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Review of the

Gainesville Regional Utilities' Proposal for a New Coal-Fired Power Plant

Prepared by
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For The
Alachua County Environmental Protection Advisory Committee

Submitted to
Alachua County Board of County Commissioners

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1.0 Introduction

This is a review of Gainesville Regional Utilities' (GRU) plan to build a new coal-fired power plant and retrofit the existing coal-fired generator, Deerhaven Unit 2. The Alachua County Environmental Protection Advisory Committee (EPAC) initiated the review in February 2004[1].

In 2003, GRU requested permission from the Gainesville City Commission to proceed with one of four alternatives to meet increasing community demand for electric energy. Three of these alternatives involved building a very large new generator burning solid fuel (coal and petroleum coke) at GRU's Deerhaven site, which is already the county's largest fixed source of air pollution. Many EPAC and community members expressed concern about potential adverse impacts of added coal-fired generating capacity. The Alachua County Commission authorized a review of the GRU proposal by EPAC in January 2004. Committee members volunteered their time and expertise to conduct this extensive review. Staff of the County Environmental Protection Department assisted the volunteers.

1.1 The GRU Proposal

GRU's current proposal has been elaborated since before EPAC's review began in January 2004, but it remains remarkably similar to the original 2003 proposal with the following basic features.[2]

1. Construct a new circulating fluidized bed (CFB) generator with a net capacity of 220 Megawatts (MW) that can be fired with woodchips or other biomass fuels, but is to be primarily fueled with petroleum coke and high sulfur coal. The capital cost of this system is estimated at $550 million dollars[3], plus interest, with a 2011 startup date (provided design and site approval application were begun by the fall of 2004 or earlier).

2. Retain the existing Deerhaven Unit #2 (a 220-MW coal-fired unit) but retrofit it with emission control equipment to reduce sulfur dioxide, oxides of nitrogen, and particulate matter emissions[4]. The capital cost of this retrofit is currently estimated as $90 million.

3. Use biomass as fuel for about 30 MW of capacity in the CFB unit, if the final design permits.

4. Combine the new generator construction and the existing unit's retrofit into a single project for the purposes of site certification and permitting. One goal is to eliminate the review of the new plant's compliance with some pollution

[1] A brief description the steps leading up to this review, which was completed at the request of the Alachua County Commission, is contained in the Appendix to this Chapter.
[2] Source: the December 2003 report cited above, and "Staff Response to Long Term Electrical Supply Plan Questions, Issues, And Recommendations Made In November 2004 To the Gainesville City Commission" Prepared by Gainesville Regional Utilities, December 2004.
[3] This is total project cost, including the cost of retrofitting Deerhaven Unit #2, but does not include interest on money borrowed to fund the project.
[4] The details of the retrofit are obscure, especially those relating particulate emissions.

regulations normally applied to new pollution sources, including review of $PM_{2.5}$ impacts[5]. This step could reduce the retrofit costs by approximately $14 million.

5. Implement new conservation and demand response programs.

6. Establish a Greenhouse Gas Offset Fund that will expend $7.2 million dollars between 2005 and 2011 to acquire carbon offsets to compensate for carbon dioxide emissions from the new circulating fluidized bed generator, and make its operations "carbon neutral" with respect to the carbon dioxide emissions of a modern natural-gas fired combined cycle generator. GRU expects that these offsets will eliminate greenhouse gas financial penalties from future regulations through the year 2023.

7. Establish monitoring of $PM_{2.5}$ ambient concentrations (details unspecified) in the local area.

1.2 Subjects Covered by EPAC

EPAC's review first considered air pollutants derived from burning coal and petroleum coke, namely:

- Carbon dioxide emissions to the atmosphere, which contribute to global warming,
- Pollutant emissions that give rise to fine particulate matter, which has very serious adverse effects on human health.

Coal was soon revealed as a poor choice because of emissions of carbon dioxide, heavy metals and other pollutants. But unless there are reasonable alternatives to a new solid fuel plant, it is pointless to object on these grounds alone. Therefore the scope of the review expanded to include additional, closely related questions:

- Could we reduce electricity demand in our service area with more aggressive conservation and energy efficiency programs? If so, what are the barriers to implementing such programs?
- Could GRU use more biomass or other renewable energy sources to reduce pollution and reduce greenhouse gas emissions substantially?
- Has GRU fully explored the health effects of added air pollution its plan entails?
- Could mandatory reductions of greenhouse gas releases impact GRU's plans?
- What strategies are available to protect the community in the face of our rapidly changing energy future?

This first chapter discusses some of the more important findings of the EPAC review. Some of the topics discussed in this summary are crosscutting issues that appear in several of the chapters. This chapter integrates many of these materials.

[5] These are the rules for Prevention of Significant Deterioration (PSD) to existing air quality for sulfur dioxide, oxides of nitrogen, and particulate matter. Sulfur dioxide and oxides of nitrogen emission reductions achieved by the Deerhaven retrofit might balance the added sulfur dioxide and nitrogen oxides emissions from the new plant. PSD requirements for particulate matter could also be avoided in this manner, provided appropriate controls are included in the retrofit, but EPA has not announced details of PSD requirements for $PM_{2.5}$.

1.3 Major Findings

1.3.1 Avoidable Barriers to Conservation and Energy Efficiency Programs (Chapters 3 and 6)

Many studies have shown that "...the cheapest, easiest and fastest kilowatt we generate is the one we can save through efficiencies"[6]. Very large energy savings can be achieved by investing in energy efficiency and other conservation programs. Studies of states or regions have show that aggressive conservation and energy efficiency programs could yield energy savings far beyond what has yet been achieved in any program, including Florida.

The community requested that the GRU electric utility use more energy conservation measures to meet future increased demands. Conservation plays a role in GRU's proposals, but only a small role. GRU now has more than enough capacity to meet current needs, and realizes no economic benefits from implementing conservation under these circumstances. GRU will add about 7 MW in demand reduction over the next 10 years, 4 MW of which represents planned new programs. These programs will reduce the growth of demand in the local area by about 6.5% by the year 2014, compared to what it would have been with no conservation. Compared to other utilities, this is a small reduction. Austin Energy expects to reduce future demand increases by more than 20 % over the same interval while California utilities will reduce them by 55% to 59% (Chapter 6). **Figure 1.1** shows GRU's planned reductions and compares them to expected reductions by other utilities.

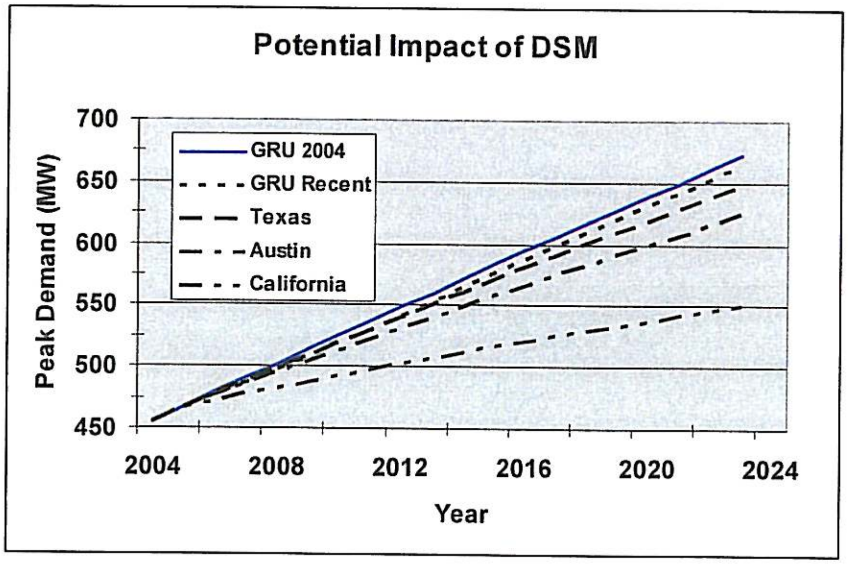

Figure 1.1 Peak demand increases over the next 10 years as originally forecast by GRU include some DSM (top line). GRU's planned DSM programs will achieve a total 6.5% reduction in demand growth ("GRU Recent"). Reductions GRU would achieve if it matched Texas, Austin Energy, or California targets are shown in this figure.

EPAC discovered significant barriers common to the electric utility industry that prevent optimum use of conservation techniques by many investor-owned utilities. Two of them are found in Gainesville. These barriers are self-imposed, and avoidable. The first is a

[6] Governor Jeb Bush 2001 "Powering the Future Energy Conference" cited by C. J. Barice in "Florida Energywise! A Strategy for Florida's Energy Future" The Final Report of the Florida Energy 2020 Study Commission, December 2001.

consequence the method chosen for calculating the annual transfer of money from the utility to the city. The second is a cost-effectiveness test chosen by GRU to evaluate specific conservation programs.

Fund Transfer Barriers

Conservation and energy efficiency programs are rarely greeted with enthusiasm by utility managers or owners, or even by city governments that own utilities. Why? The ability to obtain a profit (return on investment) and to collect enough revenue to cover fixed costs is tied to the volume of electricity sales for investor-owned utilities. This happens during the rate-setting process used by most utility commissions[7].

The Florida Public Service Commission does not regulate the City's method for calculating the amount of net GRU revenue transferred annually to the City. The City is free to choose any method to calculate the annual fund transfer. The City now uses a method similar to the one imposed on investor-owned utilities. The transfer amount is based on the volume of electricity sales, and it increases substantially if electric energy sales increase. The City loses income if sales volume drops. The formula also contains provisions for a bonus to the City if the utility generates extra electricity and sells it to other utilities.

This method of calculating City income produces a very strong incentive for GRU to generate and sell more energy, and an equally strong disincentive to adopt serious conservation and energy efficiency programs that could materially reduce the volume of electricity sales. This disincentive can give conservation and energy efficiency improvements a very low priority and lead to modest, poorly funded programs.

Gainesville could easily remove this disincentive by substituting a system that insulates the City transfer from sales volume decreases. Under such a system, the City decides in advance how much money will be transferred to its general fund each year. This amount remains fixed for the year. It is neither decreased nor increased in response to changes in the volume of sales that occur during the year. Such a system should also insure that the utility recovers its fixed costs, by establishing them in advance, and by insulating fixed costs collection from sales volume variations. This approach has been used elsewhere and is termed "revenue decoupling". The disincentive problem and its solutions are discussed in Chapter 7. The Austin, Texas, City Commission has achieved the same result simply by establishing a policy that conservation must be the first priority in meeting increased needs for energy.

RIM Test Barrier

The City has approved GRU's use of the "Rate Impact Measure" test (RIM test) to evaluate cost-effectiveness of proposed conservation or energy efficiency measures. This test says that no conservation or energy efficiency program that causes rates to be raised may be adopted by the utility. Every conservation program must pay for itself[8].

When applied exclusively, as in Gainesville, the RIM test forces a utility to reject conservation and energy efficiency investments that cost less than generation alternatives. In other words, the RIM text rejects DSM investments that reduce user needs for electricity more cheaply than

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[7] The problem derives from the fact that new rates are set only once every 5 or six years. See Chapter 6 and Bachrach, D., S. Carter and S. Jaffe, "Do Portfolio Managers Have An *Inherent* Conflict of Interest with Energy Efficiency?" *The Electricity Journal,* Volume 17, Issue 8, October 2004, pp. 52-62.
[8] Applying such a test to new generators would disallow new generators because they raise rates by large amounts.

an additional generator could supply electricity to meet those needs. As a result, least cost DSM is screened out and energy bills are unnecessarily high.

Conservation programs require investments that could raise the rates for all customers, but they will raise them less than buying a new generator. If utility planners confine themselves only to conservation programs that pass a RIM test, they will end up choosing to build generators. This profound "pro-generator" bias of the RIM test restricts the planning process from the beginning by excluding conservation investments out of hand, forcing higher electricity costs on consumers.

Gainesville is free to invest money in any conservation and energy efficiency improvements it chooses. These can be included, along with new generators, in plans to serve increasing local needs[9]. No state law requires the City to adopt the RIM test with its strong pro-generator bias. Nothing requires the City to adopt the RIM test for any purpose. Nothing prevents us from choosing the least cost DSM option even if it raises rates for all ratepayers, just as we now chose the least cost new generator option though that involves raising rates for all ratepayers (rather than just those ratepayers responsible for the need for additional energy service). Investing in all the DSM that costs less than generation would help lower bills for low-income households. Other states do not rely so heavily on the RIM test.

<u>Other RIM Test Problems</u>

GRU does not actively seek new conservation or energy efficiency programs as part of its ongoing strategic planning efforts. These programs are reviewed and selected only when GRU is considering a new generator purchase, which it last did in 1994. All conservation programs now in effect were evaluated in 1994, and were compared with the generator then under consideration.

GRU could make conservation program selection and implementation an ongoing process. We could subject these programs to any cost-effectiveness test that we choose. We could also use a large suite of cost-effectiveness tests to illuminate different features of conservation programs. We could include costs or benefits like pollution reduction, economic benefits for local businesses, landfill costs (that could be avoided if wood is used as generator fuel), or any factors of interest to our community. None of these important considerations are captured by the RIM test.

1.3.2 Health Impacts of Pollution (Chapter 2)

EPAC reviewed the potential health effects of air pollution from GRU's existing and proposed generators. 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). These particles are collectively called $PM_{2.5}$ (particulate matter less than 2.5 microns in diameter). They are well known to cause heart attacks, asthma attacks, episodes of difficult breathing among residents with emphysema or other chronic respiratory problems. Increased death rates from respiratory and cardiovascular disease, increased hospitalizations, and increased or more intense symptoms of respiratory or cardiovascular distress have all been associated with short-term

[9] GRU is not regulated under Florida Energy and Efficiency Conservation Act (FEECA) and therefore the Florida Public Service Commission places no demands on GRU as to how it evaluates conservation. FEECA requires *large* utilities to submit conservation programs for PSC approval. The commission as a matter of policy often uses a RIM test to review these programs.

exposures to elevated $PM_{2.5}$ well below the concentrations allowed by existing ambient air quality standards. Children, the elderly, asthmatics and those with other pre-existing diseases such as diabetes are more vulnerable to fine particulate pollution than other segments of the population.

Evidence about the health effects of fine particulates has prompted action among regulators. Reductions in the US 24-hour standard (65 µg/m3) and the US annual standard (15 µg/m3) are now under consideration. It is possible that a 4- to 8-hour standard could be added. California has already reduced its state annual standard to 12 µg/m3 and Canada began in 2000 to reduce its 24-hour standard to 30 µg/m3. All of this has occurred because of the serious health effects caused by $PM_{2.5}$.

Increasing scientific evidence shows that exposure to high concentrations of $PM_{2.5}$ can be very hazardous; and that in some locations, only short time exposures have adverse impacts on vulnerable individuals. This prompted EPAC to request that GRU use its modeling programs to explore the short-duration $PM_{2.5}$ air pollution concentration impacts of its generators. Separate model runs are needed for retrofitted Deerhaven Unit #2 and the proposed new generator to identify the $PM_{2.5}$ additions from each generator alone, and to evaluate air pollution impacts if no CFB generator is added. EPAC also requested separate model runs to evaluate fine particulate impacts from secondary particulate created by each solid-fuel generator.

1.3.3 Meeting the Challenge of Climate Change (Chapter 3)

Earth's climate is changing rapidly. There is little doubt among qualified scientists that Earth is getting warmer and the cause of the warming is the past and current releases of carbon dioxide into the atmosphere from burning fossil fuels. Average global temperatures increased steadily over the 20th century (**Figure 1.2**)[10]. It now appears possible that human societies may be unable to reduce heat-trapping greenhouse gas releases fast enough to keep the temperature rise from exceeding a total of 2 degrees C (3.6 degrees F) relative to pre-industrial times. The global warming to date has had very serious adverse impacts. Warming totaling the anticipated 2 degrees C is expected to result in widespread damage to Earth's ecosystems and the ability of human cultures to survive[11].

There is very strong pressure for mandatory caps on utility greenhouse gas emissions in the United States, and recent action in the U. S. Senate indicates that the outlines of a program to cap and ultimately reduce emissions of carbon dioxide and methane will be debated in 2006. Public opinion has shifted and polls indicate that the majority of Americans are concerned about global warming, and recognize the need for controls on greenhouse gas emissions.

While the federal government has yet to take decisive steps, states are leading the effort to reduce greenhouse gas emissions. Nineteen states are implementing or planning large investments in energy efficiency and renewable energy resources. Some have imposed emission caps on electric utilities, or are planning to impose them. Adoption of a national program to regulate greenhouse gas emissions in the United States is inevitable. It is impossible to predict when the regulatory programs will affect Florida, or exactly how they will regulate emissions. The electric utility industry will be among the first industries affected.

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[10] During the peak of the last ice age, the average global temperature was only 5 degrees C less than the average global temperature in the 1950's. Between 1900 and 2000, the global average rose by 0.7 degrees C, much of it since the 1970's (Figure 1). The ten hottest years on record have occurred since 1990, three of them since 2000. An additional rise of 0.7 degrees C is already in the pipeline, due to past fossil carbon dioxide emissions.
[11] These are discussed in Chapter 3.

GRU's plan does not meet the impending challenges of our changing energy future. Moreover, GRU has not conducted a systematic analysis of the risks new regulations limiting fossil carbon dioxide emissions could bring to the utility and its customers, or evaluated alternative combinations of generators and conservation options in the context of those risks.

The following are among our most relevant findings:

- Coal is the fossil fuel that will be penalized most under greenhouse gas regulations, but GRU has no plans to address coming restrictions on releasing fossil carbon dioxide now obvious in the emerging regulatory framework[12].
- GRU does not plan to implement the aggressive conservation, efficiency, and demand management programs required to reduce greenhouse gas emissions[13].
- GRU's proposed carbon "offset" plan will not protect the utility from mandatory decreases in greenhouse gas emissions when regulations are imposed. None of the claimed GRU "offsets" conform to any existing or emerging offset requirements. The GRU approach is not designed to make real or substantial reductions in greenhouse gas emissions. GRU has not explored a more realistic option to certify and protect GRU's baseline against which future emissions reductions will be evaluated (See Chapter 3 Global Warming and Strategies to Meet It, and Chapter 4, Carbon Intensity, Offsets, and the Greenhouse Gas Fund).

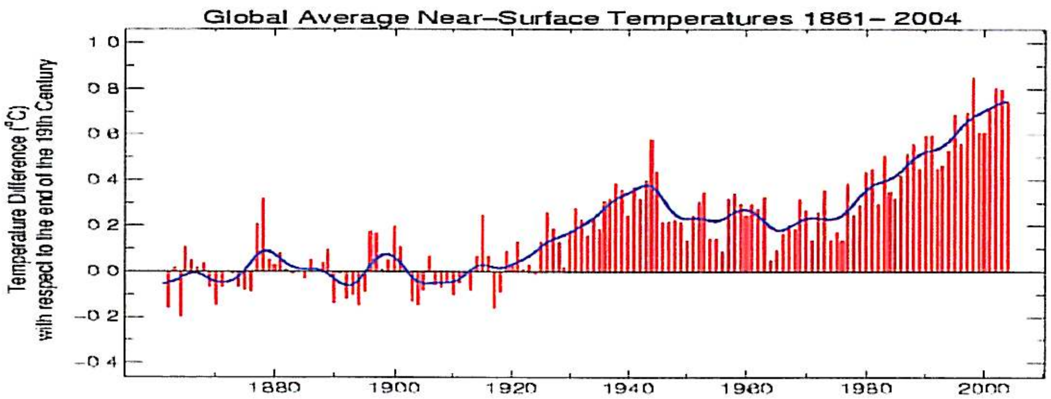


Figure 1.2. Average global temperatures are plotted here relative to the temperature in 1900, which was approximately 13.7 degrees C, and only 4.6 degrees C higher than during the peak of the last ice age.

Chapter 4 of this report discusses GRU's proposals to meet future greenhouse gas regulations. GRU plans to use coal and petroleum coke to produce over 90% of the electricity consumed in the local area. If implemented, these proposals will greatly increase GRU's fossil carbon

[12] Pressure to act to reduce and ultimately reverse the current annual increases in greenhouse gas emissions are building in the US. Mandatory carbon dioxide emission reductions from electric utilities are virtually certain. They are likely to take the form of cap-and-trade systems that allocate a utility's right to emit carbon dioxide and allow trading of these rights on a spot market.

[13] Other likely programs include subsidies for renewable energy sources, energy efficiency improvements and other measures to reduce electricity use.

dioxide emissions. GRU plans to protect itself from financial penalties under future regulation partly by relying on "offsets" for a total of 255,000 tons of carbon dioxide per year[14].

A greenhouse gas "offset" is an action that reduces emissions of greenhouse gases, or removes carbon dioxide from the atmosphere. For example, GRU counts growing pulpwood on City-owned land as an offset because the trees remove carbon dioxide from the air and convert it to plant tissue. GRU also counts past conservation activities by ratepayers and the repowering of the Kelly combined cycle plant as offsets. Carbon emission credits against carbon dioxide emissions from power plants exist only in the context of legally enforceable greenhouse gas regulations. An offset becomes an emission credit only after it has been certified as satisfying the eligibility rules incorporated in those regulations. EPAC found that none of the offsets now claimed by GRU would be acceptable under most of the regulations now under development.

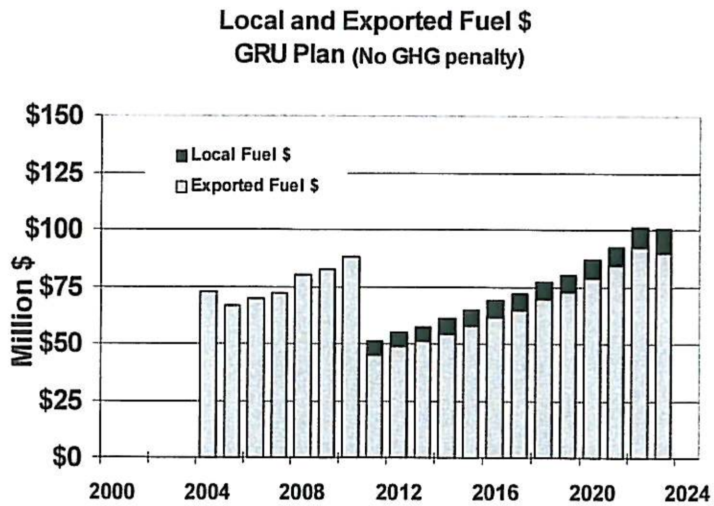
GRU's plans for a Greenhouse Gas Offset Fund have not been specified in detail, but some problems are already apparent. Compliance regulations being developed now incorporate a number of restrictions not met by the proposed GRU offsets. One is that all activities eligible for credits must be undertaken solely to supply greenhouse gas credits. Ongoing dual-purpose activities will be unacceptable, because they would occur without greenhouse gas regulations. This rules out silviculture, land development regulations, tree growth in conservation areas and many other local activities as candidates for offset carbon credits. EPAC concluded that the proposed offset strategy would not protect GRU from financial penalties when greenhouse emission reduction regulations are enacted.

1.3.4 Incorporating Biomass in GRU's Future (Chapter 8)

GRU proposes to use biomass to co-fire the new generator, but only for about 7.5% of fuel needed for the local electricity market[15]. Biomass is locally abundant and currently is our only locally available renewable fuel. Biomass produces no fossil carbon dioxide emissions[16]. Increasing biomass use in a small generator instead of building the large new coal generator could reduce GRU's total greenhouse gas emissions, thereby protecting the utility from greenhouse gas penalties under future regulations. The US DOE is currently supporting technologies for using wood and other renewable fuels. DOE might provide up to half of the capital cost for a state-of-the-art biomass generator, were the community to decide to build one, as an interim solution to the need for new capacity. This potential economic benefit was not considered in GRU planning.

EPAC explored the potential benefits of substituting a hypothetical 100-MW biomass generator[17] in place of the proposed 220-MW generator. EPAC's purpose was to illustrate the multiple benefits of greater biomass use. A new 100-MW unit and the existing GRU generating units would be able to meet the total energy consumption forecast by GRU through

[14] GRU claims offset credit for repowering a generator to make it more efficient, conservation by ratepayers, the use of landfill gas to fuel electricity generation, (inaccurately described as preventing the release of the heat-trapping gas methane) and the present of use of city land to grow pulpwood.
[15] Up to 13.7% of the fuel heat input to the proposed new circulating fluidized boiler could be derived from woody biomass, depending on the details of the design chosen by GRU.
[16] Biomass combustion produces small amounts of another greenhouse gas (nitrous oxide).
[17] EPAC did not model the hypothetical biomass generator on any existing design. It is used purely to illustrate potential advantages of biomass generation and to indicate whether the option deserves more detailed engineering and financial consideration.



approximately 2019. However, this does not mean that a 100-MW capacity addition will meet state requirements for reserve capacity[18].

Figure 1.3 - Fate of Fuel Dollars Under CFB Plan: ***Money exported out of state to pay for fossil fuel compared to that retained locally. The plotted data do not include a renewable fuel subsidy that could reduce fuel costs by about $3 million dollars.***

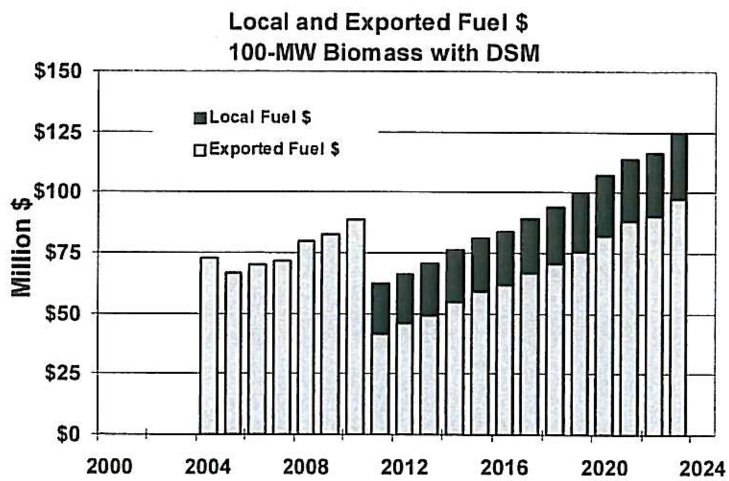


Figure 1.4 – Fate of Fuel Dollars under Biomass Plan: Money exported out of state to pay for fossil fuels compared with that retained in the local economy if GRU substitutes 100 MW of biomass to fuel electric energy generation for the proposed 220-MW CFB unit. The plotted data do not include a renewable fuel subsidy of 1.5 cents per kWh, which could reduce fuel costs by about $10 million per year.

Whether 100 MW of additional biomass-based capacity could meet needs would depend on peak energy demand reductions achieved through conservation or improved energy efficiency. Using biomass for 24% to 30% of local energy needs could deliver significant health benefits, benefits to the local economy, and function as a hedge against future greenhouse gas regulations. EPAC's analysis indicates that biomass fuel could cost slightly more than a solid fuel system if there are no limits on fossil carbon dioxide emissions, but would save money

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[18] There are differences between "energy", "capacity", and "demand". *Energy* arrives through your electric meter; it is measured in kilowatt hours (kWh) or megawatt hours (MWh). *Capacity* is the maximum amount of electricity a generator or a collection of generators is capable of producing to supply a system; it is measured in megawatts (MW). *Demand* is the amount of electricity currently needed in a power system (like GRU and its service area) at any instant in time; also expressed in MW. The local GRU system's demand is higher in summer (because of many AC units) and lower in winter (because many heat with natural gas). The relationship between demand and energy is similar to the relationship between the speed a car may be moving (demand) and the number of miles it clocks up on the odometer (energy).

when greenhouse gas regulations are implemented. This benefit was not considered in GRU analyses.

1.3.5 Natural Gas Alternatives to the Solid Fuel Plan (Chapter 5)

GRU presented a cost comparison of its solid fuel plan with two hypothetical alternatives based entirely on natural gas in December 2004. Because natural gas is extremely expensive, neither of these was offered as a serious alternative to the plan GRU has proposed. GRU used a model to simulate the use of two alternative systems that use natural gas to supply anticipated increases in local energy needs.

EPAC found that these two new "alternatives" are virtually identical to the solid-fuel plan in all important respects, except that they used expensive natural gas to meet future needs, instead of cheap coal and petroleum coke. The simulations therefore confirmed that the solid fuel system is cheaper than the alternatives simulated, but this is due exclusively to large differences in coal and gas costs, a difference that GRU projected far into the future.

GRU conducted sensitivity analyses to see whether the high costs of fossil fuel carbon dioxide emissions under a hypothetical GHG regulation could change the conclusion that the solid fuel system is cheaper than systems using natural gas. This sensitivity analysis is not a risk analysis. GRU did not compare its plant to practicable alternatives such as aggressive conservation, use of biomass fuel, and a cautious incremental approach to adding capacity. The GRU evaluation methodology is not amendable to comparisons with genuinely different approaches to meeting community electricity needs.

