on the spot market, the annual fuel bill for GRU would be approximately $160 million[30]. Conversely, if the entire fuel bill were met via petroleum coke, GRU's 2005 fuel bill would have been approximately $20 million[31]. 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[32]. 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:

- **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,

[30] 465 MW times 0.55 load factor times 8,760 hours per year times $9/MMBtu times 7,000 Btu/kWh.
[31] 465 MW times 0.55 load factor times 8,760 hours per year times $1/MMBtu times 10,000 Btu/kWh.
[32] All numbers are in nominal dollars.

petroleum coke is the least cost fuel, but there may be challenges in obtaining and/or using 100% petroleum coke. The effect of these 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.

- **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 Figure 5-___). 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.

Figure 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	3.42
Standard Deviation 1995 - 2004	1.47
Source: Platts' Gas Daily. Prices from 1995 onwards are volume-weighted averages	

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

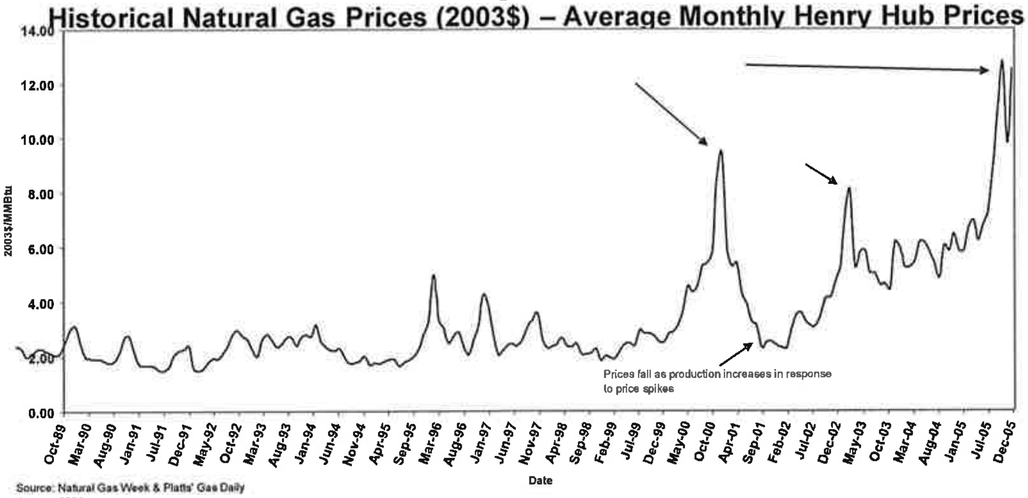

Figure 5-3

Year	Henry Hub Price (2003$/MMBtu)
1995	1.99
1996	3.18
1997	2.76
1998	2.29
1999	2.49
2000	5.00
2001	3.84
2002	3.08
2003	5.46
2004	5.77
2005	8.01
Average 1995 – 2004	3.99
Standard Deviation 1995 - 2004	1.86
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. 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.

Figure 5-4
ICF Base Case Delivered F uel Price Forecasts (Nominal $/MMBtu)

Period	Period Type	Delivered Natural Gas	Delivered Coal[1]	Natural Gas Price Premium
1995 – 2005	Historical	4.28	1.84	+2.44
2011 – 2020	Forecasts	8.26	2.02	+6.24

[1]50% Pet Coke – 50% Illinois Basin coal.

Figure 5-5
Delivered Natural Gas Price Forecasts

Year	Data	ICF Base Case3,4	GRU – IRP5
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
1995 – 2005 Average	Historical	4.28	4.28
2006 – 2010 Average	Forecast	9.27	5.90
2011 – 2020 Average	Forecast	8.26	6.09

Figure 5-6
Delivered Natural Gas Price Forecasts (Real 2003$)

Year	Data	ICF Base Case3,4	GRU – IRP5
2007	Forecast	9.29	5.56
2008	Forecast	7.85	5.10
2009	Forecast	7.11	4.94
2010	Forecast	6.40	4.77
2011	Forecast	6.48	4.77
2012	Forecast	6.33	4.86
2013	Forecast	6.41	4.96
2014	Forecast	6.33	5.11
2015	Forecast	6.27	NA
2016	Forecast	6.16	NA
2017	Forecast	5.95	NA
2018	Forecast	6.19	NA
2019	Forecast	6.38	NA
2020	Forecast	6.57	NA
1995 – 2005 Average	Historical	3.99	3.99
2006 – 2010 Average	Forecast	7.66	5.09
2011 – 2020 Average	Forecast	6.31	4.93

Figure 5-7
Delivered Coal 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

Figure 5-8
Delivered Coal 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	-7.80	-3.20
2008	Forecast	-6.35	-2.76
2009	Forecast	-5.62	-2.60

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 Figures 5-6 and 5-7). 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.

