulfur and nitrogen gas emissions (secondary particulate matter)" (EPAC 2005). The peer reviewers of the EPAC review stated the "the decision to focus on fine particulate matter for the health evaluation is appropriate..." (Numark 2005).

- Power plant stack emissions are expected to dominate other emission sources of $PM_{2.5}$ precursors, such as emissions from rail or truck transport of fuel and fugitive emissions from fuel handling on-site (range-finding calculations confirm this for truck emissions, as described later).

- Although mercury is often a main concern for power plant emissions, it appears that other local emission sources are likely to overshadow the current and potential future emissions from GRU sources (EPAC 2005).

We identify and discuss briefly certain issues other than $PM_{2.5}$ – including mercury and ozone – at various places in this section, but the emphasis is on potential exposures to $PM_{2.5}$. Note that the potential environmental impacts of CO_2 emissions are not covered in this section on health impacts; CO_2 emissions are addressed elsewhere via the inclusion of projected CO_2 allowance prices in the IPM modeling.

6.2.2 What is PM2.5, and What Are Its Health Effects?

Fine particulate matter, or $PM_{2.5}$, is the particles in the air that are generally less than or equal to 2.5 micrometers in diameter. These small particles can remain suspended in the air for very long periods of time, and can travel great distances from a source without depositing to the ground surface. $PM_{2.5}$ is typically a complex mixture of many different components, including some inert materials and some chemically reactive compounds. Some gases, including the SO_2 and NO_x emitted from power plants, can react in the presence of sunlight and other chemicals in the atmosphere and be transformed into compounds (for example, sulfates and nitrates) that are components of $PM_{2.5}$. Gases such as SO_2 and NO_x are referred to as $PM_{2.5}$ precursors because they can be converted into $PM_{2.5}$ under normal atmospheric conditions. Human exposure to $PM_{2.5}$ is associated with a number of serious health effects, including premature death and a variety of cardiovascular and respiratory illnesses and symptoms.

$PM_{2.5}$ has been an active area of research over the past decade or so. Given that there are numerous readily available, recent, and authoritative in-depth discussions of the properties and effects of $PM_{2.5}$ – including the just-published proposed rulemaking (and supporting staff paper and criteria document) for revising the national ambient air standard (US EPA 2006), as well as last year's final CAIR rulemaking (US EPA 2005a,b) – and given that a good summary has already been prepared in a prior review of the GRU proposed project (EPAC 2005), we do not summarize that information in detail here. We would, however, highlight a few considerations relevant to the analysis described in the rest of this section.

- $PM_{2.5}$ can be present in the air hundreds and even thousands of miles from the source of its precursor compounds.

- The formation and transport of $PM_{2.5}$ in the atmosphere is exceedingly complex, and depends on emissions of primary $PM_{2.5}$ and several precursor compounds, the other chemicals present in the air (background air quality), and meteorological conditions. Predictive modeling of $PM_{2.5}$ in air typically is a resource-intensive undertaking.

- No single compound from an emissions source is a consistent predictor of the concentration of $PM_{2.5}$ in air.

- There is no accepted population threshold for health effects of $PM_{2.5}$ exposure (that is, no level of exposure below which there is zero concern for health effects in an exposed population).

- The lack of complete scientific information about the mechanisms of fine particulate toxicity and about the effect of different $PM_{2.5}$ species on exposure-response (e.g., which components of the complex $PM_{2.5}$ mixture in air are more or less toxic than others) further adds to the uncertainty in estimating health impacts. There have been relatively few detailed studies of the relationship between specific chemical components of fine particulate and severity of health effects. Most epidemiological studies include populations from multiple locations, across which the composition of fine particulate is likely to vary significantly, and the differences in exposure-response relationships seen in most studies may be associated with differences in the nature of species present. Thus, there are unavoidable uncertainties associated with attempting to predict the impacts of $PM_{2.5}$ impacts using exposure-response relationships from individual studies.

6.2.3 Background – Air Quality in Alachua County

Recent reported ambient levels of $PM_{2.5}$ and other regulated air pollutants in Alachua County are shown in Exhibit 6-11, along with the applicable health-based regulatory standards. US EPA sets the national ambient air quality standards (NAAQS) to "protect public health with an adequate margin of safety" (US EPA 2006). As shown in the table, reported air concentrations of $PM_{2.5}$ and the other pollutants in Alachua County are all below the applicable regulatory standard, in most cases by considerable margins. Ozone, which typically is not primarily related to power plant emissions, is the air pollutant with the least margin between reported air concentrations and applicable standards.

Exhibit 6-11
Reported Ambient Levels and Health-based Regulatory Standards for $PM_{2.5}$ and Selected Other Air Pollutants

Air Pollutant	Averaging Period	Regulatory Level	Reported Ambient Levels, Alachua County [a]
$PM_{2.5}$	Annual	15 ug/m^3 [b]	9.9 (2002) 9.6 (2003) 10.3 (Site 23, unspecified period) [d] 10.1 (Site 24, unspecified period) [d]
	24-hr	65 ug/m^3 [c]	31 (2002) 20 (2003) 1.3-39.1 (Site 23, unspecified period) [d] 1.7-50.1 (Site 24, unspecified period) [d]
PM_{10}	Annual	50 ug/m^3	18 (2002) 16 (2003)
	24-hr	150 ug/m^3	35 (2002) 46 (2003)
Ozone	8-hr	0.08 ppm	0.072 (2003)
	1-hr	0.12 ppm	0.089 (2003)
SO_2	Annual	0.02 ppm	0.001 (2000)
NO_x	Annual	0.053 ppm	0.007 (2001)

[a] All data as reported in GRU (2003, 2004a), except as noted.
[b] No change proposed by US EPA in January 2006 NAAQS regulatory proposal (public comment was requested on lowering the annual standard to 12 ug/m^3).
[c] Change to 35 ug/m^3 proposed by US EPA in January 2006 NAAQS proposal (public comment was requested on alternative levels between 25 ug/m^3 and 65 ug/m^3).
[d] Data as reported in EPAC (2005). Data represent the entire period monitors have been in operation, dates are unspecified.

Alachua County air quality is good relative to other urban areas in the US, and relative to most US monitoring locations as a whole. The annual average $PM_{2.5}$ concentration in Alachua County, about 10 ug/m^3, falls at roughly the 25th percentile of concentrations at 780 monitoring locations nationwide for 2003 (that is, 75 percent of US locations with monitors have higher $PM_{2.5}$ concentrations than Alachua County). Annual average concentration of $PM_{2.5}$ in the Southeast US in 2003 was 12.6 ug/m^3, which is about 25 percent higher than Alachua County. Many US cities are well above the 15 ug/m^3 annual average ambient standard (US EPA 2004b).

Though the data cited in Exhibit 6-11 are insufficient to assess air pollutant trends in Alachua County over time, concentrations of $PM_{2.5}$ and other air pollutants are trending downward in most areas of the country over the past 10 years. According to US EPA's recent report on trends in airborne particulates (USEPA 2004b), $PM_{2.5}$ concentrations decreased 10 percent nationwide between 1999 and 2003, and decreased 20 percent over the same time period in the Southeast. These reductions are largely attributed to reductions in power plant emissions of SO_2 and NO_x under the federal acid rain program and other initiatives. Thus, it is probable that some downward trend in $PM_{2.5}$ concentrations is occurring in Alachua County. Furthermore, as a result of the Clean Air Interstate Rule (CAIR) finalized in March 2005 (US EPA 2005a), substantial additional reduction in SO_2 and NO_x emissions from power plants in Florida and nationwide will occur over the 15 years, resulting in additional reductions in ambient $PM_{2.5}$ levels. EPA estimates in the regulatory impact analysis for CAIR that reductions of ambient $PM_{2.5}$ in the 2010 to 2015 timeframe as a direct result of CAIR reductions will average on the order of 0.5 to 1 ug/m^3 (annual average) in the Eastern US (EPA 2005b).

As indicated in the footnotes to Exhibit 6-11, US EPA very recently completed its periodic review of the particulate matter NAAQS and has proposed certain changes to those standards (US EPA 2006). As part of this review US EPA thoroughly analyzed all the available literature on health effects of exposures to airborne particles and reviewed the levels of protection afforded by the current standards. As a result of this comprehensive review, US EPA is proposing to maintain the current annual average $PM_{2.5}$ standard of 15 ug/m^3, thereby "continuing protection against health effects associated with long-term exposures" (no change proposed); it does request public comment on possibly lowering this standard to 12 ug/m^3. Based on current $PM_{2.5}$ levels in Alachua County and the anticipated general downward trend in such levels, a lowering of the annual average standard to 12 ug/m^3 would not affect compliance at county locations.

In the same regulatory notice, US EPA is proposing to lower the 24-hour average concentration standard for $PM_{2.5}$ from 65 ug/m^3 to 35 ug/m^3, thereby "providing increased protection against health effects associated with short-term exposures" (and is requesting public comment on various possible standards from 25 ug/m^3 up to the current level of 65 ug/m^3). Although it is unclear what the final determination from US EPA will be regarding the level of the daily average standard, it is likely to end up closer to the ambient levels recently reported for Alachua County. It does not appear Alachua County levels would be in non-attainment of the new 24-hour standard, however, unless it ends up being set lower than the proposed level of 35 ug/m^3 (note that attainment is not determined by the maximum 24-hour concentration recorded over a year, but by the 3-year average of the 98th percentile values, or roughly the average of the 7th or 8th highest value in three consecutive years). Note that US EPA also considered whether to propose a standard based on shorter averaging times than 24 hours, given the growing body of studies showing effects associated with shorter (one to several hours) averaging times, but concluded that the available data "remains too limited to serve as a basis for establishing a shorter-than-24-hour fine particulate primary standard at this time" (EPA 2006).

Summary – air quality in Alachua County. The air quality in Alachua County is good, relative to many major US urban areas and the Southeast US in general, for $PM_{2.5}$ and other main pollutants associated with emissions from power plants. All federal and state ambient air quality standards are being met, with considerable margins between reported levels and applicable standards for most pollutants (ozone levels, which are not primarily related to power plant emissions, are fairly close to the applicable standards). The county is expected to remain in compliance with EPA's recently proposed new $PM_{2.5}$ regulations, which would lower the 24-hour standard by a substantial amount, when they take effect. Moreover, the current ambient levels of $PM_{2.5}$ are expected to continue trending down as the federal acid rain program emission reductions and other current program reductions continue to have impacts, and the substantial future emission reductions due to the CAIR regulations take effect.

6.2.4 Estimated Air Emissions for the Four Options

All four options will result in new air emissions of $PM_{2.5}$ precursors (e.g., SO_2, NO_x, primary PM2.5) and other pollutants (e.g., mercury), differing in the quantity and location of those emissions. Exhibit 6-12 summarizes the emission estimates, in numerical terms where possible, for the four options for the base case (base demand growth, base fuel price, base CO_2 regulation, and base biomass price) in year 2015. Activities that are expected to produce some emissions to air, but that were not fully quantified, are noted in the table. The average (unweighted) emissions across all 36 demand/fuel/ CO_2/biomass cases modeled are approximately 10 percent lower for each power option than the base case estimates shown in Exhibit 6-12, and the maximum emissions case is about 10 percent higher. Given the similar magnitudes of the estimates, plus/minus 10 percent, only the base case values are shown. Data are presented for 2015 as it is near the middle of the overall modeling period and near the peak of emissions, which decline for all options by 2020 and 2025.

All four options would be completed in the context of the planned retrofit of the existing major coal-fired unit in Alachua County (Deerhaven 2), which will substantially reduce emissions of $PM_{2.5}$ precursors from that source (compare existing versus future columns in Exhibit 6-12). When the new power options are considered in the context of the overall emissions related to electricity supply (that is, in combination with the emissions

Exhibit 6-12
Summary of Key Air Emissions for Health Impact Assessment

Emitted Pollutant	Source/ Location	Estimated Annual Emissions (tons/yr) [a]				
		Existing GRU Plants Pre-DH2 Retrofit	Future Power Options (base/base/base/base case, 2015)			
			CFB	IGCC	DSM plus Biomass	DSM plus Purchase
SO_2	Deerhaven site-new unit	n/a	780	664	15	0
	GRU-all other units	6934 (2005)	859	859	870	878
	Other local-Alachua Co	Rail transport	Rail and truck transport	Rail and truck transport	Truck transport	--
	Other regional	Rail transport	Rail and truck transport	Rail and truck transport	232 (from purchase), truck transport	235 (from purchase)
NO_x	Deerhaven site-new unit	n/a	517	143	76	0
	GRU-all other units	3989 (2005)	1080	1080	1098	1119
	Other local-Alachua Co	Rail transport	Rail and truck transport	Rail and truck transport	Truck transport	--
	Other regional	Rail transport	Rail and truck transport	Rail and truck transport	190 (from purchase), truck transport	259 (from purchase)
Particulate matter (PM)	Deerhaven site-new unit	n/a	117 (total PM) BVa	Not estimated	Not estimated	0
	GRU-all other units	237 (2003) (total PM) BVa	179 (total PM) BVa	Not estimated	Not estimated	Not estimated
	Other local-Alachua Co	Rail transport, site fugitives	Rail and truck transport, site fugitives [b]	Rail and truck transport, site fugitives [b]	Truck transport, site fugitives [b]	--
	Other regional	Rail transport	Rail and truck transport [b]	Rail and truck transport [b]	From purchase, truck transport [b]	From purchase
Mercury	Deerhaven site-new unit	n/a	<0.01	<0.01	<0.01	0
	GRU-all other units	0.07 (2005)	0.06	0.07	0.06	0.06
	Other local-Alachua Co	--	--	--	--	--
	Other regional	--	--	--	<0.01 (from purchase)	<0.01 (from purchase)

[a] Emission estimates are based on IPM modeling assumptions and outputs for this study, except for particulates (BVa = estimated actual emissions used in air modeling by Black & Veatch, 2004b). IPM modeling of CFB and IGCC units assumes 30MW biomass co-firing.
[b] There also is an unquantified but potentially relatively large reduction in particulate (including $PM_{2.5}$) emissions from reduced open burning of waste biomass associated with the CFB, IGCC, and DSM/biomass options.

from Deerhaven 2 and other smaller supply units in the county), the total $PM_{2.5}$ precursor emissions from GRU operations are expected to decrease, relative to current levels, under all four options.

Considering the new units/activities only, the CFB option has the highest local generating unit emissions of the key $PM_{2.5}$ precursors SO_2 and NO_x, followed by the IGCC option (especially lower for NO_x), and then the DSM/biomass option (especially lower for SO_2). There are no new local emissions from the DSM/power purchase option (only emissions associated with existing GRU generating units). Though not estimated in the IPM modeling, the particulate matter emissions for the four options are expected to follow a similar pattern.

Under all four options, the projected future baseline emissions from other GRU units (see rows labeled "GRU-all other units" in Exhibit 6-12) are higher (in some cases substantially higher) than the projected emissions from the new unit. Considering the baseline of emissions from other GRU units, some of the emission differences between the new units appear to diminish in significance (that is, it seems less likely that differences in future impacts would be identifiable). For example, the SO_2 emission difference between CFB and IGCC seems less significant when the baseline is considered, though the difference between these two options and the other two remains substantial. For NO_x the fairly small difference between IGCC and DSM/biomass seems less significant when considered in context of overall GRU emissions, with both options quite a bit lower than the CFB option.

The estimated increased emissions elsewhere in the modeled power regions (FRCC and SERC/Southern, which include Florida, most of Georgia, and parts of Alabama and Mississippi) under the DSM/biomass and DSM/purchase options, which are primarily a result of the power purchases predicted to be needed to supplement GRU generating capacity under these options, also are shown in Exhibit 6-12 (for the base case in 2015). Viewed from a regional perspective, these non-local emissions offset some, but not all, of the lower local SO_2 and NO_x emissions for the DSM options compared with the CFB option, and some of the lower SO_2 emissions compared with the IGCC option. For NO_x, the IGCC option has the lowest total regional emissions (i.e., non-local emissions from power purchases for the DSM options are higher than the differences in local emissions as compared with the IGCC option).

Note that the three options that include use of waste biomass as a fuel – CFB, IGCC, and DSM/biomass – could potentially decrease particulate and other emissions generated by the uncontrolled burning of that material (current practice) by replacing that practice with controlled combustion (GRU 2004b). The extent of this replacement is unknown, and thus the magnitude of emissions reductions has not been quantified.

We developed upper-bound estimates of the emissions of $PM_{2.5}$ and NO_x from the additional truck traffic generated by biomass fuel deliveries under the three options where biomass is used. We ran US EPA's MOBILE6.2 model to develop emission factors (in grams/mile) for heavy duty diesel trucks for the years 2015, 2020, and 2025. We assumed deliveries from a 50-mile radius in 25-ton capacity trucks. Based on the maximum amount of biomass used as fuel under the DSM/biomass option (447,000 tons/year), total emissions of NO_x would be less than 10 tons per year and $PM_{2.5}$ would be less than 1 ton per year throughout the period (<1 ton/year by 2025 for NO_x and <0.1 ton/year by 2025 for $PM_{2.5}$). These values are much lower than the estimated GRU stack emissions and overall emissions levels in Alachua County.

The current emissions of $PM_{2.5}$ precursors from GRU power generating units are shown in the context of recent total emission estimates for Alachua County, Florida, and the Eastern US in Exhibit 6-13. Nearly all of the current emissions of SO_2 in Alachua County are from GRU units, as is a sizable fraction (1/3 to 1/4) of the NO_x emissions. A relatively small fraction of the primary $PM_{2.5}$ emissions in the county is from GRU units. As expected, the total GRU emissions are very small relative to total emissions in the state of Florida and Eastern US (and also less than two percent of total Florida power plant emissions). It is anticipated that these basic relationships would hold in the future for the three options in which new generation units are built at Deerhaven, just at lower GRU emission levels; that is, GRU emissions will still account for the bulk of SO_2 emissions in the county, a somewhat smaller fraction of NO_x emissions, and a very small fraction of primary $PM_{2.5}$ emissions. Emissions under all options will remain an extremely low fraction of future total Florida and Eastern US emissions. Under the DSM/power purchase option, there will be no new generation unit emissions in Alachua County (only the emissions from existing units), and the new emissions elsewhere are expected to remain a very small fraction of future total Florida and Eastern US emissions.

Exhibit 6-13
GRU Emissions of $PM_{2.5}$ Precursors in Context

Emitted Pollutant	Recent Estimated Anthropogenic Emissions (tons/year, rounded)					Future Estimated GRU Emissions (all units), Highest Option, 2015 (tons/year)
	All GRU Units, 2003 [a]	Alachua, Late 1990s [b]	Alachua, 2001 [c]	Florida, 2001 [c]	Eastern US (CAIR Region), 2001 [c]	
SO_2	8,400	8,100	8,900 (8,400) [d]	740,000 (570,000)	14,000,000 (9,900,000)	1,600
NO_x	4,000	16,000	12,000 (4,300)	970,000 (310,000)	16,000,000 (4,000,000)	1,600
$PM_{2.5}$	<237	--	4,000 (380)	240,000 (32,000)	3,500,000 (520,000)	<300

[a] Black & Veatch (2004b).
[b] Alachua County Air Quality Commission Report, January 2000, as cited in GRU (2003).
[c] CAIR inventory for 2001 (US EPA 2004a).
[d] Estimated amounts from power plants only shown in parentheses.

As shown in Exhibit 6-12, mercury emissions are expected to be fairly low and at similar levels for the CFB and IGCC options, with the new units only responsible for a small fraction of the total from all future GRU unit emissions. Negligible mercury emissions from new units are expected for the two DSM options, although emissions will occur from the continuing operations of other GRU units. As seen in the table, projected total (new plus continuing units) mercury emissions are at similar levels for the four options.

Summary – emissions of PM$_{2.5}$ precursors. Highest local emissions (that is, from generating unit stacks in Alachua County) for 2015 would result from the CFB option, followed by the IGCC, the DSM/biomass, and then the DSM/power purchase (which would have no new local generating unit emissions). Under the three options having new generating units in the county, projected emissions from the new units are lower than the projected future emissions from other GRU units. Relative to current total GRU emissions in the county, all four options would result in lower total GRU emissions. When additional emissions associated with power purchases under the two DSM options are considered, there is less difference in the overall regional emissions among the four options. The CFB option remains highest for PM$_{2.5}$ precursors, followed by IGCC and DSM/biomass (roughly similar emissions), and then DSM/power purchase.

6.2.5 Comparison of Potential PM$_{2.5}$ Health Impacts of the Four Options

As described in the previous section, all four options will produce new emissions of PM$_{2.5}$ precursors. However, the relative amounts of these pollutants, and in some cases the emission locations, differ among the options. Thus, the effects on future PM$_{2.5}$ concentrations in Alachua County and elsewhere vary as well, as do the potential health impacts of both long-term and short-term PM$_{2.5}$ exposures.

Considered on their own (that is, outside of the context of overall power-related emissions in Alachua County), all four options would be expected to increase PM$_{2.5}$ levels in the state and region, in at least a small way. Unlike the other options, the DSM/power purchase option would not have new combustion-related emissions at the Deerhaven site (it would however produce increased combustion-related emissions elsewhere in the state and region due to power purchases), and therefore would be expected to have a smaller effect on PM$_{2.5}$ levels in Alachua County.

As described in the previous section, when the new power options are considered in the context of the overall emissions related to electricity supply (that is, in combination with the emissions from Deerhaven 2 and other smaller supply units in the county), the total PM$_{2.5}$ precursor emissions are expected to decrease, relative to current levels, under all four options. Viewed in this context, PM$_{2.5}$ levels in air are expected to decrease, relative to current levels, to some degree under all four options.

Even with quantitative information about the emissions differences, without additional sophisticated photochemical air modeling it is not possible to confidently estimate the magnitude of the PM$_{2.5}$ concentration differences among the options, and thus it is not possible to confidently estimate the size of health effects differences. However, the PM$_{2.5}$ air modeling sponsored by GRU in 2004 helps to bound the potential magnitude of changes in local (Alachua County) air quality, at least for some options (Black & Veatch 2004a,b). Given the geographic scope of the GRU-sponsored air modeling studies, we have focused this section on potential local health impacts (see next section for discussion of potential regional impacts). Getting better estimates would require doing new air quality modeling using the actual emissions and other specifications of the four options.

What does GRU's air modeling tell us? GRU modeled changes in ground-level $PM_{2.5}$ concentrations throughout Alachua County for its proposed CFB project. It separately modeled two sets of emissions assumptions, at actual levels and at permitted levels. The modeled emission levels are summarized in Attachment 6, Exhibit A6-1 (the modeling actually used more detailed emission estimates broken out for individual units). All the modeling was at an aggregate level, in that it considered the CFB emissions in combination with emissions from other electricity supply units in the county, including the Deerhaven 2 unit that is planned for retrofit and major emissions reductions. Only stack emissions from combustion units were considered.[69] The modeling compared the incremental $PM_{2.5}$ air quality impacts due to ***current*** emissions from all units (not including the CFB, and with Deerhaven 2 at current levels) to impacts due to ***future*** emissions from all units (including the CFB, and with Deerhaven 2 at retrofit levels). It does not appear that the $PM_{2.5}$ impacts related to the CFB emissions alone can be extracted directly from the GRU studies. Air quality impacts beyond Alachua County are not addressed in the available documentation, although the majority of $PM_{2.5}$-related public health impacts would be expected to occur beyond the county (see later discussion of local versus regional impacts).[70]

Selected results from the GRU-sponsored modeling are given in Exhibit 6-14, which shows the increments of $PM_{2.5}$ air concentration attributable to various emission scenarios. Under all scenarios and measures, modeling indicates that $PM_{2.5}$ concentration increments in Alachua County attributable to GRU emissions will either decrease slightly or remain about the same in the future (with CFB and Deerhaven 2 retrofit) compared with current conditions (based on 2003 actual or permitted emissions). The maximum future increment of $PM_{2.5}$ at projected permit maximum emission levels for all units is 0.46 ug/m^3 as annual average (and roughly 4 ug/m^3 as 24-hour average).

[69] GRU has estimated fugitive emissions from current coal handling and dust control operations as part of its Title V air operating permit, and they have been found to be "small compared to emissions from combustion" (GRU 2004b).

[70] ICF reviewed the GRU modeling documentation and believes the approach was reasonable for a screening-level modeling effort to estimate incremental differences in fine particulate matter between scenarios. However, the documentation of the context for the modeling and especially of the modeling results could be expanded. Potential technical shortcomings include (1) the Mesopuff II chemistry appears to be oversimplified, (2) 1990 ozone observations may not be representative of current conditions, and (3) formation of carbonaceous fine particulates is not considered. Given the information available, we cannot determine whether the model results are likely to be conservative or not.

Exhibit 6-14
Summary of $PM_{2.5}$ Modeling Results from GRU-sponsored Studies [a]

Emission Scenario	Air Concentration Increment (ug/m^3)[b] – $PM_{2.5}$ Annual Average		Air Concentration Increment (ug/m^3)[b] – Highest $PM_{2.5}$ 24-Hour Average	
	At Maximum Alachua County Location	County-wide Range [c]	At Maximum Alachua County Location	County-wide Range [c]
ACTUAL Emissions from all units at both Deerhaven and Kelly sites				
Current	0.038	~0.016-0.038	not modeled	not modeled
Future (w/CFB and DH2 retrofit)	0.031	~0.012-0.031	not modeled	not modeled
PERMITTED Emissions from all units at both Deerhaven and Kelly sites				
Current	0.49	~0.1-0.49	4.06	~1-4.06
Future (w/CFB and DH2 retrofit)	0.46	~0.084-0.46	4.04	~0.8-4.04
ACTUAL Emissions from all units at Deerhaven site only				
Current	0.027	not reported	not modeled	not modeled
Future (w/CFB and DH2 retrofit)	0.026	not reported	not modeled	not modeled
PERMITTED Emissions from all units at Deerhaven site only				
Current	0.17	not reported	3.68	not reported
Future (w/CFB and DH2 retrofit)	0.14	not reported	2.91	not reported

[a] Data extracted from Black & Veatch (2004a,b).
[b] Increment refers to the amount of $PM_{2.5}$ air concentration resulting from the modeled emissions for the applicable emission scenario.
[c] Ranges estimated visually from contour maps.

How do the options compare with respect to local $PM_{2.5}$ concentrations? Focusing on the modeling results for the Deerhaven units only (see Exhibit 6-14), which include the CFB emissions, we can estimate an upper bound for the potential $PM_{2.5}$ increment attributable to the CFB emissions.[71] The maximum $PM_{2.5}$ annual average increment in Alachua County from the CFB unit, based on this modeling, would be some portion of 0.14 ug/m^3 (at projected permitted emission levels), or of 0.026 ug/m^3 (at projected actual emission levels); note that the other portion of the increment would be attributable largely to retrofit Deerhaven 2 emissions. Thus, a conservative estimate of the CFB maximum increment (annual average) would be on the order of 0.02 ug/m^3 (based on actuals) to 0.1 ug/m^3 (based on permitted); average levels across the county would be lower. This increment range is fairly low relative to both the ambient standard (15 ug/m^3) and current levels in the county (10 ug/m^3). It also is below the significance criterion (0.2 ug/m^3) used by US EPA in the CAIR rulemaking to determine whether a state is having an impact on $PM_{2.5}$ levels in a downwind county (US EPA 2005a).

Given the emissions projections for the other options, they are expected to affect $PM_{2.5}$ levels in Alachua County somewhat less than the CFB option, although as noted above

[71] Note that ICF's modeling for this project estimates emissions of SO_2 that are substantially lower than those used by Black and Veatch for both the CFB unit and the other GRU units (see Attachment 6, Exhibit A6-1). This is largely because of updated assumptions we used about the sulfur content of coal and other fuels. ICF's NO_x emissions estimates are similar to those used by Black and Veatch. Overall, impacts on $PM_{2.5}$ air quality based on ICF's updated emission estimates would be expected to be somewhat lower than those predicted by Black and Veatch's modeling.

the amount of the differences cannot be estimated precisely. Differences in local $PM_{2.5}$ air quality between the CFB and IGCC options, based on the emission estimates for both the new units and the other existing GRU units, are expected to be small. The DSM/biomass option likely would have a somewhat lower impact on local $PM_{2.5}$ concentrations given its lower emissions of key precursors (especially SO_2). The DSM/purchase power option (no increase in local combustion-related emissions) would have the lowest $PM_{2.5}$ impact on Alachua County, though the location of its maximum impact is less predictable and depends on where emissions are increased as a result of power purchases.

How do the options compare with respect to potential local human health impacts from $PM_{2.5}$ exposures? The available science, which includes numerous high quality epidemiological studies, and current government science policy decisions indicate $PM_{2.5}$ should be treated as not having a population threshold for health effects in the range of ambient concentrations observed in US urban areas. The prevailing consensus in the scientific community is that any increment in $PM_{2.5}$ exposure within the range found in US urban areas is likely to be associated with increased burden of particulate-related disease and mortality. US EPA recognizes explicitly that its recently proposed ambient standards (e.g., 15 ug/m^3 annual average) do not produce zero risk, but considers the standards to "protect public health with an adequate margin of safety" (US EPA 2006). Using a range of generally accepted exposure-response models, current ambient levels of $PM_{2.5}$ in Alachua County would pose some health risk (even though regulatory standards are met), as would future ambient levels under all four options.

All four options would therefore be expected to have some health impacts due to emissions of $PM_{2.5}$ precursors from fuel combustion. Using the GRU $PM_{2.5}$ air modeling results described above, along with population and age-specific mortality-rate data for Alachua County, we have estimated an approximate range of the premature adult mortality in Alachua County from long-term exposures that is potentially attributable to the CFB option emissions. The purpose of these screening-level calculations is to identify the possible order of magnitude of potential human health impacts. For this approximation, we used a simplified version of the exposure-response modeling approaches US EPA has applied in the CAIR and other particulate risk assessment studies (US EPA 2005b). We focused on adult mortality because in damage cost and benefits analyses for $PM_{2.5}$ exposures, it typically accounts for greater than 90 percent of the ***quantifiable*** health damages/benefits. We focused on long-term exposures because that is the approach US EPA has recently taken in major particulate health effects risk analyses (US EPA 2005b, US EPA 2006). Although short-term peak $PM_{2.5}$ exposures have also been found to be associated with increases in mortality in some

studies, it is likely that the large bulk of the effect on mortality is captured by chronic exposure-response models such as the ones we used to calculate health impacts.[72]

[72] Although effects on morbidity, including respiratory and cardiovascular illness and increased doctor and emergency room visits, clearly are important impacts of $PM_{2.5}$ exposure, another reason for our focus on mortality is that more detailed air modeling characterizing short-term exposures would be needed to attempt to quantify these effects.

Results of our estimation of the possible ranges of $PM_{2.5}$-related adult mortality associated with CFB emissions are given in Exhibit 6-15.[73] Based on the projected emissions (shown in Exhibit 6-12), we estimate that incremental exposures would be associated with less than 0.19 to approximately 0.5 premature death per year for Alachua County, corresponding to an average annual risk for an individual of less than three in one million (see third row of Exhibit 6-15). There is large uncertainty associated with these estimates, with some exposure-related factors possibly contributing to the estimates being too high (for example, use of maximum exposure values for the entire county) and some exposure-related factors possibly contributing to the estimates being too low (for example, air modeling may have underestimated some processes leading to formation of $PM_{2.5}$). It is not clear whether the expected largest source of uncertainty – that is, which exposure-response relationship is most appropriate to use – results in the estimates being too high or too low.

Given the estimated local adult mortality impacts from CFB emissions, the local health impacts associated with the other options are expected to follow the same order as discussed above with respect to the impacts on local $PM_{2.5}$ air quality – the IGCC option would likely have slightly lower health impacts in the county than the CFB option, and the two DSM options would likely have somewhat lower impacts in the county than both the CFB and IGCC options. Again, we emphasize that the amount of difference between the options cannot be quantified with confidence without additional air quality and health effects modeling.

As noted above, this range-finding approximation of local $PM_{2.5}$ health impacts focused on mortality resulting from long-term exposures. A fuller, more robust characterization of health impacts, including both morbidity and mortality effects of both short-term and long-term exposures, would require additional data and resources. Regardless, the basic patterns of health impacts, in terms of the ranking of options, would be expected to be similar.

[73] As a quality assurance check, we compared our results to predicted $PM_{2.5}$ exposure levels and resulting adult mortality levels for north Florida in a recent detailed modeling report (Abt 2004). The number of predicted deaths per unit exposure level in our results is consistent with the results in that report.

Exhibit 6-15
Estimated Premature Adult Mortality in Alachua County from $PM_{2.5}$ Exposure Increments Associated with the CFB Emissions (2015)

Emission Scenario	Estimated Exposure Increment (annual average) (ug/m^3) [a]	Average Individual Risk (annual) [b]	Total Predicted Deaths per Year [b]
CFB, maximum permitted emissions (from Black & Veatch air modeling)	0.1 (at maximum county location)	6 to 16E-06	0.93 to 2.5
CFB, projected actual emissions (from Black & Veatch air modeling)	0.02 (at maximum county location)	1.2 to 3.2E-06	0.19 to 0.5
CFB, projected actual emissions (from ICF modeling for this project)	Unknown, but < 0.02 (at maximum county location)	<1.2 to 3.2E-06	<0.19 to 0.5
2003 actual emissions from all GRU units (from Black & Veatch air modeling, for reference)	0.038 (at maximum county location)	2.3 to 6.1E-06	0.32 to 0.86

[a] Derived from GRU-sponsored modeling results (Black & Veatch 2004a,b). Maximum applied to entire county area, thereby producing conservative estimates of impact (county-wide average is estimated to be half to three-fourths of maximum).

[b] Exposure-response relationships for all-cause adult mortality from both Krewski et al. (2000) and Dockery et al. (1993) were used, which yields the roughly three-fold range of results. These relationships are consistent with the range of exposure-response assumptions for adult mortality used by US EPA in recent rulemakings (EPA 2005a,b, EPA 2006). There is significant uncertainty about the form and parameterization of the exposure-response relationships for $PM_{2.5}$, and therefore all estimated impacts based on these relationships are subject to substantial uncertainty. Risks are estimated based on the projected population demographics for Alachua County residents in 2015, as estimated by US EPA (2005b).

Summary – comparison of potential local health impacts from $PM_{2.5}$ exposures. It is expected that highest local health impacts from $PM_{2.5}$ exposures would result from the CFB and IGCC options (with CFB slightly higher), followed by the DSM/biomass option, and then the DSM/power purchase option (which would have no new local generating units). Given that projected future emissions from the new units (under the three options having new generating units in the county) are lower than the projected future emissions from the other GRU units, the health impacts attributable to any of the new units would be lower than the impacts attributable to those other units. Relative to the potential level of health impacts from 2006 GRU emissions in the county, all four options would result in lower future health impacts.

6.2.6 Illustrative Regional Health Damage Cost Calculations for $PM_{2.5}$

Airborne $PM_{2.5}$ from power plant emissions is in large part a regional public health issue, and not strictly a local concern. Though there will be some near-source impacts expected, and the maximum intensity of impacts would be anticipated relatively near the source, a large fraction of the overall health impacts of precursor emissions from power plant stacks generally will be distant from the source – in some cases, quite a long distance away. This is in fact the justification for US EPA's 2005 CAIR regulations, which require states to reduce their emissions of SO_2 and NO_x based entirely on the predicted $PM_{2.5}$ formation in other downwind states resulting from those emissions (US EPA 2005a). The extensive analyses supporting CAIR show without doubt that sizable impacts from emissions in one state occur hundreds, and even thousands, of miles away. For example, Florida is included in the CAIR program for fine particulates based on US EPA's modeling that demonstrated "significant" (based on the CAIR criterion) impacts on $PM_{2.5}$ air concentrations in five counties in Georgia and two counties in Alabama resulting from emissions in Florida. In a separate ICF modeling study in 2005 of $PM_{2.5}$ impacts from two power plants in the Midwest, roughly 80 percent of the predicted health effects and damage costs were estimated to occur greater than 200 miles from the source. In a just-published study of power plant emissions in Maryland, roughly 85 percent of overall $PM_{2.5}$-related health impacts are predicted to occur beyond the state borders (Levy 2006). This spatial pattern of the impacts results from the basic physical and chemical properties of $PM_{2.5}$ and its precursors. Put simply, the fine particles are so small they can remain suspended in air for an extremely long time, and the precursor gases can travel long distances before they react and form $PM_{2.5}$. Air modeling typically shows some gradient in $PM_{2.5}$ concentrations very near a source, then a much more gradual decline with increasing distance.

In an attempt to identify the potential bounds of the regional health impacts for the four options under consideration, we have made extrapolations based on damage cost estimates in other recent analyses of $PM_{2.5}$ health impacts for different areas. We recognize that, given the situation-specific nature of many of the factors leading to health impacts (e.g., meteorology, population patterns, emission mix, background air quality), these extrapolated estimates have additional uncertainties beyond the substantial uncertainties inherent in site-specific risk assessment of $PM_{2.5}$ health impacts. Ideally, one would perform site-specific photochemical air modeling with a baseline emission inventory and receptor grid over the Eastern US, then perform probabilistic exposure-response and damage cost modeling, but such analyses are time-consuming and expensive, and the results still have significant uncertainties. Nonetheless, we believe the extrapolated numbers presented here, although uncertain, are informative and allow at least some sense of the potential magnitude of the regional impacts, and some basis for comparison of the relative magnitude of regional impacts for the four options.

Extrapolation approach. As noted above, the method we used is a major simplification of the rigorous and data-intensive modeling approach used in detailed studies, and is meant to approximate the possible range of damage costs associated with the options and to aid in comparisons of the options. We used four studies as main data sources: US EPA's regulatory impact analysis for CAIR (US EPA 2005b), an ICF 2005 modeling study of two power plants in the Midwest, a comprehensive national modeling study sponsored by the Clean Air Task Force (Abt 2004), and a recent study of power plant emissions in Maryland (Levy 2006). US EPA's study used the Community Multiscale Air Quality (CMAQ) model to estimate $PM_{2.5}$ concentrations across the US resulting from power plant emissions of $PM_{2.5}$ precursors under both a baseline scenario and a reduced SO_2 and NO_x emission scenario (i.e., the CAIR regulatory program) for 2010 and 2015. EPA then performed probabilistic exposure-response modeling of mortality and several kinds of illness, followed by probabilistic valuation modeling of the predicted health effects (that is, estimating a dollar value of health "damages"). ICF used very similar methods and data inputs in its study, except that the Regional Modeling System for Aerosols and Deposition (REMSAD) was used for the photochemical air modeling. EPA's study covered hundreds of power plants in the Eastern US, while ICF's study focused on two specific plants in the Midwest US. The Clean Air Task Force study used REMSAD for air modeling of several policy options for national reductions in $PM_{2.5}$ precursor emissions, and used exposure-response and valuation modeling methods similar to US EPA's study. The Maryland study used CALPUFF and a source-receptor matrix approach for air modeling of emissions from six power plants, and similar approaches to exposure-response modeling as the other studies (this study did not estimate dollar damages).

For purposes of application in this options comparison, we first reviewed the health effects and damage cost results from each of these studies in conjunction with the associated quantities of SO_2 and NO_x emissions. Our goal was to develop a general approximation of the magnitude of impacts associated with a given emission quantity (i.e., something roughly parallel to the environmental externality "adders" used by some states in power plant decisions). Achieving this goal is greatly complicated by the fact that emissions of primary $PM_{2.5}$ are not an adequate predictor of downwind $PM_{2.5}$ impacts, and that there are multiple important precursors (including SO_2, NO_x, primary $PM_{2.5}$, VOCs) and other determinants of airborne $PM_{2.5}$. After examining the data from the four studies, we decided to use the damage costs per ton of SO_2 plus NO_x as the estimator of regional impacts (rather than, for example, damage costs per ton of SO_2 or NO_x alone). These two pollutants are generally considered the main contributors to regional $PM_{2.5}$ resulting from power plant emissions (as evidenced by EPA's focus of the CAIR regulations only on these two pollutants), and while neither one alone nor the two in combination are expected to be linearly related to regional $PM_{2.5}$ concentrations, using the sum was considered the better approach (in part based on examination and comparison of the various possible estimators, including damage costs per ton SO_2 and damage costs per ton NO_x).

The CAIR analyses address the overall impact of emission reductions at hundreds of power plants in the Eastern US. Using the CAIR results for 2015 yields an estimator of approximately $20,000 (2003 dollars) of national damage costs from $PM_{2.5}$ health impacts (both morbidity and mortality) per combined ton of SO_2 and NO_x emitted ($99 billion in damage costs in 1999 dollars using 3 percent discounting, adjusted to $108 billion in damage costs in 2003 dollars, corresponding to roughly 5.5 million tons of emitted SO_2 plus NO_x). This large-scale, multi-plant analysis provides an aggregate-level result, which could be viewed as an averaging over many emission reductions in many different locations. ICF's modeling for two particular Midwest US locations yields an estimator for 2015 of approximately $36,000 ($39,000 for one location, $32,000 for the other[74]) (2003 dollars) of national damage costs from $PM_{2.5}$ health impacts (morbidity and mortality) per combined ton of SO_2 and NO_x emitted, which indicates the

[74] This relatively small difference, despite the fact that population close to the source is much higher for one site than the other (see Exhibit 6-16), is consistent with the observation that far-field effects dominate overall $PM_{2.5}$ damage cost estimates.

emission location may be somewhat "riskier" than the average derived from CAIR. The proportion of the damage costs accruing in-state in ICF's modeling study ranged from 10 to 20 percent for the two emission locations (both in the same state). The Clean Air Task Force study is similar to the US EPA CAIR analysis in that it is a large-scale analysis covering emissions at hundreds of power plants. The estimator derived from this study for 2015 is $15,000 (2003 dollars) of national damage costs from $PM_{2.5}$ health impacts (both morbidity and mortality) per combined ton of SO_2 and NO_x emitted (based on average of the four policy scenarios modeled, and midpoint of the 2010 and 2020 results). The estimator derived for 2015 from the Maryland study of specific power plants is $18,000 (2003 dollars) of national damage costs from $PM_{2.5}$ health impacts (both morbidity and mortality) per combined ton of SO_2 and NO_x emitted (based on average of the six plants modeled, an assumed value of statistical life of $6 million and assumption that mortality accounts for 90 percent of total damages, with results projected forward to 2015 population).

Given these four data sets – for which the derived estimators of $PM_{2.5}$-related health damages cluster reasonably close together, between $15,000 and $36,000 – and the recognition of significant uncertainty in applying these values to other power plants in other locations, we use an order-of-magnitude range of $5,000 to $50,000 per combined ton of SO_2 plus NO_x to extrapolate the potential regional health damage costs for the four options based on changes in emissions of these precursors. In-state damage costs would be expected to be a relatively small fraction (maybe 10 to 20 percent) of the total regional damage costs.

Clearly, Florida is different geographically and has different air quality conditions than the rest of the Eastern US. Florida's air quality is relatively good for $PM_{2.5}$ and other regulated air pollutants, as evidenced by the fact that, unlike most Eastern states, it has no non-attainment counties (see Abt 2004 for examples of projected future $PM_{2.5}$ levels in Florida). However, even though much of what is "downwind" for Florida emissions is over the ocean, it is clear from the CAIR modeling that Florida emissions of $PM_{2.5}$ precursors affect downwind $PM_{2.5}$ levels in states to the north. Moreover, examination of potentially exposed populations – a critically important determinant of health impacts and damage costs from $PM_{2.5}$ exposures – in proximity to Gainesville and comparison with populations relevant for CAIR and the Clean Air Task Force study (Eastern US average of 164 people per square mile, continental US average of 93 people per square mile) and for ICF's study in the Midwest US shows similar (or higher) populations for Gainesville, as shown in Exhibit 6-16, particularly at greater distances where the majority of impacts would occur. Moreover, the population surrounding Gainesville includes a higher proportion of older residents than the US average, which would tend to make the nearby risks from $PM_{2.5}$ exposure higher than for an average Eastern US location.

Exhibit 6-16
Comparison of US Population for Deerhaven and Selected Extrapolation Sites [a]

Radius from Facility (miles)	US Population (density per square mile in parentheses)		
	Deerhaven Site	Site 1, ICF Midwest Study	Site 2, ICF Midwest Study
25	285,000 (147)	297,000 (153)	66,000 (34)
50	844,000 (109)	2,410,000 (310)	123,000 (16)
200	10,900,000 (156)	6,570,000 (54)	4,520,000 (58)
500	47,500,000 (152)	37,400,000 (64)	29,000,000 (68)
1,000	188,000,000 (172)	143,000,000 (74)	119,000,000 (75)

[a] For reference, Eastern US average density is roughly 164 people per square mile, total continental US average density is roughly 93 people per square mile.

Thus, while the damage cost estimators derived above obviously are not a perfect fit for estimating and comparing health damage costs for the four options in Florida, use of the derived order-of-magnitude range appears to be a reasonable approximation given the data available to work with.

***Extrapolation results for $PM_{2.5}$ damage costs*.** The regional damage cost extrapolation results for the base case in 2015 and 2020 are presented in Exhibit 6-17 for the four options. Considering local generating unit emissions only (that is, excluding non-local emissions from power purchases under the two DSM options), the ranking of the options based on extrapolated regional $PM_{2.5}$ health damage costs is similar to the ranking based on estimated local $PM_{2.5}$ health impacts, although the two DSM options become virtually indistinguishable: CFB option > IGCC option > DSM/biomass option > DSM/power purchase option. For all options, and especially the two DSM options, the majority of regional $PM_{2.5}$ damage costs result from emissions from continued operations of existing GRU units (rather than emissions from a new unit). This baseline for all options due to emissions from future operations of existing GRU units is roughly \$10 to \$100 million in estimated health damage costs in 2015 (\$9 to 90 million in 2020). Thus, the differences between options appear most pronounced when the new units are compared in isolation. Estimated damage costs for all options are lower in 2020 than in 2015 as a result of the downward trend in emissions across all options.

Consideration of power purchases closes the gap between the CFB and IGCC options and the two DSM options. The CFB option still has the highest relative impact, but when non-local emissions from power purchases are considered, the IGCC option is very close to the two DSM options by 2020 with respect to the extrapolated regional health damage costs from $PM_{2.5}$ exposures.

Exhibit 6-17
Summary of Extrapolated Regional Health Damage Cost Estimates for $PM_{2.5}$ Exposures for the Four Options

Year/ Scenario	Source	Estimated Annual Regional Damage Costs (millions, \$2003 dollars, rounded) [a]			
		CFB	IGCC	DSM plus Biomass	DSM plus Purchase
2015/base case	New GRU unit only	\$6 – 60	\$4 - 40	\$0.5 – 5	\$0
	Existing GRU units only	\$10 – 100	\$10 – 100	\$10 – 100	\$10 – 100
	All GRU units	\$16 – 160	\$14 – 140	\$10 – 100	\$10 - 100
	Power purchases	n/a	n/a	\$2 – 20	\$2 – 20
	Total	\$16 - 160	\$14 - 140	\$12 - 120	\$12 – 120
2020/ base case	New GRU unit only	\$5 – 50	\$3 - 30	\$0.5 – 5	\$0
	Existing GRU units only	\$9 – 90	\$9 – 90	\$9 – 90	\$9 – 90
	All GRU units	\$14 – 140	\$12 - 120	\$9 - 90	\$9 – 90
	Power purchases	n/a	n/a	\$2 – 20	\$2 – 20
	Total	\$14 - 140	\$12 - 120	\$11 - 110	\$11 – 110

[a] Based on generating unit stack emissions of SO_2 and NO_x as estimated by IPM, along with the damage cost estimator range described in text.

As noted previously, emissions for the maximum fuel/demand/CO_2/biomass case are approximately 10 percent higher than the base case, and the average emissions across all 36 cases are roughly 10 percent lower than the base case presented here. Thus, extrapolated regional damage costs would follow the same pattern (maximum case about 10 percent higher than shown for the base case, average case about 10 percent lower). The ranking of options does not shift significantly across the 36 cases (minor shifts for a couple of cases), although the magnitude of the differences can change slightly.

Major uncertainties. As emphasized throughout this section, there are substantial uncertainties in any attempt to develop numerical estimates of future air quality, human exposures, and human health impacts related to $PM_{2.5}$. This is unavoidable.

Assumptions, modeling imperfections, data limitations, and simply lack of knowledge about the future all add to the uncertainty in quantitative estimation of emission patterns and levels, concentrations of $PM_{2.5}$ in the air at different locations throughout the modeling period, exposures of people to the airborne $PM_{2.5}$, and the kinds and numbers of health effects resulting from the exposures (i.e., what is the correct quantitative exposure-response relationship). Monetization of the damages associated with health impacts adds even more uncertainty, given the wide range of valuation approaches and results for health effects, including premature mortality.

We have addressed some of the uncertainty related to emissions by the study design, in which we ran 36 separate IPM cases that varied key factors related to emissions, such as future fuel costs and electricity demand. In general, we have addressed other uncertainties in our derived estimates of local health impacts and extrapolated estimates of regional health damage costs by presenting results as upper bounds and broad ranges. As noted, these estimates are not based on comprehensive new site-specific modeling for the four options, which would be needed to estimate uncertainty in any quantitative way, but are derived/extrapolated from existing modeling studies to give a sense of the potential magnitude of the health impacts, and allow comparisons of the potential relative impacts among the options.

Clearly, in these range-finding calculations, we have not attempted to quantify all health impacts of $PM_{2.5}$ exposure, but have focused on premature adult mortality as an important indicator. There are other potential health impacts that could be quantified, as well as still others that remain unquantifiable. We did not make separate estimates of impacts from short-term exposures, which would increase the impact estimates by an unknown amount, but focused on long-term exposures, again as an important indicator of the potential overall impacts. Additional uncertainty results from lack of knowledge about mechanism of effect and speciation (e.g., which components of the complex $PM_{2.5}$ mixture are more or less toxic than others). Although there is insufficient scientific data to resolve all issues related to speciation, we believe the ranges of health impact estimates presented reflect, among other factors, differences in speciation with regard to their contribution to adverse effects, as measured by numerous high-quality, multi-city epidemiological studies.

References for Section 6.2 (Potential Public Health Impacts)

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CHAPTER SEVEN
ECONOMIC IMPACT

INTRODUCTION

In this section we analyze the socioeconomic impacts of the four main resource options, as discussed in Chapter 1. The four main options are:

- 220-MW CFB plant;
- 220-MW IGCC plant;
- 75-MW Biomass plant; and
- Maximum DSM

The main socioeconomic impact analyzed in this section is the potential for job creation in the Alachua County. Since all the options involve significant investments to meet future energy demand (including options for demand-side management), they have the potential to create both local as well as regional employment opportunities. Some of these additional employment opportunities will be temporary (for example, for construction of the power plant), while others will be more permanent (for example, for operation and maintenance of the plants once they are constructed).

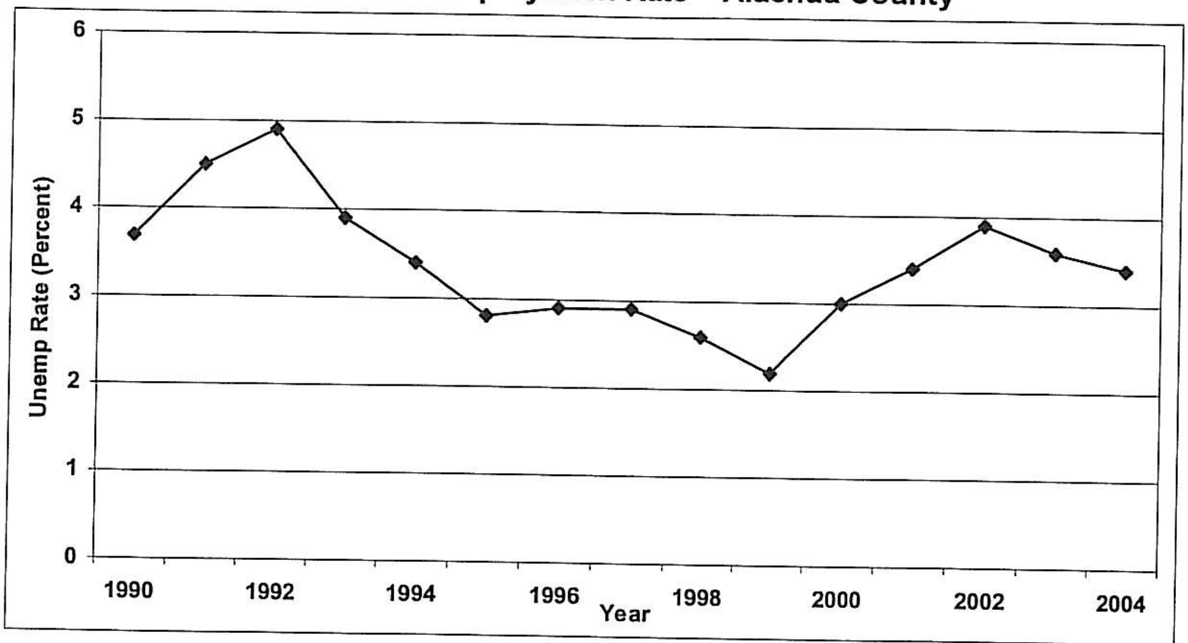
Results indicate that all the options have the potential to create significant local jobs. The CFB option can create 13,192 job years or 388 job equivalents. The IGCC option can create 11,986 job years or 353 job equivalents. The biomass plus maximum DSM option can create 10,428 job years or 338 job equivalents (under the low case), and 16,788 job years or 494 job equivalents (under the high case). Finally, the maximum DSM option by itself can create 1,500 job years or 75 job equivalents (see below for definitions of these metrics).

The section is organized as follows. We first describe the local labor market conditions to determine the potential benefits of these new jobs. We then describe the regional economic model used to estimate the new jobs created. We then describe the methodology used to estimate the jobs. The section ends with the results of the analysis.

Local Labor Market Conditions

Because the IMPLAN model (discussed below) is based on county-level data, the socioeconomic impacts are analyzed for the entire county. As Exhibit 7-1 below shows, historically, the annual unemployment rate in Alachua County has been quite low in recent years. From a peak of about 5 percent in 1992, the unemployment rate has dropped significantly to about 3.4 percent in 2004. This drop in unemployment is expected given the overall economic boom throughout the country and its effects in Florida in general, and the local economy in particular.

Exhibit 7-1
Historical Unemployment Rate – Alachua County



Source: Bureau of Labor Statistics (BLS)

Although the unemployment rate in the local economy is not high, creating additional job opportunities can have its advantages. Labor economists argue that local unemployment can be costly not only to the individuals directly affected but also to the regional/national economies. Avoiding the costs of unemployment thus leads to both private benefits (i.e., benefits to individuals directly affected) as well as social benefits (i.e., benefits to the region as a whole). Some of the potential benefits from reducing unemployment discussed in the economic literature are:[75]

- Increased productivity
- Increased individual income
- Reduced poverty
- Reduced criminal activity / policing costs
- Reduced costs of mental and physical health services
- Reduced costs of support services
- Improved life opportunities
- Reduced benefits payments
- Increased tax revenue
- Improved fiscal position

A decrease in unemployment implies an increase in worker productivity that leads to an increase in individual incomes. These in turn lead to reductions in poverty and

[75] See for example, D. Perkins and P Angley. "Values, unemployment and public policy. The need for a new direction". Discussion Paper, 2003.

unemployment benefits. Unemployment can also breed higher crime rates that require more public spending in law enforcement activities, social benefits, and state-sponsored health and other support costs. These, along with the added disadvantage of lower tax revenues, have a negative impact on state and Federal fiscal positions. Thus, the jobs created by the four resource options discussed here have the potential to bring in significant socioeconomic benefits to the region as a whole.

Modeling

To estimate the regional economic impacts of the jobs created -- through the indirect and induced multiplier effects – we use the regional economic model IMPLAN. IMPLAN is created and maintained by the Minnesota IMPLAN Group (MIG). The IMPLAN model is a static input-output framework used to analyze the effects of an economic stimulus on a pre-specified economic region, in this case, Alachua County. This model is considered static because the impacts calculated by any scenario in IMPLAN estimate the indirect and induced impacts for one time period (typically a year). The modeling framework in IMPLAN consists of two components – the descriptive model and the predictive model. The descriptive model defines the local economy in the specified modeling region, and includes accounting tables that trace the "flow of dollars from purchasers to producers within the region".[76] It also includes the trade flows that describe the movement of goods and services, both within, and outside of the modeling region (i.e., regional exports and imports with the outside world). In addition, it includes the Social Accounting Matrices (SAM) that trace the flow of money between institutions, such as transfer payments from governments to businesses and households, and taxes paid by households and businesses to governments. The predictive model consists of a set of "local-level multipliers" that can then be used to analyze the changes in final demand and their ripple effects throughout the local economy. These multipliers are thus coefficients that "describe the response of the [local] economy to a stimulus (a change in demand or production)."[77] Three types of multipliers are used in IMPLAN:

- **Direct** – represents the jobs created due to the investments that result in final demand changes, such as investments needed to build and operate a power plant.

- **Indirect** – represents the jobs created due to the industry inter-linkages caused by the iteration of industries purchasing from industries, brought about by the changes in final demands.

- **Induced** – represents the jobs created in all local industries due to consumers' consumption expenditures arising from the new household incomes that are generated by the direct and indirect effects of the final demand changes.

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[76] IMPLAN Pro Version 2.0 User Guide.
[77] *Ibid.*

To illustrate these concepts consider the following simplified example. A $10 million investment required to construct the power plant leads to 100 jobs (say) in the construction industry, due to the workers needed to construct the power plant. These jobs are the result of the direct investment and are hence termed as direct jobs in IMPLAN terminology. Because the construction industry is connected to other industries through its inter-industry linkages, the 100 direct jobs create an additional 40 jobs (say) in industries such as wholesale trade, motor vehicle parts and dealers, architectural and engineering services, etc. In the regional economic parlance (and in IMPLAN), these additional jobs are termed indirect jobs. Finally, because the direct and indirect jobs create income for the workers involved, which are then spent on various consumption activities, these expenditures lead to further economic activity and employment in the economy. In IMPLAN, these jobs, say an additional 30, are termed as induced employment and are created in sectors such as food and beverage stores (restaurants and bars), retail outlets, general merchandise stores, hospitals and physician offices, etc. Thus the total number of jobs created by the $10 million investment in this example is 170, out of which 70 jobs are created in "support" industries due to the input-output relationships between economic sectors. These 70 jobs are also referred to as the "multiplier" effects by regional economists.

Methodology

We used the IMPLAN model data for the Alachua County to estimate the potential for job creation through the various resource options. In order to estimate the potential for job creation in the regional economy, we first estimated the levels of investments needed for these options. Using data from sources discussed elsewhere in this study, we estimated the total capital and operating and maintenance (O&M) costs for the various options. For example, Chapter 4 discusses the capital costs needed for the three options involving constructing a new power plant. These costs were (2003$):

- 220 MW CFB - $470 million
- 220 MW IGCC - $445 million
- 75 MW CFB for Biomass - $170 million

We assume these investments are made over a four year period to construct the plant under each option, and divide the capital cost equally for an annual average capital cost. These are then entered into the IMPLAN model stimulating appropriate economic sectors to estimate the number of workers needed to construct the plant over the 4-year period.

Jobs that will be created due to the operation and maintenance of the plant are estimated using the levelized cost data explained in Chapter 4. In order to estimate the total annual operation cost that will create permanent jobs in the local economy, we used the VOM and FOM components of the levelized costs from Chapter 4 (in 2003$/MWh) and assumed a 85 percent capacity factor for the three plant options (again, based on Chapter 4 assumptions).

For the 75-MW Biomass plant option, we also model the economic impacts of the different biomass fuel types needed (urban wood waste, forestry residue and energy crops) and the associated transportation costs required to deliver the biomass fuel to the plant. However, because we assume that the biomass fuels will come from a 50-mile radius around the existing GRU Deerhaven plant, and because Alachua county has a total area of 874 square miles, which translates to approximately a 17-mile radius for the county, we assume that 34 percent of the all the biomass fuel needed will be supplied from the county sources creating local jobs within the county (17/50 = 34 percent). The rest two-thirds of the biomass fuel will come from out-of-county sources. We present the results for a "low case" where we estimate the jobs based on this assumption that only 34 percent of the total feedstock will create economic benefits for Alachua County. We also present a "high case" where we estimate the total jobs created by the feedstock requirements, irrespective of whether they are created in Alachua or other counties.

Cost assumptions for the DSM option – the cost assumptions used for the DSM option were based on the DSM programs discussed in Chapter 3. To calculate the total socioeconomic benefits of these programs, we estimated four types of impacts for each program:

1. GRU incentives to residential and commercial customers, which then get invested to buy equipment for DSM and associated labor costs (and hence create jobs in the local economy).

2. GRU administrative costs for local personnel and advertising to promote the DSM programs. These investments create local jobs for GRU personnel and the advertising and marketing sector (with corresponding ripple effects through the local economy).

3. Bill savings to residential and commercial customers due to reduced demand for electricity, measured by the MWh of demand replaced and the retail rates for residential and commercial customers. These savings have a positive effect on the economy because customers then spend their savings on other consumption goods creating additional local economic activity. These consumption expenditures are modeled using the consumption patterns of the median household in Alachua County.[78]

4. GRU lost revenue due to reduced demand for electricity from the grid. The DSM programs result in reduced demand for electricity from the grid, leading to lost revenue for the utility supplying the electricity, measured in terms of the reduced demand (in MWh) and the difference between retail rates and production costs. The lost revenue creates negative economic impacts as it is associated with resources taken out of the economy.

[78] Under the TRC test, although customers are expected to experience bill savings as the total cost of energy production decrease, there is the possibility that electric rates (price) may go up. Hence, participants under the DSM program may benefit at the cost of other ratepayers (for example, renters or other low income households). The RIM test avoids this conundrum.

However, the negative effects of this loss are more than offset by the positive effects generated by the bill savings to electricity customers and their subsequent spending of that money on other goods and services.

Once the investment amounts were determined, these were then used in IMPLAN to create the initial perturbations for the appropriate IMPLAN sectors to estimate the local economic impacts for Alachua County.[79]

Results

Exhibit 7-2 below presents the estimated job creation potential for the 220-MW CFB plant option.

Exhibit 7-2
Jobs Created by 220-MW CFB Coal Plant Option

Job Types	Construction Phase	Operation & Maintenance
Direct	1,181	106
Indirect	277	28
Induced	400	58
Total	**1,858**	**192**

Totals may not add due to rounding.
Source: ICF calculations based on IMPLAN model results

Construction jobs are estimated based on the capital cost assumptions for the CFB plant (explained in Chapter 4). The CFB plant is assumed to require $470 million in capital costs. We assume the plant will be constructed over a four-year period creating 1,181 construction jobs (direct). These jobs are considered temporary because they will cease to exist after the plant has been constructed. Moreover, these direct jobs create an additional 677 jobs in support industries due to the indirect (277 jobs) and induced expenditures (400 jobs).

Operation and maintenance of the CFB power plant is estimated to create a total of 192 full-time jobs in Alachua County. Out of these, 106 workers are estimated to be directly involved in operation and maintenance of the plant. Additionally, we estimate another 86 jobs will be created in Alachua County due to the indirect (28) and induced effects (58) discussed above. Unlike the construction-related jobs which are considered

[79] While estimating the local economic impacts for Alachua County, we assume that there will be significant leakages from the modeling region. This is because a small modeling area such as one county implies that some of the resources needed will be obtained from outside the county boundaries creating economic activity and jobs in other counties. This is achieved in IMPLAN by using the model-generated Regional Purchase Coefficients (RPCs). RPCs in IMPLAN represent the portion of the regional demands purchased from local producers (with the remainder being supplied by non-local producers).

temporary lasting for four years, the jobs created due to the operation of the plant would be permanent, leading to long-term benefits for the local economy in Alachua county.

In order to express the socioeconomic impacts in a common metric that can be compared across the four options, we first present the total job impacts in terms of "job years". A job year can be interpreted as a measure of the number of annual jobs created multiplied by the number of years these jobs are expected to last. Thus, for the 220-MW CFB option, the 1,858 temporary construction jobs are expected to last 4 years creating a total of 7,432 job years. Similarly, the 192 full-time operations jobs are expected to last 30 years for a total of 5,760 job years. Hence the total impact for the CFB option is estimated to be 13,192 job years. However, because the characteristics of these jobs are different (the construction jobs are temporary requiring different skills-set compared to the full-time operations jobs), the job year numbers should be interpreted with caution. Thus, we also present an alternative metric called "job equivalents" which translates the different types of jobs into equivalent jobs on a continuous basis. Because the 1,858 construction jobs last for four out of a total 34 years in the analysis (4 years for construction plus 30 years of operation of the plant), they translate to approximately 218 job equivalents on a continuous basis (=1,858/(34/4)). Similarly, the 192 full-time operations jobs translate to 170 *incremental* job equivalents on a continuous basis. Thus, using this metric, the total job equivalents for the 220-MW CFB option are 388 jobs on a continuous basis.

Exhibit 7-3 below presents the estimated job creation potential for the 220 MW IGCC plant option.

Exhibit 7-3
Jobs Created by 220-MW IGCC Plant Option

Job Types	Construction	Operation & Maintenance
Direct	1,119	91
Indirect	262	24
Induced	378	49
Total	**1,759**	**165**

Totals may not add due to rounding.
Source: ICF calculations based on IMPLAN model results

Because the investments needed for the IGCC plant are similar, but slightly smaller, to those for the CFB plant, the local economic impacts for these two options are quite similar. This is true for the 1,759 construction jobs created during the first four years only. Moreover, operation and maintenance of the IGCC plant will require an additional 91 workers annually for the life of the plant. These 91 new full-time jobs in Alachua are expected to create an additional 73 jobs due their secondary or ripple effects.

Similar to the calculations discussed above for the CFB option, the 220-MW IGCC option thus creates a total of 11,986 job years or 353 job equivalents on a continuous basis.

Exhibit 7-4 below presents the estimated job creation potential for the 75-MW Biomass plant option.

Exhibit 7-4
Jobs Created by 75-MW Biomass Plant Option

Job Types	Construction	Operation & Maintenance
Direct	427	133
Indirect	100	28
Induced	145	46
Total	**672**	**208**

Totals may not add due to rounding.
Source: ICF calculations based on IMPLAN model results

The total number of construction jobs required for the 75-MW Biomass CFB plant are lower than those for the previous two options. This is because we assume this plant will have a capacity of 75 MW as opposed to 220 MW assumed for the two previous options. As a simplifying assumption, the number of workers needed to construct a power plant is assumed to be directly proportional to the capacity of the plant, thus the total number of direct, indirect, and induced jobs created for this plant is significantly less. Again, we assume these construction jobs will be available for four years, during the construction phase of the plant.

Although the biomass plant is assumed to be smaller in size (and therefore should have less economic impact), the operation and maintenance jobs created for this plant are slightly higher than for the other two generation options. We estimate there will be a total of 208 full-time jobs created due to the biomass plant. The 208 full-time jobs estimated here are assumed to be under the "low case", where approximately one-third of the biomass feedstock needed is obtained from Alachua County, with the rest obtained from out-of-county sources and are considered leakages from this analysis (discussed above).[80]

Out of this, there will be 133 workers directly involved in the operation of the plant. Out of this, we estimate 23 new jobs created in the transportation sector to deliver the biomass fuels to the plant, and an additional 110 full-time jobs in other sectors in Alachua county to operate the plant, including supplying the different types of biomass

[80] This simplification is based on a proportionate assumption such that the supply of biomass feedstock is assumed to be linearly related to the distance from the centroid of Alachua County. Estimating the exact location of the biomass suppliers is beyond the scope of this study.

fuels. Moreover, these direct jobs are also likely to create an additional 74 jobs in the Alachua economy due to the indirect and induced multiplier effects.

Because running a biomass plant tends to be more labor intensive than some of the other generation technologies, there is potential for more long-term jobs being created in Alachua for the biomass plant option. However, the biomass plant will likely produce additional economic benefits for other counties in Florida as well. As discussed above, we assume that the feedstock needed for the biomass plant will be supplied over a 50-mile radius. Since this translates to approximately two-thirds of the feedstock required may have to be transported from outside the Alachua County (assuming a linear approximation per footnote 6), we estimate another 262 total jobs (including direct, indirect, and induced) in the feedstock sectors in other Florida counties.[81] Thus, under the high case, the total jobs created by the biomass option are 470 full-time jobs in Alachua and surrounding counties.

Similar to the calculations discussed above for the CFB option, the 75-MW biomass option thus creates a total of 8,928 job years or 263 job equivalents on a continuous basis under the low case. Similarly, it creates 16,788 job years or 494 job equivalents under the high case.

Exhibit 7-5 below presents the estimated job creation potential for the Maximum DSM option. The DSM option involves several DSM programs for the residential and commercial sectors, discussed in Chapter 3. The job creation potential for the DSM option is modeled using the four types of impacts discussed above.

Exhibit 7-5
Annual Average Jobs Created by Max DSM Option

Year	Direct	Indirect	Induced	Total
2006-2010	39	8	10	57
2011-2015	78	15	19	112
2016-2020	68	13	16	98
2020-2025	23	5	6	34
Total Job Years*	**1040**	**205**	**255**	**1,500**

* See text for total job year calculations.
Totals may not add due to rounding.
Source: ICF calculations based on IMPLAN model results

Because the DSM option modeled here involves only conservation measures to reduce the demand for electricity as opposed additional generation, the job creation potential

[81] Note that the 208 total jobs in Exhibit 7-4 includes jobs required to operate the biomass plant along with the Alachua county feedstock supply jobs. Hence that number is not directly comparable to the 262 out-of-county jobs for feedstock supply only.

should be interpreted differently. DSM jobs are presented as *annual average* for the 5-year intervals shown in the Figure above. Most programs are assumed to start in 2006 and continue until 2025. We first estimate the annual average investments required for these programs (in 2003$) and the annual average bill savings for the same period. Total economic impacts are then calculated for a "representative year" within each time period. Thus, because the spending on the DSM programs are assumed to be different in different years (as opposed to the assumed constant dollar spending for the three generation options), results are presented annually for the representative year. As a measure of the cumulative impact of the DSM option, the final row presents the results in job years, measured as the number of annual average jobs created multiplied by the number of years these jobs are expected to last.

The DSM programs are expected to impact more economic sectors in Alachua (and other Florida counties) than the other options. The total number of direct job years is estimated to be about 1,040 over the entire 20-year time period. Out of these, HVAC contractors are expected to benefit significantly (355 job years until 2025) due to the investments needed to purchase equipment for several DSM programs. Additionally, the bill savings for residential and commercial customers expected to be funneled back into the local economy will provide a boost to the regional economy and create substantial number of additional jobs. Finally, these direct jobs are expected to ripple through the economy and create more employment opportunities through the indirect and induced effects as shown in the Figure above. In summary, the maximum DSM option by itself can create an additional 1,500 job years or 75 job equivalents.