1.3.6 Off-System Sales (Chapter 7)

GRU's proposal includes significant excess energy capacity through 2023. GRU plans to use this excess capacity to generate electricity for export to other utilities in the state. Although the ability to generate and sell excess energy is described as key to the financial success of the proposal, GRU has not disclosed details of this part of its plan to the community. Critical details needed to evaluate the impact of off-system sallies include the amount of energy that will be generated for export, the amount of money GRU would earn from these sales, or the local environmental impact of excess power generation. Consequently, EPAC evaluated the opportunities to generate excess electricity if the two solid-fuel plants were operating, and reviewed the air impacts and effects this might have.

Generating electricity for off-system sales will certainly increase local air pollution. The capacity of the two solid-fuel units (Deerhaven 2 and the new generator) is so large that local needs will not consume their entire production except during a few hours each year for the first 4 or 5 years of operation. For example, GRU projections suggest that in 2015, the base units will supply about 98% of all the locally energy consumed (**Figure 1.5**). We assume that the two units will operate full time most of the year to produce energy for off system sales as well as local needs. **Figure 1.6** shows the increase in pollution that will result if GRU uses all spare capacity to generate energy for this purpose. (The pollution due to generating electricity for off-system sale was not considered in the models GRU used to evaluate pollution impacts discussed in Chapter 2 of this report.) **Figure 1.6** shows the extra sulfur dioxide and nitrogen oxide pollution that is caused by excess energy generation in the year 2015. The total amounts produced in each hour of the day are based on assumptions about the daily load supplied by GRU.

Will GRU continue to have a ready market for all the excess electric energy it can produce through and beyond 2023? If so, then GRU might be able to sell large amounts of coal-based excess energy and reap significant increases in net revenue from the sales. EPAC estimates that over the 13-year interval modeled by the EGEAS program, these two units could bring in a total of between $260 and $345 million dollars in net revenue[19], which would be around half of the service on the debt assumed to retrofit Deerhaven Unit #2 and build the new CFB generator. These figures assume that trends apparent in 2003 are projected through 2023, and that there will be a continuing need for cheap, coal-based energy. Such projections are based on the assumption that neither the federal government nor the state will regulate greenhouse gas emissions, or take any steps to reduce energy use in the state in order to reduce those emissions. Given that large reductions in state energy use that are achievable through a vigorous mandatory energy conservation program, the assumptions underlying the plan to sell excess energy must be questioned[20].

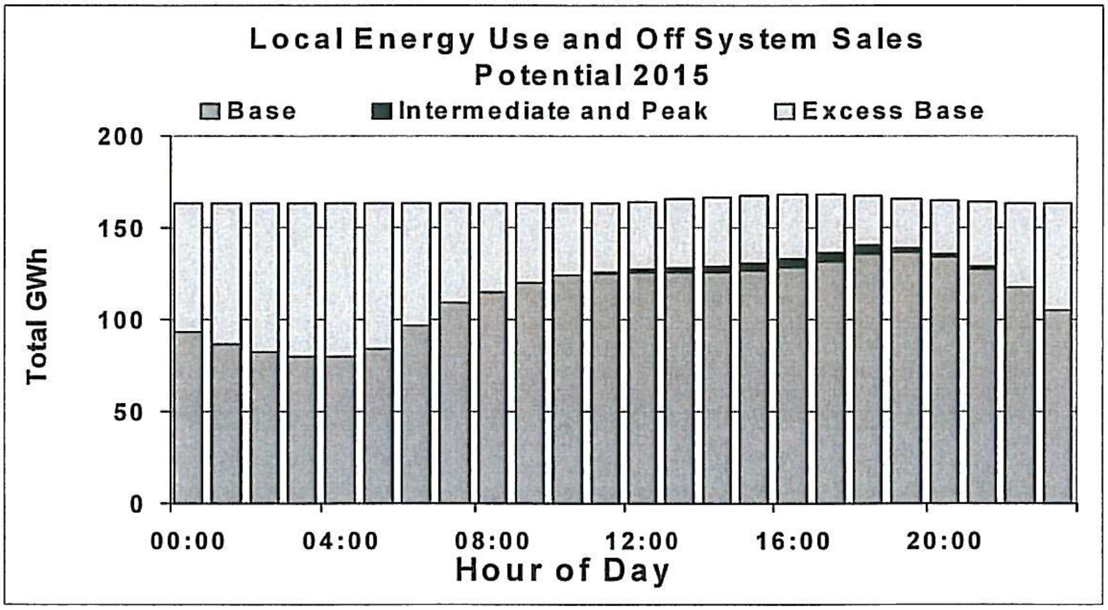

Figure 1.5 Energy from base units and other units needed to supply consumption in the local area and the total base capacity available. Each bar corresponds to the total GWh sold at that hour throughout the entire year. All but 2% of total local energy needs could be supplied by the two base units, leaving 1,000 GWh left over for off-system sales.

[19] Assumes an 85% average capacity factor, and $15 to $20 net revenue per MWh of energy sold. More income would be generated if GRU also rented capacity to other utilities via a purchase power agreement, as they currently do with the City of Starke.
[20] See Chapter 5, Off-System Sales, Chapter 2 on "Pollution and Health Impacts", Chapter 3, "The Global Climate Crisis and Strategies to Meet It", and Chapter 5, "Off System Sales".

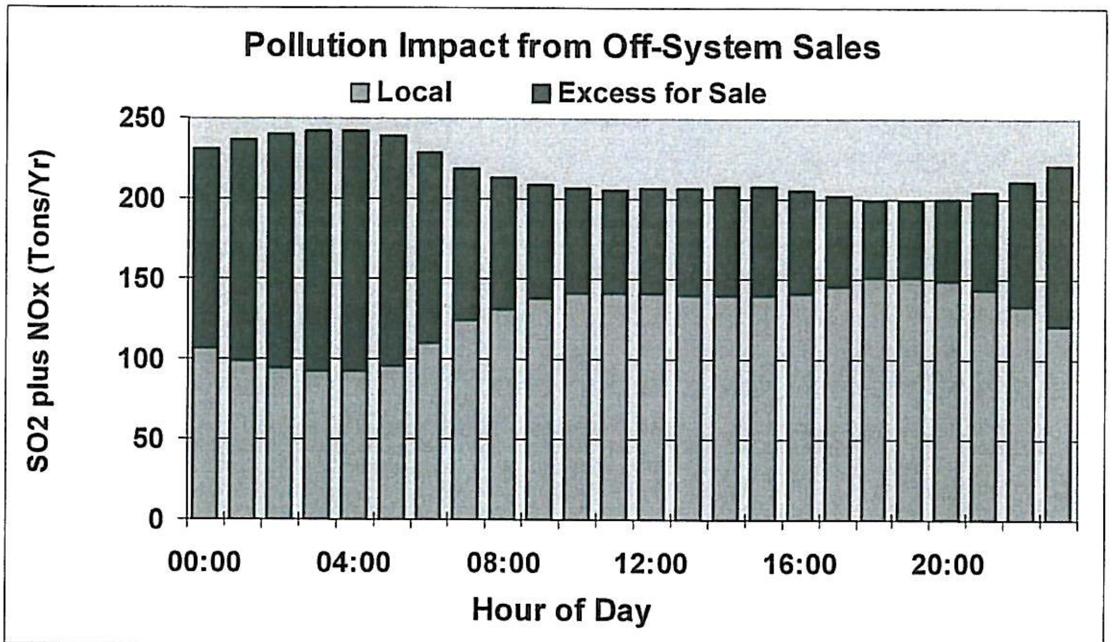

Figure 1.6 Pollutant emissions expected in 2015. Pollution emissions expected if the two solid-fuel units supply local energy needs (lower part of each bar) and generate electricity for export to other utilities (top part of each bar). Sulfur dioxide and oxides of nitrogen contribute to fine particulate pollution. This plot assumes all spare capacity is devoted to generating electricity for off-system sales. It does not show the times when the base units are off line for scheduled maintenance.

1.4 Policy Issues: What is the proper role of a municipally-owned electric utility?

Municipal utilities in Florida are free to operate differently from more closely regulated investor-owned utilities. EPAC's attempts to understand the constraints that guided GRU strategists in developing their proposal confirmed that GRU has adopted some policies similar to those of investor-owned utilities that are regulated by a state utility commission. This finding raised important policy questions:

- Should GRU use the planning methods, goals, and approaches of an investor-owned utility that merely happens to belong to a city government?
- Alternatively, could GRU's planning process include broader goals and important responsibilities to its wider community of owners?

How has GRU's approach resembled that of an investor-owned utility and what differences does this approach make? The differences in these two approaches are illustrated by the different ways EPAC and GRU approached questions about the air pollution produced by its generators. GRU focused on satisfying air quality standards, and used models to study how its plants would add pollutants to local air. The study reports were oriented toward persuading the community that its proposed new systems would meet existing ambient air quality standards.

EPAC focused on the potential effects of air pollution on community health, and confirmed that existing air quality standards for fine particulate matter are widely known to be inadequate to protect public health. EPAC also found that the new plant could have significant adverse health impacts if it adds large amounts of fine particulate matter to ground level air, even if those additions last only for a short time—a few hours or less.

EPAC requested that GRU use its models to provide more details about short-term impacts on local air, and individually explore impacts of the fine particulate air pollution of each of its proposals: retrofitting the existing plant, and building a new one. EPAC also requested that new modeling include corrections to some emission rate underestimates GRU's consultants used in their models, but these were not performed. GRU did authorize using the models to produce estimates of the very short term impacts of power plant emissions on local levels of fine particulate matter. These proved very helpful.

Other policy questions turned up in a number of EPAC's inquiries, but these are not discussed as such in most of the following chapters. Two exceptions are Chapter 5 on Alternative Systems, and Chapter 6 on Conservation and Energy Efficiency. Chapter 5 discusses policy aspects of evaluating alternatives, and Chapter 6 discusses the policy implications of the roles of GRU and the City Commission in selecting conservation and energy efficiency measures.

1.5 Final Comments

The energy industry is presently undergoing enormous change, and more dramatic changes are yet to come. In the words of Juan Garza, General Manager of Austin Electric[21]:

"*Today the electric utility industry is being rocked by change, the magnitude and swiftness of which the industry has not witnessed since its birth. This change will completely redefine the electric industry over the course of the next two decades. I believe that utilities that prepare for this change will be part of a new and dynamic energy future. I also believe that those utilities that cling solely to the past, will find themselves rendered obsolete and irrelevant by this change. It is my intention for Austin Energy to be a part of the new energy future and to play an important and significant role in defining it.*"

EPAC's review of GRU's proposals has found many areas where GRU's approach fails to respond to new challenges, and appears to embrace the old "burn to earn" model of an electric utility in the community. Greater responsiveness to the changes in the energy environment is possible, and could be usefully explored.

[21] "Austin Energy's Strategic Plan", December 2003. Available for download at: http://www.austinenergy.com/About%20Us/Newsroom/Reports/strategicPlan.pdf

Chapter 1, Appendix 1: History of the EPAC Review

In September 2003 Gainesville Regional Utilities (GRU), a municipal utility owned by the City of Gainesville Florida, began a series of public meetings to present information about the increasing demand for electric energy in its native service area[22]. In these meetings, the utility offered four alternative approaches to satisfying this demand for the interval 2003 through 2022. A document describing these alternatives and the planning process[23] used to select them was presented to the Gainesville City Commission on December 15. After several meetings and discussions with commissioners, GRU refined the options, eliminated three of them, and submitted a new plan to the City Commission featuring only one of the original four in February 2004[24].

Gainesville and the urbanized area surrounding it contain most of the population of Alachua County. The Alachua County Environmental Protection Advisory Committee (EPAC) is a committee of citizens appointed by the Alachua County Commission to advise them about environmental issues.

GRU's Deerhaven Unit #2 is Alachua County's largest point source of atmospheric pollution. It is fueled by coal combustion. The idea of adding a second coal-fired plant to the GRU fleet was greeted with caution by many EPAC members, so they voted to request the County Commission to authorize them to undertake a systematic review of the potential environmental impacts of the new plant and other features of the Integrated Resource Plan under development by GRU. This request was approved, and the review began formally in January 2004.

The review documented in these pages has been conducted by members of EPAC and an extremely knowledgeable and helpful volunteer, Dr. David Harlos, who has considerable expertise in environmental health and air pollution.

EPAC members have reviewed the documents provided to the public by GRU, as well as many additional GRU documents, reports, and similar publications. GRU staff has frequently met with EPAC members, and shown great patience and courtesy in dealing with the many requests members made while conducting the reviewing. EPAC members were helped by many local experts who shared their views, research papers, and other materials with us.

Members also reviewed the public press and, articles from the professional literature on health, climate change, and utility regulation, planning and economics. Government reports and the publications of a number of groups that conduct research on the electric utility industry were an important source of information. The reports available from the web sites of the Energy Foundation, the California Public Utilities Commission, the California Energy Commission, the Regional Greenhouse Gas Initiative, the Electric Power Research Institute, and the American Council for an Energy Efficient Economy were especially helpful, as were those from a number of consulting firms that do research for these organizations, and for State Public Interest Groups, utility regulators, and municipal or investor owned utilities.

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[22] Gainesville is in Alachua County, Florida. The native service area of Gainesville Regional Utilities includes retail customers in the City of Gainesville, Florida, plus retail customers in the urban fringe surrounding the city. In addition, GRU supplies wholesale electricity to the City of Alachua and Clay Electric Cooperative for resale to customers, most of whom are also residents of Alachua County.

[23] "Alternatives for Meeting Gainesville's Electrical Needs Through 2022: Base Studies and Preliminary Findings", Gainesville Regional Utilities, December 2003.

[24] "Meeting Electrical Needs Through 2022: Alternatives Update and Modification, Gainesville Regional Utilities Presentation to the City Commission, February 9, 2004.

Chapter 2. Pollution and Health Effects

2.0 Introduction

GRU's Deerhaven generating station is the county's largest stationary air pollution source. GRU power stations emit sulfur dioxide, nitrogen oxides, and fine particles (fine particulate matter) to the air. Fine particles are associated with a wide range of serious health impacts. Consequently, EPAC has focused most of its attention on fine particle pollution.

GRU's plan to use more coal and petroleum coke concerns many local residents and members of EPAC. Although the U. S. Environmental Protection Agency (EPA) has air quality standards for fine particles, prominent health professionals working with EPA on these problems recognize that the existing standards do not protect public health[1].

EPAC reviewed GRU's modeling studies of local air pollution impacts of its current operations; impacts from its proposed additions; data from local air monitors in the county and the state; and the extensive scientific literature about particulate matter and its health effects. EPAC's goal was to understand *potential public health impacts* of current and future operations at Deerhaven, and the limitations of current standards. Studies confirm that these standards fail to protect the most vulnerable populations from a variety of cardiovascular and respiratory problems, including premature death from heart attacks or stroke; episodes of acute bronchitis; asthma attacks; and breathing problems in individuals with pre-existing respiratory disease. Current fine particulate standards are under review and new standards will be promulgated soon.

In contrast to EPAC'S public health orientation, GRU focused only on whether its operations are likely to satisfy the *permitting requirements for a site certification application*. EPAC explored two further questions:

1. What health impacts come from fine particulate matter, especially short-term exposures?
2. Could GRU's current air pollutant emissions adversely affect health, and what health effects are likely if GRU's implements its current plans?

2.1 Key Findings

1. **The existing national air pollution standards for $PM_{2.5}$ do not protect public health[2].**
2. **Very fine particles, 2.5 microns or less in diameter ($PM_{2.5}$) in ambient air are a serious health hazard.** Many studies confirm that fine particulate matter is responsible for most of the adverse health impacts associated with

[1] American Heart Association (AHA) Scientific Statement: *"Air Pollution and Cardiovascular Disease: A Statement for Healthcare Professionals From the Expert Panel on Population and Prevention Science of the American Heart Association"* This statement was approved by the American Heart Association Science Advisory and Coordinating Committee on April 5, 2004. The committee consists of Robert D. Brook, MD; Barry Franklin, PhD, Chair; Wayne Cascio, MD; Yuling Hong, MD, PhD; George Howard, PhD; Michael Lipsett, MD; Russell Luepker, MD; Murray Mittleman, MD, ScD; Jonathan Samet, MD; Sidney C. Smith, Jr., MD; Ira Tager, MD (*Circulation* 2004 109:2655-2671) DOI: 10.1161/01.CIR.0000128587.30041.C8.
[2] *ibid.*

acute air pollution[3,4,5,6], especially among children diabetics[7] and the elderly[8]."

3. **There appears to be no threshold concentration of $PM_{2.5}$ below which adverse health impacts are absent. Consequently, increased particulate exposure increases the probability of illness among county residents, while particulate decreases are likely to produce health benefits.**

4. **At least 30% of county residents are likely to be especially susceptible to adverse health effects associated with fine particulate matter.** These include all children under 15 and all elderly residents over 65, as well as many who suffer from heart disease, asthma, diabetes, chronic bronchitis or exhibit risk factors for cardiopulmonary disease.

5. **Comparisons of the fine particle concentrations measured in local monitors and published data on adverse health impacts indicate that levels commonly observed in Alachua County may be hazardous to susceptible local residents, even though they meet existing Federal and State standards.**

6. **If GRU's plan is implemented, the Florida Dept. of Environmental Protection will require no $PM_{2.5}$ review for the new plant compliance with air quality standards; therefore, the only information about new air pollution impacts will be that *already* provided by GRU (which EPAC finds inadequate from a health perspective).**

7. **Studies of GRU's local contributions of fine particles to local air by UF consultants are seriously flawed. The conclusion that GRU contributes less than 3% of particulate matter to local monitors is not valid.**

8. **Black & Veatch studied local GRU air impacts using conventional air dispersion models. Widely recognized uncertainties in such modeling results are too large to support conclusions based on very small differences in calculated daily or annual average impacts, but they provide useful insights into the air pollution impacts of GRU's generators.**

9. **Modeling studies of one-hour impacts indicate that GRU can add large amounts of $PM_{2.5}$ to local ground level air. It is likely that every loca-**

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[3] Schwartz J, Dockery DW, Neas LM 1996 *"Is daily mortality associated specifically with fine particles?"* J Air Waste Management Assoc 46:927–939.

[4] Schwartz J, Neas LM. 2000 *"Fine particles are more strongly associated than coarse particles with acute respiratory health effects in schoolchildren"* Epidemiology 11:6–10.

[5] Samet JM, Dominici F, Curriero FC, Coursac I, Zeger SL. 2000 *"Fine particulate air pollution and mortality in 20 U.S. cities, 1987–1994"* New England J Med 343:1742–1749.

[6] Pope CA III, Burnett RT, Thun MJ, Calle EE, Krewski D, Ito K, et al. 2002 *"Lung cancer, cardiopulmonary mortality, and long-term exposure to fine particulate air pollution"* JAMA 287:1132–1141.

[7] Zanobetti A. and J Schwartz 2002 "*Cardiovascular damage by airborne particles: are diabetics more susceptible?*" Epidemiology 13(5):588- 592.

[8] Dockery DW, Pope CA, Xu X, et al. "*An association between air pollution and mortality in six US cities*" New England Journal Medicine. 1993;329:1753–1759; and Katsouyanni K, Touloumi G, Samoli E, et al. *Confounding and effect modification in the short-term effects of ambient particles on total mortality: results from 29 European cities within the APHEA2 Project.* Epidemiology. 2001;12:521–531; and Goldberg MS, Burnett RT, Bailar JC, et al. *Identification of persons with cardiorespiratory conditions who are at risk of dying from the acute effects of ambient air particles.* Environ Health Perspectives. 2001; 109(suppl 4):487–494.

tion in the county receives some added $PM_{2.5}$ from GRU's generators some of the time, but these contributions are episodic and last for only a few hours each year. At some locations, impacts are probably very high (30 to 120 ug/m3) though they may last only a few hours. Such levels are well within the range for serious health impacts revealed by health studies.

10. **Estimates of GRU's annual and daily average local $PM_{2.5}$ impacts provided by Black & Veatch[29,39] are inappropriate for evaluating fine particulate impacts[9]. The limited evidence from this GRU modeling confirms the following: 1) GRU's short-term impacts can be very high and have a large potential for adverse health effects; and; 2); the 24-hour average levels bear no systematic relationship to short-term peaks.**

11. **Additional modeling of short-term particulate impacts could help better define the potential health impacts of alternatives to GRU's proposals.** The variation in the short-term exposures is important but it can only be evaluated by looking at a wide range of model inputs and by separately examining the production of primary and secondary $PM_{2.5}$.

12. **Extremely high methyl mercury levels in many of Florida's freshwater and marine fishes have caused very serious population exposures, and are a source of concern. EPAC did not review GRU's atmospheric mercury contributions, due to resource and other limitations.** It now appears that GRU's total mercury output will be greatly overshadowed by Florida Rock Cement plant mercury emissions.

The main body of this Chapter is divided into two sections. The first (Section 2.2) concerns health hazards of fine particle pollution, and the fine particle levels already experienced in Alachua County. Part two (Section 2.3) discusses GRU's local contributions to particulate pollution in the County as shown by modeling studies performed by GRU's consultants Black & Veatch.

Health hazards from mercury and other toxic trace metals are not treated further in this Chapter. Resource limitations precluded detailed examination of the available mercury data, and EPAC could obtain little useful information about other toxic substances in the petroleum coke GRU expects to use.

2.2 Discussion: Fine Particulate Matter and its Health Effects

2.2.1. Introduction: Origin, Composition, and Distribution of Fine Particulate Matter

Airborne particulate matter (PM) is a mixture of microscopic solids and liquid droplets made of many components, including acids (such as nitrates and sulfates), organic chemicals, wind-blown dusts, smoke from forest fires and prescribed burning, spores, pollens from plants and sea salts. Combustion processes using coal and other fossil fuels, such as power generation,

[9] Although annual average measurements are adequate for determining whether the proposed GRU changes will produce a system that complies with existing standards, some adverse health impacts of fine particles result from short-term exposures that are only hours long and are not evaluated for determining compliance with standards.

industrial operations and motor vehicle fuels, emit most of the particulate matter in urban areas. Automobile and diesel exhausts are large sources of fine particulates, and sites within about 50 meters of highways typically experience high concentrations of particulate matter. Much of PM from traffic sources is less than 0.1 micron in diameter at locations near the traffic sources.

Particle size

All the particles that are defined as atmospheric particulate matter are invisibly small. Their size ranges from above 10 microns in diameter down to less than 0.1 micron. In comparison, a human hair is about 70 microns in diameter. Particulate matter composed of particles 10 microns or less in diameter is called "PM_{10}". Particulate matter composed of particles 2.5 microns or less in diameter is considered "fine" particulate matter and referred to as "$PM_{2.5}$". PM_{10} is mostly from soils, road dust, and sea salts, although some pollen may be included along with the larger soot and ash particles produced by combustion sources. That portion of PM_{10} that is above 2.5 microns in diameter is called "coarse" particulate matter, and denoted "$PM_{10\text{-}2.5}$".

$PM_{2.5}$ consists mostly of particles produced by human activities and can be very complex. Samples often include particles with carbon cores surrounded with layers of organic compounds, metals, nitrates and sulfates. Toxic trace metals may also be incorporated in fine particulates. The most serious adverse health effects are associated with exposure to $PM_{2.5}$.

Primary and Secondary Particulate Matter

There are two kinds of $PM_{2.5}$ contributed from stationary pollution sources like power plants and cement plants. The first is called "primary" $PM_{2.5}$. It consists of tiny particles of soot, fly ash, and other materials produced during combustion, as well as some particles that immediately condense in the open atmosphere as the flue gas cools[10]. Much primary particulate matter produced in coal-fired generators may be up to 10 microns in diameter, but some is below 2.5 microns and qualifies as $PM_{2.5}$.

The second and most important source of particulate matter contributed by power plants is not produced during the combustion process in the boiler itself. It is produced in the open air by reactions between pollutant gases sulfur dioxide, nitrogen oxides and other compounds in the atmosphere, such as organic particles or vapors from automobiles and trucks, and organic vapors from plants. These interact chemically to produce very small particles composed of sulfates and nitrates and organic matter. Between 75% and 80% of the $PM_{2.5}$ contributed to the local atmosphere by GRU generators is "secondary" PM.

Secondary particles are carried long distances from the sources of their gaseous precursors. Most of the eastern US—including the Southeast—have comparatively high secondary $PM_{2.5}$ concentrations containing sulfate ions derived from distant sources believed to be coal-fired power plants. These episodically contribute about 5 to 10 micrograms of $PM_{2.5}$ per cubic meter of air[11], about half of which consists of sulfate particles.

2.2.2 Why is PM a Health Concern? (Findings 1 and 2)

[10] These are termed "condensables". They are formed mostly from metals or organic vapors that condense into very tiny particles as the plume cools, less than 1 micron in diameter. Primary $PM_{2.5}$ from natural gas combustion consists almost entirely of organic condensables.

[11] These studies have been summarized in Volume I of the current draft of EPA's Air Quality Criteria Document, 2004. This document is available for download at: http://www.epa.gov/ttn/naaqs/standards/pm/s_pm_cr_cd.html

Fine particulate or $PM_{2.5}$ is a serious health hazard. When $PM_{2.5}$ is inhaled, these tiny particles penetrate deeply into the lung, where they meet the lung wall. They may pass directly through the thin lung wall cells or dissolve into the bloodstream. Insoluble toxic metals and other particles passing into the bloodstream may be deposited in other organs in the body, including the brain, and the liver.

Many studies have confirmed that fine particulate matter is responsible for most of the adverse health impacts associated with acute air pollution episodes. Fine particulate matter can adversely affect anyone, but the most susceptible groups include the elderly, children, those with respiratory or cardiovascular disease, diabetics[12,13]. The documented adverse health impacts include death from heart attacks or stroke, episodes of acute bronchitis; asthma attacks, breathing problems in individuals with pre-existing respiratory disease, atherosclerosis and a wide variety of symptoms associated with inflammatory responses, heart trouble or pulmonary problems.

The exact features responsible for fine particle adverse health effects are unclear. Their complexity and variety suggest that many properties may affect different susceptible populations in different ways. Differences in the health impacts of particulate matter in different locations may be related to differences in particle composition, or the sources and timing of exposure. Consequently predicting the impacts of particulate matter in specific locations like Alachua County, based on impacts observed elsewhere is difficult.

Studies of the way inhaled particles are deposited in the lung have confirmed that children retain more inhaled fine particulates per unit weight or lung surface than do healthy adults. Persons with emphysema and similar lung damage also retain more particulate matter than healthy persons. Other things being equal, more particles are deposited in the lung during exercise because more air is inhaled and it is inhaled more deeply.

Health Effects of Short-Term Fine Particle Exposures

Particulate matter has been monitored in a number of Florida locations for several years, beginning with 24-hour monitoring of PM_{10} in the late 1980's. Widespread monitoring of fine particles ($PM_{2.5}$) began only in 2002 in most locations.

Many scientists have used the data collected by these monitoring networks to study the incidence of PM-related health impacts of short-term exposures by comparing the incidence of various health impacts over time with the varying measured concentrations of PM over the same interval[14]. These studies reveal the effects of increasing or decreasing $PM_{2.5}$ concentrations. Most of these studies of short-term effects have employed measured average 24-hour concentrations of $PM_{2.5}$, but some have used hourly average concentrations.

Figure 2.1 summarizes the results of many of the studies of short-term exposure effects that have shown increases in the rate of occurrence of adverse health impacts. This plot shows how the rate increases when the daily $PM_{2.5}$ concentration goes up by 5 micrograms per cubic

[12] Zanobetti A and J Schwartz 2001 "*Are diabetics more susceptible to the health effects of airborne particles?*" American J Respiratory Critical Care Med. 164(5):831- 833.
[13] Zanobetti A and J Schwartz 2002 "*Cardiovascular damage by airborne particles: are diabetics more susceptible?*" Epidemiology 13(5): 588 – 592.
[14] The effects of long-term exposures have also been evaluated by comparing the incidence of different kinds of health effects in locations where the annual average PM concentrations differ, but we do not discuss these here because annual average concentrations in Gainesville are low.

meter. As shown in this figure, the rate of death due to non-accidental causes increases on average by 0.9% per 5 microgram per cubic meter increase in daily $PM_{2.5}$, while deaths from respiratory disease increase by 3%. Hospitalizations and visits to doctors increase by between about 0.6% and 2.5% as do the frequency of reported symptoms of cardiopulmonary problems.