Figure 5-9
Coal Price Volatility Greatly Dampened by Relative Stability in Transportation Costs and Contracting Prices

Year	Spot Coal Prices1 (Nominal$/MMBtu)		Average Delivered Coal Costs to Utilities (Nominal$/MMBtu)	
	PRB	Central Appalachia 1% Sulfur	GRU2	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 Figure 5-10). 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.

Figure 5-10
Delivered Utility Fuel Price Volatility – U.S. Average

Year	Nominal$/MMBtu		
	Coal – U.S. Average Delivered Utility Cost1	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 Figure 5-11).

Figure 5-11
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 AND COAL

Figure 5-12
Solid Fuel Option 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	25.6	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	28.8	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
Average	26.8	1.11	22.0	0.91	48.8	2.02

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

Figure 5-13
Solid Fuel Option 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	19.75	0.82	16.66	0.69	36.41	1.51
2012	19.73	0.82	16.62	0.69	36.34	1.51
2013	19.85	0.82	16.65	0.69	36.50	1.51
2014	20.04	0.83	16.60	0.69	36.64	1.52
2015	20.14	0.83	16.61	0.69	36.75	1.52
2016	20.29	0.84	16.62	0.69	36.92	1.53
2017	20.43	0.84	16.62	0.69	37.06	1.53
2018	20.63	0.85	16.62	0.69	37.24	1.53
2019	20.73	0.85	16.60	0.69	37.33	1.54
2020	20.89	0.86	16.65	0.69	37.54	1.54
Average	20.25	0.84	16.62	0.69	36.87	1.52

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

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 hundreds of years 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.

Figure 5-14
Delivered Solid Fossil Fuel Prices (Nominal$/MMBtu)

Solid Fossil Fuel Type	2011 – 2020
Central Appalachia	2.42
PRB	2.04
Illinois Basin	1.92
Imported Coal	2.08
Petroleum Coke	1.11
Biomass	1.99
Weighted Average[1]	1.85

[1]Ten percent biomass, ten percent pet coke, 80 percent average of delivered Illinois Basin coal costs.

Figure 5-15
Delivered Solid Fossil Fuel Prices (2003$/MMBtu)

Solid Fossil Fuel Type	2011 – 2020
Central Appalachia	
PRB	
Illinois Basin	
Imported Coal	
Petroleum Coke	
Weighted Average[1]	

[1]Ten percent biomass, ten percent pet coke, 80 percent average of delivered Illinois Basin coal costs.

Figure 5-16
Delivered Coal Costs (Nominal $/MMBtu)

Year	Data	ICF Base Case	GRU
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
1995 – 2005 Average	Historical	1.84	1.84
2006 – 2010 Average	Forecast	1.67	2.69
2011 – 2020 Average	Forecast	2.02	2.87

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Figure 5-17
Delivered Coal Costs (2003 $/MMBtu)

Year	Data	ICF Base Case	GRU
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
1995 – 2005 Average	Historical	-	-
2006 – 2010 Average	Forecast	1.50	2.32
2011 – 2020 Average	Forecast	1.52	2.27

Figure 5-18
Delivered Coal Gas Price Differential (Nominal $/MMBtu)

Year	Data	ICF Base Case	GRU - IRP
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
1995 – 2005 Average	Historical	-2.44	-2.44
2006 – 2010 Average	Forecast	-7.24	-3.21
2011 – 2020 Average	Forecast	-6.33	-3.22

Note: This table does not account for the higher thermal efficiency of a gas combined cycle over a coal plants. A combined cycle using gas requires roughly 30 percent less Btu/kWh of electricity produced. Actual ICF analysis explicitly accounts for this difference in thermal efficiencies.

Figure 5-19
Delivered Coal Gas Price Differential (2003 $/MMBtu)

Year	Data	ICF Base Case	GRU - IRP
2010	Forecast	(4.90)	(2.53)
2011	Forecast	(4.97)	(2.53)
2012	Forecast	(4.82)	(2.59)
2013	Forecast	(4.90)	(2.66)
2014	Forecast	(4.81)	(2.79)
2015	Forecast	(4.75)	NA
2016	Forecast	(4.64)	NA
2017	Forecast	(4.42)	NA
2018	Forecast	(4.66)	NA
2019	Forecast	(4.84)	NA
2020	Forecast	(5.03)	NA
1995 – 2005 Average	Historical	-	-
2006 – 2010 Average	Forecast	-	-
2011 – 2020 Average	Forecast	(4.79)	(2.62)

Note: This table does not account for the higher thermal efficiency of a gas combined cycle over a coal plants. A combined cycle using gas requires roughly 30 percent less Btu/kWh of electricity produced. Actual ICF analysis explicitly accounts for this difference in thermal efficiencies.