CHAPTER EIGHT
DETAILED MODELING RESULTS

This chapter presents selected additional detailed results of ICF's analysis. This chapter is organized into four sections. The first section discusses GRU's electric revenue requirements. The second discusses GRU operations. The third discusses emission impacts. The fourth discusses market prices for electricity.

GRU ELECTRIC REVENUE REQUIRMENTS

The key results on revenue requirements include:

- Total 20-year GRU electric revenue requirements on an undiscounted basis are $5.8 billion on average across the 144 cases.

Exhibit 8-1
Average Revenue Requirements Across All 144 Cases (Nominal MM $)

Year	Revenue Requirements Fixed	Average Cash Going Forward Costs	Total Electric
2006	79	98	177
2007	80	101	181
2008	82	104	186
2009	83	113	197
2010	84	135	219
2011	84	134	218
2012	87	142	229
2013	91	150	241
2014	94	159	253
2015	96	169	265
2016	99	180	279
2017	102	193	295
2018	105	206	311
2019	108	220	328
2020	111	236	347
2021	115	251	366
2022	118	267	386
2023	122	285	407
2024	126	304	430
2025	131	324	454
Total Undiscounted Cumulative	1,998	3,770	5,768
Average 2006 – 2025	100	188	288
NPV 2006 - 2025[1]	1,151	2,038	3,189
NPV 2012 - 2025[1]	1,013	2,017	3,030
NPV 2012 - 2020[1]	687	1,257	1,943

[1]Nominal discount rate. Net Present Value or NPV as of first year, i.e., 2006, or 2012.

- On a NPV basis, GRU's average electric revenue requirements are $3.2 billion across the 144 cases.

- The portion of GRU's revenue requirements that are fixed across scenarios equal approximately 35 percent of the total.

- 2025 revenue requirements are 2.6 times 2006 requirements in part due to general inflation which raises costs by a factor of 1.56.

- IGCC NPV revenue requirements are lower for the Base Case, the average of 36 scenarios, 2006 – 2025 NPV, 2012 – 2025 NPV, and 2012 – 2020 NPV (see Exhibits 8-1 through 8-6).

Exhibit 8-2
Revenue Requirements NPV (Nominal MM$) – Single Base Case[2]

Option	NPV 2006 - 2025[1]	Incremental NPV	% Incremental NPV
IGCC	2,935	--	--
CFB	3,099	+164	+6
Biomass Maximum DSM	3,107	+172	+6
Maximum DSM	3,139	+204	+7

[1]5.5 percent nominal discount rate.
[2]Base Demand, Base Fuel, Base CO_2, Base Biomass.

Exhibit 8-3
NPV Revenue Requirements NPV (Nominal MM$) – Average All 36 Cases

Option	NPV 2006 – 2025[1]	Incremental NPV	% Incremental NPV
IGCC	3,055	--	--
CFB	3,218	+163	+5
Maximum DSM	3,236	+181	+6
Biomass Maximum DSM	3,247	+192	+6

[1]5.5 percent nominal discount rate.

Exhibit 8-4
Revenue Requirements – NPV[1] (Nominal MM$) – Average Across All 36 Cases – Different Time Periods

Period	Option			
	CFB	IGCC	Biomass Maximum DSM	Maximum DSM
2006 – 2025	3,218	3,055	3,247	3,236
2012 – 2025	3,064	2,857	3,103	3,094
2012 – 2020	1,962	1,823	2,002	1,989

[1]Nominal discount rate of 5.4 percent. As of the first year of that period, i.e., 2006 or 2012. Includes generation going forward production costs only.

Exhibit 8-5
Revenue Requirements NPV (Nominal MM$) – Change From Least Cost Case[1] – Average Across All Cases – Different Time Periods

Period	Option			
	CFB	IGCC	Biomass Maximum DSM	Maximum DSM
2006 – 2025	+163	--	+192	+181
2012 – 2025	+208	--	+246	+237
2012 – 2020	+139	--	+180	+166

[1]Nominal discount rate of 5.4 percent. Includes generation going forward production costs only.

Exhibit 8-6
Revenue Requirements – Ranking in Different Time Periods

Period	Option			
	CFB	IGCC	Biomass Maximum DSM	Maximum DSM
2006 – 2025	#2	#1	#4	#3
2012 – 2025	#2	#1	#4	#3
2012 – 2020	#2	#1	#4	#3

[1]Use of existing plants, purchase power, new CTs. Includes generation going forward production costs only.

IGCC revenue requirements are also lower when measured for the variable portion of revenue requirements (see Exhibit 8-7). The difference is larger since it is over a smaller base.

Exhibit 8-7
Revenue Requirements – Difference Between Best and Worst Option (%) – Average All Cases – Different Time periods and measures of Revenue Requirements

Period	Selected Generation Production[2]	Total Revenue Requirement[3]
2006 – 2025	10	6
2012 – 2025	13	8
2012 – 2020	15	9

[1]Nominal discount rate of 5.4 percent.
[2]Includes generation going forward production costs only.
[3]Includes revenue requirements which are fixed across cases

Annual average revenue requirements across the 36 scenarios are shown in Exhibit 8-8. The cash production share of revenue requirements shows an increase over time exceeding other revenue requirements.

Exhibit 8-8
Average Base Case Revenue Requirements Across All 36 Scenarios (Nominal MM$)

Year	CFB			IGCC			Biomass Maximum DSM			Maximum DSM		
	Cash[2] Production	Other[3] Revenue	Total Electric	Cash[2] Production	Other[3] Revenue	Total Electric	Cash[2] Production	Other[3] Revenue	Total Electric	Cash[2] Production	Other[3] Revenue	Total Electric
2006	98	79	177	98	79	177	98	79	177	98	79	177
2007	101	80	182	101	80	182	100	80	181	100	80	181
2008	104	82	186	104	82	186	103	82	185	103	82	185
2009	114	83	198	114	83	198	112	83	196	112	83	196
2010	136	84	220	136	84	220	133	84	217	133	84	217
2011	135	84	219	119	84	203	144	84	228	139	84	223
2012	143	87	230	126	87	213	152	87	239	147	87	235
2013	151	91	242	133	91	224	159	91	251	156	91	247
2014	161	94	255	142	94	236	168	94	262	165	94	259
2015	172	96	268	152	96	248	177	96	273	175	96	271
2016	183	99	282	163	99	262	188	99	287	187	99	286
2017	196	102	298	175	102	277	201	102	303	199	102	301
2018	210	105	315	188	105	293	214	105	319	213	105	318
2019	224	108	332	202	108	310	228	108	336	227	108	335
2020	240	111	351	217	111	329	243	111	354	243	111	354
2021	256	115	371	232	115	347	258	115	372	258	115	373
2022	273	118	391	248	118	367	274	118	392	275	118	393
2023	291	122	414	265	122	388	291	122	413	292	122	415
2024	311	126	437	284	126	410	309	126	435	311	126	438
2025	332	131	462	304	131	434	328	131	458	331	131	462
Cumulative 2006-2025	3,831	1,998	5,829	3,505	1,998	5,503	3,878	1,998	5,876	3,866	1,998	5,864
NPV[1] 2006 - 2025	2,067	1,151	3,218	1,904	1,151	3,055	2,096	1,151	3,247	2,085	1,151	3,236
NPV[1] 2012 - 2025	2,051	1,013	3,064	1,844	1,013	2,857	2,090	1,013	3,103	2,081	1,013	3,094
NPV[1] 2012 - 2020	1,275	687	1,962	1,136	687	1,823	1,315	687	2,002	1,302	687	1,989

[1] Nominal discount rate. Net Present Value or NPV as of first year, i.e., 2006, or 2012.
[2] Includes transmission and distribution expenses, G&A, general fund transfer, system and load dispatch expenses, nuclear decommissioning and fuel disposal costs, debt service, and capital expenditures.
[3] SO_2, NO_x and Hg allocations are not included. Therefore, revenue requirements may be understated. However, this will not affect the results.

Exhibits 8-9 through 8-11 show the NPV for all 144 case option combinations for 2006 – 2025, 2012 – 2025, and 2012 – 2020.

Exhibit 8-9
NPV Revenue Requirement 2006 – 2025 (Nominal MM$)

Case Number	Case				Option			
	Fuel	CO_2	Demand	Biomass	CFB	IGCC	Biomass Maximum DSM	DSM
1	Low	None	Base	Base	$2,922	$2,805	$2,886	$2,816
2	Low	None	Base	High	$2,921	$2,805	$2,954	$2,816
3	Low	Base	Base	Base	$3,060	$2,911	$2,991	$2,974
4	Low	Base	Base	High	$3,029	$2,868	$3,075	$2,974
5	Low	High	Base	Base	$3,488	$3,336	$3,317	$3,359
6	Low	High	Base	High	$3,392	$3,161	$3,415	$3,359
7	Low	None	High	Base	$3,046	$2,930	$3,017	$2,951
8	Low	None	High	High	$3,046	$2,931	$3,085	$2,951
9	Low	Base	High	Base	$3,203	$3,057	$3,154	$3,137
10	Low	Base	High	High	$3,176	$3,013	$3,244	$3,137
11	Low	High	High	Base	$3,679	$3,525	$3,500	$3,529
12	Low	High	High	High	$3,572	$3,334	$3,598	$3,529
13	Base	None	Base	Base	$2,994	$2,879	$2,981	$2,933
14	Base	None	Base	High	$2,994	$2,879	$3,039	$2,933
15	Base	Base	Base	Base	$3,099	$2,935	$3,107	$3,139
16	Base	Base	Base	High	$3,060	$2,901	$3,196	$3,139
17	Base	High	Base	Base	$3,314	$3,132	$3,199	$3,328
18	Base	High	Base	High	$3,168	$2,944	$3,297	$3,328
19	Base	None	High	Base	$3,132	$3,017	$3,128	$3,090
20	Base	None	High	High	$3,132	$3,017	$3,187	$3,090
21	Base	Base	High	Base	$3,276	$3,116	$3,301	$3,338
22	Base	Base	High	High	$3,237	$3,077	$3,388	$3,338
23	Base	High	High	Base	$3,539	$3,352	$3,439	$3,576
24	Base	High	High	High	$3,369	$3,135	$3,536	$3,576
25	High	None	Base	Base	$3,019	$2,904	$3,012	$2,978
26	High	None	Base	High	$3,019	$2,905	$3,056	$2,978
27	High	Base	Base	Base	$3,156	$2,989	$3,187	$3,237
28	High	Base	Base	High	$3,115	$2,950	$3,268	$3,237
29	High	High	Base	Base	$3,401	$3,172	$3,340	$3,505
30	High	High	Base	High	$3,225	$2,993	$3,445	$3,505
31	High	None	High	Base	$3,163	$3,048	$3,167	$3,149
32	High	None	High	High	$3,163	$3,048	$3,216	$3,149
33	High	Base	High	Base	$3,345	$3,166	$3,392	$3,448
34	High	Base	High	High	$3,312	$3,140	$3,475	$3,448
35	High	High	High	Base	$3,644	$3,403	$3,599	$3,768
36	High	High	High	High	$3,453	$3,210	$3,698	$3,768

None = Low

The range is greatest for DSM and the least for IGCC.

Exhibit 8-9a
NPV Revenue Requirements – 2006 – 2025

Measure	CFB	IGCC	Biomass Maximum DSM	DSM
Highest[1]	3,679	3,525	2,886	2,816
Lowest	2,921	2,805	3,698	3,768
Range	758	720	812	952
Average	3,218	3,055	3,247	3,236

[1]Across the 36 cases.

Exhibit 8-10
NPV Revenue Requirements 2012 – 2025 (Nominal MM$)

Case Number	Case				Option			
	Fuel	CO_2	Demand	Biomass	CFB	IGCC	Biomass Maximum DSM	DSM
1	Low	None	Base	Base	$2,723	$2,576	$2,681	$2,595
2	Low	None	Base	High	$2,722	$2,576	$2,767	$2,595
3	Low	Base	Base	Base	$2,913	$2,722	$2,825	$2,810
4	Low	Base	Base	High	$2,870	$2,663	$2,932	$2,810
5	Low	High	Base	Base	$3,458	$3,280	$3,247	$3,302
6	Low	High	Base	High	$3,346	$3,048	$3,370	$3,302
7	Low	None	High	Base	$2,886	$2,740	$2,853	$2,771
8	Low	None	High	High	$2,886	$2,740	$2,938	$2,771
9	Low	Base	High	Base	$3,100	$2,914	$3,040	$3,025
10	Low	Base	High	High	$3,064	$2,854	$3,155	$3,025
11	Low	High	High	Base	$3,712	$3,530	$3,487	$3,521
12	Low	High	High	High	$3,582	$3,275	$3,610	$3,521
13	Base	None	Base	Base	$2,744	$2,599	$2,731	$2,672
14	Base	None	Base	High	$2,744	$2,599	$2,803	$2,672
15	Base	Base	Base	Base	$2,888	$2,677	$2,904	$2,952
16	Base	Base	Base	High	$2,834	$2,631	$3,018	$2,952
17	Base	High	Base	Base	$3,173	$2,945	$3,017	$3,184
18	Base	High	Base	High	$2,979	$2,691	$3,139	$3,184
19	Base	None	High	Base	$2,923	$2,779	$2,922	$2,876
20	Base	None	High	High	$2,923	$2,779	$2,997	$2,876
21	Base	Base	High	Base	$3,120	$2,915	$3,160	$3,214
22	Base	Base	High	High	$3,067	$2,861	$3,270	$3,214
23	Base	High	High	Base	$3,470	$3,236	$3,334	$3,511
24	Base	High	High	High	$3,244	$2,942	$3,457	$3,511
25	High	None	Base	Base	$2,770	$2,626	$2,765	$2,724
26	High	None	Base	High	$2,770	$2,626	$2,821	$2,724
27	High	Base	Base	Base	$2,957	$2,742	$3,004	$3,076
28	High	Base	Base	High	$2,901	$2,688	$3,109	$3,076
29	High	High	Base	Base	$3,282	$2,988	$3,193	$3,408
30	High	High	Base	High	$3,045	$2,747	$3,324	$3,408
31	High	None	High	Base	$2,956	$2,811	$2,966	$2,946
32	High	None	High	High	$2,956	$2,812	$3,028	$2,946
33	High	Base	High	Base	$3,205	$2,973	$3,273	$3,354
34	High	Base	High	High	$3,160	$2,937	$3,381	$3,354
35	High	High	High	Base	$3,602	$3,291	$3,535	$3,754
36	High	High	High	High	$3,343	$3,031	$3,658	$3,754

Exhibit 8-11
NPV Revenue Requirements 2012 – 2020 (Nominal MM$)

Case Number	Case				Option			
	Fuel	CO_2	Demand	Biomass	CFB	IGCC	Biomass Maximum DSM	DSM
1	Low	None	Base	Base	$1,817	$1,716	$1,793	$1,735
2	Low	None	Base	High	$1,816	$1,716	$1,855	$1,735
3	Low	Base	Base	Base	$1,863	$1,731	$1,833	$1,804
4	Low	Base	Base	High	$1,853	$1,730	$1,904	$1,804
5	Low	High	Base	Base	$2,211	$2,082	$2,064	$2,109
6	Low	High	Base	High	$2,099	$1,909	$2,149	$2,109
7	Low	None	High	Base	$1,891	$1,791	$1,872	$1,817
8	Low	None	High	High	$1,891	$1,791	$1,933	$1,817
9	Low	Base	High	Base	$1,938	$1,810	$1,922	$1,902
10	Low	Base	High	High	$1,933	$1,809	$1,998	$1,902
11	Low	High	High	Base	$2,331	$2,198	$2,180	$2,222
12	Low	High	High	High	$2,203	$2,005	$2,265	$2,222
13	Base	None	Base	Base	$1,823	$1,723	$1,824	$1,782
14	Base	None	Base	High	$1,823	$1,723	$1,878	$1,782
15	Base	Base	Base	Base	$1,843	$1,717	$1,888	$1,901
16	Base	Base	Base	High	$1,841	$1,717	$1,962	$1,901
17	Base	High	Base	Base	$2,054	$1,875	$1,950	$2,049
18	Base	High	Base	High	$1,907	$1,725	$2,035	$2,049
19	Base	None	High	Base	$1,903	$1,804	$1,909	$1,873
20	Base	None	High	High	$1,903	$1,804	$1,964	$1,873
21	Base	Base	High	Base	$1,934	$1,811	$1,992	$2,010
22	Base	Base	High	High	$1,936	$1,809	$2,066	$2,010
23	Base	High	High	Base	$2,181	$1,996	$2,091	$2,193
24	Base	High	High	High	$2,017	$1,827	$2,176	$2,193
25	High	None	Base	Base	$1,840	$1,742	$1,850	$1,822
26	High	None	Base	High	$1,841	$1,742	$1,889	$1,822
27	High	Base	Base	Base	$1,876	$1,749	$1,946	$1,976
28	High	Base	Base	High	$1,876	$1,746	$2,014	$1,976
29	High	High	Base	Base	$2,115	$1,870	$2,073	$2,210
30	High	High	Base	High	$1,937	$1,751	$2,163	$2,210
31	High	None	High	Base	$1,926	$1,827	$1,941	$1,923
32	High	None	High	High	$1,926	$1,827	$1,984	$1,923
33	High	Base	High	Base	$1,977	$1,838	$2,062	$2,095
34	High	Base	High	High	$1,982	$1,847	$2,127	$2,095
35	High	High	High	Base	$2,255	$1,996	$2,224	$2,369
36	High	High	High	High	$2,058	$1,866	$2,309	$2,369

Exhibits 8-12 through 8-16 show the range of results expressed for each option as frequency distributions. The height of the bar shows for each option how many of the 36 cases fall within a standard deviation or fraction of standard deviation from the mean. The maximum DSM option is the most symmetrical and spread out versus the IGCC and CFB which are more concentrated between -1.5 and +0.5 of their standard deviations.

Exhibit 8-12
Distribution of Revenue Requirements for All 36 Cases from Mean (2012 – 2025) - CFB

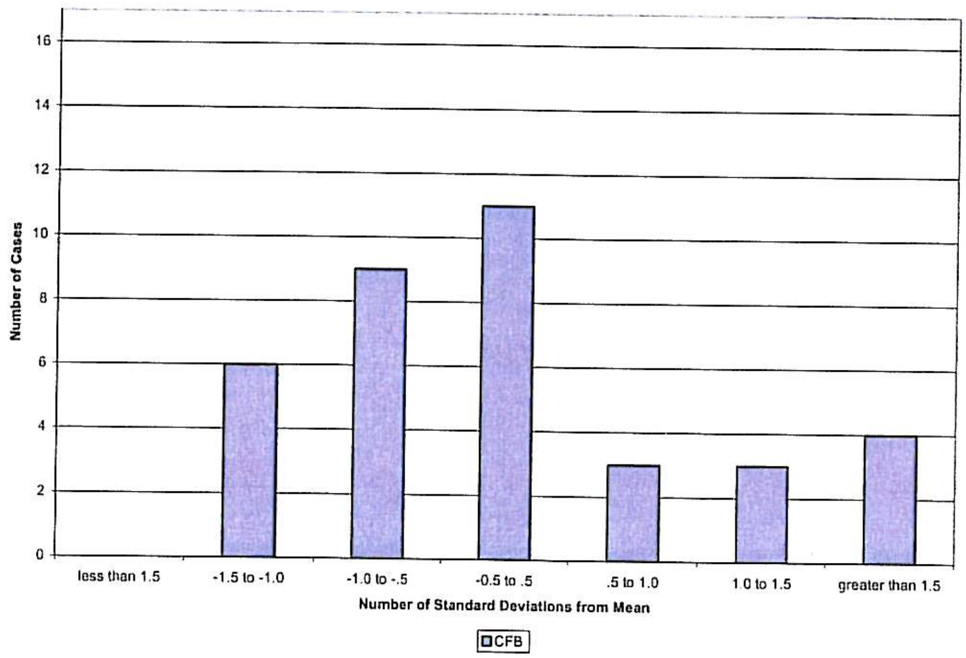


Exhibit 8-13
Distribution of Revenue Requirements for All 36 Cases from Mean - IGCC

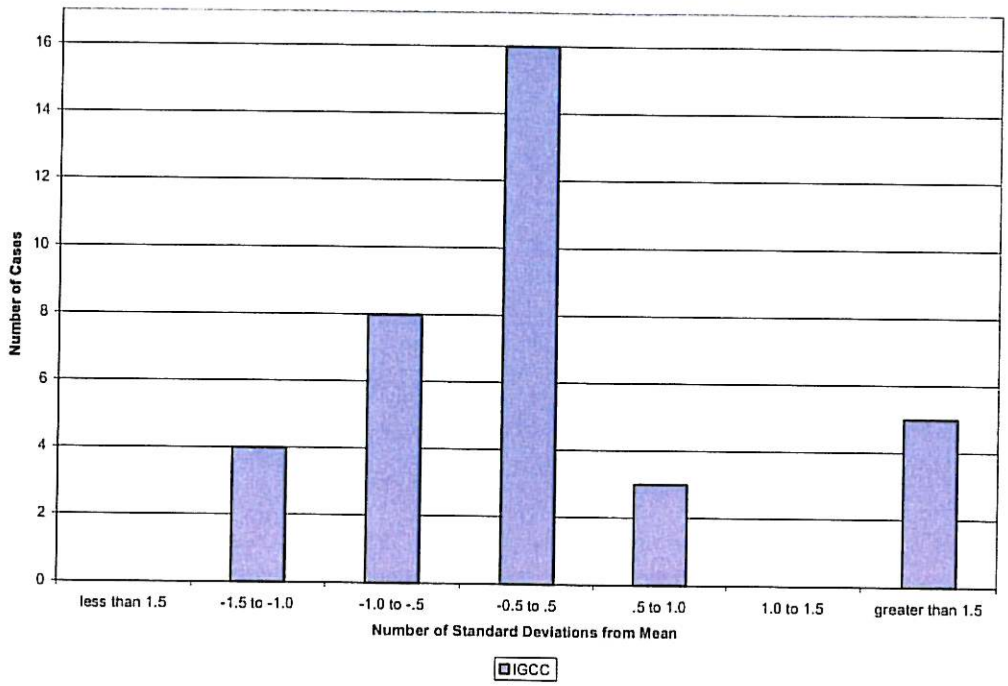


Exhibit 8-14
Distribution of Revenue Requirements for All 36 Cases from Mean – Biomass and Maximum DSM

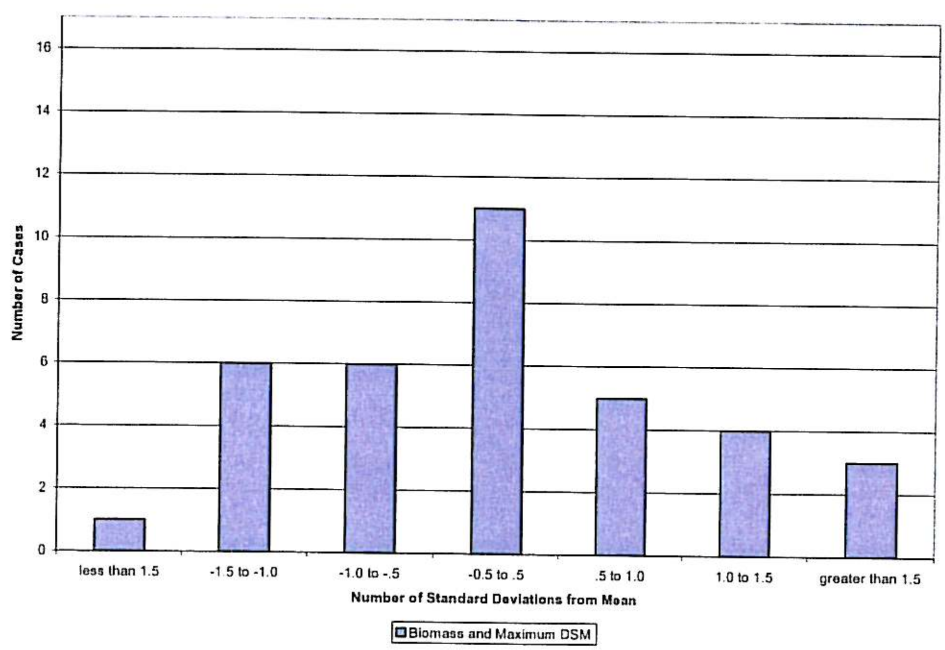


Exhibit 8-15
Distribution of Revenue Requirements for All 36 Cases from Mean – Maximum DSM

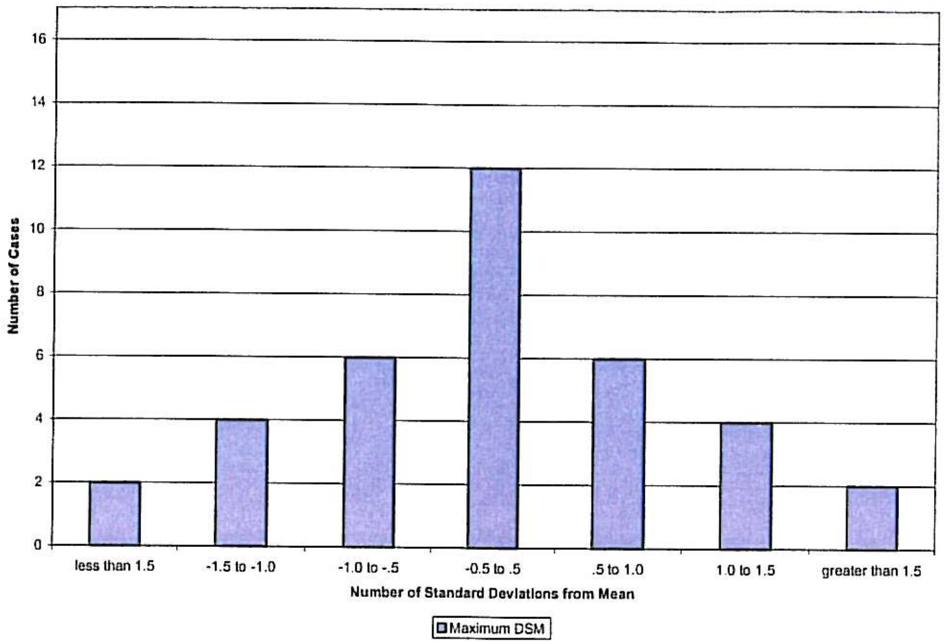
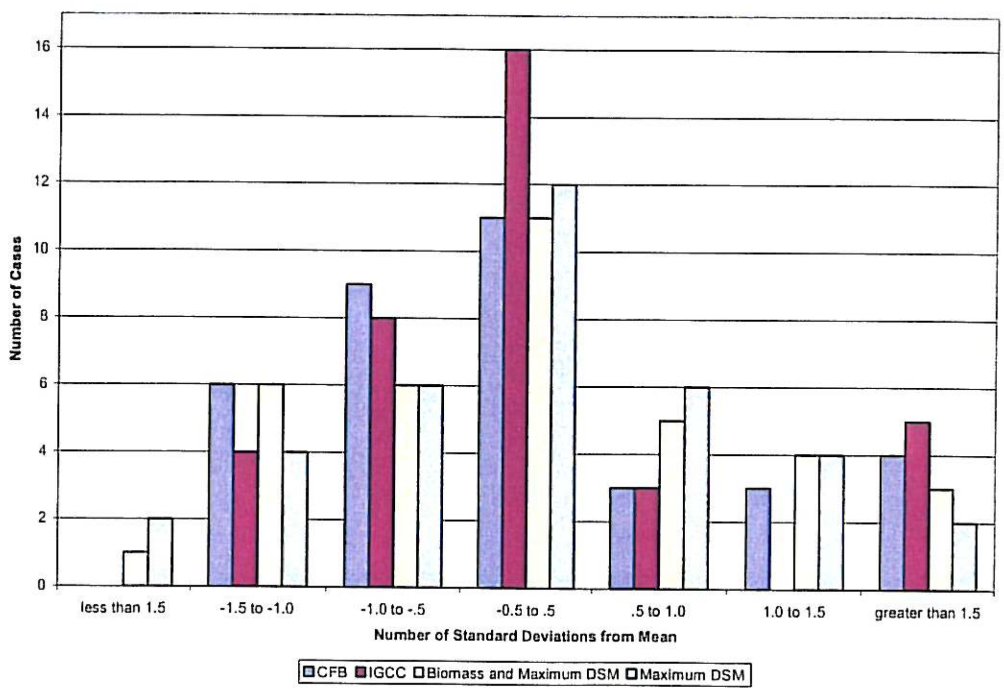


Exhibit 8-16
Distribution of Revenue Requirements for All 36 Cases from Mean – CFB, IGCC, Biomass and Maximum DSM, and Maximum DSM



Exhibits 8-17 through 8-20 show the sensitivity of the options to the highest and lowest values for each variable with all other variables at Base values. For all cases, higher demand growth greatly increases total (though not average per kWh) revenue requirements since more demand must be met, but the increase is greatest for the low generation options, i.e., Maximum DSM and Maximum DSM and Biomass.

High CO_2 allowance costs increase total CFB and IGCC revenue requirements even more than higher demand growth since these are CO_2 intensive options. However, this effect is mitigated by the ability to use biomass in these plants at varying levels. Biomass and maximum DSM is less affected by CO_2 risk since biomass is a CO_2 free option. DSM is almost as affected by high CO_2 allowance prices as IGCC and CFB since it depends on coal power imports.

Low CO_2, i.e., zero CO_2 prices lower revenue requirements in all cases. The effect is actually more pronounced for Maximum DSM which is most dependent on coal power imports from suppliers without biomass options.

Gas prices most affect the DSM options which rely on power imports.

Exhibit 8-17
CFB Case Sensitivity to Variables – 2012 - 2025

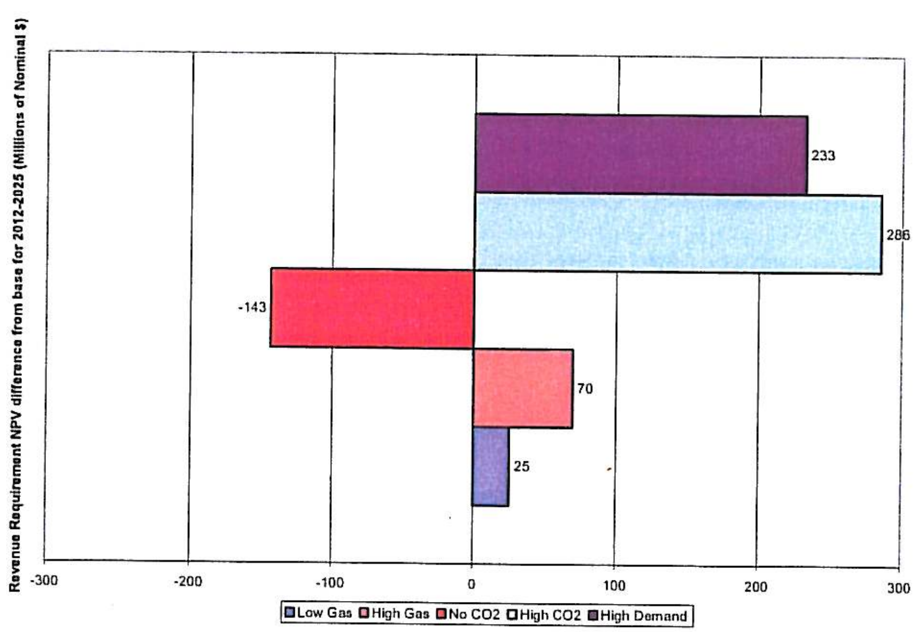


Exhibit 8-18
IGCC Case – 2012 - 2025

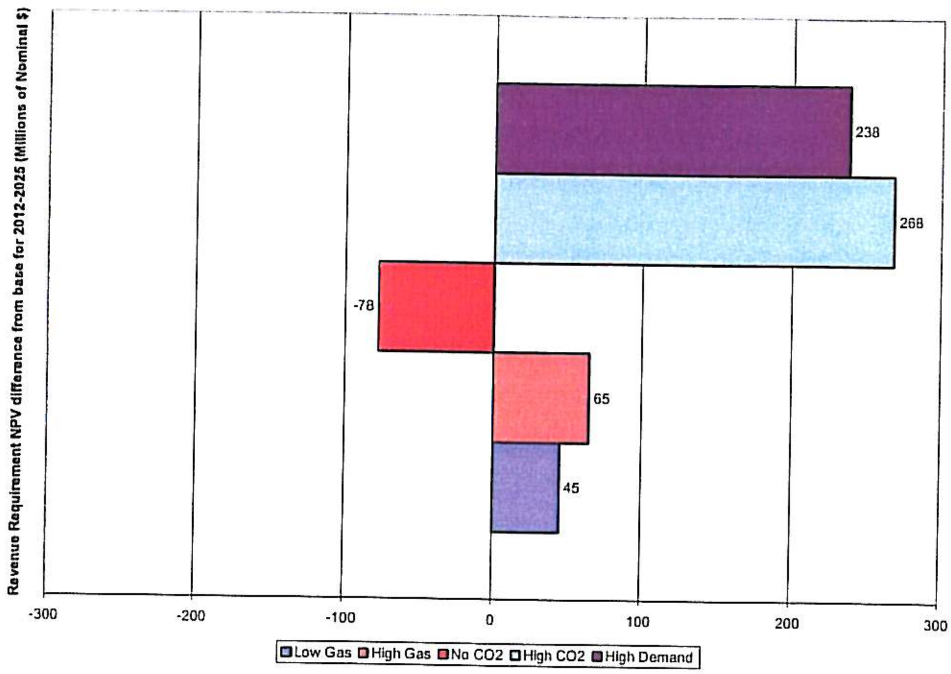
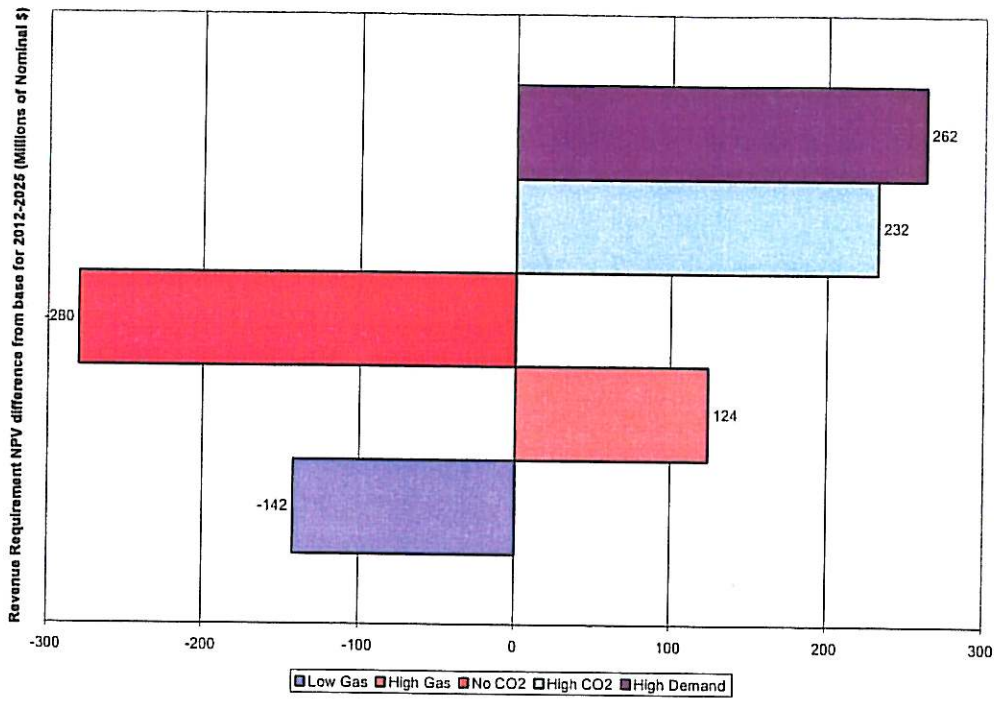


Exhibit 8-19
Biomass and Maximum DSM Case – 2012 – 2025

Exhibit 8-20
DSM Case – 2012 - 2025



IGCC average revenue requirements cost \$100.8/MWh in nominal dollars versus \$107.1/MWh for CFB, \$114.4/MWh for Biomass Maximum DSM and \$113.7/MWh for Maximum DSM (see Exhibit 8-21).

Exhibit 8-21
Per MWh Base Case Revenue Requirements (Nominal $/MWh)[1]

Year	CFB			IGCC			Biomass Maximum DSM			Maximum DSM		
	Cash Production	Other Revenue	Total Electric	Cash Production	Other Revenue	Total Electric	Cash Production	Other Revenue	Total Electric	Cash Production	Other Revenue	Total Electric
2006	45.2	36.3	81.5	45.2	36.3	81.5	45.1	36.5	81.6	45.1	36.5	81.6
2007	45.3	36.0	81.3	45.3	36.0	81.3	45.2	36.3	81.5	45.2	36.3	81.5
2008	45.5	35.7	81.2	45.5	35.7	81.2	45.3	36.1	81.4	45.3	36.1	81.4
2009	48.6	35.5	84.1	48.6	35.5	84.1	48.5	36.0	84.4	48.5	36.0	84.4
2010	56.5	35.0	91.5	56.5	35.0	91.5	56.3	35.7	92.0	56.3	35.7	92.0
2011	54.8	34.0	88.8	48.4	34.0	82.4	60.6	35.2	95.7	58.3	35.2	93.5
2012	56.7	34.7	91.4	50.0	34.7	84.7	62.8	36.2	99.0	61.0	36.2	97.2
2013	58.6	35.4	94.0	51.6	35.4	87.1	65.1	37.2	102.3	63.8	37.2	101.0
2014	61.3	35.7	97.0	54.1	35.7	89.8	68.0	37.9	105.8	66.9	37.9	104.8
2015	64.0	35.9	100.0	56.7	35.9	92.6	70.9	38.6	109.4	70.1	38.6	108.7
2016	64.3	34.7	99.0	58.4	35.5	93.9	75.5	39.7	115.2	74.3	39.4	113.7
2017	67.2	34.9	102.0	61.5	35.8	97.3	80.0	40.6	120.7	78.4	40.1	118.6
2018	71.4	35.7	107.1	65.5	36.5	102.0	84.1	41.3	125.4	82.5	40.7	123.2
2019	76.5	36.8	113.3	69.8	37.3	107.1	87.6	41.5	129.2	86.4	41.1	127.5
2020	81.8	37.9	119.7	74.1	37.9	112.0	90.3	41.3	131.6	90.2	41.3	131.6
2021	90.4	40.5	130.9	80.0	39.5	119.5	94.7	42.1	136.8	94.5	42.0	136.6
2022	97.6	42.4	140.0	85.4	40.7	126.1	99.0	42.9	141.9	99.0	42.7	141.6
2023	102.9	43.2	146.0	90.0	41.5	131.4	103.4	43.5	146.9	103.5	43.3	146.8
2024	105.2	42.8	148.0	93.4	41.6	135.0	107.6	44.0	151.6	108.1	43.9	151.9
2025	103.9	40.9	144.8	95.1	40.9	135.9	111.5	44.4	155.9	112.7	44.4	157.1
Average 2006 – 2025	69.9	37.2	107.1	63.8	37.1	100.8	75.1	39.3	114.4	74.5	39.2	113.7

[1]Calculated based on generation requirements.

The standard deviation of NPV of revenue requirements is largest for the DSM only option and lowest for IGCC (see Exhibits 8-22 and 8-23).

Exhibit 8-22
Long-Term Variability

Period	Standard Deviation of NPV for all 36 Scenarios (millions NPV)			
	CFB	IGCC	Bio-DSM	DSM Only
2006 – 2025	202	174	205	258
2012 – 2025	268	235	262	327
2012 – 2020	137	112	132	178

Exhibit 8-23
Long-Term Variability

Period	Standard Deviation of NPV for all 36 Scenarios (%)			
	CFB	IGCC	Bio-DSM	DSM Only
2006 – 2025	6	6	6	8
2012 – 2025	9	8	8	11
2012 – 2020	7	6	7	9

On an annual basis, the standard deviation is also higher for Maximum DSM and lowest for IGCC (see Exhibit 8-24).

Exhibit 8-24
Cash Forward Selected Production Related Revenue Requirements[1] – Annual Standard Deviation – Nominal MM$ - Average Across 36 Cases

Year	220 MW CFB	220 MW IGCC	75 MW Biomass Maximum DSM	Maximum DSM
2006	6.6	6.6	6.5	6.5
2007	6.7	6.7	6.5	6.5
2008	7.0	7.0	6.7	6.7
2009	7.3	7.3	6.9	6.9
2010	9.8	9.8	9.0	9.1
2011	6.9	5.6	8.5	13.0
2012	8.6	6.7	9.7	14.8
2013	10.9	8.6	11.0	16.9
2014	13.7	10.4	12.9	19.3
2015	17.1	13.3	15.0	21.9
2016	20.0	16.2	18.3	25.2
2017	23.6	19.9	22.1	29.0
2018	27.7	24.3	26.5	33.3
2019	32.5	29.5	31.4	38.1
2020	37.9	35.7	36.9	43.5
2021	41.7	39.1	40.8	47.6
2022	46.2	43.2	45.2	52.3
2023	51.5	48.1	50.1	57.6
2024	57.6	53.8	55.7	63.4
2025	64.6	60.5	61.8	70.0
TOTAL	498	452	481	582
Average	24.9	22.6	24.1	29.1

[1]Excludes sunk cost recovery, indirect G&A, taxes.

GRU OPERATIONS

GRU unplanned builds are combustion turbines for peaking and reserve margin purposes. The DSM options show the highest builds starting as early as 2014-2015 (see Exhibits 8-25 and 8-26).

Exhibit 8-25
Base Case Unplanned Builds Forecast[1] (MW)

Year	CFB	IGCC	Biomass Maximum DSM	Max DSM
2006	0	0	0	0
2007-2008	0	0	0	0
2009	0	0	0	0
2010	0	0	0	0
2011	0	0	0	0
2012-2013	0	0	0	0
2014-2015	0	0	0	0
2016-2020	0	0	0	41
2021-2025	0	0	27	61
2021-2025	159	141	147	147
Total	159	141	174	249

[1]All unplanned builds in the GRU region consist of combustion turbines.

Exhibit 8-26
Base Case GRU Capacity Expansion – 2006 – 2025 (MW)

Resource Type	Option			
	CFB	IGCC	Biomass Maximum DSM	Maximum DSM
CFB	220	--	--	--
IGCC	--	220	--	--
Biomass Only CFB	--	--	75	--
Peaking Combustion Turbine	159	141	174	249
Capacity Import – 2025	29	29	29	29
DSM – 2025	--	--	88	88
Total	408	390	366	366

Total solid fuel use is greatest for the CFB and IGCC options (see Exhibit 8-27). These plants shift from fossil fuel to biomass over time as CO_2 regulations tighten. The decrease is concentrated on petroleum coke which has higher carbon content (+10 percent) than coal. Coal use in Maximum DSM falls over time as Deerhaven 2 operations decrease, in response to CO_2 regulations tightening. Note, Maximum DSM is the only option which does not permit biomass use.

Over time, in the Base Case, GRU becomes more dependent on trucks to bring increasing amounts of biomass and less dependent on rail (see Exhibit 8-28).

Exhibit 8-27
Base Case Fuel Consumption (1,000 Tons)

Year	CFB			IGCC			75 MW Biomass Maximum DSM		Maximum DSM
	Coal	Pet Coke	Biomass	Coal	Pet Coke	Biomass	Coal	Biomass	Coal
2006	665	0	0	665	0	0	665	0	665
2007	665	0	0	665	0	0	665	0	665
2008	665	0	0	665	0	0	665	0	665
2009	669	0	0	669	0	0	669	0	669
2010	700	0	0	700	0	0	700	0	700
2011	906	256	162	861	221	114	592	418	600
2012	920	256	162	875	221	114	602	432	610
2013	934	256	162	889	221	114	612	447	620
2014	938	253	175	892	217	127	622	447	630
2015	942	250	188	895	213	140	632	447	640
2016	908	235	215	865	202	162	620	447	628
2017	875	222	244	836	191	187	609	447	615
2018	844	209	278	808	181	217	598	447	603
2019	813	197	317	780	171	251	587	447	592
2020	784	185	361	754	162	290	576	447	580
2021	728	148	440	724	133	337	572	447	576
2022	677	111	536	696	109	391	568	447	572
2023	630	74	653	668	89	455	564	447	568
2024	585	37	796	642	73	528	560	447	564
2025	544	0	971	617	60	614	556	447	560

Exhibit 8-28
Estimated Number of Railcars/Trucks Required Per Year – Base Case[1]

Year	CFB			IGCC			75 MW Biomass Maximum DSM		Maximum DSM
	Coal (Railcars)	Pet Coke (Railcars)	Biomass (Trucks)	Coal (Railcars)	Pet Coke (Railcars)	Biomass (Trucks)	Coal (Railcars)	Biomass (Trucks)	Coal (Railcars)
2006	5,786	-	-	5,786	-	-	5,786	-	5,786
2007	5,786	-	-	5,786	-	-	5,786	-	5,786
2008	5,786	-	-	5,786	-	-	5,786	-	5,786
2009	5,819	-	-	5,819	-	-	5,819	-	5,819
2010	6,087	-	-	6,087	-	-	6,087	-	6,087
2011	7,878	2,227	6,488	7,485	1,919	4,576	5,148	16,706	5,217
2012	8,000	2,227	6,488	7,607	1,919	4,576	5,235	17,294	5,304
2013	8,121	2,227	6,488	7,729	1,919	4,576	5,322	17,882	5,391
2014	8,157	2,200	7,013	7,756	1,885	5,084	5,409	17,882	5,478
2015	8,192	2,173	7,537	7,782	1,851	5,592	5,496	17,882	5,565
2016	7,896	2,047	8,582	7,521	1,753	6,471	5,395	17,882	5,457
2017	7,610	1,928	9,772	7,267	1,660	7,486	5,295	17,882	5,350
2018	7,335	1,815	11,128	7,023	1,571	8,662	5,198	17,882	5,246
2019	7,070	1,710	12,671	6,786	1,488	10,022	5,103	17,882	5,144
2020	6,814	1,610	14,428	6,558	1,409	11,595	5,009	17,882	5,043
2021	6,335	1,288	17,587	6,299	1,156	13,471	4,973	17,882	5,008
2022	5,889	966	21,437	6,050	948	15,651	4,938	17,882	4,973
2023	5,474	644	26,130	5,811	778	18,183	4,904	17,882	4,938
2024	5,089	322	31,851	5,582	638	21,124	4,869	17,882	4,904
2025	4,730	-	38,824	5,362	523	24,542	4,835	17,882	4,870

[1] Truck loads and rail car loads. Assumes 115-ton carrying capacity per railcar and 25-ton carrying capacity for trucks.

Power imports and exports vary greatly across cases (see Exhibit 8-29). Imports are the highest in the DSM options especially Maximum DSM. Imports rise between 2006 and 2011 for all options until new generation comes on-line.

Exhibit 8-29
Base Case Net Imports (000 MWh)

Year	CFB	IGCC	Biomass Maximum DSM	Maximum DSM
2006	+148	+148	+137	+137
2007	+156	+156	+141	+141
2008	+163	+163	+145	+145
2009	+185	+185	+157	+157
2010	+275	+275	+230	+230
2011	-715	-760	+245	+738
2012	-701	-745	+238	+748
2013	-687	-729	+231	+758
2014	-665	-700	+196	+703
2015	-642	-670	+161	+647
2016	-365	-455	+206	+711
2017	-207	-309	+264	+780
2018	-118	-210	+338	+857
2019	-67	-143	+433	+941
2020	-38	-97	+554	+1,034
2021	+63	-7	+596	+1,080
2022	+163	+84	+641	+1,128
2023	+264	+174	+689	+1,178
2024	+364	+265	+741	+1,230
2025	+465	+355	+797	+1,285
Average 2006 – 2025	-98	-151	+357	+731

- means export
+ means import

GRU generation mix varies across cases especially for imports and exports (see Exhibit 8-30).

Exhibit 8-30
GRU Generation – Base Case (000 MWh)

Option	2006 – 2026 Cumulative				
	Solid Fuel[1]	Natural Gas	DSM	Net Imports	Net Total
CFB	52,329	3,126	-	-1,959	53,496
IGCC	53,557	3,110	-	-3,020	53,647
Biomass – Maximum DSM	39,762	3,581	2,799	7,139	53,282
Maximum DSM	31,863	4,156	2,799	14,628	53,447

[1]Includes petroleum coke, coal, nuclear biomass, and landfill.

EMISSIONS

GRU CO_2 emissions vary more than grid-wide emissions. This is due to imports shifting emissions to other locations (see Exhibits 8-31 through 8-34).

Exhibit 8-31
CO_2 Emissions (million tons) – Average Across 36 Scenarios – 2006 – 2025 – Cumulative

Source	Option			
	CFB	IGCC	Biomass Maximum DSM	Maximum DSM
GRU	45	43	29	30
Total Grid[1]	7,567	7,565	7,559	7,563

[1]Florida plus Southern Company region.

Exhibit 8-32
SO_2 Emissions (cumulative thousand tons) – Average Across 36 Scenarios – 2006 – 2025

Source	Option			
	CFB	IGCC	Biomass Maximum DSM	Maximum DSM
GRU	49	48	40	40
Total Grid[1]	12,383	12,381	12,379	12,380

[1]Florida plus Southern Company region.

Exhibit 8-33
NO_x Emissions (thousand tons) – Average Across 36 Scenarios – 2006 – 2025 Cumulative

Source	Option			
	CFB	IGCC	Biomass Maximum DSM	Maximum DSM
GRU	38	33	32	32
Total Grid[1]	3,758	3,753	3,754	3,754

[1]Florida plus Southern Company region.

Exhibit 8-34
Hg Emissions (cumulative tons) – Average Across 36 Scenarios – 2006 – 2025

Source	Option			
	CFB	IGCC	Biomass Maximum DSM	Maximum DSM
GRU	1	1	1	1
Total Grid[1]	150.07	150.12	150.10	150.10

[1]Florida plus Southern Company region.

Local GRU CO_2 emissions rise in the CFB and IGCC options as the units come on-line. They fall as the plants shift to biomass. Under the DSM options, emissions fall over time after 2009 (see Exhibit 8-35).

Exhibit 8-35
Local CO_2 Emissions – GRU – Average Across 36 Cases

Year	220 MW CFB	220 MW IGCC	75 MW Biomass Maximum DSM	Maximum DSM
2006	1,793,000	1,793,000	1,792,422	1,792,422
2007	1,806,775	1,806,775	1,805,617	1,805,617
2008	1,820,550	1,820,550	1,818,811	1,818,811
2009	1,826,833	1,826,811	1,824,117	1,824,186
2010	1,766,128	1,766,139	1,765,039	1,763,967
2011	2,802,456	2,599,214	1,475,008	1,497,850
2012	2,773,778	2,592,107	1,480,671	1,508,631
2013	2,745,100	2,585,000	1,486,333	1,519,411
2014	2,679,069	2,537,625	1,474,092	1,513,925
2015	2,613,039	2,490,250	1,461,850	1,508,439
2016	2,532,575	2,413,101	1,415,999	1,465,598
2017	2,456,111	2,340,650	1,372,966	1,424,648
2018	2,383,353	2,272,474	1,332,476	1,385,464
2019	2,314,031	2,208,198	1,294,288	1,347,932
2020	2,247,906	2,147,486	1,258,189	1,311,947
2021	2,169,754	2,094,255	1,247,045	1,310,110
2022	2,098,139	2,044,742	1,236,631	1,308,701
2023	2,032,370	1,998,593	1,226,902	1,307,717
2024	1,971,833	1,955,492	1,217,819	1,307,154
2025	1,915,986	1,915,156	1,209,342	1,307,008
TOTAL	44,748,785	43,207,616	29,195,616	30,029,537
Average	2,237,439	2,160,381	1,459,781	1,501,477

Most SO_2 emissions are in the first four years before the retrofit of Deerhaven 2 (see Exhibit 8-36). SO_2 levels are well below 2006-2009 levels in all scenarios. They rise after the IGCC and CFB plants come on-line, and then fall as biomass displaces coal and petroleum coke. Local SO_2 emissions are the lowest for Maximum DSM. Under the Biomass Maximum DSM, we show emissions assuming that the CFB does not control for biomass related SO_2 though such controls could be implemented without materially greater capital expenditures.

Exhibit 8-36
Local SO_2 Emissions – GRU – Average Across 36 Cases

Year	220 MW CFB	220 MW IGCC	75 MW Biomass Maximum DSM	Maximum DSM
2006	6,958	6,958	6,957	6,957
2007	6,938	6,938	6,936	6,936
2008	6,919	6,919	6,915	6,915
2009	6,922	6,922	6,916	6,916
2010	952	952	952	952
2011	1,606	1,489	1,096	847
2012	1,588	1,484	1,101	849
2013	1,571	1,478	1,105	851
2014	1,531	1,449	1,095	842
2015	1,491	1,420	1,084	833
2016	1,443	1,374	1,055	805
2017	1,398	1,331	1,027	779
2018	1,355	1,291	1,000	754
2019	1,314	1,253	975	730
2020	1,275	1,217	950	708
2021	1,226	1,182	941	702
2022	1,181	1,149	932	696
2023	1,139	1,119	924	691
2024	1,101	1,091	916	686
2025	1,066	1,065	908	681
TOTAL	48,974	48,080	43,787	40,132
Average	2,449	2,404	2,189	2,007

Local NO_x emissions fall when Deerhaven 2 is retrofit with NO_x controls and stay below these levels throughout the horizon (see Exhibit 8-37).

Exhibit 8-37
Local NO_x Emissions – GRU – Average Across 36 Cases

Year	220 MW CFB	220 MW IGCC	75 MW Biomass Maximum DSM	Maximum DSM
2006	4,007	4,007	4,007	4,007
2007	4,000	4,000	3,999	3,999
2008	3,993	3,993	3,991	3,991
2009	3,999	3,999	3,995	3,995
2010	1,220	1,220	1,220	1,219
2011	1,510	1,138	1,120	1,068
2012	1,516	1,144	1,123	1,074
2013	1,522	1,151	1,126	1,079
2014	1,506	1,135	1,115	1,071
2015	1,490	1,120	1,103	1,063
2016	1,455	1,088	1,069	1,032
2017	1,422	1,058	1,037	1,001
2018	1,390	1,029	1,007	972
2019	1,360	1,002	979	945
2020	1,330	977	952	919
2021	1,319	968	942	915
2022	1,308	959	934	911
2023	1,298	951	925	908
2024	1,288	943	917	905
2025	1,278	936	910	902
TOTAL	38,212	32,818	32,471	31,979
Average	1,911	1,641	1,624	1,599

Local mercury emissions are below current levels after Deerhaven is retrofit (see Exhibit 8-38).

Exhibit 8-38
Local Hg Emissions – GRU – Average Across 36 Cases

Year	220 MW CFB	220 MW IGCC	75 MW Biomass Maximum DSM	Maximum DSM
2006	0.07	0.07	0.07	0.07
2007	0.07	0.07	0.07	0.07
2008	0.07	0.07	0.07	0.07
2009	0.07	0.07	0.07	0.07
2010	0.07	0.07	0.07	0.07
2011	0.06	0.06	0.06	0.06
2012	0.06	0.06	0.06	0.06
2013	0.06	0.06	0.06	0.06
2014	0.06	0.06	0.06	0.06
2015	0.06	0.06	0.06	0.06
2016	0.06	0.06	0.06	0.06
2017	0.05	0.06	0.05	0.05
2018	0.05	0.06	0.05	0.05
2019	0.05	0.05	0.05	0.05
2020	0.05	0.05	0.05	0.05
2021	0.05	0.05	0.05	0.05
2022	0.05	0.05	0.05	0.05
2023	0.05	0.05	0.05	0.05
2024	0.05	0.05	0.05	0.05
2025	0.05	0.05	0.05	0.05
TOTAL	1.15	1.20	1.14	1.14
Average	0.06	0.06	0.06	0.06

WHOLESALE MARKET PRICES

Base Case all hours electrical energy prices equal system lambda. They are slightly lower for the CFB and IGCC cases as there is more local low variable cost supply (see Exhibit 8-39 and 8-40).

Exhibit 8-39
All-Hours Energy Price Forecast (2003$/MWh) – Base Case

Year	CFB	IGCC	Biomass Maximum DSM	Max DSM
2006	71.5	71.5	71.5	71.5
2007	68.3	68.3	68.1	68.1
2008	65.1	65.1	64.8	64.8
2009	62.2	62.2	61.8	61.8
2010	57.7	57.7	57.7	57.7
2011	42.8	42.6	46.3	47.7
2012	44.1	44.0	47.8	49.2
2013	45.5	45.4	49.2	50.7
2014	46.1	46.1	49.8	51.5
2015	46.8	46.8	50.5	52.3
2016	47.7	47.6	51.1	52.7
2017	48.6	48.5	51.7	53.1
2018	49.5	49.4	52.4	53.5
2019	50.5	50.3	53.0	53.9
2020	51.4	51.3	53.7	54.3
2021	52.8	52.6	54.8	55.3
2022	54.1	54.0	55.9	56.3
2023	55.5	55.4	57.0	57.3
2024	56.9	56.9	58.1	58.3
2025	58.4	58.4	59.3	59.4
Average	53.8	53.7	55.7	56.5

Exhibit 8-40
All-Hours Energy Price Forecast (Nominal$/MWh) – Base Case

Year	CFB	IGCC	Biomass Maximum DSM	Max DSM
2006	76.8	76.8	76.8	76.8
2007	75.0	75.0	74.8	74.8
2008	73.0	73.0	72.6	72.6
2009	71.3	71.3	70.9	70.9
2010	67.7	67.7	67.7	67.7
2011	51.3	51.1	55.6	57.3
2012	54.1	54.0	58.6	60.4
2013	57.0	57.0	61.7	63.6
2014	59.1	59.1	63.9	66.0
2015	61.3	61.3	66.1	68.6
2016	63.9	63.8	68.5	70.6
2017	66.6	66.5	70.9	72.8
2018	69.4	69.2	73.4	75.0
2019	72.3	72.1	76.0	77.2
2020	75.4	75.1	78.7	79.6
2021	79.0	78.8	82.0	82.8
2022	82.9	82.7	85.6	86.2
2023	86.9	86.8	89.2	89.7
2024	91.2	91.1	93.0	93.4
2025	95.6	95.6	97.0	97.2
Average	71.5	71.4	74.1	75.2

Under the CFB and IGCC options, local pure capacity prices are zero due to GRU exceeding reserve requirements through to 2021 (see Exhibits 8-41 and 8-42). Capacity prices are the add-on to prices needed to provide revenues for new peaking units. These prices are especially low due to GRU's low financing costs. Prices are positive starting in 2012 in the Maximum DSM as additional capacity is needed to meet peaking needs. Prices are being set initially by import prices which are depressed as many utilities build new coal plant capacity and exceed reserve requirements. This, in turn, reflects high natural gas prices.

Exhibit 8-41
Annual Capacity Price Forecast (2003$/kW-yr) – Base Case

Year	CFB	IGCC	Biomass Maximum DSM	Max DSM
2006	0	0	0	0
2007	0	0	0	0
2008	0	0	0	0
2009	0	0	0	0
2010	0	0	0	0
2011	0	0	0	0
2012	0	0	0	9
2013	0	0	0	19
2014	0	0	0	20
2015	0	0	0	21
2016	0	0	0	21
2017	0	0	0	21
2018	0	0	0	21
2019	0	0	0	21
2020	0	0	21	21
2021	0	0	22	22
2022	0	0	23	23
2023	0	0	23	23
2024	0	0	24	24
2025	25	25	25	25
Average	1	1	7	15

Exhibit 8-42
Annual Capacity Price Forecast (Nominal$/kW-yr) – Base Case

Year	CFB	IGCC	Biomass Maximum DSM	Max DSM
2006	0	0	0	0
2007	0	0	0	0
2008	0	0	0	0
2009	0	0	0	0
2010	0	0	0	0
2011	0	0	0	0
2012	0	0	0	11
2013	0	0	0	23
2014	0	0	0	25
2015	0	0	0	27
2016	0	0	0	28
2017	0	0	0	29
2018	0	0	0	30
2019	0	0	0	30
2020	0	0	31	31
2021	0	0	33	33
2022	0	0	35	35
2023	0	0	36	36
2024	0	0	38	38
2025	40	40	40	40
Average	2	2	11	21

All hours firm prices are the sum of the capacity price and energy price where capacity price is amortized over the hours of the year (see Exhibit 8-43 and 8-44).

Exhibit 8-43
All-Hours Firm Power Price Forecast (2003$/MWh) – Base Case

Year	CFB	IGCC	Biomass Maximum DSM	Max DSM
2006	71.5	71.5	71.5	71.5
2007	68.3	68.3	68.1	68.1
2008	65.1	65.1	64.8	64.8
2009	62.2	62.2	61.8	61.8
2010	57.7	57.7	57.7	57.7
2011	42.8	42.6	46.3	47.7
2012	44.1	44.0	47.8	50.3
2013	45.5	45.4	49.2	52.8
2014	46.1	46.1	49.8	53.8
2015	46.8	46.8	50.5	54.7
2016	47.7	47.6	51.1	55.1
2017	48.6	48.5	51.7	55.5
2018	49.5	49.4	52.4	55.9
2019	50.5	50.3	53.0	56.3
2020	51.4	51.3	56.1	56.7
2021	52.8	52.6	57.3	57.8
2022	54.1	54.0	58.4	58.9
2023	55.5	55.4	59.6	60.0
2024	56.9	56.9	60.8	61.1
2025	61.2	61.2	62.1	62.2
Average	53.9	53.9	56.5	58.1

Exhibit 8-44
All-Hours Firm Power Price Forecast (Nominal$/MWh) – Base Case

Year	CFB	IGCC	Biomass Maximum DSM	Max DSM
2006	76.8	76.8	76.8	76.8
2007	75.0	75.0	74.8	74.8
2008	73.0	73.0	72.6	72.6
2009	71.3	71.3	70.9	70.9
2010	67.7	67.7	67.7	67.7
2011	51.3	51.1	55.6	57.3
2012	54.1	54.0	58.6	61.7
2013	57.0	57.0	61.7	66.2
2014	59.1	59.1	63.9	68.9
2015	61.3	61.3	66.1	71.7
2016	63.9	63.8	68.5	73.9
2017	66.6	66.5	70.9	76.1
2018	69.4	69.2	73.4	78.4
2019	72.3	72.1	76.0	80.7
2020	75.4	75.1	82.2	83.1
2021	79.0	78.8	85.8	86.6
2022	82.9	82.7	89.5	90.2
2023	86.9	86.8	93.4	93.9
2024	91.2	91.1	97.4	97.8
2025	100.2	100.2	101.6	101.9
Average	71.7	71.6	75.4	77.5

ATTACHMENTS

ATTACHMENT 1
OVERVIEW ISSUES

Exhibit A1-1
Historical Spot Power Prices in FRCC

Period	On-Peak[1] ($/MWh)	Off-Peak ($/MWh)	All-Hours ($/MWh)
2002	40.2	21.9	30.5
2003	52.0	22.7	36.5
2004	58.1	29.4	42.9
2005	85.0	44.3	63.4

Source: Power Market's Week.
[1]On-peak defined as 7:00 AM to 11:00 PM, Monday through Friday.

Exhibit A1-2
Historical Implied Heat Rates in FRCC

Period	On-Peak[1] (Btu/kWh)	Off-Peak (Btu/kWh)	All-Hours (Btu/kWh)
2002	10,632	5,800	8,071
2003	9,115	3,975	6,391
2004	9,359	4,739	6,910
2005	10,085	5,258	7,527

Source: Power Market's Week (Florida Spot power prices) and Gas Daily (Delivered to Florida City Gate).
[1]On-peak defined as 7:00 AM to 11:00 PM, Monday through Friday.

Exhibit A1-3
Key FRCC Capacity Assumptions Overview

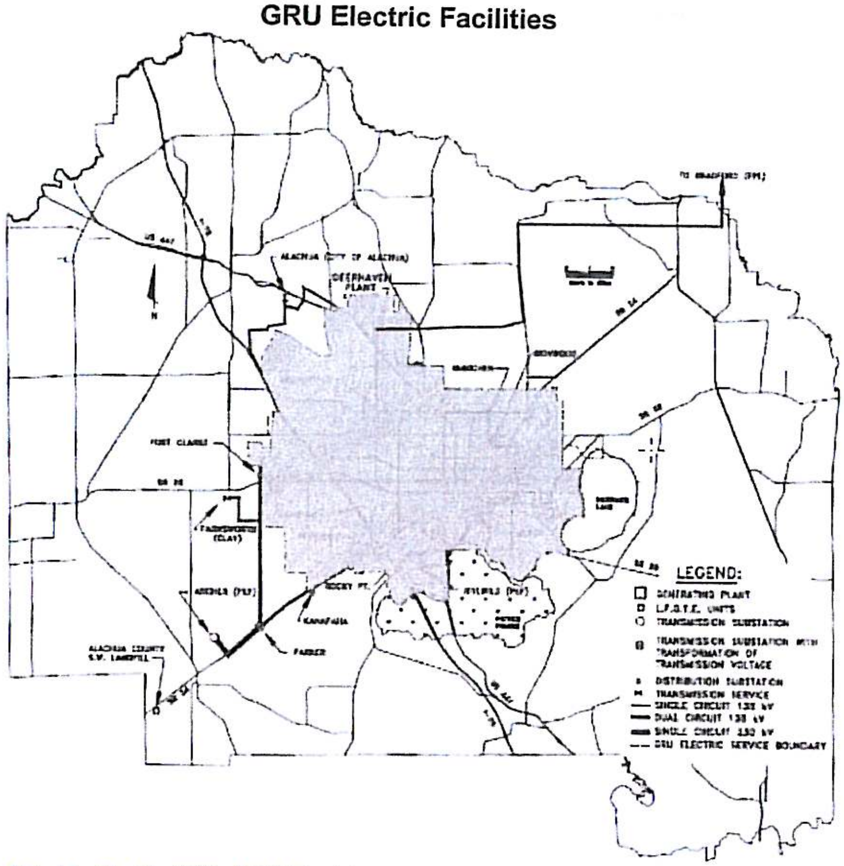
Parameter	FRCC
Recently Operational Builds 2000-2005 (MW)	18,237
Total Capacity as of July 2005 (MW)	52,452
ICF Firmly Planned Builds (MW) 2006-2007	0
New Builds	Firm builds plus non-firm builds as necessary to meet net peak demand and reserve requirements; mix of unplanned builds endogenously determined based on economics

[1] Source: ICF. Subject to review.

FRCC Geographic Scope

- FRCC encompasses Peninsular Florida, east of the Apalachicola River. It is electrically unique because it is a peninsula and is tied to the Eastern Interconnection only on one side. The FRCC is responsible for setting the reliability standards, procedures, and policies that all users of the transmission system must follow when operating in the region.
- The 29 FRCC members comprise six industry sectors: power marketers, generators, non-investor-owned utilities-wholesale, load-serving entities, generating load-serving entities, and investor-owned utilities.

Exhibit A1-4
GRU Electric Facilities



Source: A Review of Florida Electric Utility 2005 Ten-Year Site Plans, prepared by the Florida Public Service Commission, Division of Economic Regulation, December 2005

GRU Generation Assets

- GRU is the City of Gainesville enterprise arm that has the responsibility to operate and maintain the vertically integrated electric power system.
- Gainesville Regional Utilities (GRU) owns and operates two power plants, the John R. Kelly Generating Station located in downtown Gainesville, and the Deerhaven Generating Station located near the city of Alachua.
- Additionally, a 1.4 % ownership in Florida Power Corporation's Crystal River Unit 3 operated by Progress Energy Florida (PEF) and two internal combustion engines located at Alachua County Southwest Landfill of 1.3 MW provide generating capacity to the GRU system. The landfill is owned by Alachua County.
- An inter-local agreement between the City of Gainesville and Alachua County approved the concept of using landfill gas to power tow internal combustion engine generators. The County granted a special use permit and easement for GRU to operate and access the generators.

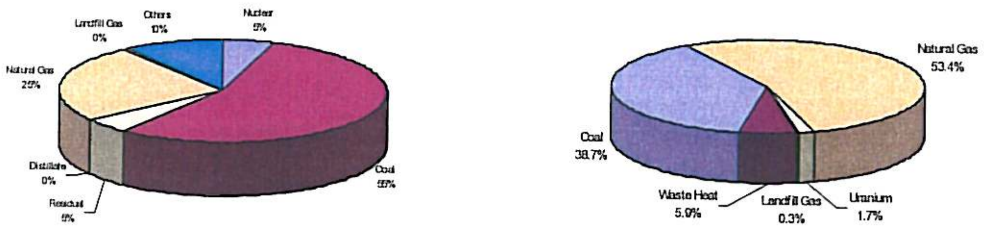
Source: A Review of Florida Electric Utility 2005 Ten-Year Site Plans, prepared by the Florida Public Service Commission, Division of
Economic Regulation, December 2005

Transmission Network

- GRU's bulk power transmission network consists of a 138 kV loop connecting the following:
  - GRU's 2 generating stations
  - GRU's 9 distribution substations
  - 3 interties with Progress Energy Florida (PEF)
  - An intertie with Florida Power and Light Company (FPL)
  - An interconnection with Clay at Farnsworth Substation, and
  - An interconnection with the City of Alachua at Alachua No.1 Substation
- State Interconnections – The system is currently interconnected with PEF and FPL at four separate points. These include:
  - A 230 kV transmission line interconnection between PEF's Archer Substation and GRU's Parker Substation with 224 MVA of transformation capacity from 230 kV to 138 kV
  - PEF's Idylwild Substation with 2 separate circuits via a 168 MVA 138/69 kV transformer at the Idylwild Substation
  - A 138 kV tie between FPL's Bradford Substation and the System's Deerhaven Substation with a thermal capacity of 224 MVA

Source: A Review of Florida Electric Utility 2005 Ten-Year Site Plans, prepared by the Florida Public Service Commission, Division of Economic Regulation, December 2005, pages 5,6,7

Exhibit A1-5
Generation & Capacity Mix: 2004



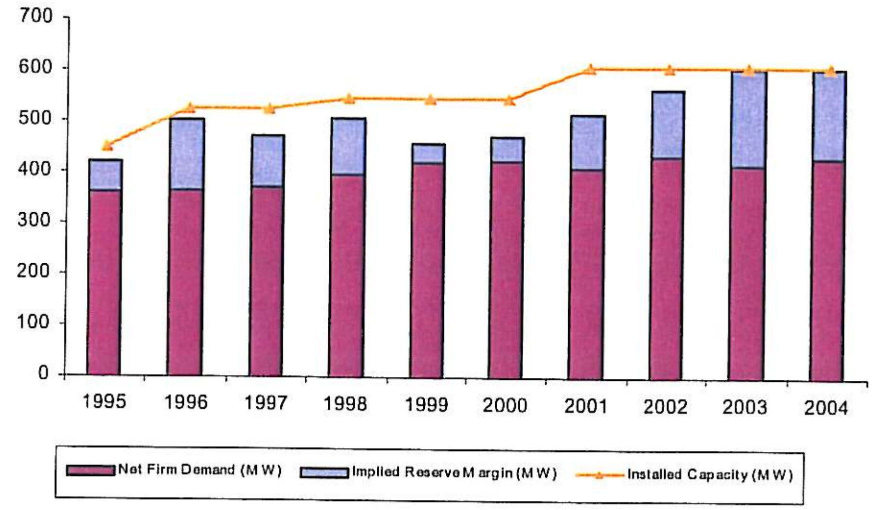
Net Energy for load includes utility use & losses

Others = Purchase energy - Starke Contract - Energy Sales

Distillate & Residual are alternate fuel (page 11)

Source: A Review of Florida Electric Utility 2005 Ten-Year Site Plans, prepared by the Florida Public Service Commission, Division of Economic Regulation, December 2005, pages 11, 42

Exhibit A1-6
Capacity & Demand (MW)



Source: A Review of Florida Electric Utility 2005 Ten-Year Site Plans, prepared by the Florida Public Service Commission, Division of Economic Regulation, December 2005, pages 37, 52

FRCC Planning Reserve Margins

- FRCC has historically required an unenforceable 15 percent installed reserve margin guideline for the FRCC system as a whole.
- In line with the above, GRU uses a planning criteria of 15% capacity reserve margin.
- Investor Owned Utilities in the region are further required to maintain an installed capacity reserve of 20 percent as based on a standing agreement with the Florida Public Services Commission.