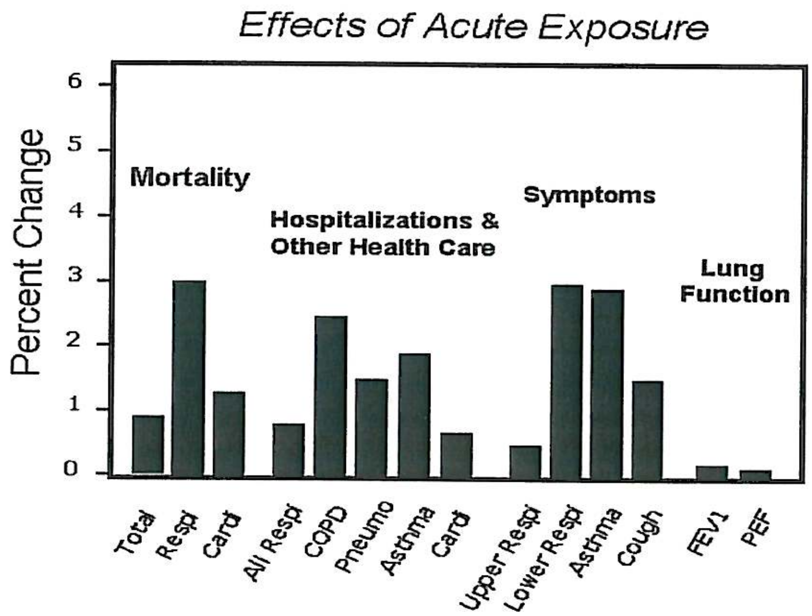

Figure 2.1 Summary of observed health effects: Approximate percent change in epidemiologic health endpoints per 5 micrograms per cubic meter (μg/m3) increase in $PM_{2.5}$ Source: Pope, et al. 2002.

The percent rate increases in **Figure 2.1** appear small in absolute terms, but they can have a profound impact over a full year, even in locations where the annual average $PM_{2.5}$ levels are moderate, because increases of 5 to 15 micrograms per cubic meter occur frequently. Each increase of 5 micrograms per cubic meter increases the death, disease and symptom rates for people experiencing the exposure increase by the amounts shown in the plots.

Adverse health effects can result from exposures that last less than 24 hours, sometimes as little as an hour or two. Frequently deaths, hospitalizations, emergency room visits, etc. often began to increase on the day that $PM_{2.5}$ concentrations increase significantly, which means that patients did not have to breathe PM-laden air for a full 24 hours before symptoms became noticeable. Studies specifically designed to explore very short-term impacts have confirmed that exposures need not last 24-hours to have important health effects. One study of heart attacks occurring in a very vulnerable population in the Boston area examined the relationship between 2-hour average $PM_{2.5}$ concentration and heart attacks. The authors found that heart attacks can sometimes be triggered by periods of high particulate concentrations lasting as short as two hours[15]. This study found that 44% more heart attacks occurred after two-hour exposures to $PM_{2.5}$ levels exceeding 17 micrograms per cubic meter than when 2-hour concentrations were below 5.2 micrograms per cubic meter. However, these short-term impacts on a vulnerable

[15] A. Peters, PhD; D. W. Dockery, J. E. Muller, and M. A. Mittleman, 2001 "Increased Particulate Air Pollution and the Triggering of Myocardial Infarction" *Circulation* 103:2810-2815.

population were not observed in a very recent Seattle study[16], or in a study in Augsberg, Germany[17]. The three study locations differ in respect to the peak concentrations of particulate matter, the daily variations in fine particle concentrations, and other features of the locations, the ambient particles, and populations studied. However, exercise and exposure to traffic for short durations were associated with myocardial infarctions in both Boston and Augsburg, and elsewhere.

Laboratory studies of healthy volunteers and animals have shown that some important physiological changes in the cardiovascular and pulmonary systems can take place as a result of very short term exposures to fine particulate matter, including cardiac arrhythmias, autonomic system changes, pulmonary inflammation and other responses. These studies confirm plausible physiological responses that account for the strong cardiovascular and cardiopulmonary impacts of elevated fine particulate matter levels[18].

2.2.3 What PM2.5 Levels are Safe? (Findings 2 and 3)

The question of whether there is a "safe" $PM_{2.5}$ concentration below which no adverse health effects are experienced has been examined by many workers. None has found such a threshold concentration.

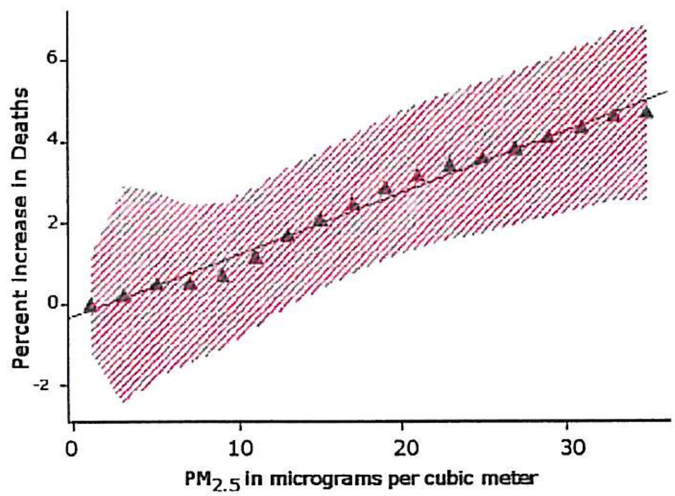

Figure 2.2 The relationship between daily average PM2.5 and percentage increase in non-accidental deaths for 6 U.S. cities. Note that every increase in daily average PM2.5 concentration comes at the expense of increased community death and illness rates (after Schwartz, et al., 2002).

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[16] Sullivan J, Sheppard L, Schreuder A, Ishikawa N, Siscovick, D, Kaufman J. 2005. Relation between short-term fine-particulate matter exposure and onset of myocardial infarction. Epidemiology 16:41–48.

[17] Peters, A. S. von Klot, M. Trentinaglia, J.f Cyrys, A. Hörmann, M. Hauptmann, H E. Wichmann, and H. Löwe, 2005,"Particulate Air Pollution and Nonfatal Cardiac Events Part I. Air Pollution, Personal Activities, and Onset of Myocardial Infarction in a Case–Crossover Study" Health Effects Institute, Report Number 124, June 2005. Available for download at: http://www.healtheffects.org/Pubs/Report124.pdf

[18] Nel, A. 2005 "Air Pollution-related Illness: Effects of Particles". Science 308:804 May;
Gold, D. A. Litonjua, J. Schwartz, E. Lovett, A. Larson, B. Nearing, G. Allen, M. Verrier, R. Cherry, and R. Verrier, 2000. "Ambient Pollution and Heart Rate Variability" Circulation 101:1267-1273
Peters, A., D. Dockery, J. Muller and M. Mittleman 2001 "Increased Particulate Air Pollution and Triggering of Myocardial Infarction" Circulation 103:2810-2815.

Most studies of short-term exposures have shown that even small increases in $PM_{2.5}$ concentrations are associated with statistically significant increases in adverse health effects. **Figure 2.2** summarizes the results of a series of studies of the populations of 6 cities in the US. Daily mortality rates for all non-accidental deaths were found to increase systematically with increasing daily $PM_{2.5}$ concentrations. This figure is taken from the work of Schwartz et al[19], who point out that these results are to be expected even if thresholds exist, but they differ for different individuals due to multiple genetic and predisposing illnesses that influence their sensitivity to particulate pollution.

The public health implications of the relationship plotted in **Figure 2.2** are clear. Every increase in $PM_{2.5}$ comes at the cost of increased likelihood of death or serious illness in the population exposed to this pollutant, and every decrease will benefit community health.

EPA is now in the process of reviewing the current $PM_{2.5}$ standards, which now limit annual average concentrations to 15 micrograms per cubic meter, and daily concentrations to 65 micrograms per cubic meter. The new annual standard is expected to be in the range 12 to 14 micrograms per cubic meter, and the new daily standard in the range of 25 to 35 micrograms per cubic meter.

At present, the EPA is not considering a health-based standard for very short durations, less than 24-hours[20], but the increasing evidence that exposures of a few hours can have serious adverse impacts has lead some advisors to believe that such standards may be enacted in the future[21].

The abundant evidence that the existing standards do not protect public health prompted the proposed standard revisions; but whether *any* new standards will be completely protective is problematic, in view of the evidence that there is no safe threshold. The public health implications of the absence of a threshold are sobering. Every reasonable daily or annual standard that the EPA could set will inevitably fail to protect the health of some portion of the population. This means that communities cannot rely on EPA standards to protect public health fully. Burning fossil fuels for energy requires that the community accept a level of harm to human populations. Cleaning emissions will reduce the level of harm, but cannot eliminate it.

2.2.4 Health Status in Alachua County: Susceptible Groups (Finding 4)

Adverse effects of particulate matter exposures tend to be concentrated in population subgroups that are especially vulnerable. These include: children and the elderly, individuals suffering from pre-existing health conditions that pre-dispose them to adverse effects, and individuals who exhibit specific risk factors for cardiovascular or cardiopulmonary conditions.

Tables 2.1 and 2.2 show the county population in susceptible age groups, along with some county health statistics. The population and the health status in the county are strongly af-

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[19] Schwartz, J., F. Laden, and A. Zanogetti, 2002 "The Concentration–Response Relation between PM2.5 and Daily Deaths" Environmental Health Perspectives 110:1025-1029.

[20] EPA sets secondary standards for non-health effects, and is considering a 4-hour rolling standard for PM2.5 to improve visibility in national parks and other areas.

[21] Consider, for example, the comment of Paul Lioy, a member of the Clean Air Scientific Advisory Committee advising the EPA on new standards: "However, the detection of cardiac health effects in populations at risk may require consideration of a shorter term standard, e.g. 1-hr or 8-hr, in future reviews." Dr. Lioy also noted that the importance of very short-duration exposures implies that it may not be valid to base standards on the concentrations monitored at a single central location, because localized "hot spots" where short-term exposures are especially important may not be reflected at the central monitoring location."

fected by the presence of a large subpopulation of young college students. The median age in the county is 29, in contrast to the 38.8 for the state as a whole. As shown in **Table 2.1**, the proportion of children under 5 years of age is lower in Alachua County than in the state as a whole, as is the proportion of the population age 65 or more.

Table 2.1 Children and Elderly Population Of Alachua County

Age	County	State
Under 15	19.0%	16.5%
over 65	9.8%	17.6%
Total	28.8%	34.1%

Table 2.2 Alachua County Health Data

Table 2.2A Percent of Population with Risk Factors for PM-related Diseases*

	% Population	Age Range		
	All Ages	18-44	45-64	65+
	100.0%	50.9%	19.3%	9.6%
Overweight or obese	43.5%	45.0%	41.2%	43.7%
Current Smoker	18.8%	21.2%	19.8%	3.6%
Ever diagnosed with high blood pressure	19.6%	8.2%	38.3%	41.3%
Taking blood pressure medication	12.9%	--	25.8%	35.9%
High chloresterol	28.9%	20.7%	34.3%	46.5%
Heart Disease***	10.9%	4.2%	12.5%	30.4%
Adults who ever had asthma	13.8%	15.1%	13.3%	8.6%
Adults who still have asthma	6.8%	8.2%	-	-
Diabetes	5.1%	2.2%	10.5%	7.8%

Table 2.2B Additional Prevalence Estimates**

Diagnosis	% of Population	Number
Asthama among school children (2000-2001)	0.90%	1909
Adult asthma	5.22%	11368
Adult chronic bronchitis	3.37%	7351
Emphysema	1.00%	2172
Total	11.35%	24740

Table 2.2C Selected Health Statistics (Annual Averages)

Diagnosis	Deaths	Hospital-izations
Coronary Heart Disease	204	1173
Stroke	113	573
Congestive Heart Failure	29	693
Chronic Lower Respiratory Disease	84	638
Asthma		1289

*Sources: Florida Department of Health Behavior Risk Factor Report for Alachua County; Florida DOH Alachua County Chronic Disease Profile, American Lung Association.

** American Lung Association; Alachua County Department of Health

***EPA Air Qualtiy Criteria Document 2004

Table 2.2 shows some of the results of an annual health status survey of state residents 18 or over that are conducted every year[22]. According to this table, over 40% of all individuals in the three age groups tabulated are overweight or obese, while nearly 19% are current smokers, 12.9% are currently taking blood pressure medication, almost 29% have high blood cholesterol levels, nearly 14% suffer from asthma, and 5.1% are diabetics. It is evident that a significant percentage of the county population is predisposed to some degree to the adverse health conditions known to be associated with PM levels in the air. Many will fall into several of the groups identified in **Table 2.2**, and no good estimates of the proportion that are affected by one or more is available. Given the data in this table, it seems likely that at least 30% of the population of the county is susceptible to PM-related health effects.

2.2.5 $PM_{2.5}$ Concentrations in Alachua County (Finding 6)

The county measures average daily (24-hour) $PM_{2.5}$ concentrations every third day at two locations. It measures hourly PM_{10} concentrations every day at one location[23]. Fine particulate concentrations and distributions at the two $PM_{2.5}$ monitoring sites are shown in **Table 2.3.**

The daily average concentrations at these two sites are low compared to many urban locations, and well within the current $PM_{2.5}$ standard of 15 micrograms per cubic meter. The averages for the whole time they have been in operation are 10.3 µg/m3 at Site 23, and 10.1 µg/m3 at Site 24. The range of daily averages is quite high: from a little over 1 microgram per cubic meter, up 39.1µg/m3 at one site and 50.1µg/m3 at the other (**Table 2.3**).

Table 2.3 PM2.5 Concentrations in Gainesville (ug/m3)

	Site 23	Site 24
Average	10.3	10.1
Standard Error	5.0	5.1
Range	1.3 to 39.1	1.7 to 50.1

Table 2.4 shows the distribution of daily average $PM_{2.5}$ concentrations. Daily concentrations of 25 micrograms per cubic meter or more occurred about 1% of days, and values over 20 micrograms occurred on about 5% of days, while values of 15 micrograms per cubic meter or more occurred between 14% and 15% of the time. These values would have little effect on healthy adults, but values above 15 micrograms per cubic meter could represent a hazard for some members of the community. Given these variations, it seems likely that at least some avoidable deaths triggered by high fine particle levels occur among county residents every year. According to one study, the death rate in Alachua County from particulate air pollution contributed from dirty power plants is between 10 and 20 per one hundred thousand population[24]. This study used a model similar to that employed by the EPA to evaluate the effects of alternative air quality standards.

[22] "County Behavioral Risk Factor Surveillance Survey for Alachua County, 2003" - Downloaded from the Florida Department of Health web site at: http://www.floridacharts.com/charts/brfss.aspx.
[23] A monitor that records hourly PM_{10} concentrations every day and one that monitors $PM_{2.5}$ concentrations every third day are operated by the state and located near the intersection of NW 53rd Avenue and 43rd Street. A second monitor that records $PM_{2.5}$ every third day is located on SW 8th Avenue.
[24] Abt Associates, 2004 "Power Plant Emissions: Particulate Matter-Related Health Damages and the Benefits of Alternative Emission Reduction Scenarios" June 2004 *Prepared for* Clean Air Task Force Boston, MA Available for download at: http://www.catf.us/publications/view/25.

Table 2.4 Percent Distribution of Daily PM2.5 Levels

Level (ug/m3)	Site 23	Site 24
25 or more	1.8%	1.3%
20 or more	5.0%	4.8%
15 or more	14.8%	13.8%

What does the 24-hour concentration tell us about the $PM_{2.5}$ concentrations that occurred during that day? Without hourly measurements to compare to the monitored daily average, it is not possible to tell how well the averages track the more dangerous high concentrations that might be occurring. In most cities, the average is a poor indicator of very short-term exposures, because the hourly values swing from high values in the morning hours to very low ones at midday, and back up again in the late afternoon. For example, a recent study of pollution levels in Steubenville, Ohio [25] confirmed that in the summer, the average hourly peak was often approximately 4 times the recorded daily average.

Analyses of the hourly $PM_{2.5}$ values recorded by a monitor in Winter Park, FL, over a period of nearly 5 years, confirms that swings are not as dramatic there as are typical in the Northeast[26]. Most of the time, the maximum hourly value was only twice the average for the day, and exceeded 3.5 only 5% of the time. This pattern is similar to that observed in Gainesville for PM_{10} measurements. Consequently, it seems likely that maximum hourly values in Gainesville are often twice or more the recorded daily average.

2.3. GRU's Impact on Local Fine Particle Concentrations in Alachua County

2.3.1 Introduction

GRU has employed two consulting groups to estimate the contributions of power plant emissions to ambient levels of particulate matter. The first of these used a conventional source apportionment model to identify the contributions of traffic, wood smoke, wind-blown soil and other sources and particles emitted from the stacks of GRU's Deerhaven Unit #2 to air sampled at several points in the city[27]. GRU employed the second group--Black & Veatch--to study the dispersion of ground level primary PM_{10}, sulfur dioxide, and nitrogen oxides[28] using conventional dispersion modeling techniques. Black & Veatch also conducted two studies of the effects of GRU power plant operations on local $PM_{2.5}$ concentrations[29,30]. None of these studies provide a clear picture of the magnitude of GRU contributions to the atmosphere.

2.3.2 State Regulatory Review of GRU Particulate Emissions (Finding 6)

[25] D.J. Connell, Withum, S. Winter, R. Statnick and R. Bilonick, 2005 "The Steubenville Comprehensive Air Monitoring Program (SCAMP): Analysis of Short-Term and Episodic Variations in PM2.5 Concentrations Using Hourly Monitoring Data" J. Air & Waste Management Association 55:559-573.
[26] Analysis conducted by EPAC using data supplied by the Florida Department of Environmental Protection.
[27] Wu, C-Y, D. Lundgren, and D. Cooper "A Study to Assess the Impact of Power Plant Particulate Emissions on Alachua County's Air Quality". GRU PO No. P13159, January 31, 2003.
[28] "Final Gainesville Regional Utilities Air Quality Impact Study for the Deerhaven and J.R. Kelly Facilities and the Future 220MW CFB, Black & Veatch, June 2004.
[29] "Gainesville Regional Utilities Final PM2.5 Air Quality Modeling Study" prepared by Black & Veatch, February 2004.
[30] "Gainesville Regional Utilities Final PM2.5 Air Quality Modeling Study: Assessing Past Actual Annual Emissions and Expected Future Actual Annual Emissions" Prepared by Black & Veatch, June 2004

Normally, when a utility seeks approval of a planned pollution source from state authorities, it must demonstrate that its anticipated pollution emissions satisfy all applicable standards. A new source adds to the pollution in the local area, and it is necessary to insure that the additions will not degrade air quality.

However GRU plans to combine the retrofit of Deerhaven Unit #2 with the construction of the new solid fuel generator, and seek only a single approval for the combined projects. Retrofit of Deerhaven Unit #2 will reduce pollutant emissions by more than the new generator will increase them. Consequently, the two projects produce net reductions in pollutant emissions. Under these circumstances, the state will not require GRU to demonstrate compliance any further than the net reduction.

But even if the city did not combine the two projects, it is unlikely that the fine particle emissions of the new generator would be subjected to scrutiny, because (a) the standards themselves are now undergoing review and are likely to be tightened, and (b) no rules for conducting new source reviews have been written or approved. It is unlikely that compliance rules will be available for two or three years, and until they are available, no new source reviews will take place.

2.3.3 Source Apportionment Study (Finding 7)

A source apportionment study attempts to identify the sources of pollutants that contribute to the mixture of particulate matter collected at a "receptor" site by using the mix of chemical compounds in each of the known sources as a kind of chemical fingerprint. Many models for source apportionment studies have been developed, and computer programs to implement these techniques are available from EPA.

C-Y Wu and colleagues at the University of Florida performed such a study[16]. These workers used an approved-EPA chemical mass balance model (CMB8) to identify fine and coarse sources of particulate matter that were collected at three different Gainesville locations to estimate the contribution by GRU's largest generator, Deerhaven Unit #2. They report that these studies showed that GRU contributes less than 1% to 3% of the fine particulate matter at receptor sites in the county. Unfortunately, these authors ignored almost all the requirements for the successful application of the source apportionment technique they employed. The CMB8 model is useful only if:

1. All particulate matter collected at the receptor site is a mixture of particulate matter from known sources;
2. All sources have been identified, and each is independent of the others;
3. None of the particles from different sources undergo chemical reactions with one another, or other chemical transformations in the atmosphere; and
4. The chemical composition of particles from every source is known and well characterized[31].

Wu et al. sampled primary particulate matter at the stacks of Deerhaven Unit #2, but ignored the fact that primary particulate is not the only particulate material contributed by GRU's power plants. Most of the local $PM_{2.5}$ added by GRU is secondary $PM_{2.5}$, produced by atmospheric chemical reactions that convert GRU's sulfur dioxide and nitrogen oxides into particles. Failure to recognize the role of atmospheric chemical reactions in modifying the particulate concentration, and in contributing secondary $PM_{2.5}$ violates all of the 4 requirements listed above. Many

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[31] J.G. Watson, N. F. Robinson, E. M. Fujita, J. Chow T. G. Pace, C. Lewis, and T. Coulter 1998 "CMB8 Applications And Validation Protocol For $PM_{2.5}$ and VOCS" Document No. 1808.2D1 September 30

additional flaws in the sampling and analysis and in the work on which much of the report is based[32] invalidate the conclusions offered by Wu et al. that GRU is the source of only 1% to 3% of particulate matter in local ground-level air. Consequently, all of the reported study conclusions are invalid.

2.3.4. Dispersion Modeling of GRU Emissions (Findings 8, 9, and 10)

Air Dispersion Modeling: Approaches and Uncertainties

The best information about GRU's contributions of particulate matter to the local atmosphere comes from modeling of $PM_{2.5}$ in local air reported by Black & Veatch[17]. They used CALPUFF, a standard dispersion modeling program, to estimate the $PM_{2.5}$ that existing and future GRU generator operations could add to county ground-level air.

This model uses hourly emission rates for sulfur dioxide, nitrogen dioxide, and primary $PM_{2.5}$ and historical meteorological data to simulate the production and dispersion of secondary $PM_{2.5}$, and the dispersion of primary $PM_{2.5}$. For every hour in the meteorological record, the program calculates the average amount of $PM_{2.5}$ delivered to ground level in each of 2,865 100-meter square grid points in the county. The model can be programmed to calculate 24-hour averages at each grid point, and identify the points where the maximum impacts occur over the full year (or years) for which meteorological data are available. Alternatively, the program can be used to calculate annual averages at each point, or 1-hour, 3-hour or 8-hour averages. In normal use, it shows the peak calculated concentration increment added at all grid points during the simulated interval, the next highest peak increment, and so forth, as well as the maximum at each of the grid points, the second highest at each, and so forth[33]. The model is usually used to estimate the amount of local air pollutant from a given source or group of sources. That is, it calculates *increments* of added pollution from GRU but not total concentration from all sources.

According to the EPA guidelines for dispersion modeling[34], all dispersion models used for regulatory purposes produce very uncertain results, including the CALPUFF model used by Black & Veatch.

Studies of the relationship between predicted dispersion model concentrations and actually measured concentrations show that the estimates are accurate only to about a factor of two. So specific estimates of the annual or daily average increment at specific locations could be in error by as much as plus or minus 50%[35], even if representative meteorological records of 3 to 5 years in length are provided as input to the model. In the present case, many additional uncertainties come from the extremely complex nature of the chemical reactions that yield secondary $PM_{2.5}$. These are influenced by many factors not considered in this model[36].

When used in support of an air permit application, CALPUFF simulations must follow strict guidelines established by EPA. These include use of a long meteorological record that is repre-

[32] P. Chuaybamroong 2002 "Composition, Particle Size, and Source of Ambient Aerosol in Alachua County, Florida" University of Florida, Master's Thesis.
[33] The model can be used to estimate total concentration at each point if the contribution from all other sources (including "background") is known.
[34] 40 CFR Ch. I (7–1–03 Edition) Appendix W to Part 51: Guideline on Air Quality Models, available for download at: http://www.epa.gov/scram001/guidance/guide/appw_03.pdf
[35] Errors could be as small as plus or minus 10 to 40% for long averaging times.
[36] Even models with very sophisticated programs to describe the chemistry that leads to the formation of secondary $PM_{2.5}$ are inaccurate.

sentative of meteorological conditions likely to be encountered in the area of interest. Current guidelines suggest a record at least 3 years long, and prefer a 5-year record[37].

The goal of the EPA requirements is to simulate meteorological conditions that are representative of the local area, and to identify "worst case" situations. Current guidelines also require that all emission sources be modeled as if they were operating at maximum emission rates. These EPA requirements do not apply in the present case, and they have not been followed by Black & Veatch.

These EPA guidelines need not be followed if modeling studies are produced only to provide guidance to decision-makers, as in the present case. Black & Veatch used only one year of meteorological data rather than the suggested three to five years of record because the modeling has been performed only to demonstrate to the public that GRU's proposals will not lead to violations of existing standards. The state is unlikely to require additional modeling satisfying EPA guidelines when and if GRU applies for site certification for the project[38]. Although the lack of a long meteorological record may not make much difference, given that the results of these modeling activities are so uncertain, the worst case conditions produced from a short weather record are likely to be less severe.

Modeling GRU's Permitted Levels

Black & Veatch reported the results of two studies that modeled $PM_{2.5}$ contributions. The first and most useful study was released in February 2004[39]. It used the CALPUFF program to estimate and compare the local impact of GRU operations if all units were operating and each released the maximum amount of pollutants permitted under existing air permits, or the maximum amount that would be allowed under expected future permits.

Air permits normally allow far larger emissions than plants typically produce, but because they are allowed, it is possible that emissions could reach the specified levels some of the time, so it is useful to consider what the impacts would be under these circumstances.

Black & Veatch modeled sources at Deerhaven separately, sources at Kelly separately, and sources at both locations in combination. EPAC focused on the Deerhaven simulations because (a) Deerhaven Unit #2 is the largest source of primary $PM_{2.5}$ and (b) its gases contribute to secondary $PM_{2.5}$, and (c) only Deerhaven emissions will be affected by GRU plans, and (d) the units at Kelly do not operate 24/7, though this is assumed in the simulation.

Black & Veatch conducted their study in accordance with EPA guidelines, except that the meteorological record used was a short one[40]. The modeled emissions corresponded to the maximum capacity emissions for all sites and all units. According to this study, under the current permit, the combined emission of the $PM_{2.5}$ precursors, sulfur dioxide and nitrogen oxides, is 8,273 lbs per hour (**Table 2.5**). When Unit #2 is retrofitted, and the new generator is built, the permitted emissions should drop by 41% to 4,866 pounds per hour. But the estimated peak an-

[37] State regulators must approve the inputs used in these models if their results are submitted in support of an air permit application. Sometimes they accept shorter records.
[38] It will be several years before regulations governing applications for air permits under the new $PM_{2.5}$ standards are ready for use, and in any case, since GRU is reducing total pollution emissions, the state will have no need to review its emissions.
[39] "Gainesville Regional Utilities Final $PM_{2.5}$ Air Quality Modeling Study" Prepared by Black & Veatch, February 2004.
[40] Black & Veatch used one year of weather data for modeling instead of the EPA recommended 3 to 5 years. This removes the larger range of variability of real world weather conditions and emphasizes the particular weather of a single year.

nual average concentration will drop only 21% to 2.9 micrograms per cubic meter from an estimated 3.7 micrograms per cubic meter under current permitted emissions. According to the model results, the annual average increments will drop from 0.18 ug/m3 to 0.14 micrograms per cubic meter (**Table 2.5**).

Table 2.5 Modeling Estimates of PM2.5 Additions to Local Air From Generators at Deerhaven*

	Assumed Emission Rates Modeled (lbs per hour)		
	SO2 and Nox	Primary PM2.5	
Current	8,273.00	130	
Future	4,866.00	103	
Percent Reduction	41%	26%	
	Maximum PM2.5 Impacts**		
	Annual	24-hour	1-Hour
Current	0.17	3.7	87
Future	0.14	2.9	64
Percent Reduction	18%	21%	26%

*Source: "Gainesville Regional Utilities Final PM2.5 Air Quality Modeling Study", prepared by Black & Veatch, February 2004

**Maximum amount added by GRU operations to any single point in the county. Does not include the PM2.5 in the air contributed by other sources.

These results illustrate an important feature of the chemical model used in this program: reducing the emissions of precursor gases sulfur dioxide and nitrogen dioxide does not proportionately reduce the $PM_{2.5}$ produced. This is also a real world feature. Secondary $PM_{2.5}$ production from gaseous precursors is poorly understood, but is influenced by large number of factors. One factor is the amount of precursor SO_2 and NOx present in the air mass where the reactions that produce secondary $PM_{2.5}$ are occurring.