Figure 5-20
Solid Fuel Option #1 – 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	55.45	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	58.89	2.68
2019	32.63	1.48	27.43	1.25	60.05	2.73
2020	33.20	1.51	28.04	1.27	61.23	2.78
Average	30.68	1.39	25.42	1.16	56.10	2.55

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

Figure 5-21
Solid Fuel Option #1 – Illinois Basin Coal (2003 $)

Year	Illinois Basin - 3% Sulfur		Transportation		Delivered[1]	
	$/ton	$/MMBtu	$/ton	$/MMBtu	$/ton	$/MMBtu
2011	23.91	1.09	19.21	0.87	43.12	1.96
2012	23.41	1.06	19.21	0.88	42.62	1.94
2013	23.35	1.06	19.21	0.87	42.56	1.94
2014	23.30	1.06	19.21	0.88	42.51	1.93
2015	23.24	1.06	19.21	0.87	42.46	1.93
2016	23.18	1.06	19.21	0.88	42.40	1.92
2017	23.08	1.05	19.21	0.87	42.29	1.92
2018	22.96	1.05	19.21	0.87	42.18	1.92
2019	22.86	1.04	19.21	0.88	42.06	1.91
2020	22.74	1.03	19.21	0.87	41.95	1.90
Average	23.20	1.06	19.21	0.87	42.41	1.93

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

Figure 5-22
Solid Fuel Option #3 – 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	48.84	1.95	19.10	0.76	67.94	2.72
2012	51.20	2.05	19.39	0.78	70.59	2.82
2013	53.41	2.14	19.68	0.79	73.09	2.92
2014	55.72	2.23	19.98	0.80	75.70	3.03
2015	58.14	2.33	20.28	0.81	78.41	3.14
2016	60.65	2.43	20.58	0.82	81.23	3.25
2017	63.51	2.54	20.89	0.84	84.39	3.38
2018	66.49	2.66	21.20	0.85	87.69	3.51
2019	69.62	2.78	21.52	0.86	91.14	3.65
2020	72.89	2.92	21.84	0.87	94.74	3.79
Average	60.05	2.40	22.17	0.89	80.49	3.22

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

Figure 5-23
Solid Fuel Option #3 – 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
Average	45.19	1.81	15.47	0.62	60.66	2.43

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

Figure 5-24
Solid Fuel Option #4 – Powder River Basin Wyoming (PRB) (Nominal $)

Year	PRB Minemouth		Transportation		Delivered[1]	
	$/ton	$/MMBtu	$/ton	$/MMBtu	$/ton	$/MMBtu
2011	8.87	0.50	35.55	2.02	44.42	2.52
2012	9.06	0.52	36.08	2.05	45.15	2.57
2013	9.21	0.52	36.62	2.08	45.84	2.60
2014	9.36	0.53	37.17	2.11	46.54	2.64
2015	9.52	0.54	37.73	2.14	47.25	2.68
2016	9.67	0.55	38.30	2.18	47.97	2.73
2017	9.77	0.55	38.87	2.21	48.64	2.76
2018	9.86	0.56	39.46	2.24	49.32	2.80
2019	9.96	0.57	40.05	2.28	50.01	2.84
2020	10.06	0.57	40.65	2.31	50.70	2.88
Average	9.53	0.54	38.05	2.16	47.58	2.70

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

Figure 5-25
Solid Fuel Option #4 – 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	36.70	2.08
2014	7.33	0.41	29.10	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	0.40	28.47	1.62	35.62	2.02
2018	7.06	0.40	28.26	1.60	35.32	2.01
2019	6.98	0.40	28.05	1.60	35.03	1.99
2020	6.89	0.39	27.85	1.58	34.73	1.97
Average	7.22	0.41	28.79	1.64	36.01	2.04

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

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[1]. They have almost never been above $20/ton, and generally have fluctuated between $10 and $70/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.

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

Figure 5-26
Solid Fuel Option #2 – Petroleum Coke (Nominal $)

Year	Pet Coke Jacksonville, FL		Transportation		Delivered[1]	
	$/ton	$/MMBtu	$/ton	$/MMBtu	$/ton	$/MMBtu
2011	18.7	0.67	16.8	0.60	35.5	1.27
2012	19.5	0.70	17.1	0.61	36.7	1.31
2013	20.4	0.73	17.5	0.63	37.9	1.36
2014	21.3	0.76	17.9	0.64	39.3	1.40
2015	22.3	0.80	18.3	0.65	40.6	1.45
2016	23.3	0.83	18.7	0.67	42.0	1.50
2017	24.3	0.87	19.2	0.68	43.5	1.55
2018	25.4	0.91	19.6	0.70	45.0	1.61
2019	26.6	0.95	20.0	0.72	46.6	1.66
2020	27.8	0.99	20.5	0.73	48.3	1.72
Average	23.0	0.82	18.6	0.66	41.5	1.48