Source: A Review of Florida Electric Utility 2005 Ten-Year Site Plans, prepared by the Florida Public Service Commission, Division of
Economic Regulation, December 2005, page 49

Exhibit A1-7
Overview of FRCC Demand and Capacity Related Assumptions

Annual Average Peak Growth (%) (2004-2014)	Treatment – Base Case	
	FRCC	GRU
2005 Net Internal Peak Demand[1] (MW)	43495	458
Annual Average Peak Growth (%) (2004-2014)	2.52%[2]	2.37%[3]
2005 Net Energy for Load[1] (GWh)	227,871	2122
Annual Average Energy Growth (%) (2004-2014)	2.46%[2]	2.40%[3]
Target Reserve Margin (%)	15% - 20%	15%
New Builds	Firm builds plus unplanned builds as necessary to meet net peak demand and reliability/reserve requirements; mix of unplanned builds endogenously determined based on economics	
Firm Builds (MW)		
In Operation 2000-2005	17034	110
Under Construction		0
2006	809	0
2007	1957	0
2008	1075	0
2009	2714	0
2010	1246	0
2011	1987	0
2012	2390	220
Total 2000-12	29212	330

1) FRCC 2005 starting point taken from NERC ES&D and GRU 2005 starting point taken from A Review of Florida Electric Utility 2005 Ten-Year Site Plans, prepared by the Florida Public Service Commission, Division of Economic Regulation, December 2005

2) FRCC annual average growth rate from 2004 Regional Load & Resource Plan for 2004-2013.

3) GRU annual average growth rate from A Review of Florida Electric Utility 2005 Ten-Year Site Plans, prepared by the Florida Public Service Commission, Division of Economic Regulation, December 2005 for 2005-2014.

Exhibit A1-8
Key Reserve Margin Assumptions Overview

Parameter	Treatment	
	FRCC	GRU
Planning Reserve Margin (%)	Varies between 15% and 20%	15%

Key Reserve Margin Assumptions Overview

- FRCC has historically required an unenforceable 15 percent installed reserve margin guideline for the FRCC system as a whole. GRU also uses a planning criteria of 15% capacity reserve margin.
- Investor Owned Utilities in the region are further required to maintain an installed capacity reserve of 20 percent as based on a standing agreement with the Florida Public Services Commission.
- Going forward, ICF projects a 23 percent planning reserve margin in the near-term and gradually declining to 18 percent by 2014.

Note: Interruptible load is accounted in the Reserve Margin calculation.

Key Transmission Assumptions

- Power will flow on an economic basis subject to transmission limits, as specified by the total transfer capability, and subject to transmission costs and losses. We assume no charges for moving power within FRCC and an approximately $2.50/MWh transmission charge to move power to and from neighboring regions, e.g., Southern. Regions without an ISO / RTO structure and associated "pancaking" may have higher near-term charges for movements to neighboring areas.

- The transmission capacities specified above reflect both simultaneous and non-simultaneous total transfer capabilities (TTC). TTC's represent non-firm transmission capacity used in our modeling to capture energy transfers and are typically higher than the First Contingency Transfer Capabilities (FCTTC) used to model capacity transfers, which capture an "N-0" contingency level.

- Simultaneous (joint) import or export transfers are usually lower than the sum of non-simultaneous transfers. Simultaneous transfer limitations are captured in our modeling by using joint interface capacities for all interconnecting paths to a region and reflects "N-1" contingency levels.

Exhibit A1-9
Control Area Resources Modeled

Area Name	Generation (MW)	Load (MW)
Progress Energy Florida	12,113	10,433
Florida Power & Light	22,719	19,749
Gainesville Regional Utilities	579	458
Jacksonville Electric	3,877	2,572
Lakeland	1,087	666
Orlando Utilities Commission	2,433	1,130
Seminole Electric Cooperative	2,045	408
Tallahassee	670	550
Tampa Electric Company	4,786	4,569

1) ICF relies on various sources to account for the generation capacities in the sub-regions including EIA-860, NERC ES&D, Energy Velocity, SNL and press releases.
2) Load values are derived from NERC ES&D 2005, and allocated according to sub-regional weightings. GRU demand from A Review of Florida Electric Utility 2005 Ten-Year Site Plans, prepared by the Florida Public Service Commission, Division of Economic Regulation, December 2005

Exhibit A1-10
Summer Power Flow Limits

SUMMER POWER FLOW LIMITS

Transmission Line Number	Description	Normal 100° C (MVA)	Limiting Device	8-Hour Emergency 125° C (MVA)	Limiting Device
1	McMichen - Depot East	236.2	Conductor	282.0	Conductor
2	Millhopper - Depot West	236.2	Conductor	282.0	Conductor
3	Deerhaven - McMichen	236.2	Conductor	282.0	Conductor
6	Deerhaven - Millhopper	236.2	Conductor	282.0	Conductor
7	Depot East - Idylwild	191.2 [1]	Line Trap	191.2 [1]	Line Trap
8	Depot West - Serenola	236.2	Conductor	282.0	Conductor
9	Idylwild - Parker	191.2 [1]	Line Trap	191.2 [1]	Line Trap
10	Serenola - Sugarfoot	236.2	Conductor	282.0	Conductor
11	Parker - Clay Tap	236.2	Conductor	282.0	Conductor
12	Parker - Ft. Clarke	236.2	Conductor	282.0	Conductor
13	Clay Tap - Ft. Clarke	236.2	Conductor	282.0	Conductor
14	Ft. Clarke - Alachua	299.7	Conductor	356.0	Conductor
15	Deerhaven - Bradford	224.0	Transformer	224.0	Transformer
16	Sugarfoot - Parker	236.2	Conductor	282.0	Conductor
20	Parker - Archer	224.0	Transformer	224.0	Transformer
22	Alachua - Deerhaven	299.7	Conductor	356.0	Conductor
xx	Clay Tap - Farnsworth	236.2	Conductor	282.0	Conductor
xx	Idylwild - FPC	168.0	Transformer	168.0	Transformer

[1] –Rating effective through Spring, 2005 (estimate). At this point in time, the 800 ampere wave traps on the Depot E – Idylwild 138 KV and Parker – Idylwild 138 KV circuit at Idylwild will be removed. Thereafter, the normal and emergency rating will be 236.2 MVA and 282.0 MVA, respectively.

Assumptions:

100 °C for normal conductor operation
125 °C for emergency 8 hour conductor operation
40 °C ambient air temperature
2 ft/sec wind speed
T-75 & T-76 are based on a 65 °C oil temperature rise

Exhibit A1-11
Schedule 1 – Existing Generating Facilities

Schedule 1
EXISTING GENERATING FACILITIES

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Primary Fuel Type	(6) Primary Fuel Trans.	(7) Alternate Fuel Type	(8) Alternate Fuel Trans.	(9) Alt. Fuel Storage (Days)	(10) Commercial In-Service Month/Year	(11) Expected Retirement Month/Year	(12) Gross Capability Summer MW	(13) Gross Capability Winter MW	(14) Net Capability Summer MW	(15) Net Capability Winter MW	(16) Status
J. R. Kelly		Alachua County Section 4									150	139	177	166	
	FS08	Township 10 S	CA	WH	PL				[4/65 5/01]	2051	38	32	37	37	OP
	FS07	Range 20 E	ST	NG	PL	RFO	TK		5/61	5/11	24	24	23	23	OP
	GT04	(GRU)	CT	NG	PL	DFO	TK		5/01	2051	76	82	75	81	OP
	GT03		GT	NG	PL	DFO	TK		5/69	2019	14	15	14	15	OP
	GT02		GT	NG	PL	DFO	TK		2/69	2016	14	15	14	15	OP
	GT01		GT	NG	PL	DFO	TK		2/68	2015	14	15	14	15	OP
Deerhaven		Alachua County Sections 26,27,35									451	461	422	432	
	FS02	Township 8 S	ST	BIT	RR				10/81	2031	240	249	225	228	OP
	FS01	Range 19 E	ST	NG	PL	RFO	TK		8/72	2023	88	88	83	83	OP
	GT03	(GRU)	GT	NG	PL	DFO	TK		1/96	2046	76	82	75	81	OP
	GT02		GT	NG	PL	DFO	TK		5/76	2026	19	21	18	20	OP
	GT01		GT	NG	PL	DFO	TK		7/76	2026	19	21	18	20	OP
Crystal River ([illegible])	3	Citrus County Section 33 Township 17 S Range 16 E (FPC)	ST	NUC	TK				3/77	2037	11	11	11	11	OP
SW Landfill		Alachua County Section 19									1.64	1.64	1.3	1.3	
	SW-1	Township 11 S	IC	LFG	PL				12/03	12/09	0.82	0.82	0.65	0.65	OP
	SW-2	Range 19 E	IC	LFG	PL				12/03	12/15	0.82	0.82	0.65	0.65	OP
System Total													611	630	

Unit Type
CA = Combined Cycle Steam Part
CT = Combined Cycle Combustion Turbine Part
GT = Gas Turbine
ST = Steam Turbine
IC = Internal Combustion (diesel piston) Engine

Fuel Type
NG = Natural Gas
BIT = Bituminous Coal
NUC = Uranium
RFO = Residual Fuel Oil
DFO = Distillate Fuel Oil
WH = Waste Heat
LFG = Landfill Gas

Transportation Method
PL = Pipe Line
RR = Railroad
TK = Truck

Status
OP = Operational

ATTACHMENT 2
DEMAND

Exhibit A2-1
Schedule 2.1 – History and Forecast of Energy Consumption and Number of Customers by Customer Class

Schedule 2.1
History and Forecast of Energy Consumption and Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			RESIDENTIAL			COMMERCIAL *		
Year	Service Area Population	Persons per Household	GWh	Average Number of Customers	Average kWh per Customer	GWh	Average Number of Customers	Average kWh per Customer
1995	147,248	2.37	704	62,130	11,329	590	7,305	80,767
1996	150,322	2.37	718	63,427	11,313	594	7,539	78,813
1997	153,759	2.36	705	65,152	10,817	598	7,750	77,193
1998	156,707	2.35	777	66,722	11,649	640	7,868	81,363
1999	161,076	2.35	763	68,543	11,137	648	8,095	80,036
2000	164,584	2.34	788	70,335	11,202	674	8,368	80,490
2001	168,395	2.34	803	72,391	11,092	697	8,603	80,986
2002	172,755	2.34	851	73,827	11,527	721	8,776	82,112
2003	174,227	2.34	854	74,456	11,467	726	8,959	81,090
2004	179,459	2.33	878	77,021	11,398	739	9,225	80,143
2005	183,126	2.33	884	78,676	11,236	762	9,462	80,534
2006	186,685	2.33	907	80,288	11,297	784	9,693	80,887
2007	190,237	2.32	931	81,900	11,368	808	9,923	81,424
2008	193,683	2.32	956	83,470	11,453	831	10,148	81,888
2009	197,122	2.32	982	85,039	11,548	854	10,373	82,331
2010	200,455	2.32	1,007	86,567	11,633	877	10,591	82,803
2011	203,781	2.31	1,030	88,094	11,692	899	10,810	83,164
2012	207,002	2.31	1,053	89,579	11,755	921	11,023	83,556
2013	210,216	2.31	1,077	91,064	11,827	943	11,235	83,934
2014	213,325	2.31	1,102	92,506	11,913	966	11,442	84,429

* Commercial includes General Service Non-Demand and General Service Demand Rate Classes

Exhibit A2-2
Schedule 2.2 - History and Forecast of Energy Consumption and Number of Customers by Customer Class

Schedule 2.2
History and Forecast of Energy Consumption and Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	INDUSTRIAL **						
Year	GWh	Average Number of Customers	Average MWh per Customer	Railroads and Railways GWh	Street and Highway Lighting GWh	Other Sales to Public Authorities GWh	Total Sales to Ultimate Consumers GWh
1995	137	13	10,521	0	19	0	1,449
1996	148	15	9,893	0	19	0	1,479
1997	151	15	10,059	0	21	0	1,475
1998	157	15	10,443	0	21	0	1,595
1999	173	17	10,186	0	22	0	1,606
2000	172	17	10,114	0	22	0	1,656
2001	173	17	10,182	0	23	0	1,696
2002	178	18	10,175	0	24	0	1,774
2003	181	19	9,581	0	24	0	1,786
2004	189	18	10,444	0	25	0	1,830
2005	191	18	10,437	0	26	0	1,883
2006	191	18	10,437	0	26	0	1,909
2007	192	18	10,492	0	27	0	1,956
2008	192	18	10,492	0	29	0	2,006

Schedule 3.1
History and Forecast of Summer Peak Demand - MW
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Comm./Ind Load Management	Comm./Ind. Conservation	Net Firm Demand
1995	377	24	337	0	0	9	0	7	361
1996	360	24	341	0	0	6	0	7	365
1997	369	24	349	0	0	6	0	7	373
1998	411	28	370	0	0	6	0	7	396
1999	434	25	393	0	0	6	0	7	419
2000	440	26	397	0	0	6	0	7	425
2001	423	26	381	0	0	7	0	7	409
2002	448	32	401	0	0	7	0	7	433
2003	429	33	384	0	0	6	0	8	417
2004	444	33	398	0	0	6	0	8	432
2005	469	35	423	0	0	6	0	5	456
2006	461	36	434	0	0	6	0	5	470
2007	493	36	445	0	0	6	0	4	493
2008	504	39	456	0	0	6	0	3	495
2009	517	40	469	0	0	6	0	3	508
2010	529	41	478	0	0	6	0	2	520
2011	540	42	493	0	0	6	0	2	532
2012	552	44	500	0	0	6	0	2	544
2013	566	45	511	0	0	7	0	3	556
2014	579	48	523	0	0	7	0	2	569

Exhibit A2-4
Schedule 3.2 – History and Forecast of Winter Peak Demand – MW – Base Case

Schedule 3.2
History and Forecast of Winter Peak Demand - MW
Base Case

(1) Winter	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
1995 / 1996	381	29	317	0	0	29	0	7	345
1996 / 1997	343	26	280	0	0	30	0	7	306
1997 / 1998	319	23	259	0	0	30	0	7	282
1998 / 1999	389	28	323	0	0	31	0	7	351
1999 / 2000	373	27	310	0	0	29	0	7	337
2000 / 2001	398	33	331	0	0	28	0	6	364
2001 / 2002	402	33	336	0	0	27	0	6	369
2002 / 2003	425	37	357	0	0	26	0	5	394
2003 / 2004	380	31	319	0	0	25	0	5	350
2004 / 2005	404	36	341	0	0	24	0	4	377
2005 / 2006	415	37	353	0	0	22	0	3	390
2006 / 2007	424	39	363	0	0	20	0	2	402
2007 / 2008	434	40	374	0	0	18	0	2	414
2008 / 2009	444	41	386	0	0	16	0	1	427
2009 / 2010	454	42	397	0	0	14	0	1	439
2010 / 2011	464	44	405	0	0	14	0	1	449
2011 / 2012	474	45	413	0	0	15	0	1	458
2012 / 2013	484	46	422	0	0	15	0	1	468
2013 / 2014	494	47	430	0	0	16	0	1	477
2014 / 2015	505	48	439	0	0	17	0	1	487

Schedule 3.3 – History and Forecast of Net Energy for Load – GWh – Base Case

Schedule 3.3
History and Forecast of Net Energy for Load - GWH
Base Case

(1) Year	(2) Total	(3) Residential Conservation	(4) Comm./Ind. Conservation	(5) Retail	(6) Wholesale	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load Factor %
1995	1,711	43	20	1,448	101	97	1,646	52.10%
1996	1,721	42	21	1,479	105	75	1,659	51.99%
1997	1,728	44	21	1,475	104	62	1,681	50.94%
1998	1,947	47	21	1,598	105	78	1,779	51.25%
1999	1,969	50	21	1,608	109	63	1,783	46.87%
2000	1,939	50	21	1,658	120	93	1,885	50.19%
2001	1,953	50	20	1,698	125	62	1,892	52.54%
2002	2,079	52	19	1,774	142	92	2,005	52.95%
2003	2,066	53	15	1,738	146	53	2,015	55.15%
2004	2,119	53	15	1,830	149	70	2,049	54.14%
2005	2,190	53	15	1,862	155	104	2,122	52.89%
2006	2,243	52	14	1,910	160	107	2,177	52.96%
2007	2,298	51	12	1,957	166	110	2,233	52.75%
2008	2,350	49	10	2,007	171	113	2,291	52.93%
2009	2,408	46	9	2,058	176	115	2,349	52.79%
2010	2,462	47	9	2,107	192	118	2,407	52.94%
2011	2,519	50	9	2,152	197	121	2,460	52.79%
2012	2,574	52	9	2,199	192	123	2,514	52.75%
2013	2,632	54	9	2,247	197	125	2,570	52.77%
2014	2,691	56	9	2,296	202	129	2,627	52.70%

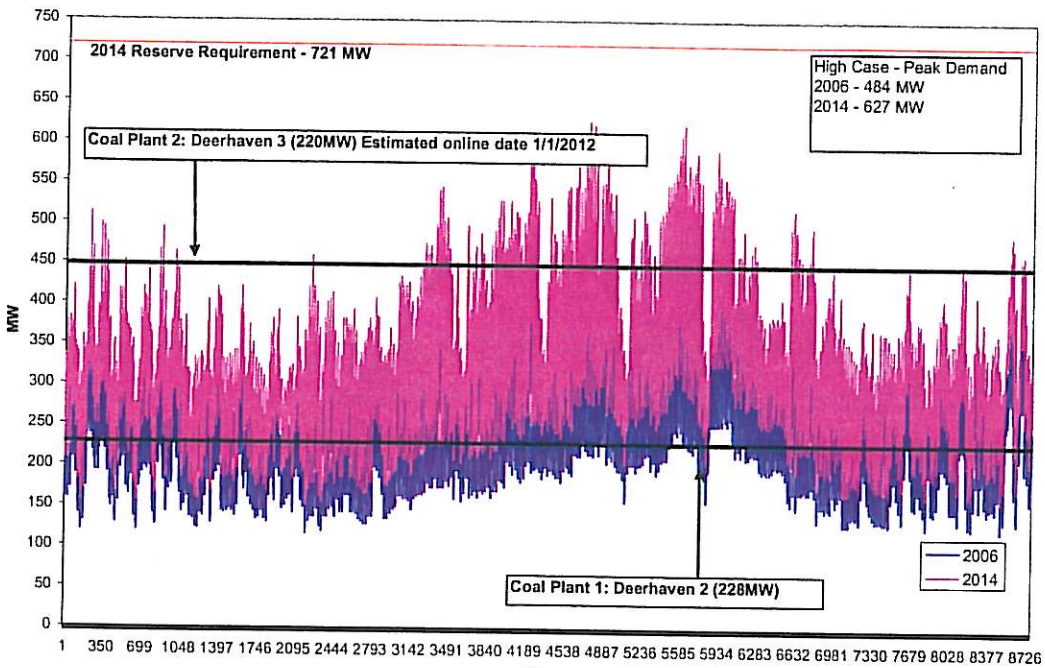
Exhibit A2-5
Schedule 7.1 – Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Summer Peak

Schedule 7.1
Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	System Firm Summer Peak Demand	Reserve Margin (1) before Maintenance		Scheduled Maintenance	Reserve Margin (1) after Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
1995	452	0	33	0	419	361	58	16.1%	0	58	16.1%
1996	527	16	43	0	502	365	137	37.5%	0	137	37.5%
1997	527	30	55	0	472	373	99	26.5%	0	99	26.5%
1998	550	21	73	0	505	393	112	28.5%	0	112	28.5%
1999	550	32	112	0	472	419	53	12.6%	14	39	9.3%
2000	550	0	78	0	472	425	47	11.1%	0	47	11.1%
2001	510	0	93	0	517	409	108	26.4%	0	108	26.4%
2002	510	0	43	0	567	433	134	30.9%	0	134	30.9%
2003	510	0	3	0	607	417	190	45.6%	0	190	45.6%
2004	511	0	3	0	608	432	176	40.7%	0	176	40.7%
2005	511	0	3	0	608	458	150	32.8%	0	150	32.8%
2006	511	0	3	0	608	470	138	29.4%	0	138	29.4%
2007	511	0	0	0	611	483	128	26.5%	0	128	26.5%
2008	511	0	0	0	611	495	116	23.5%	0	116	23.5%
2009	511	0	0	0	611	508	103	20.3%	0	103	20.3%
2010	598	0	0	0	595	520	75	15.0%	0	75	15.0%
2011	795	0	0	0	795	532	263	49.4%	0	263	49.4%
2012	795	0	0	0	795	544	251	46.1%	0	251	46.1%
2013	795	0	0	0	795	556	239	43.0%	0	239	43.0%
2014	795	0	0	0	795	569	226	39.7%	0	226	39.7%

(1) GRU provides reserve margin backup for 3 MW Schedule D contract with the City of Starke.

Exhibit A2-6
2006 and 2014 High Demand – Compared to Illustrative Supply Stack



Source: Hourly load curves adjusted from GRU's forecasted 2006 load shape.

ATTACHMENT 3
DSM

DSM Supporting Data

Exhibit A3-1. Residential Measures – Savings and Cost-effectiveness Characteristics (Direct Load Control Measures Considered Separately)

End Use	Measure Name	Life	kWh Savings	kW Savings	% kWh Savings	% kW Savings	Incremental Costs	TRC	RIM
Central A/C	Solar gain controls such as exterior shades	20	1,138	0.81	22.5%	19.6%	$72.21	24.86	1.42
Central A/C	Shade Screens	9	1,481	1.07	29.3%	26.0%	$189.00	11.06	2.14
Central A/C	Window Film	9	1,661	1.26	32.8%	30.7%	$372.00	6.55	2.23
Central A/C	Central A/C - various equipment retrofits (EER & tonnage)	15	509	0.36	8.6%	8.7%	$138.74	5.48	1.60
Central A/C	Air sealing (caulking, weatherstripping, hole sealing)	13	429	0.35	5.6%	8.4%	$178.20	3.87	1.89
Central A/C	Energy Star or better windows	25	4	0.00	24.7%	29.9%	$4.04	1.78	1.59
Central A/C	Two speed Central AC	15	1,488	1.21	29.4%	29.4%	$1,400.00	1.76	1.77
Central A/C	Landscape Shading	15	570	0.39	11.3%	9.4%	$681.00	1.22	1.56
Central A/C	Insulated metal or fiberglass doors	20	57	0.05	0.6%	1.3%	$95.00	1.15	1.74
Central A/C	Refrigerant charge testing and recharging	3	354	0.22	7.0%	5.3%	$100.00	0.61	0.65
Central A/C	Whole House Fan	15	596	0.00	11.8%	0.0%	$569.00	0.49	0.50
Central A/C	Duct Insulation	15	455	0.00	9.0%	0.0%	$456.00	0.47	0.50
Central A/C	Shell insulation upgrades	25	0	0.00	1.6%	2.4%	$0.24	0.36	1.12
Central A/C	Filter cleaning and/or replacement	5	126	0.05	2.5%	1.3%	$100.00	0.33	0.62
Central A/C	Duct Sealing	15	294	0.00	5.2%	0.0%	$630.00	0.22	0.50
Central A/C	Reflective Roof Coatings	3	319	0.11	6.3%	2.6%	$1,375.00	0.04	0.65
Central A/C	Solar control glazing	1	0	0.00	0.0%	0.0%	$0.00	0.00	0.00
Central A/C	Programmable Thermostat	11	291	-0.22	4.0%	-5.3%	$58.00	-3.51	0.00
Clothes Dryer	Energy Star or better clothes dryer (Elec)	18	75	0.01	9.8%	9.8%	$238.00	0.24	0.73
Clothes Washer	Energy Star Clothes Washers - All Electric	15	124	0.02	21.3%	21.3%	$50.00	1.65	0.71
Dishwasher	Energy Star Dishwasher - Electric DHW	13	175	0.02	26.0%	26.0%	$204.00	0.52	0.71
Freezer	Remove 2nd Freezer	13	1,662	0.30	100.0%	100.0%	$97.75	11.80	0.82
Freezer	Energy Star or better freezer	15	39	0.01	22.7%	22.7%	$133.75	0.21	0.78
Lighting	Compact fluorescent lamps (CFLs)	8	46	0.00	75.1%	75.1%	$5.24	3.55	0.68
Lighting	Outdoor Floodlight	16	1,189	0.00	20.0%	0.0%	$196.85	2.91	0.50
Lighting	Motion Detectors	13	78	0.00	95.0%	95.0%	$42.00	0.94	0.59
Refrigerator	Remove 2nd Refrigerator	15	1,946	0.31	100.0%	100.0%	$97.75	13.93	0.75
Refrigerator	Energy Star or better refrigerator	15	124	0.12	40.5%	40.5%	$133.75	1.73	2.00
Room A/C	Solar gain controls such as exterior shades	20	431	0.23	27.6%	21.4%	$72.21	7.95	1.20
Room A/C	Room A/C - various equipment retrofits (EER & tonnage)	15	234	0.16	15.0%	14.8%	$96.45	3.58	1.58
Room A/C	Air sealing (caulking, weatherstripping, hole sealing)	13	88	0.09	5.6%	8.4%	$178.20	0.97	2.30
Room A/C	Energy Star or better windows	25	2	0.00	32.2%	32.2%	$4.04	0.59	1.22
Room A/C	Ceiling Fan	9	100	0.07	6.5%	6.5%	$241.00	0.58	2.10
Room A/C	Insulated metal or fiberglass doors	20	25	0.02	0.0%	1.4%	$95.00	0.38	1.30
Room A/C	Refrigerant charge testing and recharging	3	109	0.06	7.0%	5.3%	$100.00	0.19	0.65
Room A/C	Attic, roof, wall, perimeter, knee wall, underfloor insulation	25	0	0.00	2.1%	2.4%	$0.24	0.17	0.71
Room A/C	Filter cleaning and/or replacement	5	39	0.01	2.5%	1.3%	$100.00	0.10	0.62
Room A/C	Solar control glazing	1	0	0.00	0.0%	0.0%	$0.00	0.00	0.00
Space Heat	Air sealing (caulking, weatherstripping, hole sealing)	13	429	0.35	14.7%	8.4%	$178.20	3.87	1.89
Space Heat	Insulated metal or fiberglass doors	20	25	0.05	2.6%	1.3%	$95.00	0.97	3.31
Space Heat	Shell insulation upgrades	25	0	0.00	10.4%	2.4%	$0.24	0.29	1.62
Space Heat	Attic Radiant Barriers	15	125	0.00	12.8%	10.5%	$641.00	0.09	0.50
Space Heat	Duct Insulation	15	88	0.00	9.0%	0.0%	$456.00	0.09	0.50
Space Heat	Furnace upgrades	20	121	0.00	12.4%	0.0%	$746.50	0.09	0.49
Space Heat	Energy Star or better windows	25	0	0.00	6.2%	29.9%	$4.04	0.03	0.48
Space Heat	Duct Sealing	15	33	0.00	3.3%	0.0%	$630.00	0.02	0.50
Space Heat	Programmable Thermostat	11	89	-0.22	9.1%	-5.3%	$58.00	-4.89	0.00
Space Heat	Air sealing (caulking, weatherstripping, hole sealing)	13	429	0.35	14.7%	8.4%	$178.20	3.87	1.89
Space Heat	Insulated metal or fiberglass doors	20	57	0.05	2.6%	1.3%	$95.00	1.15	1.74
Space Heat	Heat Pump - Maintenance	15	96	0.00	9.8%	9.8%	$80.00	0.56	0.50
Space Heat	Energy Star or better windows	25	4	0.00	6.2%	29.9%	$4.04	0.54	0.48
Space Heat	Energy Star or better heat pump upgrade	20	509	0.00	7.5%	8.7%	$531.80	0.52	0.49
Space Heat	Duct Insulation	15	455	0.00	0.0%	0.0%	$456.00	0.47	0.50
Space Heat	Duct Sealing	15	294	0.00	3.3%	0.0%	$630.00	0.22	0.50
Space Heat	Shell insulation upgrades (Wall and Slab, Elec)	25	0	0.00	10.4%	2.4%	$0.24	0.16	0.48
Space Heat	Two speed Heat Pump - Elec Resis Heater	15	303	0.00	31.1%	21.7%	$1,290.00	0.11	0.50
Space Heat	Two speed Heat Pump	15	292	0.00	29.9%	15.7%	$1,290.00	0.11	0.50
Space Heat	Attic Radiant Barriers (Elec)	15	125	0.00	12.8%	10.5%	$641.00	0.09	0.50
Space Heat	Ground Source Heat Pump	15	286	0.00	29.3%	29.0%	$2,749.00	0.05	0.50
Space Heat	Ground Source Heat Pump - Elec Resis Heater	15	286	0.00	29.3%	29.0%	$2,749.00	0.05	0.50
Space Heat	Heat Pump - Load Control	15	39	0.00	4.0%	34.7%	$842.69	0.02	0.50
Space Heat	Programmable Thermostat	11	291	-0.22	9.1%	-5.3%	$58.00	-3.51	-0.92
Water Heat	Pipe Wrap (Elec)	15	96	0.01	4.0%	4.0%	$2.70	21.83	0.66
Water Heat	Faucet Aerators (Elec)	10	73	0.01	3.0%	3.0%	$4.82	7.91	0.74
Water Heat	Water heat tank wraps and bottom boards (Elec)	10	251	0.02	10.0%	10.0%	$17.00	7.66	0.73
Water Heat	Low Flow Showerheads (Elec)	10	186	0.02	7.5%	7.5%	$20.00	4.84	0.73
Water Heat	Tank temperature setback (Elec)	5	268	0.01	5.5%	5.5%	$25.00	2.78	0.62
Water Heat	Vapor-compression cycle	15	463	0.00	4.8%	0.0%	$106.12	2.03	0.50
Water Heat	Heater efficiency upgrades (Elec)	15	128	0.02	9.9%	9.9%	$50.00	1.91	0.80
Water Heat	Heat Trap - Water Lines	15	49	0.01	5.0%	5.0%	$60.00	0.68	0.89
Water Heat	Solar Water Heater	15	1,466	0.20	65.0%	82.0%	$2,322.56	0.42	0.71
Water Heat	Heat Pump WH - Add On	15	452	0.07	46.0%	28.9%	$1,395.56	0.23	0.74
Water Heat	Heat Recovery Water Heater	15	103	0.10	10.5%	42.2%	$909.81	0.22	2.07
Water Heat	Heat Pump WH - Integral	15	452	0.07	46.0%	28.9%	$2,036.56	0.15	0.74

Exhibit A3-1. Residential Measures – Technical and Economic Potential (Direct Load Control Measures Considered Separately)

End Use	Measure Name	1-Saturation Factor	Applicability Factor	Technical Potential (kWh)	Economic Potential (kWh)	Technical Potential (kW)	Economic Potential (kW)
Central A/C	Solar gain controls such as exterior shades	0.80	0.50	14,684,791	14,684,791	10,426	10,426
Central A/C	Shade Screens	0.80	0.00	0	0	0	0
Central A/C	Window Film	0.80	0.50	19,492,140	19,492,140	15,007	15,007
Central A/C	Central A/C - various equipment retrofits (EER & tonnage)	0.80	1.00	8,874,706	8,874,706	7,462	7,462
Central A/C	Air sealing (caulking, weatherstripping, hole sealing)	0.80	0.75	4,064,908	4,064,908	5,027	5,027
Central A/C	Energy Star or better windows	0.80	0.00	0	0	0	0
Central A/C	Two speed Central AC	0.00	0.00	0	0	0	0
Central A/C	Landscape Shading	0.80	0.00	0	0	0	0
Central A/C	Insulated metal or fiberglass doors	0.80	0.80	461,865	461,865	792	792
Central A/C	Refrigerant charge testing and recharging	0.80	0.75	4,845,448	4,845,448	2,988	2,988
Central A/C	Whole House Fan	0.80	0.50	5,211,298	0	0	0
Central A/C	Duct Insulation	0.80	0.00	0	0	0	0
Central A/C	Shell insulation upgrades	0.80	0.05	66,384	0	87	0
Central A/C	Filter cleaning and/or replacement	0.80	0.75	1,578,048	0	709	0
Central A/C	Duct Sealing	0.80	0.80	3,428,815	0	0	0
Central A/C	Reflective Roof Coatings	0.80	0.50	2,524,464	0	934	0
Central A/C	Solar control glazing	0.80	0.00	0	0	0	0
Central A/C	Programmable Thermostat	0.80	0.75	2,336,649	0	0	0
Clothes Dryer	Energy Star or better clothes dryer (Elec)	0.94	1.00	3,845,395	0	655	0
Clothes Washer	Energy Star Clothes Washers - All Electric	0.95	1.00	1,005,192	1,005,192	138	138
Dishwasher	Energy Star Dishwasher - Electric DHW	0.80	1.00	809,677	809,677	97	97
Freezer	Remove 2nd Freezer	0.80	0.20	2,918,181	2,918,181	523	523
Freezer	Energy Star or better freezer	0.80	1.00	2,777,211	0	498	0
Lighting	Compact fluorescent lamps (CFLs)	0.86	0.60	47,454,698	47,454,698	2,334	2,334
Lighting	Outdoor Floodlight	0.86	0.50	6,445,376	6,445,376	0	0
Lighting	Motion Detectors	0.86	0.50	27,977,815	27,977,815	1,506	1,506
Refrigerator	Remove 2nd Refrigerator	0.80	0.20	8,690,986	8,690,986	1,389	1,389
Refrigerator	Energy Star or better refrigerator	0.80	1.00	14,783,368	14,783,368	2,362	2,362
Room A/C	Solar gain controls such as exterior shades	0.80	0.80	1,710,404	1,710,404	928	928
Room A/C	Room A/C - various equipment retrofits (EER & tonnage)	0.80	1.00	955,904	955,904	694	694
Room A/C	Air sealing (caulking, weatherstripping, hole sealing)	0.80	0.75	237,315	237,315	260	260
Room A/C	Energy Star or better windows	0.80	0.80	1,395,108	1,395,108	1,012	1,012
Room A/C	Ceiling Fan	0.80	0.00	0	0	0	0
Room A/C	Insulated metal or fiberglass doors	0.80	0.80	0	0	35	0
Room A/C	Refrigerant charge testing and recharging	0.80	0.75	225,468	0	123	0
Room A/C	Attic, roof, wall, perimeter, knee wall, underfloor insulation	0.80	0.05	4,220	0	4	0
Room A/C	Filter cleaning and/or replacement	0.80	0.75	77,079	0	29	0
Room A/C	Solar control glazing	0.80	0.00	0	0	0	0
Space Heat	Air sealing (caulking, weatherstripping, hole sealing)	1.00	0.80	4,008,468	4,008,468	0	0
Space Heat	Insulated metal or fiberglass doors	1.00	0.80	619,809	619,809	0	0
Space Heat	Shell insulation upgrades	1.00	0.05	152,838	0	0	0
Space Heat	Attic Radiant Barriers	1.00	0.50	1,869,402	0	0	0
Space Heat	Duct Insulation	1.00	0.00	0	0	0	0
Space Heat	Furnace upgrades	1.00	1.00	3,401,515	0	0	0
Space Heat	Energy Star or better windows	1.00	0.80	1,188,663	0	0	0
Space Heat	Duct Sealing	1.00	0.80	610,449	0	0	0
Space Heat	Programmable Thermostat	1.00	1.00	2,030,679	0	0	0
Space Heat	Air sealing (caulking, weatherstripping, hole sealing)	0.67	0.75	3,397,013	3,397,013	0	0
Space Heat	Insulated metal or fiberglass doors	0.67	0.80	588,285	588,285	0	0
Space Heat	Heat Pump - Maintenance	0.67	1.00	2,770,143	2,770,143	0	0
Space Heat	Energy Star or better windows	0.67	0.80	1,301,200	1,301,200	0	0
Space Heat	Energy Star or better heat pump upgrade	0.67	1.00	1,907,185	1,907,185	0	0
Space Heat	Duct Insulation	0.67	0.00	0	0	0	0
Space Heat	Duct Sealing	0.67	0.80	645,854	0	0	0
Space Heat	Shell insulation upgrades (Wall and Slab, Elec)	0.67	0.05	123,165	0	0	0
Space Heat	Two speed Heat Pump - Elec Resis Heater	0.67	0.50	3,672,204	0	0	0
Space Heat	Two speed Heat Pump	0.67	0.50	3,171,261	0	0	0
Space Heat	Attic Radiant Barriers (Elec)	0.67	0.50	1,218,017	0	0	0
Space Heat	Ground Source Heat Pump	0.67	0.50	2,673,343	0	0	0
Space Heat	Ground Source Heat Pump - Elec Resis Heater	0.67	0.50	2,412,691	0	0	0
Space Heat	Heat Pump - Load Control	0.67	0.68	408,004	0	0	0
Space Heat	Programmable Thermostat	0.67	1.00	1,335,138	0	0	0
Water Heat	Pipe Wrap (Elec)	0.86	0.50	1,612,495	1,612,495	161	161
Water Heat	Faucet Aerators (Elec)	0.86	0.50	1,188,045	1,188,045	119	119
Water Heat	Water heat tank wraps and bottom boards (Elec)	0.86	0.20	1,560,799	1,560,799	156	156
Water Heat	Low Flow Showerheads (Elec)	0.86	0.50	2,878,132	2,878,132	288	288
Water Heat	Tank temperature setback (Elec)	0.86	0.50	2,043,991	2,043,991	205	205
Water Heat	Vapor-compression cycle	0.86	0.50	1,741,780	1,741,780	0	0
Water Heat	Heater efficiency upgrades (Elec)	0.86	1.00	7,053,319	7,053,319	721	721
Water Heat	Heat Trap - Water Lines	0.86	0.25	812,903	812,903	83	83
Water Heat	Solar Water Heater	0.86	0.25	10,432,058	0	770	0
Water Heat	Heat Pump WH - Add On	0.86	0.50	12,707,882	0	447	0
Water Heat	Heat Recovery Water Heater	0.86	0.50	2,328,611	0	572	0
Water Heat	Heat Pump WH - Integral	0.86	0.50	9,742,266	0	321	0

Exhibit A3-1 Residential Direct Load Control Programs Assumptions

	Central Air Conditioner DLC	**Hot Water DLC**
Description	Cycle 15 minutes for every 30 up to 3 hours, summer only	Continuous shutdown up to 4 hours, all seasons
kW/Household	5.2	0.3
Savings Factor	50%	100%
kW Savings/Household	2.6	0.3
Annual Incentive Payment	$21.00	$18.00
$/kW-yr Incentives	$8.13	$68.70
Administrative Costs ($/kW-yr)	$4.06	$34.35
O&M Costs ($/Household)	$30.00	$0.00
O&M Costs ($/kW-yr)	$11.61	$0.00
Total Ongoing Program Costs	**$23.81**	**$103.05**
Installation Cost ($/Household)	$250.00	$250.00
Installation Cost ($/kW)	**$96.78**	**$954.13**
Days Per Year	10	20
Hours Per Day	3	4
Maximum kWh/Year-Household	77.5	21.0

Exhibit A3-2 Commercial Measures – Savings & Cost-Effectiveness Characteristics Technical/Economic Potential

Subsector	End Use	Technology Type	Measure Name	Life	Incremental Costs	kWh Savings	kW Savings	% kWh Savings	% kW Savings	Applicability Factor	1-Saturation Factor	Technical Potential (kWh)	TRC	RIM	Economic Potential (kWh)	Technical Potential (kW)	Economic Potential (kW)
Colleges	Cooking	All	Infrared Fryer	15	$99.12	0	0.00	9.6%	9.8%	0.60	0.80	3,860	0.00	26.56	0	0	0
Colleges	Cooking	All	Convection Oven	14	$88.77	0	0.00	4.7%	4.7%	0.49	0.80	1,448	0.00	27.88	0	0	0
Colleges	Cooking	All	Infrared Conveyor Oven	14	$93.02	0	0.00	5.0%	5.0%	0.49	0.80	1,512	0.00	27.88	0	0	0
Colleges	Cooking	All	Power Burner Fryer	15	$99.69	0	0.00	2.7%	2.7%	0.48	0.80	788	0.00	26.56	0	0	0
Colleges	Cooking	All	Power Burner Oven	16	$102.00	0	0.00	2.4%	2.4%	0.54	0.80	790	0.00	25.40	0	0	0
Colleges	Cooking	All	Efficient Infrared Griddle	14	$112.64	0	0.00	2.3%	2.3%	0.56	0.80	780	0.00	27.88	0	0	0
Colleges	Cooling	Chillers	High-efficiency chillers	20	$43.22	60	0.08	14.9%	22.1%	0.85	0.90	101,197	3.35	3.18	101,197	128	128
Colleges	Cooling	Chillers	Window treatment	11	$0.74	1	0.00	16.2%	18.6%	0.00	0.90	0	2.26	3.57	0	0	0
Colleges	Cooling	Chillers	Energy management controls	10	$1,107.82	1,616	1.28	9.6%	8.9%	0.00	0.90	0	2.24	3.24	0	0	0
Colleges	Cooling	Chillers	Chiller economizers (water side), or air side economizers	13	$71.04	104	0.00	25.6%	0.0%	0.00	0.90	0	0.63	0.83	0	0	0
Colleges	Cooling	Chillers	Variable-speed drives	15	$63.82	23	0.02	5.6%	5.6%	0.00	0.90	0	0.61	2.78	0	0	0
Colleges	Cooling	Chillers	Improved maintenance and diagnostics	1	$751.34	3,740	3.19	22.3%	22.3%	0.84	0.90	133,474	0.32	0.99	0	107	0
Colleges	Cooling	Chillers	Cool (reflective) rooftops	21	$0.54	0	0.00	0.5%	0.0%	0.24	0.90	702	0.02	0.81	0	0	0
Colleges	Cooling	Chillers	Installation of wall, roof, or ceiling insulation	21	$0.60	0	0.00	0.0%	0.1%	0.54	0.90	68	0.00	5.75	0	0	0
Colleges	Cooling	Chillers	Optimize chilled water and condenser water setting	3	$103.98	0	0.00	1.1%	1.1%	0.78	0.90	5,160	0.00	0.95	0	4	0
Colleges	Cooling	Chillers	Installation of low-E glass or multiple glazed windows	30	$0.67	1	0.00	13.5%	14.5%	0.44	0.90	34,757	0.00	0.00	0	30	0
Colleges	Cooling	Chillers	Cool Storage	1	$0.00	0	0.00	0.0%	0.0%	0.71	0.90	0	0.00	0.00	0	0	0
Colleges	Cooling	Chillers	Heat Pipe Enhanced DX	20	$0.00	0	0.00	0.0%	0.0%	0.50	0.90	0	0.00	0.00	0	0	0
Colleges	Cooling	DX Units	Window treatment	11	$0.74	1	0.00	16.2%	18.6%	0.00	0.95	0	2.26	3.57	0	0	0
Colleges	Cooling	DX Units	Energy management controls	10	$1,107.82	1,616	1.28	9.6%	8.9%	0.00	0.95	0	2.24	3.24	0	0	0
Colleges	Cooling	DX Units	High-efficiency packaged DX A/C	18	$99.97	88	0.08	21.2%	22.9%	0.93	0.95	145,785	1.60	2.70	145,785	135	135
Colleges	Cooling	DX Units	Variable-speed drives	15	$63.82	23	0.02	5.6%	5.6%	0.00	0.95	0	0.61	2.78	0	0	0
Colleges	Cooling	DX Units	Improved maintenance and diagnostics	1	$751.34	3,740	3.19	22.3%	22.3%	0.84	0.95	112,082	0.32	0.99	0	94	0
Colleges	Cooling	DX Units	Cool (reflective) rooftops	21	$0.54	0	0.00	0.5%	0.0%	0.24	0.95	582	0.02	0.81	0	0	0
Colleges	Cooling	DX Units	Installation of wall, roof, or ceiling insulation	21	$0.60	0	0.00	0.0%	0.1%	0.54	0.95	56	0.00	5.75	0	0	0
Colleges	Cooling	DX Units	Installation of low-E glass or multiple glazed windows	30	$0.67	1	0.00	13.5%	14.5%	0.44	0.95	29,083	0.00	0.00	0	26	0
Colleges	Cooling	DX Units	Cool Storage	1	$0.00	0	0.00	0.0%	0.0%	0.71	0.95	0	0.00	0.00	0	0	0
Colleges	Cooling	DX Units	Heat Pipe Enhanced DX	20	$0.00	0	0.00	0.0%	0.0%	0.50	0.95	0	0.00	0.00	0	0	0
Colleges	Cooling	Room AC	Window treatment	11	$0.74	1	0.00	16.2%	18.6%	0.00	0.90	0	2.29	3.57	0	0	0
Colleges	Cooling	Room AC	Energy management controls	10	$1,107.82	1,616	1.28	9.6%	8.9%	0.00	0.90	0	2.24	3.24	0	0	0
Colleges	Cooling	Room AC	Variable-speed drives	15	$63.82	23	0.02	5.6%	5.6%	0.00	0.90	0	0.61	2.78	0	0	0
Colleges	Cooling	Room AC	Improved maintenance and diagnostics	1	$751.34	3,740	3.19	22.3%	22.3%	0.84	0.90	135,778	0.32	0.99	0	116	0
Colleges	Cooling	Room AC	Cool (reflective) rooftops	21	$0.54	0	0.00	0.5%	0.0%	0.24	0.90	714	0.02	0.81	0	0	0
Colleges	Cooling	Room AC	Installation of wall, roof, or ceiling insulation	21	$0.60	0	0.00	0.0%	0.1%	0.54	0.90	69	0.00	5.75	0	0	0
Colleges	Cooling	Room AC	Installation of low-E glass or multiple glazed windows	30	$0.67	1	0.00	13.5%	14.5%	0.44	0.90	35,637	0.00	0.00	0	33	0
Colleges	Cooling	Room AC	Cool Storage	1	$0.00	0	0.00	0.0%	0.0%	0.71	0.90	0	0.00	0.00	0	0	0
Colleges	Cooling	Room AC	Heat Pipe Enhanced DX	20	$0.00	0	0.00	0.0%	0.0%	0.50	0.90	0	0.00	0.00	0	0	0
Colleges	Heating	Cntrl - HP	Window treatment	10	$0.65	3	0.00	35.8%	16.6%	0.99	0.80	32,924	1.68	0.85	32,924	0	0
Colleges	Heating	Cntrl - HP	Installation of low-E glass or multiple glazed windows	23	$2.46	1	0.00	8.8%	11.8%	0.76	0.80	4,435	0.17	0.81	0	0	0
Colleges	Heating	Cntrl - HP	Infiltration Reduction	16	$0.44	0	0.00	7.7%	10.5%	0.94	0.80	4,564	0.13	0.81	0	0	0
Colleges	Heating	Cntrl - HP	Cool (reflective) rooftops	21	$0.64	0	0.00	-0.4%	0.2%	0.00	0.80	0	-0.02	0.81	0	0	0
Colleges	Heating	Cntrl - RTU/Furn	Window treatment	10	$0.65	3	0.00	35.8%	16.6%	0.99	0.80	131,694	1.68	0.85	131,694	0	0
Colleges	Heating	Cntrl - RTU/Furn	Installation of low-E glass or multiple glazed windows	23	$2.46	1	0.00	8.8%	11.8%	0.76	0.80	17,740	0.17	0.81	0	0	0
Colleges	Heating	Cntrl - RTU/Furn	Infiltration Reduction	16	$0.44	0	0.00	7.7%	10.5%	0.94	0.80	18,255	0.13	0.81	0	0	0
Colleges	Heating	Cntrl - RTU/Furn	Cool (reflective) rooftops	21	$0.64	0	0.00	-0.4%	0.2%	0.00	0.80	0	-0.02	0.81	0	0	0
Colleges	Heating	Unitary	Window treatment	10	$0.65	3	0.00	35.8%	16.6%	0.99	0.80	98,771	1.68	0.85	98,771	0	0
Colleges	Heating	Unitary	Installation of low-E glass or multiple glazed windows	23	$2.46	1	0.00	8.8%	11.8%	0.76	0.80	13,305	0.17	0.81	0	0	0
Colleges	Heating	Unitary	Infiltration Reduction	16	$0.44	0	0.00	7.7%	10.5%	0.94	0.80	13,691	0.13	0.81	0	0	0
Colleges	Heating	Unitary	Cool (reflective) rooftops	21	$0.64	0	0.00	-0.4%	0.2%	0.00	0.80	0	-0.02	0.81	0	0	0
Colleges	Lighting - Ext	E Incand.	High-intensity discharge lamps (incandescent to hi-pres sodium)	14	$148.29	2,050	0.50	71.5%	71.5%	0.73	0.80	107,404	11.14	1.44	107,404	1	1
Colleges	Lighting - Ext	E Incand.	Outdoor lighting controls for incandescent (photocell/timeclock)	8	$109.02	1,528	0.00	25.2%	0.0%	0.74	0.80	22,101	4.73	0.89	22,101	0	0
Colleges	Lighting - Ext	Fluor	T8 lamps with electronic ballasts (2L4')	18	$3.75	45	0.01	35.7%	35.7%	0.91	0.80	10,968	10.46	1.34	10,968	0	0
Colleges	Lighting - Ext	Fluor	Outdoor lighting controls for fluorescent (photocell/timeclock)	8	$113.91	293	0.00	28.1%	0.0%	0.66	0.80	4,629	0.87	0.89	4,629	0	0
Colleges	Lighting - Ext	HID	Outdoor lighting controls for HID (photocell/timeclock)	8	$108.99	1,528	0.00	27.4%	0.0%	0.70	0.80	44,427	4.73	0.89	44,427	0	0
Colleges	Lighting - Ext	HID	High-intensity discharge lamps (mercury vapor to hi-pres sodium)	16	$154.57	841	0.21	51.9%	51.9%	0.99	0.80	86,790	4.56	1.38	86,790	1	1
Colleges	Lighting - Int	4' Fluor	T8 lamps with electronic ballasts (2L4')	16	$5.71	33	0.01	32.9%	32.9%	0.88	0.20	265,608	5.63	1.58	265,608	13	13
Colleges	Lighting - Int	4' Fluor	Occupancy sensors for 4' fluorescent	8	$11.65	54	0.01	23.1%	23.1%	0.95	0.80	751,922	3.28	1.81	751,922	37	37
Colleges	Lighting - Int	4' Fluor	Reflectors for 4' fluorescent	17	$27.48	79	0.03	43.2%	43.2%	0.39	0.80	483,868	2.81	1.55	483,868	24	24
Colleges	Lighting - Int	4' Fluor	Perimeter dimming for 4' fluorescent	13	$113.81	59	0.04	34.6%	73.2%	0.10	0.80	81,415	0.78	2.69	81,415	8	8
Colleges	Lighting - Int	8' Fluor	Reflectors for 8' fluorescent	16	$27.13	124	0.04	41.0%	41.0%	0.38	0.80	46,982	4.41	1.58	46,982	2	2
Colleges	Lighting - Int	8' Fluor	Perimeter dimming for 8' fluorescent	19	$52.86	109	0.09	27.8%	85.0%	0.11	0.80	8,091	3.64	2.51	8,091	1	1
Colleges	Lighting - Int	8' Fluor	T8 lamps with electronic ballasts (2L8')	15	$9.95	33	0.01	18.3%	18.3%	0.87	0.20	10,116	3.17	1.01	10,116	0	0
Colleges	Lighting - Int	8' Fluor	Occupancy sensors for 8' fluorescent	11	$27.60	93	0.02	21.3%	20.0%	0.79	0.80	41,495	2.48	1.54	41,495	2	2
Colleges	Lighting - Int	Exit Signs	LED Exit Signs	10	$44.53	315	0.04	74.3%	74.3%	0.94	0.80	157,650	3.65	1.22	157,650	8	8
Colleges	Lighting - Int	HID	High-intensity discharge lamps (incandescent to metal halide)	17	$245.28	333	0.11	45.8%	45.8%	0.19	1.00	0	1.33	1.55	0	0	0
Colleges	Lighting - Int	Incand.	Compact flourescent lamp (modular)	9	-$45.29	172	0.09	64.9%	64.9%	0.96	0.05	5,093	-3.20	1.98	0	0	0
Colleges	Office Equip - Non PC	Copy/Fax	Power management enabling - copier	4	$44.60	470	0.00	53.8%	18.8%	0.65	0.80	29,886	2.31	0.99	29,886	0	0
Colleges	Office Equip - Non PC	Copy/Fax	External hardware control - printers	4	$165.99	160	0.00	54.4%	0.0%	0.52	0.80	17,488	0.21	0.99	0	0	0
Colleges	Office Equip - Non PC	Copy/Fax	Nighttime shutdown - printers	4	$636.74	142	0.00	56.6%	0.0%	0.94	0.80	25,430	0.05	0.99	0	0	0
Colleges	Office Equip - Non PC	Monitors	Network power management enabling - monitor	4	$4.67	117	0.00	72.8%	25.5%	0.58	0.80	295,444	5.40	0.99	295,444	3	3
Colleges	Office Equip - Non PC	Monitors	Power management enabling - monitor	3	$7.42	115	0.00	71.8%	25.1%	0.00	0.80	0	2.08	1.01	0	0	0
Colleges	Office Equip - PC	CPUs	External hardware control - monitors	5	$101.37	97	0.00	69.9%	0.0%	0.40	0.80	149,548	0.25	0.97	0	0	0
Colleges	Office Equip - PC	CPUs	Power management enabling - PC	4	$13.29	90	0.00	37.5%	13.1%	0.70	0.80	167,930	1.48	0.99	167,930	2	2
Colleges	Refrigeration	Compressors	LCD monitor	5	$455.58	80	0.00	49.7%	49.7%	0.92	0.80	233,939	0.05	0.97	0	8	0
Colleges	Refrigeration	Compressors	Demand defrost electric	9	$0.03	3	0.00	9.0%	9.0%	0.00	0.99	0	31.44	0.94	0	0	0
Colleges	Refrigeration	Compressors	Demand hot gas defrost	10	$0.03	1	0.00	3.3%	3.3%	0.00	0.99	0	14.08	0.92	0	0	0
Colleges	Refrigeration	Compressors	Efficiency compressor motor retrofit	10	$0.07	2	0.00	6.6%	6.6%	0.00	0.99	0	11.09	0.92	0	0	0
Colleges	Refrigeration	Compressors	Floating head pressure controls	10	$0.11	2	0.00	6.5%	0.0%	0.00	0.99	0	8.84	0.81	0	0	0
Colleges	Refrigeration	Compressors	Anti-sweat (humidistat) controls	14	$0.14	1	0.00	4.5%	1.8%	0.00	0.30	0	4.45	0.84	0	0	0
Colleges	Refrigeration	Compressors	Strip curtains for walk-ins	4	$0.05	1	0.00	3.2%	3.2%	0.00	0.99	0	3.91	0.99	0	0	0

Subsector	End Use	Technology Type	Measure Name	Life	Incremental Costs	kWh Savings	kW Savings	% kWh Savings	% kW Savings	Applicability Factor	1-Saturation Factor	Technical Potential (kWh)	TRC	RIM	Economic Potential (kWh)	Technical Potential (kW)	Economic Potential (kW)
Colleges	Refrigeration	Compressors	Night covers for display cases	5	$0.14	2	0.00	5.5%	0.0%	0.00	0.99	0	3.14	0.97	0	0	0
Colleges	Refrigeration	Compressors	Evaporator fan controller for MT walk-ins	5	$0.05	0	0.00	1.2%	1.2%	0.00	0.99	0	1.81	0.97	0	0	0
Colleges	Refrigeration	Compressors	Compressor VSD retrofit	11	$0.45	2	0.00	5.1%	2.5%	0.00	0.99	0	1.40	0.87	0	0	0
Colleges	Refrigeration	Compressors	Refrigeration commissioning	3	$0.20	1	0.00	4.5%	4.5%	0.00	0.99	0	1.17	1.01	0	0	0
Colleges	Refrigeration	Fans/Motors	Demand defrost electric	9	$0.03	3	0.00	9.0%	9.0%	0.00	0.99	0	31.44	0.94	0	0	0
Colleges	Refrigeration	Fans/Motors	Demand hot gas defrost	10	$0.03	1	0.00	3.3%	3.3%	0.00	0.99	0	14.08	0.92	0	0	0
Colleges	Refrigeration	Fans/Motors	Anti-sweat (humidistat) controls	14	$0.14	1	0.00	4.5%	1.8%	0.00	0.30	0	4.45	0.84	0	0	0
Colleges	Refrigeration	Fans/Motors	Strip curtains for walk-ins	4	$0.05	1	0.00	3.2%	3.2%	0.00	0.99	0	3.91	0.99	0	0	0
Colleges	Refrigeration	Fans/Motors	Night covers for display cases	5	$0.14	2	0.00	5.5%	0.0%	0.00	0.99	0	3.14	0.97	0	0	0
Colleges	Refrigeration	Fans/Motors	Evaporator fan controller for MT walk-ins	5	$0.05	0	0.00	1.2%	1.2%	0.00	0.99	0	1.81	0.97	0	0	0
Colleges	Refrigeration	Fans/Motors	High-efficiency fan motors	18	$1.12	3	0.00	11.4%	11.4%	0.00	0.99	0	1.66	0.85	0	0	0
Colleges	Refrigeration	Fans/Motors	Refrigeration commissioning	3	$0.20	1	0.00	4.5%	4.5%	0.00	0.99	0	1.17	1.01	0	0	0
Colleges	Ventilation	Motor	Premium-efficiency motors	16	$5.71	164	0.04	4.9%	6.0%	0.99	0.95	17,706	25.07	1.44	17,706	5	5
Colleges	Ventilation	Motor	CV to VAV conversion	22	$98.07	1,000	0.22	33.0%	33.0%	0.25	0.95	29,222	9.02	1.23	29,222	6	6
Colleges	Ventilation	Motor	Variable-speed drives	8	$0.23	2	0.00	6.0%	1.2%	0.99	0.95	19,278	3.56	1.05	19,278	1	1
Colleges	Ventilation	Motor	Unoccupied OA reduction	14	$112.66	500	0.01	5.1%	0.5%	0.85	0.95	13,051	2.14	0.88	13,051	0	0
Colleges	Ventilation	Motor	Automatic OA reduction control	15	$773.99	1,160	0.03	9.2%	0.9%	0.81	0.95	21,619	0.75	0.87	21,619	1	1
Colleges	Ventilation	Motor	Installation of nighttime pre-cooling controls and systems	10	$88.90	0	0.00	0.0%	22.8%	0.66	0.95	0	0.00	35.93	0	10	0
Colleges	Ventilation	Motor	Installation of outside air reset controls	1	$0.66	0	0.00	0.0%	0.0%	0.85	0.95	0	0.00	0.00	0	0	0
Colleges	Ventilation	Motor	Reducing minimum outside air requirements	1	$0.64	0	0.00	0.0%	0.0%	0.81	0.95	0	0.00	0.00	0	0	0
Colleges	Ventilation	Motor w/VFD	Premium-efficiency motors	16	$5.71	164	0.04	4.9%	6.0%	0.99	0.95	17,706	25.07	1.44	17,706	5	5
Colleges	Ventilation	Motor w/VFD	CV to VAV conversion	22	$98.07	1,000	0.22	33.0%	33.0%	0.25	0.95	29,222	9.02	1.23	29,222	6	6
Colleges	Ventilation	Motor w/VFD	Unoccupied OA reduction	14	$112.66	500	0.01	5.1%	0.5%	0.85	0.95	13,838	2.14	0.88	13,838	0	0
Colleges	Ventilation	Motor w/VFD	Automatic OA reduction control	15	$773.99	1,160	0.03	9.2%	0.9%	0.81	0.95	22,921	0.75	0.87	22,921	1	1
Colleges	Ventilation	Motor w/VFD	Installation of nighttime pre-cooling controls and systems	10	$88.90	0	0.00	0.0%	22.8%	0.66	0.95	0	0.00	35.93	0	10	0
Colleges	Ventilation	Motor w/VFD	Installation of outside air reset controls	1	$0.66	0	0.00	0.0%	0.0%	0.85	0.95	0	0.00	0.00	0	0	0
Colleges	Ventilation	Motor w/VFD	Reducing minimum outside air requirements	1	$0.64	0	0.00	0.0%	0.0%	0.81	0.95	0	0.00	0.00	0	0	0
Colleges	Water Heating	Call	Faucet Aerator	11	$0.01	0	0.00	1.9%	1.9%	0.72	0.80	15,334	1.30	33.35	15,334	4	4
Colleges	Water Heating	Call	Tank Insulation	15	$0.03	0	0.00	8.0%	8.0%	0.87	0.80	76,631	1.28	26.55	76,631	22	22
Colleges	Water Heating	Call	Circulation Pump Timelocks	13	$0.01	0	0.00	2.9%	2.9%	0.74	0.80	21,959	1.07	29.41	21,959	6	6
Colleges	Water Heating	Call	Instanteous Water Heater <=200 MBTUH	16	$0.07	0	0.00	9.7%	9.7%	0.74	0.80	73,001	0.66	25.40	73,001	21	21
Colleges	Water Heating	Call	Low Flow Showerheads	10	$0.02	0	0.00	2.2%	2.2%	0.63	0.80	13,189	0.61	35.93	13,189	4	4
Colleges	Water Heating	Call	Heater efficiency upgrade	12	$0.24	0	0.00	24.8%	24.8%	0.87	0.80	206,593	0.47	31.22	0	59	0
Colleges	Water Heating	Call	Pipe Insulation	16	$0.02	0	0.00	1.7%	1.7%	0.76	0.80	10,209	0.44	25.40	0	3	0
Colleges	Water Heating	Call	Solar Water Heater	1	$0.00	0	0.00	0.0%	0.0%	0.76	0.80	0	0.00	1.06	0	0	0
Colleges	Water Heating	Call	Heat Recovery Water Heater	1	$0.00	0	0.00	0.0%	0.0%	0.69	0.80	0	0.00	1.06	0	0	0
Schools	Cooking	All	Infrared Fryer	15	$99.12	0	0.00	9.6%	9.6%	0.60	0.80	9,007	0.00	26.56	0	1	0
Schools	Cooking	All	Convection Oven	14	$86.77	0	0.00	4.7%	4.7%	0.49	0.80	3,379	0.00	27.88	0	0	0
Schools	Cooking	All	Infrared Conveyor Oven	14	$93.02	0	0.00	5.0%	5.0%	0.49	0.80	3,527	0.00	27.88	0	0	0
Schools	Cooking	All	Power Burner Fryer	15	$96.69	0	0.00	2.7%	2.7%	0.48	0.80	1,839	0.00	28.55	0	0	0
Schools	Cooking	All	Power Burner Oven	16	$102.60	0	0.00	2.4%	2.4%	0.54	0.80	1,857	0.00	25.40	0	0	0
Schools	Cooking	All	Efficient Infrared Griddle	14	$112.64	0	0.00	2.3%	2.3%	0.56	0.80	1,820	0.00	27.88	0	0	0
Schools	Cooling	Chillers	High-efficiency chillers	20	$43.22	60	0.12	14.9%	22.1%	0.85	0.90	236,126	4.81	4.30	236,126	469	469
Schools	Cooling	Chillers	Window treatment	11	$0.74	1	0.00	16.2%	18.6%	0.00	0.90	0	3.27	4.92	0	0	0
Schools	Cooling	Chillers	Energy management controls	10	$1,107.82	1,616	2.01	9.6%	8.9%	0.00	0.90	0	3.20	4.45	0	0	0
Schools	Cooling	Chillers	Variable-speed drives	15	$63.82	23	0.03	5.6%	5.6%	0.00	0.90	0	0.87	3.76	0	0	0
Schools	Cooling	Chillers	Chiller economizers (water side), or air side economizers	13	$71.04	104	0.00	25.6%	0.0%	0.00	0.90	0	0.63	0.83	0	0	0
Schools	Cooling	Chillers	Improved maintenance and diagnostics	1	$751.34	3,740	5.00	22.3%	22.3%	0.84	0.90	311,439	0.32	0.96	0	390	0
Schools	Cooling	Chillers	Cool (reflective) rooftops	21	$0.54	0	0.00	0.5%	0.0%	0.24	0.90	1,037	0.02	0.81	0	0	0
Schools	Cooling	Chillers	Installation of wall, roof, or ceiling insulation	21	$0.60	0	0.00	0.0%	0.1%	0.54	0.90	158	0.00	7.62	0	1	0
Schools	Cooling	Chillers	Optimize chilled water and condenser water setting	3	$103.98	0	0.00	1.1%	1.1%	0.78	0.90	12,039	0.00	0.91	0	15	0
Schools	Cooling	Chillers	Installation of low-E glass or multiple glazed windows	30	$0.67	1	0.00	13.5%	14.5%	0.44	0.90	81,099	0.00	0.00	0	109	0
Schools	Cooling	Chillers	Cool Storage	1	$0.00	0	0.00	0.0%	0.0%	0.71	0.90	0	0.00	0.00	0	0	0
Schools	Cooling	Chillers	Heat Pipe Enhanced DX	20	$0.00	0	0.00	0.0%	0.0%	0.50	0.90	0	0.00	0.00	0	0	0
Schools	Cooling	DX Units	Window treatment	11	$0.74	1	0.00	16.2%	18.6%	0.00	0.95	0	3.27	4.92	0	0	0
Schools	Cooling	DX Units	Energy management controls	10	$1,107.82	1,616	2.01	9.6%	8.9%	0.00	0.95	0	3.20	4.45	0	0	0
Schools	Cooling	DX Units	High-efficiency packaged DX A/C	18	$99.97	86	0.12	21.2%	22.9%	0.93	0.95	340,164	2.26	3.63	340,164	491	491
Schools	Cooling	DX Units	Variable-speed drives	15	$63.82	23	0.03	5.6%	5.6%	0.00	0.95	0	0.87	3.76	0	0	0
Schools	Cooling	DX Units	Improved maintenance and diagnostics	1	$751.34	3,740	5.00	22.3%	22.3%	0.84	0.95	261,524	0.32	0.96	0	343	0
Schools	Cooling	DX Units	Cool (reflective) rooftops	21	$0.54	0	0.00	0.5%	0.0%	0.24	0.95	1,359	0.02	0.81	0	0	0
Schools	Cooling	DX Units	Installation of wall, roof, or ceiling insulation	21	$0.60	0	0.00	0.0%	0.1%	0.54	0.95	131	0.00	7.62	0	1	0
Schools	Cooling	DX Units	Installation of low-E glass or multiple glazed windows	30	$0.67	1	0.00	13.5%	14.5%	0.44	0.95	67,861	0.00	0.00	0	96	0
Schools	Cooling	DX Units	Cool Storage	1	$0.00	0	0.00	0.0%	0.0%	0.71	0.95	0	0.00	0.00	0	0	0
Schools	Cooling	DX Units	Heat Pipe Enhanced DX	20	$0.00	0	0.00	0.0%	0.0%	0.50	0.95	0	0.00	0.00	0	0	0
Schools	Cooling	Room AC	Window treatment	11	$0.74	1	0.00	16.2%	18.6%	0.00	0.90	0	3.27	4.92	0	0	0
Schools	Cooling	Room AC	Energy management controls	10	$1,107.82	1,616	2.01	9.6%	8.9%	0.00	0.90	0	3.20	4.45	0	0	0
Schools	Cooling	Room AC	Variable-speed drives	15	$63.82	23	0.03	5.6%	5.6%	0.00	0.90	0	0.87	3.76	0	0	0
Schools	Cooling	Room AC	Improved maintenance and diagnostics	1	$751.34	3,740	5.00	22.3%	22.3%	0.84	0.90	316,815	0.32	0.96	0	423	0
Schools	Cooling	Room AC	Cool (reflective) rooftops	21	$0.54	0	0.00	0.5%	0.0%	0.24	0.90	1,665	0.02	0.81	0	0	0
Schools	Cooling	Room AC	Installation of wall, roof, or ceiling insulation	21	$0.60	0	0.00	0.0%	0.1%	0.54	0.90	161	0.00	7.62	0	1	0
Schools	Cooling	Room AC	Installation of low-E glass or multiple glazed windows	30	$0.67	1	0.00	13.5%	14.5%	0.44	0.90	83,154	0.00	0.00	0	119	0
Schools	Cooling	Room AC	Cool Storage	1	$0.00	0	0.00	0.0%	0.0%	0.71	0.90	0	0.00	0.00	0	0	0
Schools	Cooling	Room AC	Heat Pipe Enhanced DX	20	$0.00	0	0.00	0.0%	0.0%	0.50	0.90	0	0.00	0.00	0	0	0
Schools	Heating	Cntrl - HP	Window treatment	10	$0.65	3	0.00	35.8%	16.6%	0.99	0.80	76,822	1.68	0.85	76,822	0	0
Schools	Heating	Cntrl - HP	Installation of low-E glass or multiple glazed windows	23	$2.46	1	0.00	8.8%	11.8%	0.76	0.80	10,348	0.17	0.81	0	0	0
Schools	Heating	Cntrl - HP	Infiltration Reduction	16	$0.44	0	0.00	7.7%	10.5%	0.94	0.80	10,648	0.13	0.81	0	0	0
Schools	Heating	Cntrl - HP	Cool (reflective) rooftops	21	$0.64	0	0.00	-0.4%	0.2%	0.00	0.80	0	-0.02	0.81	0	0	0
Schools	Heating	Cntrl - RTU/Furn	Window treatment	10	$0.65	3	0.00	35.8%	16.6%	0.99	0.80	307,287	1.68	0.85	307,287	0	0
Schools	Heating	Cntrl - RTU/Furn	Installation of low-E glass or multiple glazed windows	23	$2.46	1	0.00	8.8%	11.8%	0.76	0.80	41,394	0.17	0.81	0	0	0
Schools	Heating	Cntrl - RTU/Furn	Infiltration Reduction	16	$0.44	0	0.00	7.7%	10.5%	0.94	0.80	42,596	0.13	0.81	0	0	0