The **Table 2.5** data also illustrate another feature of pollutant distributions in Alachua County. The peak one-hour GRU impact is very large compared to the peak average 24-hour impact. This is due to the variability of wind direction common in the county. A brief inspection of hourly wind direction data confirms that it frequently changes 20 to 40 degrees or more from hour to hour[41] .and wind blows evenly from all directions over the course of a year. This means that no location in the county is likely to be downwind of Deerhaven more than an about 80 to 200 hours in any one year, or more than a few hours in any single day. The rest of the time the power plant impact will be zero. This leads to very low average annual and daily impacts everywhere in the county[42], but higher short-term impacts. In general, with modeled results as with monitored results, averaging for 24 hours or longer masks hourly variability with its higher exposure levels that could have important health implications for the community.

[41] Wind direction is not usually recorded continuously by the weather bureau. It is sampled once per hour, as are all the other surface met data used in most dispersion modeling programs. This is a major source of the uncertainties characteristic of regulatory model estimates.

[42] Another curiosity in this table is the fact that the calculated peak 24-hour averages are only very slightly more than the peak 1-hour average divided by 24. This implies that if the site that received the peak one-hour increment was also the site with the peak 24-hour increment, little or no $PM_{2.5}$ was delivered there at any other time on the day in question, a conclusion compatible with the known wind direction variability in this area.

Hourly Increments to Local Ground Level Air

Although the Black & Veatch report includes only 24-hr and annual average impact data, they also ran the model with the same inputs to produce average one-hour contributions to local air[43]. The results confirmed substantial very short-term impacts from GRU operations. Under "current" permit conditions, the maximum impact to a single location was estimated at 87±44 micrograms per cubic meter, which translates into an impact in the range 42 to over 130 micrograms per cubic meter given the uncertainties in model results.

Under expected future permit conditions, the maximum impact calculated by the model is only a little lower: 65 ± 32 micrograms per cubic meter or about 33 to 97 micrograms per cubic meter (**Table 2.5**). Large impacts in this range occurred only once during the simulated year of operation, but substantial 1-hour impacts of about 15 micrograms or more were found over almost 9% of the county area at least once per year, and impacts of 10 micrograms or more are estimated to occur over 14% of the county area.

The permitted hourly emissions modeled by Black & Veatch are larger than the emissions from Deerhaven generators now, but not much larger. The available data suggests that when both Deerhaven Unit #1 and Unit #2 are operating—which is most of the time—their combined emissions total about 3,400 pounds per hour of gaseous pollutant precursors to $PM_{2.5}$, and about 140 pounds per hour of primary $PM_{2.5}$. These are about 30% below the modeled figures, so we conclude that, given the uncertainties, these results are a useful guide to the current GRU impact on local air. These impacts are mapped in **Figure 2.3**. The reader is cautioned that the estimated values could be in error by plus or minus 50%. That is, the impacts are likely to fall between 50% and 150% of the listed values. Furthermore, the areas impacted could be larger or smaller than those shown and affected areas will vary from year-to-year.

In spite of these uncertainties, it seems likely that GRU does adversely impact ground-level air all over the county and in many locations the impacts are substantial though infrequent.

[43] The partial results of this modeling exercise were supplied to EPAC by GRU, but were not widely distributed to the community.

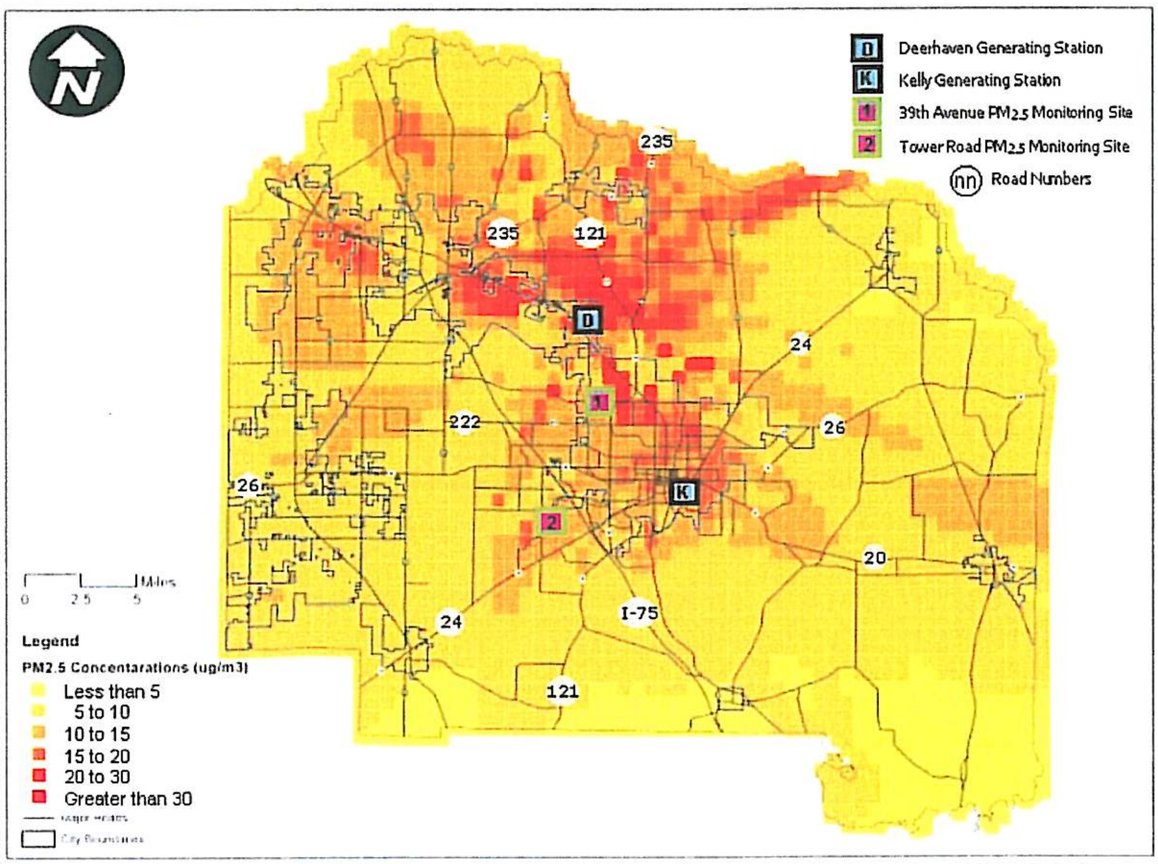

Figure 2.3. Maximum one hour additions of PM2.5 to local ground level air from Deerhaven generators as estimated by dispersion modeling. **The emissions used are about 25% higher than those occurring now. The estimates are not very accurate, but they indicate that GRU's impacts can be very high some of the time.**

<u>"Actual" and "Expected" Emissions and their Impacts</u>

The second Black & Veatch study adds little to our knowledge of GRU's current or potential future impacts, because it used unrealistically low estimates of hourly pollutant emissions. The study contrasts the 2003 emissions -- when Deerhaven Unit #2 operated less than usual--with a different set of emissions described in one GRU report [44] as "expected operations" that will occur in the future after a new generator is built and Deerhaven Unit #2 has been retrofitted. The emission rates used to explore the "expected operations" are significantly lower than those the community will be exposed to. They are based on the annual pollutant emissions that would occur if GRU produced only enough electricity to fill local needs, and none for sale to other utilities in the state[45]. Generating electricity for off-system sales is a major component of GRU's

[44] See "Planning Study of The Effects of Gainesville's Long Term Electrical Energy Supply Plans on Ambient Air Quality and Greenhouse Gas Emissions" Gainesville Regional Utilities September 30, 2004, especially pages 9-12 and Table 5.
[45] Artificially low hourly emissions were estimated by dividing the possible annual emissions by the number of hours in a year.

proposal, and modeling that fails to take into consideration pollution from electricity production for off-system sales will fail to produce useful estimates of future $PM_{2.5}$ impacts.

GRU uses the estimated maximum annual impacts derived from these two studies to support its contention that $PM_{2.5}$ levels will be lower if its proposals are accepted. This conclusion is based on an 18% difference between the estimated annual maxima of the 2003 simulation and that of the "expected future" simulation. The uncertainty in each of the two estimates is plus or minus 50%. Consequently, a calculated difference of 18% is an inadequate basis for any conclusions.

Using CALPUFF Modeling Results

In view of these very large uncertainties, it is unwise to place much emphasis on the specific values provided by these modeling runs. Though the long-term averages are less likely to be in serious error than short-term estimates, long-term averages do not supply information that is useful for evaluating potential health effects. However, these simulation studies have demonstrated three important facts:

- GRU is likely to have significant short-term impacts on $PM_{2.5}$ concentrations everywhere in the county for at last a few hours each year.
- In some populated areas these impacts could be in the range of 30 to 100 micrograms per cubic meter at some points, and in the range of 7.5 to 30 at many, though they will be brief and infrequent.
- There is no way to predict the magnitude of GRU air particulate matter impacts accurately.

EPAC has urged GRU to run these models again with different, more realistic inputs to explore short-term impacts more carefully, and also to explore the separate effects of retrofitting Deerhaven Unit #2 and adding a new generator. This would provide more insight into the pollution impacts that GRU would have if the new generator were built and would reveal to the community some of the possible health costs of new and modified power plants.

Chapter 3. The Climate Crisis and Strategies to Meet It

3.0 Introduction

The world climate system is undergoing massive and rapid changes. Scientific studies[1] confirm that these are largely due to human activities releasing heat trapping "greenhouse gases"[2] like carbon dioxide into the atmosphere, chiefly from the combustion of coal, oil, and natural gas.

The world has experienced only the beginning of the adverse impacts of climate change. Even if we immediately stopped all human additions of heat-trapping gases, significant future heating is inevitable over the next 30 years or more.

Scientific understanding of climate is incomplete and many uncertainties remain, but there is a strong consensus among climate scientists about the nature of the fundamental problem, and the steps needed to combat it. This scientific consensus holds that we must reduce world greenhouse emissions by about 50% to 80% to avoid catastrophic and possibly run-away heating of the globe, and that we have less than 50 years to accomplish this monumental task. How much less time we have one of the most critical uncertainties facing policy makers today. One widely respected study says that the "tipping point"—the point beyond which cuts in greenhouse gas emissions will be insufficient to stave off major climate disasters—will occur within ten years[3].

The need to reduce greenhouse gas emissions and "de-carbonize" our industries is one driver for rapid change in the electric utility industry. The US electric power industry is the source of 39% of the nation's industrial carbon dioxide emissions. Substantially reducing these emissions in the face of expected increases in electricity demand is shaping an energy future dramatically different from any that has been experienced since the industry began a century ago.

There are additional drivers for change. Oil and natural gas are becoming scarce and their costs are rising, along with world demand. Although coal remains available in the US, its price is likely to rise. Utilities are already turning to low quality coals as Appalachian coal reserves decline. Estimated US coal reserves could last possibly 300 to 500 years *at the current rate of consumption*. But the supply could run low much sooner if coal is used to replace liquid transportation fuels[4]. Meanwhile, technological advances are steadily reducing the costs of non-fossil fuel energy sources (wind, solar, and ocean current), though when these will be cost competitive with fossil fuels and sufficiently reliable for utility use is very uncertain.

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[1] See July 21 testimony of Ralph Cicerone, president of the US National Academy of Science to the Congress at: http://www7.nationalacademies.org/ocga/testimony/Global_Climate_Change_Policy_and_Budget_Review.asp, and the July_2005 Statement of 11 National Academies of Sciences on Global Warming, Appendix 1 to this chapter.

[2] The greenhouse gases are carbon dioxide, methane, and nitrous oxide—all of which have natural as well as industrial sources—and a number of gases not found in nature, such as fluorocarbons, sulfur hexafluoride, and other gases with important industrial uses.

[3] "Meeting the Climate Challenge: Recommendations of the International Climate Change Taskforce" January 2005. Available for download from a link at: http://www.americanprogress.org/atf/cf/{E9245FE4-9A2B-43C7-A521-5D6FF2E06E03}/CLIMATECHALLENGE.PDF. Senator Olympia Snowe, of Maine, is a co-chair of this task force.

[4] The Energy Information Agency estimates recoverable US coal reserves as 268 million tons, while geological data suggest that a total of 469 million tons is potentially available with new technology. Current US coal consumption is 1.1 million tons per year, estimated to rise to 1.5 million tons per year by 2025. These data imply between 176 and 325 years' supply, but it could be much less if consumption rises significantly, as would be the case if coal were used a source of transportation fuels.

Many features of the country's emerging energy environment can now be broadly discerned, even though critical details remain uncertain:

- All fossil fuels and fuel technologies will increase in cost, partly because of rapidly rising global demand, but also because of declining economically accessible reserves.
- State and federal programs that impose mandatory limits on the emission of carbon dioxide by utilities will be approved within the next decade and implemented within 10 to15 years or sooner.
- New, "de-carbonized" technologies for producing electricity with little or no greenhouse gas emissions will be increasingly available, though they will probably be expensive, and may not be widely available for 10 to 20 years or more.

Planning for the new energy environment presents formidable difficulties. The primary uncertainty is when and how carbon dioxide emission caps will be imposed on electric utilities. At some point, mandatory caps on carbon dioxide emissions are likely, along with penalties for non-complying utilities. Recent US Senate action suggests that major features and timing of future mandatory emission controls will be discernable within a few years[5]. Subsidies will encourage renewable energy; new standards for efficient appliances and other equipment will encourage energy efficiency and reduce demand.

Good utility planning requires more than advance notice of regulatory changes. Utility planners need reliable predictions of fuel availability and cost, as well as information about the timing, cost, and performance of future technologies. With increasing world demand for oil and natural gas and declining reserves of all US fossil fuels, predictions of future fuel costs become increasingly unreliable. It is even harder to predict when a "promising" technology becomes "proven", and therefore attractive to a prudent utility planner.

What strategic options are available to a utility when so much information about critical features of the future energy environment is extremely uncertain or absent? Should a utility assume that carbon dioxide controls will be imposed, and begin to adapt to them now? Or, should it assume that future costs of carbon-dioxide regulations would be negligible, and proceed to lock in a future that is committed to a single, currently cheap fuel? Or should it remain flexible, and delay major decisions until critical planning information is available?

EPAC has reviewed GRU's plans for new generating capacity in the context of global warming and the energy future it presages. We have compared GRU's response to that of other utilities and to actions strongly recommended by a number of studies of the options available to meet the global climate crisis. The goal has been to identify policy options available to a small municipal utility facing the enormous future uncertainties.

3.1 Key Findings

[5] See the "Sense of the Senate" resolution quoted below, and news posted at the web site of the National Commission on Energy Polity at: http://www.energycommission.org/, and the information contained in Appendices 3.2 and 3.3 to this chapter.

1. A growing number of political and business leaders and a large majority of the public have accepted the fact of global warming. Many are now defining steps to meet the challenges it presents.

2. Uncertainty hampers planning for these challenges. Important questions about new regulations the federal government may impose and the costs and performance characteristics of emerging low carbon technologies remain unanswered. Other states' greenhouse gas programs for utilities provide a guide to regulatory changes likely to be imposed nationally, or in Florida. They include:

- **Major emphasis on energy efficiency programs to reduce wasteful energy use, including new building, appliance, and other standards to promote electric energy efficiency;**

- **Subsidies for low-carbon energy technologies, renewable fuels, and other technologies that minimize greenhouse gas emissions during electricity production;**

- **Mandatory use of renewable energy sources (wood, wind, wave or current, solar, etc.); and**

- **Mandatory caps on greenhouse gas emissions by electric utilities, with financial penalties on emissions that exceed allocated caps.**

3. Carbon capture and sequestration (CCS) is technology for storing fossil fuel carbon dioxide in geological formations such as deep saline aquifers. Although the technology has never been demonstrated, its potential availability has been assumed by many policy makers.. Utilities that seek to add new generating capacity now face a dilemma: conventional coal-fired generators cannot be effectively retrofitted to CCS, but new power plants that can be adapted are currently more expensive to build. Neither Deerhaven Unit #2 nor the proposed new circulating fluidized bed (CFB) generator are likely to accommodate a retrofit to adapt them to CCS.

4. If GRU builds the new 220-megawatt generator, it locks the community into a long-term commitment to solid fossil fuels, and increases the following risks:

- **Financial penalties for carbon dioxide emissions, which will become increasingly stringent with passing time;**

- **A very costly retrofit for carbon dioxide sequestration (if possible);**

- **Abandoning the unit as a stranded asset should operating costs become too high, or if sequestration proves to be too expensive.**

5. GRU has not defined or evaluated alternative strategies that would reduce exposure to greenhouse gas penalties, nor has it assessed the risks represented by future regulation of fossil carbon dioxide emissions.

6. GRU could implement alternative strategies including:

- **Delay deciding on a large new generator until after information about new regulations, new technologies, and the potential availability of electric energy from other utilities in the state becomes available (large-scale systems that capture and store carbon dioxide could be operating in the state within 15 to 20 years).**

- **Implement improved energy efficiency and conservation programs to delay need for new generating capacity for 5 years or more[6];**

- **Incrementally increase generating capacity by building a small biomass generator and acting to secure local biomass sources[7];**

- **Make other incremental modifications of the existing fleet.**

7. The only sure way to prepare our community for unknown future risks is to retain the flexibility to adapt to the changing energy environment as it develops. This could be achieved with some mix of the options listed under Finding 6 above.

3.2 Discussion

3.2.1 Global Warming and the National Policy Debate (Finding 1)

<u>The Scientific Consensus</u>

The growing climate crisis has been a scientific concern for nearly fifty years[8]. Accumulating evidence that human activities have a dangerous impact on climate has been widely accepted by qualified scientists. In the US and some other countries a tiny minority of scientific "contrarians" funded by fossil fuel industries and their allies have challenged the mainstream climate change conclusions[9]. For a time, these contrarians and their allies[10] were successful in paralyzing action on the national level. Although they retain credibility in some circles, contrarians have lost the support of most of the public and much of the business community[11].

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[6] Discussed in Chapter 6 below.
[7] Discussed in Chapter 8 below.
[8] The American Physics Institute web site on history at http://www.aip.org/history/climate/index.html#.
[9] A brief description of some of the misrepresentations offered by climate skeptics is included in Appendix 4 to this chapter. This appendix contains an annotated bibliography of recommended reading.
[10] Allies and supporters of the climate skeptics include most of the fossil fuel, electric power, and transportation industries, all of which will be significantly impacted by reductions in fossil fuel use, or penalties on carbon dioxide emissions. One scholarly work identified 14 conservative think tanks that actively oppose controls on GHG emissions and provide financial support for climate skeptics. (See McCright, Aaron A. M., and R. E. Dunlap, 2000 "Challenging Global Warming as a Social Problem: An Analysis of the Conservative Movement's Counter-Claims." Social Problems 47:499-522, and McCright. A. M. and R. E. Dunlap 2003 "Defeating Kyoto: The Conservative Movement's Impact on U.S. Climate Change Policy", Social Problems, Vol. 50 pp 348-373. Both are available from links at: http://www.abo.fi/6thNESS/Filer/Abstract_Dunlap.htm). The controversy is briefly discussed in appendix 4 to this Chapter, which also includes a small, annotated bibliography of sources of information about global warming.
[11] While some "climate skeptics" have scientific qualifications, few are climate scientists, and none have credibility in the scientific community. "Among those with the training and knowledge to penetrate the relevant scientific literatures, the debate about whether global climate is now being changed by human-produced greenhouse-gases is essentially over. Few of the climate-change "skeptics" who appear in the op-ed pages of *The Washington Post* and *The Wall Street Journal* have any scientific credibility at all." Professor John P. Holdren, "Risks from Global Climate Change.

The U. S. National Academy of Sciences and the National Science Academies of 10 other countries recently issued a statement summarizing the scientific consensus on global warming, and urging their governments to take steps to reduce greenhouse gas emissions. This statement is reproduced in Appendix 3.1 to this Chapter.

Two reports that summarize mainstream climate science and recommend policies to meet the climate crisis have been especially influential in recent months. One of these is the report of the International Climate Change Taskforce, a group co-chaired by Senator Olympia Snowe (Maine) and Stephen Byers, MP (UK). Its report, "Meeting the Climate Challenge" [1,12] briefly summarizes some of the devastating consequences of failing to act to reduce greenhouse gas emissions.

Most scientists now recognize that humans have been strongly affecting climate for at least 100 years, and possibly as long as 5,000 years[13]. Very rapid temperature increases have occurred in the Arctic where they have had extremely serious adverse impacts on food resources, wildlife and local cultures, as well as on the built environment[14].

National Policy

The official US position on global warming is that the science is questionable and mandatory controls on carbon dioxide and other greenhouse gas emissions are not warranted until the scientific uncertainties have been resolved. But many politicians, the public and significant elements in business communities take a different position, as expressed in the recent statements of the governors of two west-coast states:

> *"Here in Oregon we're putting together a battle plan to reduce greenhouse gases – the primary cause of global warming . . . We are not going to wait for federal leadership... We've got too much to lose if global warming continues unabated. And we've got too much to gain by being a leader in climate solutions"* Governor Ted Kulongoski, May 5, 2004[15].

> *"I say the debate is over. We know the science. We see the threat. And we know the time for action is now",* Governor Arnold Schwartzenegger, June 1, 2005[16].

Businesses from all sectors are recognizing that greenhouse gases must be reduced, and many are calling for early Federal action[17]. Much of the pressure from the business community,

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"What do we know? What should we do?" Presentation to the Institutional Investors Conference on Climate Risk, November 21, 2003.

[12] See also the companion study to the report of the one cited in footnote 1 above. It is "Ending the Energy Stalemate: a Bipartisan Strategy to Meet America's Energy Challenges" National Commission on Energy Policy December 2004 Available from: http://www.energycommission.org/, that contains a specific recommendations for energy conservation and research initiatives incorporated in the Bingaman amendment to the Energy Bill that passed the U. S. Senate in June 2005.

[13] See Rudimann, W. F. 2005 "How Did Humans First Alter Climate", Scientific American, March 2005, pp 46-53.

[14] See the Arctic Climate Impact Assessment site and links at: http://www.acia.uaf.edu/

[15] Speech by Governor to Oregon Environmental Council, available on the internet for download at: http://governor.oregon.gov/Gov/speech_050404.shtml

[16] Governor's Remarks at World Environment Day Conference Wednesday, 06/01/2005 03:00 pm Available from a link at: http://www.climatechange.ca.gov

[17] Many businesses have committed to reducing their greenhouse gas emissions, and some produce products that contribute to reducing greenhouse gases worldwide. A useful site where some business actions are described is: http://www.pewclimate.org/companies_leading_the_way_belc/company_profiles/index.cfm other approaches are described in the news articles reproduced in Appendix 3.2.

especially the utility industry, reflects the planning problems imposed by the current state of regulatory uncertainty. Some of the issues have been explored in a recent article in USA Today, entitled "The Debate is Over: Globe is Warming", and in the Los Angeles Times. Excerpts from both are included in Appendix 2 to this chapter.

Public opinion strongly favors prompt action on global warming[18], a position that is also reflected in editorials. USA Today, the most widely read of American newspapers, has been sharply critical of the Bush administration's refusal to accept and act on the scientific consensus[19]. Other newspapers have also called on the administration to wake up to the problem and act[20].

The current scientific understanding of global warming is summarized in a statement issued by the national scientific academies of eleven countries. This statement is included as Appendix 1 of this chapter. The statement calls on President Bush and the leaders of other national governments to recognize that global warming is real and to adopt policies and strategies to reduce greenhouse gas emissions.

While it is questionable whether the present administration will ever exert leadership on the issue, the U. S. Senate has responded to growing awareness of the climate crisis. Senate Energy Committee Chairman Pete Domenici introduced a very important "Sense of the Senate" resolution on climate change with the co-sponsorship of Senator Jeff Bingaman of New Mexico and other leading Senators. This resolution states that climate change is at least in part caused by human activity and must be addressed by a mandatory policy that reduces greenhouse gas emissions while growing the American economy and engaging the developing world.

SENSE OF THE SENATE ON CLIMATE CHANGE

(a) FINDINGS —Congress finds that—

1) Greenhouse gases accumulating in the atmosphere are causing average temperatures to rise at a rate outside the range of natural variability and are posing a substantial risk of rising sea-levels, altered patterns of atmospheric and oceanic circulation, and increased frequency and severity of floods and droughts;

2) There is a growing scientific consensus that human activity is a substantial cause of greenhouse gas accumulation in the atmosphere; and

3) Mandatory steps will be required to slow or stop the growth of greenhouse gas emissions.

(b) SENSE OF THE SENATE — It is the sense of the Senate that Congress should enact a comprehensive and effective national program of mandatory, market-based limits and incentives on emissions of greenhouse gases that slow, stop, and reverse the growth of such emissions at a rate and in a manner that—

1) Will not significantly harm the United States economy; and

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[18] See the July 5, 2005 Report of Program on International Policy at: http://www.pipa.org/OnlineReports/ClimateChange/Press_07_05_05.pdf
[19] This editorial condemns administration policy as "...the modern day equivalent of the flat earth brigade" It is available at: http://www.usatoday.com/news/opinion/editorials/2005-06-14-our-view_x.htm
[20] See the Los Angeles Times article "A Shift to Green" published June 12, 2005, and available at: http://news.yahoo.com/news?tmpl=story&u=/latimests/20050612/ts_latimes/ashifttogreen

2) Will encourage comparable action by other nations that are major trading partners and key contributors to global emissions.

3.2.2 State Action on Global Warming (Finding 2)

Leadership on global warming has moved to the states, which are taking the lead in planning and implementing greenhouse gas emission reductions. Three kinds of regulations applied or under development in various forms in US states are:

- Increasing the efficiency of electricity use by utility customers,
- Imposing mandatory renewable energy portfolios on electric utilities, so more electricity is derived from renewable fuels.
- Imposing caps on the amount of carbon dioxide that utilities can emit, and allowing utilities to trade the rights to emit greenhouse gases.

Energy Efficiency Improvements

Very significant reductions in energy use can be economically achieved by increasing energy efficiency on the customer side of the meter. Studies have shown that much electricity is wasted, and that electric utilities could satisfy customer needs with less electricity at lower cost. *Strategic planners look upon energy savings as a low cost substitute for new generators.*

Although effective energy efficiency improvements require investments, their cost can be as little as half the cost of building and operating generators to produce electrical energy. For example, a study of energy use in southwestern states[21] confirmed that huge savings in energy use could be attained by energy efficiency improvements at an average cost of approximately two cents per kilowatt-hour. This study considered the options for improved energy efficiency in Arizona, Colorado, Nevada, New Mexico, Utah, and Wyoming. It compared a projected "business as usual" scenario for electricity consumption with possible savings from aggressive energy efficiency improvements. Efficiency improvements were estimated to reduce demand growth from 2.6% per year to 0.7% and to reduce electric energy consumption by 18% by 2010, and 33% by 2020. Program costs were estimated at $9 billion and benefits at $37 billion.

These findings are representative of other studies of the whole US, or of individual states. For example, Kieth et al[22] estimate that by employing a balance of energy efficiency and renewable energy options, the US could reduce electricity consumption by 28% by 2020 relative to a "business as usual" base reference case. This study concludes that instead of a net increase of 48% in greenhouse gas emissions from the nation's electric utility industry, energy efficiency and greater reliance on renewable fuels could achieve a net 21% reduction in greenhouse gas emissions. Similar results have been shown by studies of opportunities for energy efficiency improvements in California, Nevada, Oregon and Washington. One study concluded that electricity demand in Florida could be reduced by 9.7% and natural gas use by Florida's electric

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[21] "The New Mother Lode: The Potential for More Efficient Electricity Use in the Southwest" November 2002 a product of the Southwest Energy Efficiency Project (SWEEP) available for download at: http://www.swenergy.org/nml/New_Mother_Lode.pdf.

[22] Keith, G. B. Biewald, A. Sommer, P. Henn, M. Breceda, 2003, "Estimating the Emission Reduction Benefits of Renewable Electricity and Energy Efficiency in North America: *Experience and Methods"* Available for download at: http://www.synapse-energy.com/Downloads/Synapse-report-cec-displacement-background.pdf.

utilities could be reduced by 8.3% by 2020 relative to the business as usual demand projected by the Energy Information Agency of the Department of Energy[23].

Many energy efficiency improvements experienced or expected are due to federal or state standards for buildings and appliances. Florida has "good" building standards that are better than those in many other states, but they could be strengthened. Residential use accounts for 52% of Florida electric energy consumption. More efficient water heaters and HVAC systems, smart thermostats, better insulation and other efficiency-enhancing improvements in new construction could go far toward reducing energy consumption in the state and in GRU's service area.