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

Figure 5-27
Solid Fuel Option #2 – Petroleum Coke (2003 $)

Year	Pet Coke Jacksonville, FL		Transportation		Delivered[1]	
	$/ton	$/MMBtu	$/ton	$/MMBtu	$/ton	$/MMBtu
2011	15.65	0.56	14.06	0.50	29.71	1.06
2012	15.96	0.57	14.00	0.50	30.04	1.07
2013	16.33	0.58	14.01	0.50	30.34	1.09
2014	16.68	0.60	14.01	0.50	30.77	1.10
2015	17.07	0.61	14.01	0.50	31.09	1.11
2016	17.45	0.62	14.00	0.50	31.45	1.12
2017	17.80	0.64	14.06	0.50	31.86	1.14
2018	18.19	0.65	14.04	0.50	32.23	1.15
2019	18.63	0.67	14.01	0.50	32.64	1.16
2020	19.04	0.68	14.04	0.50	33.09	1.18
Average	17.28	0.62	14.02	0.50	31.32	1.12

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

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:

Base Case and High Case Parameters

Figure 5-28
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

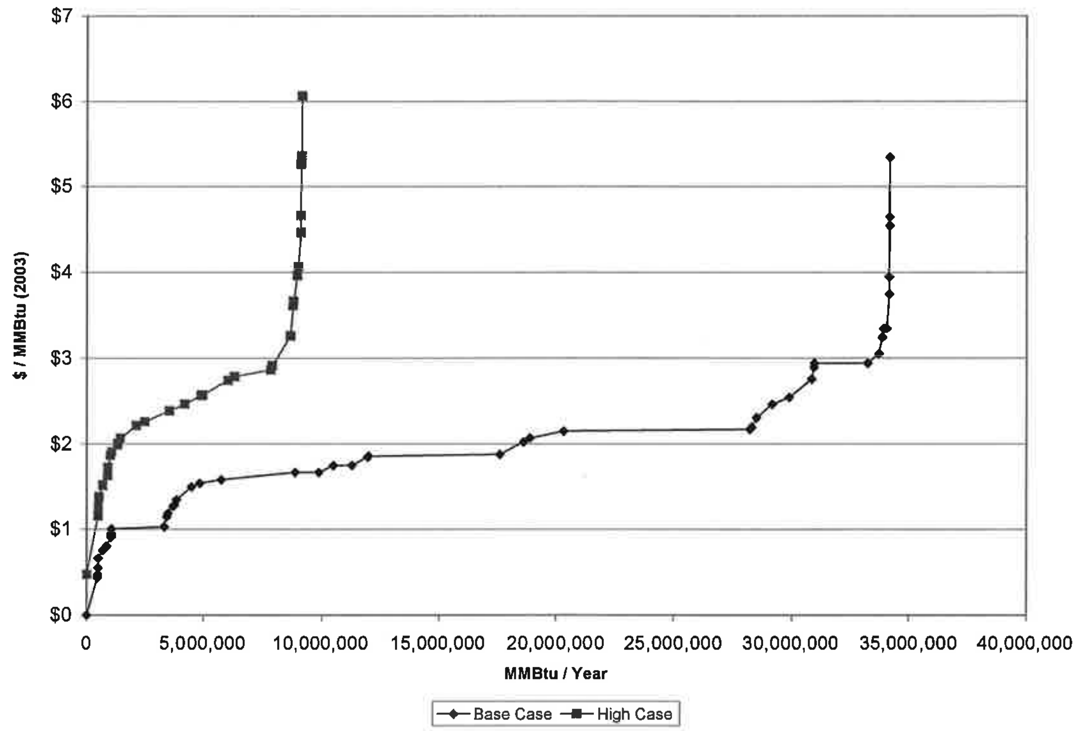
A summary table and a graphical representation of the biomass curves follow below. The full biomass supply curve tables, along with the calculations inherent in them, can be found in the Attachment.

Figure 5-29
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

Figure 5-30
Biomass Supply Curves Graph



NATURAL GAS PRICE FORECAST

ICF forecasts show a large gap between natural gas and coal than GRU.

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Figure 5-31
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	8.33
2009	6.71	7.68
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		

[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.