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Subsector	End Use	Technology Type	Measure Name	Life	Incremental Costs	kWh Savings	kW Savings	% kWh Savings	% kW Savings	Applicability Factor	1-Saturation Factor	Technical Potential (kWh)	TRC	RIM	Economic Potential (kWh)	Technical Potential (kW)	Economic Potential (kW)
Schools	Heating	Cntrl - RTU/Furn	Cool (reflective) rooftops	21	$0.64	0	0.00	-0.4%	0.2%	0.00	0.80	0	-0.02	0.81	0	0	0
Schools	Heating	Unitary	Window treatment	10	$0.65	3	0.00	35.8%	16.6%	0.99	0.80	230,465	1.68	0.85	230,465	0	0
Schools	Heating	Unitary	Installation of low-E glass or multiple glazed windows	23	$2.46	1	0.00	8.8%	11.8%	0.76	0.80	31,045	0.17	0.81	0	0	0
Schools	Heating	Unitary	Infiltration Reduction	16	$0.44	0	0.00	7.7%	10.5%	0.94	0.80	31,947	0.13	0.81	0	0	0
Schools	Heating	Unitary	Cool (reflective) rooftops	21	$0.64	0	0.00	-0.4%	0.2%	0.00	0.80	0	-0.02	0.81	0	0	0
Schools	Lighting - Ext	E Incand.	High-intensity discharge lamps (incandescent to hi-pres sodium)	14	$148.29	2,050	0.50	71.5%	71.5%	0.73	0.80	250,610	11.14	1.44	250,610	5	5
Schools	Lighting - Ext	E Incand.	Outdoor lighting controls for incandescent (photocell/timeclock)	8	$109.02	1,528	0.00	25.2%	0.0%	0.74	0.80	51,569	4.73	0.89	51,569	0	0
Schools	Lighting - Ext	Fluor	T8 lamps with electronic ballasts (2L4')	18	$3.75	45	0.01	35.7%	35.7%	0.91	0.80	25,592	10.46	1.34	25,592	1	1
Schools	Lighting - Ext	Fluor	Outdoor lighting controls for fluorescent (photocell/timeclock)	8	$113.91	293	0.00	28.1%	0.0%	0.66	0.80	10,800	0.87	0.89	10,800	0	0
Schools	Lighting - Ext	HID	Outdoor lighting controls for HID (photocell/timeclock)	8	$108.99	1,528	0.00	27.4%	0.0%	0.79	0.80	103,663	4.73	0.89	103,663	0	0
Schools	Lighting - Ext	HID	High-intensity discharge lamps (mercury vapor to hi-pres sodium)	16	$154.57	841	0.21	51.9%	51.9%	0.99	0.80	202,511	4.56	1.38	202,511	5	5
Schools	Lighting - Int	4' Fluor	T8 lamps with electronic ballasts (2L4')	16	$5.71	33	0.01	32.9%	32.9%	0.88	0.20	619,753	5.63	1.58	619,753	48	48
Schools	Lighting - Int	4' Fluor	Occupancy sensors for 4' fluorescent	8	$11.65	54	0.01	23.1%	23.1%	0.95	0.80	1,754,485	3.28	1.81	1,754,485	135	135
Schools	Lighting - Int	4' Fluor	Reflectors for 4' fluorescent	17	$27.48	79	0.03	43.2%	43.2%	0.39	0.80	1,129,025	2.81	1.55	1,129,025	87	87
Schools	Lighting - Int	4' Fluor	Perimeter dimming for 4' fluorescent	13	$113.81	59	0.04	34.6%	73.2%	0.10	0.80	189,968	0.78	2.69	189,968	31	31
Schools	Lighting - Int	8' Fluor	Reflectors for 8' fluorescent	16	$27.13	124	0.04	41.0%	41.0%	0.38	0.80	109,625	4.41	1.58	109,625	8	8
Schools	Lighting - Int	8' Fluor	Perimeter dimming for 8' fluorescent	19	$52.86	109	0.09	27.6%	85.0%	0.11	0.80	18,879	3.04	2.51	18,879	4	4
Schools	Lighting - Int	8' Fluor	T8 lamps with electronic ballasts (2L8')	15	$9.95	33	0.01	18.3%	18.3%	0.87	0.20	23,605	3.17	1.61	23,605	2	2
Schools	Lighting - Int	8' Fluor	Occupancy sensors for 8' fluorescent	11	$27.60	93	0.02	21.3%	20.0%	0.79	0.80	96,821	2.48	1.54	96,821	7	7
Schools	Lighting - Int	Exit Signs	LED Exit Signs	10	$44.53	315	0.04	74.3%	74.3%	0.94	0.80	367,849	3.85	1.22	367,849	28	28
Schools	Lighting - Int	HID	High-intensity discharge lamps (incandescent to metal halide)	17	$245.28	333	0.11	45.8%	45.8%	0.19	1.00	0	1.33	1.55	0	0	0
Schools	Lighting - Int	Incand.	Compact flourescent lamp (modular)	9	-$45.29	172	0.06	64.9%	64.9%	0.96	0.05	11,883	-3.20	1.98	0	1	0
Schools	Office Equip - Non PC	Copy/Fax	Power management enabling - copier	4	$44.60	470	0.01	53.8%	18.8%	0.65	0.80	69,735	2.31	0.99	69,735	1	1
Schools	Office Equip - Non PC	Copy/Fax	External hardware control - printers	4	$165.99	160	0.00	54.4%	0.0%	0.52	0.80	40,805	0.21	0.99	0	0	0
Schools	Office Equip - Non PC	Copy/Fax	Nighttime shutdown - printers	4	$636.74	142	0.00	56.6%	0.0%	0.94	0.80	59,337	0.05	0.99	0	0	0
Schools	Office Equip - Non PC	Monitors	Network power management enabling - monitor	4	$4.67	117	0.00	72.8%	25.5%	0.58	0.80	689,369	5.46	0.99	689,369	11	11
Schools	Office Equip - Non PC	Monitors	Power management enabling - monitor	3	$7.42	115	0.00	71.8%	25.1%	0.00	0.80	0	2.68	1.01	0	0	0
Schools	Office Equip - Non PC	Monitors	External hardware control - monitors	5	$101.37	97	0.00	69.9%	0.0%	0.46	0.80	348,946	0.25	0.97	0	0	0
Schools	Office Equip - PC	CPUs	Power management enabling - PC	4	$13.29	90	0.00	37.5%	13.1%	0.70	0.80	391,836	1.48	0.99	391,836	6	6
Schools	Office Equip - PC	CPUs	LCD monitor	5	$455.58	80	0.00	49.7%	49.7%	0.92	0.80	545,858	0.05	0.96	0	29	0
Schools	Refrigeration	Compressors	Demand defrost electric	9	$0.03	3	0.00	9.0%	9.0%	0.00	0.99	0	32.73	0.97	0	0	0
Schools	Refrigeration	Compressors	Demand hot gas defrost	10	$0.03	1	0.00	3.3%	3.3%	0.00	0.99	0	14.63	0.95	0	0	0
Schools	Refrigeration	Compressors	Efficiency compressor motor retrofit	10	$0.07	2	0.00	6.6%	6.6%	0.00	0.99	0	11.53	0.95	0	0	0
Schools	Refrigeration	Compressors	Floating head pressure controls	16	$0.11	2	0.00	6.5%	0.0%	0.00	0.99	0	8.84	0.81	0	0	0
Schools	Refrigeration	Compressors	Anti-sweat (humidistat) controls	14	$0.14	1	0.00	4.5%	1.8%	0.00	0.30	0	4.51	0.85	0	0	0
Schools	Refrigeration	Compressors	Strip curtains for walk-ins	4	$0.05	1	0.00	3.2%	3.2%	0.00	0.99	0	3.91	0.99	0	0	0
Schools	Refrigeration	Compressors	Night covers for display cases	5	$0.14	2	0.00	5.5%	0.0%	0.00	0.99	0	3.14	0.97	0	0	0
Schools	Refrigeration	Compressors	Evaporator fan controller for MT walk-ins	5	$0.05	0	0.00	1.2%	1.2%	0.00	0.99	0	1.81	0.97	0	0	0
Schools	Refrigeration	Compressors	Compressor VSD retrofit	11	$0.45	2	0.00	5.1%	2.5%	0.00	0.99	0	1.43	0.89	0	0	0
Schools	Refrigeration	Compressors	Refrigeration commissioning	3	$0.20	1	0.00	4.5%	4.5%	0.00	0.99	0	1.17	1.01	0	0	0
Schools	Refrigeration	Fans/Motors	Demand defrost electric	9	$0.03	3	0.00	9.0%	9.0%	0.00	0.99	0	32.73	0.97	0	0	0
Schools	Refrigeration	Fans/Motors	Demand hot gas defrost	10	$0.03	1	0.00	3.3%	3.3%	0.00	0.90	0	14.63	0.95	0	0	0
Schools	Refrigeration	Fans/Motors	Anti-sweat (humidistat) controls	14	$0.14	1	0.00	4.5%	1.8%	0.00	0.30	0	4.51	0.85	0	0	0
Schools	Refrigeration	Fans/Motors	Strip curtains for walk-ins	4	$0.05	1	0.00	3.2%	3.2%	0.00	0.99	0	3.91	0.99	0	0	0
Schools	Refrigeration	Fans/Motors	Night covers for display cases	5	$0.14	2	0.00	5.5%	0.0%	0.00	0.99	0	3.14	0.97	0	0	0
Schools	Refrigeration	Fans/Motors	Evaporator fan controller for MT walk-ins	5	$0.05	0	0.00	1.2%	1.2%	0.00	0.99	0	1.81	0.97	0	0	0
Schools	Refrigeration	Fans/Motors	High-efficiency fan motors	18	$1.12	3	0.00	11.4%	11.4%	0.00	0.99	0	1.71	0.88	0	0	0
Schools	Refrigeration	Fans/Motors	Refrigeration commissioning	3	$0.20	1	0.00	4.5%	4.5%	0.00	0.99	0	1.17	1.01	0	0	0
Schools	Ventilation	Motor	Premium-efficiency motors	16	$5.71	164	0.07	4.9%	6.0%	0.99	0.95	41,314	31.43	1.78	41,314	17	17
Schools	Ventilation	Motor	CV to VAV conversion	22	$98.07	1,000	0.34	33.0%	33.0%	0.25	0.95	68,185	10.85	1.47	68,185	23	23
Schools	Ventilation	Motor	Variable-speed drives	8	$0.23	2	0.00	6.0%	1.2%	0.99	0.95	44,982	3.88	1.14	44,982	3	3
Schools	Ventilation	Motor	Unoccupied OA reduction	14	$112.66	500	0.02	5.1%	0.5%	0.85	0.95	30,453	2.22	0.91	30,453	1	1
Schools	Ventilation	Motor	Automatic OA reduction control	15	$773.99	1,160	0.04	9.2%	0.9%	0.81	0.95	50,445	0.77	0.90	50,445	2	2
Schools	Ventilation	Motor	Installation of nighttime pre-cooling controls and systems	10	$88.90	0	0.00	0.0%	22.8%	0.66	0.95	0	0.00	35.93	0	37	0
Schools	Ventilation	Motor	Installation of outside air reset controls	1	$0.86	0	0.00	0.0%	0.0%	0.85	0.95	0	0.00	0.00	0	0	0
Schools	Ventilation	Motor	Reducing minimum outside air requirements	1	$0.84	0	0.00	0.0%	0.0%	0.81	0.95	0	0.00	0.00	0	0	0
Schools	Ventilation	Motor w/VFD	Premium-efficiency motors	16	$5.71	164	0.07	4.9%	6.0%	0.99	0.95	41,314	31.43	1.78	41,314	17	17
Schools	Ventilation	Motor w/VFD	CV to VAV conversion	22	$98.07	1,000	0.34	33.0%	33.0%	0.25	0.95	68,185	10.85	1.47	68,185	23	23
Schools	Ventilation	Motor w/VFD	Unoccupied OA reduction	14	$112.66	500	0.02	5.1%	0.5%	0.85	0.95	32,288	2.22	0.91	32,288	1	1
Schools	Ventilation	Motor w/VFD	Automatic OA reduction control	15	$773.99	1,160	0.04	9.2%	0.9%	0.81	0.95	53,483	0.77	0.90	53,483	2	2
Schools	Ventilation	Motor w/VFD	Installation of nighttime pre-cooling controls and systems	10	$88.90	0	0.00	0.0%	22.8%	0.66	0.95	0	0.00	35.93	0	38	0
Schools	Ventilation	Motor w/VFD	Installation of outside air reset controls	1	$0.86	0	0.00	0.0%	0.0%	0.85	0.95	0	0.00	0.00	0	0	0
Schools	Ventilation	Motor w/VFD	Reducing minimum outside air requirements	1	$0.84	0	0.00	0.0%	0.0%	0.81	0.95	0	0.00	0.00	0	0	0
Schools	Water Heating	Call	Faucet Aerator	11	$0.01	0	0.00	1.9%	1.9%	0.72	0.80	35,780	2.03	33.35	35,780	16	16
Schools	Water Heating	Call	Tank Insulation	15	$0.03	0	0.00	8.0%	8.0%	0.87	0.80	178,805	2.00	26.55	178,805	80	80
Schools	Water Heating	Call	Circulation Pump Timelocks	13	$0.01	0	0.00	2.9%	2.9%	0.74	0.80	51,238	1.68	29.42	51,238	23	23
Schools	Water Heating	Call	Instanteous Water Heater <=200 MBTUH	16	$0.07	0	0.00	9.7%	9.7%	0.74	0.80	170,336	1.04	25.40	170,336	77	77
Schools	Water Heating	Call	Low Flow Showerheads	10	$0.02	0	0.00	2.2%	2.2%	0.63	0.80	30,773	0.95	35.93	30,773	14	14
Schools	Water Heating	Call	Heater efficiency upgrade	12	$0.24	0	0.00	24.8%	24.8%	0.87	0.80	482,051	0.74	31.22	482,051	217	217
Schools	Water Heating	Call	Pipe Insulation	16	$0.02	0	0.00	1.7%	1.7%	0.76	0.80	23,822	0.69	25.40	23,822	11	11
Schools	Water Heating	Call	Solar Water Heater	1	$0.00	0	0.00	0.0%	0.0%	0.76	0.80	0	0.00	1.06	0	0	0
Schools	Water Heating	Call	Heat Recovery Water Heater	1	$0.00	0	0.00	0.0%	0.0%	0.69	0.80	0	0.00	1.06	0	0	0
Hotels/Motels	Cooking	All	Infrared Fryer	15	$99.12	0	0.00	9.6%	9.6%	0.48	0.80	41,376	0.00	26.56	0	4	0
Hotels/Motels	Cooking	All	Convection Oven	14	$86.77	0	0.00	4.7%	4.7%	0.58	0.80	23,207	0.00	27.88	0	2	0
Hotels/Motels	Cooking	All	Infrared Conveyor Oven	14	$93.02	0	0.00	5.0%	5.0%	0.51	0.80	21,616	0.00	27.88	0	2	0
Hotels/Motels	Cooking	All	Power Burner Fryer	15	$96.69	0	0.00	2.7%	2.7%	0.43	0.80	9,517	0.00	26.56	0	1	0
Hotels/Motels	Cooking	All	Power Burner Oven	16	$102.60	0	0.00	2.4%	2.4%	0.56	0.80	11,212	0.00	25.40	0	1	0
Hotels/Motels	Cooking	All	Efficient Infrared Griddle	14	$112.64	0	0.00	2.3%	2.3%	0.52	0.80	9,745	0.00	27.88	0	1	0
Hotels/Motels	Cooling	Chillers	High-efficiency chillers	20	$43.22	179	0.02	47.5%	12.8%	0.87	0.90	1,536,965	2.76	0.99	1,536,965	134	134
Hotels/Motels	Cooling	Chillers	Window treatment	11	$0.74	2	0.00	24.9%	13.5%	0.00	0.90	0	1.92	1.37	0	0	0

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Subsector	End Use	Technology Type	Measure Name	Life	Incremental Costs	kWh Savings	kW Savings	% kWh Savings	% kW Savings	Applicability Factor	1-Saturation Factor	Technical Potential (kWh)	TRC	RIM	Economic Potential (kWh)	Technical Potential (kW)	Economic Potential (kW)
Hotels/Motels	Cooling	Chillers	Energy management controls	10	$1,107.82	1,380	0.15	5.3%	1.7%	0.00	0.90	0	0.66	1.19	0	0	0
Hotels/Motels	Cooling	Chillers	Chiller economizers (water side), or air side economizers	13	$71.04	98	0.00	25.6%	0.0%	0.00	0.90	0	0.59	0.83	0	0	0
Hotels/Motels	Cooling	Chillers	Variable-speed drives	15	$63.82	21	0.01	5.6%	5.6%	0.68	0.90	89,159	0.31	1.60	0	42	0
Hotels/Motels	Cooling	Chillers	Cool (reflective) rooftops	21	$0.54	0	0.00	1.2%	0.4%	0.22	0.90	6,090	0.08	1.02	0	1	0
Hotels/Motels	Cooling	Chillers	Improved maintenance and diagnostics	1	$751.34	847	1.23	3.3%	14.6%	0.98	0.90	72,011	0.07	0.95	0	150	0
Hotels/Motels	Cooling	Chillers	Installation of wall, roof, or ceiling insulation	21	$0.60	0	0.00	0.0%	0.1%	0.61	0.90	283	0.00	3.01	0	0	0
Hotels/Motels	Cooling	Chillers	Optimize chilled water and condenser water setting	3	$103.98	0	0.00	1.1%	1.1%	0.60	0.90	14,780	0.00	0.99	0	6	0
Hotels/Motels	Cooling	Chillers	Installation of low-E glass or multiple glazed windows	30	$0.67	1	0.00	10.7%	0.0%	0.44	0.90	102,426	0.00	0.00	0	0	0
Hotels/Motels	Cooling	Chillers	Cool Storage	1	$0.00	0	0.00	0.0%	0.0%	0.76	0.90	0	0.00	0.00	0	0	0
Hotels/Motels	Cooling	Chillers	Heat Pipe Enhanced DX	20	$0.00	0	0.00	0.0%	0.0%	0.50	0.90	0	0.00	0.00	0	0	0
Hotels/Motels	Cooling	DX Units	Window treatment	11	$0.74	2	0.00	24.9%	13.5%	0.00	0.95	0	1.92	1.37	0	0	0
Hotels/Motels	Cooling	DX Units	High-efficiency packaged DX A/C	18	$98.97	128	0.02	33.9%	13.4%	0.90	0.95	2,135,983	0.89	1.09	2,135,983	274	274
Hotels/Motels	Cooling	DX Units	Energy management controls	10	$1,107.82	1,380	0.15	5.3%	1.7%	0.00	0.95	0	0.66	1.19	0	0	0
Hotels/Motels	Cooling	DX Units	Variable-speed drives	15	$63.82	21	0.01	5.6%	5.6%	0.68	0.95	190,231	0.31	1.60	0	77	0
Hotels/Motels	Cooling	DX Units	Cool (reflective) rooftops	21	$0.54	0	0.00	1.2%	0.4%	0.22	0.95	12,967	0.08	1.02	0	2	0
Hotels/Motels	Cooling	DX Units	Improved maintenance and diagnostics	1	$751.34	847	1.23	3.3%	14.6%	0.98	0.95	153,318	0.07	0.95	0	277	0
Hotels/Motels	Cooling	DX Units	Installation of wall, roof, or ceiling insulation	21	$0.60	0	0.00	0.0%	0.1%	0.61	0.95	601	0.00	3.01	0	1	0
Hotels/Motels	Cooling	DX Units	Installation of low-E glass or multiple glazed windows	30	$0.67	1	0.00	10.7%	0.0%	0.44	0.95	219,052	0.00	0.00	0	0	0
Hotels/Motels	Cooling	DX Units	Cool Storage	1	$0.00	0	0.00	0.0%	0.0%	0.76	0.95	0	0.00	0.00	0	0	0
Hotels/Motels	Cooling	DX Units	Heat Pipe Enhanced DX	20	$0.00	0	0.00	0.0%	0.0%	0.50	0.95	0	0.00	0.00	0	0	0
Hotels/Motels	Cooling	Room AC	Window treatment	11	$0.74	2	0.00	24.9%	13.5%	0.00	0.90	0	1.92	1.37	0	0	0
Hotels/Motels	Cooling	Room AC	Energy management controls	10	$1,107.82	1,380	0.15	5.3%	1.7%	0.00	0.90	0	0.66	1.19	0	0	0
Hotels/Motels	Cooling	Room AC	Variable-speed drives	15	$63.82	21	0.01	5.6%	5.6%	0.68	0.90	548,518	0.31	1.60	0	178	0
Hotels/Motels	Cooling	Room AC	Cool (reflective) rooftops	21	$0.54	0	0.00	1.2%	0.4%	0.22	0.90	37,465	0.08	1.02	0	4	0
Hotels/Motels	Cooling	Room AC	Improved maintenance and diagnostics	1	$751.34	847	1.23	3.3%	14.6%	0.98	0.90	443,022	0.07	0.95	0	642	0
Hotels/Motels	Cooling	Room AC	Installation of wall, roof, or ceiling insulation	21	$0.60	0	0.00	0.0%	0.1%	0.61	0.90	1,740	0.00	3.01	0	2	0
Hotels/Motels	Cooling	Room AC	Installation of low-E glass or multiple glazed windows	30	$0.67	1	0.00	10.7%	0.0%	0.44	0.90	634,021	0.00	0.00	0	0	0
Hotels/Motels	Cooling	Room AC	Cool Storage	1	$0.00	0	0.00	0.0%	0.0%	0.76	0.90	0	0.00	0.00	0	0	0
Hotels/Motels	Cooling	Room AC	Heat Pipe Enhanced DX	20	$0.00	0	0.00	0.0%	0.0%	0.50	0.90	0	0.00	0.00	0	0	0
Hotels/Motels	Heating	Cntrl - HP	Window treatment	10	$0.65	3	0.00	56.6%	16.6%	0.99	0.80	93,038	1.87	0.85	93,038	0	0
Hotels/Motels	Heating	Cntrl - HP	Installation of low-E glass or multiple glazed windows	23	$2.46	2	0.00	40.9%	11.8%	0.88	0.80	33,044	0.55	0.81	33,044	0	0
Hotels/Motels	Heating	Cntrl - HP	Infiltration Reduction	16	$0.44	0	0.00	7.7%	10.5%	0.86	0.80	4,372	0.10	0.81	0	0	0
Hotels/Motels	Heating	Cntrl - HP	Cool (reflective) rooftops	21	$0.64	0	0.00	-0.7%	0.2%	0.00	0.80	0	-0.02	0.81	0	0	0
Hotels/Motels	Heating	Cntrl - RTU/Furn	Window treatment	10	$0.65	3	0.00	56.6%	16.6%	0.99	0.80	24,166	1.87	0.85	24,166	0	0
Hotels/Motels	Heating	Cntrl - RTU/Furn	Installation of low-E glass or multiple glazed windows	23	$2.46	2	0.00	40.9%	11.8%	0.88	0.80	8,583	0.55	0.81	8,583	0	0
Hotels/Motels	Heating	Cntrl - RTU/Furn	Infiltration Reduction	16	$0.44	0	0.00	7.7%	10.5%	0.86	0.80	1,135	0.10	0.81	0	0	0
Hotels/Motels	Heating	Cntrl - RTU/Furn	Cool (reflective) rooftops	21	$0.64	0	0.00	-0.7%	0.2%	0.00	0.80	0	-0.02	0.81	0	0	0
Hotels/Motels	Heating	Unitary	Window treatment	10	$0.65	3	0.00	56.6%	16.6%	0.99	0.80	1,091,080	1.87	0.85	1,091,080	0	0
Hotels/Motels	Heating	Unitary	Installation of low-E glass or multiple glazed windows	23	$2.46	2	0.00	40.9%	11.8%	0.88	0.80	387,518	0.55	0.81	387,518	0	0
Hotels/Motels	Heating	Unitary	Infiltration Reduction	16	$0.44	0	0.00	7.7%	10.5%	0.86	0.80	51,267	0.10	0.81	0	0	0
Hotels/Motels	Heating	Unitary	Cool (reflective) rooftops	21	$0.64	0	0.00	-0.7%	0.2%	0.00	0.80	0	-0.02	0.81	0	0	0
Hotels/Motels	Lighting - Ext	E Incand.	High-intensity discharge lamps (incandescent to hi-pres sodium)	14	$148.29	2,050	0.50	71.5%	71.5%	0.76	0.80	485,962	11.14	1.44	485,962	3	3
Hotels/Motels	Lighting - Ext	E Incand.	Outdoor lighting controls for incandescent (photocell/timeclock)	8	$109.02	1,528	0.00	25.2%	0.0%	0.70	0.80	89,738	4.73	0.89	89,738	0	0
Hotels/Motels	Lighting - Ext	Fluor	T8 lamps with electronic ballasts (2L4')	18	$3.75	45	0.01	35.7%	35.7%	0.98	0.80	108,271	10.46	1.34	108,271	1	1
Hotels/Motels	Lighting - Ext	Fluor	Outdoor lighting controls for fluorescent (photocell/timeclock)	8	$113.91	293	0.00	28.1%	0.0%	0.81	0.80	38,415	0.87	0.89	38,415	0	0
Hotels/Motels	Lighting - Ext	HID	Outdoor lighting controls for HID (photocell/timeclock)	8	$108.99	1,528	0.00	27.4%	0.0%	0.72	0.80	178,418	4.73	0.89	178,418	0	0
Hotels/Motels	Lighting - Ext	HID	High-intensity discharge lamps (mercury vapor to hi-pres sodium)	16	$154.57	841	0.21	51.9%	51.9%	0.91	0.80	358,942	4.56	1.38	358,942	3	3
Hotels/Motels	Lighting - Int	4' Fluor	T8 lamps with electronic ballasts (2L4')	16	$5.71	61	0.01	32.9%	32.9%	0.97	0.20	593,301	7.93	1.24	593,301	39	39
Hotels/Motels	Lighting - Int	4' Fluor	Reflectors for 4' fluorescent	17	$27.48	143	0.03	43.2%	43.2%	0.44	0.80	1,338,826	3.97	1.22	1,338,826	88	88
Hotels/Motels	Lighting - Int	4' Fluor	Occupancy sensors for 4' fluorescent	8	$11.65	54	0.01	23.1%	23.1%	0.94	0.80	1,281,568	3.28	1.81	1,281,568	84	84
Hotels/Motels	Lighting - Int	4' Fluor	Perimeter dimming for 4' fluorescent	13	$113.81	59	0.04	34.6%	73.2%	0.08	0.80	136,995	0.78	2.69	136,995	19	19
Hotels/Motels	Lighting - Int	8' Fluor	Reflectors for 8' fluorescent	16	$27.13	226	0.04	41.0%	41.0%	0.37	0.80	82,599	0.22	1.24	82,599	5	5
Hotels/Motels	Lighting - Int	8' Fluor	T8 lamps with electronic ballasts (2L8')	15	$9.95	61	0.01	18.3%	18.3%	0.84	0.20	18,119	4.45	1.26	18,119	1	1
Hotels/Motels	Lighting - Int	8' Fluor	Perimeter dimming for 8' fluorescent	19	$52.86	109	0.09	27.8%	85.0%	0.11	0.80	13,857	3.64	2.51	13,857	3	3
Hotels/Motels	Lighting - Int	8' Fluor	Occupancy sensors for 8' fluorescent	11	$27.60	93	0.02	21.3%	20.0%	0.71	0.80	67,216	2.48	1.54	67,216	4	4
Hotels/Motels	Lighting - Int	Exit Signs	LED Exit Signs	10	$44.53	315	0.04	74.3%	74.3%	0.94	0.80	340,526	3.85	1.22	340,526	22	22
Hotels/Motels	Lighting - Int	HID	High-intensity discharge lamps (incandescent to metal halide)	17	$245.28	605	0.11	45.8%	45.8%	0.21	1.00	0	1.88	1.22	0	0	0
Hotels/Motels	Lighting - Int	Incand.	Compact flourescent lamp (modular)	9	-$45.29	314	0.06	64.9%	64.9%	0.96	0.05	50,330	-4.31	1.49	0	3	0
Hotels/Motels	Office Equip - Non PC	Copy/Fax	Power management enabling - copier	4	$44.60	470	0.01	53.8%	18.8%	0.74	0.80	455,809	2.31	0.99	455,809	11	11
Hotels/Motels	Office Equip - Non PC	Copy/Fax	External hardware control - printers	4	$165.99	160	0.00	54.4%	0.0%	0.51	0.80	217,313	0.21	0.99	0	0	0
Hotels/Motels	Office Equip - Non PC	Copy/Fax	Nighttime shutdown - printers	4	$636.74	142	0.00	56.6%	0.0%	0.83	0.80	284,068	0.05	0.99	0	0	0
Hotels/Motels	Office Equip - Non PC	Monitors	Network power management enabling - monitor	4	$4.67	117	0.00	72.8%	25.5%	0.73	0.80	1,223,315	5.46	0.99	1,223,315	31	31
Hotels/Motels	Office Equip - Non PC	Monitors	Power management enabling - monitor	3	$7.42	115	0.00	71.8%	25.1%	0.00	0.80	0	2.68	1.01	0	0	0
Hotels/Motels	Office Equip - Non PC	Monitors	External hardware control - monitors	5	$101.37	97	0.00	69.9%	0.0%	0.52	0.80	479,017	0.25	0.97	0	0	0
Hotels/Motels	Office Equip - PC	CPUs	Power management enabling - PC	4	$13.29	90	0.00	37.5%	13.1%	0.67	0.80	447,085	1.48	0.99	447,085	11	11
Hotels/Motels	Office Equip - PC	CPUs	LCD monitor	5	$455.58	80	0.01	49.7%	49.7%	0.99	0.80	691,464	0.05	0.96	0	57	0
Hotels/Motels	Refrigeration	Compressors	Demand defrost electric	9	$0.03	3	0.00	9.0%	9.0%	0.00	0.99	0	37.57	1.11	0	0	0
Hotels/Motels	Refrigeration	Compressors	Demand hot gas defrost	10	$0.03	1	0.00	3.3%	3.3%	0.00	0.99	0	16.69	1.08	0	0	0
Hotels/Motels	Refrigeration	Compressors	Efficiency compressor motor retrofit	10	$0.07	2	0.00	6.6%	6.6%	0.00	0.99	0	13.15	1.08	0	0	0
Hotels/Motels	Refrigeration	Compressors	Floating head pressure controls	16	$0.11	2	0.00	6.5%	0.0%	0.00	0.99	0	8.84	0.81	0	0	0
Hotels/Motels	Refrigeration	Compressors	Anti-sweat (humidistat) controls	14	$0.14	1	0.00	4.5%	1.8%	0.00	0.30	0	4.74	0.90	0	0	0
Hotels/Motels	Refrigeration	Compressors	Strip curtains for walk-ins	4	$0.05	1	0.00	3.2%	3.2%	0.00	0.99	0	3.91	0.98	0	0	0
Hotels/Motels	Refrigeration	Compressors	Night covers for display cases	5	$0.14	2	0.00	5.5%	0.0%	0.00	0.99	0	3.14	0.97	0	0	0
Hotels/Motels	Refrigeration	Compressors	Evaporator fan controller for MT walk-ins	5	$0.05	0	0.00	1.2%	1.2%	0.00	0.99	0	1.81	0.98	0	0	0
Hotels/Motels	Refrigeration	Compressors	Compressor VSD retrofit	11	$0.45	2	0.00	5.1%	2.5%	0.00	0.99	0	1.53	0.95	0	0	0
Hotels/Motels	Refrigeration	Compressors	Refrigeration commissioning	3	$0.20	1	0.00	4.5%	4.5%	0.00	0.99	0	1.17	1.01	0	0	0
Hotels/Motels	Refrigeration	Fans/Motors	Demand defrost electric	9	$0.03	3	0.00	9.0%	9.0%	0.00	0.99	0	37.57	1.11	0	0	0
Hotels/Motels	Refrigeration	Fans/Motors	Demand hot gas defrost	10	$0.03	1	0.00	3.3%	3.3%	0.00	0.99	0	16.69	1.08	0	0	0
Hotels/Motels	Refrigeration	Fans/Motors	Anti-sweat (humidistat) controls	14	$0.14	1	0.00	4.5%	1.8%	0.00	0.30	0	4.74	0.90	0	0	0
Hotels/Motels	Refrigeration	Fans/Motors	Strip curtains for walk-ins	4	$0.05	1	0.00	3.2%	3.2%	0.00	0.99	0	3.91	0.98	0	0	0

Subsector	End Use	Technology Type	Measure Name	Life	Incremental Costs	kWh Savings	kW Savings	% kWh Savings	% kW Savings	Applicability Factor	1-Saturation Factor	Technical Potential (kWh)	TRC	RIM	Economic Potential (kWh)	Technical Potential (kW)	Economic Potential (kW)
Hotels/Motels	Refrigeration	Fans/Motors	Night covers for display cases	5	$0.14	2	0.00	5.5%	0.0%	0.00	0.99	0	3.14	0.97	0	0	0
Hotels/Motels	Refrigeration	Fans/Motors	High-efficiency fan motors	18	$1.12	3	0.00	11.4%	11.4%	0.00	0.99	0	1.89	0.97	0	0	0
Hotels/Motels	Refrigeration	Fans/Motors	Evaporator fan controller for MT walk-ins	5	$0.05	0	0.00	1.2%	1.2%	0.00	0.99	0	1.81	0.96	0	0	0
Hotels/Motels	Refrigeration	Fans/Motors	Refrigeration commissioning	3	$0.20	1	0.00	4.5%	4.5%	0.00	0.99	0	1.17	1.01	0	0	0
Hotels/Motels	Ventilation	Motor	Variable-speed drives	8	$0.23	13	0.00	37.9%	1.2%	0.98	0.95	495,367	19.08	0.90	495,367	1	1
Hotels/Motels	Ventilation	Motor	Premium-efficiency motors	16	$5.71	164	0.01	4.9%	6.0%	1.00	0.95	41,678	17.20	1.01	41,678	5	5
Hotels/Motels	Ventilation	Motor	CV to VAV conversion	22	$98.07	1,148	0.01	37.9%	4.5%	0.24	0.95	73,741	6.77	0.82	73,741	1	1
Hotels/Motels	Ventilation	Motor	Unoccupied OA reduction	14	$112.66	634	0.01	6.4%	1.7%	0.82	0.95	39,399	2.67	0.87	39,399	1	1
Hotels/Motels	Ventilation	Motor	Automatic OA reduction control	15	$773.99	942	0.03	7.5%	3.5%	0.70	0.95	36,922	0.62	0.89	36,922	2	2
Hotels/Motels	Ventilation	Motor	Installation of nighttime pre-cooling controls and systems	10	$88.90	0	0.00	0.0%	22.8%	0.75	0.95	0	0.00	35.93	0	13	0
Hotels/Motels	Ventilation	Motor	Installation of outside air reset controls	1	$0.86	0	0.00	0.0%	0.0%	0.68	0.95	0	0.00	0.00	0	0	0
Hotels/Motels	Ventilation	Motor	Reducing minimum outside air requirements	1	$0.84	0	0.00	0.0%	0.0%	0.72	0.95	0	0.00	0.00	0	0	0
Hotels/Motels	Ventilation	Motor w/VFD	Premium-efficiency motors	16	$5.71	164	0.01	4.9%	6.0%	1.00	0.95	64,548	17.20	1.01	64,548	5	5
Hotels/Motels	Ventilation	Motor w/VFD	CV to VAV conversion	22	$98.07	1,148	0.01	37.9%	4.5%	0.24	0.95	114,205	6.77	0.82	114,205	1	1
Hotels/Motels	Ventilation	Motor w/VFD	Unoccupied OA reduction	14	$112.66	634	0.01	6.4%	1.7%	0.82	0.95	61,018	2.67	0.87	61,018	1	1
Hotels/Motels	Ventilation	Motor w/VFD	Automatic OA reduction control	15	$773.99	942	0.03	7.5%	3.5%	0.70	0.95	57,182	0.62	0.89	57,182	2	2
Hotels/Motels	Ventilation	Motor w/VFD	Installation of nighttime pre-cooling controls and systems	10	$88.90	0	0.00	0.0%	22.8%	0.75	0.95	0	0.00	35.93	0	13	0
Hotels/Motels	Ventilation	Motor w/VFD	Installation of outside air reset controls	1	$0.86	0	0.00	0.0%	0.0%	0.68	0.95	0	0.00	0.00	0	0	0
Hotels/Motels	Ventilation	Motor w/VFD	Reducing minimum outside air requirements	1	$0.84	0	0.00	0.0%	0.0%	0.72	0.95	0	0.00	0.00	0	0	0
Hotels/Motels	Water Heating	Call	Faucet Aerator	11	$0.01	0	0.00	1.9%	1.9%	0.71	0.80	54,629	0.51	33.34	54,629	4	4
Hotels/Motels	Water Heating	Call	Tank Insulation	15	$0.03	0	0.00	8.0%	8.0%	0.61	0.80	191,841	0.50	26.55	191,841	14	14
Hotels/Motels	Water Heating	Call	Circulation Pump Timelocks	13	$0.01	0	0.00	2.9%	2.9%	0.68	0.80	73,361	0.42	29.41	0	5	0
Hotels/Motels	Water Heating	Call	Instanteous Water Heater <=200 MBTUH	16	$0.07	0	0.00	9.7%	9.7%	0.80	0.80	289,928	0.26	25.40	0	21	0
Hotels/Motels	Water Heating	Call	Low Flow Showerheads	10	$0.02	0	0.00	2.2%	2.2%	0.85	0.80	63,901	0.24	35.92	0	5	0
Hotels/Motels	Water Heating	Call	Heater efficiency upgrade	12	$0.24	0	0.00	24.8%	24.8%	0.84	0.80	724,144	0.19	31.22	0	53	0
Hotels/Motels	Water Heating	Call	Pipe Insulation	16	$0.02	0	0.00	1.7%	1.7%	0.73	0.80	35,887	0.17	25.39	0	3	0
Hotels/Motels	Water Heating	Call	Solar Water Heater	1	$0.00	0	0.00	0.0%	0.0%	0.69	0.80	0	0.00	1.06	0	0	0
Hotels/Motels	Water Heating	Call	Heat Recovery Water Heater	1	$0.00	0	0.00	0.0%	0.0%	0.57	0.80	0	0.00	1.06	0	0	0
Restaurant/Bars	Cooking	All	Infrared Fryer	15	$99.12	0	0.00	9.6%	9.6%	0.48	0.80	191,891	0.00	26.56	0	42	0
Restaurant/Bars	Cooking	All	Convection Oven	14	$86.77	0	0.00	4.7%	4.7%	0.58	0.80	107,629	0.00	27.88	0	24	0
Restaurant/Bars	Cooking	All	Infrared Conveyor Oven	14	$93.02	0	0.00	5.0%	5.0%	0.51	0.80	100,251	0.00	27.88	0	22	0
Restaurant/Bars	Cooking	All	Power Burner Fryer	15	$96.69	0	0.00	2.7%	2.7%	0.43	0.80	44,136	0.00	26.56	0	10	0
Restaurant/Bars	Cooking	All	Power Burner Oven	16	$102.60	0	0.00	2.4%	2.4%	0.56	0.80	51,999	0.00	25.40	0	12	0
Restaurant/Bars	Cooking	All	Efficient Infrared Griddle	14	$112.64	0	0.00	2.3%	2.3%	0.52	0.80	45,195	0.00	27.88	0	10	0
Restaurant/Bars	Cooling	Chillers	High-efficiency chillers	20	$43.22	1,090	0.08	47.3%	7.2%	0.87	0.90	540,896	16.34	0.96	540,896	40	40
Restaurant/Bars	Cooling	Chillers	Chiller economizers (water side), or air side economizers	13	$71.04	590	0.00	25.6%	0.0%	0.00	0.90	0	3.59	0.83	0	0	0
Restaurant/Bars	Cooling	Chillers	Energy management controls	10	$1,107.82	7,546	0.15	4.9%	0.2%	0.00	0.90	0	2.77	0.92	0	0	0
Restaurant/Bars	Cooling	Chillers	Variable-speed drives	15	$63.82	130	0.06	5.6%	5.6%	0.00	0.90	0	2.37	1.95	0	0	0
Restaurant/Bars	Cooling	Chillers	Window treatment	11	$0.74	2	0.00	4.5%	1.2%	0.00	0.90	0	1.81	1.22	0	0	0
Restaurant/Bars	Cooling	Chillers	Cool (reflective) rooftops	21	$0.54	0	0.00	1.5%	0.3%	0.00	0.90	0	0.61	1.03	0	0	0
Restaurant/Bars	Cooling	Chillers	Installation of wall, roof, or ceiling insulation	21	$0.60	0	0.00	0.0%	0.1%	0.61	0.90	107	0.01	3.90	0	0	0
Restaurant/Bars	Cooling	Chillers	Optimize chilled water and condenser water setting	3	$103.98	0	0.00	1.1%	1.1%	0.60	0.90	5,612	0.00	0.97	0	4	0
Restaurant/Bars	Cooling	Chillers	Installation of low-E glass or multiple glazed windows	30	$0.67	1	0.00	1.6%	0.4%	0.44	0.90	5,696	0.00	0.00	0	1	0
Restaurant/Bars	Cooling	Chillers	Cool Storage	1	$0.00	0	0.00	0.0%	0.0%	0.76	0.90	0	0.00	0.00	0	0	0
Restaurant/Bars	Cooling	Chillers	Heat Pipe Enhanced DX	20	$0.00	0	0.00	0.0%	0.0%	0.50	0.90	0	0.00	0.00	0	0	0
Restaurant/Bars	Cooling	Chillers	Improved maintenance and diagnostics	1	$751.34	-1,687	5.79	-1.1%	7.9%	0.98	0.90	-8,824	-0.14	1.47	0	46	0
Restaurant/Bars	Cooling	DX Units	High-efficiency packaged DX A/C	18	$99.97	775	0.09	33.6%	8.1%	0.90	0.95	2,671,893	5.28	1.07	2,671,893	309	309
Restaurant/Bars	Cooling	DX Units	Energy management controls	10	$1,107.82	7,546	0.15	4.9%	0.2%	0.00	0.95	0	2.77	0.92	0	0	0
Restaurant/Bars	Cooling	DX Units	Variable-speed drives	15	$63.82	130	0.06	5.6%	5.6%	0.00	0.95	0	2.37	1.95	0	0	0
Restaurant/Bars	Cooling	DX Units	Window treatment	11	$0.74	2	0.00	4.5%	1.2%	0.00	0.95	0	1.81	1.22	0	0	0
Restaurant/Bars	Cooling	DX Units	Cool (reflective) rooftops	21	$0.54	0	0.00	1.5%	0.3%	0.00	0.95	0	0.61	1.03	0	0	0
Restaurant/Bars	Cooling	DX Units	Installation of wall, roof, or ceiling insulation	21	$0.60	0	0.00	0.0%	0.1%	0.61	0.95	819	0.01	3.90	0	2	0
Restaurant/Bars	Cooling	DX Units	Installation of low-E glass or multiple glazed windows	30	$0.67	1	0.00	1.6%	0.4%	0.44	0.95	43,683	0.00	0.00	0	8	0
Restaurant/Bars	Cooling	DX Units	Cool Storage	1	$0.00	0	0.00	0.0%	0.0%	0.76	0.95	0	0.00	0.00	0	0	0
Restaurant/Bars	Cooling	DX Units	Heat Pipe Enhanced DX	20	$0.00	0	0.00	0.0%	0.0%	0.50	0.95	0	0.00	0.00	0	0	0
Restaurant/Bars	Cooling	DX Units	Improved maintenance and diagnostics	1	$751.34	-1,687	5.79	-1.1%	7.9%	0.98	0.95	-67,650	-0.14	1.47	0	305	0
Restaurant/Bars	Cooling	Room AC	Energy management controls	10	$1,107.82	7,546	0.15	4.9%	0.2%	0.00	0.90	0	2.77	0.92	0	0	0
Restaurant/Bars	Cooling	Room AC	Variable-speed drives	15	$63.82	130	0.06	5.6%	5.6%	0.00	0.90	0	2.37	1.95	0	0	0
Restaurant/Bars	Cooling	Room AC	Window treatment	11	$0.74	2	0.00	4.5%	1.2%	0.00	0.90	0	1.81	1.22	0	0	0
Restaurant/Bars	Cooling	Room AC	Cool (reflective) rooftops	21	$0.54	0	0.00	1.5%	0.3%	0.00	0.90	0	0.61	1.03	0	0	0
Restaurant/Bars	Cooling	Room AC	Installation of wall, roof, or ceiling insulation	21	$0.60	0	0.00	0.0%	0.1%	0.61	0.90	640	0.01	3.90	0	1	0
Restaurant/Bars	Cooling	Room AC	Installation of low-E glass or multiple glazed windows	30	$0.67	1	0.00	1.6%	0.4%	0.44	0.90	34,162	0.00	0.00	0	5	0
Restaurant/Bars	Cooling	Room AC	Cool Storage	1	$0.00	0	0.00	0.0%	0.0%	0.76	0.90	0	0.00	0.00	0	0	0
Restaurant/Bars	Cooling	Room AC	Heat Pipe Enhanced DX	20	$0.00	0	0.00	0.0%	0.0%	0.50	0.90	0	0.00	0.00	0	0	0
Restaurant/Bars	Cooling	Room AC	Improved maintenance and diagnostics	1	$751.34	-1,687	5.79	-1.1%	7.9%	0.98	0.90	-52,924	-0.14	1.47	0	183	0
Restaurant/Bars	Heating	Cntrl - HP	Window treatment	10	$0.65	0	0.00	6.2%	16.6%	0.99	0.80	0	0.14	0.85	0	0	0
Restaurant/Bars	Heating	Cntrl - HP	Infiltration Reduction	16	$0.44	0	0.00	7.7%	10.5%	0.86	0.80	0	0.06	0.81	0	0	0
Restaurant/Bars	Heating	Cntrl - HP	Installation of low-E glass or multiple glazed windows	23	$2.46	0	0.00	3.1%	11.8%	0.88	0.80	0	0.03	0.81	0	0	0
Restaurant/Bars	Heating	Cntrl - HP	Cool (reflective) rooftops	21	$0.64	0	0.00	0.0%	0.2%	0.00	0.80	0	0.00	0.81	0	0	0
Restaurant/Bars	Heating	Cntrl - RTU/Furn	Window treatment	10	$0.65	0	0.00	6.2%	16.6%	0.99	0.80	100,611	0.14	0.85	0	0	0
Restaurant/Bars	Heating	Cntrl - RTU/Furn	Infiltration Reduction	16	$0.44	0	0.00	7.7%	10.5%	0.86	0.80	103,325	0.06	0.81	0	0	0
Restaurant/Bars	Heating	Cntrl - RTU/Furn	Installation of low-E glass or multiple glazed windows	23	$2.46	0	0.00	3.1%	11.8%	0.88	0.80	40,192	0.03	0.81	0	0	0
Restaurant/Bars	Heating	Cntrl - RTU/Furn	Cool (reflective) rooftops	21	$0.64	0	0.00	0.0%	0.2%	0.00	0.80	0	0.00	0.81	0	0	0
Restaurant/Bars	Heating	Unitary	Window treatment	10	$0.65	0	0.00	6.2%	16.6%	0.99	0.80	506	0.14	0.85	0	0	0
Restaurant/Bars	Heating	Unitary	Infiltration Reduction	16	$0.44	0	0.00	7.7%	10.5%	0.86	0.80	519	0.06	0.81	0	0	0
Restaurant/Bars	Heating	Unitary	Installation of low-E glass or multiple glazed windows	23	$2.46	0	0.00	3.1%	11.8%	0.88	0.80	202	0.03	0.81	0	0	0
Restaurant/Bars	Heating	Unitary	Cool (reflective) rooftops	21	$0.64	0	0.00	0.0%	0.2%	0.00	0.80	0	0.00	0.81	0	0	0
Restaurant/Bars	Lighting - Ext	E Incand.	High-intensity discharge lamps (incandescent to hi-pres sodium)	14	$148.29	2,050	0.50	71.5%	71.5%	0.76	0.80	908,151	11.14	1.44	908,151	11	11
Restaurant/Bars	Lighting - Ext	E Incand.	Outdoor lighting controls for incandescent (photocell/timeclock)	8	$109.02	1,528	0.00	25.2%	0.0%	0.70	0.80	167,700	4.73	0.89	167,700	0	0
Restaurant/Bars	Lighting - Ext	Fluor	T8 lamps with electronic ballasts (2L4')	18	$3.75	45	0.01	35.7%	35.7%	0.98	0.80	266,642	10.46	1.34	266,642	3	3

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Subsector	End Use	Technology Type	Measure Name	Life	Incremental Costs	kWh Savings	kW Savings	% kWh Savings	% kW Savings	Applicability Factor	1-Saturation Factor	Technical Potential (kWh)	TRC	RIM	Economic Potential (kWh)	Technical Potential (kW)	Economic Potential (kW)
Restaurant/Bars	Lighting - Ext	Fluor	Outdoor lighting controls for fluorescent (photocell/timeclock)	8	$113.91	293	0.00	28.1%	0.0%	0.61	0.80	94,606	0.87	0.89	94,606	0	0
Restaurant/Bars	Lighting - Ext	HID	Outdoor lighting controls for HID (photocell/timeclock)	8	$108.99	1,528	0.00	27.4%	0.0%	0.72	0.80	333,421	4.73	0.89	333,421	0	0
Restaurant/Bars	Lighting - Ext	HID	High-intensity discharge lamps (mercury vapor to hi-pres sodium)	16	$154.57	841	0.21	51.9%	51.9%	0.91	0.80	670,781	4.56	1.38	670,781	10	10
Restaurant/Bars	Lighting - Int	4' Fluor	T8 lamps with electronic ballasts (2L4')	16	$5.71	51	0.01	32.9%	32.9%	0.97	0.20	323,633	7.09	1.32	323,633	64	64
Restaurant/Bars	Lighting - Int	4' Fluor	Reflectors for 4' fluorescent	17	$27.48	120	0.03	43.2%	43.2%	0.44	0.80	730,301	3.55	1.30	730,301	145	145
Restaurant/Bars	Lighting - Int	4' Fluor	Occupancy sensors for 4' fluorescent	8	$11.65	54	0.01	23.1%	23.1%	0.94	0.80	699,067	3.28	1.81	699,067	138	138
Restaurant/Bars	Lighting - Int	4' Fluor	Perimeter dimming for 4' fluorescent	13	$113.81	59	0.04	34.6%	73.2%	0.08	0.80	74,728	0.78	2.69	74,728	31	31
Restaurant/Bars	Lighting - Int	8' Fluor	Reflectors for 8' fluorescent	16	$27.13	189	0.04	41.0%	41.0%	0.37	0.80	154,403	5.56	1.32	154,403	31	31
Restaurant/Bars	Lighting - Int	8' Fluor	T8 lamps with electronic ballasts (2L8')	15	$9.95	51	0.01	18.3%	18.3%	0.84	0.20	33,870	3.99	1.35	33,870	7	7
Restaurant/Bars	Lighting - Int	8' Fluor	Perimeter dimming for 8' fluorescent	19	$52.86	109	0.09	27.8%	65.0%	0.11	0.80	25,904	3.64	2.51	25,904	16	16
Restaurant/Bars	Lighting - Int	8' Fluor	Occupancy sensors for 8' fluorescent	11	$27.60	93	0.02	21.3%	20.0%	0.71	0.80	125,646	2.48	1.54	125,646	22	22
Restaurant/Bars	Lighting - Int	Exit Signs	LED Exit Signs	10	$44.53	315	0.04	74.3%	74.3%	0.94	0.80	209,594	3.85	1.22	209,594	42	42
Restaurant/Bars	Lighting - Int	HID	High-intensity discharge lamps (incandescent to metal halide)	17	$245.28	506	0.11	45.8%	45.8%	0.21	1.00	0	1.68	1.30	0	0	0
Restaurant/Bars	Lighting - Int	Incand.	Compact flourescent lamp (modular)	9	-$45.29	262	0.06	64.9%	64.9%	0.96	0.05	25,714	-3.91	1.61	0	5	0
Restaurant/Bars	Office Equip - Non PC	Copy/Fax	Power management enabling - copier	4	$44.60	470	0.03	53.8%	18.8%	0.74	0.80	250,892	2.31	0.99	250,892	13	13
Restaurant/Bars	Office Equip - Non PC	Copy/Fax	External hardware control - printers	4	$165.99	160	0.00	54.4%	0.0%	0.51	0.80	119,618	0.21	0.99	0	0	0
Restaurant/Bars	Office Equip - Non PC	Copy/Fax	Nighttime shutdown - printers	4	$636.74	142	0.00	56.6%	0.0%	0.83	0.80	156,360	0.05	0.99	0	0	0
Restaurant/Bars	Office Equip - Non PC	Monitors	Network power management enabling - monitor	4	$4.67	117	0.01	72.8%	25.5%	0.73	0.80	705,415	5.46	0.99	705,415	38	38
Restaurant/Bars	Office Equip - Non PC	Monitors	Power management enabling - monitor	3	$7.42	115	0.01	71.8%	25.1%	0.00	0.80	0	2.68	1.01	0	0	0
Restaurant/Bars	Office Equip - Non PC	Monitors	External hardware control - monitors	5	$101.37	97	0.00	69.9%	0.0%	0.52	0.80	276,221	0.25	0.97	0	0	0
Restaurant/Bars	Office Equip - PC	CPUs	Power management enabling - PC	4	$13.29	90	0.00	37.5%	13.1%	0.67	0.80	265,391	1.48	0.99	265,391	14	14
Restaurant/Bars	Office Equip - PC	CPUs	LCD monitor	5	$455.58	80	0.01	49.7%	49.7%	0.99	0.80	410,455	0.05	0.96	0	73	0
Restaurant/Bars	Refrigeration	Compressors	Demand defrost electric	9	$0.03	3	0.00	9.0%	9.0%	0.00	0.99	0	45.77	1.35	0	0	0
Restaurant/Bars	Refrigeration	Compressors	Demand hot gas defrost	10	$0.03	1	0.00	3.3%	3.3%	0.75	0.99	192,449	20.18	1.30	192,449	27	27
Restaurant/Bars	Refrigeration	Compressors	Efficiency compressor motor retrofit	10	$0.07	2	0.00	6.6%	6.6%	1.00	0.99	505,043	15.91	1.30	505,043	70	70
Restaurant/Bars	Refrigeration	Compressors	Floating head pressure controls	16	$0.11	2	0.00	6.5%	0.0%	0.50	0.99	230,231	8.84	0.81	230,231	0	0
Restaurant/Bars	Refrigeration	Compressors	Anti-sweat (humidistat) controls	14	$0.14	1	0.00	4.5%	1.8%	0.00	0.30	0	5.12	0.97	0	0	0
Restaurant/Bars	Refrigeration	Compressors	Strip curtains for walk-ins	4	$0.05	1	0.00	3.2%	3.2%	0.75	0.99	164,374	3.91	0.98	164,374	24	24
Restaurant/Bars	Refrigeration	Compressors	Night covers for display cases	5	$0.14	2	0.00	5.5%	0.0%	0.50	0.99	185,723	3.14	0.97	185,723	0	0
Restaurant/Bars	Refrigeration	Compressors	Evaporator fan controller for MT walk-ins	5	$0.05	0	0.00	1.2%	1.2%	0.50	0.99	38,342	1.81	0.96	38,342	6	6
Restaurant/Bars	Refrigeration	Compressors	Compressor VSD retrofit	11	$0.45	2	0.00	5.1%	2.5%	0.50	0.99	165,228	1.70	1.05	165,228	12	12
Restaurant/Bars	Refrigeration	Compressors	Refrigeration commissioning	3	$0.20	1	0.00	4.5%	4.5%	0.50	0.99	144,073	1.17	1.00	144,073	22	22
Restaurant/Bars	Refrigeration	Fans/Motors	Demand defrost electric	9	$0.03	3	0.00	9.0%	9.0%	0.75	0.99	225,296	45.77	1.35	225,296	31	31
Restaurant/Bars	Refrigeration	Fans/Motors	Demand hot gas defrost	10	$0.03	1	0.00	3.3%	3.3%	0.75	0.99	76,991	20.18	1.30	76,991	11	11
Restaurant/Bars	Refrigeration	Fans/Motors	Anti-sweat (humidistat) controls	14	$0.14	1	0.00	4.5%	1.8%	0.50	0.30	20,652	5.12	0.97	20,652	1	1
Restaurant/Bars	Refrigeration	Fans/Motors	Strip curtains for walk-ins	4	$0.05	1	0.00	3.2%	3.2%	0.75	0.99	72,206	3.91	0.98	72,206	10	10
Restaurant/Bars	Refrigeration	Fans/Motors	Night covers for display cases	5	$0.14	2	0.00	5.5%	0.0%	0.50	0.99	81,583	3.14	0.97	81,583	0	0
Restaurant/Bars	Refrigeration	Fans/Motors	High-efficiency fan motors	18	$1.12	3	0.00	11.4%	11.4%	1.00	0.99	328,521	2.20	1.12	328,521	47	47
Restaurant/Bars	Refrigeration	Fans/Motors	Evaporator fan controller for MT walk-ins	5	$0.05	0	0.00	1.2%	1.2%	0.50	0.99	14,941	1.81	0.96	14,941	2	2
Restaurant/Bars	Refrigeration	Fans/Motors	Refrigeration commissioning	3	$0.20	1	0.00	4.5%	4.5%	0.50	0.99	57,588	1.17	1.00	57,588	8	8
Restaurant/Bars	Ventilation	Motor	Premium-efficiency motors	16	$5.71	164	0.03	4.9%	6.0%	1.00	0.95	53,722	20.35	1.18	53,722	8	8
Restaurant/Bars	Ventilation	Motor	Variable-speed drives	8	$0.23	13	0.00	36.5%	1.2%	0.98	0.95	378,702	18.54	0.90	378,702	2	2
Restaurant/Bars	Ventilation	Motor	CV to VAV conversion	22	$98.07	1,106	0.00	36.5%	-0.1%	0.24	0.95	60,303	6.39	0.81	60,303	0	0
Restaurant/Bars	Ventilation	Motor	Unoccupied OA reduction	14	$112.66	1,044	0.00	10.6%	0.2%	0.82	0.95	55,263	4.20	0.83	55,263	0	0
Restaurant/Bars	Ventilation	Motor	Automatic OA reduction control	15	$773.99	1,662	0.03	13.2%	2.1%	0.70	0.95	53,622	1.07	0.87	53,622	2	2
Restaurant/Bars	Ventilation	Motor	Installation of nighttime pre-cooling controls and systems	10	$88.90	0	0.00	0.0%	22.8%	0.75	0.95	0	0.00	35.93	0	22	0
Restaurant/Bars	Ventilation	Motor	Installation of outside air reset controls	1	$0.86	0	0.00	0.0%	0.0%	0.68	0.95	0	0.00	0.00	0	0	0
Restaurant/Bars	Ventilation	Motor	Reducing minimum outside air requirements	1	$0.84	0	0.00	0.0%	0.0%	0.72	0.95	0	0.00	0.00	0	0	0
Restaurant/Bars	Ventilation	Motor w/VFD	Premium-efficiency motors	16	$5.71	164	0.03	4.9%	6.0%	1.00	0.95	53,722	20.35	1.18	53,722	8	8
Restaurant/Bars	Ventilation	Motor w/VFD	CV to VAV conversion	22	$98.07	1,106	0.00	36.5%	-0.1%	0.24	0.95	91,534	6.39	0.81	91,534	0	0
Restaurant/Bars	Ventilation	Motor w/VFD	Unoccupied OA reduction	14	$112.66	1,044	0.00	10.6%	0.2%	0.82	0.95	83,883	4.20	0.83	83,883	0	0
Restaurant/Bars	Ventilation	Motor w/VFD	Automatic OA reduction control	15	$773.99	1,662	0.03	13.2%	2.1%	0.70	0.95	81,392	1.07	0.87	81,392	2	2
Restaurant/Bars	Ventilation	Motor w/VFD	Installation of nighttime pre-cooling controls and systems	10	$88.90	0	0.00	0.0%	22.8%	0.75	0.95	0	0.00	35.93	0	22	0
Restaurant/Bars	Ventilation	Motor w/VFD	Installation of outside air reset controls	1	$0.86	0	0.00	0.0%	0.0%	0.68	0.95	0	0.00	0.00	0	0	0
Restaurant/Bars	Ventilation	Motor w/VFD	Reducing minimum outside air requirements	1	$0.84	0	0.00	0.0%	0.0%	0.72	0.95	0	0.00	0.00	0	0	0
Restaurant/Bars	Water Heating	Call	Faucet Aerator	11	$0.01	0	0.00	1.9%	1.9%	0.71	0.80	25,409	1.24	33.35	25,409	5	5
Restaurant/Bars	Water Heating	Call	Tank Insulation	15	$0.03	0	0.00	8.0%	8.0%	0.01	0.80	89,231	1.22	26.55	89,231	18	18
Restaurant/Bars	Water Heating	Call	Circulation Pump Timeclocks	13	$0.01	0	0.00	2.9%	2.9%	0.68	0.80	34,122	1.03	29.41	34,122	7	7
Restaurant/Bars	Water Heating	Call	Instanteous Water Heater <=200 MBTUH	16	$0.07	0	0.00	9.7%	9.7%	0.80	0.80	134,854	0.64	25.40	134,854	27	27
Restaurant/Bars	Water Heating	Call	Low Flow Showerheads	10	$0.02	0	0.00	2.2%	2.2%	0.85	0.80	29,722	0.58	35.93	29,722	6	6
Restaurant/Bars	Water Heating	Call	Heater efficiency upgrade	12	$0.24	0	0.00	24.8%	24.8%	0.84	0.80	336,820	0.45	31.22	0	67	0
Restaurant/Bars	Water Heating	Call	Pipe Insulation	16	$0.02	0	0.00	1.7%	1.7%	0.73	0.80	16,692	0.42	25.40	0	3	0
Restaurant/Bars	Water Heating	Call	Solar Water Heater	1	$0.00	0	0.00	0.0%	0.0%	0.69	0.80	0	0.00	1.06	0	0	0
Restaurant/Bars	Water Heating	Call	Heat Recovery Water Heater	1	$0.00	0	0.00	0.0%	0.0%	0.57	0.80	0	0.00	1.06	0	0	0
Supermarket/Grocery	Cooking	All	Infrared Fryer	15	$99.12	0	0.00	9.6%	9.6%	0.48	0.80	35,348	0.00	26.56	0	4	0
Supermarket/Grocery	Cooking	All	Convection Oven	14	$86.77	0	0.00	4.7%	4.7%	0.58	0.80	19,626	0.00	27.88	0	2	0
Supermarket/Grocery	Cooking	All	Infrared Conveyor Oven	14	$93.02	0	0.00	5.0%	5.0%	0.51	0.80	18,467	0.00	27.88	0	2	0
Supermarket/Grocery	Cooking	All	Power Burner Fryer	15	$96.69	0	0.00	2.7%	2.7%	0.43	0.80	8,130	0.00	26.56	0	1	0
Supermarket/Grocery	Cooking	All	Power Burner Oven	16	$102.60	0	0.00	2.4%	2.4%	0.56	0.80	9,579	0.00	25.40	0	1	0
Supermarket/Grocery	Cooking	All	Efficient Infrared Griddle	14	$112.64	0	0.00	2.3%	2.3%	0.52	0.80	8,325	0.00	27.88	0	1	0
Supermarket/Grocery	Cooling	Chillers	High-efficiency chillers	20	$43.22	739	0.05	47.1%	9.5%	0.87	0.90	228,952	10.91	0.95	228,952	15	15
Supermarket/Grocery	Cooling	Chillers	Chiller economizers (water side), or air side economizers	13	$71.04	401	0.00	25.6%	0.0%	0.00	0.90	0	2.44	0.83	0	0	0
Supermarket/Grocery	Cooling	Chillers	Variable-speed drives	15	$83.82	88	0.03	5.6%	5.6%	0.00	0.90	0	1.31	1.61	0	0	0
Supermarket/Grocery	Cooling	Chillers	Cool (reflective) rooftops	21	$0.54	0	0.00	3.5%	1.3%	0.22	0.90	2,751	0.47	1.04	0	0	0
Supermarket/Grocery	Cooling	Chillers	Energy management controls	10	$1,107.82	764	-0.02	1.6%	-0.1%	0.71	0.90	3,870	0.24	0.78	0	0	0
Supermarket/Grocery	Cooling	Chillers	Window treatment	11	$0.74	0	0.00	1.8%	0.7%	0.84	0.90	5,129	0.23	1.22	0	1	0
Supermarket/Grocery	Cooling	Chillers	Improved maintenance and diagnostics	1	$751.34	768	1.89	1.8%	11.7%	0.98	0.90	5,260	0.07	0.88	0	19	0
Supermarket/Grocery	Cooling	Chillers	Installation of wall, roof, or ceiling insulation	21	$0.60	0	0.00	0.0%	0.1%	0.61	0.90	44	0.00	3.04	0	0	0
Supermarket/Grocery	Cooling	Chillers	Optimize chilled water and condenser water setting	3	$103.98	0	0.00	1.1%	1.1%	0.60	0.90	2,284	0.00	0.99	0	1	0
Supermarket/Grocery	Cooling	Chillers	Installation of low-E glass or multiple glazed windows	30	$0.67	0	0.00	0.6%	0.2%	0.44	0.90	839	0.00	0.00	0	0	0