Rhode Island, New Jersey, California, Connecticut, Washington, and Arizona are among the states that recently established new energy standards for appliances[24].

Mandatory Renewable Energy Portfolios

Renewable energy is any energy produced from a renewable resource, such as wood or other plant material, sunshine, winds, ocean waves and currents, or hydroelectricity. Twenty-eight states promote the use of renewable energy resources [25] and nineteen states have imposed or are planning to impose mandatory renewable energy portfolios on electric utilities. Renewable energy sources reduce pollution and most are immune to the cost fluctuations typical of fossil fuel markets. By displacing some of the fossil fuels used to generate electricity, renewable energy sources reduce the emission of carbon dioxide into the atmosphere[26].

Florida has little wind or conventional hydropower renewable energy sources, and solar energy produced by means of photovoltaic cells remains too expensive to be a significant source of electricity here in Gainesville[27]. However, Japan is the leader in solar energy development, and is supporting intensive research projects aimed at reducing the capital cost of solar PV energy to $2,048 per kilowatt by the year 2020 (cost expressed in 2002 dollars). By comparison, coal-based energy combined with carbon capture and storage is expected at least this expensive. Ocean wave and current energy conversion is an extremely promising technology that could potentially supply Florida with significant amounts of carbon-free energy.

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[23] Elliot, R, and A. Shipley, "Impacts of Energy Efficiency And Renewable Energy On Natural Gas Markets: Updated and Expanded Analysis" April 2005 Report Number E052 of the American Council for an Energy-Efficient Economy Available for download at www.aceee.org

[24] See Pew Foundation web site: http://www.pewclimate.org/what_s_being_done/in_the_states/news.cfm. The Pew Foundation project on Climate change also maintains a search data base of state programs at http://www.pewclimate.org/what_s_being_done/in_the_states/database.cfm

[25] See the Database of State Incentives for Renewable Energy (DSIRE) at http://www.dsireusa.org/ and http://www.crest.org/rps_map.html. The former lists 28 states with some form of renewable energy legislation, while the latter shows 20 with mandatory standards.

[26] Biomass comprises trees or other plant material but it is considered "carbon neutral" when used as a fuel. Burning biomass releases to the atmosphere the carbon dioxide the plant initially removed from the atmosphere to form its plant tissue. In contrast, burning fossil fuels releases to the atmosphere carbon that nature had locked up in geological reservoirs millions of years ago. Without human intervention, that carbon would remain sequestered away from the atmosphere for millions of years.

[27] See "An Assessment of Renewable Electric Generating Technologies for Florida" Prepared by the Florida Public Service Commission and the Department of Environmental Protection. Available for download at: http://www.psc.state.fl.us/industry/electric_gas/Renewable_Energy_Assessment.pdf

Cap-and-Trade Programs

Some states are developing regulations to cap and ultimately reduce greenhouse gas emissions, using market forces to effect reductions in emissions. Cap and trade programs allocate pollution emissions rights to the companies covered by the program. The recipients have the option of either investing in equipment to directly reduce emissions, or to purchasing emission rights from another party.

The essential features of cap and trade programs are as follows:

1. ***An emissions "cap"***: a limit on the total amount of greenhouse gases that that can be emitted (released) from all regulated sources (e.g., power plants) in the region covered;
2. ***Allowances***: an allowance is an authorization to emit a certain amount of a pollutant;
3. ***Measurements***: of baseline of emissions for each company covered by the legislation, and accurate subsequent emissions tracking;
4. ***Flexibility***: sources can choose how to reduce emissions, including buying additional allowances from other sources that reduce emissions;,
5. ***Allowance trading***: sources can buy or sell allowances in an open market;
6. ***Compliance***: at the end of each compliance period, each source must own allowances equal to its emissions, which then expire.

The allowances assigned to each participant may be based on their past emissions, but will be smaller than historical emissions to insure that emissions actually drop[28].

The US uses a cap-and-trade system to control sulfur dioxide and nitrogen oxide releases to reduce acid rain. This is the model for carbon dioxide cap and trade systems now in use or under development elsewhere. One important difference between the acid rain program and most existing or proposed carbon dioxide cap-and-trade programs is that the carbon dioxide schemes permit emission credits (tradable emission rights) for activities that remove greenhouse gases from the atmosphere, or prevent their release into the atmosphere. Such activities include growing plants that fix atmospheric carbon in plant biomass (for example, in forests), or preventing the release of greenhouse gases to the atmosphere—by preserving forests, or reducing methane emissions from wastewater treatment plants, etc. Such tradable carbon emission rights impose high costs on the regulatory system and on its participants for measurement, monitoring, and certification of biomass carbon dioxide removal or emission prevention strategies.

Many proposed or existing cap-and-trade schemes designed to limit greenhouse gas emissions from utilities allocate emissions on an historical basis, awarding each a percentage of its emissions as of a specific date in the past[29]. Such scheme may be biased against utilities in locations where demand is growing due to migration, and benefit those where population is declining.

An alternative allocation system for utilities could ignore past performance and base emission allocations on efficiency. For example, utilities could be awarded emission rights based on the amount of energy they produce. Such a scheme benefits utilities that use low carbon fuel (natural gas) and have efficient generators (combined cycle systems). A scheme like this

[28] Many variations on the basic cap and trade program described here are under consideration by the Regional Greenhouse Gas Initiative (RGGI). See www.reggi.org
[29] Under the Kyoto Protocol, countries are assigned a cap defined in terms of their emissions in the year 1990. The McCain-Lieberman Climate Stewardship Act offered in the U. S. Senate proposes caps based on emissions in 2000.

punishes utilities that depend on high carbon fuels (coal and petroleum coke), or high-carbon technologies such as the circulation fluidized bed (CFB) generator that GRU proposes[30].

The likely costs of carbon dioxide allocations under a cap-and-trade system depend entirely on the details of the regulations and how the cap is set. If the cap is too low, then demand for carbon allocation units will be high and costs could skyrocket unless they are controlled with a "safety valve" that sets a maximum price for traded emission rights. A lenient cap could keep prices much lower than the true costs of carbon dioxide emission reductions, in which case the system would achieve few genuine emission reductions. If it is to work, the cost of the tradable allocation must be slightly higher than the cost of physically reducing greenhouse gas emissions.

Some state and regional greenhouse gas initiatives are briefly described in Appendix 3 of this chapter. These activities demonstrate a growing pressure within the US to adopt regulations to reduce the emissions of greenhouse gases. This pressure is likely to increase, as climate change issues and corrective measures become well understood by the by the public and elected officials.

3.2.3 New Technologies for Meeting the Near-Term Climate Challenge (Findings 3 and 4)

Three important recent studies discuss technological options for meeting the climate challenge. These are a report issued by the International Climate Change Task Force[31], a report from its companion organization the National Commission on Energy Policy[32], and the Pew Foundation report on the US electric power sector and climate change mitigation[33]. All three discuss the need for new technologies to reduce dependence on fossil fuels, or make fossil fuel technologies "green" through carbon capture and storage (CCS). This process removes carbon produced during coal combustion, and compresses it for transport to a geological storage site, where it is injected into an underground site. All the reports focus on conventional technologies or slightly advanced technologies that are likely to be available in the near term.

Rubin, et al., reviewed studies of the economics of CCS in different fossil fuel-fired systems[34]. They compared post-combustion carbon dioxide capture from the exhaust stream in a conventional pulverized coal plant (PC), with carbon dioxide removal during the fossil fuel gasification in an integrated gasification-combined cycle (IGCC) generating system.

Post-combustion carbon capture with PC plants is technically possible but extremely expensive. A conventional pulverized coal system consumes about 30% more coal just to run a carbon dioxide scrubber, and capturing carbon dioxide adds to the cost. Even in a new very large plant

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[30] REGGI paper.
[31] "Meeting the Climate Challenge: Recommendations of the International Climate Change Task Force" January 2005. Available for download from a link at: http://www.americanprogress.org/atf/cf/{E9245FE4-9A2B-43C7-A521-5D6FF2E06E03}/CLIMATECHALLENGE.PDF
[32] Report of the National Commission on Energy Policy This organization was appointed and supported by a group of foundations. Its report and a large compendium of technical support materials are available for download at: http://www.energycommission.org/. This report has been extremely influential, and its principles were incorporated the "sense of the Senate" discussed above.
[33] Morgan, G, J. Apt, and L. Lave, Carnegie Mellon University, 2005, "The U. S. Electric Power Sector and Climate Change Mitigation" Published by the Pew Center for Climate Change, June 2005. Available for download at: http://www.pewclimate.org/global-warming-in-depth/all_reports/electricity/index.cfm
[34] Rubin, E.S., A.B. Rao and C. Chen. "Comparative Assessments of Fossil Fuel Power Plants With Carbon Dioxide Capture and Storage". Available at: http://uregina.ca/ghgt7/PDF/papers/pcc-/475.pdf

with significant economies of scale (500-MW to 1,200-MW), such a system could cost about $50 per ton to remove and sequester carbon dioxide, *assuming* a nearby injection site and low injection costs. The capital cost of a typical new PC system with carbon capture is estimated at over $2,200 per kWh, compared with $1,200 per kWh without the CCS capability (**Table 3.1**).

Table 3.1 Cost Comparison: New Generator Costs with and without Carbon Capture and Storage

Cost and Performance Measures	Pulverized Coal	IGCC*	NGCC **
Emission Rate w/o Capture (kg CO_2 / MWh)	795	757	358
Emission Rate with Capture (kg CO_2 / MWh)	116	113	50
Percent CO_2 Reduction per kWh (%)	85	85	87
Capital Cost w/o Capture ($ / kW)	$1,260	$1,380	$560
Capital Cost with Capture ($ / kW)	$2,210	$1,880	$1,190
Percent Increase in Capital Cost (%)	77%	36%	110%
COE w/o Capture ($ / MWh)	$45	$48	$31
COE with Capture ($ / MWh)	$77	$65	$46
Percent Increase in COE w/ Capture (%)	73%	35%	48%
Cost of CO_2 Avoided ($ / T CO_2)	$47	$26	$47
Cost of CO_2 Captured ($ / T CO_2)	$34	$22	$41
Energy Penalty for Capture (% of Rated MW)	27%	16%	15%

* *Integrated Gasification with Combined Cycle*

** *Natural Gas Combined Cycle*

Source: See text.

More cost-effective systems for extracting carbon dioxide produced during power generation from solid fuels already exist. Integrated gasification combined cycle (IGCC) technology gasifies solid fuel under pressure and separates carbon dioxide in a concentrated stream as a byproduct of hydrogen production. The hydrogen is used to fire a combined cycle generator system. The gasification process also facilitates mercury and sulfur removal and produces almost no nitrogen oxides. Today's IGCC technology without carbon sequestration is about 10% more expensive than pulverized coal systems, but under greenhouse gas regulations, IGCC would be much more economical than conventional pulverized coal. Carbon dioxide storage costs are estimated at $30 per ton with a capital cost increase of about $500 per kWh. If GRU built an IGCC system, it would require little adaptation for carbon capture, but it would initially be more costly than the proposed CFB.

The Rubin study assumes that carbon capture is built into generators from the beginning, and the generators evaluated are large, technologically advanced, and highly efficient systems. It is very uncertain whether the proposed GRU generator can be retrofitted for carbon capture and how much such a retrofit would cost. There is no practical method for removing carbon dioxide at the stack where flue gases emerge. However, Rubin et al made some assumptions about the possible costs of using such a system to retrofit pulverized coal (PC) and similar generators with CCS. If such a system is built into a new PC unit, it will add $1000 per kWh to the capital cost of the new unit. Retrofitting such a unit to a small generator that GRU plans to build could not cost less than $1000 per kWh, and is like to cost far more, assuming it is possible at all. The result would add over $50 per ton of carbon dioxide, or more than 4 cents per kWh, including the added 30% fuel penalty.

We conclude that all carbon capture and sequestration is likely to be extremely costly to retrofit to the existing Deerhaven Unit #2 and the proposed CFB, assuming it is technically feasible at all, something that appears very doubtful at the present time.

The Dilemma

Any large utility that cannot delay new generator construction must make a difficult choice between a cheaper system that cannot be easily adapted to carbon capture and storage, and a slightly more expensive IGCC system that could be readily adapted[35]. The utility dilemma is whether to choose the more expensive IGCC system and be prepared for a comparatively inexpensive future retrofit to reduce carbon dioxide emissions with CCS, or to choose the cheapest solid fuel system to minimize today's building costs[36] but face a future retrofit that would be very expensive (or worse). Many utilities in Florida are seeking approval to build conventional coal-fired generators, which may be a very expensive choice when greenhouse gas regulations are imposed. These utility choices seem to reflect an assumption that no mandatory greenhouse gas regulations will be imposed within a relevant planning horizon or that penalties for greenhouse gas emissions will be insignificant.

Luckily, Gainesville does not face this dilemma now. It has other options, and need not add a large new generator at this time. It can afford to increase generating capacity incrementally, while reducing energy consumption. Additional alternative low carbon options for generating electricity are likely to be available in the comparatively near future (10 to 15 years).

Nuclear fuels are increasingly proposed for power generation. Some assume up to 30% of future energy needs will be filled with nuclear power through the end of this century, a position echoed in the Pew Foundation Report and the NCEP studies cited above, as well as other sources. But there are many serious economic and social barriers to increasing nuclear use, including the increasing and still unknown cost of safely storing nuclear waste and uncertainties regarding the current technical feasibility of adequate long-term storage[37]. Existing waste must be kept securely out of the environment for many tens of thousands of years. Plutonium, which must remain safely sequestered for more than half a million years, is also an extremely toxic poison. All terrestrial fossil fuel resources will be exhausted long before some of the sites for holding the wastes already produced by nuclear power plants can be safely abandoned in 10,000 AD and later. Security considerations are also a major barrier to increased energy production from nuclear fission, and one that will increase substantially if nuclear power use increases. Design, approval, and construction of nuclear power plants take 15 to 20 years. They are extremely expensive, and may not be cost-competitive with renewable energy resources such as wind and ocean currents, or fossil fuel use in integrated gasification combined cycle units.

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[35] Alternatives like bio-digestion of farm wastes to produce methane, or the use of manure and other biological products as fuels, offshore wave and current-derived electrical energy and other unconventional sources are under development and some are very promising, but it will be some years before any become a producing technology.
[36] Some state utility commissions require that the least expensive generating alternative be adopted, to minimize costs to consumers. Not all of them recognize the potential advantages of IGCC under mandated GHG reductions.
[37] Storage in very deep geological formations is preferred, but its cost is likely to be very high (see report of the National Academy of Engineering "Disposition of High-Level Waste and Spent Nuclear Fuel: The Continuing Societal and Technical Challenges" by the Committee on Disposition of High-Level Radioactive Waste Through Geological Isolation, Board on Radioactive Waste Management, National Research Council, 2001 A proposed Nevada storage facility in Nevada by the Nuclear Energy Institute is on hold as a consequence of a 2004 court decision http://www.nei.org/index.asp?catnum=2&catid=69

3.2.4 Assessing the Financial Risks of Future Greenhouse Gas Regulations (Finding 5)

Carbon dioxide emissions will be regulated during the lifetime of the retrofitted Deerhaven Unit #2, and that of the proposed CFB generator (if it is built). If GRU's proposals are implemented, over 90% of the electricity used in the local community will be derived from coal. The CFB unit will release over a ton of carbon dioxide for every MWh of electricity it generates, assuming it co-fires biomass. This is two and a half times the amount of carbon dioxide produced by a modern natural gas-fired combined cycle unit. The Deerhaven Unit #2 will produce about 10% more carbon dioxide than the CFB generator. Is there any way to assess the risk to the utility and the Gainesville community of choosing the system GRU proposes?

Many utilities now develop and evaluate different combinations of generators, energy efficiency and conservation options, and fuels in order to compare the risk each combination represents under future carbon emission regulations[38] [39]. These combinations are termed "portfolios". The goal of risk analysis is to pick the portfolio that reduces exposure to financial risk to a level deemed appropriate. Some states require that long term plans for new generating capacity be evaluated with respect to specific potential costs of carbon credits. For example, Oregon requires comparisons of the consequences of carbon dioxide costs of $0, $10, $25, and $40 per ton. California requires utilities to evaluate long-term plans under the assumption that carbon dioxide will cost $5.00 per ton in the near term, $12.50 per ton beginning in 2008, and $17.50 per ton by 2013[37]. Some utilities assume that all emission will be subject to these costs, while others assume that existing emissions will be grandfathered, and only new plants will be regulated.

Risk analyses will sometimes show that the portfolio that best reduces long-term financial risks will increase rates in the near-term, before carbon emission regulations begin. In effect, the utility incurs a small cost in the near-term to hedge against a much larger long-term risk, a policy that will be viewed as a prudent one in many circumstances.

Utilities that have conducted risk analyses find that future costs of carbon in the range $20 per ton and up can very significantly influence the calculated financial risk of alternative portfolios.

GRU has not performed risk analyses of this nature [40]

3.2.5. GRU's Plans and Options (Findings 6 and 7)

GRU's proposal to build a new 220-MW generator that uses coal and petroleum coke, and operate it together with the existing coal-fired unit will make solid fuel the source of approximately 90% of the energy used locally, up from the current 68%. Carbon dioxide emissions are expected to increase by about 1.5 million tons when the retrofitted DH2 and the

[38] See a useful recent summary of these actions by Bokenkamp, K., H. LaFlash, V. Singh, and D. Bachrach-Wang. "Hedging Carbon Risk: Protecting Customers and Shareholds from the Financial Risk Associated with Carbon Dioxide Emissions", The Electricity Journal, Vol. 16, Issue 6, July 2005, pp 11-24.
[39] Harrington, C, D. Moskovitz, W. Shirley, F. Weston, R. Sedano, and R. Cowart, "Portfolio Management: Protecting Customers in an Electric market That Isn't Working Very Well. 2002. Paper prepared by the Regulatory Assistance Project for the Energy Foundation and the Hewlett Foundation. Available for download at: http://www.raponline.org/showpdf.asp?PDF_URL='Pubs/PortfolioManagement/PortfolioMgmtReport%2Epdf
[40] The sensitivity analyses GRU performed on the models it used to simulate the performance of its proposed solid-fuel plan and compare it to nearly identical plans that use natural gas to fuel future expansions of capacity is not risk analysis. The difference is discussed in Chapter 5 below.

new CFB units come on-line. Consequently compliance with future mandatory greenhouse gas regulations could be extremely costly.

Compliance requirements are likely to be mild at first, (assuming that they are not delayed for more than a few years). Most proposals regulating greenhouse gases incorporate financial penalties for utilities that do not meet their allocated emission caps and cannot purchase carbon reduction credits to make up for excess emissions[41]. The international task force calls for penalties not to exceed $7.00 per ton of carbon dioxide until CCS systems are available and widely used, which could be as late as 2015 or 2020. Such low penalties will not reduce emissions significantly. If they are adopted, the world is unlikely to reach the 60% reduction that is the minimum believed to be necessary by the year 2050.

We can expect far higher penalties as increasingly stringent regulations after regulations are implemented. Ultimately, penalties must approximate the cost of mitigating emissions, likely to be at least $30 to $50 per ton of carbon dioxide, assuming the estimates of Rubin et al. for mitigation with CCS and an IGCC are accurate.

Two ways to reduce the future carbon emission penalties are to (1) use renewable wood and other biomass that does not add to the atmosphere burden of fossil carbon dioxide, and (2) significantly reduce the use of electricity in the local service area. EPAC has reviewed GRU's plans for biomass fuel use, and for reducing electricity demand growth rates in the local service area.

Unlike some large municipal or investor-owned utilities in the state, Gainesville has significant extra capacity now. GRU could postpone a generating technology decision for a few years if it were to adopt an aggressive campaign to promote conservation and energy efficiency. EPAC has found that greater biomass use is possible. A new, small biomass generator could probably delay the need for new generating capacity[42] long enough for greenhouse gas regulations to emerge, making it possible to plan adaptations to them.

Moreover, a review of the very modest GRU conservation programs suggests that these could be significantly increased. They could achieve far greater energy consumption and demand reductions than have been achieved to date. Conservation could reduce future peak energy needs by up to 60 MW or more by 2020 or even earlier[43], further delaying the need for a decision on new generating capacity.

The Intergovernmental Panel on Climate Change is currently working on its fourth assessment. This will summarize climate science, the expected impacts of climate change on social and economic systems, and the options for adapting to or mitigating the effects of increasing global warming. This report will clarify the magnitude and timing of needs for greenhouse gas reductions. The rapid attitude changes in the US Senate suggest that the results of the assessment will give rise to action at the Federal level. The fourth assessment report will be released in January 2007. Scientists are presently at work preparing drafts of the various components of the report to be circulated among all the IPCC reviewers. These will be available to the public in a few months.

[41] GRU proposes to meet future greenhouse gas emission regulations with a "Greenhouse Gas Fund", but EPAC finds that the GRU scheme is unlikely to provide the protection needed. The approach is discussed in Chapter 5 of this report.
[42] See Chapter 8.
[43] See Chapter 6.

EPAC's review strongly suggests that GRU can delay a decision to add a large power plant for three years or more. The advantages of this option are self-evident. Within three years, more information about new regulations, and the potential availability of new technologies will be available. The new technologies might include CCS systems that could be incorporated in new GRU generators, or large solid-fuel based generators at other points in the state that could provide reasonably priced energy for Gainesville[44]. The studies presented in this report indicate that in so doing we could be more energy efficient, use a significant quantity of local biomass, and emit less harmful air pollution.

Strategic Considerations

The preceding discussions have confirmed that the world is at serious risk of climate changes to which we may be unable to adapt. Governments are beginning to appreciate the dimensions of the climate crisis and to develop methods to deal with it.

Mandatory greenhouse gas reductions will be enacted in the United States, and these are likely to be accompanied by subsidies for renewable fuels, new energy efficiency standards, and significant increases in energy costs, as well as the accelerated development of technologies that produce electric energy without emitting greenhouse gases to the environment. These developments are very likely. They add new layers of uncertainty to utility planning.

GRU faces a future of major changes in the energy environment, yet it lacks detailed information about exactly what those changes will be or when they will occur. GRU can choose either of two strategic approaches to meet rising energy needs:

- Option 1. Supply forecasted energy needs by building generators that use currently cheap solid fuels (coal and petroleum coke). Assume either that (a) any future financial penalties on carbon dioxide emissions will be small compared to the current and future cost advantage of solid fuels, or (b) climate scientists are in error and there is no global warming crisis.

  This option makes a 50-year commitment to expensive generators that emit very large amounts of carbon dioxide. It largely eliminates the community's financial ability to adapt to a changing regulatory environment or to new technologies as they emerge. GRU has chosen this option

- Option 2. Delay commitments to new fossil fuel-based generators as long as possible and invest in conservation options to reduce future demand. Make no long-term commitments to any new fossil fuel-based technologies. Invest in economical, local, and renewable energy sources where possible, to minimize exposure to future greenhouse gas financial penalties.

A detailed risk assessment of alternative portfolios of the kind described in the second option above would illuminate new ways to approach this community problem.

Chapter 3, Appendix 1: Statement of the Academies of Science

In an unprecedented show of scientific consensus and unanimity, The Presidents of the Academies of Science of Brazil, Canada, China, France, Germany, India, Italy, Japan Russia, the United Kingdom and the United States of America have all signed the following statement:

Climate change is real

There will always be uncertainty in understanding a system as complex as the world's climate. However there is now strong evidence that significant global warming is occurring[1]. The evidence comes from direct measurements of rising surface air temperatures and subsurface ocean temperatures and from phenomena such as increases in average global sea levels, retreating glaciers, and changes to many physical and biological systems. It is likely that most of the warming in recent decades can be attributed to human activities (IPCC 2001)[2]. This warming has already led to changes in the Earth's climate.

The existence of greenhouse gases in the atmosphere is vital to life on Earth – in their absence average temperatures would be about 30 centigrade degrees lower than they are today. But human activities are now causing atmospheric concentrations of greenhouse gases – including carbon dioxide, methane, tropospheric ozone, and nitrous oxide – to rise well above pre-industrial levels. Carbon dioxide levels have increased from 280 ppm in 1750 to over 375 ppm today – higher than any previous levels that can be reliably measured (i.e. in the last 420,000 years). Increasing greenhouse gases are causing temperatures to rise; the Earth's surface warmed by approximately 0.6 centigrade degrees over the twentieth century. The Intergovernmental Panel on Climate Change (IPCC) projected that the average global surface temperatures will continue to increase to between 1.4 centigrade degrees and 5.8 centigrade degrees above 1990 levels, by 2100.

Reduce the Causes of Climate Change

The scientific understanding of climate change is now sufficiently clear to justify nations taking prompt action. It is vital that all nations identify cost-effective steps that they can take now, to contribute to substantial and long-term reduction in net global greenhouse gas emissions.

Action taken now to reduce significantly the build-up of greenhouse gases in the atmosphere will lessen the magnitude and rate of climate change. As the United Nations Framework Convention on Climate Change (UNFCCC) recognizes, a lack of full scientific certainty about some aspects of climate change is not a reason for delaying an immediate response that will, at a reasonable cost, prevent dangerous anthropogenic interference with the climate system.

As nations and economies develop over the next 25 years, world primary energy demand is estimated to increase by almost 60%. Fossil fuels, which are responsible for the majority of carbon dioxide emissions produced by human activities, provide valuable resources for many nations and are projected to provide 85% of this demand (IEA 2004)[3]. Minimizing the amount of this carbon dioxide reaching the atmosphere presents a huge challenge. There are many potentially cost-effective technological options that could contribute to stabilizing greenhouse gas concentrations. These are at various stages of research and development. However barriers to their broad deployment still need to be overcome.

Carbon dioxide can remain in the atmosphere for many decades. Even with possible lowered emission rates we will be experiencing the impacts of climate change throughout the 21st century and beyond. Failure to implement significant reductions in net greenhouse gas emissions now will make the job much harder in the future.

Prepare for the Consequences of Climate Change

Major parts of the climate system respond slowly to changes in greenhouse gas concentrations. Even if greenhouse gas emissions were stabilized instantly at today's levels, the climate would still continue to change as it adapts to the increased emission of recent decades. Further changes in climate are therefore unavoidable. Nations must prepare for them.

The projected changes in climate will have both beneficial and adverse effects at the regional level, for example on water resources, agriculture, natural ecosystems and human health. The larger and faster the changes in climate, the more likely it is that adverse effects will dominate. Increasing temperatures are likely to increase the frequency and severity of weather events such as heat waves and heavy rainfall. Increasing temperatures could lead to large-scale effects such as melting of large ice sheets (with major impacts on low-lying regions throughout the world). The IPCC estimates that the combined effects of ice melting and seawater expansion from ocean warming are projected to cause the global mean sea-level to rise by between 0.1 and 0.9 meters between 1990 and 2100. In Bangladesh alone, a 0.5 meter sea-level rise would place about 6 million people at risk from flooding.

Developing nations that lack the infrastructure or resources to respond to the impacts of climate change will be particularly affected. It is clear that many of the world's poorest people are likely to suffer the most from climate change. Long-term global efforts to create a more healthy, prosperous and sustainable world may be severely hindered by changes in the climate.

The task of devising and implementing strategies to adapt to the consequences of climate change will require worldwide collaborative inputs from a wide range of experts, including physical and natural scientists, engineers, social scientists, medical scientists, those in the humanities, business leaders and economists.

Conclusion

We urge all nations, in the line with the UNFCCC principles[4], to take prompt action to reduce the causes of climate change, adapt to its impacts and ensure that the issue is included in all relevant national and international strategies. As national science academies, we commit to working with governments to help develop and implement the national and international response to the challenge of climate change.

G8 nations have been responsible for much of the past greenhouse gas emissions. As parties to the UNFCCC, G8 nations are committed to showing leadership in addressing climate change and assisting developing nations to meet the challenges of adaptation and mitigation. We call on world leaders, including those meeting at the Gleneagles G8 Summit in July 2005, to:

- Acknowledge that the threat of climate change is clear and increasing.
- Launch an international study[5] to explore scientifically informed targets for atmospheric greenhouse gas concentrations, and their associated emissions scenarios, that will enable nations to avoid impacts deemed unacceptable.

- Identify cost-effective steps that can be taken now to contribute to substantial and long-term reduction in net global greenhouse gas emissions.
- Recognize that delayed action will increase the risk of adverse environmental effects and will likely incur a greater cost.
- Work with developing nations to build a scientific and technological capacity best suited to their circumstances, enabling them to develop innovative solutions to mitigate and adapt to the adverse effects of climate change, while explicitly recognizing their legitimate development rights.
- Show leadership in developing and deploying clean energy technologies and approaches to energy efficiency, and share this knowledge with all other nations.
- Mobilize the science and technology community to enhance research and development efforts, which can better inform climate change decisions."