Figure 5-32
Forecast Fuel Prices – 2011 – 2014 (Nominal $/MMBtu)

Source	Delivered Natural Gas	Delivered Coal1	Gas Premium
ICF Base Case	7.89	1.87	+6.02
GRU IRP	6.09	2.82	+3.27

Figure 5-33
Henry Hub Natural Gas Price Projection ($/MMBtu) – Base Case CO_2 UPDATE NUMBERS

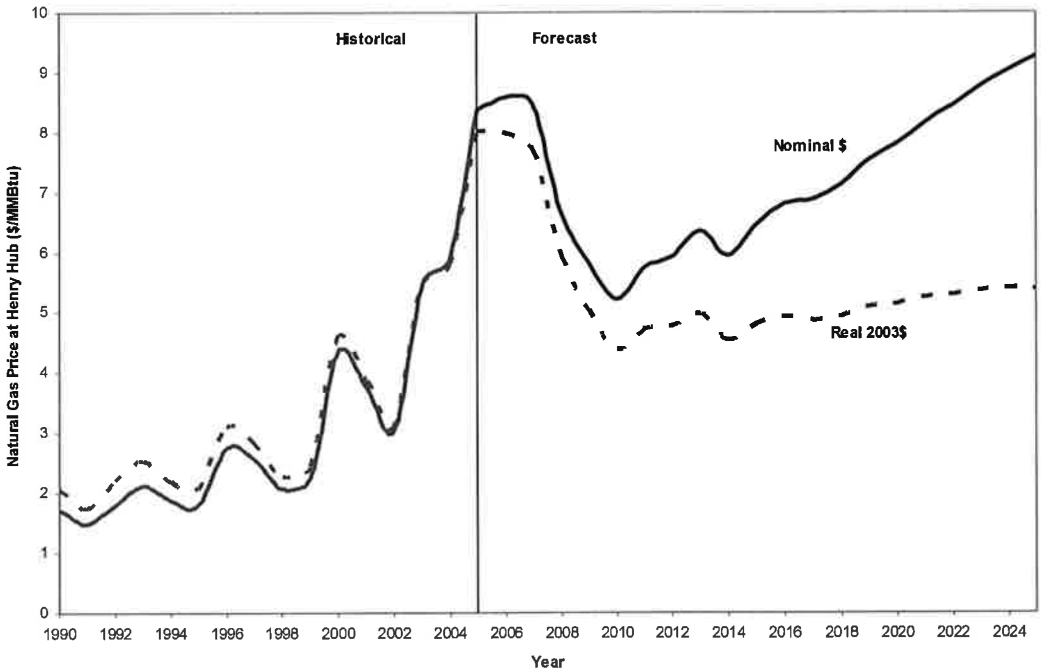
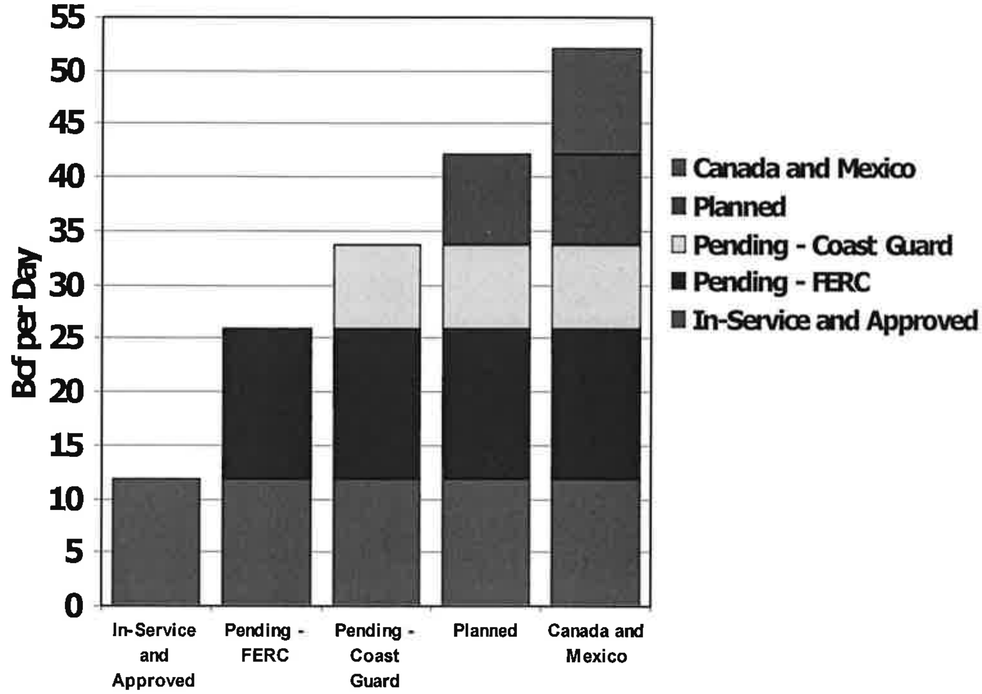


Figure 5-34
Maximum LNG Deliverability Growth



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.

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

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

OIL PRICE FORECAST

Figure 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

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Figure 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	1.60	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]	1.16	1.15	1.07

[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. Return to fundamentals forecast in 2010.