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Subsector	End Use	Technology Type	Measure Name	Life	Incremental Costs	kWh Savings	kW Savings	% kWh Savings	% kW Savings	Applicability Factor	1-Saturation Factor	Technical Potential (kWh)	TRC	RIM	Economic Potential (kWh)	Technical Potential (kW)	Economic Potential (kW)
Supermarket/Grocery	Cooling	Chillers	Cool Storage	1	$0.00	0	0.00	0.0%	0.0%	0.76	0.90	0	0.00	0.00	0	0	0
Supermarket/Grocery	Cooling	Chillers	Heat Pipe Enhanced DX	20	$0.00	0	0.00	0.0%	0.0%	0.50	0.90	0	0.00	0.00	0	0	0
Supermarket/Grocery	Cooling	DX Units	High-efficiency packaged DX A/C	18	$99.97	524	0.05	33.4%	10.3%	0.90	0.95	1,314,385	3.46	1.03	1,314,385	134	134
Supermarket/Grocery	Cooling	DX Units	Variable-speed drives	15	$63.82	88	0.03	5.6%	5.6%	0.00	0.95	0	1.31	1.61	0	0	0
Supermarket/Grocery	Cooling	DX Units	Cool (reflective) rooftops	21	$0.54	0	0.00	3.5%	1.3%	0.22	0.95	24,442	0.47	1.04	0	4	0
Supermarket/Grocery	Cooling	DX Units	Energy management controls	10	$1,107.82	764	-0.02	1.6%	-0.1%	0.71	0.95	34,378	0.24	0.78	0	-1	0
Supermarket/Grocery	Cooling	DX Units	Window treatment	11	$0.74	0	0.00	1.8%	0.7%	0.84	0.95	45,531	0.23	1.22	0	7	0
Supermarket/Grocery	Cooling	DX Units	Improved maintenance and diagnostics	1	$751.34	768	1.89	1.6%	11.7%	0.98	0.95	46,659	0.07	0.88	0	150	0
Supermarket/Grocery	Cooling	DX Units	Installation of wall, roof, or ceiling insulation	21	$0.60	0	0.00	0.0%	0.1%	0.61	0.95	388	0.00	3.04	0	1	0
Supermarket/Grocery	Cooling	DX Units	Installation of low-E glass or multiple glazed windows	30	$0.67	0	0.00	0.6%	0.2%	0.44	0.95	7,481	0.00	0.00	0	1	0
Supermarket/Grocery	Cooling	DX Units	Cool Storage	1	$0.00	0	0.00	0.0%	0.0%	0.76	0.95	0	0.00	0.00	0	0	0
Supermarket/Grocery	Cooling	DX Units	Heat Pipe Enhanced DX	20	$0.00	0	0.00	0.0%	0.0%	0.50	0.95	0	0.00	0.00	0	0	0
Supermarket/Grocery	Cooling	Room AC	Variable-speed drives	15	$63.82	88	0.03	5.6%	5.6%	0.00	0.90	0	1.31	1.61	0	0	0
Supermarket/Grocery	Cooling	Room AC	Cool (reflective) rooftops	21	$0.54	0	0.00	3.5%	1.3%	0.22	0.90	11,221	0.47	1.04	0	1	0
Supermarket/Grocery	Cooling	Room AC	Energy management controls	10	$1,107.82	764	-0.02	1.6%	-0.1%	0.71	0.90	15,788	0.24	0.78	0	0	0
Supermarket/Grocery	Cooling	Room AC	Window treatment	11	$0.74	0	0.00	1.8%	0.7%	0.84	0.90	20,922	0.23	1.22	0	3	0
Supermarket/Grocery	Cooling	Room AC	Improved maintenance and diagnostics	1	$751.34	768	1.89	1.6%	11.7%	0.98	0.90	21,457	0.07	0.88	0	54	0
Supermarket/Grocery	Cooling	Room AC	Installation of wall, roof, or ceiling insulation	21	$0.60	0	0.00	0.0%	0.1%	0.61	0.90	178	0.00	3.04	0	0	0
Supermarket/Grocery	Cooling	Room AC	Installation of low-E glass or multiple glazed windows	30	$0.67	0	0.00	0.6%	0.2%	0.44	0.90	3,443	0.00	0.00	0	0	0
Supermarket/Grocery	Cooling	Room AC	Cool Storage	1	$0.00	0	0.00	0.0%	0.0%	0.76	0.90	0	0.00	0.00	0	0	0
Supermarket/Grocery	Cooling	Room AC	Heat Pipe Enhanced DX	20	$0.00	0	0.00	0.0%	0.0%	0.50	0.90	0	0.00	0.00	0	0	0
Supermarket/Grocery	Heating	Cntrl - HP	Window treatment	10	$0.65	1	0.00	14.2%	16.6%	0.99	0.80	0	0.52	0.85	0	0	0
Supermarket/Grocery	Heating	Cntrl - HP	Installation of low-E glass or multiple glazed windows	23	$2.46	0	0.00	7.3%	11.8%	0.88	0.80	0	0.11	0.81	0	0	0
Supermarket/Grocery	Heating	Cntrl - HP	Infiltration Reduction	16	$0.44	0	0.00	7.7%	10.5%	0.86	0.80	0	0.10	0.81	0	0	0
Supermarket/Grocery	Heating	Cntrl - HP	Cool (reflective) rooftops	21	$0.64	0	0.00	-2.0%	0.2%	0.00	0.80	0	-0.07	0.81	0	0	0
Supermarket/Grocery	Heating	Cntrl - RTU/Furn	Window treatment	10	$0.65	1	0.00	14.2%	16.6%	0.99	0.80	173,770	0.52	0.85	173,770	0	0
Supermarket/Grocery	Heating	Cntrl - RTU/Furn	Installation of low-E glass or multiple glazed windows	23	$2.46	0	0.00	7.3%	11.8%	0.88	0.80	70,123	0.11	0.81	0	0	0
Supermarket/Grocery	Heating	Cntrl - RTU/Furn	Infiltration Reduction	16	$0.44	0	0.00	7.7%	10.5%	0.86	0.80	69,241	0.10	0.81	0	0	0
Supermarket/Grocery	Heating	Cntrl - RTU/Furn	Cool (reflective) rooftops	21	$0.64	0	0.00	-2.0%	0.2%	0.00	0.80	0	-0.07	0.81	0	0	0
Supermarket/Grocery	Heating	Unitary	Window treatment	10	$0.65	1	0.00	14.2%	16.6%	0.99	0.80	57,000	0.52	0.85	57,000	0	0
Supermarket/Grocery	Heating	Unitary	Installation of low-E glass or multiple glazed windows	23	$2.40	0	0.00	7.3%	11.8%	0.88	0.80	23,002	0.11	0.81	0	0	0
Supermarket/Grocery	Heating	Unitary	Infiltration Reduction	16	$0.44	0	0.00	7.7%	10.5%	0.86	0.80	22,712	0.10	0.81	0	0	0
Supermarket/Grocery	Heating	Unitary	Cool (reflective) rooftops	21	$0.64	0	0.00	-2.0%	0.2%	0.00	0.80	0	-0.07	0.81	0	0	0
Supermarket/Grocery	Lighting - Ext	E Incand.	High-intensity discharge lamps (incandescent to hi-pres sodium)	14	$148.29	2,050	0.50	71.5%	71.5%	0.76	0.80	30,246	11.14	1.44	30,246	0	0
Supermarket/Grocery	Lighting - Ext	E Incand.	Outdoor lighting controls for incandescent (photocell/timeclock)	8	$109.02	1,528	0.00	25.2%	0.0%	0.70	0.80	5,585	4.73	0.89	5,585	0	0
Supermarket/Grocery	Lighting - Ext	Fluor	T8 lamps with electronic ballasts (2L4')	18	$3.75	45	0.01	35.7%	35.7%	0.98	0.80	34,774	10.46	1.34	34,774	0	0
Supermarket/Grocery	Lighting - Ext	Fluor	Outdoor lighting controls for fluorescent (photocell/timeclock)	8	$113.91	293	0.00	28.1%	0.0%	0.61	0.80	12,338	0.87	0.89	12,338	0	0
Supermarket/Grocery	Lighting - Ext	HID	Outdoor lighting controls for HID (photocell/timeclock)	8	$108.99	1,528	0.00	27.4%	0.0%	0.72	0.80	37,507	4.73	0.89	37,507	0	0
Supermarket/Grocery	Lighting - Ext	HID	High-intensity discharge lamps (mercury vapor to hi-pres sodium)	16	$154.57	841	0.21	51.9%	51.9%	0.91	0.80	75,457	4.56	1.38	75,457	1	1
Supermarket/Grocery	Lighting - Int	4' Fluor	T8 lamps with electronic ballasts (2L4')	16	$5.71	64	0.01	32.9%	32.9%	0.97	0.20	145,671	8.21	1.22	145,671	17	17
Supermarket/Grocery	Lighting - Int	4' Fluor	Reflectors for 4' fluorescent	17	$27.48	151	0.03	43.2%	43.2%	0.44	0.80	328,718	4.11	1.20	328,718	39	39
Supermarket/Grocery	Lighting - Int	4' Fluor	Occupancy sensors for 4' fluorescent	8	$11.65	54	0.01	23.1%	23.1%	0.94	0.80	314,659	3.28	1.81	314,659	37	37
Supermarket/Grocery	Lighting - Int	4' Fluor	Perimeter dimming for 4' fluorescent	13	$113.81	50	0.04	34.6%	73.2%	0.08	0.80	33,636	0.78	2.60	33,636	8	8
Supermarket/Grocery	Lighting - Int	8' Fluor	Reflectors for 8' fluorescent	16	$27.13	238	0.04	41.0%	41.0%	0.37	0.80	589,134	6.43	1.22	589,134	70	70
Supermarket/Grocery	Lighting - Int	8' Fluor	T8 lamps with electronic ballasts (2L8')	15	$9.95	64	0.01	18.3%	18.3%	0.84	0.20	129,234	4.60	1.24	129,234	15	15
Supermarket/Grocery	Lighting - Int	8' Fluor	Perimeter dimming for 8' fluorescent	19	$52.86	109	0.09	27.8%	85.0%	0.11	0.80	98,837	3.64	2.51	98,837	36	36
Supermarket/Grocery	Lighting - Int	8' Fluor	Occupancy sensors for 8' fluorescent	11	$27.60	93	0.02	21.3%	20.0%	0.71	0.80	479,409	2.48	1.54	479,409	51	51
Supermarket/Grocery	Lighting - Int	Exit Signs	LED Exit Signs	10	$44.53	315	0.04	74.3%	74.3%	0.94	0.80	237,168	3.85	1.22	237,168	28	28
Supermarket/Grocery	Lighting - Int	HID	High-intensity discharge lamps (incandescent to metal halide)	17	$245.28	638	0.11	45.8%	45.8%	0.21	1.00	0	1.95	1.20	0	0	0
Supermarket/Grocery	Lighting - Int	Incand.	Compact flourescent lamp (modular)	9	-$45.29	331	0.06	64.9%	64.9%	0.96	0.05	1,604	-4.45	1.46	0	0	0
Supermarket/Grocery	Office Equip - Non PC	Copy/Fax	Power management enabling - copier	4	$44.60	470	0.02	53.8%	18.8%	0.74	0.80	218,423	2.31	0.99	218,423	8	8
Supermarket/Grocery	Office Equip - Non PC	Copy/Fax	External hardware control - printers	4	$165.99	160	0.00	54.4%	0.0%	0.51	0.80	103,182	0.21	0.99	0	0	0
Supermarket/Grocery	Office Equip - Non PC	Copy/Fax	Nighttime shutdown - printers	4	$636.74	142	0.00	56.6%	0.0%	0.83	0.80	134,878	0.05	0.99	0	0	0
Supermarket/Grocery	Office Equip - Non PC	Monitors	Network power management enabling - monitor	4	$4.67	117	0.00	72.8%	25.5%	0.73	0.80	393,474	5.46	0.99	393,474	15	15
Supermarket/Grocery	Office Equip - Non PC	Monitors	Power management enabling - monitor	3	$7.42	115	0.00	71.8%	25.1%	0.00	0.80	0	2.68	1.01	0	0	0
Supermarket/Grocery	Office Equip - Non PC	Monitors	External hardware control - monitors	5	$101.37	97	0.00	69.9%	0.0%	0.52	0.80	154,073	0.25	0.97	0	0	0
Supermarket/Grocery	Office Equip - PC	CPUs	Power management enabling - PC	4	$13.29	90	0.00	37.5%	13.1%	0.67	0.80	115,203	1.48	0.99	115,203	4	4
Supermarket/Grocery	Office Equip - PC	CPUs	LCD monitor	5	$455.58	80	0.01	49.7%	49.7%	0.99	0.80	178,174	0.05	0.96	0	22	0
Supermarket/Grocery	Refrigeration	Compressors	Demand defrost electric	9	$0.03	3	0.00	9.0%	9.0%	0.00	0.99	0	43.15	1.27	0	0	0
Supermarket/Grocery	Refrigeration	Compressors	Demand hot gas defrost	10	$0.03	1	0.00	3.3%	3.3%	0.75	0.99	643,067	19.07	1.23	643,067	76	76
Supermarket/Grocery	Refrigeration	Compressors	Efficiency compressor motor retrofit	10	$0.07	2	0.00	6.6%	6.6%	1.00	0.99	1,687,599	15.03	1.23	1,687,599	198	198
Supermarket/Grocery	Refrigeration	Compressors	Floating head pressure controls	16	$0.11	2	0.00	6.5%	0.0%	0.50	0.99	769,318	8.84	0.81	769,318	0	0
Supermarket/Grocery	Refrigeration	Compressors	Anti-sweat (humidistat) controls	14	$0.14	1	0.00	4.5%	1.8%	0.00	0.30	0	5.00	0.94	0	0	0
Supermarket/Grocery	Refrigeration	Compressors	Strip curtains for walk-ins	4	$0.05	1	0.00	3.2%	3.2%	0.75	0.99	549,256	3.91	0.98	549,256	67	67
Supermarket/Grocery	Refrigeration	Compressors	Night covers for display cases	5	$0.14	2	0.00	5.5%	0.0%	0.50	0.99	620,591	3.14	0.97	620,591	0	0
Supermarket/Grocery	Refrigeration	Compressors	Evaporator fan controller for MT walk-ins	5	$0.05	0	0.00	1.2%	1.2%	0.50	0.99	128,121	1.81	0.96	128,121	16	16
Supermarket/Grocery	Refrigeration	Compressors	Compressor VSD retrofit	11	$0.45	2	0.00	5.1%	2.5%	0.50	0.99	552,109	1.65	1.02	552,109	34	34
Supermarket/Grocery	Refrigeration	Compressors	Refrigeration commissioning	3	$0.20	1	0.00	4.5%	4.5%	0.50	0.99	481,421	1.17	1.00	481,421	61	61
Supermarket/Grocery	Refrigeration	Fans/Motors	Demand defrost electric	9	$0.03	3	0.00	9.0%	9.0%	0.75	0.99	752,826	43.15	1.27	752,826	88	88
Supermarket/Grocery	Refrigeration	Fans/Motors	Demand hot gas defrost	10	$0.03	1	0.00	3.3%	3.3%	0.75	0.99	257,266	19.07	1.23	257,266	30	30
Supermarket/Grocery	Refrigeration	Fans/Motors	Anti-sweat (humidistat) controls	14	$0.14	1	0.00	4.5%	1.8%	0.50	0.30	69,010	5.00	0.94	69,010	3	3
Supermarket/Grocery	Refrigeration	Fans/Motors	Strip curtains for walk-ins	4	$0.05	1	0.00	3.2%	3.2%	0.75	0.99	241,275	3.91	0.98	241,275	28	28
Supermarket/Grocery	Refrigeration	Fans/Motors	Night covers for display cases	5	$0.14	2	0.00	5.5%	0.0%	0.50	0.99	272,611	3.14	0.97	272,611	0	0
Supermarket/Grocery	Refrigeration	Fans/Motors	High-efficiency fan motors	18	$1.12	3	0.00	11.4%	11.4%	1.00	0.99	1,097,752	2.11	1.07	1,097,752	133	133
Supermarket/Grocery	Refrigeration	Fans/Motors	Evaporator fan controller for MT walk-ins	5	$0.05	0	0.00	1.2%	1.2%	0.50	0.99	49,926	1.81	0.96	49,926	6	6
Supermarket/Grocery	Refrigeration	Fans/Motors	Refrigeration commissioning	3	$0.20	1	0.00	4.5%	4.5%	0.50	0.99	192,429	1.17	1.00	192,429	23	23
Supermarket/Grocery	Ventilation	Motor	Premium-efficiency motors	16	$5.71	164	0.02	4.9%	6.0%	1.00	0.95	41,014	18.74	1.09	41,014	5	5
Supermarket/Grocery	Ventilation	Motor	Variable-speed drives	8	$0.23	8	0.00	22.5%	1.2%	0.98	0.95	178,418	11.48	0.91	178,418	1	1
Supermarket/Grocery	Ventilation	Motor	CV to VAV conversion	22	$98.07	682	-0.01	22.5%	-2.6%	0.24	0.95	34,044	3.83	0.78	34,044	0	0
Supermarket/Grocery	Ventilation	Motor	Unoccupied OA reduction	14	$112.66	478	0.00	4.8%	-0.1%	0.82	0.95	23,933	1.89	0.82	23,933	0	0

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Subsector	End Use	Technology Type	Measure Name	Life	Incremental Costs	kWh Savings	kW Savings	% kWh Savings	% kW Savings	Applicability Factor	1-Saturation Factor	Technical Potential (kWh)	TRC	RIM	Economic Potential (kWh)	Technical Potential (kW)	Economic Potential (kW)
Supermarket/Grocery	Ventilation	Motor	Automatic OA reduction control	15	$773.99	599	0.00	4.8%	0.2%	0.70	0.95	19,169	0.37	0.83	0	0	0
Supermarket/Grocery	Ventilation	Motor	Installation of nighttime pre-cooling controls and systems	10	$86.90	0	0.00	0.0%	22.8%	0.75	0.95	0	0.00	35.93	0	13	0
Supermarket/Grocery	Ventilation	Motor	Installation of outside air reset controls	1	$0.86	0	0.00	0.0%	0.0%	0.68	0.95	0	0.00	0.00	0	0	0
Supermarket/Grocery	Ventilation	Motor	Reducing minimum outside air requirements	1	$0.84	0	0.00	0.0%	0.0%	0.72	0.95	0	0.00	0.00	0	0	0
Supermarket/Grocery	Ventilation	Motor w/VFD	Premium-efficiency motors	16	$5.71	164	0.02	4.9%	6.0%	1.00	0.95	41,014	18.74	1.09	41,014	5	5
Supermarket/Grocery	Ventilation	Motor w/VFD	CV to VAV conversion	22	$98.07	682	-0.01	22.5%	-2.6%	0.24	0.95	43,125	3.83	0.78	43,125	0	0
Supermarket/Grocery	Ventilation	Motor w/VFD	Unoccupied OA reduction	14	$112.66	478	0.00	4.8%	-0.1%	0.82	0.95	30,316	1.89	0.82	30,316	0	0
Supermarket/Grocery	Ventilation	Motor w/VFD	Automatic OA reduction control	15	$773.99	599	0.00	4.8%	0.2%	0.70	0.95	24,282	0.37	0.83	0	0	0
Supermarket/Grocery	Ventilation	Motor w/VFD	Installation of nighttime pre-cooling controls and systems	10	$86.90	0	0.00	0.0%	22.8%	0.75	0.95	0	0.00	35.93	0	13	0
Supermarket/Grocery	Ventilation	Motor w/VFD	Installation of outside air reset controls	1	$0.86	0	0.00	0.0%	0.0%	0.68	0.95	0	0.00	0.00	0	0	0
Supermarket/Grocery	Ventilation	Motor w/VFD	Reducing minimum outside air requirements	1	$0.84	0	0.00	0.0%	0.0%	0.72	0.95	0	0.00	0.00	0	0	0
Supermarket/Grocery	Water Heating	Call	Faucet Aerator	11	$0.01	0	0.00	1.9%	1.9%	0.71	0.80	51,342	0.71	33.35	51,342	6	6
Supermarket/Grocery	Water Heating	Call	Tank Insulation	15	$0.03	0	0.00	8.0%	8.0%	0.61	0.80	180,300	0.70	26.55	180,300	22	22
Supermarket/Grocery	Water Heating	Call	Circulation Pump Timelocks	13	$0.01	0	0.00	2.9%	2.9%	0.68	0.80	68,947	0.59	29.41	68,947	8	8
Supermarket/Grocery	Water Heating	Call	Instanteous Water Heater <=200 MBTUH	16	$0.07	0	0.00	9.7%	9.7%	0.80	0.80	272,487	0.37	25.40	0	33	0
Supermarket/Grocery	Water Heating	Call	Low Flow Showerheads	10	$0.02	0	0.00	2.2%	2.2%	0.85	0.80	60,057	0.34	35.92	0	7	0
Supermarket/Grocery	Water Heating	Call	Heater efficiency upgrade	12	$0.24	0	0.00	24.8%	24.8%	0.84	0.80	680,582	0.26	31.22	0	81	0
Supermarket/Grocery	Water Heating	Call	Pipe Insulation	16	$0.02	0	0.00	1.7%	1.7%	0.73	0.80	33,728	0.24	25.39	0	4	0
Supermarket/Grocery	Water Heating	Call	Solar Water Heater	1	$0.00	0	0.00	0.0%	0.0%	0.69	0.80	0	0.00	1.06	0	0	0
Supermarket/Grocery	Water Heating	Call	Heat Recovery Water Heater	1	$0.00	0	0.00	0.0%	0.0%	0.57	0.80	0	0.00	1.06	0	0	0
Hospital/Clinic	Cooking	All	Infrared Fryer	15	$99.12	0	0.00	9.6%	9.6%	0.49	0.80	10,124	0.00	26.56	0	1	0
Hospital/Clinic	Cooking	All	Convection Oven	14	$86.77	0	0.00	4.7%	4.7%	0.51	0.80	4,917	0.00	27.88	0	1	0
Hospital/Clinic	Cooking	All	Infrared Conveyor Oven	14	$93.02	0	0.00	5.0%	5.0%	0.58	0.80	5,869	0.00	27.88	0	1	0
Hospital/Clinic	Cooking	All	Power Burner Fryer	15	$96.69	0	0.00	2.7%	2.7%	0.54	0.80	2,867	0.00	26.56	0	0	0
Hospital/Clinic	Cooking	All	Power Burner Oven	16	$102.60	0	0.00	2.4%	2.4%	0.55	0.80	2,610	0.00	25.40	0	0	0
Hospital/Clinic	Cooking	All	Efficient Infrared Griddle	14	$112.64	0	0.00	2.3%	2.3%	0.41	0.80	1,831	0.00	27.88	0	0	0
Hospital/Clinic	Cooling	Chillers	High-efficiency chillers	20	$43.22	370	0.04	47.6%	17.3%	0.97	0.90	1,230,357	6.06	1.05	1,230,357	141	141
Hospital/Clinic	Cooling	Chillers	Window treatment	11	$0.74	2	0.00	22.1%	16.3%	0.00	0.90	0	1.61	1.53	0	0	0
Hospital/Clinic	Cooling	Chillers	Chiller economizers (water side), or air side economizers	13	$71.04	199	0.00	25.6%	0.0%	0.00	0.90	0	1.21	0.83	0	0	0
Hospital/Clinic	Cooling	Chillers	Variable-speed drives	15	$63.82	44	0.01	5.6%	5.6%	0.00	0.90	0	0.64	1.58	0	0	0
Hospital/Clinic	Cooling	Chillers	Energy management controls	10	$1,107.82	874	0.14	4.0%	2.0%	0.78	0.90	48,975	0.48	1.35	0	11	0
Hospital/Clinic	Cooling	Chillers	Cool (reflective) rooftops	21	$0.54	0	0.00	0.6%	0.2%	0.27	0.90	2,296	0.03	1.07	0	0	0
Hospital/Clinic	Cooling	Chillers	Installation of wall, roof, or ceiling insulation	21	$0.60	0	0.00	0.0%	0.1%	0.42	0.90	138	0.00	2.96	0	0	0
Hospital/Clinic	Cooling	Chillers	Optimize chilled water and condenser water setting	3	$103.98	0	0.00	1.1%	1.1%	0.72	0.90	12,175	0.00	0.99	0	6	0
Hospital/Clinic	Cooling	Chillers	Installation of low-E glass or multiple glazed windows	30	$0.67	1	0.00	9.7%	6.3%	0.50	0.90	72,923	0.00	0.00	0	22	0
Hospital/Clinic	Cooling	Chillers	Cool Storage	1	$0.00	0	0.00	0.0%	0.0%	0.65	0.90	0	0.00	0.00	0	0	0
Hospital/Clinic	Cooling	Chillers	Heat Pipe Enhanced DX	20	$0.00	0	0.00	0.0%	0.0%	0.50	0.90	0	0.00	0.00	0	0	0
Hospital/Clinic	Cooling	Chillers	Improved maintenance and diagnostics	1	$751.34	-135	1.11	-0.6%	16.2%	0.92	0.90	-8,218	-0.01	3.21	0	101	0
Hospital/Clinic	Cooling	DX Units	High-efficiency packaged DX A/C	18	$99.97	264	0.04	34.0%	17.1%	0.92	0.95	1,634,980	1.97	1.16	1,634,980	260	260
Hospital/Clinic	Cooling	DX Units	Window treatment	11	$0.74	2	0.00	22.1%	16.3%	0.00	0.95	0	1.61	1.53	0	0	0
Hospital/Clinic	Cooling	DX Units	Variable-speed drives	15	$63.82	44	0.01	5.6%	5.6%	0.00	0.95	0	0.64	1.58	0	0	0
Hospital/Clinic	Cooling	DX Units	Energy management controls	10	$1,107.82	874	0.14	4.0%	2.0%	0.78	0.95	114,783	0.48	1.35	0	22	0
Hospital/Clinic	Cooling	DX Units	Cool (reflective) rooftops	21	$0.54	0	0.00	0.6%	0.2%	0.27	0.95	5,373	0.03	1.07	0	1	0
Hospital/Clinic	Cooling	DX Units	Installation of wall, roof, or ceiling insulation	21	$0.60	0	0.00	0.0%	0.1%	0.42	0.95	323	0.00	2.96	0	0	0
Hospital/Clinic	Cooling	DX Units	Installation of low-E glass or multiple glazed windows	30	$0.67	1	0.00	9.7%	6.3%	0.50	0.95	171,866	0.00	0.00	0	44	0
Hospital/Clinic	Cooling	DX Units	Cool Storage	1	$0.00	0	0.00	0.0%	0.0%	0.65	0.95	0	0.00	0.00	0	0	0
Hospital/Clinic	Cooling	DX Units	Heat Pipe Enhanced DX	20	$0.00	0	0.00	0.0%	0.0%	0.50	0.95	0	0.00	0.00	0	0	0
Hospital/Clinic	Cooling	DX Units	Improved maintenance and diagnostics	1	$751.34	-135	1.11	-0.6%	16.2%	0.92	0.95	-19,319	-0.01	3.21	0	199	0
Hospital/Clinic	Cooling	Room AC	Window treatment	11	$0.74	2	0.00	22.1%	16.3%	0.00	0.90	0	1.61	1.53	0	0	0
Hospital/Clinic	Cooling	Room AC	Variable-speed drives	15	$63.82	44	0.01	5.6%	5.6%	0.00	0.90	0	0.64	1.58	0	0	0
Hospital/Clinic	Cooling	Room AC	Energy management controls	10	$1,107.82	874	0.14	4.0%	2.0%	0.78	0.90	67,025	0.48	1.35	0	10	0
Hospital/Clinic	Cooling	Room AC	Cool (reflective) rooftops	21	$0.54	0	0.00	0.6%	0.2%	0.27	0.90	3,143	0.03	1.07	0	0	0
Hospital/Clinic	Cooling	Room AC	Installation of wall, roof, or ceiling insulation	21	$0.60	0	0.00	0.0%	0.1%	0.42	0.90	189	0.00	2.96	0	0	0
Hospital/Clinic	Cooling	Room AC	Installation of low-E glass or multiple glazed windows	30	$0.67	1	0.00	9.7%	6.3%	0.50	0.90	100,528	0.00	0.00	0	21	0
Hospital/Clinic	Cooling	Room AC	Cool Storage	1	$0.00	0	0.00	0.0%	0.0%	0.65	0.90	0	0.00	0.00	0	0	0
Hospital/Clinic	Cooling	Room AC	Heat Pipe Enhanced DX	20	$0.00	0	0.00	0.0%	0.0%	0.50	0.90	0	0.00	0.00	0	0	0
Hospital/Clinic	Cooling	Room AC	Improved maintenance and diagnostics	1	$751.34	-135	1.11	-0.6%	16.2%	0.92	0.90	-11,329	-0.01	3.21	0	96	0
Hospital/Clinic	Heating	Cntrl - HP	Window treatment	10	$0.65	4	0.00	51.4%	16.6%	0.96	0.80	0	2.15	0.85	0	0	0
Hospital/Clinic	Heating	Cntrl - HP	Installation of low-E glass or multiple glazed windows	23	$2.46	3	0.00	36.1%	11.8%	0.86	0.80	0	0.61	0.81	0	0	0
Hospital/Clinic	Heating	Cntrl - HP	Infiltration Reduction	16	$0.44	0	0.00	7.7%	10.5%	0.84	0.80	0	0.12	0.81	0	0	0
Hospital/Clinic	Heating	Cntrl - HP	Cool (reflective) rooftops	21	$0.64	0	0.00	-0.4%	0.2%	0.00	0.80	0	-0.01	0.81	0	0	0
Hospital/Clinic	Heating	Cntrl - RTU/Furn	Window treatment	10	$0.65	4	0.00	51.4%	16.6%	0.96	0.80	338,713	2.15	0.85	338,713	0	0
Hospital/Clinic	Heating	Cntrl - RTU/Furn	Installation of low-E glass or multiple glazed windows	23	$2.46	3	0.00	36.1%	11.8%	0.86	0.80	129,201	0.61	0.81	129,201	0	0
Hospital/Clinic	Heating	Cntrl - RTU/Furn	Infiltration Reduction	16	$0.44	0	0.00	7.7%	10.5%	0.84	0.80	20,096	0.12	0.81	0	0	0
Hospital/Clinic	Heating	Cntrl - RTU/Furn	Cool (reflective) rooftops	21	$0.64	0	0.00	-0.4%	0.2%	0.00	0.80	0	-0.01	0.81	0	0	0
Hospital/Clinic	Heating	Unitary	Window treatment	10	$0.65	4	0.00	51.4%	16.6%	0.96	0.80	208,481	2.15	0.85	208,481	0	0
Hospital/Clinic	Heating	Unitary	Installation of low-E glass or multiple glazed windows	23	$2.46	3	0.00	36.1%	11.8%	0.86	0.80	79,524	0.61	0.81	79,524	0	0
Hospital/Clinic	Heating	Unitary	Infiltration Reduction	16	$0.44	0	0.00	7.7%	10.5%	0.84	0.80	12,369	0.12	0.81	0	0	0
Hospital/Clinic	Heating	Unitary	Cool (reflective) rooftops	21	$0.64	0	0.00	-0.4%	0.2%	0.00	0.80	0	-0.01	0.81	0	0	0
Hospital/Clinic	Lighting - Ext	E Incand.	High-intensity discharge lamps (incandescent to hi-pres sodium)	14	$148.29	2,050	0.50	71.5%	71.5%	0.90	0.80	204,781	11.14	1.44	204,781	2	2
Hospital/Clinic	Lighting - Ext	E Incand.	Outdoor lighting controls for incandescent (photocell/timeclock)	8	$109.02	1,528	0.00	25.2%	0.0%	0.79	0.80	30,801	4.73	0.89	30,801	0	0
Hospital/Clinic	Lighting - Ext	Fluor	T8 lamps with electronic ballasts (2L4')	18	$3.75	45	0.01	35.7%	35.7%	0.86	0.80	45,425	10.46	1.34	45,425	0	0
Hospital/Clinic	Lighting - Ext	Fluor	Outdoor lighting controls for fluorescent (photocell/timeclock)	8	$113.91	293	0.00	28.1%	0.0%	0.80	0.80	25,065	0.87	0.89	25,065	0	0
Hospital/Clinic	Lighting - Ext	HID	Outdoor lighting controls for HID (photocell/timeclock)	8	$108.99	1,528	0.00	27.4%	0.0%	0.72	0.80	61,896	4.73	0.89	61,896	0	0
Hospital/Clinic	Lighting - Ext	HID	High-intensity discharge lamps (mercury vapor to hi-pres sodium)	16	$154.57	841	0.21	51.9%	51.9%	0.98	0.80	133,797	4.56	1.38	133,797	1	1
Hospital/Clinic	Lighting - Int	4' Fluor	T8 lamps with electronic ballasts (2L4')	16	$5.71	48	0.01	32.9%	32.9%	0.87	0.20	1,139,661	0.91	1.35	1,139,661	126	126
Hospital/Clinic	Lighting - Int	4' Fluor	Reflectors for 4' fluorescent	17	$27.48	114	0.03	43.2%	43.2%	0.39	0.80	2,534,833	3.45	1.32	2,534,833	280	280
Hospital/Clinic	Lighting - Int	4' Fluor	Occupancy sensors for 4' fluorescent	8	$11.65	54	0.01	23.1%	23.1%	0.90	0.80	2,681,377	3.28	1.81	2,681,377	296	296
Hospital/Clinic	Lighting - Int	4' Fluor	Perimeter dimming for 4' fluorescent	13	$113.81	59	0.04	34.6%	73.2%	0.09	0.80	343,327	0.78	2.69	343,327	80	80
Hospital/Clinic	Lighting - Int	8' Fluor	Reflectors for 8' fluorescent	16	$27.13	180	0.04	41.0%	41.0%	0.43	0.80	57,743	5.41	1.35	57,743	6	6

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Subsector	End Use	Technology Type	Measure Name	Life	Incremental Costs	kWh Savings	kW Savings	% kWh Savings	% kW Savings	Applicability Factor	1-Saturation Factor	Technical Potential (kWh)	TRC	RIM	Economic Potential (kWh)	Technical Potential (kW)	Economic Potential (kW)
Hospital/Clinic	Lighting - Int	8' Fluor	T8 lamps with electronic ballasts (2L8')	15	$9.95	48	0.01	18.3%	18.3%	0.97	0.20	12,422	3.88	1.37	12,422	1	1
Hospital/Clinic	Lighting - Int	8' Fluor	Perimeter dimming for 8' fluorescent	19	$52.86	109	0.09	27.8%	85.0%	0.11	0.80	8,264	3.64	2.51	8,264	3	3
Hospital/Clinic	Lighting - Int	8' Fluor	Occupancy sensors for 8' fluorescent	11	$27.60	93	0.02	21.3%	20.0%	0.79	0.80	44,126	2.48	1.54	44,126	4	4
Hospital/Clinic	Lighting - Int	Exit Signs	LED Exit Signs	10	$44.53	315	0.04	74.3%	74.3%	0.95	0.80	563,653	3.85	1.22	563,653	62	62
Hospital/Clinic	Lighting - Int	HID	High-intensity discharge lamps (incandescent to metal halide)	17	$245.28	484	0.11	45.8%	45.8%	0.20	1.00	0	1.64	1.32	0	0	0
Hospital/Clinic	Lighting - Int	Incand.	Compact flourescent lamp (modular)	9	-$45.29	251	0.06	64.9%	64.9%	0.97	0.05	13,654	-3.82	1.64	0	2	0
Hospital/Clinic	Office Equip - Non PC	Copy/Fax	Power management enabling - copier	4	$44.60	470	0.02	53.8%	18.8%	0.76	0.80	979,675	2.31	0.99	979,675	37	37
Hospital/Clinic	Office Equip - Non PC	Copy/Fax	External hardware control - printers	4	$165.99	160	0.00	54.4%	0.0%	0.56	0.80	496,563	0.21	0.99	0	0	0
Hospital/Clinic	Office Equip - Non PC	Copy/Fax	Nighttime shutdown - printers	4	$636.74	142	0.00	56.6%	0.0%	0.94	0.80	645,029	0.05	0.99	0	0	0
Hospital/Clinic	Office Equip - Non PC	Monitors	Network power management enabling - monitor	4	$4.67	117	0.00	72.8%	25.5%	0.76	0.80	4,371,406	5.46	0.99	4,371,406	164	164
Hospital/Clinic	Office Equip - Non PC	Monitors	Power management enabling - monitor	3	$7.42	115	0.00	71.8%	25.1%	0.00	0.80	0	2.68	1.01	0	0	0
Hospital/Clinic	Office Equip - Non PC	Monitors	External hardware control - monitors	5	$101.37	97	0.00	69.9%	0.0%	0.44	0.80	1,377,255	0.25	0.97	0	0	0
Hospital/Clinic	Office Equip - PC	CPUs	Power management enabling - PC	4	$13.29	90	0.00	37.5%	13.1%	0.58	0.80	1,002,992	1.48	0.99	1,002,992	38	38
Hospital/Clinic	Office Equip - PC	CPUs	LCD monitor	5	$455.58	80	0.01	49.7%	49.7%	0.97	0.80	1,843,868	0.05	0.96	0	224	0
Hospital/Clinic	Refrigeration	Compressors	Demand defrost electric	9	$0.03	3	0.00	9.0%	9.0%	0.00	0.99	0	40.82	1.21	0	0	0
Hospital/Clinic	Refrigeration	Compressors	Demand hot gas defrost	10	$0.03	1	0.00	3.3%	3.3%	0.00	0.99	0	18.08	1.17	0	0	0
Hospital/Clinic	Refrigeration	Compressors	Efficiency compressor motor retrofit	10	$0.07	2	0.00	6.6%	6.6%	0.00	0.99	0	14.25	1.17	0	0	0
Hospital/Clinic	Refrigeration	Compressors	Floating head pressure controls	16	$0.11	2	0.00	6.5%	0.0%	0.00	0.99	0	8.84	0.81	0	0	0
Hospital/Clinic	Refrigeration	Compressors	Anti-sweat (humidistat) controls	14	$0.14	1	0.00	4.5%	1.8%	0.00	0.30	0	4.89	0.92	0	0	0
Hospital/Clinic	Refrigeration	Compressors	Strip curtains for walk-ins	4	$0.05	1	0.00	3.2%	3.2%	0.00	0.99	0	3.91	0.98	0	0	0
Hospital/Clinic	Refrigeration	Compressors	Night covers for display cases	5	$0.14	2	0.00	5.5%	0.0%	0.00	0.99	0	3.14	0.97	0	0	0
Hospital/Clinic	Refrigeration	Compressors	Evaporator fan controller for MT walk-ins	5	$0.05	0	0.00	1.2%	1.2%	0.00	0.99	0	1.81	0.96	0	0	0
Hospital/Clinic	Refrigeration	Compressors	Compressor VSD retrofit	11	$0.45	2	0.00	5.1%	2.5%	0.00	0.99	0	1.60	0.99	0	0	0
Hospital/Clinic	Refrigeration	Compressors	Refrigeration commissioning	3	$0.20	1	0.00	4.5%	4.5%	0.00	0.99	0	1.17	1.01	0	0	0
Hospital/Clinic	Refrigeration	Fans/Motors	Demand defrost electric	9	$0.03	3	0.00	9.0%	9.0%	0.00	0.99	0	40.82	1.21	0	0	0
Hospital/Clinic	Refrigeration	Fans/Motors	Demand hot gas defrost	10	$0.03	1	0.00	3.3%	3.3%	0.00	0.99	0	18.08	1.17	0	0	0
Hospital/Clinic	Refrigeration	Fans/Motors	Anti-sweat (humidistat) controls	14	$0.14	1	0.00	4.5%	1.8%	0.00	0.30	0	4.89	0.92	0	0	0
Hospital/Clinic	Refrigeration	Fans/Motors	Strip curtains for walk-ins	4	$0.05	1	0.00	3.2%	3.2%	0.00	0.99	0	3.91	0.98	0	0	0
Hospital/Clinic	Refrigeration	Fans/Motors	Night covers for display cases	5	$0.14	2	0.00	5.5%	0.0%	0.00	0.99	0	3.14	0.97	0	0	0
Hospital/Clinic	Refrigeration	Fans/Motors	High-efficiency fan motors	18	$1.12	3	0.00	11.4%	11.4%	0.00	0.99	0	2.02	1.03	0	0	0
Hospital/Clinic	Refrigeration	Fans/Motors	Evaporator fan controller for MT walk-ins	5	$0.05	0	0.00	1.2%	1.2%	0.00	0.99	0	1.81	0.96	0	0	0
Hospital/Clinic	Refrigeration	Fans/Motors	Refrigeration commissioning	3	$0.20	1	0.00	4.5%	4.5%	0.00	0.99	0	1.17	1.01	0	0	0
Hospital/Clinic	Ventilation	Motor	Variable-speed drives	8	$0.23	14	0.00	39.6%	1.2%	1.00	0.95	875,070	19.97	0.90	875,070	2	2
Hospital/Clinic	Ventilation	Motor	Premium-efficiency motors	16	$5.71	164	0.02	4.9%	6.0%	0.88	0.95	59,607	18.41	1.07	59,607	10	10
Hospital/Clinic	Ventilation	Motor	CV to VAV conversion	22	$98.07	1,199	0.02	39.6%	7.3%	0.26	0.95	139,527	7.22	0.84	139,527	4	4
Hospital/Clinic	Ventilation	Motor	Unoccupied OA reduction	14	$112.66	354	0.02	3.6%	2.0%	0.76	0.95	32,584	1.64	0.95	32,584	3	3
Hospital/Clinic	Ventilation	Motor	Automatic OA reduction control	15	$773.99	583	0.03	4.6%	2.9%	0.65	0.95	35,017	0.41	0.96	0	3	0
Hospital/Clinic	Ventilation	Motor	Installation of nighttime pre-cooling controls and systems	10	$88.90	0	0.00	0.0%	22.8%	0.62	0.95	0	0.00	35.93	0	25	0
Hospital/Clinic	Ventilation	Motor	Installation of outside air reset controls	1	$0.86	0	0.00	0.0%	0.0%	0.86	0.95	0	0.00	0.00	0	0	0
Hospital/Clinic	Ventilation	Motor	Reducing minimum outside air requirements	1	$0.84	0	0.00	0.0%	0.0%	0.66	0.95	0	0.00	0.00	0	0	0
Hospital/Clinic	Ventilation	Motor w/VFD	Premium-efficiency motors	16	$5.71	164	0.02	4.9%	6.0%	0.88	0.95	95,318	18.41	1.07	95,318	10	10
Hospital/Clinic	Ventilation	Motor w/VFD	CV to VAV conversion	22	$98.07	1,199	0.02	39.6%	7.3%	0.26	0.95	223,118	7.22	0.84	223,118	4	4
Hospital/Clinic	Ventilation	Motor w/VFD	Unoccupied OA reduction	14	$112.66	354	0.02	3.6%	2.0%	0.76	0.95	52,106	1.64	0.95	52,106	3	3
Hospital/Clinic	Ventilation	Motor w/VFD	Automatic OA reduction control	15	$773.99	583	0.03	4.6%	2.9%	0.65	0.95	55,996	0.41	0.96	0	3	0
Hospital/Clinic	Ventilation	Motor w/VFD	Installation of nighttime pre-cooling controls and systems	10	$88.90	0	0.00	0.0%	22.8%	0.62	0.95	0	0.00	35.93	0	25	0
Hospital/Clinic	Ventilation	Motor w/VFD	Installation of outside air reset controls	1	$0.86	0	0.00	0.0%	0.0%	0.86	0.95	0	0.00	0.00	0	0	0
Hospital/Clinic	Ventilation	Motor w/VFD	Reducing minimum outside air requirements	1	$0.84	0	0.00	0.0%	0.0%	0.66	0.95	0	0.00	0.00	0	0	0
Hospital/Clinic	Water Heating	Call	Faucet Aerator	11	$0.01	0	0.00	1.9%	1.9%	0.85	0.80	24,233	0.45	33.34	0	3	0
Hospital/Clinic	Water Heating	Call	Tank Insulation	15	$0.03	0	0.00	8.0%	8.0%	0.63	0.80	73,640	0.44	26.55	0	8	0
Hospital/Clinic	Water Heating	Call	Circulation Pump Timelocks	13	$0.01	0	0.00	2.9%	2.9%	0.65	0.80	26,125	0.37	29.41	0	3	0
Hospital/Clinic	Water Heating	Call	Instanteous Water Heater <=200 MBTUH	18	$0.07	0	0.00	9.7%	9.7%	0.82	0.80	109,766	0.23	25.40	0	12	0
Hospital/Clinic	Water Heating	Call	Low Flow Showerheads	10	$0.02	0	0.00	2.2%	2.2%	0.72	0.80	20,233	0.21	35.92	0	2	0
Hospital/Clinic	Water Heating	Call	Heater efficiency upgrade	12	$0.24	0	0.00	24.8%	24.8%	0.81	0.80	257,801	0.16	31.22	0	28	0
Hospital/Clinic	Water Heating	Call	Pipe Insulation	16	$0.02	0	0.00	1.7%	1.7%	0.63	0.80	11,608	0.15	25.39	0	1	0
Hospital/Clinic	Water Heating	Call	Solar Water Heater	1	$0.00	0	0.00	0.0%	0.0%	0.75	0.80	0	0.00	1.06	0	0	0
Hospital/Clinic	Water Heating	Call	Heat Recovery Water Heater	1	$0.00	0	0.00	0.0%	0.0%	0.76	0.80	0	0.00	1.06	0	0	0
Offices	Cooking	All	Infrared Fryer	15	$99.12	0	0.00	9.6%	9.6%	0.43	0.80	15,282	0.00	28.56	0	4	0
Offices	Cooking	All	Convection Oven	14	$86.77	0	0.00	4.7%	4.7%	0.49	0.80	8,178	0.00	27.88	0	2	0
Offices	Cooking	All	Infrared Conveyor Oven	14	$93.02	0	0.00	5.0%	5.0%	0.60	0.80	10,550	0.00	27.88	0	3	0
Offices	Cooking	All	Power Burner Fryer	15	$96.69	0	0.00	2.7%	2.7%	0.55	0.80	5,051	0.00	26.55	0	1	0
Offices	Cooking	All	Power Burner Oven	16	$102.60	0	0.00	2.4%	2.4%	0.47	0.80	3,892	0.00	25.40	0	1	0
Offices	Cooking	All	Efficient Infrared Griddle	14	$112.64	0	0.00	2.3%	2.3%	0.58	0.80	4,519	0.00	27.88	0	1	0
Offices	Cooling	Chillers	High-efficiency chillers	20	$43.22	437	0.09	47.4%	17.0%	1.00	0.90	2,245,923	8.41	1.22	2,245,923	447	447
Offices	Cooling	Chillers	Window treatment	11	$0.74	3	0.00	23.4%	14.6%	0.00	0.90	0	3.25	1.86	0	0	0
Offices	Cooling	Chillers	Energy management controls	10	$1,107.82	2,708	0.66	8.0%	3.5%	0.00	0.90	0	1.80	1.63	0	0	0
Offices	Cooling	Chillers	Chiller economizers (water side), or air side economizers	13	$71.04	236	0.00	25.6%	0.0%	0.00	0.90	0	1.43	0.83	0	0	0
Offices	Cooling	Chillers	Variable-speed drives	15	$63.82	52	0.03	5.6%	5.6%	0.00	0.90	0	1.04	2.13	0	0	0
Offices	Cooling	Chillers	Cool (reflective) rooftops	21	$0.54	0	0.00	0.5%	0.1%	0.26	0.90	3,698	0.05	1.12	0	1	0
Offices	Cooling	Chillers	Installation of wall, roof, or ceiling insulation	21	$0.60	0	0.00	0.0%	0.1%	0.53	0.90	313	0.00	4.32	0	1	0
Offices	Cooling	Chillers	Optimize chilled water and condenser water setting	3	$103.98	0	0.00	1.1%	1.1%	0.76	0.90	23,450	0.00	0.97	0	19	0
Offices	Cooling	Chillers	Installation of low-E glass or multiple glazed windows	30	$0.67	1	0.00	10.8%	0.5%	0.57	0.90	167,986	0.00	0.00	0	6	0
Offices	Cooling	Chillers	Cool Storage	1	$0.00	0	0.00	0.0%	0.0%	0.67	0.90	0	0.00	0.00	0	0	0
Offices	Cooling	Chillers	Heat Pipe Enhanced DX	20	$0.00	0	0.00	0.0%	0.0%	0.50	0.90	0	0.00	0.00	0	0	0
Offices	Cooling	Chillers	Improved maintenance and diagnostics	1	$751.34	-1,407	2.56	-4.2%	13.6%	0.90	0.90	-95,708	-0.12	1.25	0	272	0
Offices	Cooling	DX Units	Window treatment	11	$0.74	3	0.00	23.4%	14.6%	0.00	0.95	0	3.25	1.86	0	0	0
Offices	Cooling	DX Units	High-efficiency packaged DX A/C	18	$99.97	312	0.09	33.8%	16.8%	1.00	0.95	3,252,592	2.86	1.41	3,252,592	900	900
Offices	Cooling	DX Units	Energy management controls	10	$1,107.82	2,708	0.66	8.0%	3.5%	0.00	0.95	0	1.80	1.63	0	0	0
Offices	Cooling	DX Units	Variable-speed drives	15	$63.82	52	0.03	5.6%	5.6%	0.00	0.95	0	1.04	2.13	0	0	0
Offices	Cooling	DX Units	Cool (reflective) rooftops	21	$0.54	0	0.00	0.5%	0.1%	0.26	0.95	8,877	0.05	1.12	0	2	0
Offices	Cooling	DX Units	Installation of wall, roof, or ceiling insulation	21	$0.60	0	0.00	0.0%	0.1%	0.53	0.95	751	0.00	4.32	0	2	0

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Subsector	End Use	Technology Type	Measure Name	Life	Incremental Costs	kWh Savings	kW Savings	% kWh Savings	% kW Savings	Applicability Factor	1-Saturation Factor	Technical Potential (kWh)	TRC	RIM	Economic Potential (kWh)	Technical Potential (kW)	Economic Potential (kW)
Offices	Cooling	DX Units	Installation of low-E glass or multiple glazed windows	30	$0.67	1	0.00	10.8%	0.5%	0.57	0.95	408,312	0.00	0.00	0	12	0
Offices	Cooling	DX Units	Cool Storage	1	$0.00	0	0.00	0.0%	0.0%	0.67	0.95	0	0.00	0.00	0	0	0
Offices	Cooling	DX Units	Heat Pipe Enhanced DX	20	$0.00	0	0.00	0.0%	0.0%	0.50	0.95	0	0.00	0.00	0	0	0
Offices	Cooling	DX Units	Improved maintenance and diagnostics	1	$751.34	-1,407	2.56	-4.2%	13.6%	0.90	0.95	-230,732	-0.12	1.25	0	551	0
Offices	Cooling	Room AC	Window treatment	11	$0.74	3	0.00	23.4%	14.6%	0.00	0.90	0	3.25	1.86	0	0	0
Offices	Cooling	Room AC	Energy management controls	10	$1,107.82	2,708	0.66	8.0%	3.5%	0.00	0.90	0	1.80	1.63	0	0	0
Offices	Cooling	Room AC	Variable-speed drives	15	$63.62	52	0.03	5.6%	5.6%	0.00	0.90	0	1.04	2.13	0	0	0
Offices	Cooling	Room AC	Cool (reflective) rooftops	21	$0.54	0	0.00	0.5%	0.1%	0.26	0.90	980	0.05	1.12	0	0	0
Offices	Cooling	Room AC	Installation of wall, roof, or ceiling insulation	21	$0.60	0	0.00	0.0%	0.1%	0.53	0.90	84	0.00	4.32	0	0	0
Offices	Cooling	Room AC	Installation of low-E glass or multiple glazed windows	30	$0.67	1	0.00	10.8%	0.5%	0.57	0.90	45,287	0.00	0.00	0	1	0
Offices	Cooling	Room AC	Cool Storage	1	$0.00	0	0.00	0.0%	0.0%	0.67	0.90	0	0.00	0.00	0	0	0
Offices	Cooling	Room AC	Heat Pipe Enhanced DX	20	$0.00	0	0.00	0.0%	0.0%	0.50	0.90	0	0.00	0.00	0	0	0
Offices	Cooling	Room AC	Improved maintenance and diagnostics	1	$751.34	-1,407	2.56	-4.2%	13.6%	0.90	0.90	-25,802	-0.12	1.25	0	50	0
Offices	Heating	Cntrl - HP	Window treatment	10	$0.65	1	0.00	25.1%	16.6%	0.78	0.80	48,215	0.54	0.85	48,215	0	0
Offices	Heating	Cntrl - HP	Installation of low-E glass or multiple glazed windows	23	$2.46	0	0.00	12.4%	11.8%	0.77	0.80	19,994	0.11	0.81	0	0	0
Offices	Heating	Cntrl - HP	Infiltration Reduction	16	$0.44	0	0.00	7.7%	10.5%	0.82	0.80	12,125	0.06	0.81	0	0	0
Offices	Heating	Cntrl - HP	Cool (reflective) rooftops	21	$0.64	0	0.00	-0.2%	0.2%	0.00	0.80	0	0.00	0.81	0	0	0
Offices	Heating	Cntrl - RTU/Furn	Window treatment	10	$0.65	1	0.00	25.1%	16.6%	0.78	0.80	357,539	0.54	0.85	357,539	0	0
Offices	Heating	Cntrl - RTU/Furn	Installation of low-E glass or multiple glazed windows	23	$2.46	0	0.00	12.4%	11.8%	0.77	0.80	148,269	0.11	0.81	0	0	0
Offices	Heating	Cntrl - RTU/Furn	Infiltration Reduction	16	$0.44	0	0.00	7.7%	10.5%	0.82	0.80	89,917	0.06	0.81	0	0	0
Offices	Heating	Cntrl - RTU/Furn	Cool (reflective) rooftops	21	$0.64	0	0.00	-0.2%	0.2%	0.00	0.80	0	0.00	0.81	0	0	0
Offices	Heating	Unitary	Window treatment	10	$0.65	1	0.00	25.1%	16.6%	0.78	0.80	220,409	0.54	0.85	220,409	0	0
Offices	Heating	Unitary	Installation of low-E glass or multiple glazed windows	23	$2.46	0	0.00	12.4%	11.8%	0.77	0.80	91,402	0.11	0.81	0	0	0
Offices	Heating	Unitary	Infiltration Reduction	16	$0.44	0	0.00	7.7%	10.5%	0.82	0.80	55,430	0.06	0.81	0	0	0
Offices	Heating	Unitary	Cool (reflective) rooftops	21	$0.64	0	0.00	-0.2%	0.2%	0.00	0.80	0	0.00	0.81	0	0	0
Offices	Lighting - Ext	E Incand.	High-intensity discharge lamps (incandescent to hi-pres sodium)	14	$148.29	2,050	0.50	71.5%	71.5%	0.78	0.80	1,465,140	11.14	1.44	1,465,140	18	18
Offices	Lighting - Ext	E Incand.	Outdoor lighting controls for incandescent (photocell/timeclock)	8	$109.02	1,528	0.00	25.2%	0.0%	0.66	0.80	240,065	4.73	0.89	240,065	0	0
Offices	Lighting - Ext	Fluor	T8 lamps with electronic ballasts (2L4')	18	$3.75	45	0.01	35.7%	35.7%	0.97	0.80	1,139,601	10.46	1.34	1,139,601	14	14
Offices	Lighting - Ext	Fluor	Outdoor lighting controls for fluorescent (photocell/timeclock)	8	$113.91	293	0.00	28.1%	0.0%	0.80	0.80	528,475	0.87	0.89	528,475	0	0
Offices	Lighting - Ext	HID	Outdoor lighting controls for HID (photocell/timeclock)	8	$108.99	1,528	0.00	27.4%	0.0%	0.66	0.80	1,825,222	4.73	0.89	1,825,222	0	0
Offices	Lighting - Ext	HID	High-intensity discharge lamps (mercury vapor to hi-pres sodium)	16	$154.57	841	0.21	51.9%	51.9%	0.87	0.80	3,931,572	4.56	1.38	3,931,572	57	57
Offices	Lighting - Int	4' Fluor	T8 lamps with electronic ballasts (2L4')	16	$5.71	44	0.01	32.9%	32.9%	0.80	0.20	1,682,452	6.53	1.40	1,682,452	337	337
Offices	Lighting - Int	4' Fluor	Occupancy sensors for 4' fluorescent	8	$11.65	54	0.01	23.1%	23.1%	0.83	0.80	4,679,855	3.28	1.81	4,679,855	937	937
Offices	Lighting - Int	4' Fluor	Reflectors for 4' fluorescent	17	$27.48	104	0.03	43.2%	43.2%	0.36	0.80	3,227,125	3.26	1.37	3,227,125	646	646
Offices	Lighting - Int	4' Fluor	Perimeter dimming for 4' fluorescent	13	$113.81	59	0.04	34.6%	73.2%	0.10	0.80	632,794	0.78	2.69	632,794	268	268
Offices	Lighting - Int	8' Fluor	Reflectors for 8' fluorescent	16	$27.13	164	0.04	41.0%	41.0%	0.38	0.80	269,514	5.12	1.40	269,514	54	54
Offices	Lighting - Int	8' Fluor	T8 lamps with electronic ballasts (2L8')	15	$9.95	44	0.01	18.3%	18.3%	0.96	0.20	66,166	3.68	1.42	66,166	13	13
Offices	Lighting - Int	8' Fluor	Perimeter dimming for 8' fluorescent	19	$52.86	109	0.09	27.8%	85.0%	0.08	0.80	31,457	3.64	2.51	31,457	19	19
Offices	Lighting - Int	8' Fluor	Occupancy sensors for 8' fluorescent	11	$27.60	93	0.02	21.3%	20.0%	0.93	0.80	281,220	2.48	1.54	281,220	51	51
Offices	Lighting - Int	Exit Signs	LED Exit Signs	10	$44.53	315	0.04	74.3%	74.3%	0.99	0.80	1,046,988	3.85	1.22	1,046,988	210	210
Offices	Lighting - Int	HID	High-intensity discharge lamps (incandescent to metal halide)	17	$245.28	440	0.11	45.8%	45.8%	0.21	1.00	0	1.55	1.37	0	0	0
Offices	Lighting - Int	Incand.	Compact flourescent lamp (modular)	9	-$45.29	228	0.05	64.9%	64.9%	0.92	0.05	18,454	-3.64	1.72	0	4	0
Offices	Office Equip - Non PC	Copy/Fax	Power management enabling - copier	4	$44.60	470	0.03	53.8%	18.8%	0.57	0.80	1,974,165	2.31	0.99	1,974,165	109	109
Offices	Office Equip - Non PC	Copy/Fax	External hardware control - printers	4	$165.99	160	0.00	54.4%	0.0%	0.49	0.80	1,291,543	0.21	0.99	0	0	0
Offices	Office Equip - Non PC	Copy/Fax	Nighttime shutdown - printers	4	$636.74	142	0.00	56.6%	0.0%	0.96	0.80	2,054,117	0.05	0.99	0	0	0
Offices	Office Equip - Non PC	Monitors	Network power management enabling - monitor	4	$4.67	117	0.01	72.8%	25.5%	0.65	0.80	8,974,530	5.46	0.99	8,974,530	497	497
Offices	Office Equip - Non PC	Monitors	Power management enabling - monitor	3	$7.42	115	0.01	71.8%	25.1%	0.00	0.80	0	2.68	1.01	0	0	0
Offices	Office Equip - Non PC	Monitors	External hardware control - monitors	5	$101.37	97	0.00	69.9%	0.0%	0.48	0.80	3,930,933	0.25	0.97	0	0	0
Offices	Office Equip - PC	CPUs	Power management enabling - PC	4	$13.29	90	0.00	37.5%	13.1%	0.64	0.80	3,661,743	1.48	0.99	3,661,743	203	203
Offices	Office Equip - PC	CPUs	LCD monitor	5	$455.58	80	0.01	49.7%	49.7%	0.97	0.80	5,946,033	0.05	0.96	0	1,086	0
Offices	Refrigeration	Compressors	Demand defrost electric	9	$0.03	3	0.00	9.0%	9.0%	0.00	0.99	0	45.60	1.34	0	0	0
Offices	Refrigeration	Compressors	Demand hot gas defrost	10	$0.03	1	0.00	3.3%	3.3%	0.00	0.99	0	20.11	1.29	0	0	0
Offices	Refrigeration	Compressors	Efficiency compressor motor retrofit	10	$0.07	2	0.00	6.6%	6.6%	0.00	0.99	0	15.85	1.29	0	0	0
Offices	Refrigeration	Compressors	Floating head pressure controls	16	$0.11	2	0.00	6.5%	0.0%	0.00	0.99	0	8.84	0.81	0	0	0
Offices	Refrigeration	Compressors	Anti-sweat (humidistat) controls	14	$0.14	1	0.00	4.5%	1.8%	0.00	0.30	0	5.12	0.96	0	0	0
Offices	Refrigeration	Compressors	Strip curtains for walk-ins	4	$0.05	1	0.00	3.2%	3.2%	0.00	0.99	0	3.91	0.98	0	0	0
Offices	Refrigeration	Compressors	Night covers for display cases	5	$0.14	2	0.00	5.5%	0.0%	0.00	0.99	0	3.14	0.97	0	0	0
Offices	Refrigeration	Compressors	Evaporator fan controller for MT walk-ins	5	$0.05	0	0.00	1.2%	1.2%	0.00	0.99	0	1.81	0.96	0	0	0
Offices	Refrigeration	Compressors	Compressor VSD retrofit	11	$0.45	2	0.00	5.1%	2.5%	0.00	0.99	0	1.70	1.05	0	0	0
Offices	Refrigeration	Compressors	Refrigeration commissioning	3	$0.20	1	0.00	4.5%	4.5%	0.00	0.99	0	1.17	1.00	0	0	0
Offices	Refrigeration	Fans/Motors	Demand defrost electric	9	$0.03	3	0.00	9.0%	9.0%	0.00	0.99	0	45.60	1.34	0	0	0
Offices	Refrigeration	Fans/Motors	Demand hot gas defrost	10	$0.03	1	0.00	3.3%	3.3%	0.00	0.99	0	20.11	1.29	0	0	0
Offices	Refrigeration	Fans/Motors	Anti-sweat (humidistat) controls	14	$0.14	1	0.00	4.5%	1.8%	0.00	0.30	0	5.12	0.96	0	0	0
Offices	Refrigeration	Fans/Motors	Strip curtains for walk-ins	4	$0.05	1	0.00	3.2%	3.2%	0.00	0.99	0	3.91	0.98	0	0	0
Offices	Refrigeration	Fans/Motors	Night covers for display cases	5	$0.14	2	0.00	5.5%	0.0%	0.00	0.99	0	3.14	0.97	0	0	0
Offices	Refrigeration	Fans/Motors	High-efficiency fan motors	18	$1.12	3	0.00	11.4%	11.4%	0.00	0.99	0	2.20	1.11	0	0	0
Offices	Refrigeration	Fans/Motors	Evaporator fan controller for MT walk-ins	5	$0.05	0	0.00	1.2%	1.2%	0.00	0.99	0	1.81	0.96	0	0	0
Offices	Refrigeration	Fans/Motors	Refrigeration commissioning	3	$0.20	1	0.00	4.5%	4.5%	0.00	0.99	0	1.17	1.00	0	0	0
Offices	Ventilation	Motor	Variable-speed drives	8	$0.23	16	0.00	45.3%	1.2%	0.95	0.95	2,394,507	23.05	0.91	2,394,507	11	11
Offices	Ventilation	Motor	Premium-efficiency motors	16	$5.71	164	0.04	4.9%	6.0%	1.00	0.95	159,411	22.85	1.32	159,411	58	58
Offices	Ventilation	Motor	CV to VAV conversion	22	$98.07	1,373	0.07	45.3%	13.9%	0.26	0.95	374,860	9.03	0.91	374,860	33	33
Offices	Ventilation	Motor	Unoccupied OA reduction	14	$112.66	1,038	0.06	10.5%	3.5%	0.80	0.95	233,885	4.93	0.97	233,885	25	25
Offices	Ventilation	Motor	Automatic OA reduction control	15	$773.99	2,232	0.24	17.7%	10.9%	0.82	0.95	371,827	1.80	1.08	371,827	76	76
Offices	Ventilation	Motor	Installation of nighttime pre-cooling controls and systems	10	$88.90	0	0.00	0.0%	22.8%	0.88	0.95	0	0.00	35.93	0	156	0
Offices	Ventilation	Motor	Installation of outside air reset controls	1	$0.86	0	0.00	0.0%	0.0%	0.69	0.95	0	0.00	0.00	0	0	0
Offices	Ventilation	Motor	Reducing minimum outside air requirements	1	$0.84	0	0.00	0.0%	0.0%	0.88	0.95	0	0.00	0.00	0	0	0
Offices	Ventilation	Motor w/VFD	Premium-efficiency motors	16	$5.71	164	0.04	4.9%	6.0%	1.00	0.95	269,790	22.85	1.32	269,790	58	58
Offices	Ventilation	Motor w/VFD	CV to VAV conversion	22	$98.07	1,373	0.07	45.3%	13.9%	0.26	0.95	634,422	9.03	0.91	634,422	34	34
Offices	Ventilation	Motor w/VFD	Unoccupied OA reduction	14	$112.66	1,038	0.06	10.5%	3.5%	0.80	0.95	395,832	4.93	0.97	395,832	25	25
Offices	Ventilation	Motor w/VFD	Automatic OA reduction control	15	$773.99	2,232	0.24	17.7%	10.9%	0.82	0.95	629,287	1.80	1.08	629,287	77	77

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Subsector	End Use	Technology Type	Measure Name	Life	Incremental Costs	kWh Savings	kW Savings	% kWh Savings	% kW Savings	Applicability Factor	1-Saturation Factor	Technical Potential (kWh)	TRC	RIM	Economic Potential (kWh)	Technical Potential (kW)	Economic Potential (kW)
Offices	Ventilation	Motor w/VFD	Installation of nighttime pre-cooling controls and systems	10	$88.90	0	0.00	0.0%	22.8%	0.88	0.95	0	0.00	35.93	0	158	0
Offices	Ventilation	Motor w/VFD	Installation of outside air reset controls	1	$0.86	0	0.00	0.0%	0.0%	0.69	0.95	0	0.00	0.00	0	0	0
Offices	Ventilation	Motor w/VFD	Reducing minimum outside air requirements	1	$0.84	0	0.00	0.0%	0.0%	0.89	0.95	0	0.00	0.00	0	0	0
Offices	Water Heating	Coil	Faucet Aerator	11	$0.01	0	0.00	1.9%	1.9%	0.88	0.80	25,197	0.12	33.29	0	3	0
Offices	Water Heating	Coil	Tank Insulation	15	$0.03	0	0.00	8.0%	8.0%	0.91	0.80	106,572	0.12	26.54	0	14	0
Offices	Water Heating	Coil	Circulation Pump Timeclocks	13	$0.01	0	0.00	2.9%	2.9%	0.67	0.80	26,605	0.10	29.38	0	4	0
Offices	Water Heating	Coil	Instantaneous Water Heater <=200 MBTUH	16	$0.07	0	0.00	9.7%	9.7%	0.71	0.80	94,016	0.06	25.39	0	13	0
Offices	Water Heating	Coil	Low Flow Showerheads	10	$0.02	0	0.00	2.2%	2.2%	0.80	0.80	22,148	0.06	35.87	0	3	0
Offices	Water Heating	Coil	Heater efficiency upgrade	12	$0.24	0	0.00	24.8%	24.8%	0.81	0.80	254,529	0.04	31.22	0	34	0
Offices	Water Heating	Coil	Pipe Insulation	16	$0.02	0	0.00	1.7%	1.7%	0.88	0.80	16,029	0.04	25.35	0	2	0
Offices	Water Heating	Coil	Solar Water Heater	1	$0.00	0	0.00	0.0%	0.0%	0.57	0.80	0	0.00	1.06	0	0	0
Offices	Water Heating	Coil	Heat Recovery Water Heater	1	$0.00	0	0.00	0.0%	0.0%	0.73	0.80	0	0.00	1.06	0	0	0
Retail Outlet	Cooking	All	Infrared Fryer	15	$99.12	0	0.00	9.6%	9.6%	0.50	0.80	18,536	0.00	26.56	0	5	0
Retail Outlet	Cooking	All	Convection Oven	14	$86.77	0	0.00	4.7%	4.7%	0.51	0.80	8,770	0.00	27.88	0	2	0
Retail Outlet	Cooking	All	Infrared Conveyor Oven	14	$93.02	0	0.00	5.0%	5.0%	0.41	0.80	7,504	0.00	27.88	0	2	0
Retail Outlet	Cooking	All	Power Burner Fryer	15	$96.69	0	0.00	2.7%	2.7%	0.47	0.80	4,499	0.00	26.56	0	1	0
Retail Outlet	Cooking	All	Power Burner Oven	16	$102.60	0	0.00	2.4%	2.4%	0.48	0.80	4,084	0.00	25.40	0	1	0
Retail Outlet	Cooking	All	Efficient Infrared Griddle	14	$112.64	0	0.00	2.3%	2.3%	0.49	0.80	3,984	0.00	27.88	0	1	0
Retail Outlet	Cooling	Chillers	High-efficiency chillers	20	$43.22	382	0.06	47.1%	10.4%	0.97	0.90	1,011,804	6.55	1.15	1,011,804	167	167
Retail Outlet	Cooling	Chillers	Chiller economizers (water side), or air side economizers	13	$71.04	197	0.00	25.6%	0.0%	0.00	0.90	0	1.20	0.83	0	0	0
Retail Outlet	Cooling	Chillers	Variable-speed drives	15	$63.82	43	0.03	5.6%	5.6%	0.00	0.90	0	1.06	2.55	0	0	0
Retail Outlet	Cooling	Chillers	Cool (reflective) rooftops	21	$0.54	0	0.00	2.5%	1.0%	0.22	0.90	7,390	0.22	1.40	0	3	0
Retail Outlet	Cooling	Chillers	Window treatment	11	$0.74	0	0.00	1.5%	0.6%	0.86	0.90	16,409	0.13	1.72	0	8	0
Retail Outlet	Cooling	Chillers	Energy management controls	10	$1,107.82	360	-0.01	1.5%	-0.1%	0.85	0.90	16,621	0.10	0.73	0	-1	0
Retail Outlet	Cooling	Chillers	Improved maintenance and diagnostics	1	$751.34	460	2.19	2.0%	12.5%	0.99	0.90	24,439	0.04	0.76	0	184	0
Retail Outlet	Cooling	Chillers	Installation of wall, roof, or ceiling insulation	21	$0.60	0	0.00	0.0%	0.1%	0.61	0.90	162	0.00	5.27	0	1	0
Retail Outlet	Cooling	Chillers	Optimize chilled water and condenser water setting	3	$103.98	0	0.00	1.1%	1.1%	0.65	0.90	9,101	0.00	0.95	0	10	0
Retail Outlet	Cooling	Chillers	Installation of low-E glass or multiple glazed windows	30	$0.67	0	0.00	0.5%	0.2%	0.57	0.90	3,185	0.00	0.00	0	2	0
Retail Outlet	Cooling	Chillers	Cool Storage	1	$0.00	0	0.00	0.0%	0.0%	0.79	0.90	0	0.00	0.00	0	0	0
Retail Outlet	Cooling	Chillers	Heat Pipe Enhanced DX	20	$0.00	0	0.00	0.0%	0.0%	0.50	0.90	0	0.00	0.00	0	0	0
Retail Outlet	Cooling	DX Units	High-efficiency packaged DX A/C	18	$99.97	257	0.06	33.4%	11.1%	0.84	0.95	2,559,014	2.25	1.35	2,559,014	637	637
Retail Outlet	Cooling	DX Units	Variable-speed drives	15	$63.82	43	0.03	5.6%	5.6%	0.00	0.95	0	1.06	2.55	0	0	0
Retail Outlet	Cooling	DX Units	Cool (reflective) rooftops	21	$0.54	0	0.00	2.5%	1.0%	0.22	0.95	38,064	0.22	1.40	0	14	0
Retail Outlet	Cooling	DX Units	Window treatment	11	$0.74	0	0.00	1.5%	0.6%	0.86	0.95	84,493	0.13	1.72	0	31	0
Retail Outlet	Cooling	DX Units	Energy management controls	10	$1,107.82	360	-0.01	1.5%	-0.1%	0.85	0.95	85,529	0.10	0.73	0	-4	0
Retail Outlet	Cooling	DX Units	Improved maintenance and diagnostics	1	$751.34	460	2.19	2.0%	12.5%	0.99	0.95	125,675	0.04	0.76	0	761	0
Retail Outlet	Cooling	DX Units	Installation of wall, roof, or ceiling insulation	21	$0.60	0	0.00	0.0%	0.1%	0.61	0.95	835	0.00	5.27	0	3	0
Retail Outlet	Cooling	DX Units	Installation of low-E glass or multiple glazed windows	30	$0.67	0	0.00	0.5%	0.2%	0.57	0.95	16,473	0.00	0.00	0	7	0
Retail Outlet	Cooling	DX Units	Cool Storage	1	$0.00	0	0.00	0.0%	0.0%	0.79	0.95	0	0.00	0.00	0	0	0
Retail Outlet	Cooling	DX Units	Heat Pipe Enhanced DX	20	$0.00	0	0.00	0.0%	0.0%	0.50	0.05	0	0.00	0.00	0	0	0
Retail Outlet	Cooling	Room AC	Variable-speed drives	15	$63.82	43	0.03	5.6%	5.6%	0.00	0.90	0	1.06	2.55	0	0	0
Retail Outlet	Cooling	Room AC	Cool (reflective) rooftops	21	$0.54	0	0.00	2.5%	1.0%	0.22	0.90	25,174	0.22	1.40	0	7	0
Retail Outlet	Cooling	Room AC	Window treatment	11	$0.74	0	0.00	1.5%	0.6%	0.86	0.90	55,897	0.13	1.72	0	17	0
Retail Outlet	Cooling	Room AC	Energy management controls	10	$1,107.82	360	-0.01	1.5%	-0.1%	0.85	0.90	56,619	0.10	0.73	0	-2	0
Retail Outlet	Cooling	Room AC	Improved maintenance and diagnostics	1	$751.34	460	2.19	2.0%	12.5%	0.99	0.90	83,250	0.04	0.76	0	405	0
Retail Outlet	Cooling	Room AC	Installation of wall, roof, or ceiling insulation	21	$0.60	0	0.00	0.0%	0.1%	0.61	0.90	554	0.00	5.27	0	1	0
Retail Outlet	Cooling	Room AC	Installation of low-E glass or multiple glazed windows	30	$0.67	0	0.00	0.5%	0.2%	0.57	0.90	10,923	0.00	0.00	0	4	0
Retail Outlet	Cooling	Room AC	Cool Storage	1	$0.00	0	0.00	0.0%	0.0%	0.79	0.90	0	0.00	0.00	0	0	0
Retail Outlet	Cooling	Room AC	Heat Pipe Enhanced DX	20	$0.00	0	0.00	0.0%	0.0%	0.50	0.90	0	0.00	0.00	0	0	0
Retail Outlet	Heating	Cntrl - HP	Window treatment	10	$0.65	1	0.00	15.8%	16.6%	0.98	0.80	0	0.29	0.85	0	0	0
Retail Outlet	Heating	Cntrl - HP	Infiltration Reduction	16	$0.44	0	0.00	7.7%	10.5%	0.84	0.80	0	0.05	0.81	0	0	0
Retail Outlet	Heating	Cntrl - HP	Installation of low-E glass or multiple glazed windows	23	$2.46	0	0.00	6.5%	11.8%	0.68	0.80	0	0.05	0.81	0	0	0
Retail Outlet	Heating	Cntrl - HP	Cool (reflective) rooftops	21	$0.64	0	0.00	-4.2%	0.2%	0.00	0.80	0	-0.07	0.81	0	0	0
Retail Outlet	Heating	Cntrl - RTU/Furn	Window treatment	10	$0.65	1	0.00	15.8%	16.6%	0.98	0.80	571,246	0.29	0.85	0	0	0
Retail Outlet	Heating	Cntrl - RTU/Furn	Infiltration Reduction	16	$0.44	0	0.00	7.7%	10.5%	0.84	0.80	209,294	0.05	0.81	0	0	0
Retail Outlet	Heating	Cntrl - RTU/Furn	Installation of low-E glass or multiple glazed windows	23	$2.46	0	0.00	6.5%	11.8%	0.68	0.80	135,875	0.05	0.81	0	0	0
Retail Outlet	Heating	Cntrl - RTU/Furn	Cool (reflective) rooftops	21	$0.64	0	0.00	-4.2%	0.2%	0.00	0.80	0	-0.07	0.81	0	0	0
Retail Outlet	Heating	Unitary	Window treatment	10	$0.65	1	0.00	15.8%	16.6%	0.98	0.80	107,193	0.29	0.85	0	0	0
Retail Outlet	Heating	Unitary	Infiltration Reduction	16	$0.44	0	0.00	7.7%	10.5%	0.84	0.80	39,274	0.05	0.81	0	0	0
Retail Outlet	Heating	Unitary	Installation of low-E glass or multiple glazed windows	23	$2.46	0	0.00	6.5%	11.8%	0.68	0.80	25,497	0.05	0.81	0	0	0
Retail Outlet	Heating	Unitary	Cool (reflective) rooftops	21	$0.64	0	0.00	-4.2%	0.2%	0.00	0.80	0	-0.07	0.81	0	0	0
Retail Outlet	Lighting - Ext	E Incand.	High-intensity discharge lamps (incandescent to hi-pres sodium)	14	$148.29	2,050	0.50	71.5%	71.5%	0.73	0.80	404,073	11.14	1.44	404,073	7	7
Retail Outlet	Lighting - Ext	E Incand.	Outdoor lighting controls for incandescent (photocell/timeclock)	8	$109.02	1,528	0.00	25.2%	0.0%	0.66	0.80	75,176	4.73	0.89	75,176	0	0
Retail Outlet	Lighting - Ext	Fluor	T8 lamps with electronic ballasts (2L4')	18	$3.75	45	0.01	35.7%	35.7%	0.87	0.80	294,063	10.46	1.34	294,063	5	5
Retail Outlet	Lighting - Ext	Fluor	Outdoor lighting controls for fluorescent (photocell/timeclock)	8	$113.91	293	0.00	28.1%	0.0%	0.86	0.80	172,327	0.87	0.89	172,327	0	0
Retail Outlet	Lighting - Ext	HID	Outdoor lighting controls for HID (photocell/timeclock)	8	$108.99	1,528	0.00	27.4%	0.0%	0.73	0.80	412,593	4.73	0.89	412,593	0	0
Retail Outlet	Lighting - Ext	HID	High-intensity discharge lamps (mercury vapor to hi-pres sodium)	16	$154.57	841	0.21	51.9%	51.9%	0.92	0.80	832,888	4.56	1.38	832,888	16	16
Retail Outlet	Lighting - Int	4' Fluor	T8 lamps with electronic ballasts (2L4')	16	$5.71	40	0.01	32.9%	32.9%	1.00	0.20	1,735,691	6.95	1.34	1,735,691	398	398
Retail Outlet	Lighting - Int	4' Fluor	Reflectors for 4' fluorescent	17	$27.48	116	0.03	43.2%	43.2%	0.44	0.80	3,784,505	3.48	1.32	3,784,505	867	867
Retail Outlet	Lighting - Int	4' Fluor	Occupancy sensors for 4' fluorescent	8	$11.65	54	0.01	23.1%	23.1%	0.87	0.80	3,362,810	3.28	1.81	3,362,810	770	770
Retail Outlet	Lighting - Int	4' Fluor	Perimeter dimming for 4' fluorescent	13	$113.81	59	0.04	34.6%	73.2%	0.11	0.80	548,501	0.78	2.69	548,501	266	266
Retail Outlet	Lighting - Int	8' Fluor	Reflectors for 8' fluorescent	16	$27.13	182	0.04	41.0%	41.0%	0.35	0.80	2,402,113	5.45	1.34	2,402,113	553	553
Retail Outlet	Lighting - Int	8' Fluor	T8 lamps with electronic ballasts (2L8')	15	$9.95	49	0.01	18.3%	18.3%	1.00	0.20	667,993	3.91	1.36	667,993	154	154
Retail Outlet	Lighting - Int	8' Fluor	Perimeter dimming for 8' fluorescent	19	$52.86	109	0.09	27.8%	85.0%	0.11	0.80	424,314	3.64	2.51	424,314	299	299
Retail Outlet	Lighting - Int	8' Fluor	Occupancy sensors for 8' fluorescent	11	$27.60	93	0.02	21.3%	20.0%	0.76	0.80	2,211,114	2.48	1.54	2,211,114	455	455
Retail Outlet	Lighting - Int	Exit Signs	LED Exit Signs	10	$44.53	315	0.04	74.3%	74.3%	1.00	0.80	1,630,528	3.85	1.22	1,630,528	374	374
Retail Outlet	Lighting - Int	HID	High-intensity discharge lamps (incandescent to metal halide)	17	$245.28	490	0.11	45.8%	45.8%	0.18	1.00	0	1.65	1.32	0	0	0
Retail Outlet	Lighting - Int	Incand.	Compact flourescent lamp (modular)	9	-$45.29	254	0.06	64.9%	64.9%	0.93	0.05	47,997	-3.84	1.63	0	11	0
Retail Outlet	Office Equip - Non PC	CopyFax	Power management enabling - copier	4	$44.60	470	0.03	53.8%	18.8%	0.57	0.80	760,807	2.31	0.98	760,807	51	51
Retail Outlet	Office Equip - Non PC	CopyFax	External hardware control - printers	[illegible]	$165.99	160	0.00	54.4%	0.0%	0.46	0.80	460,533	0.21	0.99	0	0	0