Notes and references

1 This statement concentrates on climate change associated with global warming. We use the UNFCCC definition of climate change, which is 'a change of climate which is attributed directly or indirectly to human activity that alters the composition of the global atmosphere and which is in addition to natural climate variability observed over comparable time periods'.
2 IPCC (2001). Third Assessment Report. We recognize the international scientific consensus of the Intergovernmental Panel on Climate Change (IPCC).
3 IEA (2004). World Energy Outlook 4. Although long-term projections of future world energy demand and supply are highly uncertain, the World Energy Outlook produced by the International Energy Agency (IEA) is a useful source of information about possible future energy scenarios.
4 With special emphasis on the first principle of the UNFCCC, which states: 'The Parties should protect the climate system for the benefit of present and future generations of humankind, on the basis of equity and in accordance with their common but differentiated responsibilities and respective capabilities. Accordingly, the developed country Parties should take the lead in combating climate change and the adverse effects thereof'.
5 Recognizing and building on the IPCC's ongoing work on emission scenarios.

Chapter 3, Appendix 2: Recent Newspaper Articles

A. Miguel Bustillo June 12: "A Shift to Green", LA Times
B. Dan Vergano, USA TODAY, Posted 6/12/2005. "The debate's over: Globe *is* warming"

A. Excerpts from Los Angeles Times article "A Shift to Green" By Miguel Bustillo Times Staff Writer Published Sunday, June 12, 2005, and available on the internet at: news.yahoo.com/news?tmpl=story&u=/latimests/20050612/ts_latimes/ashifttogreen

American corporations are increasingly calling for action on global warming, sensing a business opportunity in cutting greenhouse gases while hoping to shape regulations they believe are inevitable.

Bucking the Bush administration's position that tougher rules would harm the U.S. economy, Fortune 500 companies including General Electric Co., Duke Energy Corp. and JP Morgan Chase & Co. in recent months have championed stronger government measures to reduce industrial releases of carbon dioxide, the main heat-trapping gas that scientists have linked to rising temperatures and sea levels.

This shift in corporate thinking was on display at a congressional hearing last week, where executives from large companies including DuPont Co., United Technologies Corp. and Baxter International Inc. described how they were getting an early start on reducing greenhouse gas emissions — something they believe they would be required to do sooner or later.

People increasingly will believe that greenhouse gas emissions should be reduced and that actions should begin today to prepare for that eventuality," James Rogers, the chairman of power generator Cinergy Corp., told the House Science Committee on Wednesday. Rogers now advocates a national program to reduce greenhouse gas emissions.

The number of companies involved remains small, but it is growing, particularly in the energy sector, and is emerging as a new dynamic in the debate over the future of America's global warming policies. The U.S., the world's largest emitter of greenhouse gases, was the only major developed nation other than Australia to reject the Kyoto Protocol, an international pact to cut emissions to about 5% below 1990 levels by 2012...

...Many multinational companies, which already deal with carbon reduction regulations in other parts of the world, believe it's only a matter of time before they will be required in the U.S. Rather than resist the inevitable, they want to help shape new regulations in a way that will give them a competitive advantage.

In addition, some companies fear that in the absence of federal action, many cities and states, which already are proposing their own regulations, will create a hodgepodge of compliance standards across the country...

Those concerns were amplified this month, when California Gov. Arnold Schwarzenegger signed an executive order that pledges to reduce the state's emissions by more than 80% in the next half-century.

"We don't need a patchwork of inconsistent state or local regulations to complicate and increase the cost of compliance," Duke Energy Chairman Paul Anderson said in an April speech to Charlotte, N.C., business leaders in which he surprised the electric power industry by advocating a federal tax on the carbon content of fossil fuels. "Yet a patchwork is exactly what we are getting, due to federal inaction."

Duke, which has announced plans to acquire Cinergy, formally proposed the levy to President Bush's tax reform panel in April — an approach that critics noted would penalize Duke far less than some competitors in the electricity business that depend more on coal power.

"Businesses don't like taxes, and they don't like uncertainty. Right now, they face a future where they will be hit with some kind of regulation on carbon, and a growing number of them are saying, if we take some actions now perhaps we can avoid stronger actions later," said Sen. Thomas R. Carper (news, bio, voting record) (D-Del.) who has proposed legislation to reduce carbon dioxide along with traditional smog-forming pollutants.

"There is more support for doing something than there was a year ago," Carper said. "Will there be enough to pass one of them? Anybody's guess right now."

The Bush administration, which has pursued an energy policy that heavily promotes fossil fuels, has shown few signs of altering its position on climate change, however.

The American Petroleum Institute has been lobbying against the recommendations of the National Commission on Energy Policy, which also suggested a moderated "cap and trade" system in which companies that reduced more than their share of greenhouse gases would obtain credits they could sell to others.

A similar, less restricted market is already underway in Europe, where a ton of carbon credits was recently valued at $25.

There is also far less momentum for global warming regulations in the House than in the Senate, backers acknowledge, making passage of any legislation unlikely.
"We're not there yet in the House, quite frankly. These businesses are way ahead of us," said Rep. Sherwood L. Boehlert (news, bio, voting record) (R-N.Y.), who supports a federal program to reduce greenhouse gases. The Bush administration stance "happens to be wrong," he added, but he expressed optimism that it could change as dissenting businesses become more vocal.

"American industry leaders are not calling for us to adopt Kyoto, but they are growing increasingly impatient with the voluntary approach," said William K. Reilly, who served as head of the Environmental Protection Agency under President George H.W. Bush and is co-chairman of the National Commission on Energy Policy.

At the heart of the increase in corporate advocacy on global warming is a belief that the U.S. is missing a golden opportunity to cash in on the burgeoning worldwide response to the threat.

Some companies are concerned that the Bush administration's voluntary programs are too weak to encourage expanded use of cleaner technologies such as solar, wind and even nuclear power, compared with the market-based regulations now required nearly everywhere else in the developed world. Japan now leads the world in the development of solar power cells, and Europe is the top producer of wind-power machinery.

Some companies are also concerned that by failing to assert leadership on global warming, the U.S. is allowing the European Union — and a number of states around the country — to dictate how industries are expected to conduct themselves around the world.

"We think the science is pretty compelling, and it is appropriate to take action now" to reduce global warming, said Helen Howes, Vice President for environment, health and safety at Exelon Corp., one of the nation's largest utilities, which participated in the National Commission on Energy Policy. "You have seen thawing in the Arctic, issues of potential rising water levels. For us, because we have a lot of nuclear plants that use a lot of cooling water, we are worried that water supplies may not be as reliable in the future."

Though some corporations are willingly stepping forward with proposals to tackle global warming, others are being dragged into the debate by socially conscious shareholders.

Evangelical and environmental investor groups, as well as state pension fund officials who together control more than $3 trillion in assets, are pushing resolutions at shareholder meetings that seek to compel companies to disclose their financial exposure to global warming regulations.
The resolutions almost never win majority support. But in response to the pressure, many companies are choosing to develop global warming policies to head off continuing confrontations.

Some are even putting pressure on their corporate peers. JP Morgan Chase recently announced that it would ask clients that are large emitters of greenhouse gases to develop reduction plans, following similar commitments by Citigroup Inc. and Bank of America Corp.

"Two years ago, the concept of climate risk was something alien to investors. That's certainly not the case today," said Mindy S. Lubber, the president of Ceres, an organization that compels companies to embrace environmental responsibility. "Investors are raising these issues because they feel that they are affecting the value of companies, and they are raising the issues en masse. It is a good thing because it is prompting dialogue and discussion.

-- USA Today, June

B. Excerpts from USA Today Article "The debate's over: Globe *is* warming"
By Dan Vergano, USA TODAY. Posted 6/12/2005 Available at:
http://www.usatoday.com/news/world/2005-06-12-global-warming-cover_x.htm?POE=NEWISVA

Don't look now, but the ground has shifted on global warming. After decades of debate over whether the planet is heating and, if so, whose fault it is, divergent groups are joining hands with little fanfare to deal with a problem they say people can no longer avoid.

General Electric is the latest big corporate convert; politicians at the state and national level are looking for solutions; and religious groups are taking philosophical and financial stands to slow the progression of climate change.

They agree that the problem is real. A recent study led by James Hansen of the NASA Goddard Institute for Space Studies confirms that, because of carbon dioxide emissions and other greenhouse gases, Earth is trapping more energy from the sun than it is releasing back into space.

The U.N. International Panel on Climate Change (IPCC) estimates that global temperatures will rise 2 to 10 degrees by 2100. A "middle of the road" projection is for an average 5-degree increase by the end of the century, says Caspar Amman of the National Center for Atmospheric Research in Boulder, Colo.

What the various factions don't necessarily agree on is what to do about it. The heart of the discussion is "really about how to deal with climate change, not whether it's happening," says energy technology expert James Dooley of the Battelle Joint Global Change Research Institute in College Park, Md. "What are my company's options for reducing greenhouse gas emissions? Are there new business opportunities associated with addressing climate change? Those are the questions many businesses are asking today."

<u>The players</u>

GE Chairman Jeffrey Immelt recently announced that his company, which reports $135 billion in annual revenue, will spend $1.5 billion a year to research conservation, pollution and the emission of greenhouse gases. Joining him for the announcement were executives from such mainline corporations as American Electric Power, Boeing and Cinergy.

Religious groups, such as the United States Catholic Conference of Bishops, National Association of Evangelicals and National Council of Churches, have joined with scientists to call for action on climate change under the National Religious Partnership for the Environment. "Global warming is a universal moral challenge," the partnership's statement says.

And high-profile politicians from both parties are getting into the act. For example, California Gov. Arnold Schwarzenegger has called for a reduction of more than 80% over the next five decades in his state's emission of greenhouse gases that heat in the atmosphere.

To be sure, many companies — most notably oil industry leader ExxonMobil — still express skepticism about the effects of global warming. And the Bush administration has supported research and voluntary initiatives but has pulled back from a multi-nation pact on environmental constraints.

The administration was on the defensive last week when *The New York Times* reported that a staff lawyer has been softening scientific assessments of global warming. White House spokesman Scott McClellan defended such action as a routine part of a multi-agency review process.

Nonetheless, the tides of change appear to be moving on....

"As big companies fall off the 'I don't believe in climate change' bandwagon, people will start to take this more seriously," says environmental scientist Don Kennedy, editor in chief of the journal *Science*. Companies aren't changing because of a sudden love for the environment, Kennedy says, but because they see change as an opportunity to protect their investments.

-- *USA Today*

Chapter 3, Appendix 3: State and Regional Greenhouse Gas Policies[1]

Recent State Actions

In July 2005, **Rhode Island** adopted an act that calls for minimum efficiency standards for 14 appliances. Some of these appliance standards are based on the U.S. Environmental Protection Agency (EPA) and the U.S. Department of Energy's Energy Star standards and California's existing appliance standards. The standards are expected to reduce annual GHG emissions by 20,000 tons and save the state $225 million in reduced energy generation costs over the next 25 years. Rhode Island joins Washington, Maryland, Connecticut, Arizona, New Jersey, and California in setting efficiency standards for household and commercial appliances.

New Mexico joined a growing number of states with targets for greenhouse gas emissions reductions when Governor Bill Richardson signed an Executive Order on Thursday, June 9, 2005. The Governor set New Mexico's targets at achieving 2000 emissions levels by 2012, 10% below 2000 levels by 2020, and a 75% reduction below 2000 emission levels by 2050. These goals supplement New Mexico's suite of climate-friendly policies that includes a renewable portfolio standard, a renewable energy tax credit, and a goal to increase energy efficiency.

In June 2005, **California** established greenhouse gas emissions targets for the state that would reduce greenhouse gas emissions by 11% over the next five years, 25% by 2020, and 80% by 2050. (These targets are equivalent to reaching 2000 GHG emissions levels by 2010; and 1990 levels by 2020). California has a variety of existing policies and programs addressing climate change and electric energy use. The state also approved an ambitious target of demand side management programs to reduce the peak demand expected in 2013 by 5000 gigawatts, and total energy use in the state by 23,000 gigawatt hours. This represents a reduction of the growth in demand of 55% to 59% over the decade.

On May 9, 2005, **Oregon** adopted two bills that will increase both supply and demand for renewable energy generation. On the supply side, SB 5111 offers tax breaks to Oregon companies that manufacture and sell solar equipment. On the demand side, SB 5101 offers the first state feed-in credit for solar and wind energy production. A feed-in credit provides performance-based tax breaks for small-scale renewable energy generation to "feed" electricity into the grid; a similar German law spurred high levels of investment in renewables.

Montana recently took a step towards increasing renewable generation in the state by passing Senate Bill 415, which requires that 10% of the electricity sold in Montana come from renewable sources by 2010 and 15% by 2015. The bill also calls for a renewable energy credit tracking system and leaves open the option to trade renewable energy credits outside of the state. The legislation contains a cost cap that encourages utilities to invest in renewable generation that is cost competitive with conventional generation.

On April 28, 2005, **North Dakota** adopted a legislative package that encourages wind power,

[1] This summary has used materials from sources cited in the text and in addition has also relied on the resources of the Pew Global Warming web site (www.pewclimate.org) and on a paper by Johnston, L., A. Roschelle, and B. Biewald, 2005, "Taking Climate Change into Account in Utility Planning: Zero is the Wrong Carbon Value". Synapse Energy Economics (available for download at http://www.synapse-energy.com/Downloads/synapse-report-carbon-policy-mar-05.pdf).

ethanol, and biodiesel. North Dakota will now allow renewable energy credits (RECs) from in-state generation to be sold to out-of-state buyers, and will lower the barriers to siting wind power generators, and investing in new transmission. Adequate transmission capacity is often a serious barrier to wind investments. The Legislature authorized continued funding for the ethanol incentives championed by the governor, as well as tax breaks for the purchase and production of both ethanol and biodiesel.

On April 22, 2005, **Iowa** Governor Thomas Vilsack signed an executive order instructing state agencies to increase their operational energy efficiency and renewable energy use. The order mandates a 15% improvement in energy efficiency at state facilities by 2010, and the procurement of hybrid or alternative-fuel vehicles for non-law enforcement state vehicles. The governor also directed state agencies to purchase equipment with the lowest life-cycle cost when possible, and to purchase 10% of their electricity from renewable sources. Iowa is the nation's top producer of ethanol, one of the fuels that can be used by the vehicles mandated by the order. Iowa also has over 600MW of wind capacity, in part due to a Renewable Portfolio Standard that the state passed in 1999.

On April 8, 2005 **Washington** Governor Christine Gregoire signed a bill mandating that all new public buildings meet the US Green Building Council's Leadership in Environmental Design (LEED) Silver standards. Washington is the first state in the country to require such standards. The law will apply to new public facilities over 5,000 square feet, as well as major renovation projects. A building can achieve a LEED standard by earning points based on energy efficiency, use of sustainable materials, and other environmental attributes. Currently over 1,900 buildings in the United States completed or in progress meet one of the LEED standards.

Arizona, New Jersey, and **California** announced new appliance efficiency standards this spring. On March 8th, Acting New Jersey Governor Richard Codey approved higher standards for eight products, including commercial refrigerators and washing machines. New Jersey projects consumer savings of over $742 million by 2020 on their utility bills. Also in March, the California Energy Commission set standards for 17 products, and estimates these regulations will save consumers $3 billion over 15 years. Most recently, in April Arizona Governor Janet Napolitano signed into law efficiency standards for 12 appliances. These states' standards are for products not covered by federal standards. Without a waiver from the Department of Energy, states may not set standards for products with existing federal standards. **Maryland** and **Connecticut** have also passed appliance efficiency standards.

In March 2005, the **New Mexico** legislature passed three bills to promote energy efficiency and renewable energy investments in the state. One provides for $20 million in bonds to support energy efficiency and solar projects in existing buildings, another encourages public gas and electric utilities to invest in energy efficiency partly in order to slow the export of money to out-of-state electricity generators, and the third facilitates energy upgrades in public buildings.

On February 11, 2005, Governor Janet Napolitano of Arizona signed an executive order requiring new state-funded buildings to derive at least 10% of their energy from renewable sources, either directly or through the purchase of renewable energy credits. This executive order also requires new state buildings to meet the "silver" level of the Leadership in Energy and Environmental Design (LEED) standards.

In December the **California** Public Utilities Commission (CPUC) approved a required "carbon adder" for inclusion in resource plans for California's three large investor owned utilities, Pacific

Gas and Electric Company, Southern California Edison, and San Diego Gas and Electric Company. The carbon adder explicitly takes into account the social cost of carbon emissions from electricity generation facilities when comparing prices of fossil fuel and renewable generation, as well as demand-side management investments. The carbon adder will be used for utility planning purposes only, and will not be assessed to consumers. Taking the cost of carbon into account will mean that a power source is considered more cost effective if it avoids a ton of carbon dioxide emissions for $8 to $25. The CPUC based this range of costs on a number of studies, including the Idaho Power Company's 2004 resource planning process, which assessed a carbon adder of $12.30 per ton of carbon dioxide.

In December **Pennsylvania** adopted an Alternative Energy Portfolio Standard that requires the use of wind, solar, coalmine methane, small hydropower, geothermal and biomass energy sources. The legislation specifies that by 2020, 0.5% of energy must be derived from solar sources, the most solar power mandated by any state. The legislation also requires the use of waste coal, demand side management, large hydropower sources, municipal solid waste and coal integrated gasification combined cycle (IGCC).

In 2001 **Massachusetts** passed legislation limiting carbon dioxide emissions from fossil fueled power plants[2]. This multi-pollutant legislation requires emission reductions including carbon dioxide reductions from the six highest emitting power plants in the state. Allocation of emission rights is based on an efficiency criterion of 1800 lbs/MWh, which is a 10% reduction from historic baseline. New power plant with a capacity greater than 100 MW are required to offset 1% of their carbon dioxide emissions for 20 years, or pay a fine of $1.50 per ton of carbon dioxide. Massachusetts is one of the 9 states in the Regional Greenhouse Gas Initiative (see below).

• In 1997 **Oregon** an emission standard for new power or expanded power plants of not more than 0.675 lbs of carbon dioxide per kWh, which is about 15% lower than the most efficient natural gas-fired plant. The state also created a non-profit Climate Trust to implement to implement offsets with funds provided by the electric generating industry. A generator can choose to either meet the emissions standard or donate funds to the Climate Trust. The donation level was originally set at $0.57 per ton of carbon dioxide, but is subject to change based on the actual cost of carbon dioxide offsets.

• The **New Hampshire** "Clean Power Act" (HB 284), approved in May 2002, requires carbon dioxide reductions from the three existing fossil-fuel power plants in the state. The law requires the plants to stabilize their carbon dioxide emissions at 1990 levels (which is approximately three percent below their 1999 levels) by the end of 2006. This carbon dioxide emission reduction is consistent with the Climate Change Action Plan adopted by the New England Governors and Eastern Canadian Premiers (see below). Plants have the option to reduce their emissions on site or to purchase emissions credits from outside of the state.

• In **New Jersey**, the Department of Environmental Protection released the New Jersey Sustainability Greenhouse Gas Action Plan in April 2000. The Plan provides a framework for reducing greenhouse gas emissions to 3.5 percent below their 1990 levels by 2005. Under the Plan, Public Service Enterprise Group, the state's largest utility, pledged to reduce total emissions from all of its fossil fuel-based plants by 15% below 1990 levels by 2005. This would

[2] Anne Egelston, "Oregon, Massachusetts Lead the Way in GHG Reductions," *Environmental Finance*, July-August 2001.

require its fossil fuel-fired units to limit their carbon dioxide emissions to 1450 lbs/MWh in 2005, compared to 1706 lb/MWh in 1990. If PSEG fails to achieve the goal, it must pay the Department of Environmental Protection $1 per pound/MWh it falls short of its goal, up to $1.5 million. The fund will be used to support carbon dioxide reduction projects within New Jersey.

• The **New York** Greenhouse Gas Task Force was created by Governor Pataki in June 2001. The purpose of the Task Force is to develop recommendations for ways to significantly reduce the state's emissions of greenhouse gases, and New York is currently considering whether to adopt the recommendations of the Greenhouse Gas Task Force. The 2002 State Energy Plan also recommends that the state commit to a goal of reducing greenhouse gas emissions by 5 percent below1990 levels by 2010, and 10 percent below 1990 levels by 2020. New York is one of the states in the RGGI project.

• In addition to the regulations and programs described above, 25 states are working with the U.S. Environmental Protection Agency ("EPA") to develop climate action plans that identify cost-effective options for reducing greenhouse gas emissions at the state level. At least 19 states have completed an action plan to date. Many states have other policies such as renewable portfolio standards and energy efficiency programs that serve to reduce carbon dioxide emissions from the electricity sector either in effect or in development.

Regional Initiatives

Actions by individual states have been seconded by several regional initiatives to reduce greenhouse gas emissions:

One of the more interesting regional actions was initiated in 2001, when New England Governors and Eastern Canadian Premiers signed an agreement for a comprehensive regional Climate Change Action Plan[3]. Nine Northeast and Mid-Atlantic states (DE, ME, MA, NH, NJ, NY, RI, VT) have formed "The Regional Greenhouse Gas Initiative" (RGGI) in a cooperative effort to discuss the design of a regional cap-and-trade program initially covering carbon dioxide emissions from power plants in the region. Collectively, these RGGI states contribute to 9.3% of total US carbon dioxide emissions and together rank as fifth highest carbon dioxide emitter in the world. Pennsylvania, Maryland, the District of Columbia, the Eastern Canadian Provinces, and New Brunswick are official "observers" in the RGGI process. A Model Rule is scheduled to be issued in 2005. In this process, carbon dioxide emissions from fossil fuel fired electricity generating units will be capped at specific levels.[4]

The plan centers on three main goals. The short-term goal of the Plan is to reduce regional greenhouse gas emissions to 1990 levels by 2010. The mid-term goal is to reduce regional GHG emissions by at least 10% below 1990 levels by 2020, consistent with reductions necessary worldwide to eliminate any dangerous threat to the climate. The Plan also provides for the establishment of a regional standardized inventory and registry of greenhouse gas emissions and an interactive, five-year process, starting in 2005, to adjust the goals if necessary and set future emission reduction goals.

[3] New England Governors and Eastern Canadian Premiers, *Climate Change Action Plan: 2001*, August 2001.
[4] Information about the progress of the planning efforts can be found at www.rggi.org

The long-term goal of the Plan is to reduce regional greenhouse gas emissions in proportions consistent with reductions necessary worldwide to eliminate any dangerous threat to the climate, which recent science suggests will require reductions of 75-85% below current levels. The Plan also provides for the establishment of a regional standardized inventory and registry of greenhouse gas emissions.

In September 2003, the Governors of **California, Washington, and Oregon** established the West Coast Governor's Climate Change Initiative, stating that "global warming will have serious adverse consequences on the economy, health, and environment of the west coast states, and that the states must act individually and regionally to reduce greenhouse gas emissions and to achieve a variety of economic benefits from lower dependence on fossil fuels."[5] Emissions in these three states are comparable to those of the RGGI states.

In fact, RGGI and the West Coast Governors' Initiative have been communicating with regard to potentially linking their cap and trade programs.[6] • **California**'s Governor Schwarzenegger and **New Mexico**'s Governor Richardson proposed that 18 western states generate 30,000 MW of electricity from renewable source by 2015. This proposal was unanimously adopted in June 2004[7].

In July 2004, **California, Connecticut, Iowa, New Jersey, New York, Rhode Island, Vermont, and Wisconsin** filed a suit against five utility companies, which together, emit 10% of the nation's annual carbon dioxide. This suit seeks emissions reductions rather than financial penalties.

Actions by Cities

Many cities are also adopting climate change policies. The Cities for Climate Protection Campaign (CCP), begun in 1993, is a global campaign to reduce the emissions that cause global warming and air pollution[8]. By 1999, the campaign had engaged more than 350 local governments, which jointly accounted for approximately 7 percent of global greenhouse gas emissions. Over 150 cities in the U.S. have adopted plans and initiatives to reduce emissions of greenhouse gases, setting emissions reduction targets and taking measures within municipal government operations.

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[5] See letter from the California Energy Commission and the California Environmental Protection Agency to interested parties, April 16, 2004, at: http://www.energy.ca.gov/global_climate_change/westcoastgov/

[6] Fontaine, Peter, "Greenhouse –Gas Emissions: A New World Order," *Public Utilities Fortnightly*, February 2005

[7]34 Jacobson, Sanne, Neil Numark and Paloma Sarria, "Greenhouse – Gas Emissions: A Changing US Climate," *Public Utilities Fortnightly*, February 2005.

[8] Both Gainesville and Alachua County are members of this organization. Information on the Cities for Climate Protection Campaign, including links to over 150 cities that have adopted greenhouse gas reduction measures, is available at http://www.iclei.org/projserv.htm#ccp

Chapter 3 Appendix 4: Additional Information Sources

Many printed books and articles, and Internet sites provide information about climate change and responses to it. This appendix is a guide to some useful resources readers can consult.

Quick looks for non-technical readers:

If you have only a little time, and no interest in technical issues, consider the following:

"Climate of Man", a three-part article published in this spring in The New Yorker magazine, is the best available introduction to global warming. Writer Elizabeth Kolberg interviewed leading climate scientists, and discusses their current research and their concerns about global warming. The article provides the non-scientist with information about the methods used by the climate scientists the author interviewed, and some important recent findings about the impacts we can expect from past and continued increases in greenhouse gas emissions induced by human activities.
Kolberg's article conveys the frustration and deep concern all legitimate climate scientists feel about global warming, and how urgently they advocate steps to reduce greenhouse gas emissions. The articles appeared in the New Yorker on April 25, 2005, May 2, 2005 and May 9, 2005. These are available at the Alachua County Public Library.
In July 2005, all thee parts of the article were available for download at the NewYorker Internet site at
http://www.newyorker.com/fact/content/?050425fa_fact3
http://www.newyorker.com/fact/content/?050502fa_fact3
http://www.newyorker.com/fact/content/?050509fa_fact3

The Scientific American is an excellent source for non-technical readers. It has been publishing articles about important global warming research since the early 60's. Recent articles about global warming that we recommend include:
"Defusing the Global Warming Time Bomb" by James Hansen[1]. This article was published in Scientific American in March 2004 (pp 68-77) and is available from Dr. Hansen's web site at Columbia University. http://www.columbia.edu/~jeh1/hansen_timebomb.pdf
"Abrupt Climate Change" by Richard B. Alley, (Scientific American, November 2004, pp 62 to 69) discusses the evidence for large abrupt temperature shifts in the comparatively recent past (up to18,000 years ago) that imply that climate is the result of the delicate balancing of many interacting forces.
"Spring Forward", Daniel Grossman, Scientific American, January 2004 (pp 86 to 91) describes some of the indicators of global warming—effects we can see all around us. As temperatures rise sooner in spring, interdependent species in many ecosystems are shifting dangerously out of sync, weakening the links in the food chain. How global warming stresses ecosystems is described in this article.
The digital version of the Scientific American has excellent reports from earlier years available for download at http://www.sciamdigital.com/. These are free to subscribers, or can be purchased for a small sum.

Science Basics. Basic information about how carbon dioxide and other greenhouse gases influence the temperature of the earth is available at many Internet sites. Scientific knowledge is accumulating

[1] A 2004 lecture by Dr. Hansen entitled "Dangerous Anthropogenic Interference: A Discussion of Humanity's Faustian Climate Bargain and the Payments Coming Due" is also available at this site, and is highly recommended for readers who want to understand the implications of the climate findings. It consists of a short text and excellent graphics. Download it from: http://www.columbia.edu/~jeh1/dai_complete.pdf

rapidly, and sites can become obsolete quickly. Always check the date of the last posting on sites you are browsing, and be sure that the site you are looking at is not dedicated to misleading the public[2].

One very good source of basic information is the web site of the **Koshland Science Museum of the National Academy of Sciences**. The National Academy was established to advise the government about scientific issues. The home page of the section on Global Warming is:
http://www.koshland-science-museum.org/exhibitgcc/index.jsp
Links to good short videos about fundamentals are located in the sidebar on the right of the home page. This page contains links to sections with more advanced information. This site was developed in 2005 and additions are added regularly. All the information at this site is up to date. .

Other US Government Sites. Many US Government agencies conduct research of various kinds related to global warming and at one time had useful web sites devoted to educating citizens who lack technical backgrounds. Unfortunately, many of these agencies have stopped updating their sites, some of which are now so out-of-date they can actually mislead the unwary browser. The government agencies that deal closely with climate change include the Environmental Protection Agency (EPA), the National Oceanic and Atmospheric Administration (NOAA), the National Aeronautics and Space Administration (NASA). Many agencies have programs that contribute to climate science goals.