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Figure 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

Figure 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. Gulf
2007	Forecast	1.15	1.15	1.07
2008	Forecast	1.24	1.24	1.15
2009	Forecast	1.37	1.51	1.10
2010	Forecast	1.57	1.91	1.02
2011	Forecast	1.50	1.82	0.98
2012	Forecast	1.45	1.73	0.95
2013	Forecast	1.35	1.61	0.88
2014	Forecast	1.30	1.55	0.85
2015	Forecast	1.22	1.45	0.80
2016	Forecast	1.21	1.45	0.80
2017	Forecast	1.25	1.49	0.82
2018	Forecast	1.17	1.40	0.76
2019	Forecast	1.12	1.34	0.72
2020	Forecast	1.55	1.27	0.68
Average Historical (1995-2005)		1.31	1.48	0.96
Average Forecast (2006-2009)		1.23	1.26	1.09
Average Forecast (2010-2020)		1.29	1.55	0.84

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

Figure 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	1.8 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 cofired with biomass

Figure 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

Figure 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.

In addition, ICF analyzed a High CO_2 Case where prices are assumed to start at $15/ton CO2 in 2010 and reach over $26/ton by 2020. This policy reflects a non-probability weighted scenario where CO_2 policy with limited allowance of offsets starts in 2010.

Figure 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[33]) CO_2 range, and since the summer of 2005, trading in the 20 - 30 Euro/ton ($24 - $36) range. 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.

[33] Assumes $1.20/Euro

Figure 6-5
ETS Historical CO2 Prices (Euro/Ton)[34]

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 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. 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

[34] Source – evolution Markets, LLC

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 Table 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.

Figure 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 ICF – High Case – 2010 – 2020	7 21.8	1.7 – 2.7 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

Figure 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

Figure 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

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

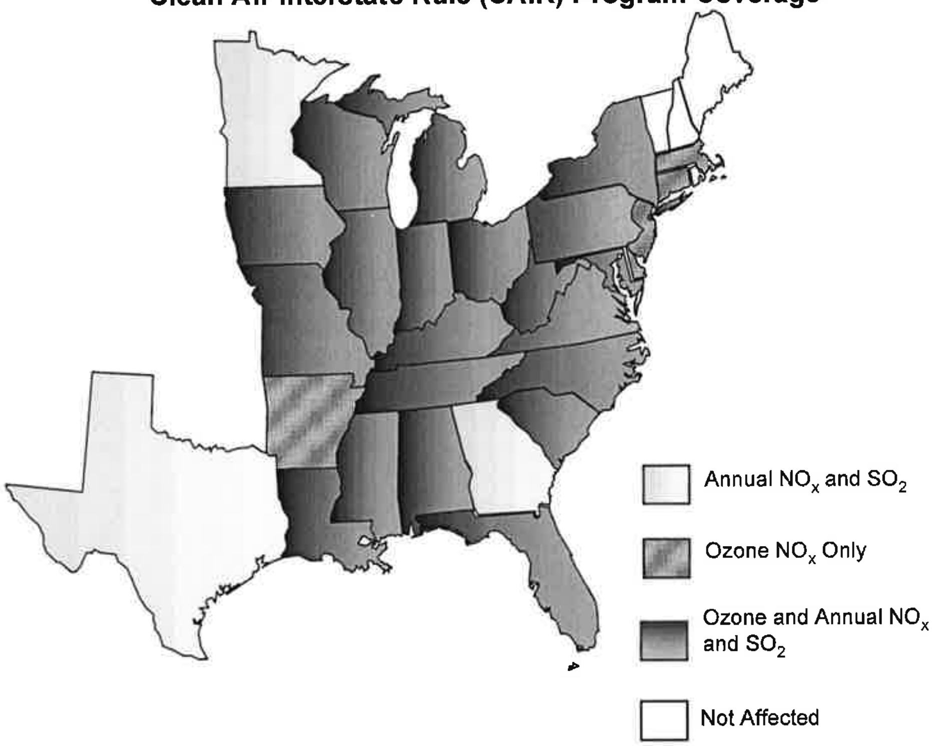
Year	Title IV SO_2 Pre-2010	Title IV SO_2 Post-2010	SIP/CAIR Ozone NO_X	CAIR Annual NO_X	Mercury ($/lb)	CO_2
2011 – 2025 Average	1,500	500	3,000	1,500	30,000	10

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). 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.

Figure 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

Introduction

In this section, we build on prior analyses and findings by various parties related to Gainesville Regional Utilities' (GRU) planned project that are relevant to its public health impacts, compile and analyze new information from the available literature and data bases, and identify and describe the potential public health impacts of the four power options – CFB, IGCC, DSM/biomass, and DSM/power purchase.[35] 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, dose-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 (due to, for example, significant questions about the input data, model completeness, and algorithm formulation) would remain quite large.