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Subsector	End Use	Technology Type	Measure Name	Life	Incremental Costs	kWh Savings	kW Savings	% kWh Savings	% kW Savings	Applicability Factor	1-Saturation Factor	Technical Potential (kWh)	TRC	RIM	Economic Potential (kWh)	Technical Potential (kW)	Economic Potential (kW)
Retail Outlet	Office Equip - Non PC	Copy/Fax	Nighttime shutdown - printers	4	$636.74	142	0.00	56.8%	0.0%	0.90	0.80	753,694	0.05	0.99	0	0	0
Retail Outlet	Office Equip - Non PC	Monitors	Network power management enabling - monitor	4	$4.67	117	0.01	72.8%	25.5%	0.67	0.80	1,993,128	5.46	0.98	1,993,128	134	134
Retail Outlet	Office Equip - Non PC	Monitors	Power management enabling - monitor	3	$7.42	115	0.01	71.8%	25.1%	0.00	0.80	0	2.68	1.01	0	0	0
Retail Outlet	Office Equip - Non PC	Monitors	External hardware control - monitors	5	$101.37	97	0.00	69.9%	0.0%	0.60	0.80	1,031,080	0.25	0.97	0	0	0
Retail Outlet	Office Equip - PC	CPUs	Power management enabling - PC	4	$13.29	90	0.01	37.5%	13.1%	0.64	0.80	725,561	1.48	0.98	725,561	49	49
Retail Outlet	Office Equip - PC	CPUs	LCD monitor	5	$455.58	80	0.02	49.7%	49.7%	0.77	0.80	940,610	0.05	0.95	0	208	0
Retail Outlet	Refrigeration	Compressors	Demand defrost electric	9	$0.03	3	0.00	9.0%	9.0%	0.00	0.99	0	50.61	1.48	0	0	0
Retail Outlet	Refrigeration	Compressors	Demand hot gas defrost	10	$0.03	1	0.00	3.3%	3.3%	0.00	0.99	0	22.24	1.43	0	0	0
Retail Outlet	Refrigeration	Compressors	Efficiency compressor motor retrofit	10	$0.07	2	0.00	6.6%	6.6%	0.00	0.99	0	17.53	1.43	0	0	0
Retail Outlet	Refrigeration	Compressors	Floating head pressure controls	16	$0.11	2	0.00	6.5%	0.0%	0.00	0.99	0	8.84	0.81	0	0	0
Retail Outlet	Refrigeration	Compressors	Anti-sweat (humidistat) controls	14	$0.14	1	0.00	4.5%	1.8%	0.00	0.30	0	5.35	1.01	0	0	0
Retail Outlet	Refrigeration	Compressors	Strip curtains for walk-ins	4	$0.05	1	0.00	3.2%	3.2%	0.00	0.99	0	3.91	0.98	0	0	0
Retail Outlet	Refrigeration	Compressors	Night covers for display cases	5	$0.14	2	0.00	5.5%	0.0%	0.00	0.99	0	3.14	0.97	0	0	0
Retail Outlet	Refrigeration	Compressors	Evaporator fan controller for MT walk-ins	5	$0.05	0	0.00	1.2%	1.2%	0.00	0.99	0	1.81	0.95	0	0	0
Retail Outlet	Refrigeration	Compressors	Compressor VSD retrofit	11	$0.45	2	0.00	5.1%	2.5%	0.00	0.99	0	1.81	1.11	0	0	0
Retail Outlet	Refrigeration	Compressors	Refrigeration commissioning	3	$0.20	1	0.00	4.5%	4.5%	0.00	0.99	0	1.17	1.00	0	0	0
Retail Outlet	Refrigeration	Fans/Motors	Demand defrost electric	9	$0.03	3	0.00	9.0%	9.0%	0.00	0.99	0	50.61	1.48	0	0	0
Retail Outlet	Refrigeration	Fans/Motors	Demand hot gas defrost	10	$0.03	1	0.00	3.3%	3.3%	0.00	0.99	0	22.24	1.43	0	0	0
Retail Outlet	Refrigeration	Fans/Motors	Anti-sweat (humidistat) controls	14	$0.14	1	0.00	4.5%	1.8%	0.00	0.30	0	5.35	1.01	0	0	0
Retail Outlet	Refrigeration	Fans/Motors	Strip curtains for walk-ins	4	$0.05	1	0.00	3.2%	3.2%	0.00	0.99	0	3.91	0.98	0	0	0
Retail Outlet	Refrigeration	Fans/Motors	Night covers for display cases	5	$0.14	2	0.00	5.5%	0.0%	0.00	0.99	0	3.14	0.97	0	0	0
Retail Outlet	Refrigeration	Fans/Motors	High-efficiency fan motors	18	$1.12	3	0.00	11.4%	11.4%	0.00	0.99	0	2.39	1.21	0	0	0
Retail Outlet	Refrigeration	Fans/Motors	Evaporator fan controller for MT walk-ins	5	$0.05	0	0.00	1.2%	1.2%	0.00	0.99	0	1.81	0.95	0	0	0
Retail Outlet	Refrigeration	Fans/Motors	Refrigeration commissioning	3	$0.20	1	0.00	4.5%	4.5%	0.00	0.99	0	1.17	1.00	0	0	0
Retail Outlet	Ventilation	Motor	Premium-efficiency motors	16	$5.71	164	0.04	4.9%	6.0%	0.99	0.95	133,982	24.43	1.41	133,982	34	34
Retail Outlet	Ventilation	Motor	Variable-speed drives	8	$0.23	8	0.00	22.6%	1.2%	0.92	0.95	546,863	11.82	0.93	546,863	6	6
Retail Outlet	Ventilation	Motor	CV to VAV conversion	22	$98.07	685	-0.02	22.6%	-2.9%	0.29	0.95	139,953	3.70	0.76	139,953	-4	-4
Retail Outlet	Ventilation	Motor	Unoccupied OA reduction	14	$112.66	533	0.00	5.4%	-0.1%	0.67	0.95	71,460	2.10	0.81	71,460	0	0
Retail Outlet	Ventilation	Motor	Automatic OA reduction control	15	$773.99	702	0.03	5.6%	1.0%	0.73	0.95	77,586	0.47	0.91	0	4	0
Retail Outlet	Ventilation	Motor	Installation of nighttime pre-cooling controls and systems	10	$88.90	0	0.00	0.0%	22.8%	0.87	0.95	0	0.00	35.93	0	105	0
Retail Outlet	Ventilation	Motor	Installation of outside air reset controls	1	$0.86	0	0.00	0.0%	0.0%	0.71	0.95	0	0.00	0.00	0	0	0
Retail Outlet	Ventilation	Motor	Reducing minimum outside air requirements	1	$0.84	0	0.00	0.0%	0.0%	0.84	0.95	0	0.00	0.00	0	0	0
Retail Outlet	Ventilation	Motor w/VFD	Premium-efficiency motors	16	$5.71	164	0.04	4.9%	6.0%	0.99	0.95	133,982	24.43	1.41	133,982	34	34
Retail Outlet	Ventilation	Motor w/VFD	CV to VAV conversion	22	$98.07	685	-0.02	22.6%	-2.9%	0.29	0.95	174,271	3.70	0.76	174,271	-4	-4
Retail Outlet	Ventilation	Motor w/VFD	Unoccupied OA reduction	14	$112.66	533	0.00	5.4%	-0.1%	0.67	0.95	88,983	2.10	0.81	88,983	0	0
Retail Outlet	Ventilation	Motor w/VFD	Automatic OA reduction control	15	$773.99	702	0.03	5.6%	1.0%	0.73	0.95	96,612	0.47	0.91	0	4	0
Retail Outlet	Ventilation	Motor w/VFD	Installation of nighttime pre-cooling controls and systems	10	$88.90	0	0.00	0.0%	22.8%	0.87	0.95	0	0.00	35.93	0	106	0
Retail Outlet	Ventilation	Motor w/VFD	Installation of outside air reset controls	1	$0.86	0	0.00	0.0%	0.0%	0.71	0.95	0	0.00	0.00	0	0	0
Retail Outlet	Ventilation	Motor w/VFD	Reducing minimum outside air requirements	1	$0.84	0	0.00	0.0%	0.0%	0.84	0.95	0	0.00	0.00	0	0	0
Retail Outlet	Water Heating	Call	Faucet Aerator	11	$0.01	0	0.00	1.9%	1.9%	0.79	0.80	154,589	0.95	33.35	154,589	39	39
Retail Outlet	Water Heating	Call	Tank Insulation	15	$0.03	0	0.00	8.0%	8.0%	0.77	0.80	623,641	0.94	26.55	623,641	157	157
Retail Outlet	Water Heating	Call	Circulation Pump Timelocks	13	$0.01	0	0.00	2.9%	2.9%	0.78	0.80	213,181	0.79	29.41	213,181	54	54
Retail Outlet	Water Heating	Call	Instanteous Water Heater <=200 MBTUH	16	$0.07	0	0.00	9.7%	9.7%	0.65	0.80	589,095	0.49	25.40	0	148	0
Retail Outlet	Water Heating	Call	Low Flow Showerheads	10	$0.02	0	0.00	2.2%	2.2%	0.73	0.80	141,006	0.45	35.92	0	36	0
Retail Outlet	Water Heating	Call	Heater efficiency upgrade	12	$0.24	0	0.00	24.8%	24.8%	0.77	0.80	1,687,129	0.35	31.22	0	425	0
Retail Outlet	Water Heating	Call	Pipe Insulation	16	$0.02	0	0.00	1.7%	1.7%	0.77	0.80	98,463	0.32	25.39	0	25	0
Retail Outlet	Water Heating	Call	Solar Water Heater	1	$0.00	0	0.00	0.0%	0.0%	0.79	0.80	0	0.00	1.06	0	0	0
Retail Outlet	Water Heating	Call	Heat Recovery Water Heater	1	$0.00	0	0.00	0.0%	0.0%	0.64	0.80	0	0.00	1.06	0	0	0
Warehouse	Cooking	All	Infrared Fryer	15	$99.12	0	0.00	9.6%	9.6%	0.61	0.80	329	0.00	26.55	0	0	0
Warehouse	Cooking	All	Convection Oven	14	$86.77	0	0.00	4.7%	4.7%	0.51	0.80	127	0.00	27.88	0	0	0
Warehouse	Cooking	All	Infrared Conveyor Oven	14	$93.02	0	0.00	5.0%	5.0%	0.55	0.80	148	0.00	27.88	0	0	0
Warehouse	Cooking	All	Power Burner Fryer	15	$96.69	0	0.00	2.7%	2.7%	0.46	0.80	64	0.00	26.55	0	0	0
Warehouse	Cooking	All	Power Burner Oven	16	$102.60	0	0.00	2.4%	2.4%	0.53	0.80	66	0.00	25.40	0	0	0
Warehouse	Cooking	All	Efficient Infrared Griddle	14	$112.64	0	0.00	2.3%	2.3%	0.54	0.80	63	0.00	27.88	0	0	0
Warehouse	Cooling	Chillers	High-efficiency chillers	20	$43.22	65	0.02	14.9%	22.1%	0.96	0.90	20,460	1.34	1.31	20,460	5	5
Warehouse	Cooling	Chillers	Window treatment	11	$0.74	1	0.00	16.2%	18.6%	0.00	0.90	0	1.18	1.41	0	0	0
Warehouse	Cooling	Chillers	Chiller economizers (water side), or air side economizers	13	$71.04	111	0.00	25.6%	0.0%	0.00	0.90	0	0.67	0.83	0	0	0
Warehouse	Cooling	Chillers	Variable-speed drives	15	$63.82	24	0.00	5.6%	5.6%	0.71	0.90	4,967	0.27	1.22	0	1	0
Warehouse	Cooling	Chillers	Energy management controls	10	$1,107.82	381	0.06	9.6%	8.9%	0.97	0.90	11,299	0.21	1.34	0	2	0
Warehouse	Cooling	Chillers	Improved maintenance and diagnostics	1	$751.34	883	0.15	22.3%	22.3%	0.81	0.90	19,905	0.08	1.05	0	3	0
Warehouse	Cooling	Chillers	Cool (reflective) rooftops	21	$0.54	0	0.00	0.5%	0.0%	0.23	0.90	104	0.00	0.81	0	0	0
Warehouse	Cooling	Chillers	Installation of wall, roof, or ceiling insulation	21	$0.60	0	0.00	0.0%	0.1%	0.54	0.90	11	0.00	1.99	0	0	0
Warehouse	Cooling	Chillers	Optimize chilled water and condenser water setting	3	$103.98	0	0.00	1.1%	1.1%	0.76	0.90	790	0.00	1.00	0	0	0
Warehouse	Cooling	Chillers	Installation of low-E glass or multiple glazed windows	30	$0.67	1	0.00	13.5%	14.5%	0.51	0.90	6,273	0.00	0.00	0	1	0
Warehouse	Cooling	Chillers	Cool Storage	1	$0.00	0	0.00	0.0%	0.0%	0.72	0.90	0	0.00	0.00	0	0	0
Warehouse	Cooling	Chillers	Heat Pipe Enhanced DX	20	$0.00	0	0.00	0.0%	0.0%	0.50	0.90	0	0.00	0.00	0	0	0
Warehouse	Cooling	DX Units	Window treatment	11	$0.74	1	0.00	16.2%	18.6%	0.00	0.95	0	1.18	1.41	0	0	0
Warehouse	Cooling	DX Units	High-efficiency packaged DX A/C	18	$99.97	92	0.02	21.2%	22.9%	0.97	0.95	70,668	0.71	1.20	70,668	13	13
Warehouse	Cooling	DX Units	Variable-speed drives	15	$63.82	24	0.00	5.6%	5.6%	0.71	0.95	10,946	0.27	1.22	0	2	0
Warehouse	Cooling	DX Units	Energy management controls	10	$1,107.82	381	0.06	9.6%	8.9%	0.97	0.95	24,848	0.21	1.34	0	4	0
Warehouse	Cooling	DX Units	Improved maintenance and diagnostics	1	$751.34	883	0.15	22.3%	22.3%	0.81	0.95	43,549	0.08	1.05	0	7	0
Warehouse	Cooling	DX Units	Cool (reflective) rooftops	21	$0.54	0	0.00	0.5%	0.0%	0.23	0.95	224	0.00	0.81	0	0	0
Warehouse	Cooling	DX Units	Installation of wall, roof, or ceiling insulation	21	$0.60	0	0.00	0.0%	0.1%	0.54	0.95	23	0.00	1.99	0	0	0
Warehouse	Cooling	DX Units	Installation of low-E glass or multiple glazed windows	30	$0.67	1	0.00	13.5%	14.5%	0.51	0.95	13,681	0.00	0.00	0	2	0
Warehouse	Cooling	DX Units	Cool Storage	1	$0.00	0	0.00	0.0%	0.0%	0.72	0.95	0	0.00	0.00	0	0	0
Warehouse	Cooling	DX Units	Heat Pipe Enhanced DX	20	$0.00	0	0.00	0.0%	0.0%	0.50	0.95	0	0.00	0.00	0	0	0
Warehouse	Cooling	Room AC	Window treatment	11	$0.74	1	0.00	16.2%	18.6%	0.00	0.90	0	1.18	1.41	0	0	0
Warehouse	Cooling	Room AC	Variable-speed drives	15	$63.82	24	0.00	5.6%	5.6%	0.71	0.90	8,999	0.27	1.22	0	1	0
Warehouse	Cooling	Room AC	Energy management controls	10	$1,107.82	381	0.06	9.6%	8.9%	0.97	0.90	20,470	0.21	1.34	0	3	0
Warehouse	Cooling	Room AC	Improved maintenance and diagnostics	1	$751.34	883	0.15	22.3%	22.3%	0.81	0.90	36,061	0.08	1.05	0	6	0

Subsector	End Use	Technology Type	Measure Name	Life	Incremental Costs	kWh Savings	kW Savings	% kWh Savings	% kW Savings	Applicability Factor	1-Saturation Factor	Technical Potential (kWh)	TRC	RIM	Economic Potential (kWh)	Technical Potential (kW)	Economic Potential (kW)
Warehouse	Cooling	Room AC	Cool (reflective) rooftops	21	$0.54	0	0.00	0.5%	0.0%	0.23	0.90	188	0.00	0.81	0	0	0
Warehouse	Cooling	Room AC	Installation of wall, roof, or ceiling insulation	21	$0.60	0	0.00	0.0%	0.1%	0.54	0.90	19	0.00	1.99	0	0	0
Warehouse	Cooling	Room AC	Installation of low-E glass or multiple glazed windows	30	$0.67	1	0.00	13.5%	14.5%	0.51	0.90	11,452	0.00	0.00	0	2	0
Warehouse	Cooling	Room AC	Cool Storage	1	$0.00	0	0.00	0.0%	0.0%	0.72	0.90	0	0.00	0.00	0	0	0
Warehouse	Cooling	Room AC	Heat Pipe Enhanced DX	20	$0.00	0	0.00	0.0%	0.0%	0.50	0.90	0	0.00	0.00	0	0	0
Warehouse	Heating	Cntrl - HP	Window treatment	10	$0.65	1	0.00	35.8%	16.6%	0.91	0.80	9,284	0.42	0.85	0	0	0
Warehouse	Heating	Cntrl - HP	Installation of low-E glass or multiple glazed windows	23	$2.46	0	0.00	8.8%	11.8%	0.87	0.80	1,604	0.04	0.81	0	0	0
Warehouse	Heating	Cntrl - HP	Infiltration Reduction	16	$0.44	0	0.00	7.7%	10.5%	0.86	0.80	1,313	0.03	0.81	0	0	0
Warehouse	Heating	Cntrl - HP	Cool (reflective) rooftops	21	$0.64	0	0.00	-0.4%	0.2%	0.00	0.80	0	0.00	0.81	0	0	0
Warehouse	Heating	Cntrl - RTU/Furn	Window treatment	10	$0.65	1	0.00	35.8%	16.6%	0.91	0.80	0	0.42	0.85	0	0	0
Warehouse	Heating	Cntrl - RTU/Furn	Installation of low-E glass or multiple glazed windows	23	$2.46	0	0.00	8.8%	11.8%	0.87	0.80	0	0.04	0.81	0	0	0
Warehouse	Heating	Cntrl - RTU/Furn	Infiltration Reduction	16	$0.44	0	0.00	7.7%	10.5%	0.86	0.80	0	0.03	0.81	0	0	0
Warehouse	Heating	Cntrl - RTU/Furn	Cool (reflective) rooftops	21	$0.64	0	0.00	-0.4%	0.2%	0.00	0.80	0	0.00	0.81	0	0	0
Warehouse	Heating	Unitary	Window treatment	10	$0.65	1	0.00	35.8%	16.6%	0.91	0.80	61,585	0.42	0.85	0	0	0
Warehouse	Heating	Unitary	Installation of low-E glass or multiple glazed windows	23	$2.46	0	0.00	8.8%	11.8%	0.87	0.80	10,642	0.04	0.81	0	0	0
Warehouse	Heating	Unitary	Infiltration Reduction	16	$0.44	0	0.00	7.7%	10.5%	0.86	0.80	8,710	0.03	0.81	0	0	0
Warehouse	Heating	Unitary	Cool (reflective) rooftops	21	$0.64	0	0.00	-0.4%	0.2%	0.00	0.80	0	0.00	0.81	0	0	0
Warehouse	Lighting - Ext	E Incand.	High-intensity discharge lamps (incandescent to hi-pres sodium)	14	$148.29	2,050	0.50	71.5%	71.5%	0.82	0.80	7,904	11.14	1.44	7,904	0	0
Warehouse	Lighting - Ext	E Incand.	Outdoor lighting controls for incandescent (photocell/timeclock)	8	$109.02	1,528	0.00	25.2%	0.0%	0.60	0.80	1,079	4.73	0.89	1,079	0	0
Warehouse	Lighting - Ext	Fluor	T8 lamps with electronic ballasts (2L4')	18	$3.75	45	0.01	35.7%	35.7%	0.97	0.80	6,384	10.46	1.34	6,384	0	0
Warehouse	Lighting - Ext	Fluor	Outdoor lighting controls for fluorescent (photocell/timeclock)	8	$113.91	293	0.00	28.1%	0.0%	0.74	0.80	2,752	0.87	0.89	2,752	0	0
Warehouse	Lighting - Ext	HID	Outdoor lighting controls for HID (photocell/timeclock)	8	$108.99	1,528	0.00	27.4%	0.0%	0.59	0.80	10,965	4.73	0.89	10,965	0	0
Warehouse	Lighting - Ext	HID	High-intensity discharge lamps (mercury vapor to hi-pres sodium)	16	$154.57	841	0.21	51.9%	51.9%	0.97	0.80	29,695	4.56	1.38	29,695	0	0
Warehouse	Lighting - Int	4' Fluor	T8 lamps with electronic ballasts (2L4')	16	$5.71	39	0.01	32.9%	32.9%	0.97	0.20	62,820	6.12	1.47	62,820	17	17
Warehouse	Lighting - Int	4' Fluor	Occupancy sensors for 4' fluorescent	8	$11.65	54	0.01	23.1%	23.1%	0.77	0.80	130,841	3.28	1.81	130,841	34	34
Warehouse	Lighting - Int	4' Fluor	Reflectors for 4' fluorescent	17	$27.48	92	0.03	43.2%	43.2%	0.36	0.80	96,549	3.05	1.44	96,549	25	25
Warehouse	Lighting - Int	4' Fluor	Perimeter dimming for 4' fluorescent	13	$113.81	59	0.04	34.6%	73.2%	0.09	0.80	16,523	0.78	2.69	16,523	9	9
Warehouse	Lighting - Int	8' Fluor	Reflectors for 8' fluorescent	16	$27.13	146	0.04	41.0%	41.0%	0.48	0.80	212,852	4.79	1.47	212,852	56	56
Warehouse	Lighting - Int	8' Fluor	Perimeter dimming for 8' fluorescent	19	$52.86	109	0.09	27.8%	85.0%	0.11	0.80	27,221	3.64	2.51	27,221	22	22
Warehouse	Lighting - Int	8' Fluor	T8 lamps with electronic ballasts (2L8')	15	$9.95	39	0.01	18.3%	18.3%	0.79	0.20	31,912	3.44	1.50	31,912	8	8
Warehouse	Lighting - Int	8' Fluor	Occupancy sensors for 8' fluorescent	11	$27.60	93	0.02	21.3%	20.0%	0.86	0.80	156,333	2.48	1.54	156,333	37	37
Warehouse	Lighting - Int	Exit Signs	LED Exit Signs	10	$44.53	315	0.04	74.3%	74.3%	0.88	0.80	126,960	3.85	1.22	126,960	33	33
Warehouse	Lighting - Int	HID	High-intensity discharge lamps (incandescent to metal halide)	17	$245.28	391	0.11	45.8%	45.8%	0.17	1.00	0	1.45	1.44	0	0	0
Warehouse	Lighting - Int	Incand.	Compact flourescent lamp (modular)	9	-$45.29	202	0.06	64.9%	64.9%	0.94	0.05	3,257	-3.43	1.82	0	1	0
Warehouse	Office Equip - Non PC	Copy/Fax	Power management enabling - copier	4	$44.60	470	0.03	53.8%	18.8%	0.65	0.80	116,797	2.31	0.99	116,797	7	7
Warehouse	Office Equip - Non PC	Copy/Fax	External hardware control - printers	4	$165.99	160	0.00	54.4%	0.0%	0.43	0.80	57,208	0.21	0.99	0	0	0
Warehouse	Office Equip - Non PC	Copy/Fax	Nighttime shutdown - printers	4	$636.74	142	0.00	56.6%	0.0%	0.99	0.80	110,727	0.05	0.99	0	0	0
Warehouse	Office Equip - Non PC	Monitors	Network power management enabling - monitor	4	$4.67	117	0.01	72.8%	25.5%	0.75	0.80	349,090	5.46	0.99	349,090	22	22
Warehouse	Office Equip - Non PC	Monitors	Power management enabling - monitor	3	$7.42	115	0.01	71.8%	25.1%	0.00	0.80	0	2.68	1.01	0	0	0
Warehouse	Office Equip - Non PC	Monitors	External hardware control - monitors	5	$101.37	97	0.00	69.9%	0.0%	0.56	0.80	143,227	0.25	0.97	0	0	0
Warehouse	Office Equip - PC	CPUs	Power management enabling - PC	4	$13.29	90	0.01	37.5%	13.1%	0.58	0.80	105,284	1.48	0.99	105,284	7	7
Warehouse	Office Equip - PC	CPUs	LCD monitor	5	$455.58	80	0.01	49.7%	49.7%	0.97	0.80	190,852	0.05	0.95	0	39	0
Warehouse	Refrigeration	Compressors	Demand defrost electric	9	$0.03	3	0.00	9.0%	9.0%	0.00	0.99	0	48.77	1.43	0	0	0
Warehouse	Refrigeration	Compressors	Demand hot gas defrost	10	$0.03	1	0.00	3.3%	3.3%	0.00	0.99	0	21.46	1.38	0	0	0
Warehouse	Refrigeration	Compressors	Efficiency compressor motor retrofit	10	$0.07	2	0.00	6.6%	6.6%	0.00	0.99	0	16.92	1.38	0	0	0
Warehouse	Refrigeration	Compressors	Floating head pressure controls	16	$0.11	2	0.00	6.5%	0.0%	0.00	0.99	0	8.84	0.81	0	0	0
Warehouse	Refrigeration	Compressors	Anti-sweat (humidistat) controls	14	$0.14	1	0.00	4.5%	1.8%	0.00	0.30	0	5.27	0.99	0	0	0
Warehouse	Refrigeration	Compressors	Strip curtains for walk-ins	4	$0.05	1	0.00	3.2%	3.2%	0.00	0.99	0	3.91	0.98	0	0	0
Warehouse	Refrigeration	Compressors	Night covers for display cases	5	$0.14	2	0.00	5.5%	0.0%	0.00	0.99	0	3.14	0.97	0	0	0
Warehouse	Refrigeration	Compressors	Evaporator fan controller for MT walk-ins	5	$0.05	0	0.00	1.2%	1.2%	0.00	0.99	0	1.81	0.95	0	0	0
Warehouse	Refrigeration	Compressors	Compressor VSD retrofit	11	$0.45	2	0.00	5.1%	2.5%	0.00	0.99	0	1.77	1.09	0	0	0
Warehouse	Refrigeration	Compressors	Refrigeration commissioning	3	$0.20	1	0.00	4.5%	4.5%	0.00	0.99	0	1.17	1.00	0	0	0
Warehouse	Refrigeration	Fans/Motors	Demand defrost electric	9	$0.03	3	0.00	9.0%	9.0%	0.00	0.99	0	48.77	1.43	0	0	0
Warehouse	Refrigeration	Fans/Motors	Demand hot gas defrost	10	$0.03	1	0.00	3.3%	3.3%	0.00	0.99	0	21.46	1.38	0	0	0
Warehouse	Refrigeration	Fans/Motors	Anti-sweat (humidistat) controls	14	$0.14	1	0.00	4.5%	1.8%	0.00	0.30	0	5.27	0.99	0	0	0
Warehouse	Refrigeration	Fans/Motors	Strip curtains for walk-ins	4	$0.05	1	0.00	3.2%	3.2%	0.00	0.99	0	3.91	0.98	0	0	0
Warehouse	Refrigeration	Fans/Motors	Night covers for display cases	5	$0.14	2	0.00	5.5%	0.0%	0.00	0.99	0	3.14	0.97	0	0	0
Warehouse	Refrigeration	Fans/Motors	High-efficiency fan motors	18	$1.12	3	0.00	11.4%	11.4%	0.00	0.99	0	2.32	1.17	0	0	0
Warehouse	Refrigeration	Fans/Motors	Evaporator fan controller for MT walk-ins	5	$0.05	0	0.00	1.2%	1.2%	0.00	0.99	0	1.81	0.95	0	0	0
Warehouse	Refrigeration	Fans/Motors	Refrigeration commissioning	3	$0.20	1	0.00	4.5%	4.5%	0.00	0.99	0	1.17	1.00	0	0	0
Warehouse	Ventilation	Motor	Premium-efficiency motors	16	$5.71	164	0.03	4.9%	6.0%	0.90	0.95	2,031	20.64	1.20	2,031	0	0
Warehouse	Ventilation	Motor	CV to VAV conversion	22	$98.07	1,000	0.13	33.0%	33.0%	0.30	0.95	4,396	7.74	1.07	4,396	1	1
Warehouse	Ventilation	Motor	Variable-speed drives	8	$0.23	2	0.00	6.0%	1.2%	0.97	0.95	2,323	3.34	0.99	2,323	0	0
Warehouse	Ventilation	Motor	Unoccupied OA reduction	14	$112.66	500	0.01	5.1%	0.5%	0.68	0.95	1,295	2.08	0.86	1,295	0	0
Warehouse	Ventilation	Motor	Automatic OA reduction control	15	$773.99	1,160	0.02	9.2%	0.9%	0.67	0.95	2,236	0.73	0.85	2,236	0	0
Warehouse	Ventilation	Motor	Installation of nighttime pre-cooling controls and systems	10	$88.90	0	0.00	0.0%	22.8%	0.77	0.95	0	0.00	35.93	0	1	0
Warehouse	Ventilation	Motor	Installation of outside air reset controls	1	$0.86	0	0.00	0.0%	0.0%	0.70	0.95	0	0.00	0.00	0	0	0
Warehouse	Ventilation	Motor	Reducing minimum outside air requirements	1	$0.84	0	0.00	0.0%	0.0%	0.85	0.95	0	0.00	0.00	0	0	0
Warehouse	Ventilation	Motor w/VFD	Premium-efficiency motors	16	$5.71	164	0.03	4.9%	6.0%	0.90	0.95	2,031	20.64	1.20	2,031	0	0
Warehouse	Ventilation	Motor w/VFD	CV to VAV conversion	22	$98.07	1,000	0.13	33.0%	33.0%	0.30	0.95	4,396	7.74	1.07	4,396	1	1
Warehouse	Ventilation	Motor w/VFD	Unoccupied OA reduction	14	$112.66	500	0.01	5.1%	0.5%	0.68	0.95	1,371	2.08	0.86	1,371	0	0
Warehouse	Ventilation	Motor w/VFD	Automatic OA reduction control	15	$773.99	1,160	0.02	9.2%	0.9%	0.67	0.95	2,367	0.73	0.85	2,367	0	0
Warehouse	Ventilation	Motor w/VFD	Installation of nighttime pre-cooling controls and systems	10	$88.90	0	0.00	0.0%	22.8%	0.77	0.95	0	0.00	35.93	0	1	0
Warehouse	Ventilation	Motor w/VFD	Installation of outside air reset controls	1	$0.86	0	0.00	0.0%	0.0%	0.70	0.95	0	0.00	0.00	0	0	0
Warehouse	Ventilation	Motor w/VFD	Reducing minimum outside air requirements	1	$0.84	0	0.00	0.0%	0.0%	0.85	0.95	0	0.00	0.00	0	0	0
Warehouse	Water Heating	Call	Faucet Aerator	11	$0.01	0	0.00	1.9%	1.9%	0.71	0.80	2,256	0.17	33.31	0	0	0
Warehouse	Water Heating	Call	Tank Insulation	15	$0.03	0	0.00	8.0%	8.0%	0.65	0.80	8,498	0.17	26.55	0	2	0
Warehouse	Water Heating	Call	Circulation Pump Timelocks	13	$0.01	0	0.00	2.9%	2.9%	0.79	0.80	3,529	0.14	29.39	0	1	0
Warehouse	Water Heating	Call	Instanteous Water Heater <=200 MBTUH	16	$0.07	0	0.00	9.7%	9.7%	0.66	0.80	9,858	0.09	25.39	0	2	0
Warehouse	Water Heating	Call	Low Flow Showerheads	[illegible]	$0.02	0	0.00	2.2%	2.2%	0.86	0.80	2,706	0.08	35.89	0	1	0

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Subsector	End Use	Technology Type	Measure Name	Life	Incremental Costs	kWh Savings	kW Savings	% kWh Savings	% kW Savings	Applicability Factor	1-Saturation Factor	Technical Potential (kWh)	TRC	RIM	Economic Potential (kWh)	Technical Potential (kW)	Economic Potential (kW)
Warehouse	Water Heating	Call	Heater efficiency upgrade	12	$0.24	0	0.00	24.8%	24.8%	0.61	0.80	21,910	0.06	31.22	0	5	0
Warehouse	Water Heating	Call	Pipe Insulation	16	$0.02	0	0.00	1.7%	1.7%	0.84	0.80	1,812	0.06	25.36	0	0	0
Warehouse	Water Heating	Call	Solar Water Heater	1	$0.00	0	0.00	0.0%	0.0%	0.77	0.80	0	0.00	1.06	0	0	0
Warehouse	Water Heating	Call	Heat Recovery Water Heater	1	$0.00	0	0.00	0.0%	0.0%	0.70	0.80	0	0.00	1.06	0	0	0
Misc	Cooking	All	Infrared Fryer	15	$99.12	0	0.00	9.6%	9.6%	0.53	0.80	31,371	0.00	26.56	0	17	0
Misc	Cooking	All	Convection Oven	14	$88.77	0	0.00	4.7%	4.7%	0.46	0.80	12,760	0.00	27.88	0	7	0
Misc	Cooking	All	Infrared Conveyor Oven	14	$93.02	0	0.00	5.0%	5.0%	0.56	0.80	17,073	0.00	27.88	0	9	0
Misc	Cooking	All	Power Burner Fryer	15	$98.69	0	0.00	2.7%	2.7%	0.59	0.80	9,036	0.00	26.56	0	5	0
Misc	Cooking	All	Power Burner Oven	16	$102.60	0	0.00	2.4%	2.4%	0.52	0.80	7,069	0.00	25.40	0	4	0
Misc	Cooking	All	Efficient Infrared Griddle	14	$112.64	0	0.00	2.3%	2.3%	0.49	0.80	6,325	0.00	27.88	0	3	0
Misc	Cooling	Chillers	High-efficiency chillers	20	$43.22	130	0.05	14.9%	22.1%	0.88	0.90	261,418	3.45	1.64	261,418	108	108
Misc	Cooling	Chillers	Chiller economizers (water side), or air side economizers	13	$71.04	224	0.00	25.6%	0.0%	0.00	0.90	0	1.36	0.83	0	0	0
Misc	Cooling	Chillers	Energy management controls	10	$1,107.82	1,616	0.42	9.6%	8.9%	0.00	0.90	0	1.10	1.67	0	0	0
Misc	Cooling	Chillers	Window treatment	11	$0.74	1	0.00	16.2%	18.6%	0.00	0.90	0	1.07	1.78	0	0	0
Misc	Cooling	Chillers	Variable-speed drives	15	$63.82	49	0.01	5.6%	5.6%	0.00	0.90	0	0.67	1.49	0	0	0
Misc	Cooling	Chillers	Improved maintenance and diagnostics	1	$751.34	3,740	1.04	22.3%	22.3%	0.93	0.90	362,522	0.32	1.04	0	94	0
Misc	Cooling	Chillers	Cool (reflective) rooftops	21	$0.54	0	0.00	0.5%	0.0%	0.22	0.90	1,516	0.02	0.81	0	0	0
Misc	Cooling	Chillers	Installation of wall, roof, or ceiling insulation	21	$0.60	0	0.00	0.0%	0.1%	0.54	0.90	165	0.00	2.72	0	0	0
Misc	Cooling	Chillers	Optimize chilled water and condenser water setting	3	$103.98	0	0.00	1.1%	1.1%	0.75	0.90	11,996	0.00	0.99	0	3	0
Misc	Cooling	Chillers	Installation of low-E glass or multiple glazed windows	30	$0.67	1	0.00	13.5%	14.5%	0.53	0.90	101,738	0.00	0.00	0	28	0
Misc	Cooling	Chillers	Cool Storage	1	$0.00	0	0.00	0.0%	0.0%	0.75	0.90	0	0.00	0.00	0	0	0
Misc	Cooling	Chillers	Heat Pipe Enhanced DX	20	$0.00	0	0.00	0.0%	0.0%	0.50	0.90	0	0.00	0.00	0	0	0
Misc	Cooling	DX Units	High-efficiency packaged DX A/C	18	$99.97	166	0.06	21.2%	22.9%	0.99	0.95	1,440,620	1.76	1.46	1,440,620	432	432
Misc	Cooling	DX Units	Energy management controls	10	$1,107.82	1,616	0.42	9.6%	8.9%	0.00	0.95	0	1.10	1.67	0	0	0
Misc	Cooling	DX Units	Window treatment	11	$0.74	1	0.00	16.2%	18.6%	0.00	0.95	0	1.07	1.78	0	0	0
Misc	Cooling	DX Units	Variable-speed drives	15	$63.82	49	0.01	5.6%	5.6%	0.00	0.95	0	0.67	1.49	0	0	0
Misc	Cooling	DX Units	Improved maintenance and diagnostics	1	$751.34	3,740	1.04	22.3%	22.3%	0.93	0.95	1,137,242	0.32	1.04	0	309	0
Misc	Cooling	DX Units	Cool (reflective) rooftops	21	$0.54	0	0.00	0.5%	0.0%	0.22	0.95	4,696	0.02	0.81	0	0	0
Misc	Cooling	DX Units	Installation of wall, roof, or ceiling insulation	21	$0.60	0	0.00	0.0%	0.1%	0.54	0.95	511	0.00	2.72	0	1	0
Misc	Cooling	DX Units	Installation of low-E glass or multiple glazed windows	30	$0.67	1	0.00	13.5%	14.5%	0.53	0.95	317,484	0.00	0.00	0	93	0
Misc	Cooling	DX Units	Cool Storage	1	$0.00	0	0.00	0.0%	0.0%	0.75	0.95	0	0.00	0.00	0	0	0
Misc	Cooling	DX Units	Heat Pipe Enhanced DX	20	$0.00	0	0.00	0.0%	0.0%	0.50	0.95	0	0.00	0.00	0	0	0
Misc	Cooling	Room AC	Energy management controls	10	$1,107.82	1,616	0.42	9.6%	8.9%	0.00	0.90	0	1.10	1.67	0	0	0
Misc	Cooling	Room AC	Window treatment	11	$0.74	1	0.00	16.2%	18.6%	0.00	0.90	0	1.07	1.78	0	0	0
Misc	Cooling	Room AC	Variable-speed drives	15	$63.82	49	0.01	5.6%	5.6%	0.00	0.90	0	0.67	1.49	0	0	0
Misc	Cooling	Room AC	Improved maintenance and diagnostics	1	$751.34	3,740	1.04	22.3%	22.3%	0.93	0.90	1,757,146	0.32	1.04	0	487	0
Misc	Cooling	Room AC	Cool (reflective) rooftops	21	$0.54	0	0.00	0.5%	0.0%	0.22	0.90	7,349	0.02	0.81	0	0	0
Misc	Cooling	Room AC	Installation of wall, roof, or ceiling insulation	21	$0.60	0	0.00	0.0%	0.1%	0.54	0.90	800	0.00	2.72	0	1	0
Misc	Cooling	Room AC	Installation of low-E glass or multiple glazed windows	30	$0.67	1	0.00	13.5%	14.5%	0.53	0.90	496,896	0.00	0.00	0	148	0
Misc	Cooling	Room AC	Cool Storage	1	$0.00	0	0.00	0.0%	0.0%	0.75	0.90	0	0.00	0.00	0	0	0
Misc	Cooling	Room AC	Heat Pipe Enhanced DX	20	$0.00	0	0.00	0.0%	0.0%	0.50	0.90	0	0.00	0.00	0	0	0
Misc	Heating	Cntrl - HP	Window treatment	10	$0.65	3	0.00	35.8%	16.6%	0.91	0.80	0	1.68	0.85	0	0	0
Misc	Heating	Cntrl - HP	Installation of low-E glass or multiple glazed windows	23	$2.46	1	0.00	8.8%	11.8%	0.86	0.80	0	0.17	0.81	0	0	0
Misc	Heating	Cntrl - HP	Infiltration Reduction	16	$0.44	0	0.00	7.7%	10.5%	0.95	0.80	0	0.13	0.81	0	0	0
Misc	Heating	Cntrl - HP	Cool (reflective) rooftops	21	$0.64	0	0.00	-0.4%	0.2%	0.00	0.80	0	-0.02	0.81	0	0	0
Misc	Heating	Cntrl - RTU/Furn	Window treatment	10	$0.65	3	0.00	35.8%	16.6%	0.91	0.80	615,302	1.68	0.85	615,302	0	0
Misc	Heating	Cntrl - RTU/Furn	Installation of low-E glass or multiple glazed windows	23	$2.46	1	0.00	8.8%	11.8%	0.86	0.80	104,972	0.17	0.81	0	0	0
Misc	Heating	Cntrl - RTU/Furn	Infiltration Reduction	16	$0.44	0	0.00	7.7%	10.5%	0.95	0.80	96,055	0.13	0.81	0	0	0
Misc	Heating	Cntrl - RTU/Furn	Cool (reflective) rooftops	21	$0.64	0	0.00	-0.4%	0.2%	0.00	0.80	0	-0.02	0.81	0	0	0
Misc	Heating	Unitary	Window treatment	10	$0.65	3	0.00	35.8%	16.6%	0.91	0.80	799,185	1.68	0.85	799,185	0	0
Misc	Heating	Unitary	Installation of low-E glass or multiple glazed windows	23	$2.46	1	0.00	8.8%	11.8%	0.86	0.80	136,343	0.17	0.81	0	0	0
Misc	Heating	Unitary	Infiltration Reduction	16	$0.44	0	0.00	7.7%	10.5%	0.95	0.80	124,760	0.13	0.81	0	0	0
Misc	Heating	Unitary	Cool (reflective) rooftops	21	$0.64	0	0.00	-0.4%	0.2%	0.00	0.80	0	-0.02	0.81	0	0	0
Misc	Lighting - Ext	E Incand.	High-intensity discharge lamps (incandescent to hi-pres sodium)	14	$148.29	2,050	0.50	71.5%	71.5%	0.75	0.80	604,383	11.14	1.44	604,383	13	13
Misc	Lighting - Ext	E Incand.	Outdoor lighting controls for incandescent (photocell/timeclock)	8	$109.02	1,528	0.00	25.2%	0.0%	0.73	0.80	120,129	4.73	0.89	120,129	0	0
Misc	Lighting - Ext	Fluor	T8 lamps with electronic ballasts (2L4')	18	$3.75	45	0.01	35.7%	35.7%	0.91	0.80	169,901	10.46	1.34	169,901	4	4
Misc	Lighting - Ext	Fluor	Outdoor lighting controls for fluorescent (photocell/timeclock)	8	$113.91	293	0.00	28.1%	0.0%	0.76	0.80	81,421	0.87	0.89	81,421	0	0
Misc	Lighting - Ext	HID	Outdoor lighting controls for HID (photocell/timeclock)	8	$108.99	1,528	0.00	27.4%	0.0%	0.76	0.80	507,986	4.73	0.89	507,986	0	0
Misc	Lighting - Ext	HID	High-intensity discharge lamps (mercury vapor to hi-pres sodium)	16	$154.57	841	0.21	51.9%	51.9%	0.80	0.80	850,532	4.58	1.38	850,532	22	22
Misc	Lighting - Int	4' Fluor	T8 lamps with electronic ballasts (2L4')	16	$5.71	50	0.01	32.9%	32.9%	0.89	0.20	778,485	7.00	1.33	778,485	345	345
Misc	Lighting - Int	4' Fluor	Reflectors for 4' fluorescent	17	$27.48	117	0.03	43.2%	43.2%	0.44	0.80	1,920,780	3.50	1.31	1,920,780	852	852
Misc	Lighting - Int	4' Fluor	Occupancy sensors for 4' fluorescent	8	$11.65	54	0.01	23.1%	23.1%	0.77	0.80	1,500,822	3.28	1.81	1,500,822	666	666
Misc	Lighting - Int	4' Fluor	Perimeter dimming for 4' fluorescent	13	$113.81	59	0.04	34.6%	73.2%	0.10	0.80	264,075	0.78	2.09	264,075	248	248
Misc	Lighting - Int	8' Fluor	Reflectors for 8' fluorescent	16	$27.13	185	0.04	41.0%	41.0%	0.35	0.80	494,027	5.49	1.33	494,027	220	220
Misc	Lighting - Int	8' Fluor	T8 lamps with electronic ballasts (2L8')	15	$8.95	50	0.01	18.3%	18.3%	0.76	0.20	104,805	3.93	1.38	104,805	47	47
Misc	Lighting - Int	8' Fluor	Perimeter dimming for 8' fluorescent	19	$52.86	109	0.09	27.8%	85.0%	0.10	0.80	81,917	3.64	2.51	81,917	112	112
Misc	Lighting - Int	8' Fluor	Occupancy sensors for 8' fluorescent	11	$27.60	93	0.02	21.3%	20.0%	0.85	0.80	513,197	2.48	1.54	513,197	205	205
Misc	Lighting - Int	Exit Signs	LED Exit Signs	10	$44.53	315	0.04	74.3%	74.3%	0.84	0.80	547,402	3.85	1.22	547,402	243	243
Misc	Lighting - Int	HID	High-intensity discharge lamps (incandescent to metal halide)	17	$245.28	495	0.11	45.8%	45.8%	0.20	1.00	0	1.66	1.31	0	0	0
Misc	Lighting - Int	Incand.	Compact flourescent lamp (modular)	9	-$45.29	257	0.06	64.9%	64.9%	0.80	0.05	27,078	-3.86	1.62	0	12	0
Misc	Office Equip - Non PC	Copy/Fax	Power management enabling - copier	4	$44.60	470	0.05	53.8%	18.8%	0.69	0.80	3,440,120	2.31	0.98	3,440,120	368	368
Misc	Office Equip - Non PC	Copy/Fax	External hardware control - printers	4	$165.99	160	0.00	54.4%	0.0%	0.54	0.80	1,924,723	0.21	0.99	0	0	0
Misc	Office Equip - Non PC	Copy/Fax	Nighttime shutdown - printers	4	$636.74	142	0.00	56.6%	0.0%	0.99	0.80	2,812,051	0.05	0.99	0	0	0
Misc	Office Equip - Non PC	Monitors	Network power management enabling - monitor	4	$4.67	117	0.01	72.8%	25.5%	0.81	0.80	8,721,591	5.46	0.98	8,721,591	933	933
Misc	Office Equip - Non PC	Monitors	Power management enabling - monitor	3	$7.42	115	0.01	71.8%	25.1%	0.00	0.80	0	2.68	1.00	0	0	0
Misc	Office Equip - Non PC	Monitors	External hardware control - monitors	5	$101.37	97	0.00	69.9%	0.0%	0.42	0.80	2,317,253	0.25	0.97	0	0	0
Misc	Office Equip - PC	CPUs	Power management enabling - PC	4	$13.29	90	0.01	37.5%	13.1%	0.69	0.80	2,677,911	1.48	0.98	2,677,911	286	286
Misc	Office Equip - PC	CPUs	LCD monitor	5	$455.58	80	0.02	49.7%	49.7%	0.98	0.80	3,974,827	0.05	0.94	0	1,421	0
Misc	Refrigeration	Compressors	Demand defrost electric	9	$0.03	3	0.00	9.0%	9.0%	0.00	0.99	0	62.20	1.81	0	0	0
Misc	Refrigeration	Compressors	Demand hot gas defrost	10	$0.03	1	0.00	3.3%	3.3%	0.00	0.99	0	27.18	1.73	0	0	0

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Subsector	End Use	Technology Type	Measure Name	Life	Incremental Costs	kWh Savings	kW Savings	% kWh Savings	% kW Savings	Applicability Factor	1-Saturation Factor	Technical Potential (kWh)	TRC	RIM	Economic Potential (kWh)	Technical Potential (kW)	Economic Potential (kW)
Misc	Refrigeration	Compressors	Efficiency compressor motor retrofit	10	$0.07	2	0.00	6.6%	6.6%	0.00	0.99	0	21.42	1.73	0	0	0
Misc	Refrigeration	Compressors	Floating head pressure controls	16	$0.11	2	0.00	6.5%	0.0%	0.00	0.99	0	8.84	0.81	0	0	0
Misc	Refrigeration	Compressors	Anti-sweat (humidistat) controls	14	$0.14	1	0.00	4.5%	1.8%	0.00	0.30	0	5.90	1.11	0	0	0
Misc	Refrigeration	Compressors	Strip curtains for walk-ins	4	$0.05	1	0.00	3.2%	3.2%	0.00	0.99	0	3.91	0.97	0	0	0
Misc	Refrigeration	Compressors	Night covers for display cases	5	$0.14	2	0.00	5.5%	0.0%	0.00	0.99	0	3.14	0.97	0	0	0
Misc	Refrigeration	Compressors	Compressor VSD retrofit	11	$0.45	2	0.00	5.1%	2.5%	0.00	0.99	0	2.05	1.26	0	0	0
Misc	Refrigeration	Compressors	Evaporator fan controller for MT walk-ins	5	$0.05	0	0.00	1.2%	1.2%	0.00	0.99	0	1.81	0.95	0	0	0
Misc	Refrigeration	Compressors	Refrigeration commissioning	3	$0.20	1	0.00	4.5%	4.5%	0.00	0.99	0	1.17	0.99	0	0	0
Misc	Refrigeration	Fans/Motors	Demand defrost electric	9	$0.03	3	0.00	9.0%	9.0%	0.00	0.99	0	62.20	1.81	0	0	0
Misc	Refrigeration	Fans/Motors	Demand hot gas defrost	10	$0.03	1	0.00	3.3%	3.3%	0.00	0.99	0	27.16	1.73	0	0	0
Misc	Refrigeration	Fans/Motors	Anti-sweat (humidistat) controls	14	$0.14	1	0.00	4.5%	1.8%	0.00	0.30	0	5.90	1.11	0	0	0
Misc	Refrigeration	Fans/Motors	Strip curtains for walk-ins	4	$0.05	1	0.00	3.2%	3.2%	0.00	0.99	0	3.91	0.97	0	0	0
Misc	Refrigeration	Fans/Motors	Night covers for display cases	5	$0.14	2	0.00	5.5%	0.0%	0.00	0.99	0	3.14	0.97	0	0	0
Misc	Refrigeration	Fans/Motors	High-efficiency fan motors	18	$1.12	3	0.00	11.4%	11.4%	0.00	0.99	0	2.82	1.41	0	0	0
Misc	Refrigeration	Fans/Motors	Evaporator fan controller for MT walk-ins	5	$0.05	0	0.00	1.2%	1.2%	0.00	0.99	0	1.81	0.95	0	0	0
Misc	Refrigeration	Fans/Motors	Refrigeration commissioning	3	$0.20	1	0.00	4.5%	4.5%	0.00	0.99	0	1.17	0.99	0	0	0
Misc	Ventilation	Motor	Premium-efficiency motors	16	$5.71	164	0.04	4.9%	6.0%	0.95	0.95	246,061	25.30	1.45	246,061	68	68
Misc	Ventilation	Motor	CV to VAV conversion	22	$98.07	1,000	0.22	33.0%	33.0%	0.21	0.95	349,682	9.09	1.24	349,682	77	77
Misc	Ventilation	Motor	Variable-speed drives	8	$0.23	2	0.00	6.0%	1.2%	0.89	0.95	255,210	3.58	1.05	255,210	11	11
Misc	Ventilation	Motor	Unoccupied OA reduction	14	$112.66	500	0.01	5.1%	0.5%	0.77	0.95	177,231	2.14	0.88	177,231	4	4
Misc	Ventilation	Motor	Automatic OA reduction control	15	$773.99	1,160	0.03	9.2%	0.9%	0.85	0.95	339,886	0.75	0.87	339,886	8	8
Misc	Ventilation	Motor	Installation of nighttime pre-cooling controls and systems	10	$88.90	0	0.00	0.0%	22.8%	0.71	0.95	0	0.00	35.93	0	165	0
Misc	Ventilation	Motor	Installation of outside air reset controls	1	$0.86	0	0.00	0.0%	0.0%	0.79	0.95	0	0.00	0.00	0	0	0
Misc	Ventilation	Motor	Reducing minimum outside air requirements	1	$0.84	0	0.00	0.0%	0.0%	0.70	0.95	0	0.00	0.00	0	0	0
Misc	Ventilation	Motor w/VFD	Premium-efficiency motors	16	$5.71	164	0.04	4.9%	6.0%	0.95	0.95	246,061	25.30	1.45	246,061	68	68
Misc	Ventilation	Motor w/VFD	CV to VAV conversion	22	$98.07	1,000	0.22	33.0%	33.0%	0.21	0.95	349,682	9.09	1.24	349,682	77	77
Misc	Ventilation	Motor w/VFD	Unoccupied OA reduction	14	$112.66	500	0.01	5.1%	0.5%	0.77	0.95	186,712	2.14	0.88	186,712	4	4
Misc	Ventilation	Motor w/VFD	Automatic OA reduction control	15	$773.99	1,160	0.03	9.2%	0.9%	0.85	0.95	358,069	0.75	0.87	358,069	8	8
Misc	Ventilation	Motor w/VFD	Installation of nighttime pre-cooling controls and systems	10	$88.90	0	0.00	0.0%	22.8%	0.71	0.95	0	0.00	35.93	0	167	0
Misc	Ventilation	Motor w/VFD	Installation of outside air reset controls	1	$0.86	0	0.00	0.0%	0.0%	0.79	0.95	0	0.00	0.00	0	0	0
Misc	Ventilation	Motor w/VFD	Reducing minimum outside air requirements	1	$0.84	0	0.00	0.0%	0.0%	0.70	0.95	0	0.00	0.00	0	0	0
Misc	Water Heating	Call	Faucet Aerator	11	$0.01	0	0.00	1.9%	1.9%	0.74	0.80	49,020	1.67	33.35	49,020	18	18
Misc	Water Heating	Call	Tank Insulation	15	$0.03	0	0.00	8.0%	8.0%	0.77	0.80	211,301	1.64	26.55	211,301	78	78
Misc	Water Heating	Call	Circulation Pump Timelocks	13	$0.01	0	0.00	2.9%	2.9%	0.82	0.80	76,943	1.38	29.42	76,943	28	28
Misc	Water Heating	Call	Instanteous Water Heater <=200 MBTUH	18	$0.07	0	0.00	9.7%	9.7%	0.60	0.80	186,529	0.85	25.40	186,529	69	69
Misc	Water Heating	Call	Low Flow Showerheads	10	$0.02	0	0.00	2.2%	2.2%	0.79	0.80	51,931	0.78	35.93	51,931	19	19
Misc	Water Heating	Call	Heater efficiency upgrade	12	$0.24	0	0.00	24.8%	24.8%	0.57	0.80	427,076	0.61	31.22	427,076	158	158
Misc	Water Heating	Call	Pipe Insulation	16	$0.02	0	0.00	1.7%	1.7%	0.82	0.80	37,663	0.56	25.40	37,663	14	14
Misc	Water Heating	Call	Solar Water Heater	1	$0.00	0	0.00	0.0%	0.0%	0.83	0.80	0	0.00	1.06	0	0	0
Misc	Water Heating	Call	Heat Recovery Water Heater	1	$0.00	0	0.00	0.0%	0.0%	0.83	0.80	0	0.00	1.06	0	0	0

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DOE-2 Model Runs Summary

Exhibit A3-3. New Residential Measures – Baseline and Upgrade Characteristics

	Heatpump			Duct Leakage		Thermostat		Infiltration		Window		Frame Wall Insulation	
	Existing	Baseline	Upgrade	Baseline	Upgrade	Baseline	Upgrade	Baseline	Upgrade	Baseline	Upgrade	Baseline	Upgrade
House Type	Slab on Grade			Slab on Grade		Slab on Grade		Slab on Grade		Slab on Grade		Slab on Grade	
Number of Stories	1			1		1		1		1		1	
Square Feet per Floor	1883			1883		1883		1883		1883		1883	
% Window Area	16.8%			16.8%		16.8%		16.8%		16.8%		16.8%	
Duct Location	Attic			Attic		Attic		Attic		Attic		Attic	
Roof Solar Absorptivity	0.75			0.75		0.75		0.75		0.75		0.75	
Attic Insulation	30			30		30		30		30		30	
Wall Construction	Block Wall			Block Wall		Block Wall		Block Wall		Block Wall		2x4	2x6
Wall Cavity Insulation	0			0		0		0		0		13	19
Wall Sheathing	3			3		3		3		3		1	
Door R	1.5			1.5		1.5		1.5		1.5		1.5	
Window U	0.75			0.75		0.75		0.75		0.75	0.40	0.75	
Window SHGC	0.40			0.40		0.40		0.40		0.40	0.35	0.40	
Infiltration Value	0.00048			0.00048		0.00048		0.00048	0.35	0.00048		0.00048	
Infiltration Units	SLA			SLA		SLA		SLA	ACH	SLA		SLA	
System Type	Heatpump			Heatpump		Heatpump		Heatpump		Heatpump		Heatpump	
Cooling Efficiency (SEER)	10	13	14	13		13		13		13		13	
Heating Efficiency (COP)	2.0	2.3	2.5	2.3		2.3		2.3		2.3		2.3	
Duct R	6			6		6		6		6		6	
Duct Leakage (cfm/100 SF)	8			8	4	8		8		8		8	
Thermostat	Manual			Manual		Manual	Program	Manual		Manual		Manual	

	Block Wall Insulation		Attic Insulation		Door		HVAC upgrade to Ground Source			AC		
	Baseline	Upgrade	Baseline	Upgrade	Baseline	Upgrade	Existing	Baseline	Upgrade	Existing	Baseline	Upgrade
House Type	Slab on Grade		Slab on Grade		Slab on Grade		Slab on Grade			Slab on Grade		
Number of Stories	1		1		1		1			1		
Square Feet per Floor	1883		1883		1883		1883			1883		
% Window Area	16.8%		16.8%		16.8%		16.8%			16.8%		
Duct Location	Attic		Attic		Attic		Attic			Attic		
Roof Solar Absorptivity	0.75		0.75		0.75		0.75			0.75		
Attic Insulation	30		30	38	30		30			30		
Wall Construction	Block Wall		Block Wall		Block Wall		Block Wall			Block Wall		
Wall Cavity Insulation	0		0		0		0			0		
Wall Sheathing	3	5	3		3		3			3		
Door R	1.5		1.5		1.5	4	1.5			1.5		
Window U	0.75		0.75		0.75		0.75			0.75		
Window SHGC	0.40		0.40		0.40		0.40			0.40		
Infiltration Value	0.00048		0.00048		0.00048		0.00048			0.00048		
Infiltration Units	SLA		SLA		SLA		SLA			SLA		
System Type	Heatpump		Heatpump		Heatpump		AC with Electi	Heatpump	Heatpump	AC with Electric		
Cooling Efficiency (SEER)	13		13		13		10	13	18	10	13	15
Heating Efficiency (COP)	2.3		2.3		2.3		1.0	2.3	3.5	1.0		
Duct R	6		6		6		6			6		
Duct Leakage (cfm/100 SF)	8		8		8		8			8		
Thermostat	Manual		Manual		Manual		Manual			Manual		

	Exterior Shades		Shade Screens		Landscape Shading		Window Film		Roof Reflective		ENERGY STAR Home	
	Baseline	Upgrade	Baseline	Upgrade	Baseline	Upgrade	Baseline	Upgrade	Baseline	Upgrade	Baseline	Upgrade
House Type	Slab on Grade		Slab on Grade		Slab on Grade		Slab on Grade		Slab on Grade		Slab on Grade	
Number of Stories	1		1		1		1		1		1	
Square Feet per Floor	1883		1883		1883		1883		1883		1883	
% Window Area	16.8%		16.8%		16.8%		16.8%		16.8%		16.8%	
Duct Location	Attic		Attic		Attic		Attic		Attic		Attic	
Roof Solar Absorptivity	0.75		0.75		0.75		0.75		0.95	0.2	0.75	
Attic Insulation	30		30		30		30		30		30	
Wall Construction	Block Wall		Block Wall		Block Wall		Block Wall		Block Wall		Block Wall	
Wall Cavity Insulation	0		0		0		0		0		0	
Wall Sheathing	3		3		3		3		3		3	5
Door R	1.5		1.5		1.5		1.5		1.5		1.5	
Window U	0.75		0.75	0.71	0.75		0.75	0.64	0.75		0.75	0.55
Window SHGC	0.40	0.20	0.40	0.14	0.40	0.30	0.40	0.10	0.40		0.40	0.35
Infiltration Value	0.00048		0.00048		0.00048		0.00048		0.00048		0.00048	7
Infiltration Units	SLA		SLA		SLA		SLA		SLA		SLA	ACH50
System Type	Heatpump		Heatpump		Heatpump		Heatpump		Heatpump		Heatpump	
Cooling Efficiency (SEER)	13		13		13		13		13		13	14
Heating Efficiency (COP)	2.3		2.3		2.3		2.3		2.3		2.3	2.4
Duct R	6		6		6		6		6		6	
Duct Leakage (cfm/100 SF)	8		8		8		8		8		8	4
Thermostat	Manual		Manual		Manual		Manual		Manual		Manual	Program

Exhibit A3-3. Existing Residential Measures – Baseline and Upgrade Characteristics

	Duct Leakage		Thermostat		Infiltration		Frame Wall Insulation		Block Wall Insulation	
	Baseline	Upgrade	Baseline	Upgrade	Baseline	Upgrade	Baseline	Upgrade	Baseline	Upgrade
House Type	Slab on Grade		Slab on Grade		Slab on Grade		Slab on Grade		Slab on Grade	
Number of Stories	1		1		1		1		1	
Square Feet per Floor	1883		1883		1883		1883		1883	
% Window Area	16.8%		16.8%		16.8%		16.8%		16.8%	
Duct Location	Attic		Attic		Attic		Attic		Attic	
Roof Solar Absorptivity	0.75		0.75		0.75		0.75		0.75	
Attic Insulation	19		19		19		19		19	
Wall Construction	8		8		8		1	2	8	
Wall Cavity Insulation	0		0		0		11	19	0	
Wall Sheathing	1		1		1		1		1	5
Door R	1.5		1.5		1.5		1.5		1.5	
Window U	1.1		1.1		1.1		1.1		1.1	
Window SHGC	0.75		0.75		0.75		0.75		0.75	
Infiltration Value	0.00048		0.00048		0.55	0.35	0.00048		0.00048	
Infiltration Units	SLA		SLA		ACH	ACH	SLA		SLA	
System Type	AC with Electric		AC with Electric		AC with Electric		AC with Electric		AC with Electric	
Cooling Efficiency (SEER)	10		10		10		10		10	
Heating Efficiency (COP)	1		1		1		1		1	
Duct R	6		6		6		6		6	
Duct Leakage (cfm/100 SF)	10	6	10		10		10		10	
Thermostat	Manual		Manual	Program	Manual		Manual		Manual	

	Attic Insulation		Door		Exterior Shades		Shade Screens		Landscape Shading	
	Baseline	Upgrade	Baseline	Upgrade	Baseline	Upgrade	Baseline	Upgrade	Baseline	Upgrade
House Type	Slab on Grade		Slab on Grade		Slab on Grade		Slab on Grade		Slab on Grade	
Number of Stories	1		1		1		1		1	
Square Feet per Floor	1883		1883		1883		1883		1883	
% Window Area	16.8%		16.8%		16.8%		16.8%		16.8%	
Duct Location	Attic		Attic		Attic		Attic		Attic	
Roof Solar Absorptivity	0.75		0.75		0.75		0.75		0.75	
Attic Insulation	19	38	19		19		19		19	
Wall Construction	8		8		8		8		8	
Wall Cavity Insulation	0		0		0		0		0	
Wall Sheathing	1		1		1		1		1	
Door R	1.5		1.5	4	1.5		1.5		1.5	
Window U	1.1		1.1		1.1		1.1	1.045	1.1	
Window SHGC	0.75		0.75		0.75	0.375	0.75	0.2625	0.75	0.5625
Infiltration Value	0.00048		0.00048		0.00048		0.00048		0.00048	
Infiltration Units	SLA		SLA		SLA		SLA		SLA	
System Type	AC with Electric		AC with Electric		AC with Electric		AC with Electric		AC with Electric	
Cooling Efficiency (SEER)	10		10		10		10		10	
Heating Efficiency (COP)	1		1		1		1		1	
Duct R	6		6		6		6		6	
Duct Leakage (cfm/100 SF)	10		10		10		10		10	
Thermostat	Manual		Manual		Manual		Manual		Manual	