The **NOAA "Paleo Perspectives"** site at: http://www.ncdc.noaa.gov/paleo/perspectives.html is a very informative site. This web page contains links to three subjects: abrupt climate change, drought, and global warming. The last of these has not been updated since 2000, but little of its information is misleading. The evidence confirming that the global average Northern Hemisphere is warmer than any time since the year 1000 is now stronger than indicated at this site.

Additional Sites with Basic Information:

National Center for Atmospheric Research (NCAR). Research on atmospheric processes and many aspects of global climate change has been conducted at NCAR for the last 40 years and it is the home of many leading climate scientists. The NCAR climate change site at: http://eo.ucar.edu/basics/cc1.html is one of the best on the Internet.

USA Today. This newspaper maintains an excellent source of basic information and breaking news at: http://www.usatoday.com/weather/resources/climate/climate-sci-resources.htm. Excellent videos with basic science information are available this site. The links page connects to many good sources[3].

The **Pew Climate Center** was established in 1998 to work for common sense solutions to the problems represented by climate change. It has a strong business outreach program and works to promote joint action by business leaders, policy makers and scientists. Basic information about climate science is found at http://www.pewclimate.org/global-warming-basics/. The center funds studies of the economics of many aspects of climate change, and is the home of the Business Environmental Leadership Council. The center maintains very useful databases of state and city actions re global warming and carbon emission reductions.

The National Resources Defense Council devotes much of its site to global warming, beginning at http://www.nrdc.org/globalWarming/default.asp. The NRDC reports current breaking news, and

[2] The controversy about climate science is discussed below.
[3] Unfortunately, you will have to pay to download news articles in the USA Today archives.

maintains a staff of utility experts that conduct research on economic issues relating to electric utility operations. The latter is headquartered in California, where it works with the California Energy commission and the California Public Utility Commission and other state agencies, and some municipal utilities.

The BBC is a good source of basic information and recent news, Climate information begins at: http://www.bbc.co.uk/climate/

Breaking News
Several web sites issue informative press releases about recent research, or summarize current research. Here is a short list of good ones:

The UK **Parliamentary Office of Science and Technology** publishes **"POSTNOTE",** which offers summaries of recent news about scientific topics. Number 245 July 2005 is an excellent summary of "Rapid Climate Change", describing the most recent developments relating to abrupt climate change. It can be downloaded at: http://www.parliament.uk/documents/upload/POSTpn245.pdf

The **NASA Goddard Institute for Space Studies** is a major center of research on climate science that provides links to timely and very informative discussions of its research at **http://www.giss.nasa.gov/research/news/ .** Links to other sites that describe NASA research are also located here.

The **NASA Earth Observatory** is a source of satellite photos some of which document the impact of global warming. The links below the photo on the right access abundant resources for technical and non-technical readers alike. The URL is http://earthobservatory.nasa.gov/Newsroom/

History. Concern that carbon dioxide released from fossil fuel burning could be influencing the climate now began to be voiced almost 50 years ago, when scientists first applied carbon-14 dating techniques to marine carbon, and discovered that it was heavily diluted with "old" carbon from fossil fuels. This history is charmingly summarized "The Discovery of Global Warming", published by the Harvard University Press in 2001 (http://www.hup.harvard.edu/catalog/WEADIS.html). The book summarized materials its author Spencer R. Weart had developed for the American Physics Institute. These materials and much supplementary information are available at the API web site. The climate section of this web site is a treasure house of information, expressed in a series of essays that cover different topics. Check the table of contents at the following site: http://www.aip.org/history/climate/index.html# , and jump in for a leisurely read. The history takes the reader up to 1988, and while some of the essays deal with events occurring after that date, there has been no attempt to present a full and detailed picture of climate research post 1988.

Help for Non-Scientists
Non-scientists who are concerned, intelligent, and willing to study will never the less have trouble understanding the current scientific literature, or perceiving the implications of reports in the public press. Every paper published in a scientific journal is embedded in an intellectual context of research findings well known to the authors, the peer reviewers, and their professional audience, but inaccessible to the ordinary citizen.
Until December 2004, journalists and others lacking a strong scientific background had no way to interpret the significance of new research findings. In that month, nine climate scientists started **Realclimate.org** and began posting essays explaining the issues in language journalists and others could understand. The purpose was to supply journalists with a source of timely, accurate information, and to counter the systematic misrepresentations offered by the so-called "climate skeptics" and their allies. The latter are ideologically opposed to environmental regulations or perceive major financial

advantages in avoiding restrictions on greenhouse gas emissions[4]. The website is http://www.realclimate.org/. Interested individuals can sign up for email alerts.

Controversy and Counter Claims

Readers who conduct a search of the Internet using search terms like "global warming" or "climate change" will retrieve many of the sites listed above. Their search will also retrieve a very large number of sites that challenge the validity of the conclusions of the overwhelming majority of scientists who are professionally qualified to speak on climate change. A very tiny minority of scientists are featured as experts in dozens of sites that challenge the mainstream scientific consensus. These scientists are referred to as climate science "skeptics" or "contrarians". Many politically conservative groups have become allied with corporate interests that see regulations of greenhouse gases as a threat to their profits. Such groups are engaged in a relentless public relations campaign to convince the American public that global warming is not a problem and no steps need be taken to combat it. Many claim that scientists are in error or disagree about the fundamental problem.
One can identify some of these web sites by the claims they make about climate science. The following claims are among those encountered often:

1. "*Climate scientists disagree about whether global warming is occurring and whether carbon dioxide from fossil fuels has caused it.*" This claim is sometimes based on little other than publications by non-scientists or by credentialed scientists who publish in the public press (Wall Street Journal, the Washington Times and some other newspapers).
   Some base the claim that scientists are uncertain about the causes of global warming on a misrepresentation of the kind of uncertainties about important scientific details that do exist. For example, the U. S. National Academy of Sciences has reviewed global climate science many times, and always concluded that the major conclusions are scientifically justified, but that there are uncertainties and further research is needed.
   Contrarians interpret such statements about uncertainties as evidence of fundamental questions about the reality of global science, and the validity of the evidence that, in reality, is widely accepted. Some claims about "disagreements" simply misrepresent of the way working scientists criticize one another's published reports—a normal feature of all rigorously intellectual inquiries.

2. "*Scientists ignore the global warming impact of water vapor, which is a natural constituent of the atmosphere responsible for most of the greenhouse effect*". Many web sites repeat the fallacious claim that humans contribute less than 1% of the greenhouse gases that trap heat in the atmosphere, the rest being water vapor, which is a natural product. About 65 to 70% of the heat redirected back to the earth by greenhouse gases in the atmosphere is due to the presence of water vapor (not 1%), but the fundamental mistake lies not in the quantitative error, but in the idea that water vapor is a "forcing" that contributes to global warming. The amount of water vapor in the atmosphere depends on air temperature, which in turn depends on the presence of carbon dioxide and other greenhouse gases in the atmosphere. Thirty-six percent of the carbon dioxide now in the atmosphere was added by human activities after the beginning of the industrial revolution. Cold air is dry. The air held little water vapor at the close of the last ice age 10,000 years ago, and the carbon dioxide concentration was about

[4] See McCright, A. M. and R. E. Dunlap, 2000 "Challenging Global Warming as a Social Problem: An Analysis of the Conservative Movement's Counter Claims", 2000, Social Problems, Vol 47, pp 499-522. and McCright:. A. M., and R. E. Dunlap 2003 "Defeating Kyoto: The Conservative Movement's Impact on U.S. Climate Change Policy", Social Problems, Vol 50 pp 348-373. Both are available from links at http://www.abo.fi/6thNESS/Filer/Abstract_Dunlap.htm

200 ppm. Gradually the temperature increased, and as it did, carbon dioxide concentrations increased to the normal interglacial value of 280 ppm, the air warmed up, and its water vapor content increased, which in turn added to the greenhouse effect. The water vapor presence is one of the many feedback effects that make temperature increases self-amplifying. This role of water vapor as a greenhouse gas is discussed on the realclimate web site: www.realclimate.org .

3. "*The current global temperature reflects the natural variations in temperature the earth has experienced in the past.*" One form or another of this claim has been a regular feature of contrarian positions for many years. Currently it focuses on a 1998 publication that combined a variety of proxy records of past temperatures to arrive at an estimate of the average northern hemisphere temperature variations over the last millennium. The authors of the papers used long records of tree rings, corals, lake sediments and ice cores that reflect past temperatures. These are called "proxy" records. These were combined statistically to estimate the temperature of the northern hemisphere for the last 1,000 years. Later, new evidence was used to produce an estimate of the global temperature. The estimates have been independently confirmed many times. The temperature plot is sometimes called the "hockey stick" because it is relatively constant for a long duration, and then curves sharply and shoots up to high levels and its shape is similar to that of a hockey stick.
This temperature record has never figured among the strongest evidence of climate change. However, it makes a good public relations target readily understood by the average non-scientist. The authors of the hockey stick papers have been attacked in the press, derided on talk radio and on many web sites, insulted and harassed by members of Congress, and even targeted by name by the Wall Street Journal. Contrarians Willie Soon, Sallie Baliunas and their colleagues are a major source of the claims that the "hockey stick" is in error. These authors also contend that recent temperature increases reflect a normal "rebound" from the mid-19th century end of the "little ice age" when global temperatures were low. The many errors in the work by Soon and colleagues are discussed on the realclimate web site, as is the evidence for a "little ice age" and a "medieval warm period"—another climatic regime that figures prominently in challenges to mainstream science.
(Stanford climatologist Steve Schnieder discusses the careers and claims of Soon, Baliunas and other "contrarians" on his web site. Select "contrarians" in the sidebar at: http://stephenschneider.stanford.edu/Climate/Climate_Science/CliSciFrameset.html).

4. "*The models that scientists use are deliberately biased and unreliable*". Critics who base arguments about global warming on these and related grounds do not disclose the information about the many ways modelers test their models, or their successes in reproducing historic climate effects. The Realclimate web site contains information about the care modelers take to make sure their models are adequate.

5. "*There is a conspiracy among scientists to misrepresent the experimental evidence and other facts*". Measurements that confirm that fossil fuel burning has greatly added to the carbon dioxide in the atmosphere provide the strongest evidence that humans are changing the climate. Given increases in atmospheric carbon dioxide, simple physics will tell you that the temperature is bound to increase.
    a. The carbon dioxide concentration in the atmosphere has not exceeded 300 ppm in the last 400,000 years. Most of that time it ranged between 200 ppm (during ice ages) and 280 ppm (between ice ages and during the last 10,000 years). This information comes from measuring the composition of air bubbles trapped in Antarctic ice cores.

b. Large quantities of fossil fuel carbon dioxide identifiable by its great carbon-fourteen age is present in the ocean, as gas dissolved in the water, and in shells and tissue of living marine organisms.
c. In less than 50 years, the carbon dioxide concentration of the atmosphere has risen from 315 parts per million to near 380 parts per million, as determined by long-term measurements at Mauna Loa, HI[5].

Contrarians cannot explain these facts away, so they usually ignore them when addressing scientifically unsophisticated audiences. When the facts cannot be evaded, contrarians try to account for them as the product of a very large conspiracy of secretive scientists who systematically fake all the data, though few can offer any explanations about what could motivate scientists to do this[6]

[5] The PBS program "NOW" surveyed political and scientific opinion about global warming on April 22, 2005. The program transcript is available at http://www.pbs.org/now/transcript/transcriptNOW116_full.html, a page with also contains links to fully discussions and background under the heading "More on These Stories". A special section for educators is linked here. Oklahoma Senator James Inohofe is identified as claiming that global warming predictions are a "hoax" perpetrated on the American public.

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Chapter 4: Carbon Intensity, Offsets, and the Greenhouse Gas Fund

4.0 Introduction

If GRU builds a new solid fuel generator, solid fuel (coal and petroleum coke) will generate more than 90% of the local electricity after this unit and the retrofitted Deerhaven Unit #2 begin operating. Burning solid fuels to generate electricity releases far more carbon dioxide to the atmosphere than burning oil or natural gas[1]. Carbon dioxide (CO_2) is one of several greenhouse gases (GHG) that contribute to global warming and are likely to be regulated in the near future. If GRU's builds a new solid fuel generator, its carbon dioxide emissions will increase significantly.

The electric utility industry often describes GHG emissions in terms of the amount of carbon dioxide released to the atmosphere per unit of energy generated. This measure is called "carbon intensity"[2]. Carbon intensity of electricity generation is reported in units of pounds of carbon dioxide per kWh or MWh generated. In 2003 the investor-owned electric utility industry adopted a goal of reducing the greenhouse gas emission per unit of electricity produced by 3 to 5% by 2013[3]. However, it is not certain that these carbon intensity reductions will reduce carbon emissions that contribute to global warming. In 1990, carbon intensity in the electric utility industry was 1,773 pounds per megawatt hour and by 2001 it had declined about 3.5% to 1,706 pounds per megawatt hour. But in this interval, carbon dioxide emissions from the industry increased by 23%.

Carbon intensity per million dollars of gross national product is a measure used to compare different economies. Countries with large smokestack industries usually have a high carbon intensity, while countries with little heavy industry often have low carbon intensities, especially if their economies are technologically advanced.

President Bush has proposed that reducing carbon intensity of the entire US economy is the way to combat global warming. However, carbon intensity reductions do not—by themselves—achieve reductions in total emissions. In the US, fossil carbon dioxide emissions have *increased* by 30% since 1990, while carbon intensity has *declined* by over 19%. The goal of reducing greenhouse gases to the atmosphere is different from reducing carbon intensity.

GRU includes reducing carbon intensity as one of the six goals of its solid fuel plan[4]. In many GRU presentations, they have claimed that carbon dioxide emission increases that may result from its proposed new circulating fluidized bed (CFB) generator will be balanced (offset) by:

- Past carbon dioxide emission reductions resulting from conservation, and a lowered need for electricity,
- Past reductions due to using a more efficient generator to produce electricity (the Kelly combined cycle plant)[5],

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[1] Coal and petroleum coke produce more carbon dioxide per unit heat, and generators that use these fuels need more units of heat to produce a unit of electricity than the most modern natural gas-fired "combined cycle" units.
[2] The amount of carbon dioxide per unit of gross domestic product is a measure used to compare different countries. National goals for greenhouse gases have been defined by the U.S. Government in terms of reducing the amount of carbon dioxide equivalent[2] released nationally relative to the gross domestic product.
[3] Goal announced by the Edison Electric Institute in 2001.
[4] "Alternatives for Meeting Gainesville's Electrical Requirements Through 2023" Gainesville Regional Utilities, December 2003. This document is also referred to as the IRP or the IRP document.

- The use of landfill gas to generate electricity,
- Sequestration of carbon in pulpwood forests, and
- Photovoltaic solar energy installations that produce electricity but release no carbon dioxide.

An "offset" is an action that reduces GHG emissions or removes GHG from the atmosphere to compensate for fossil fuel carbon dioxide emissions. Most existing or planned greenhouse gas regulations include provisions for offset credit for the sequestration[6] of carbon that occurs when growing plants incorporate atmospheric carbon dioxide in their tissues. Greenhouse gas reduction regulations are also expected to provide for trading credits for reducing GHG emissions from other sources, such as wastewater treatment plant methane and nitrous oxide, both potent greenhouse gases[7].

In December 2004, GRU announced a plan to establish a greenhouse gas fund to develop carbon sequestration or local GHG emission reduction projects. The goal of this plan is to provide valuable "carbon credits" the utility could exchange for the right to release fossil fuel carbon dioxide to the atmosphere under future GHG regulations, thereby avoiding likely financial penalties from those regulations.

EPAC has reviewed the expected carbon dioxide emissions and carbon intensity values if GRU's proposals are approved. We also reviewed GRU's proposed use of offsets to compensate for fossil fuel greenhouse gas emissions, and its proposal for a Greenhouse Gas fund projects that provide offsets.

4.1 Key Findings

1. **GRU's plan would increase its atmospheric carbon dioxide emissions, compared to the year before the new and retrofitted plants come on line, because coal and petroleum coke release large amounts of carbon dioxide per unit kWh generated.** Increases exceeding 900,000 tons (40%) will occur the first full year the new and retrofitted units go on-line compared to the prior year. The overall increase between 2004 and 2023 would exceed one and a half million tons (about 80% of 2004 emissions)[8]. The proposed CFB technology releases an extra one half ton of carbon dioxide equivalents per ton of fuel compared to other coal-using technologies[9].

2. **GRU claims that "offsets" can balance some of these increases in carbon dioxide emissions, but these claims are not valid.** Most of the claims reflect a

[5] See reference in footnote 4 above.
[6] Sequestration refers to the removal of CO_2 from the atmosphere and its storage in a reservoir of some kind, or the collection of fossil CO_2 and its injection into geological deposits like coal beds or deep underground brine reservoirs.
[7] Nitrous oxide is approximately 310 times more effective as a greenhouse gas than carbon dioxide, while methane is 23 times as effective. Sulfur hexafluoride is a gas with industrial applications, including insulation in large electric transformers used in some GRU substations. It is the most potent greenhouse gas of all: one pound of sulfur hexafluoride in equivalent in global warming potential to 12 tons of CO_2. This and other industrial gases that have significant global warming potentials are discussed at: http://www.eia.doe.gov/oiaf/1605/vr99data/chapter6.html
[8] EPAC use two data sources for these calculations. Data for the interval 2001 through 2014 are taken from actual past emissions and 10-yr projections found in the Ten Year Site Plans GRU submits annually to the Florida Public Service Commission. Data for the years 2004 through 2023 were based on a simulation of the proposed new system conducted by GRU. The latter are discussed in Chapter 5.
[9] Nitrous oxide is 310 times more effective than CO_2 in trapping heat. It is produced during low temperature combustion in the CFB unit. Low temperature combustion reduces the amount of acid-forming oxides of nitrogen produced.

misunderstanding of offsets, and how they are acquired. GRU's erroneous calculations include counting some past GHG reductions twice, and mistakenly crediting itself with preventing methane emissions from the Alachua County landfills. GRU failed to recognize the importance of the eligibility requirement for "additionality"[10] or for the duration of carbon sequestration. GRU claims offsets in excess of 255,000 tons of carbon dioxide, but EPAC concludes that only about 33 tons may be valid.

3. **Instead of declining, GRU's carbon intensity will actually increase by about 38% during the first year the retrofitted DH2 and the new CFB generator go on line, relative to carbon dioxide emissions in the prior year.**

4. **GRU has proposed a multimillion-dollar fund to purchase offsets to compensate for the increased GHG emissions from its CFB unit. However, such purchases are unlikely to yield credits that will reduce financial penalties under future regulations for carbon dioxide emissions.** No US state has announced compliance regulations for carbon offsets under a law that caps total emissions. Such compliance regulations are likely to parallel existing compliance requirements for trading pollution credits under current American acid rain programs. The "offsets" acquired by the fund proposed by GRU are unlikely to satisfy these compliance regulations.

5. **GRU could prepare for future regulations by carefully inventorying and documenting all its baseline greenhouse gas emissions (including those from the wastewater and natural gas utilities), having them independently certified, and registering them in a suitable registry.** Such an inventory would establish the current emissions baseline. This would insure that eligible projects that reduce emissions (conservation, increases in end-use efficiency, reductions of emissions from the wastewater treatment plants, etc) are taken into consideration when emission rights are allocated under future regulations. The City Commission directed GRU to produce an inventory of its greenhouse gas emissions, but none has been released to date.

4.2 Discussion

4.2.1 Carbon Dioxide Emissions under GRU's Plans (Finding 1)

One of the most important features of GRU's capacity expansion plan is that it substitutes inexpensive coal for expensive natural gas. At present, about 68% of the GRU energy production is from coal, but in 2011, if GRU's plans are implemented; over 90% of the energy used in the local service area will be derived from coal. Coal combustion releases far more carbon dioxide to the atmosphere than combustion of natural gas or even oil. This means that increased carbon dioxide emissions are inevitable under GRU's plan. The carbon dioxide emission per kWh generated depends on generator types and their fuels. **Figure 4.1** shows the amount of carbon dioxide released by different GRU generators, and by the CFB unit planned for the future.

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[10] The "additionality" requirement holds that credit can be given only for offsets that are in addition to existing projects. The Oregon standard phrases this requirement as follows: "It must be demonstrated that an offset project would not otherwise occur without the funding provided by the offset purchaser."

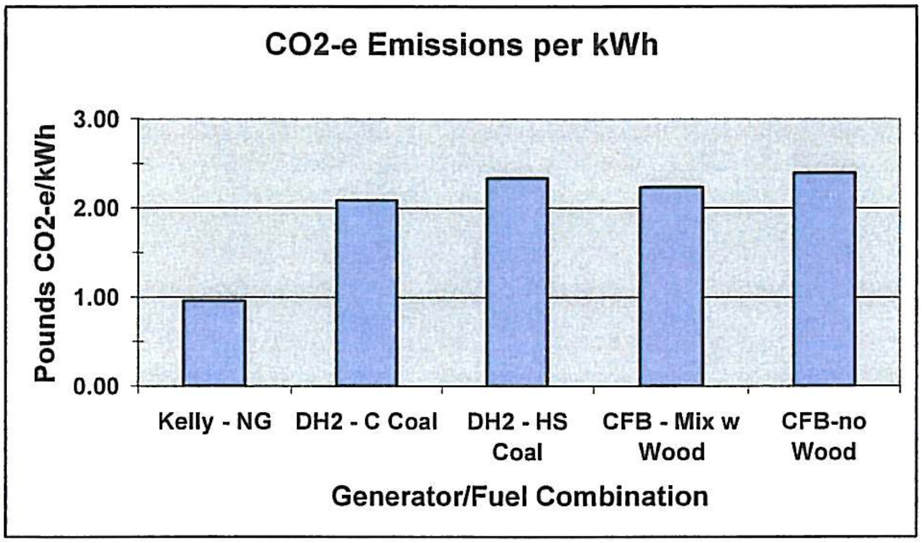

Figure 4.1. Greenhouse gas emissions for different fuels and generators used by GRU. The Kelly combined cycle generator is the most efficient one in the GRU fleet. Currently Deerhaven Unit #2 burns low sulfur "compliance" coal, but after its retrofit will use high sulfur fuel. The CFB unit adds the equivalent of one half ton of carbon dioxide emission per ton of fuel because nitrous oxide is produced by its low-temperature combustion process. The plot assumes all units are operating at maximum efficiency.

The natural gas estimate in **Figure 4.1** assumes the use of GRU's most efficient generator (the combined cycle unit at Kelly). Gas-fired peaking units at Kelly are far less efficient. One of the smaller peaking units used chiefly when demand is very high would release about 1.75 pounds of carbon dioxide per kWh generated. Low sulfur "compliance" coal is now used in Deerhaven Unit #2. "HS coal" is high sulfur coal that will be used in the retrofitted Deerhaven Unit #2, and in the CFB unit if it is built. The final two entries in the plot correspond to the mix of coal, petroleum coke and wood that may be used in the CFB unit and the emissions if no wood is co-fired with the other fuels in the CFB. It is evident from the data shown in **Figure 4.1** that GRU carbon dioxide emissions must increase if the proportion of solid fuel increases and the proportion of natural gas decreases.

Past and future estimated greenhouse gas CO2-equivalent[11] emissions are shown in **Figure 4.2.**

[11] CO_2-equivalents are used when the estimate includes the global warming potentials of heat-trapping gases like methane and nitrous oxide. All EPAC estimates of GRU emissions after 2011 include the effects of the nitrous oxide emissions from the CFB unit.

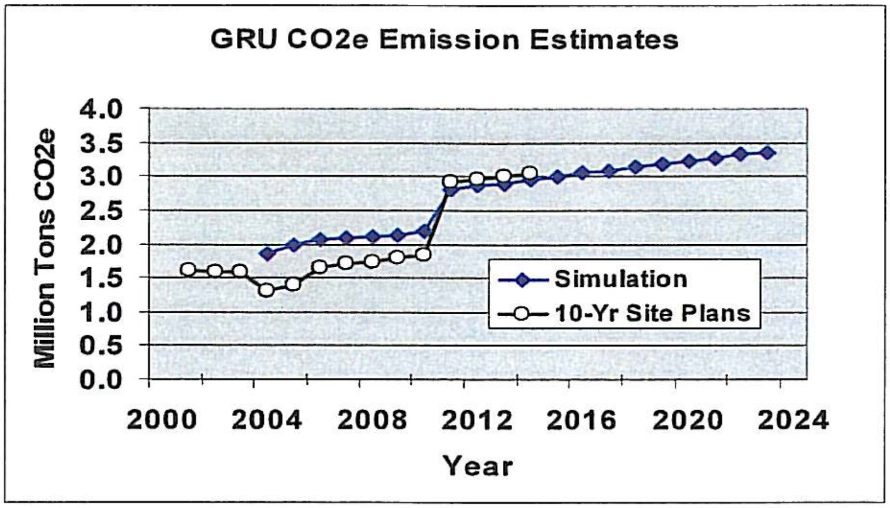

Figure 4.2. Estimates of future CO2-equivalent emissions based on ten-year site plan projections and GRU simulations. Data for 2001-2004 reflect past experience. The Ten-Year Site Plan projections are believed to be more accurate than those from the simulations are. The CFB alone will contribute over 1.5 million tons of CO2-e to the atmosphere after 2011, just to supply local energy needs. The data include the effects of nitrous oxide emissions from the new CFB unit and assume that biomass accounts for approximately 7.5% of total energy after 2011. Emissions resulting from electricity generation to support off-system sales are not included.

Two sets of estimates are plotted in Figure 4.2. One is based on the data in the Ten Year Site Plans GRU submits annually to the Florida Public Service Commission. These show actual fuel consumption for the years 2001 through 2004, and projected consumption for 2005 through 2014. EPAC produced the plots using emission factors for coal and petcoke supplied by GRU, and other emission factors published by the Department of Energy, or the EPA. The second type of data in **Figure 4.2** shows simulated emissions based on a GRU simulation of its solid fuel plan operations[12]. There are differences between the two sets of plotted data. Some are within the normal limits of data used for strategic planning, but EPAC regards the Ten-Year Site Plans as more reliable indicators of local energy fuel use.

Inspection of **Figure 4.2** confirms a sharp increase in emissions when the new CFB unit begins operating. This is due to the shift to coal for over 90% of local energy use. This plot confirms that carbon dioxide emissions increase sharply in 2011, when the retrofitted Deerhaven Unit #2 and the new CFB unit go on-line, and coal becomes the source of about 90% of local energy use.

4.2.2. Emission Offset Claims Not Valid (Finding 2)

In many reports and presentations to the City Commission, GRU staff claimed that past carbon dioxide emission reductions could be credited against future emissions, and used to reduce the effective carbon dioxide emissions. **Tables 4.1** and **4.2** show some of the claimed offsets and the carbon intensity reductions attributed to them. GRU's assumptions regarding how offsets are calculated and used are in error. The errors are discussed below.

[12] These simulations are discussed in Chapter 5.

Double Counting

Most of the offsets listed in **Table 4.1** represent double counting of emission reductions. GRU employs a bookkeeping procedure to subtract from the emissions occurring in one year, reductions in emissions due to conservation or other actions in a prior year. But that prior year action has already physically reduced the emissions. The GRU bookkeeping calculation subtracts emission reductions a second time. [13]

Table 4.1

GRU CO_2 Offsets (tons/yr)

Waste Wood Fuel (Proposed)[1]	271,776
Kelly CC1 Repowering[2]	90,524
Demand-Side Management	74,000
Landfill Gas to Energy Project[3]	57,120
Forest Protection (10,000 acres)[4]	33,917
Solar at the Airport (proposed)	16
Systems Control Center Solar	12
Solar in Schools	5

1. 30 MW of DH3
2. Assumes avoidance of DH2 coal-fired generation by 2002 CC1 steam turbine generation efficiency gains.
3. Assumes two units operating at 75% capacity factor. Adjusted for methane reduction credit using 2001 IPPC Global Warming Potentials.
4. Assumes average 3.39 tons CO_2 / acre / year

Table 4.2

Overall CO_2 Intensity
Would Be Reduced By 14%

Year	Carbon Emissions (Million Tons CO_2)	Carbon Intensity* (lb-CO2/Gross MWh)
2003	1.8	1,998
2012	3.2	1,721

* Adjusted To Reflect No Offsets in 2003. Carbon Offsets Include Treating Biomass As Carbon Neutral, Methane Reductions from Landfill Gas, Demand Side Management, Equipment Effiecency Upgrades and Photovoltiac Electric Installations.

[13] The additionality requirement precludes obtaining credit for emission reductions, or carbon sequestration that would happen even if there were no GHG regulations.