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 impacts, such as those related to fuel extraction and processing, as well as possibly those related to manufacture and disposal of products used as part of energy efficiency and conservation activities. A number of these issues with potential to have impacts on public health have been considered in prior studies performed by GRU (2003, 2004a,b), local agencies (ACEPD 2004), citizens groups (EPAC 2005), and others (Numark 2005).

After an initial review of prior studies related to potential health impacts of GRU's planned project and various alternatives, we decided to focus this analysis on airborne

[35] The four power options are described in detail earlier in this report (refer to Chapter 1 for more information).

fine particulate matter (also referred to as $PM_{2.5}$) resulting from power plant stack emissions for the four options. There are three 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 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 (for example, fine particulates have the strongest relationship to mortality impacts, and are the biggest contributor to estimated monetary damages).

- Based on our review of the prior studies related to the GRU planned 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).

- Although mercury is often a major 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 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.

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 active 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 to 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 $PM_{2.5}$. Exposure to $PM_{2.5}$ is associated with a number of serious health effects, including premature death and a number 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 (EPA 2006) and last year's final rulemaking for the Clean Air Interstate Rule (CAIR) (EPA 2005a,b) – and given that a good summary has already been prepared for a prior review of the GRU proposed project (EPAC 2005), we do not summarize $PM_{2.5}$ in detail here. We would, however, highlight a few considerations important 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 compounds that reacted to form it.

- The formation and transport of $PM_{2.5}$ in the atmosphere is exceedingly complex, and depends on both emissions of primary $PM_{2.5}$ and several precursor compounds, the other chemicals present in the air (background air quality), and the meteorology. 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 no concern for health effects in an exposed population).

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 Figure 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." 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 is not primarily a power plant-related issue, is the air pollutant with the least margin between reported air concentrations and applicable standards.

Figure 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 Figure 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 next five to fifteen 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 Figure 6-11, US EPA very recently completed its periodic review of the particulate matter NAAQS and has proposed certain changes to those standards (USEPA 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, even 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 other 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.

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. Figure 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 CO2 regulation, and base biomass price) in year 2015. Activities that are expected to produce some emissions to air, but that were not quantified, are noted in the table.

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 Figure 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 from Deerhaven 2 and other smaller supply units in the county), the total $PM_{2.5}$ precursor emissions are expected to decrease, relative to 2006 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, and then the DSM/biomass option, which is considerably lower (especially 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 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 (and even DSM/power purchase) seems less significant when considered in context of overall GRU emissions, with both options quite a bit lower than the CFB option. Will discuss power purchase results for final report

Figure 6-12
Summary of Key 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	708	641	15	0
	GRU-all other units	6934 (2005)	859	859	865	874
	Other local-Alachua Co	Rail transport	Rail transport, some truck	Rail transport, some truck	Truck transport	--
	Other regional	Rail transport	Rail transport, some truck	Rail transport, some truck	__ [b] (at purchase sites), truck transport	__ [b] (at purchase sites)
NO_x	Deerhaven site-new unit	n/a	515	142	75	0
	GRU-all other units	3989 (2005)	1080	1080	1092	1110
	Other local-Alachua Co	Rail transport, site fugitives	Rail transport, some truck	Rail transport, some truck	Truck transport	--
	Other regional	Rail transport	Rail transport, some truck	Rail transport, some truck	__ [b] (at purchase sites), truck transport	__ [b] (at purchase sites)
Particulate matter (PM)	Deerhaven site-new unit	n/a	117 BVa	Not estimated	Not estimated	Not estimated
	GRU-all other units	237 BVa (2003)	179 BVa	Not estimated	Not estimated	Not estimated
	Other local-Alachua Co	Rail transport, site fugitives	Rail transport, site fugitives, some truck	Rail transport, site fugitives, some truck	Truck transport, site fugitives	--
	Other regional	Rail transport	Rail transport, some truck	Rail transport, some truck	At purchase sites, truck transport	At purchase sites
Mercury	Deerhaven site-new unit	n/a	<0.01	<0.01	0	0
	GRU-all other units	0.07 (2005)	0.06	0.06	0.06	0.06
	Other local-Alachua Co	--	--	--	--	--
	Other regional	--	--	--	__ [b] (at purchase sites)	__ [b] (at purchase sites)

[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 assume 30MW biomass co-firing.[b] Results to be added for final report.

Note that the three options that include at least some 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 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 Figure 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 be similar 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.

Figure 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]	
SO2	8,400	8,100	8,900 (8,400) [d]	740,000 (570,000)	14,000,000 (9,900,000)	1,600
NOx	4,000	16,000	12,000 (4,300)	970,000 (310,000)	16,000,000 (4,000,000)	1,600
PM2.5	<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.