	Window Film		Roof Reflective		ENERGY STAR	
	Baseline	Upgrade	Baseline	Upgrade	Baseline	Upgrade
House Type	Slab on Grade		Slab on Grade		Slab on Grade	
Number of Stories	1		1		1	
Square Feet per Floor	1883		1883		1883	
% Window Area	16.8%		16.8%		16.8%	
Duct Location	Attic		Attic		Attic	
Roof Solar Absorptivity	0.75		0.95	0.2	0.75	
Attic Insulation	19		19		19	30
Wall Construction	8		8		8	
Wall Cavity Insulation	0		0		0	
Wall Sheathing	1		1		1	
Door R	1.5		1.5		1.5	
Window U	1.1	0.935	1.1		1.1	
Window SHGC	0.75	0.1875	0.75		0.75	
Infiltration Value	0.00048		0.00048		0.00048	
Infiltration Units	SLA		SLA		SLA	
System Type	AC with Electric		AC with Electric		AC with Electric	
Cooling Efficiency (SEER)	10		10		10	14
Heating Efficiency (COP)	1		1		1	
Duct R	6		6		6	
Duct Leakage (cfm/100 SF)	10		10		10	6
Thermostat	Manual		Manual		Manual	

Exhibit A3-3. Residential Room A/C Measures – Baseline and Upgrade Characteristics

	Infiltration		Window		Frame Wall Insulation		Block Wall Insulation	
	Baseline	Upgrade	Baseline	Upgrade	Baseline	Upgrade	Baseline	Upgrade
House Type	Slab on Grade		Slab on Grade		Slab on Grade		Slab on Grade	
Number of Stories	1		1		1		1	
Square Feet per Floor	1883		1883		1883		1883	
% Window Area	16.8%		16.8%		16.8%		16.8%	
Duct Location	Attic		Attic		Attic		Attic	
Roof Solar Absorptivity	0.75		0.75		0.75		0.75	
Attic Insulation	19		19		19		19	
Wall Construction	8		8		1	2	8	
Wall Cavity Insulation	0		0		11	19	0	
Wall Sheathing	3		3		1		3	5
Door R	1.5		1.5		1.5		1.5	
Window U	1.1		1.1	0.4	1.1		1.1	
Window SHGC	0.75		0.75	0.35	0.75		0.75	
Infiltration Value	0.00048	0.35	0.00048		0.00048		0.00048	
Infiltration Units	SLA	ACH	SLA		SLA		SLA	
System Type	Room AC		Room AC		Room AC		Room AC	
Cooling Efficiency (SEER)	8		8		8		8	
Heating Efficiency (COP)	1		1		1		1	
Duct R	6		6		6		6	
Duct Leakage (cfm/100 SF)	0		0		0		0	
Thermostat	Manual		Manual		Manual		Manual	

	Attic Insulation		Door		Exterior Shades		AC		
	Baseline	Upgrade	Baseline	Upgrade	Baseline	Upgrade	Existing	Baseline	Upgrade
House Type	Slab on Grade		Slab on Grade		Slab on Grade		Slab on Grade		
Number of Stories	1		1		1		1		
Square Feet per Floor	1883		1883		1883		1883		
% Window Area	16.8%		16.8%		16.8%		16.8%		
Duct Location	Attic		Attic		Attic		Attic		
Roof Solar Absorptivity	0.75		0.75		0.75		0.75		
Attic Insulation	19	38	19		19		19		
Wall Construction	8		8		8		8		
Wall Cavity Insulation	0		0		0		0		
Wall Sheathing	3		3		3		3		
Door R	1.5		1.5	4	1.5		1.5		
Window U	1.1		1.1		1.1		1.1		
Window SHGC	0.75		0.75		0.75	0.375	0.75		
Infiltration Value	0.00048		0.00048		0.00048		0.00048		
Infiltration Units	SLA		SLA		SLA		SLA		
System Type	Room AC		Room AC		Room AC		Room AC		
Cooling Efficiency (SEER)	8		8		8		8	9	10.5
Heating Efficiency (COP)	1		1		1		1		
Duct R	6		6		6		6		
Duct Leakage (cfm/100 SF)	0		0		0		0		
Thermostat	Manual		Manual		Manual		Manual		

Exhibit A3-3. Commercial Building Type Baseline Characteristics

	Grocery	Hotel	Hospital	Office	Retail	Restaurant
	Baseline	Baseline	Baseline	Baseline	Baseline	Baseline
Square Feet per Floor	40000	30000	30000	30000	100000	3000
% Window Area (WWA)	5%	33%	50%	50%	6%	10%
Number of Stories	1	4	8	8	1	1
Wall Insulation	13	13	13	13	13	13
Wall Sheathing	2	2	2	2	2	2
Attic Insulation	23	24	15	17	33	21
Window U	0.7	0.7	0.7	0.7	0.7	0.7
Window SHGC	0.78	0.78	0.78	0.78	0.78	0.78
Outdoor Air (ac/h)	0.35	0.5	1.2	2.5	0.5	4
Roof Solar Absorptivity	0.75	0.75	0.75	0.75	0.75	0.75
Cooling Efficiency (EER)	9.21	15	14.75	9.63	8.84	8.68
Fan Type	1	1	1	1	1	1
Duct Loss	0%	0%	0%	0%	0%	0%

Exhibit A3-3. Commercial Measures – Baseline and Upgrade Characteristics

	Window Treatment		Cool (reflective) rooftops		Installation of Low-E glass or multiple glazed windows		High-efficiency chillers (Existing: 0.85 kW/ton; Baseline: 0.65 kW/ton; Upgrade: 0.45 kW/ton)			Automatic OA reduction control	
	Baseline	Upgrade	Baseline	Upgrade	Baseline	Upgrade	Existing	Baseline	Upgrade	Baseline	Upgrade
Window U	0.75	0.75			0.65	0.45					
Window SHGC	1.035	0.46			0.55	0.35					
Outdoor Air										100% constant	75% variable
Roof Solar Absorptivity			0.95	0.2							
Cooling Efficiency							0.85	0.65	0.45		
Fan Type											
Duct Loss											

	Energy management controls		Improved maintenance and diagnostics		Variable-speed drives		High-efficiency packaged DX A/C (Existing: 8 EER; Baseline: 10 EER; Upgrade: 12 EER)			Unoccupied OA reduction	
	Baseline	Upgrade	Baseline	Upgrade	Baseline	Upgrade	Existing	Baseline	Upgrade	Baseline	Upgrade
Window U											
Window SHGC											
Outdoor Air										Fixed Control	Enthalpy Controled
Roof Solar Absorptivity											
Cooling Efficiency							8	10	12		
Fan Type	Constant Temperature	Variable Temperature			Constant	Variable					
Duct Loss			0%	5%							

Exhibit A3-4. GRU Cumulative Avoided Costs

Year	NPV Avoided Cost / kWh	NPV Avoided Cost / kW
2006	$0.0643	$0.00
2007	$0.1219	$0.00
2008	$0.1732	$0.00
2009	$0.2189	$0.00
2010	$0.2594	$0.00
2011	$0.2953	$0.00
2012	$0.3166	$1,460.09
2013	$0.3373	$1,460.09
2014	$0.3575	$1,460.09
2015	$0.3771	$1,460.09
2016	$0.3961	$1,460.09
2017	$0.4145	$1,460.09
2018	$0.4323	$1,460.09
2019	$0.4495	$1,460.09
2020	$0.4662	$1,460.09
2021	$0.4822	$1,460.09
2022	$0.4977	$1,460.09
2023	$0.5126	$1,460.09
2024	$0.5270	$1,460.09
2025	$0.5408	$1,460.09
2026	$0.5541	$1,460.09
2027	$0.5668	$1,460.09
2028	$0.5791	$1,460.09
2029	$0.5908	$1,460.09
2030	$0.6021	$1,460.09

Discount Rate: 6.75%
2012 Capital Cost: $2,306.50 / kW
Winter Peak hours: 331
Summer Peak hours: 1377
Off Peak hours: 7052
Source: GRU Strategic Planning

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Exhibit A3-5 Measure to Program Mapping

Program	Technology Type	Measure
Residential CFL Program		Compact fluorescent lamps (CFLs)
Residential Fridge/Freezer Buyback		Remove 2nd Freezer
		Remove 2nd Refrigerator
Home Performance with Energy Star (Marginally Cost-Effective Measures)		Whole House Fan
		Duct Insulation
Home Performance with Energy Star (Cost-Effective Measures)		Solar gain controls such as exterior shades
		Shade Screens
		Window Film
		Central A/C - various equipment retrofits (EER & tonnage)
		Refrigerant charge testing and recharging
		Air sealing (caulking, weatherstripping, hole sealing)
		Two speed Central AC
		Energy Star or better windows
		Filter cleaning and/or replacement
		Landscape Shading
		Insulated metal or fiberglass doors
Comprehensive Water Heating Program		Pipe Wrap (Elec)
		Water heat tank wraps and bottom boards (Elec)
		Low Flow Showerheads (Elec)
		Faucet Aerators (Elec)
		Vapor-compression cycle
		Heater efficiency upgrades (Elec)
		Heat Trap - Water Lines
Residential Solar Water Heater		Solar Water Heater
Residential Appliance		Energy Star or better refrigerator
		Energy Star Clothes Washers - All Electric
Residential A/C Rebate, Weatherization, & A/C Tune-Up Program (Marginally Cost-Effective Measures)		Whole House Fan
		Duct Insulation
Residential A/C Rebate, Weatherization, & A/C Tune-Up Program (Cost-Effective Measures)		Solar gain controls such as exterior shades
		Shade Screens
		Window Film
		Central A/C - various equipment retrofits (EER & tonnage)
		Refrigerant charge testing and recharging
		Air sealing (caulking, weatherstripping, hole sealing)
		Two speed Central AC
		Energy Star or better windows
		Filter cleaning and/or replacement
		Landscape Shading
		Insulated metal or fiberglass doors
Residential A/C Direct Load Control		Central AC Direct Load Control
Residential Water Heating Direct Load Control		Water Heating Direct Load Control
Energy Star Homes		14 SEER AC
		8.2 HSPF heat pump
		Programmable Thermostat
		Duct leakage of 4 cfm / 100 sq. ft of conditioned space
		Duct insulation of R-6
		Infiltration of 7 ACH50
		R-30 attic insulation
		R-5 exterior wall sheathing on block walls
		No slab insulation
		U-value: 0.55 and SHGC: 0.35 for windows
		40 gallon electric water heater with 0.93 EF
		ENERGY STAR dishwasher and refrigerator with 3 ENERGY STAR light fixtures

Exhibit A3-5 Measure to Program Mapping (Continued)

Program	Technology Type	Measure
Commercial Cooling	Chillers	High-efficiency chillers
	DX Units	High-efficiency packaged DX A/C
Commercial Lighting - Exterior	E Incand.	High-intensity discharge lamps (incandescent to hi-pres sodium)
	E Incand.	Outdoor lighting controls for incandescent (photocell/timeclock)
	Fluor	T8 lamps with electronic ballasts (2L4')
	Fluor	Outdoor lighting controls for fluorescent (photocell/timeclock)
	HID	Outdoor lighting controls for HID (photocell/timeclock)
	HID	High-intensity discharge lamps (mercury vapor to hi-pres sodium)
Commercial Lighting - Interior	4' Fluor	T8 lamps with electronic ballasts (2L4')
	4' Fluor	Reflectors for 4' fluorescent
	4' Fluor	Occupancy sensors for 4' fluorescent
	8' Fluor	Reflectors for 8' fluorescent
	8' Fluor	T8 lamps with electronic ballasts (2L8')
	8' Fluor	Occupancy sensors for 8' fluorescent
	8' Fluor	Perimeter dimming for 8' fluorescent
	Exit Signs	LED Exit Signs
	HID	High-intensity discharge lamps (incandescent to metal halide)
Commercial Office Equipment	Copy/Fax	Power management enabling - copier
	Monitors	Network power management enabling - monitor
	Monitors	Power management enabling - monitor
	CPUs	Power management enabling - PC
Grocery and Restaurant Refrigeration Program		Demand defrost electric
		Demand hot gas defrost
		Efficiency compressor motor retrofit
		Floating head pressure controls
		Anti-sweat (humidistat) controls
		Strip curtains for walk-ins
		Night covers for display cases
		Evaporator fan controller for MT walk-ins
		Compressor VSD retrofit
		Refrigeration commissioning
Commercial Ventilation		Premium-efficiency motors
		Variable-speed drives
		CV to VAV conversion
		Unoccupied OA reduction
		Automatic OA reduction control
Commercial Water Heating		Faucet Aerator
		Tank Insulation
		Circulation Pump Timelocks
		Instanteous Water Heater <=200 MBTUH
		Low Flow Showerheads
		Heater efficiency upgrade
		Pipe Insulation

A3-6. Adoption Curve Function

MS_0: Market share of the technology or product in an initial year
C: The product's assumed maximum market share; and
A: A parameter representing "adoptive influence," which influences the speed at which a technology gains share in the market.

$$\boxed{MS_t = \frac{C}{1+e^{\left[-At+\ln\left(\frac{1-MS_0/C}{MS_0/C}\right)\right]}}}$$

A3-7 Supply Curves

The levelized costs in each of the supply curves below are for technology costs only, and do not include program incentive or administration costs. Thus, this supply curve should not be compared to the program DSM supply curve shown earlier in this report. Also note that the discount rate and the methodology used is not intended to match IPM's methodology for developing its supply curves of generating or DSM capacity. These curves simply illustrate the amount and cost of DSM available from the various technologies considered.

The levelized or annualized cost of energy or peak demand is calculated for each measure as follows. First, it is necessary to derive the capital recovery rate, or CRR: For consistency with GRU's avoided costs documentation, we have used a discount rate of 6.75% to determine these annualized costs.

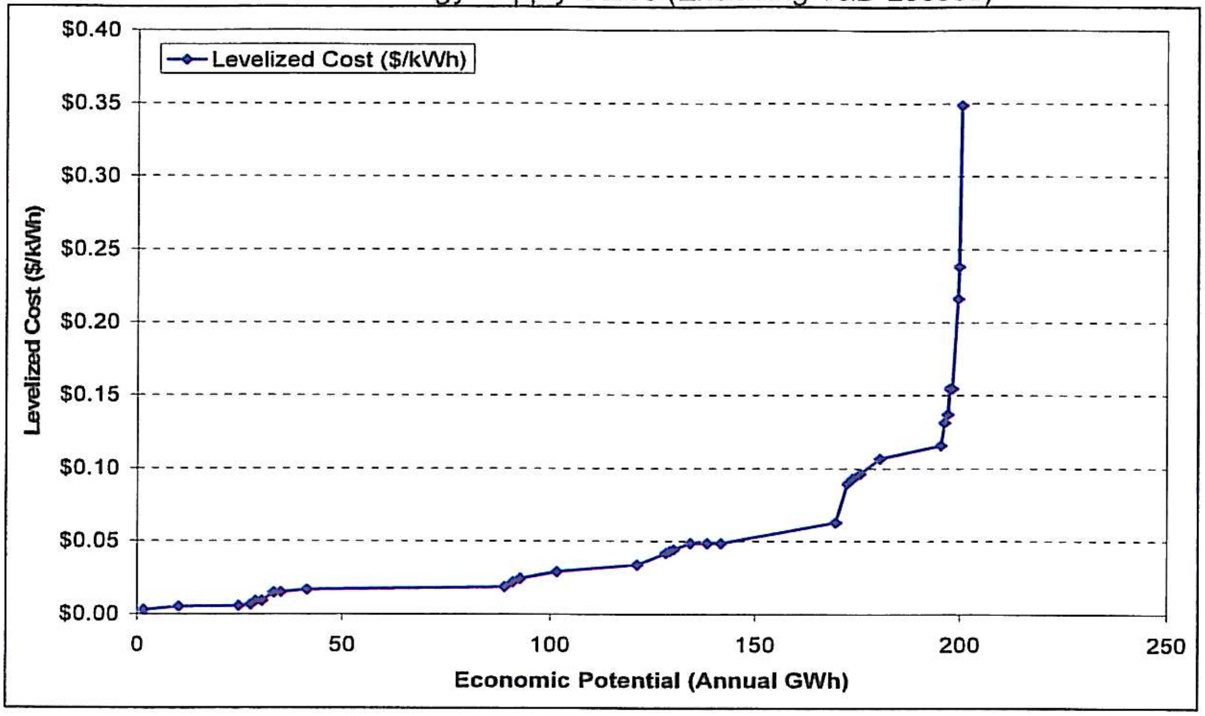
CRR = d / [1 – (1 + d)^(-n)]

Where *d* is the discount rate (6.75%) and *n* is the effective useful life of the measure. Using the CRR, the levelized cost of energy is:

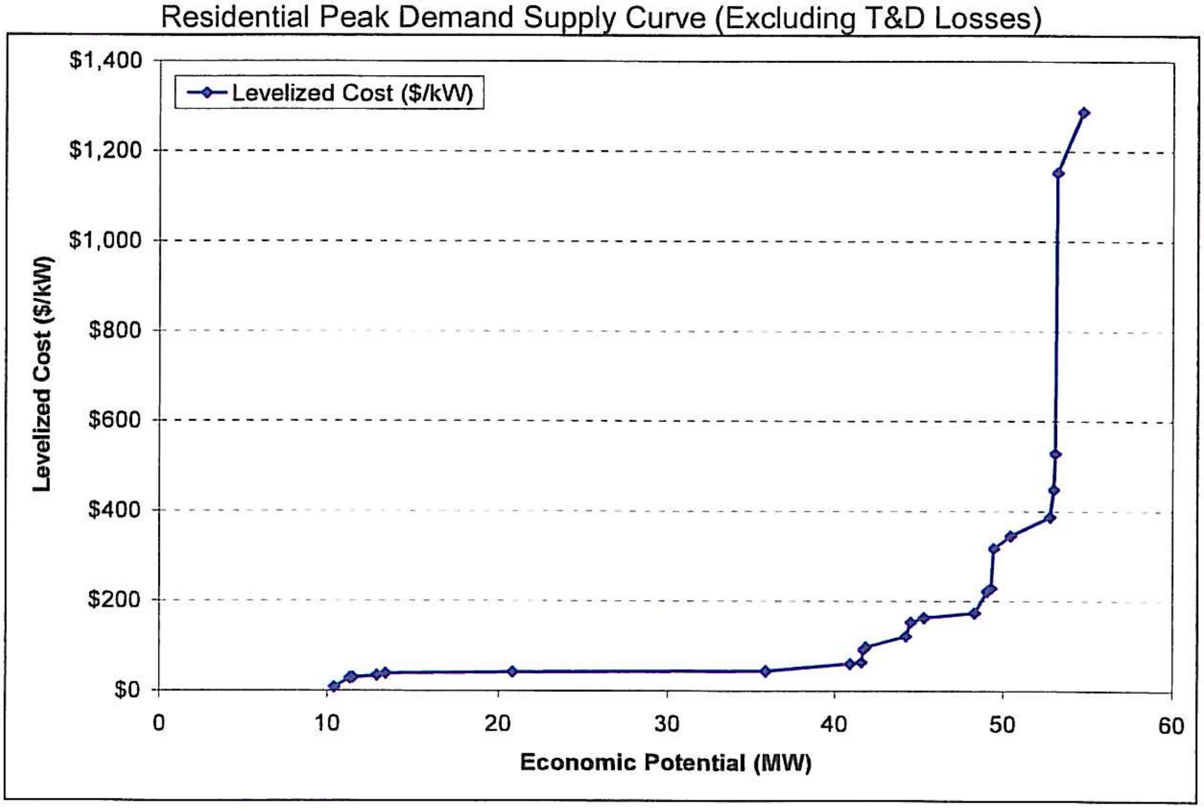
Levelized cost per kWh = Incremental Measure Cost x CRR / Annual kWh Savings
Levelized cost per kW = Incremental Measure Cost x CRR / Peak Demand Savings

All measures are ranked by ascending levelized cost, with each measure adding to the cumulative total DSM potential (MW or MWh). These curves thus describe, from a purely technology cost standpoint, what amount of economic DSM (TRC>=0.5) is available for a certain cost. The actual cost of delivering these DSM savings through programs would exceed the costs noted here due to the program costs associated with marketing, administration, education, and any engineering services provided.

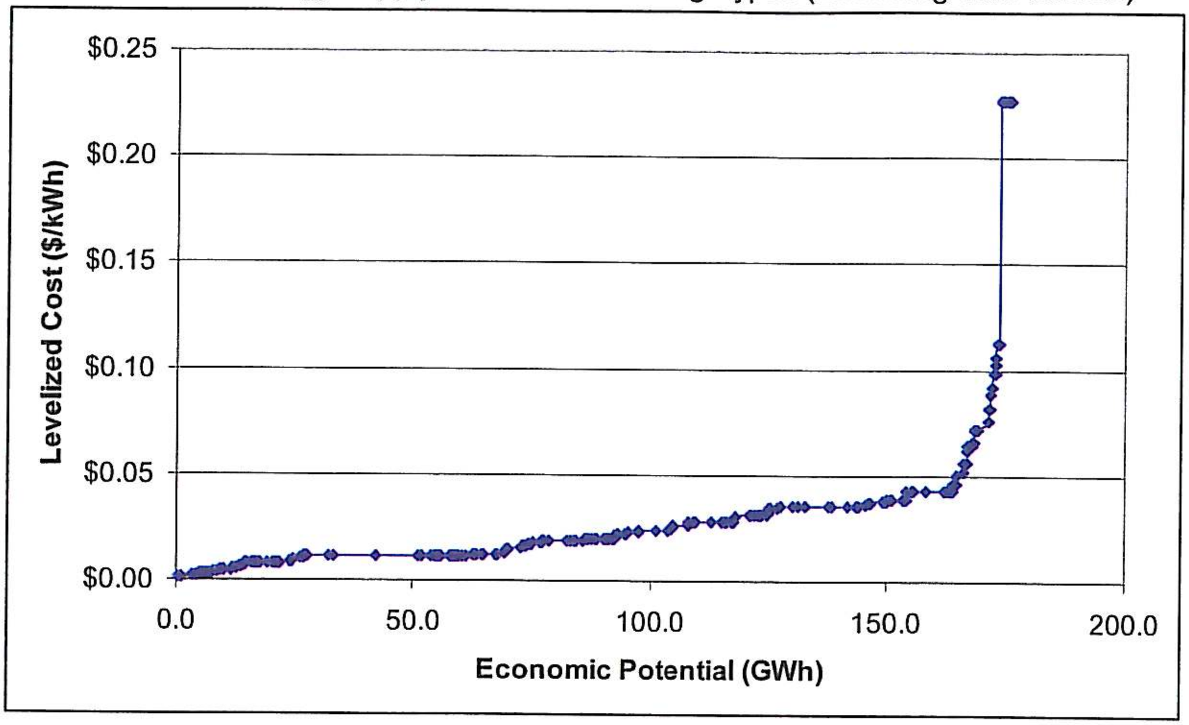
Residential Energy Supply Curve (Excluding T&D Losses)



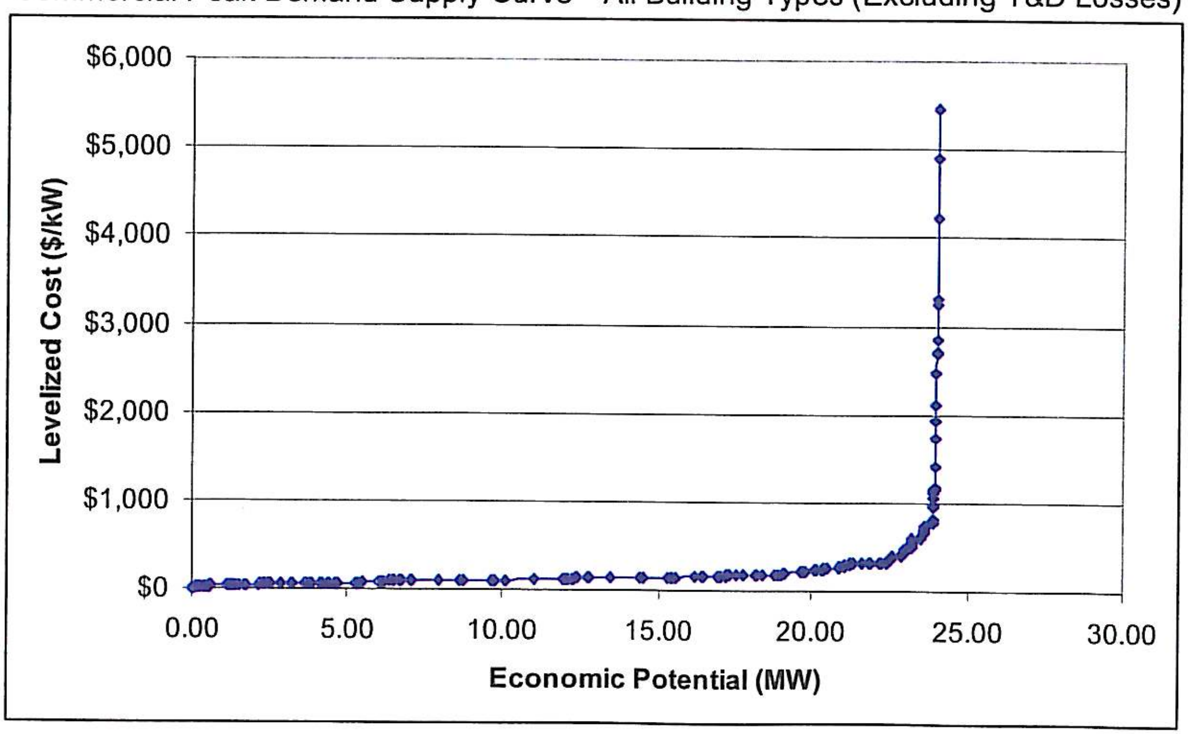
Residential Peak Demand Supply Curve (Excluding T&D Losses)



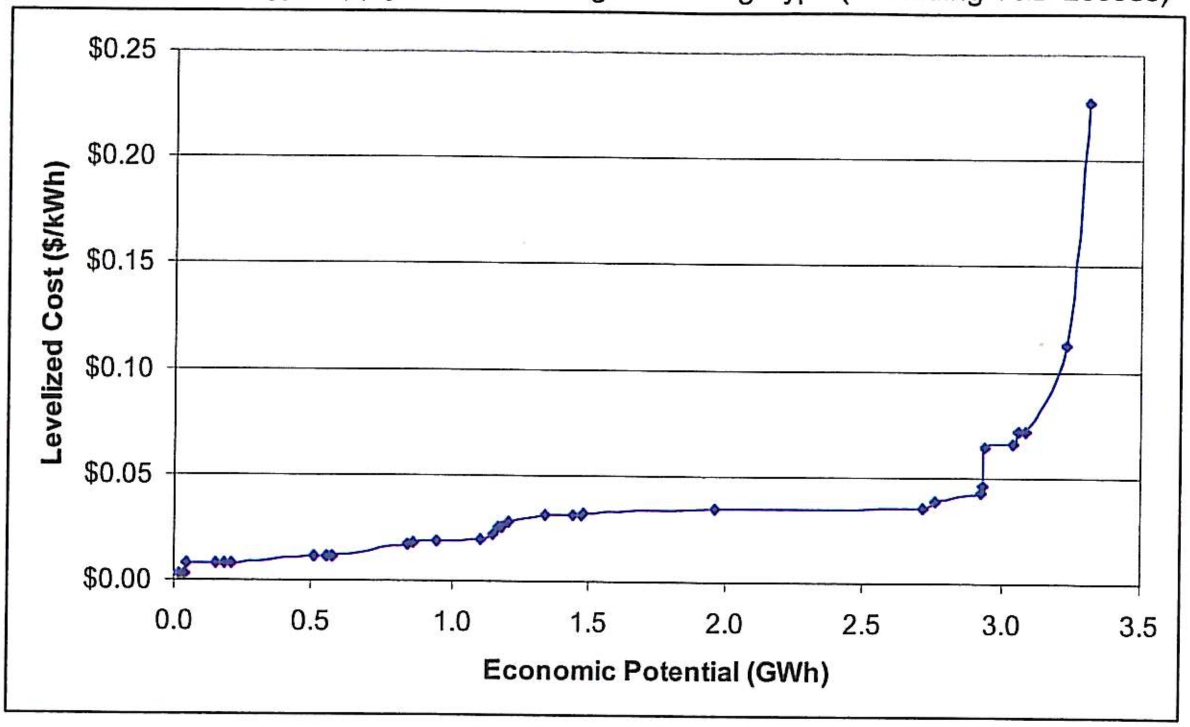
Commercial Energy Supply Curve—All Building Types (Excluding T&D Losses)



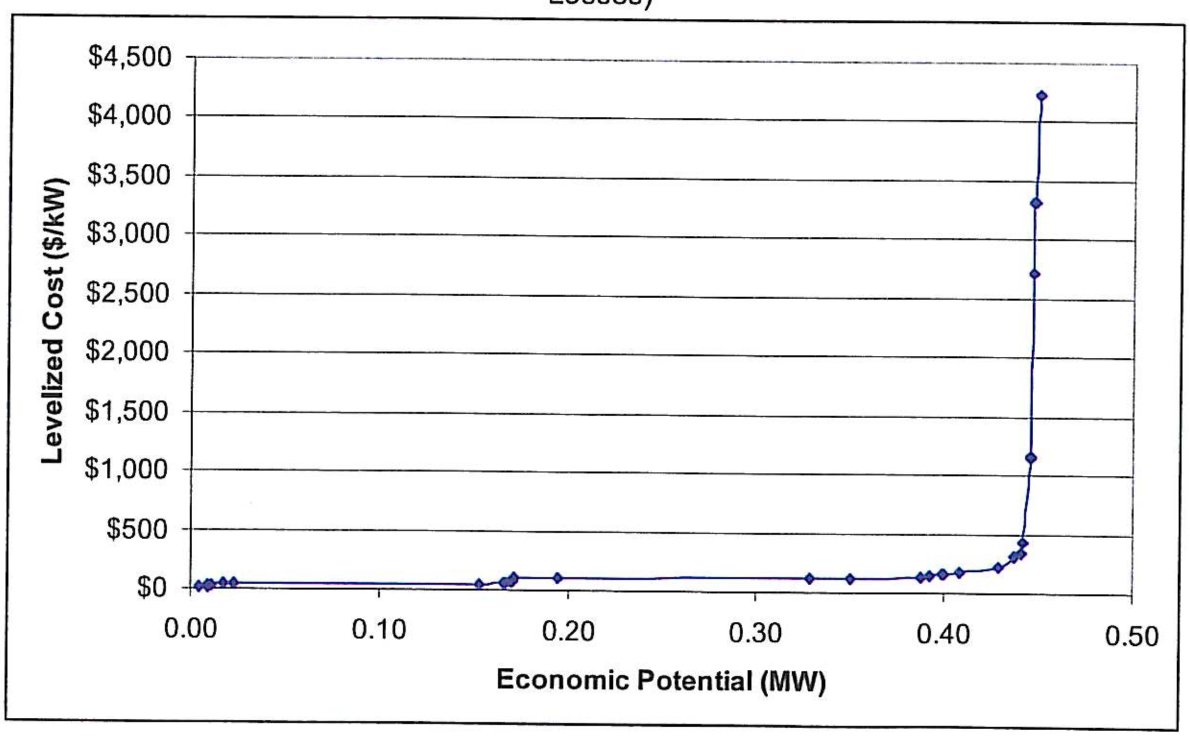
Commercial Peak Demand Supply Curve—All Building Types (Excluding T&D Losses)



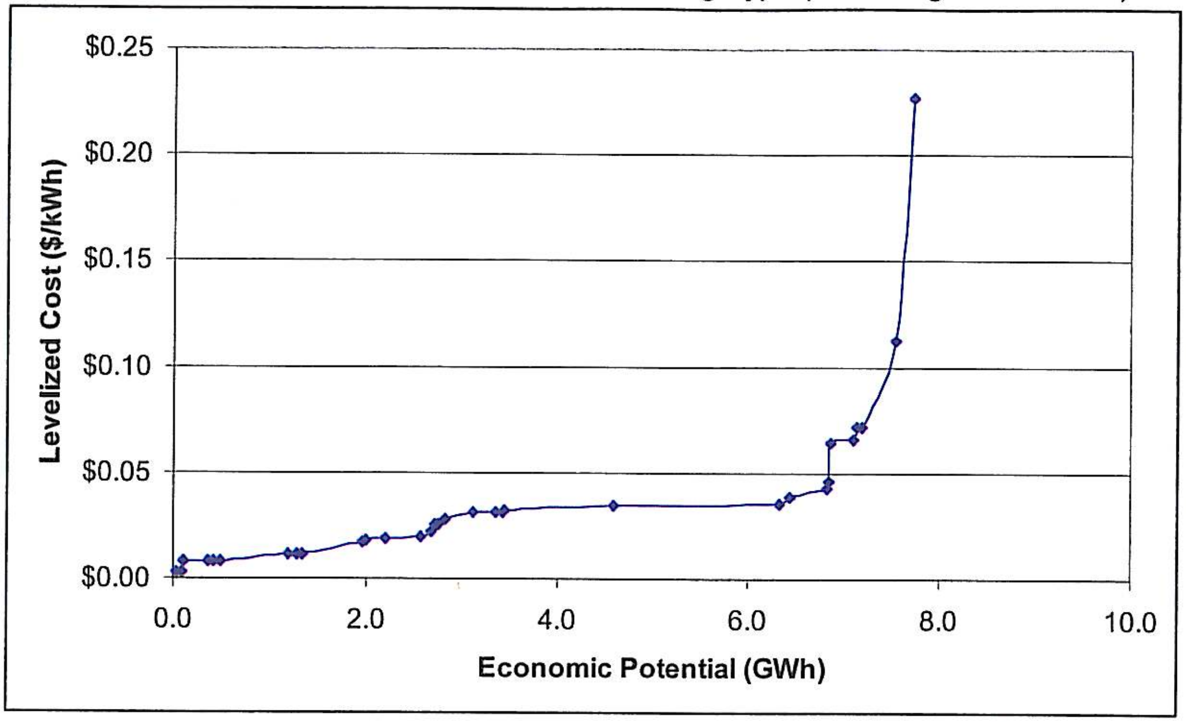
Commercial Energy Supply Curve—Colleges Building Type (Excluding T&D Losses)



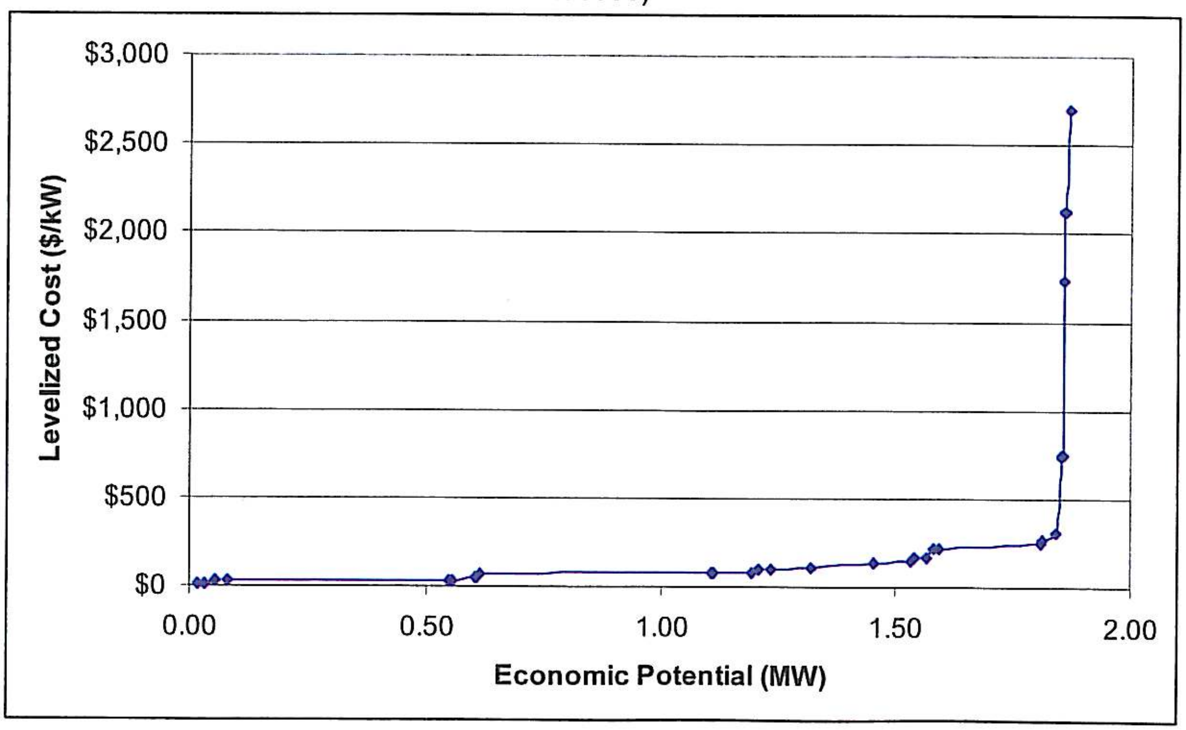
Commercial Peak Demand Supply Curve—Colleges Building Type (Excluding T&D Losses)



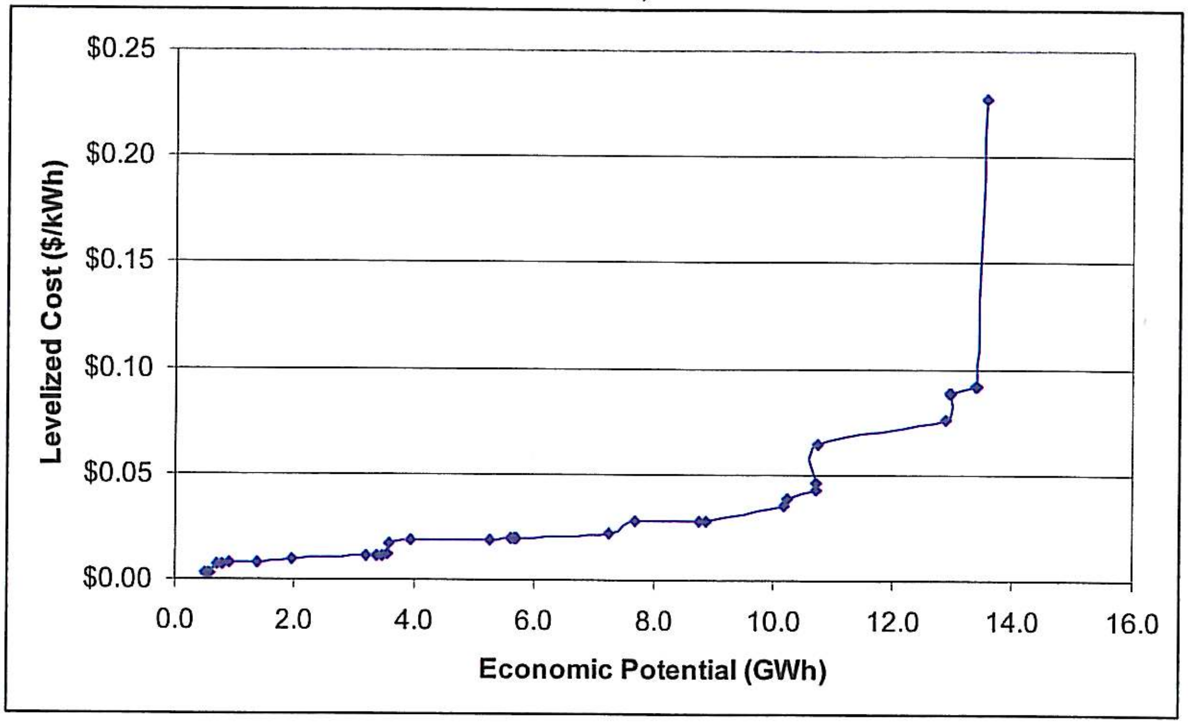
Commercial Energy Supply Curve—Schools Building Type (Excluding T&D Losses)



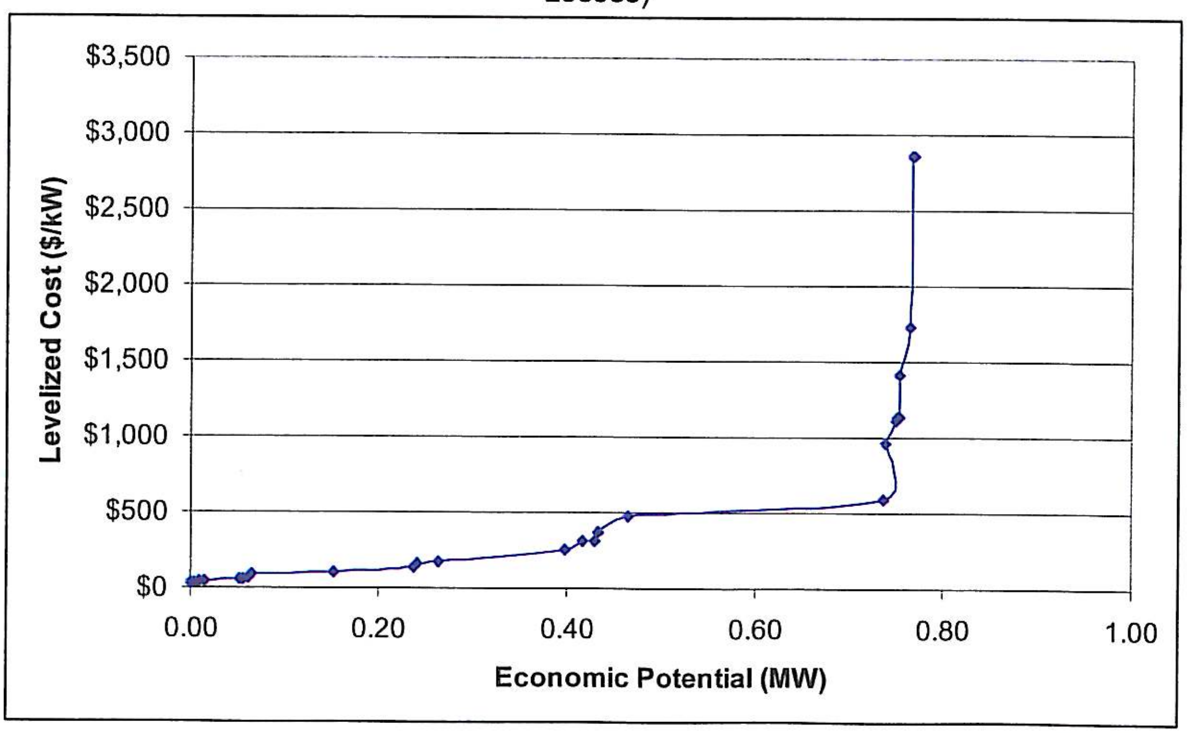
Commercial Peak Demand Supply Curve—Schools Building Type (Excluding T&D Losses)



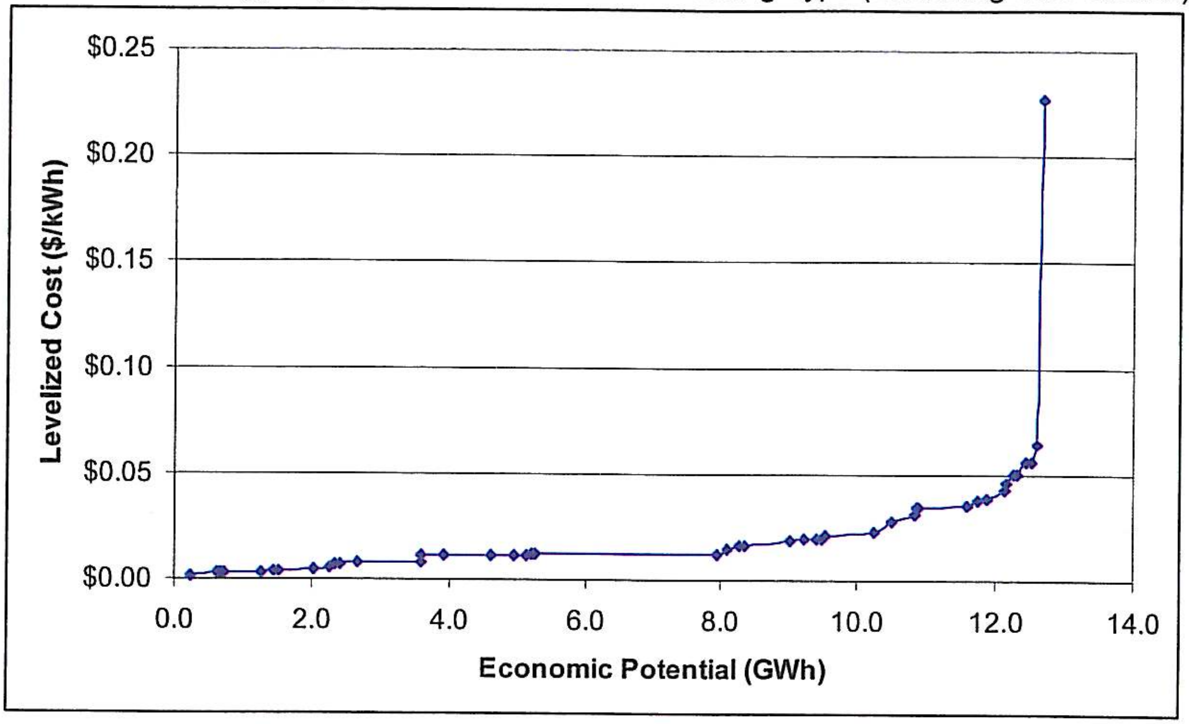
Commercial Energy Supply Curve—Hotels/Motels Building Type (Excluding T&D Losses)



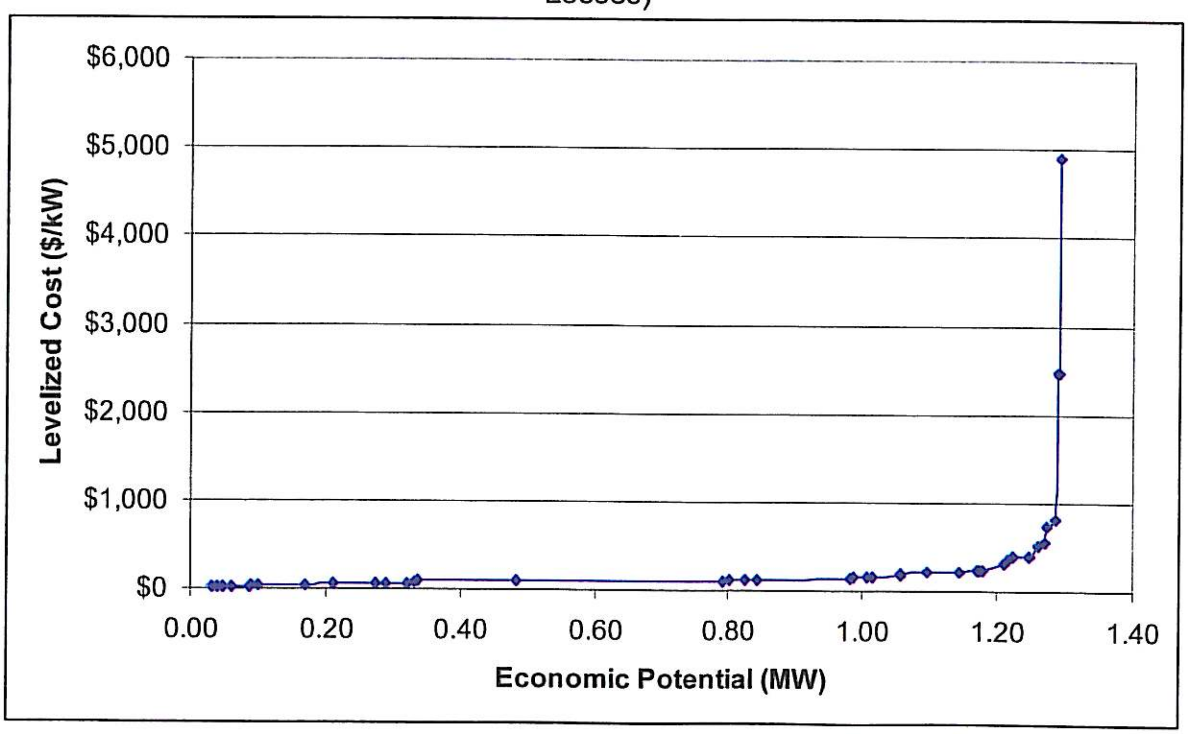
Commercial Peak Demand Supply Curve—Hotels/Motels Building Type (Excluding T&D Losses)



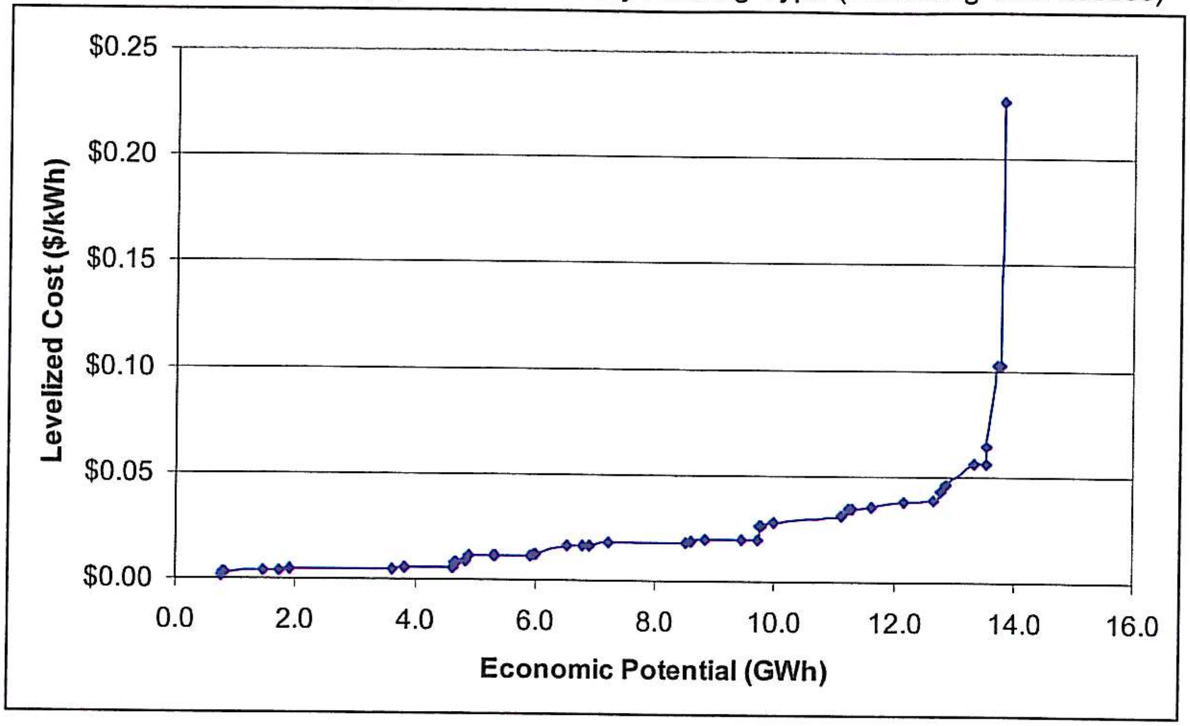
Commercial Energy Supply Curve—Restaurants Building Type (Excluding T&D Losses)



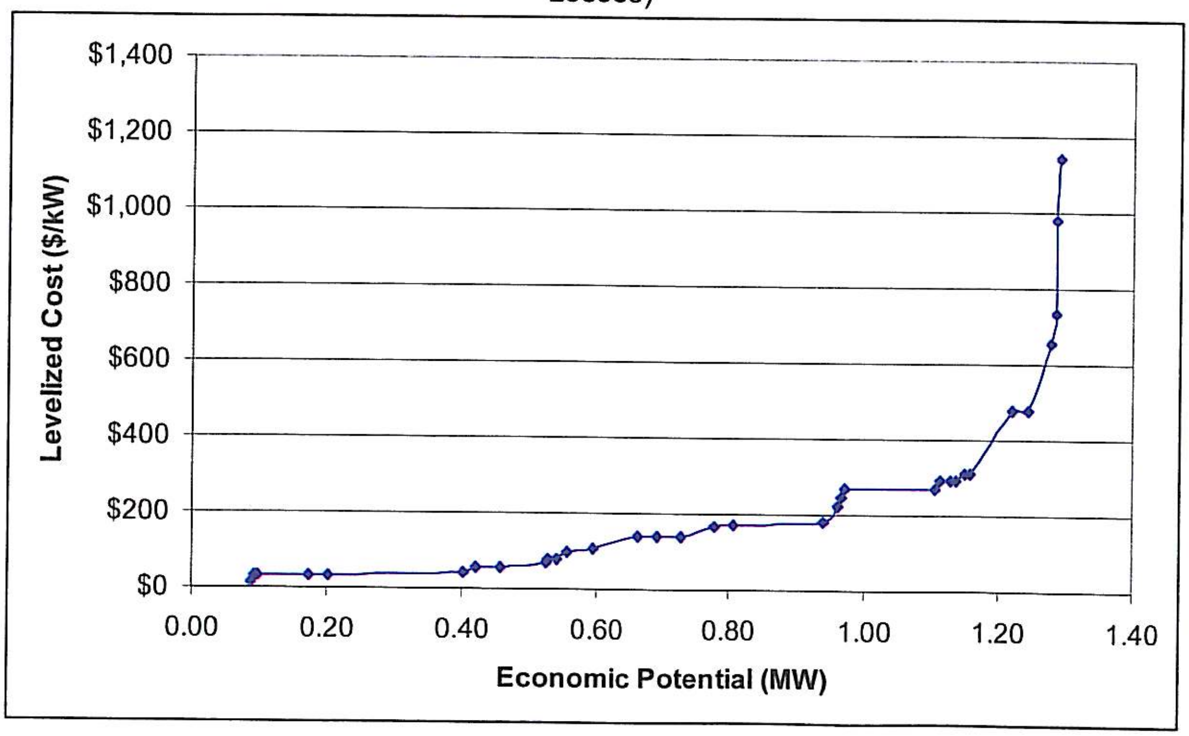
Commercial Peak Demand Supply Curve—Restaurants Building Type (Excluding T&D Losses)



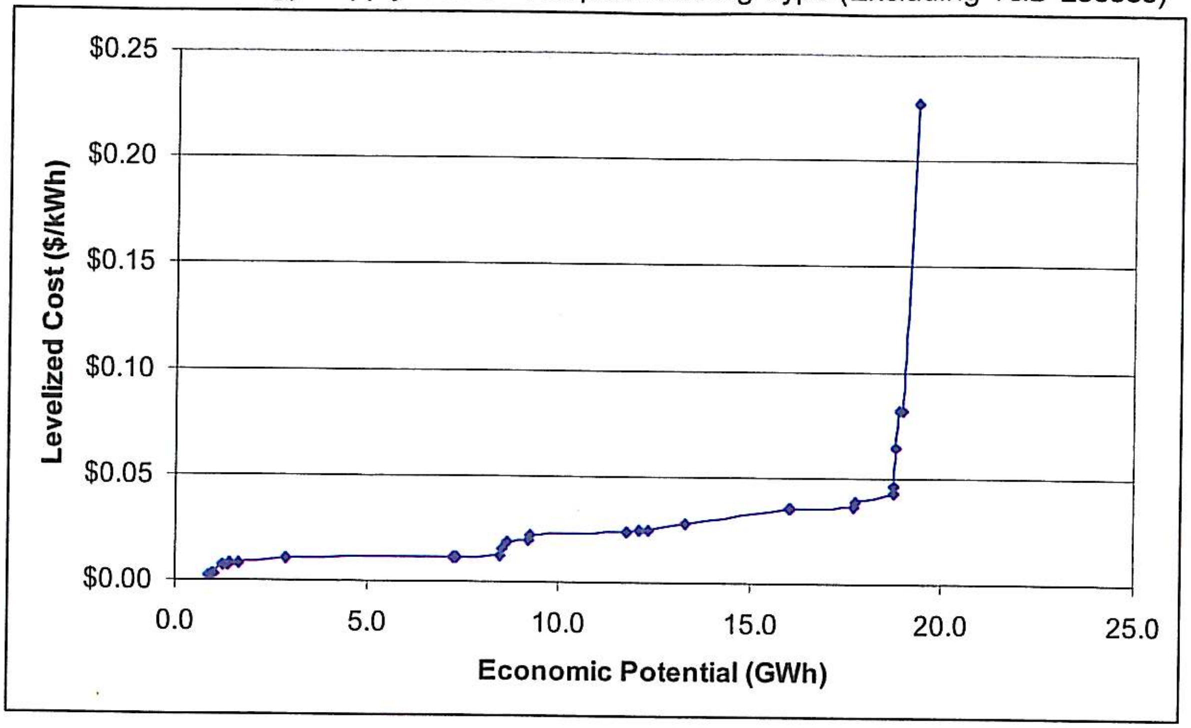
Commercial Energy Supply Curve—Grocery Building Type (Excluding T&D Losses)



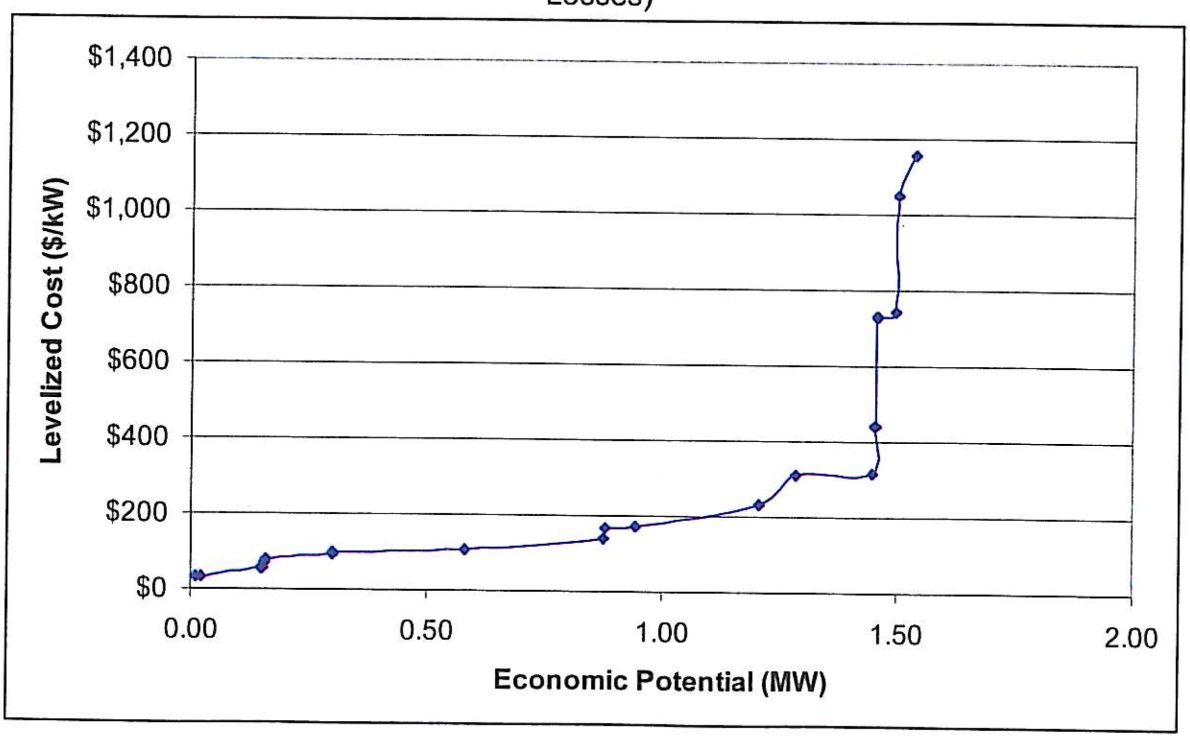
Commercial Peak Demand Supply Curve—Grocery Building Type (Excluding T&D Losses)



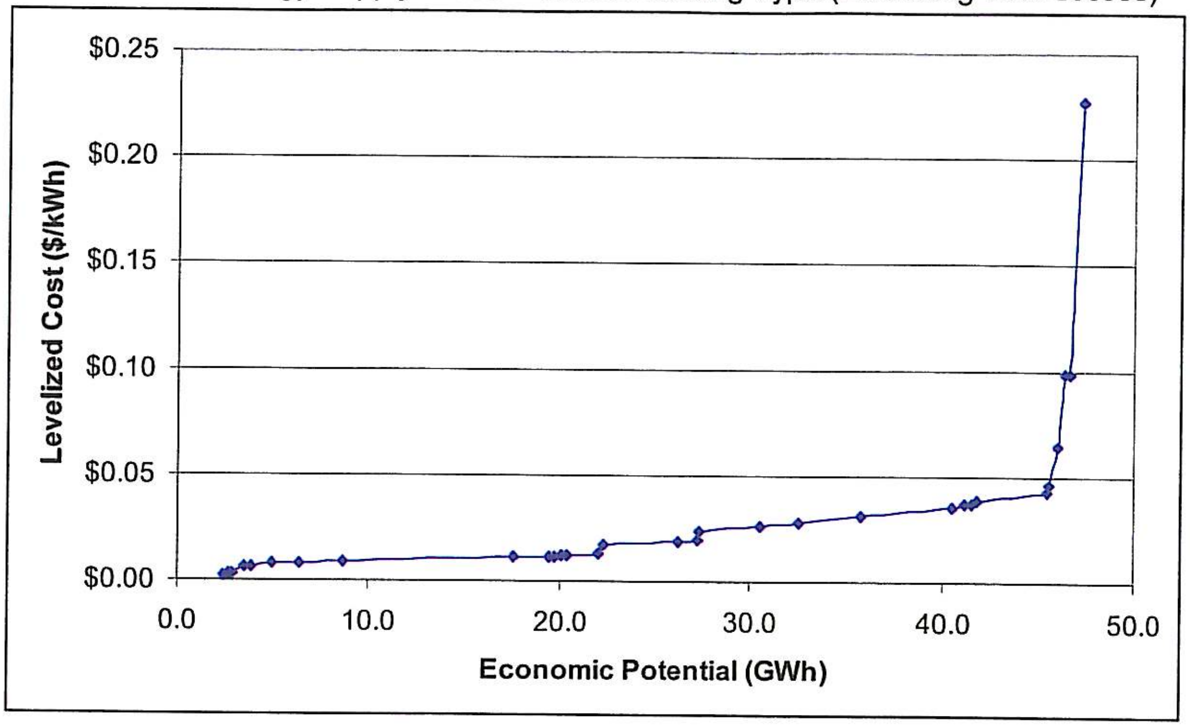
Commercial Energy Supply Curve—Hospital Building Type (Excluding T&D Losses)



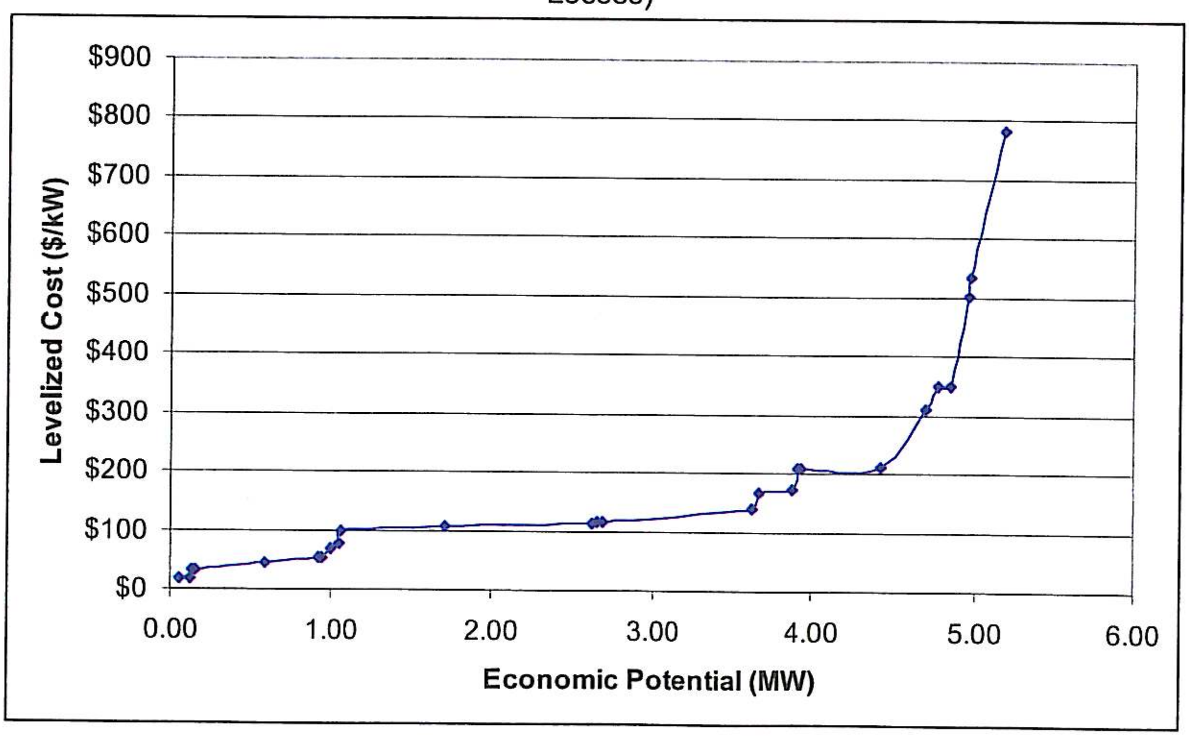
Commercial Peak Demand Supply Curve—Hospital Building Type (Excluding T&D Losses)



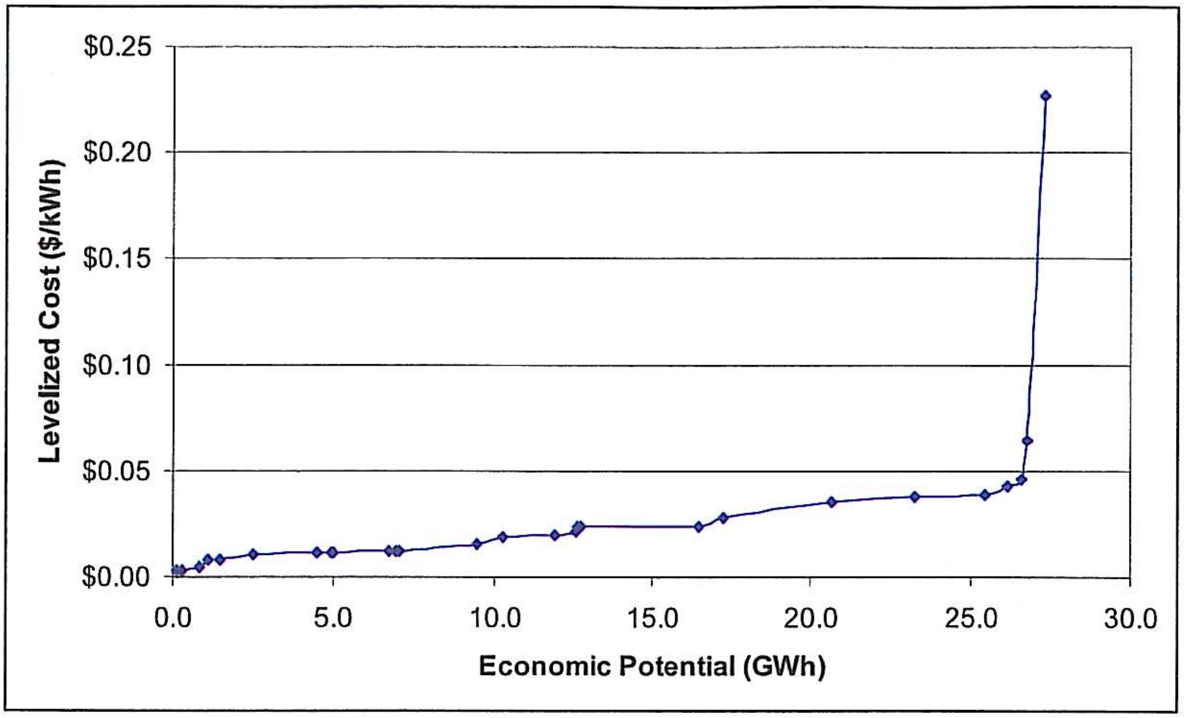
Commercial Energy Supply Curve—Offices Building Type (Excluding T&D Losses)



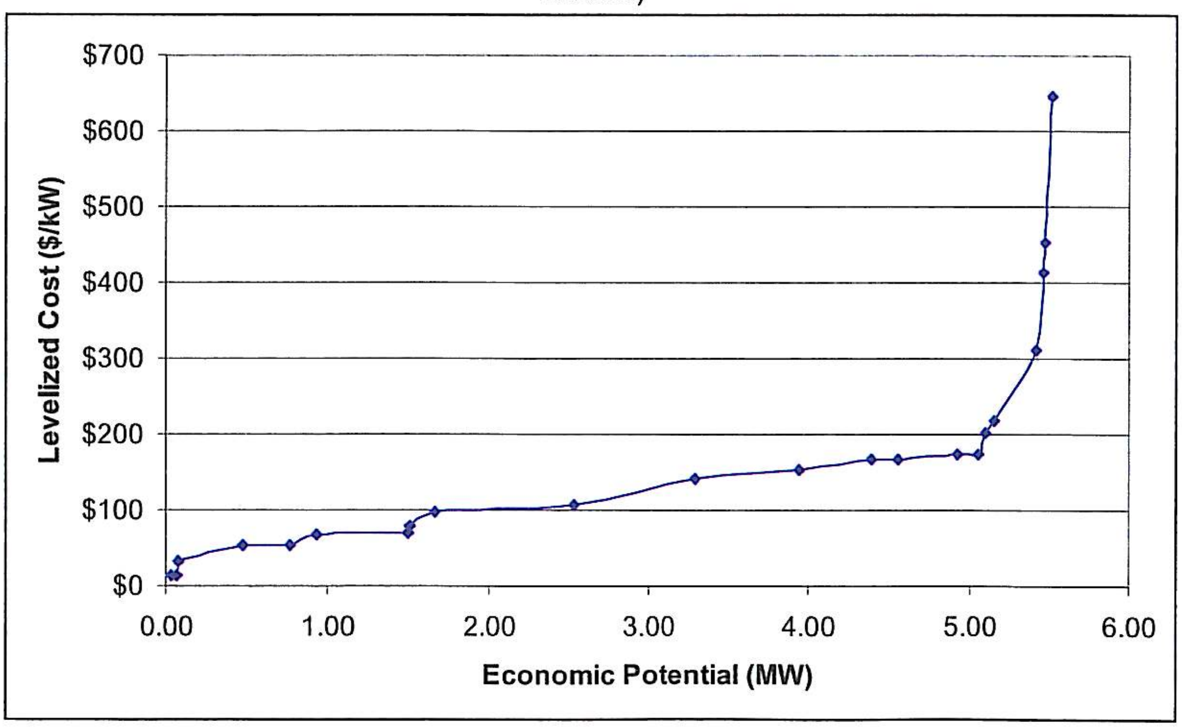
Commercial Peak Demand Supply Curve—Offices Building Type (Excluding T&D Losses)



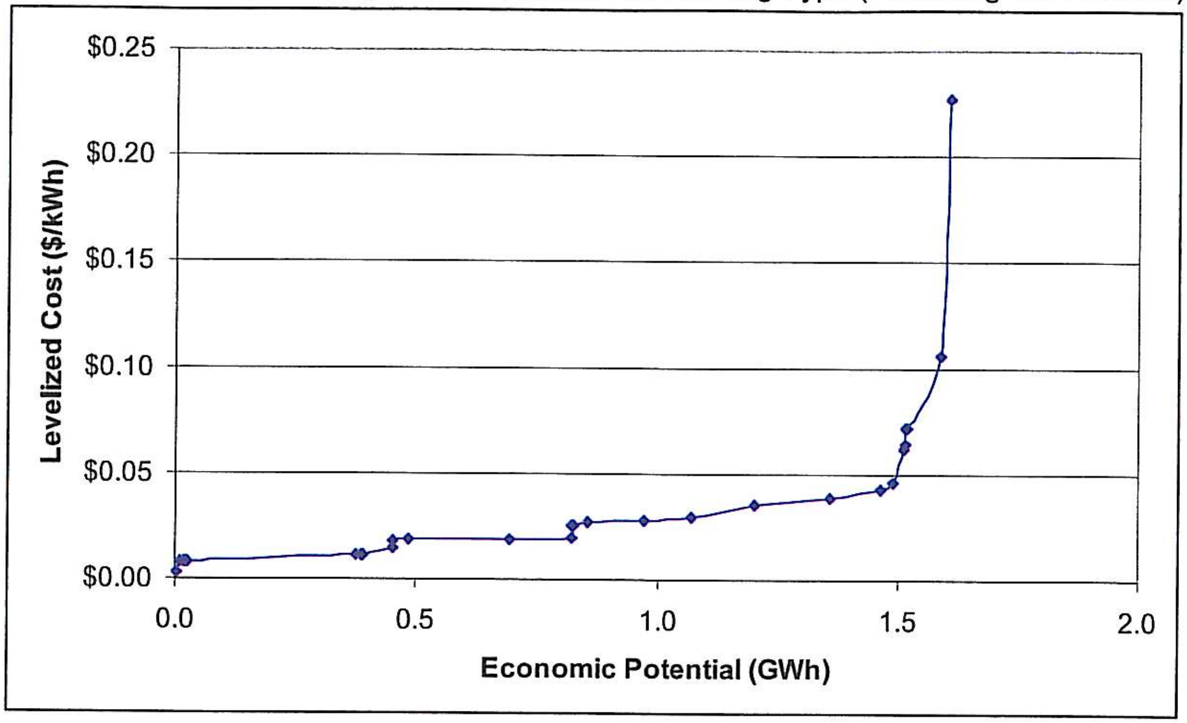
Commercial Energy Supply Curve—Retail Building Type (Excluding T&D Losses)



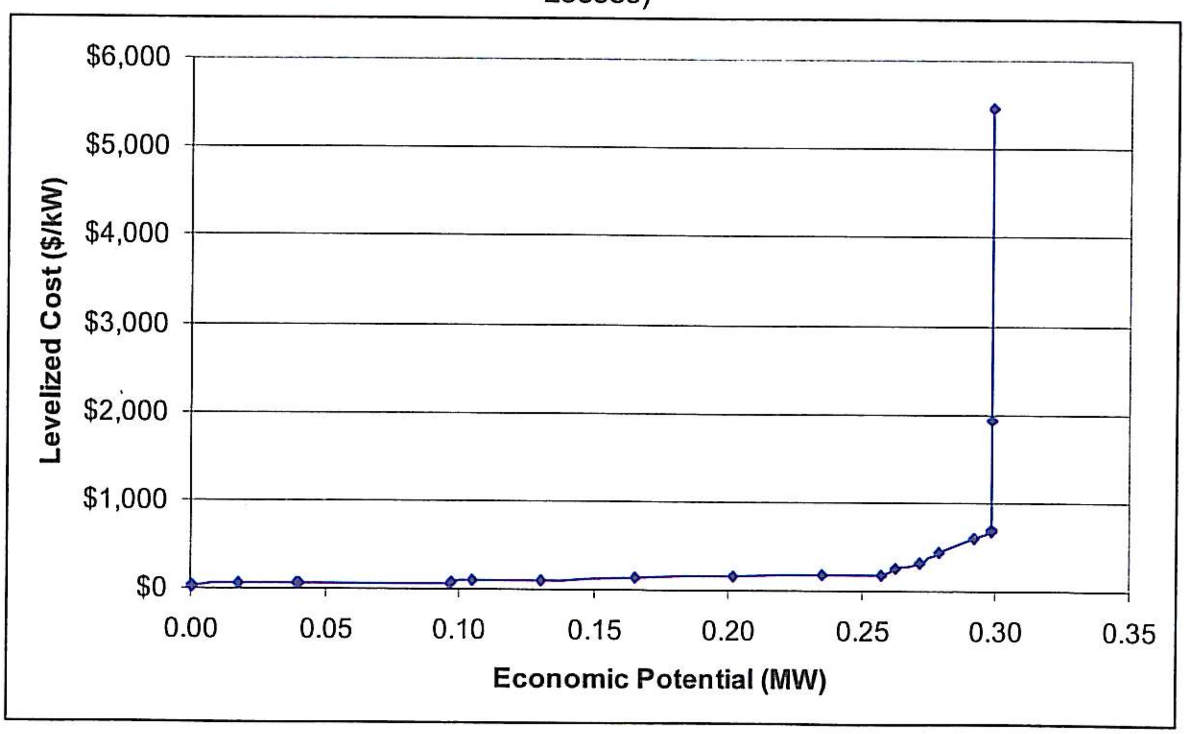
Commercial Peak Demand Supply Curve—Retail Building Type (Excluding T&D Losses)



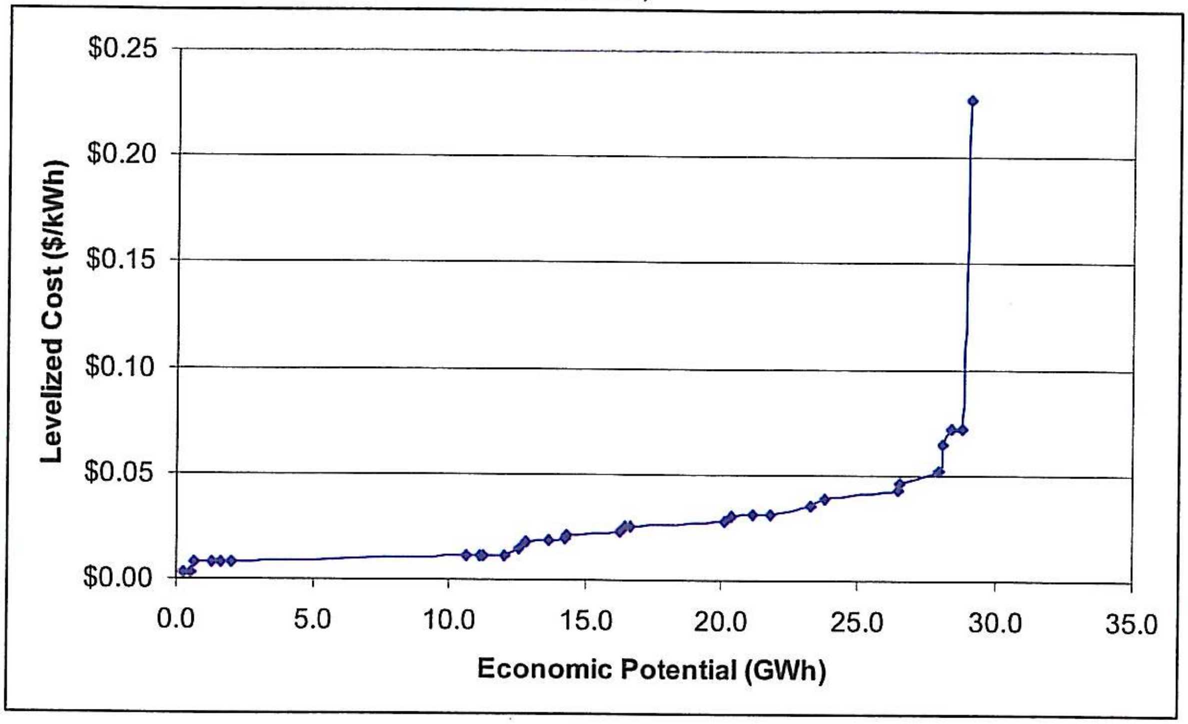
Commercial Energy Supply Curve—Warehouse Building Type (Excluding T&D Losses)



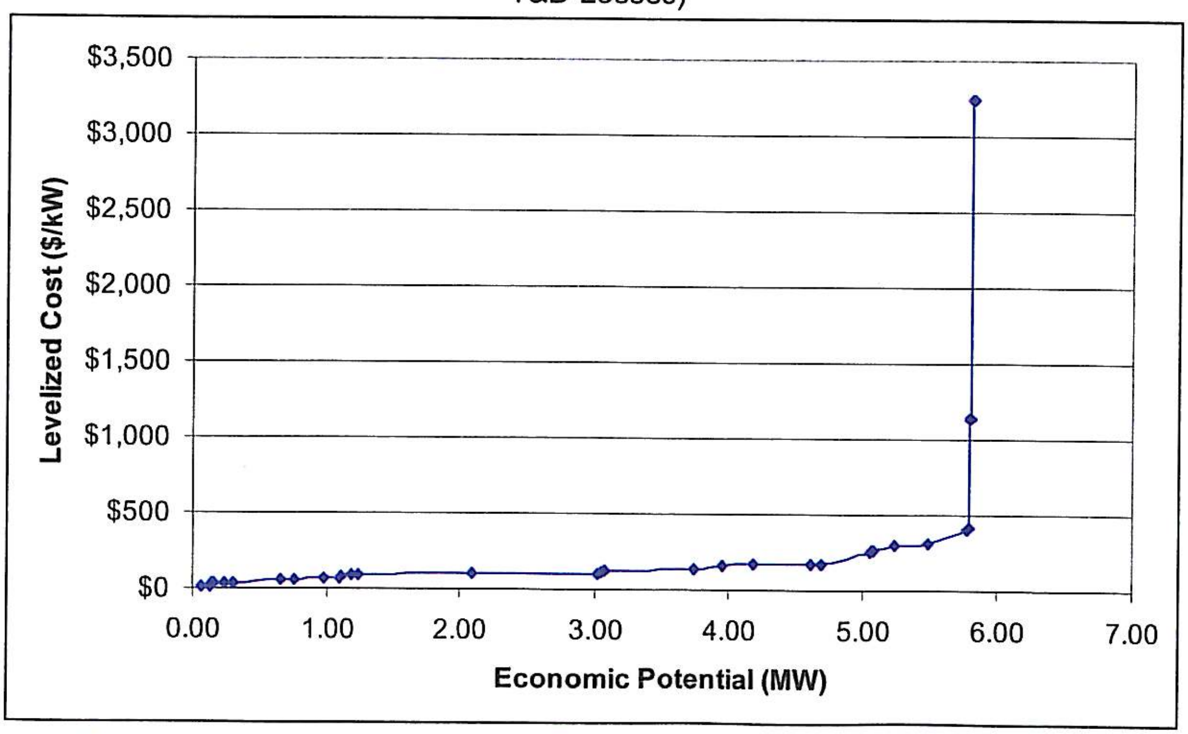
Commercial Peak Demand Supply Curve—Warehouse Building Type (Excluding T&D Losses)



Commercial Energy Supply Curve—Miscellaneous Building Type (Excluding T&D Losses)



Commercial Peak Demand Supply Curve—Miscellaneous Building Type (Excluding T&D Losses)



ATTACHMENT 4
GENERATION OPTIONS AND FINANCING COSTS

New Power Plant Costs

- New Power Plants – New combined cycle plants are assumed to be available at a cost of $626/kW (2003$) in 2006 in FRCC, and new simple cycle units are at a cost of $386/kW (2003$).
  - On an ISO basis, FRCC combined cycle costs are approximately at a 7 percent discount to the U.S. average
  - Costs for gas-fired equipment are generally decreasing modestly in real terms from 2006 through 2025. We assume flat costs in the near term for pulverized coal equipment in real terms.
  - The build mix is determined through economics.
- ICF imposes restrictions on the start dates of model additions to account for the necessary construction/permitting lag times and the commercial acceptance of new technology:
  - LM6000s are allowed to be built in 2006
  - Simple cycle turbines no earlier than 2009
  - Combined cycles and cogeneration units starting in 2009
  - Supercritical coal builds are allowed in 2011, with no coal builds in certain regions in the model such as in New England, large parts of New York and PJM East
  - IGCC are allowed in 2013

Key Plant Performance Assumptions

- New Unit Characteristics - New combined cycles and simple cycle units are assumed to have heat rates (HHV) of 7,100 Btu/kWh and 10,825 Btu/kWh in 2004, respectively. They start at higher levels and improve modestly over time due to the commercial acceptance of the next generation of turbines such as the FB, G and H technology.

- New supercritical coal units are assumed to have a heat rate of approximately 9,888 Btu/kWh and IGCC's heat rate are assumed to be around 7,908 Btu/kWh. For the IGCC unit coming online in 2013 we assume a 7FA-technology power island.

Key Plant Performance Assumptions

- Fossil Plant Availability – Existing plant availability is overall consistent with historical levels.

- Combined cycle units are provided the option to turndown overnight to a minimum level of 50 percent of full load. This decision whether to run at minimum load or to cycle off completely is based on economics.

    - The model considers the cost of start up incurred by turning off overnight and weighs this against losses incurred by operating "out of money", i.e., with a variable cost higher than the energy price.

    - In regions with high off-peak prices, the units will typically choose to turndown to minimum levels. In regions dominated by low variable cost capacity with low off-peak prices, the model will typically cycle the combined cycle units off at night and incur the cost of an additional start. The 50 percent minimum operating level is based on environmental considerations. Low NO_x burners, which are required by BACT and LAER regulations, cannot achieve single digit NO_x levels at low air/fuel mixtures.

Exhibit A4-1
Key Nuclear Performance Assumptions

Plant	Generator	Capacity	Availability
Turkey Point	3	666	90.3
Turkey Point	4	666	90.2
St. Lucie	1	839	90.7
St. Lucie	2	839	90.0
Crystal River	3	812	90.0
Total / Average		3,822	90.2
Source: ICF			

Key Plant Performance Assumptions

- Nuclear Performance - We assume availabilities consistent with recent historical levels and the improving performance trend. Note that while many units in the nuclear fleet are performing above their historical EFOR we continue to enforce this parameter which is typically 5 to 6 percent.

- Nuclear plants are assumed to operate until their license expires and for an additional 20-year license extension, unless it is economic to retire them earlier.

In review of process contingency risk impacts on IGCC costs, we have updated our view for the 220 MW class. For example, values have been revised from $2,070/kW to $2,200/kW for a Brownfield scenario. In this table, we also show costs for CFB stations that would be designed to maximize the use of biomass in a solid fuel facility. Values are higher than the bituminous-fired CFB due in large part to the larger furnace box requirements.

ATTACHMENT 5
FUEL

Exhibit A5-1
Delivered Natural Gas Price Forecasts[1,2] (Nominal $/MMBtu)

Year	Data	ICF Base Case[3,4]	GRU – IRP[5]
1995	Historical	2.33	2.33
1996	Historical	3.37	3.37
1997	Historical	3.3	3.3
1998	Historical	2.87	2.87
1999	Historical	2.86	2.86
2000	Historical	4.53	4.53
2001	Historical	4.91	4.91
2002	Historical	3.82	3.82
2003	Historical	5.80	5.80
2004	Historical	6.15	6.15
2005	Historical	7.18	7.18
2006	Forecast	10.02	6.50

[1] Assumes 2.63% inflation from 2003 to 2004 dollars, and 2.25 percent per year future general inflation rate.
[2] Assumes all gas commodity contracting is at spot and no financial hedging.
[3] Assumes $0.39 (2003$) for gas transportation/basis premium over Henry Hub Louisiana commodity cost delivered to Florida.
[4] ICF 2006-2008 forecasts are derived from NYMEX Henry Hub natural gas futures traded on 1/5/2006. 2009 is interpolated from 2008 and 2010 ICF forecast. A basis differential derived from GRU's delivered price is applied to this base price.
[5] GRU forecast as of April 2005, Source: A Review of Florida Electric Utility 2005 Ten-Year Site Plans, prepared by the Florida Public Service Commission, Division of Economic Regulation, December 2005.

HOW TO INTERPRET THE GAS PRICE FORECASTS

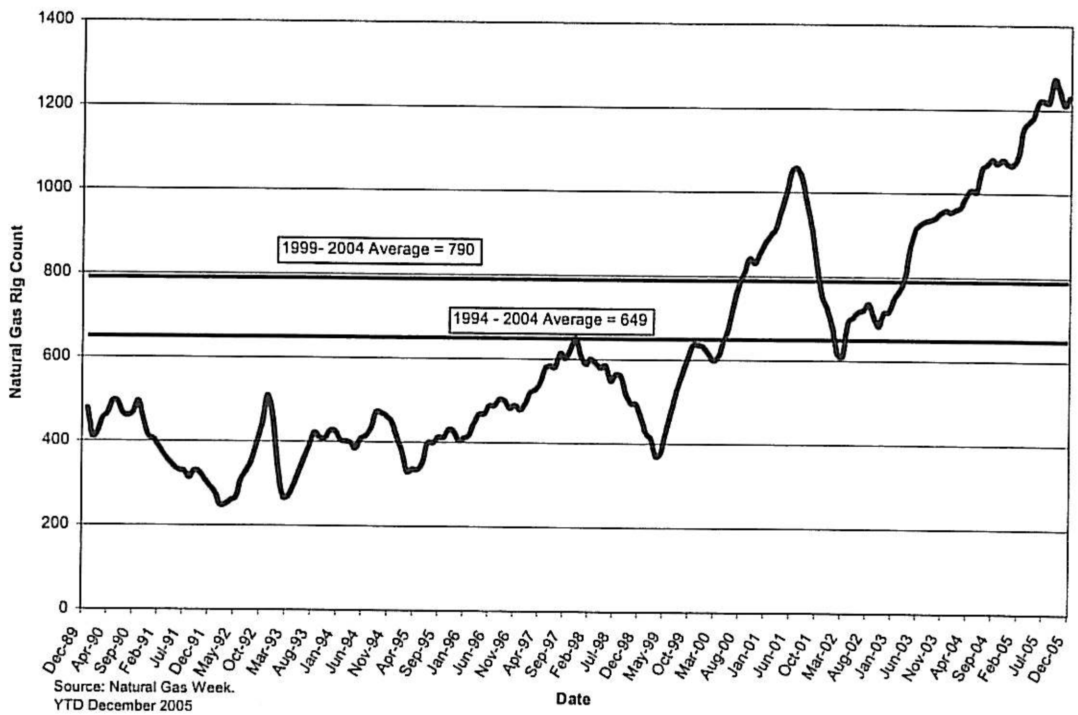
- These forecasts represent a fundamentals view of gas prices over the long term.
  - They do not incorporate the effects of the hurricanes on natural gas prices. These are expected to reduce production in the near term, with full recovery within two years.
  - Nor do they reflect short term phenomena or speculative behavior by traders
- As a long-term fundamentals approach, using a linear programming model of the gas market, the forecasts incorporates "perfect foresight" and thus tends to smooth out the volatility that characterizes gas markets.

- Current NYMEX prices at Henry Hub represent this volatility in the markets and today are higher than prices in the model.
  - Futures prices are a poor predictor of long term gas price trends.
  - Except for the near-by strike months, futures contracts are thinly traded, and tend to fluctuate in response to current market conditions

DISCUSSION OF BASE CASE GAS PRICE FORECAST

The Base Case shows a natural gas price decline in 2017 as Alaskan volumes (4 Bcf/d) enter the market.

Exhibit A5-2
Natural Gas Rig Count



Source: Natural Gas Week.
YTD December 2005

Natural Gas Market Trends

- Natural Gas Prices
  - In the 1990s, natural gas prices were low. The average Henry Hub price in the 1989 to 2000 period was $2.51/MMBtu (in 2003$).

- Since 2000, both natural gas prices and volatility have significantly increased.

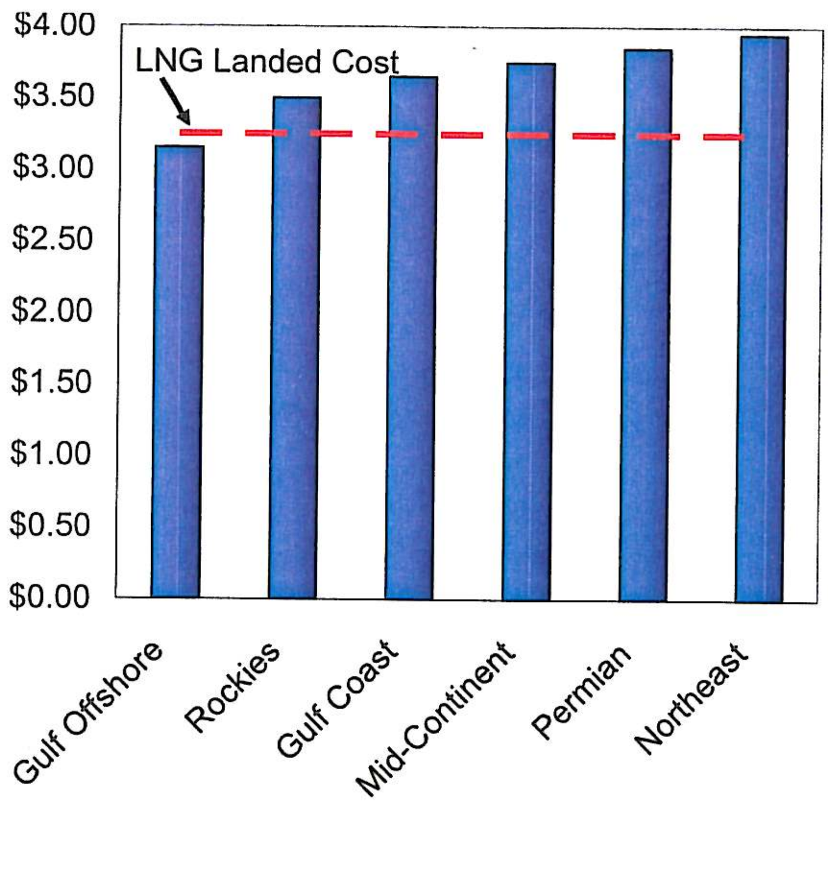
- Natural Gas Supply

  - After rising by nearly 70 percent from 1999 to 2001, the U.S. rig count fell dramatically in 2002 due to the Enron collapse, low gas prices in 2002 and financial problems in the energy industry.

  - Rig counts have been climbing steadily since 2002, but activity has not yielded large increases in short-term production levels.

  - While the drilling and supply response in the U.S. and Canada will impact prices, LNG will be the key incremental supply.

Exhibit A5-3
LNG Could be Landed in the US at Low Cost



- ICF forecasts large increases in LNG and offshore Gulf supply. While expensive, these supplies are not as costly as current prices indicate. The high prices are related to a tight demand and supply balance in energy markets generally, and in the oil market particularly.

- As international supply and demand for LNG grows, and as alternative markets for the natural gas develop, e.g. gas-to-liquids plants, LNG will likely be priced into the US based on international supply and demand conditions.

- In a U.S. market with an average demand of 60 Bcf per day, LNG terminal capacity is poised to significantly increase.

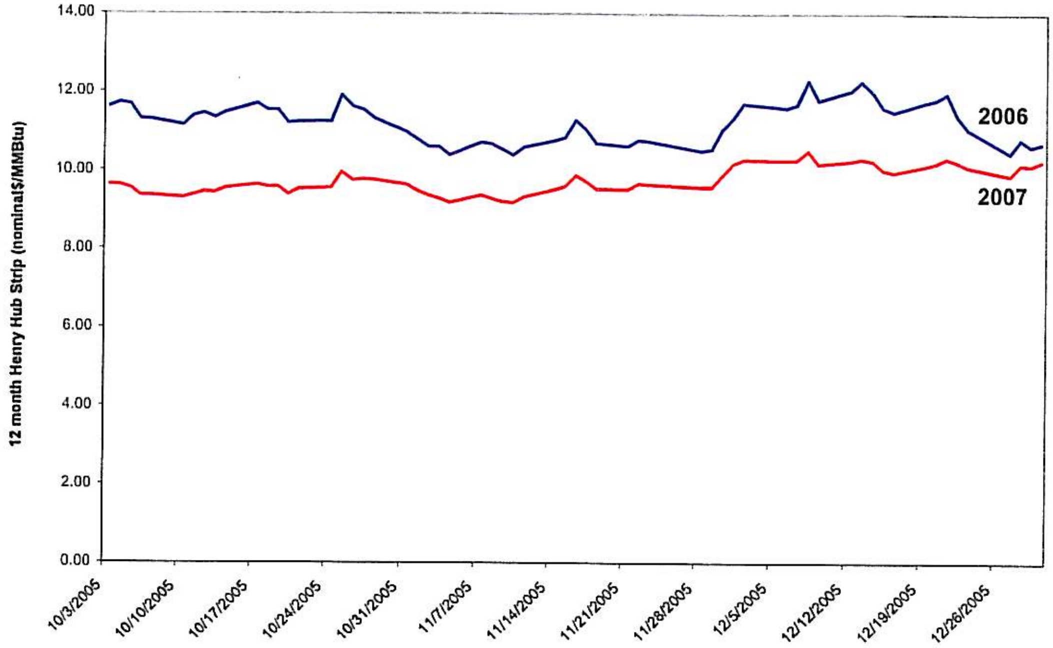
- With the recent passage of the Energy Policy Act, Congress intends to remove barriers to adding new LNG capacity by strengthening FERC jurisdiction over siting of new LNG terminals.

- Not all of the proposed projects will be built, but the critical issue is expected to be the clearing price of LNG, not import capacity.

Long-Term Market Dynamics Support a Decline in Current Prices by 2010

- Supply
  - Increasing LNG imports, reaching over 4 Tcf by 2012 .
  - Modest supply response in lower 48 as unconventional production kicks in and higher production from Gulf of Mexico offshore.
  - Alaskan gas by 2016; Mackenzie Delta volumes by 2010.
  - Energy Policy Act promotes gas production, LNG imports, pipeline facilities expansions.
- Demand
  - At the current high price of natural gas, the demand for natural gas may be temporarily weakened.

Exhibit A5-4
NYMEX Gas Futures (Nominal $/MMBtu)



Source: Bloomberg (NYMEX) natural gas futures prices for 2005 and 2007 from transactions dated 10/3/2005-12/30/2005

Recent Historical Crude Oil Prices

- Crude oil prices have been rising since early 1999, exceeding the 1990s average by 2000. The primary drivers for higher crude prices have been higher global oil demand and low excess, or spare crude oil production capacity

- This increase has accelerated over the last two years. Current high oil prices have not been seen since the early 1980s, after correcting for inflation.

- Oil prices affect most fuel markets. This is due to fuel-on-fuel competition and the correlation of demand and economic factors.

- Although low excess capacity has driven up prices, these may not be sustainable, and will trigger supply and demand reactions such as:

  - Oil supply response
  - LNG development
  - Coal development
  - Non-fossil energy development
  - Slower economic growth
  - Energy efficiency

- The exact pace of these changes is difficult to predict because they involve large capital investments and intersect with government policy.

Exhibit A5-5
Low Excess Capacity and Low Days of Supply Are Fundamentals Supporting High Crude Prices

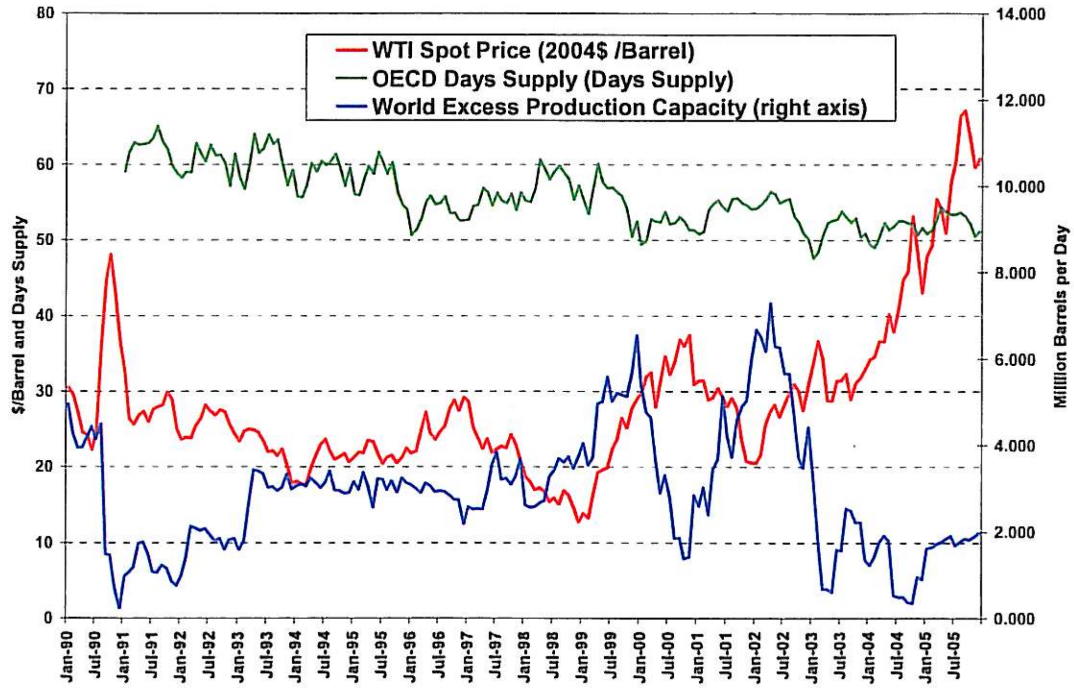
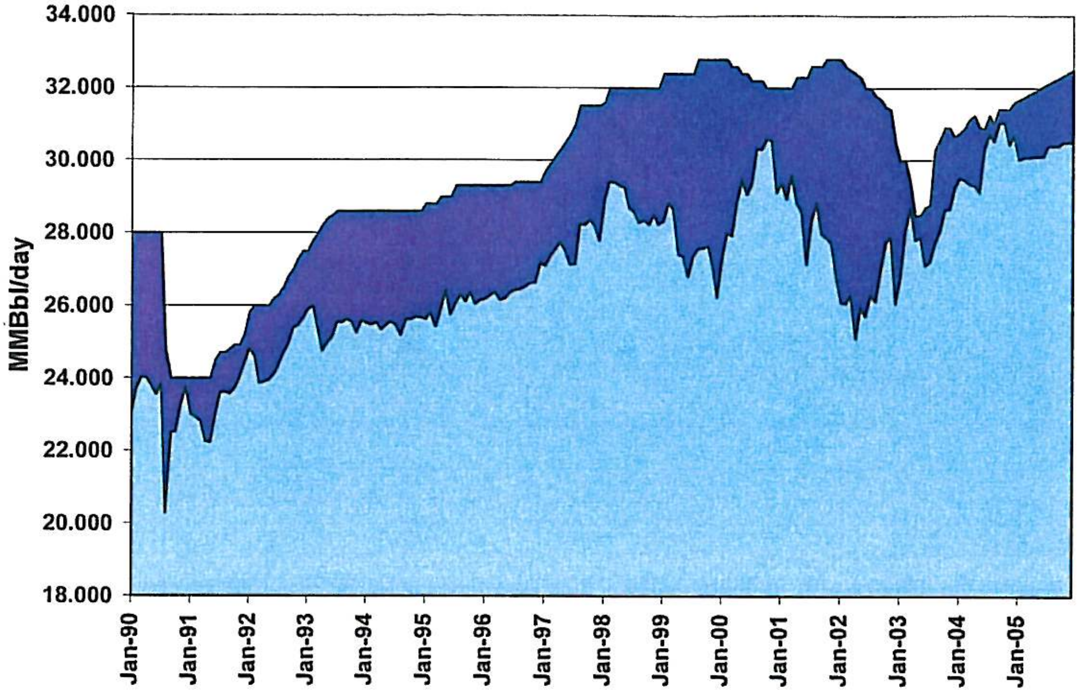


Exhibit A5-6
OPEC Spare Capacity is Extremely Tight Right Now



World Crude Oil Production Has Been Unable to Keep Up With Demand

- Oil production has risen by more than 10 percent since 1999 and is at the highest level since at least 1994. Russia and OPEC production have grown the most. However, oil supply growth has been eclipsed by stronger demand growth.
- As oil demand stretches supply, prices are, in part, set by inter-fuel competition. Thus, oil price effects will be moderated as other energy sectors respond along with responses within the oil sector.
- The reduction in spare global refining capacity is creating higher price levels for refined products which is additive to the fundamentals supporting crude prices. We anticipate this tightness to be sustained through the balance of the decade unless global demands moderate

Fundamental Market Factors Outlook

- Rapid increase in global product demands will continue, with some moderation
- Tight spare global crude production capacity in short term, with investment impact emerging

- Continued reduction trends in product sulfur levels across the world
- Tight refining capacity, with new investments impacting in the 2009 plus timeframe

Results in an environment of:

Overall Outlook for Oil Markets

- Continued high prices for crude and products versus history, barring sustained demand abatement
- Price volatility across all products based on real and perceived supply/demand disruptions
- Strong premiums for crudes and products which have low sulfur versus higher sulfur grades
- Premiums will drive investments in refining capacity, alternative clean fuels (GTL, etc)
- Oil prices – For 2006, we project a price of approximately $53/bbl in real 2003$. Beyond 2006, our outlook for crude oil prices is for equilibrium prices in the $45 to $55/bbl range (2003$)
- In 2006, ICF expects short term moderation in price from 2005 levels due to price impact on demand. Current price run up is due to Iranian and Nigerian political unrest, and potential threat to spare capacity
- From 2006 onwards, ICF price forecast takes into account the current market situation, market fundamentals and the changes expected to occur in the market
- From 2006 to 2012, increase in production investment will offset continued demand increase in developing countries
- Saudi production growth in 2012 to 2015 will further moderate price
- Beyond 2015, steady demand growth and high cost of more unconventional crude sources cause a steady rise in price

Distillate Fuel Assumptions

- The high margins between distillate fuels and crude (No.2 & LSD spread vs WTI) since mid 2004 will be sustained due to continued tight global refinery capacity, increased global dieselization, and continued lower global sulfur limits in fuel.

- The forecast incorporates a significantly higher distillate margin through 1Q 2006 due to short term tightness stemming from the hurricane impacts on refining capacity, but also includes some peak periods in 2006 and 2010 as ULSD, and off-road diesel sulfur requirements are implemented.

- Premiums for ULSD vs LSD will be high (10 cpg average) for a number of years, and then moderate as refiners and the distribution system are essentially all handling ULSD quality product.

Residual Fuel Assumptions

- The residual fuel market is typically driven by demand pulls from utilities and for ship bunkering needs. U.S. demands are met by a mix of refinery production (55%) and imports (45%), with about 30% of U.S. refinery production exported.

- The market for residual products is not driven by crude prices as much as by alternative fuel prices for utilities, primarily gas. The rise in crude prices since 2004 have resulted in a much wider spread between crude price (WTI) and residual fuels.

- The residual market for utility grade (1%) was tight in 4Q 2005 due to supply disruptions impacting refiners and blenders, and high gas prices driving utilities to oil.

- Utilities and Industrials who burn residual are limited by sulfur emissions on the maximum allowable that can be burned. This limitation on demand, coupled with more global heavy crude production, will tend to sustain the wider spreads between WTI and residual fuel in the future.

- The market has currently shifted back as gas prices have rapidly fallen. ICF expects low Sulfur residual fuel prices to track gas prices.

Outlook for Low Sulfur, High Sulfur, and 1% Residual Oil Specifications

- On road Ultra-Low Sulfur Diesel (15 ppm sulfur) phases in June 1, 2006 with an 80% compliance factor. The full phase-in will begin in 2010.

- The recently proposed off-road rule will require non-road diesel to be under 500 ppm (except for heating oil use). This same rule will phase out all 15-500 ppm diesel oil except locomotive and marine diesel use in 2012. Heating oil use may still exceed the 500 ppm threshold after 2012 according to this proposed rule.

- There are no foreseen changes for residual oil (less than 1%) regulations at this time in the U.S. However, sulfur restrictions beginning in 2006 for bunker fuels in the Baltic, and 2007 in the North Sea will impact global low sulfur supply balances.

Distillate Price Projection

- High demand growth on a global basis for diesel fuel and tighter sulfur specifications will sustain distillate margins at well above historical levels.
- Distillate (No 2) premiums vs WTI have risen from $2-3/bbl in the 1990's/early 2000's to $4 in 2004, $11 in 2005. We anticipate some moderation, but only after ULSD is implemented in 2006.
- Distillate margins should moderate based on refinery capacity and sulfur handling growth, but will likely remain in the $8/bbl range over the period.
- The 2010/2011 period should see a higher premium as ULSD is introduced for off-road use.

Residual Price Projection

- As Crude and Product prices have escalated from 2003, residual price has lagged
- Historical discounts vs. WTI have widened from $3-4/bbl for 1% sulfur residual fuel to $13-16 in 2004 and 2005
- Impact of the hurricanes on residual production, especially low sulfur, created a short term reduction in the discount, however, wider spreads are being restored as gas prices have fallen.
- Assuming historic residual fuel demand levels for power generation in the US, longer term discounts vs WTI should be in the $13-16/bbl range
- The variability in residual fuel prices versus WTI is a reflection of the stronger relationship between gas prices and residual fuel in recent years.

Exhibit A5-7
Oil Product Price Forecast ($/MMBtu)

Oil Product (Commodity)	ICF Forecast (2003 $)	ICF Forecast (Nominal $)
0.05% Sulphur Distillate (Gulf Coast)		
2006	11.40	11.81
2010	10.48	11.71
2015	9.52	11.74
2020	10.15	13.80
2025	10.78	16.18
1% Sulphur Residual (Gulf Coast)		
2006	6.04	6.45
2010	5.54	6.77
2015	5.18	7.39
2020	5.37	9.01
2025	5.60	11.00
1.5% Sulphur Residual (Gulf Coast)		
2006	5.80	6.21
2010	5.29	6.52
2015	4.91	7.13
2020	5.13	8.77
2025	5.39	10.79
3% Sulphur Residual (Gulf Coast)		
2006	5.08	5.49
2010	4.54	5.78
2015	4.12	6.33
2020	4.40	8.04
2025	4.74	10.14

Note: Spreads between commodity price and WTI Spot price are not subject to dollar inflation rates. Therefore, Nominal Commodity Price = (Real WTI Spot Price + Real Transportation Cost) / Dollar Inflation Factor ± WTI-Commodity Price Spread

Exhibit A5-8
ICF Fuel Oil Forecast Trends – 2003 $/MMBtu

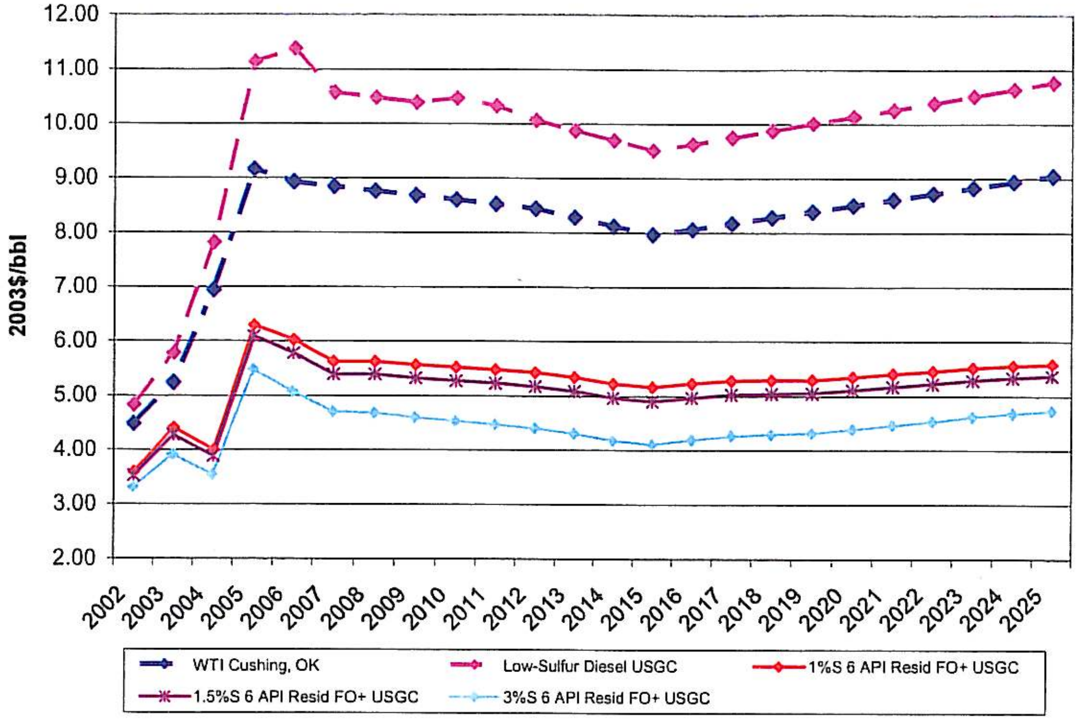
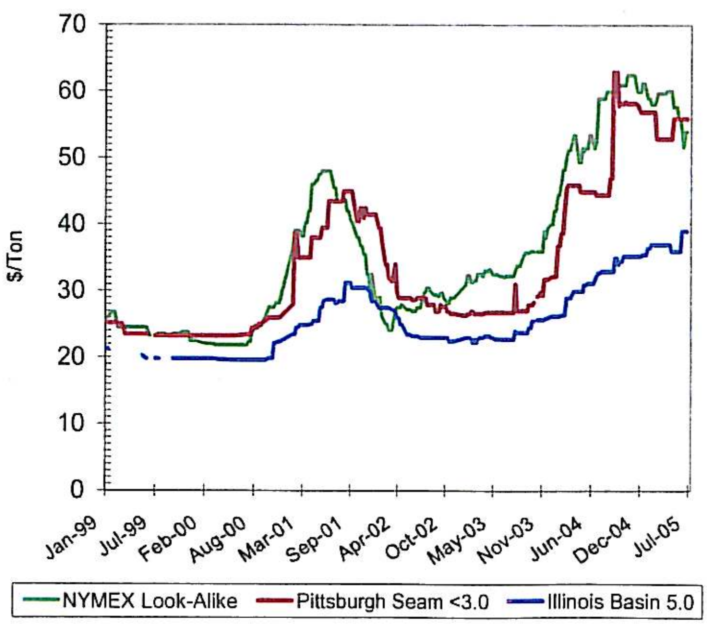


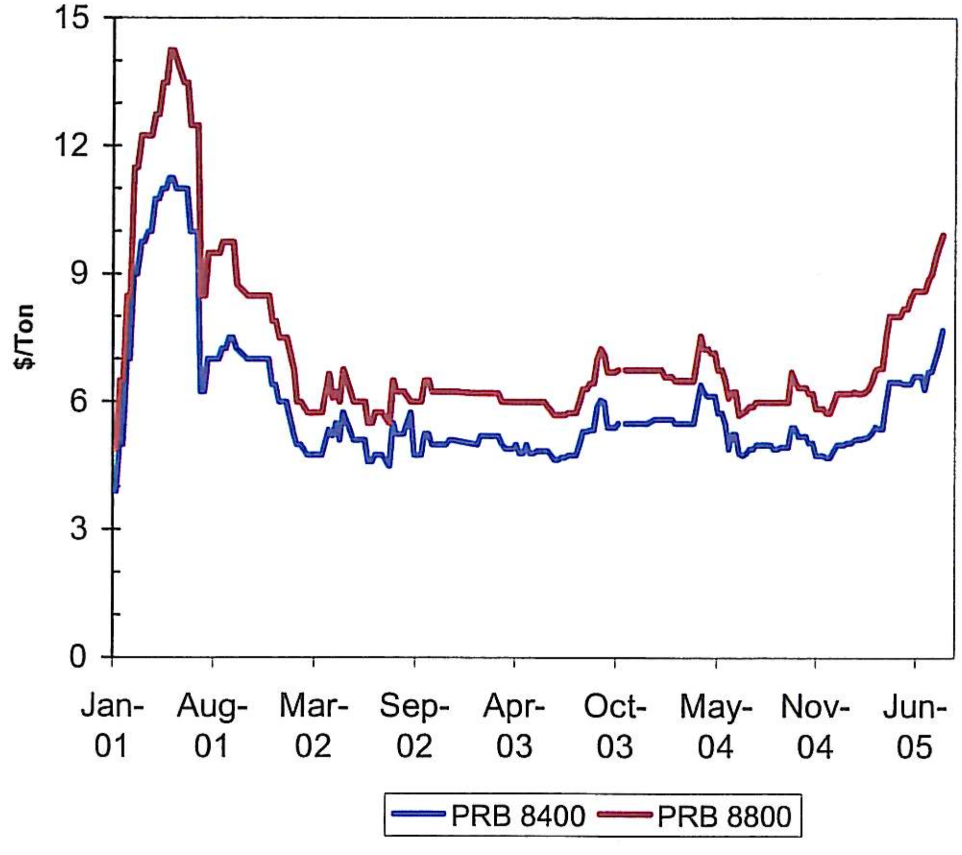
Exhibit A5-9
Eastern Coal Prices Remain High and Volatile



- Prices for eastern coals reached record levels in the summer of 2004, but softened in the second half of 2004 and early months of 2005.

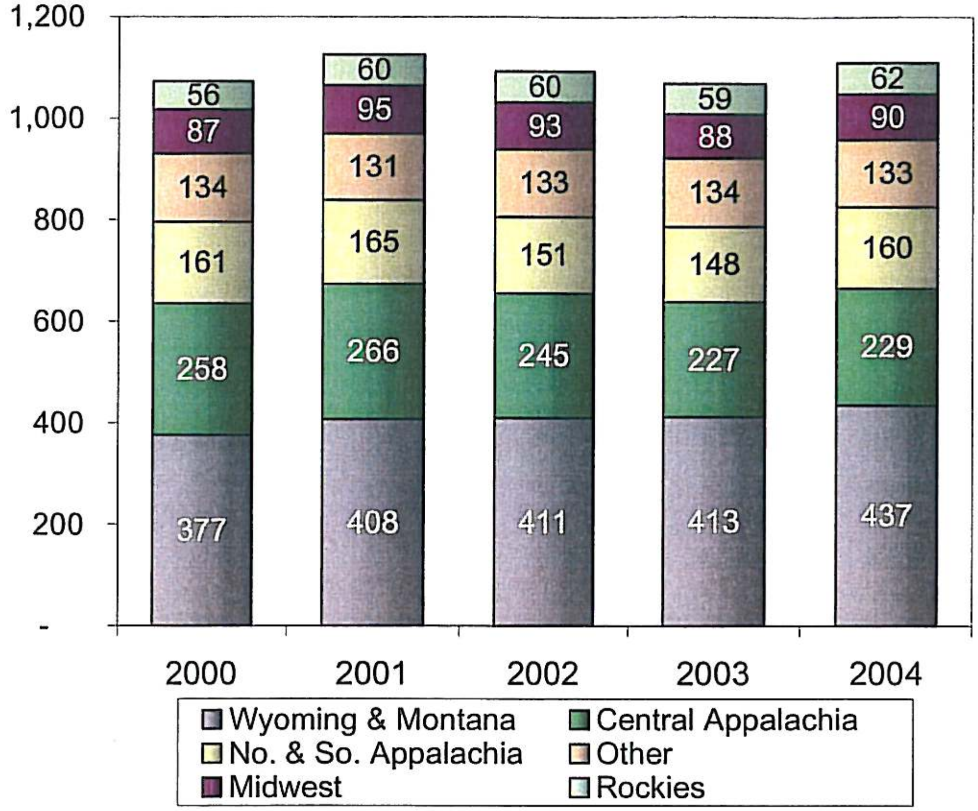
- Eastern prices began to move up again with the announcement of the extensive rail maintenance plan that will reduce delivery capacity for PRB coal through the end of 2005.

Exhibit A5-10
PRB Coal Prices Have Finally Begun to Move Up



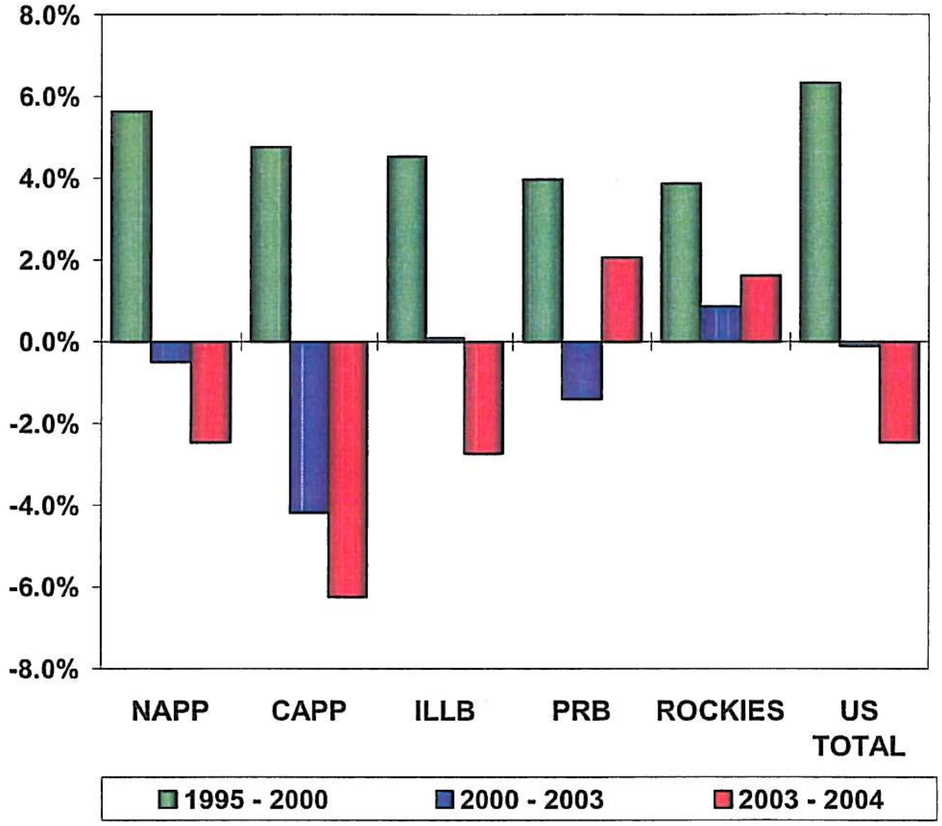
- Though PRB prices were flat throughout 2003 and 2004, prices began moving upwards in May 2005 on the heels of two train derailments and the resultant extensive rail maintenance plan.

Exhibit A5-11
Coal Production Began to Respond to Record High Prices in 2004



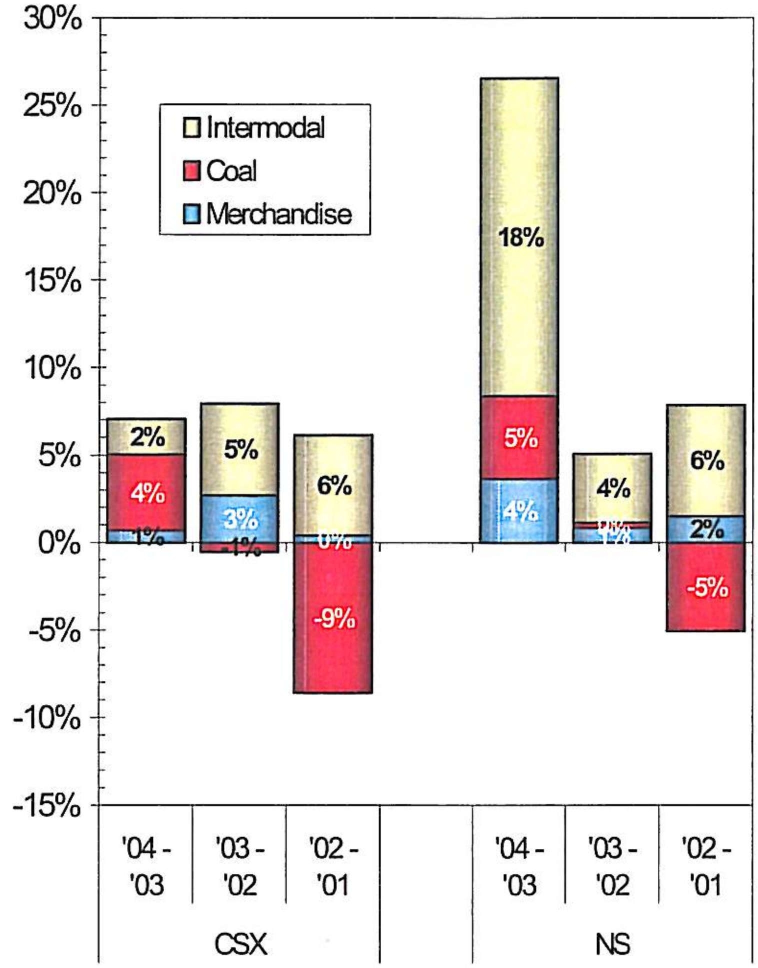
- Total coal production increased by 42 million tons, reaching its highest level since 2001.
- Central Appalachian coal production showed a slight increase in 2004, but still remained 14 percent below 2001 levels.
- Northern Appalachia production increased by over 8 percent in 2004, approaching the levels achieved in 2001.
- The PRB continued to offset production lost from Central Appalachia, adding 24 million more tons in 2004.

Exhibit A5-12
Eastern Coal Mine Productivity Continues to Decline



- At the aggregate national level, coal mine productivity has reversed a long term positive trend, flattening over the period 2000 to 2003, and then falling by over 2 percent in 2004.
- The drop in productivity was principally due to performance in the Appalachia regions and the Illinois Basin. In 2004, coal mine productivity declined at an even faster rate in these eastern regions.
- In the west, productivity growth began recovering in 2003 and posted gains by 2004.
- A major issue for coal markets continues to be whether the recent decline in productivity is a temporary aberration, or the new reality.

Exhibit A5-13
Eastern Railroads May Not be Able to Meet the Shift in Demand Resulting from PRB Rail Woes



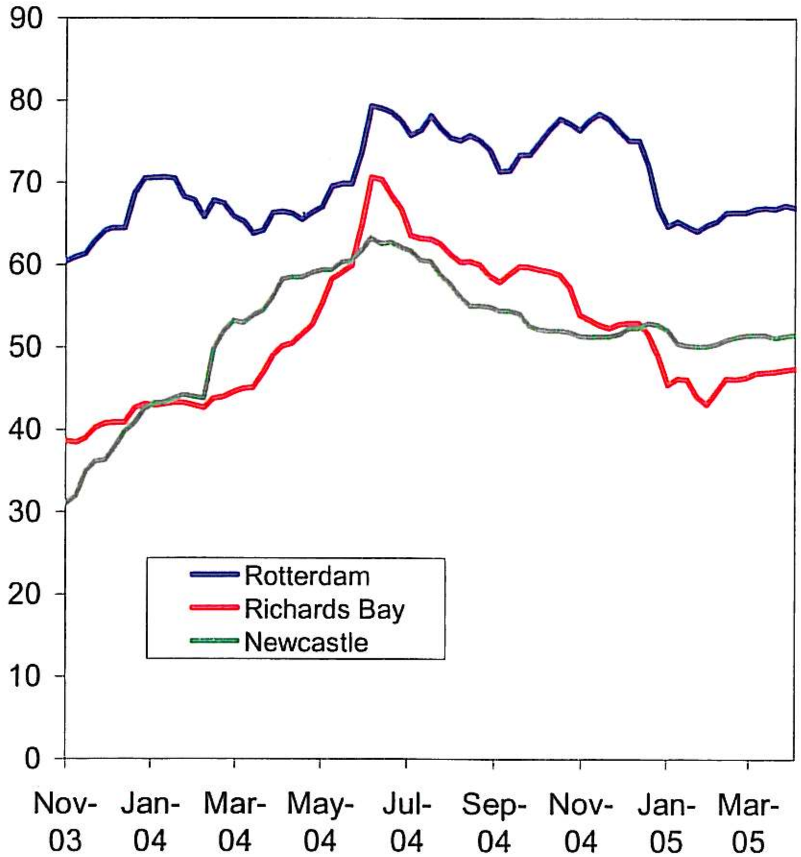
- Despite concerns about eastern rail performance in 2004, car loadings increased for both NS and CSX.
- Eastern rail performance still has ground to make up, as higher car loadings led to lower train speeds in the first half of the year, as compared to 2004.
- The Eastern coal delivery load will be stressed further by customers attempting to replace their lost PRB supply.
- CSX has announced a rail expansion plan to increase carload and train capacity out of the Illinois basin by about 5%. The plan will cost approximately $800,000 over two years

- Utility coal stocks continued to decline reaching new lows in 2005, even before the PRB rail problems began.
- Major coal producers and utilities began repositioning themselves after the full impact of the PRB track problems crystallized.
- Power producers in the southeast have begun turning to Colombian coal to rebuild their coal stocks.

    - The combined high mine mouth prices and rail capacity problems for domestic coal have made the high delivered cost of import coal economic.

    - No other economic alternatives are available until at least 2006.

Exhibit A5-14
International Coal Markets Softened in 2005

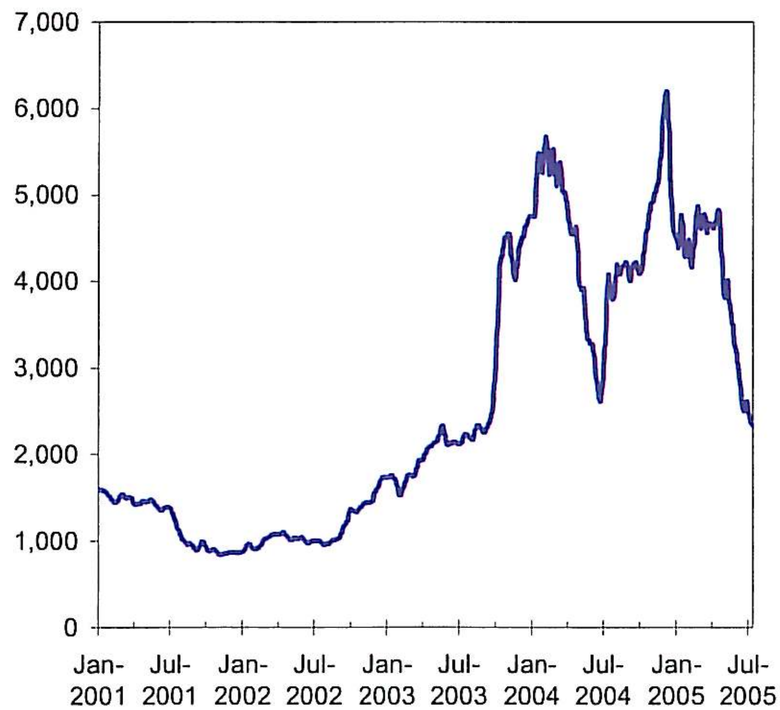


- International coal prices peaked in mid-2004 both at origination and delivery ports.

- While origination prices for international coal have softened through much of the remainder of 2004 and 2005, destination prices were held high through the remainder of 2004.

- However, as discussed on the following slide, international freight rates have fallen in 2005, leading to a decline in coal prices at the destination port as well.

Exhibit A5-15
International Freight Rates Have Returned to pre-2004 Levels



- A key measure of seaborne freight rates is the Baltic Dry Index (BDI). The BDI stayed under 2,500 over the entire period from 2000 through 2003.

- Dramatic increases occurred in 2004 principally in response to growth in China and India. By mid-2005, however, the BDI fell back into the 2,500 range.

- The return to pre-2004 levels is due in part to a reduction in the demand for international transport.

    - Reduced Chinese imports, particularly iron ore
    - A slowing of US economic growth
    - Growth of world trade in general has slowed

- In addition, shipping capacity has begun to respond to record high prices. The typical lead time for new shipping capacity is 18 months to 2 years. It has now been 2 years since the initial run-up in the BDI. Ship makers are now filling orders that resulted from earlier peaks in shipping prices.

Coal Prices are Projected to Decline as Producers Respond to Record High Prices

- The elevated price of natural gas and oil, low coal stockpiles at utilities, and, production and transportation problems have created a volatile market situation in which coal prices have risen well above production costs for existing as well as new mines in many regions.

- However, producers have already begun to respond to these record price levels. As new coal mines come on line and supply increases, coal prices will fall back towards production costs.

- In the Expected Case, coal prices are projected to decline in the mid-term. In the long-term, Expected Case eastern low sulfur coal prices are projected to begin increasing as depletion becomes an issue and new mines are brought online with thinner seams and higher overburden ratios.

EPA's New Air Pollution Regulations Shift Coal Production Away From PRB and Central Appalachia

- PRB coal production in 2008 is projected to be 50 million tons higher than 2004 in the 4P Expected Case. However, production subsequently declines as power companies install SO2 scrubbers to comply with CAIR and CAMR and switch to medium and high sulfur.

- By 2025, coal production in the PRB is projected to decline by approximately 75 million tons below 2004 levels.

- Central Appalachian coal production, which is the source of most eastern low sulfur compliance coal, continues to slowly decline until 2008, when production begins to decline more rapidly as plants scrub and switch away from low sulfur coals. Reserve exhaustion also plays a significant role in Central Appalachia, as many of the low cost reserves have been mined.

- In contrast, medium and high sulfur coal producers, particularly those in the Illinois Basin and Northern Appalachia, are projected to increase output substantially after 2008

- The Rockies encounter a small interruption in its rising coal production in 2008 and 2009, but returns to a rising trajectory once the compliance transition to scrubbing is complete. This is due to the reserves in the Rockies including both low and high sulfur coal types.

The Presence of a Carbon Policy Has the Single Largest Affect on Coal Production

- The Expected Case, which includes a moderate carbon dioxide policy, produces approximately 1.15 billion tons of coal in 2016 and just over 1.2 billion tons of coal in 2025. The virtually flat coal trajectory is due to the high CO_2 emissions of coal relative to other fuel types. CO_2 prices in the 4P Expected Case are projected to rise from $7.70 per ton in 2016 to $21.7 per ton in 2025 in 2003 dollars.

- In contrast, coal production increases by 300 million tons by 2025 in the absence of a carbon policy in the 3P scenario.

  - Coal production in the Midwest region, which produces primarily high sulfur coal burned in scrubbed plants, increases by 125 million tons between 2016 and 2025 in the 3P case, while production in the expected case is virtually flat. This reflects the increased coal generation and a corresponding increase in scrubbing needed to comply with EPA's CAIR and CAMR regulations. High sulfur Northern Appalachian coal prices are somewhat higher in the 3P case due to higher demand, but prices are moderated by the greater supply of competing high sulfur coal from new Midwestern mines.

  - PRB coal production increases by 75 million tons between 2016 and 2025 in the 3P case, as the low cost production there allows it to dominate coal supply to unscrubbed units and new coal plants in western states.

  - Central Appalachian coal follows a similar production and price trajectory in both cases due to reserve exhaustion and the impact of coal-switching.

Exhibit A5-16
4P Minemouth Coal Price Forecast

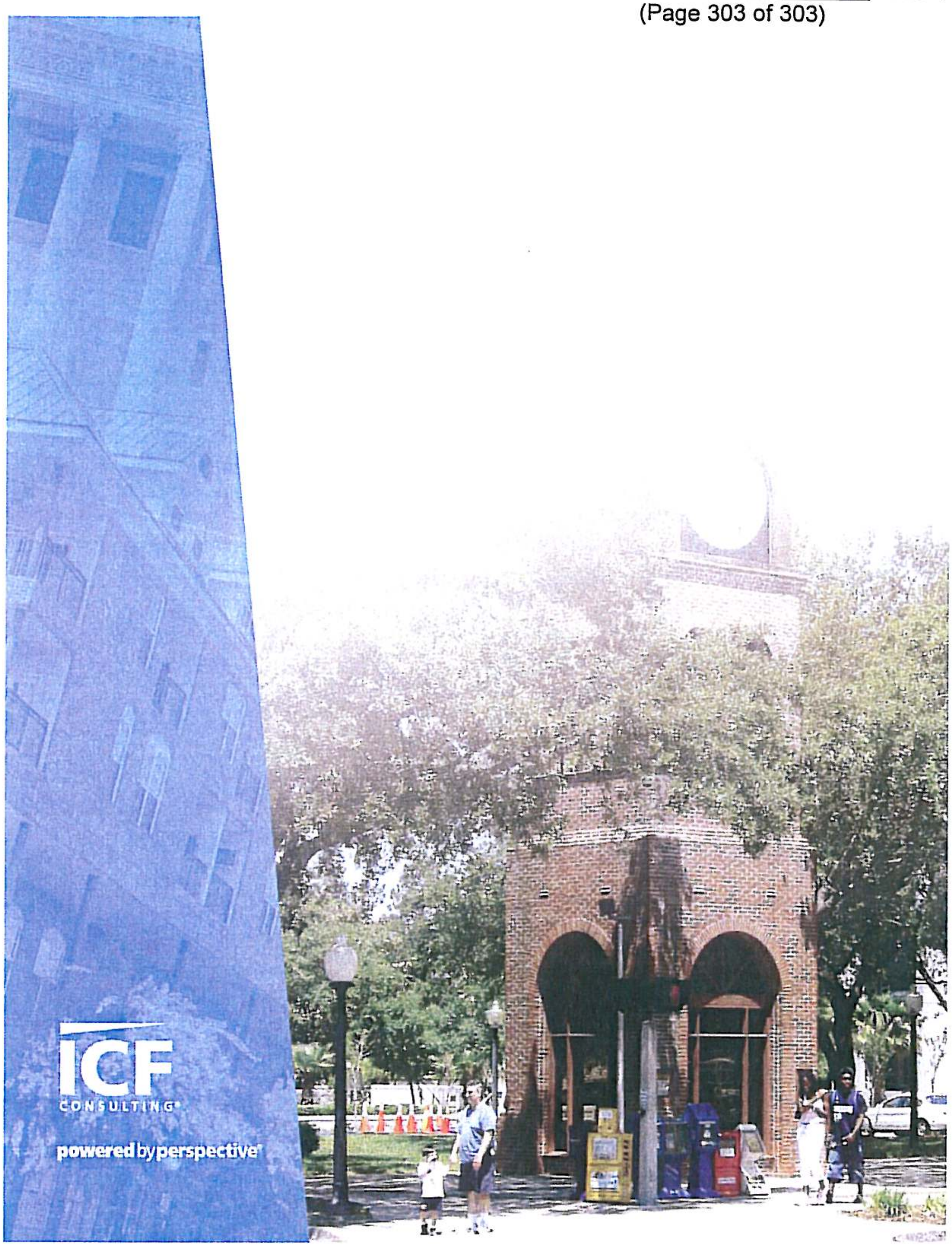
Minemouth Coal Type	ICF Forecast (2003$/ton)	ICF Forecast (Nominal$/ton)
Central Appalachia Low Sulfur (1.0%+ Sulfur, 12,500 Btu/lb)		
2011	40.73	48.84
2015	44.35	58.14
2020	49.75	72.89
Powder River Basin (0.4% Sulfur, 8,800 Btu/lb)		
2011	7.39	8.87
2015	7.26	9.52
2020	6.86	10.06
Illinois River Basin (3.0% Sulfur, 11,000 Btu/lb)		
2011	25.46	30.26
2015	24.18	32.52
2020	23.68	36.03
Northern Appalachia (3.0%+ Sulfur, 13,000 Btu/lb)		
2011	29.67	35.27
2015	27.72	37.28
2020	28.35	43.14
Venezuelan Coal (0.6% Sulfur,12,200 Btu/lb)		
2011	33.49	40.17
2015	33.00	43.26
2020	34.24	50.17
Petroleum Coke (6.0% Sulfur,14,000 Btu/lb)		
2011	22.79	22.79
2015	22.79	22.79
2020	22.79	22.79

ATTACHMENT 6
ENVIRONMENAL AND HEALTH

Exhibit A6-1
Detailed Quantitative Emissions Estimates for $PM_{2.5}$ Impact Assessment

Emitted Pollutant	Source/ Location	Estimated Annual Emissions (tons/yr) [a]					
		Existing GRU Plants (for context)		Future Power Options (base/base/base/base case, 2015)			
		Pre-DH2 Retrofit	Post-DH2 Retrofit	CFB	IGCC	DSM plus Biomass	DSM plus Purchase
SO_2	Deerhaven site-new unit (stack)	n/a	n/a	708 ICF 1163 BVa 1367 BVp	641 ICF	15 ICF	0
	GRU-all other units (stack)	6934 ICF 8354 BVa 27690 BVp	859 2313 BVa 17266 BVp	859 ICF 2313 BVa 17266 BVp	859 ICF	865 ICF	874 ICF
	Other-regional (stack)	n/a	n/a	n/a	n/a	n/a	n/a
NO_x	Deerhaven site-new unit (stack)	n/a	n/a	515 ICF 621 BVa 731 BVp	142 ICF	75 ICF	0
	GRU-all other units (stack)	3989 ICF 3992 BVa 14213 BVp	1080 ICF 971 BVa 7617 BVp	1080 ICF 971 BVa 7617 BVp	1080 ICF	1092 ICF	1110 ICF
	Other-regional (stack)	n/a	n/a	n/a	n/a	n/a	n/a
PM	Deerhaven site-new unit (stack)	n/a	n/a	117 BVa 136 BVp	not estimated	not estimated	Not estimated
	GRU-all other units (stack)	237 BVa 1840 BVp	179 BVa 934 BVp	179 BVa 934 BVp	not estimated	not estimated	Not estimated
	Other-regional (stack)	n/a	n/a	n/a	n/a	not estimated	Not estimated

[a] Data sources: ICF = IPM modeling assumptions and outputs for this study, BVa = actual emissions used in air modeling by Black & Veatch (2004b), BVp = potential emissions used in air modeling by Black & Veatch (2004a). IPM modeling of CFB and IGCC units assume 30MW biomass co-firing.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