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 2006 GRU emissions in the county, all four options would result in lower total GRU emissions. Will summarize power purchase emissions results for final report

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.

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 2006 levels***, under all four options. Viewed in this context, $PM_{2.5}$ levels are expected to decrease, ***relative to 2006 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 $PM_{2.5}$ 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 these air modeling studies, we have focused this section on potential local health impacts (see next section for discussion of 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 Appendix Figure 6-1 (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.[36] The modeling compared the incremental $PM_{2.5}$ 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).[37]

Selected results from the GRU-sponsored modeling are given in Figure 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 $PM_{2.5}$ concentrations in Alachua County will either decrease slightly or remain about the same in the future (with CFB and Deerhaven 2 retrofit) compared with current concentrations (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).

How do the options compare with respect to local $PM_{2.5}$ concentrations? Focusing on the modeling results for the Deerhaven units only (see Figure 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.[38] 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

[36] 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).

[37] 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.

[38] 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 Appendix Figure 6-1). 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.

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.

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

Emission Scenario	Increment (ug/m^3) [b] – PM2.5 Annual Average		Incremental Increase (ug/m^3) [b] – Highest PM2.5 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.

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 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 baseline GRU units, are expected to be small. The DSM/biomass option likely would have an even lower local impact on $PM_{2.5}$ 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 impacts is less predictable and depends on where emissions are increased as a result of power purchases. It is possible that from a regional perspective, this option may be comparable from a health perspective to the CFB, or conceivably even worse, if substantial power purchases come from relatively high-emitting power plants or from plants in higher-risk locations.

<u>How do the options compare with respect to potential local human health impacts from $PM_{2.5}$ exposures</u>? The available science 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. Thus, there is no "zero-risk" level for $PM_{2.5}$ exposures, and all exposures at least theoretically would pose some finite health risk. US EPA recognizes 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." Under a no-threshold assumption, current ambient levels of $PM_{2.5}$ in Alachua County pose some health risk, as would future ambient levels under all four options.

Given the lack of a health effects threshold, all four options would be expected to have some health impacts related 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 range of the magnitude of potential human health impacts. For this approximation, we used a simplified version of the dose-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.[39]

Results of our estimation of the possible ranges of $PM_{2.5}$-related adult mortality associated with CFB emissions are given in Figure 6-15.[40] Based on the projected emissions (shown in Figure 6-12), we estimate less than 0.19 to 0.5 premature death per year for Alachua County, corresponding to an average annual risk for an individual of less than three in a million. There is large uncertainty associated with these

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[39] 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 quantify morbidity.

[40] As a quality assurance check, we compared our results to results to the $PM_{2.5}$ 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.

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 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 dose-response relationship is most appropriate to use – results in the estimates being too high or too low.

Figure 6-15
Estimated Premature Adult Mortality in Alachua County from PM2.5 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 (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] Dose-response relationships for all-cause adult mortality from both Krewski et al. (2000) and Dockery et al. (1993) were used, which yields the range of results. These relationships are consistent with the range of dose-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 dose-response relationships for $PM_{2.5}$, and therefore all estimated impacts based on these relationships are subject to substantial uncertainty.

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 pattern as discussed above with respect to the impacts on local $PM_{2.5}$ air quality – the IGCC option would likely have similar (slightly lower) health impacts in the county as the CFB option, and the two DSM options would have somewhat lower impacts in the county. 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.

<u>Summary – comparison of potential local health impacts from $PM_{2.5}$ exposures</u>. 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 emissions from the new units (under the three options having new generating units in the county) are lower than the projected future emissions from 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. Impact of regional emissions from power purchases to be added for final report

Illustrative 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, 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 distance away. This is in fact the justification for US EPA's 2005 CAIR regulations, which require states to reduce emissions of SO_2 and NO_x based entirely on the predicted impacts in other downwind states of $PM_{2.5}$ formed in the atmosphere from those pollutants (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 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. In a separate ICF modeling study in 2005 of PM2.5 impacts from two power plants in the Midwest, roughly 80 percent of the predicted health effects and damage costs occurred greater than 200 miles from the source. 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 great 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 spreading out of the $PM_{2.5}$ concentrations with very slow additional decline with distance.

In an attempt to identify the potential bounds of the regional health impacts for the four options under consideration, we have extrapolated based on damage cost estimates in other recent analyses of $PM_{2.5}$ health impacts for different areas. We recognize that these extrapolated estimates have substantial uncertainty, given the situation-specific nature of many of the factors leading to health impacts (e.g., meteorology, population patterns, emission mix, background air quality). Preferably, one would perform site-specific photochemical air modeling with a baseline emission inventory and receptor grid over the Eastern US, then perform probabilistic dose-response and damage cost modeling, but such analyses are time-consuming and expensive, and the results still