[15] . The question of double counting has been addressed several times in the literature. Some rather abstruse features of double counting are discussed in Appendix 2.

Consider the following simple example. Suppose that a factory uses coal and emits a million tons of carbon dioxide every year. Suppose further that in 2002, it undertakes a program that reduces the emissions in all subsequent years to 950,000 tons. It cannot later claim the 50,000-ton reduction as an "offset" against its 950,000 ton emissions, to infer a corrected emission of 900,000 tons, because this is equivalent of counting the 50,000 tons twice[15]. Many compliance rules preclude bookkeeping corrections of the kind GRU uses. All emissions and offsets must be physically real and capable of being measured[16].

Most of GRU's claimed "offsets" represent this kind of double counting, including the reductions claimed for re-powering the Kelly plant as a combined cycle unit, and those claimed for prior conservation efforts. **Table 4.1** has an entry for the use of waste wood in the future CFB boiler, but as wood is carbon neutral, it normally is not counted as contributing fossil carbon dioxide emissions to the atmosphere[17] and should not be counted as an offset in the manner proposed.

Two of the offset claims in **Table 4.1** do not represent double counting, but they are not valid for other reasons. These are the claimed credit for reducing methane emissions from the landfills, and the claimed credit for pulpwood silviculture sequestration on some City-owned property.

Landfill Methane Claims

GRU calculates an offset credit of 57,120 tons of carbon dioxide for preventing methane emissions from Alachua County landfills. This is the CO_2-equivalent of 2,383 tons of methane collected from the landfill and used to generate electricity. According to GRU, this methane would have entered the atmosphere had there been no generators at the landfills to produce electricity from it. GRU infers a large credit because methane has a global warming potential more than 20 times that of carbon dioxide.

GRU is in error in claiming credit for preventing methane emissions. No methane was emitted from the landfills prior to installing the generators. Methane was collected and flared in compliance with EPA regulations, and the resulting waste heat was dissipated into the air. GRU is now harnessing that waste heat to produce electricity.

Carbon Sequestration in Forests

Some City-owned land is used for growing trees for pulpwood under an arrangement with a local forester. GRU estimates the annual conversion of carbon dioxide from the atmosphere into wood and other plant products at an average of 3.39 tons of carbon dioxide per acre for the 20-year cropping cycle, for an average annual offset of 33, 917 tons of sequestered carbon dioxide. While it is true that forests and other plants remove carbon dioxide from the atmosphere and convert some of it to plant tissue, the mere fact of such conversion is not enough to qualify as sequestration of atmospheric carbon dioxide. To balance the emission of fossil fuel carbon dioxide, the sequestration should remove the carbon dioxide for as long as the fossil GHG it balances remains in the atmosphere.

The question of how long the wood must survive and keep the carbon in it away from the atmosphere is a critical one. Durations are specified in the detailed compliance regulations of different jurisdictions. Many Kyoto countries use 100 years as the minimum term of

[16] See "Demonstration of Real" in Appendix 1.
[17] EPAC has not counted carbon dioxide from wood fuels in analyses presented above. However, we have counted the nitrous oxide that is produced when wood is burned in the CFB unit. For this reason, no wood waste burning offset can be validly applied to the figures presented here.

sequestration, on the assumption that carbon dioxide remains in the atmosphere for about 100 years before being absorbed in cold seawater, and transferred to the deep ocean[18]. Some jurisdictions require that all trees that offset fossil fuel carbon emissions remain in perpetuity in conservation areas, and are never harvested[19].

An offset is not equivalent to a compliance credit that will save GRU money, or compensate for huge GHG releases to the atmosphere. *An offset becomes a compliance credit only in the context of a legally enforced GHG credit trading system, and only when it is found to comply with all the restrictions and eligibility requirements of that system.*

No American local or regional government agency has yet imposed a cap-and-trade system within its jurisdiction and developed the detailed regulations that govern the nature and eligibility of carbon credits. When these are developed, they are likely to follow the model of pollution emissions trading under the American acid rain program. Appendix 1 contains a list of eligibility rules from a demonstration program used to evaluate such regulations.

One critical requirement of all state implementations of the acid rain pollution-trading scheme is that credit cannot be awarded for activities that represent business as usual, or are performed for reasons other than to comply with the restrictions of the acid rain program. This is called the "additionality" requirement, or the "surplus" requirement.

Carbon credit compliance regulations that follow this model will preclude awarding credits for carbon sequestration that would happen anyway in the absence of GHG regulations. This would rule out awarding compliance credits for sequestering carbon in forests that are legally protected from harvest (for example, in state forests, or on conservation land), or required to remediate environmental damage (like the open pit mine restoration programs in many states) or forests that are grown and harvested as part of an on-going agricultural effort.

4.2.3 Increase in Carbon Intensity (Finding 3)

Carbon intensity increases in 2011 in parallel increases in the amount of coal-derived carbon dioxide emitted. **Figure 4.3** shows estimates of the GRU carbon intensity changes over time, based on the site plans and the simulations. None of the plotted data include carbon offsets claimed by GRU, for the reasons discussed above.

In several documents and presentations, GRU reports a 14% decline in carbon intensity between 2003 and 2012 (**Table 4.2**). This estimate results from a curious manipulation of the basis of the calculation. If GRU's reasoning about offsets contributing to carbon emission reductions were valid, then many of those applied in 2012 would also apply in 2003. But according to a footnote in the table, GRU "adjusted" the 2003 emissions to eliminate the offsets due to conservation, Kelly re-powering, and silviculture[20]. Recalculation of GRU's data in **Table**

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[18] Fossil carbon released to the atmosphere as carbon dioxide actually remains there much longer than 100 years. The 100-year figure appears to be based on the fact that the International Panel on Climate Change is authorized to consider impacts through the year 2100. In other words, it is a consequence of a policy decision. It will be many thousands of years before atmospheric carbon dioxide concentrations return to their pre-industrial level of 280 ppm. The best estimates range from 10,000 to about 100,000 years,

[19] This very brief discussion of carbon sequestration in forests glosses over a host of critical details relating to how carbon is removed from the atmosphere by plants, where it is sequestered (soil, root structure, stem wood, etc.) and how long it takes before harvested wood products decay and the carbon in them is returned to the atmosphere.

[20] This table estimates the 2012 CO_2 emissions as 3.2 million tons. Both DH2 and the new CFB would have to operate at or near maximum capacity to produce this much carbon dioxide. EPAC has not explored this issue because GRU has never been able to fill any public information requests for estimates of off-system sales expected

4.2 shows that if these offsets were allowed in both years, the carbon intensity decline in 2012 would be only about 4% relative to 2003, as determined from the supplied data supplied[21]. In any case, EPAC's estimates of carbon intensity presented above more accurately reflect the very large increase in carbon intensity that GRU's proposals would affect.

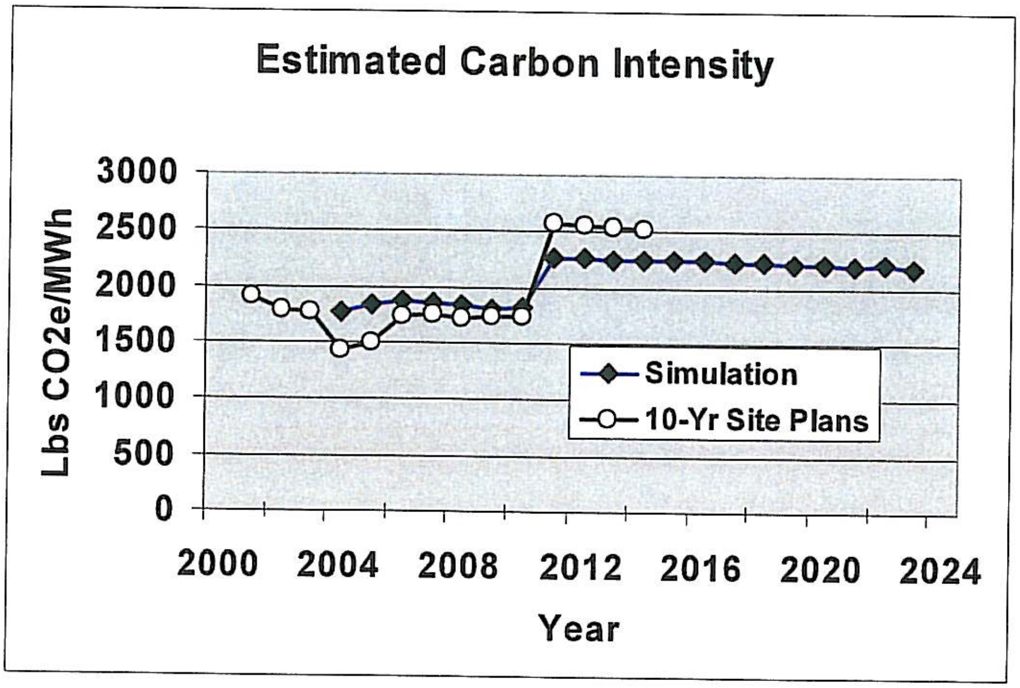

Figure 4.3. Carbon intensity increases dramatically when GRU switches to 90% solid fuel to generate electricity to serve the local area. This is assumed to occur in January 2011. According to the data in the most recent Ten Year Site Plan, its use will cause a carbon intensity increase of over 50% relative to 2010. The plotted data do not include GRU's claimed offset credits, or energy generation for off-system sales.

4.2.4 The Greenhouse Gas Fund (Finding 4)

GRU proposes to establish a funding source to acquire greenhouse gas offsets for climate protection[22]. As conceived by GRU management, a total of approximately $7 million dollars will be spent over the interval 2005 through 2011 to acquire greenhouse gas offsets to provide credits to compensate an annual emission of 459,000 tons of GHG released to the atmosphere by the new CFB unit.

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after the new CFB unit becomes operational, on the grounds than no analyses of these sales has been performed by GRU or its consultants.

[21] This table estimates the 2012 CO_2 emissions as 3.2 million tons, which are much higher than the CO_2 that would be emitted to generate electricity for the local service area. Both Deerhaven Unit 2 and the new CFB would have to operate at or near maximum capacity to produce this much carbon dioxide, which suggests that the analysis assumed these units will be used for generate energy for off-system sales. EPAC has not explored this issue. GRU has been unable to fill any public information requests for estimates of off-system sales expected after the new CFB unit becomes operational. According to GRU, analyses of these sales opportunities have not been conducted.

[22] See Section E of Staff Response to Long Term Electrical Supply Plan Questions, Issues, and Recommendations Made in November 2004 to the Gainesville City Commission", Prepared By Gainesville Regional Utilities, December 2004.

Several questions arise in connection with this fund, especially about whether any money spent by GRU in the manner proposed would provide tradable credits to apply against future GHG emission restrictions.

Compliance Requirements

Compliance regulations are in development in other countries and in some US jurisdictions[23]. These will incorporate several important principles affecting the kinds of benefits GRU could gain for offsets supported by its GHG fund.

GRU provides only a very sketchy list of economic sectors and actions that it views as contributing offset credits. These include "agriculture, transportation, industrial, commercial, and residential sectors"; and "Local policies such as land use, zoning, and development regulations can also play a role."

The additionality requirement discussed above is a very important requirement designed to weed out free riders that seek compensation for reductions/removals that would occur anyway. The list of potential sources of offset credits suggests that all should be carefully reviewed to be sure they satisfy the additionality requirement.

Other also important compliance requirements might make it difficult for GRU to realize significant benefits from offset projects conducted in the local community.

1. Ownership. The companies or individuals that own the offset project and are legally responsible for its attendant obligations must be clearly identified. These obligations will include monitoring the project, reporting its status, conducting regular measurement and verification activities, and, periodically, having these certified by an outside agency. Some interpret this requirement as excluding all but owners of the projects from seeking credit, but other positions have been proposed[24].

2. Laws implementing GHG reductions by a state or regional government usually specify that projects be submitted to a special agency—often an independent registry—that reviews them and decides whether they are eligible. Spending money on offsets before ascertaining their eligibility as carbon emission credits could be unwise.

3. Start date. Some GHG credit compliance regulations specify a start date and consider only projects begun after that date. This helps to insure additionality because it eliminates activities that were ongoing prior to cap-and-trade regulations and their associated carbon credit trading schemes. The Kyoto Protocol requires a rather lenient 1990 start date, but some Kyoto countries will use the date on which trading regulations are legally authorized as the start date.

Quantity of Emissions Offsets Proposed

GRU's Greenhouse Fund proposal targets developing offsets for 459,000 tons of carbon dioxide. This figure represents the difference between the annual CO_2 emissions of a modern gas-fired combined cycle generator and the CFB emissions.

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[23] Appendices 1 and 2 to this chapter 4 discuss compliance requirements for emission reduction credits developed in a demonstration GHG cap-and-trade program.
[24] Opinion about the necessity of this ownership requirement varies. See, for example, the discussions of options for the Regional Greenhouse Gas Initiative.

The reasoning underlying this method of calculating how many tons of carbon dioxide offsets are needed to compensate for CFB emissions may be based on regulations currently enforced by the state of Oregon. At present, Oregon requires a one-time offset payment for natural gas-fired base units that will emit more than 0.675 pounds per kWh of carbon dioxide. These regulations date back to 1993, and are presently being revised.. Other GHG regulation schemes may grandfather existing power plant emissions in the early stages of their implementation. Nevertheless, curtailing increases in emissions and ultimately reducing their total is the goal of GHG regulations. Consequently, any such grandfathering is unlikely to be a common or longstanding feature of rules adopted by states.

GRU's discussion of offset credits in sections 4.2.2 through 4.2.4 reflects the belief that an offset credit can be used repeatedly in every year subsequent to the one in which it was first acquired. This is not the case. Most GHG regulations currently under consideration feature cap-and-trade schemes and all require that emissions in excess of allocations be met every year with tradable credits. Once used for this purpose, credits expire.

GRU's Greenhouse Gas Fund proposal reflects the same error about the longevity of offset credits. GRU envisions spending a nominal total of $7.2 million dollars between 2005 and 2011 to acquire 459,000 tons of offset credits, at a price of approximately $1.50 per ton. These offsets together with the 255,000 tons already claimed by GRU are expected to offset a total of 714,000 tons of carbon dioxide emissions from the CFB unit every year between 2012 and 2042. This not a wise investment, as credits used in one year cannot be used again.

It is not entirely clear why GRU ignores the very large future carbon dioxide emissions from the retrofitted Deerhaven Unit #2. It seems likely that when GHG caps are initiated, they may be very lenient and apply only to a small proportion of emissions, but most will increase in stringency, probably by increasing the proportion of emissions controlled, reducing allocations, and/or increasing the cost of emission reduction credits. Consequently, it is not prudent to ignore the carbon dioxide emissions of other GRU generators.

Costs of Emission Credits

GRU used the going price for a ton of carbon dioxide on the Chicago Climate Exchange (CCX) during the final months of 2004 to estimate the amount of money it should pay local projects that remove carbon dioxide from the atmosphere. The CCX cost of credits is estimated at $1.50. This low price reflects the fact that the "credits" that trade on this exchange are used largely for public relations purposes by the corporations that use the exchange[25]. Initially there were no verification or certification requirements for any of the credits offered for sale.

A good system for insuring that CCX credits reflect real GHG emission reductions or sequestration has yet to be fully implemented. Effective verification, certification, and monitoring of GHG reduction projects are costly. The current low CCX carbon credit price does not reflect such costs. When GHG regulations are imposed, the costs of emission reduction credits will increase to reflect them. Currently, there are many sellers for every buyer of carbon

[25] See the "The Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard", Developed by the World Business Council for Sustainable development and The World Resources Institute. Available for download via a link at: http://pubs.wri.org/pubs_description.cfm?PubID=3872

credits traded on the Chicago Climate Exchange[26], probably because the credits obtained there are not certain to fulfill compliance requirements once GHG regulations are implemented.

4.2.5 Protecting the Baseline (Finding 5)

Cap and trade systems for regulating greenhouse gas emissions are under development in many jurisdictions in the US and elsewhere. Utilities, factories, and other entities that are covered by these regulations will be required to establish a "baseline" of emissions against which future changes in emissions will be judged. They will have to measure, verify, certify and report their GHG emissions as part of the procedures that will be followed under cap-and-trade programs.

The baseline emissions are used to determine GHG reduction targets and allocate tradable emission rights. If GRU takes steps to reduce its emissions prior to the initiation of such GHG regulations, but fails to now document reductions very carefully, it could be in danger of having these reductions ignored when baselines are subsequently established. That is, the utility would not be credited for any "early-bird" reductions achieved. If GRU were to inventory its GHG emissions now and develop a baseline, it could very possibly find significant "early-bird" GHG emission reductions.

The only way to insure credit for these early bird steps to minimize GHG emissions from GRU operations is to establish a baseline. This entails conducting a detailed emission inventory, and certifying it and then registering in a suitable registry.

Several groups have issued protocols for conducting these inventories and establishing baselines. The World Business Council developed one of the best for Sustainable Development and the World Resources Institute[22]. It is a blueprint of steps needed to inventory GHG emissions. In the case of GRU, the inventory should probably include both the electric and the natural gas utilities, and possibly all the water, and wastewater utilities, as well. According to the protocol issued by the World Business Council, all divisions that are under one management should be included in the baseline. The California Climate Action Registry, which is presently the model after which many other state registries are being designed, requires that combined natural gas and electric utilities submit combined baseline data.

[26] Personal communication between Dian Deevey and Richard Rosensweig, Manager, Natsource, Washington DC, February 2005. At that time there were 20 sellers to every buyer.

Chapter 4, Appendix 1: Compliance Requirements for Projects Demonstrating GHG Reductions[1]

In order to be credible, a system for awarding greenhouse gas credits must insure that the credits represent genuine reductions in emissions that can be applied against a mandatory emission limit and have value in a market place. Such credits exist only in the context of the enforceable laws that mandate reductions, and these may allow credit for "offsets".

Tradable emission reduction credits (ERCs) for sulfur dioxide and oxides of nitrogen have been defined by the EPA. Rules for carbon credit trading in the European Market and under the Kyoto Protocol are based on pioneering work in the US acid rain program.

NESCAUM[2] is conducting a demonstration greenhouse gas credit trading program whose rules reflect the compliance systems under development elsewhere. All the requirements of this demonstration program reflect internationally accepted standards. The following summary of the NESCAUM green trading project guidelines is taken from a paper analyzing and comparing different programs for demonstrating and measuring greenhouse gas emissions and reductions[3].

To guide participants in submitting projects, the NESCAUM Demonstration Project developed a "Check List," which provided guidelines in important aspects of quantification. The main quantification aspects are listed below, as laid out in the Check List.

• **Baseline Emissions Determination/Base Period Used**. Describe the baseline activity level and associated emissions during the baseline period for the applicable equipment/process as a rate per: hour of operation, capacity factor, production output, fuel consumption (type, amount), etc. Use the lower of the historical or allowable emission rate for a time period that corresponds to the generating period for the baseline emissions. Include a quantitative analysis of the uncertainty of the baseline where possible or at least a qualitative discussion of the baseline uncertainty.

• **Demonstration of Surplus**. Describe all applicable state and federal regulations as well as voluntary commitments relating to the pollutant. Demonstrate that the ERCs created are surplus to those regulations. Include notification whether the case study is or will be reported to any

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[1] These compliance rules have been developed by the Northeast States for Coordinated Air Use Management (NESCAUM), an interstate association of air quality control divisions in the Northeast states. The eight member states are comprised of the six New England States, as well as New York and New Jersey. This document was downloaded from: www.nescaum.org

[2] NESCAUM" is the acronym for the Northeast States for Coordinated Air Use Management, an interstate association of air quality control divisions in the Northeast states. The eight member states are the six New England States, plus New York and New Jersey

[3] Keith, G. B. Biewald, A. Sommer, P. Henn, M. Breceda, 2003, "Estimating the Emission Reduction Benefits of Renewable Electricity and Energy Efficiency in North America: *Experience and Methods"* Available for download at: http://www.synapse-energy.com/Downloads/Synapse-report-cec-displacement-background.pdf. Many additional useful analyses of the complicated issues relating to greenhouse gas regulations and credit trading can be found at the NESCAUM web site:www.nescaum.org

voluntary reporting program (i.e., Voluntary Challenge Registry or the Voluntary Reporting Program for GHG Emissions Reductions as established under section 1605 (b) of the Energy Policy Act of 1992). Describe any uncertainty regarding the claim that this activity is surplus.

• **Demonstration of Real.** An emission reduction is real if it is a reduction in actual emissions, resulting from a specific and identifiable action or undertaking, net leakage of emissions. Explain how a real reduction in actual emissions has occurred due to a change in process, technology and or operation. This section should include a statement declaring the availability of documents which provide insight into the claimed emissions reductions for any future verification of the case study.

• **Quantification of Emission Reductions**. This section should include a detailed quantification of emission reductions resulting from the project. Document the actual reduction beyond the baseline emission level. Describe the actual activity level and associated emissions during the period for the applicable equipment/process as a rate consistent with that used for the baseline. Describe the technology and equipment changes, operational changes, the extent that the reduction is dependent upon any change in operating methods and the expected duration of the emission reduction strategy. Uncertainties should be noted quantitatively when possible in each step of the equation (i.e., emission factors, monitoring equipment, etc.). A qualitative discussion must at least be provided. Point out the assumptions inherent in the calculation and an overall degree of certainty of the calculation (low, medium or high).

• **Data Integrity and Uncertainty**. Provide a detailed sample of the ERC calculation showing units and conversions. Describe the sources of any factors or conversions included in calculations. Describe the type of measurement or calculation used to determine the baseline and actual emissions. Where measured data is used, provide statistical support for the level of certainty/significance, e.g. the accuracy, range and repeatability of the instrumentation used to gather data. Describe the procedures followed to ensure the integrity and accuracy of the data. Where the data has been obtained through any mathematical model, show all assumptions and formula applied. Consolidate all the areas of uncertainty here. In addition, after quantitatively and qualitatively explaining the areas of uncertainty in the case study, conclude with a statement as to the overall certainty that the emission reductions attributed to the case study actually occurred (low, medium or high).

• **Emission Reduction Credits Created**. Show total actual emissions during the credit-generating period, the calculated baseline emissions and the net ERCs created annually and over the lifetime of the project. Note any significant intervals during the generating/creation period when the strategy was not in place or credits were not generated. Give reasons for such intervals.

• **Ownership.** Any issues regarding ownership of the emission reduction credits are to be addressed in this section. Identify the owner(s) of the facility, the entities paying the operational costs of the facility, and the entities that paid for or subsidized the initial and the ongoing costs of the emission reduction action. Include a clear statement of what fraction of the title to the credits reported in this case study are claimed by each of the credit owners.

• **Other Environmental Impacts** (e.g., other air pollutants, nuclear). Identify any positive or negative environmental impacts that may result from the strategy and quantify these impacts as much as possible. Stationary source strategies may need to evaluate the potential for load shifting. Mobile source strategies should evaluate the geographic range of vehicle operation.

Chapter 4, Appendix 2: Double Counting Credits

NESCAUM[1] has operated a demonstration Greenhouse Gas Trading project for several years. Many policy issues have been discussed during the project, including "offsets" and specifically double counting of demand reductions that lead to utility greenhouse gas emission reductions.

The purpose of regulations governing emission reduction credits, or any kind of "offset" is to facilitate market mechanisms in reducing GHG emissions. A market needs something to trade, and the basic question is whether traded items represent "real" reductions or just convenient ways for entities like utilities to dodge real reductions. The following text is from a progress report documenting the NESCAUM study of regulations for governing emission reduction credits:

At a recent STAPPA/ALAPCO[2] GHG Committee meeting, Doug Howell of Seattle City Light discussed a problem Seattle City Light is having. They are required to purchase offsets for their CO_2 emissions. Among the offsets they buy are emissions reductions attributable to conservation measures which increase energy efficiency, thereby reducing the demand for electricity purchased from electric power generators. They would like to have these offsets recognized as tradable, but emissions traders such as Natsource do not recognize reductions in "indirect emissions" -- i.e., reductions in the demand for electricity -- as offsets.

The only reductions from electricity generation that are now traded come from reductions in direct emissions by power generators. They come from net reductions of direct emissions from measures such as (1) fuel switching and improved efficiency of fuel use occurring at existing power plants; and (2) generation from new sources such as wind and solar, which are credited with displacing electric power generation from competing power plants, thereby reducing those plants' direct emissions.

Natsource and other emissions brokers are unwilling to trade in offsets that are based on reductions because they consider such "offsets" to be double counting. This evaluation is grounded in the assumption that any mandatory regulatory program will set emissions caps at electric power plants in absolute tons, based on their historic emissions levels. Compliance with such a cap can be achieved by reducing a plant's output of electricity, and, proportionately, its fuel use and emissions. Under this kind of cap, energy efficiency measures that reduce customer demand for electricity should not be credited as offsets. If they were, they would be counted twice:

(1) The decrease in demand for electricity would reduce its production, helping electricity generators meet their emissions allowances, and
(2) The offset could be purchased by an electricity generator to augment its emissions allowance.

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[1] NESCAUM" is the acronym for the Northeast States for Coordinated Air Use Management, an interstate association of air quality control divisions in the Northeast states. The eight member states are comprised of the six New England States, as well as New York and New Jersey
[2] STAPPA/ALAPCO - The State and Territorial Air Pollution Program Administrators (STAPPA) and Association of Local Air Pollution Control Officials (ALAPCO) are two national associations of air pollution control agencies throughout the United States. See: http://www.4cleanair.org/

Another problem in crediting emissions reductions due to increased efficiency in energy use is that appropriate baselines would have to be established. This may be a burdensome task given the wide range of uses of electricity. Establishing emissions rate baselines is also necessary in order to quantify direct emissions reductions from increased energy efficiency for uses of energy other than electricity, such as for transportation and space heating.

Chapter 5. Meeting Energy Needs with Natural Gas: GRU's Alternatives

5.0 Introduction

On November 15, 2004, GRU publicly presented the City Commission with an affordability analysis of its proposed new solid-fuel fired generator and the retrofit of existing Deerhaven Unit #2[1]. This presentation featured several tables comparing the present value of this plan with that of two alternative approaches based entirely on natural gas use for all new capacity needs in the interval 2004-2023[2]. These tables documented the simulations of the operations of GRU's planned system incorporating a new generator using coal and petroleum coke and two alternative approaches that substitute natural gas-fired generators for the coal/petcoke generator. The simulations used different assumptions regarding the relative fuel costs, and the possible "carbon tax" costs reflecting future financial penalties for carbon dioxide emissions. These simulations confirmed that the two alternative natural gas approaches are more expensive than the coal-petcoke option favored by GRU (see **Table 5.1**).

No details of the alternative plans were included in the publicly distributed materials, so EPAC requested and obtained copies of the output from these simulations[3]. These were examined to determine whether the alternatives represented realistic options and met the expressed public preferences[4]. The latter include: increased investment in energy conservation, increased use of renewable energy sources, avoidance of coal, reduced air pollution, low energy costs for consumers, and continuation of money transfers to the City treasury to help keep property taxes low[5].

5.1 Key Findings

1. GRU compared the costs of two ways to use natural gas to generate additional electricity for the local community with the costs of generating that electricity from coal/petroleum coke under its preferred plan. GRU did not compare its preferred plan with plans featuring options advocated by the community such as increased reliance on biomass fuels, and reducing demand through conservation and energy efficiency improvements, nor did it compare the current plan with a "wait and see" strategy of incremental expansions of generating capacity.

2. GRU's simulations confirm that using cheap coal to fuel generators produces less expensive electricity than using expensive natural gas, a conclusion that follows from the differences between the price of natural gas and that of solid fuels. This price difference is so large the conclusions are insensitive to hypothetical penalties for carbon dioxide emissions to the atmosphere.

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[1] "Long Term Electrical Supply: Affordability in an Uncertain Future"; Presentation to the Gainesville City Commission, November 15, 2004.
[2] GRU also presented information about the present value over the interval 2004 through 2054.
[3] GRU supplied EPAC with output from a total of 9 simulations between November, 2004 and March, 2005.
[4] Some of the preferences expressed by residents who attended a series of workshops held by GRU in the fall of 2003 were presented verbally to the City Commission in December, 2003 and March 2004.
[5] Alternatives for Meeting Gainesville's Electrical Requirements Through 2022: Base Studies and Preliminary Findings. Gainesville Regional Utilities, 2003.

3. The sole criterion used to compare alternative scenarios is net present value of future energy production.

4. The natural gas plans GRU compared to the solid fuel plan are unrealistic. Neither represents a genuine alternative to the plan GRU has proposed[6].

5. The pollution impacts of GRU's plan are ignored in this comparison.

6. Policy considerations suggest that other alternatives than those considered by GRU should be evaluated. Alternatives that offer some protection against potentially high costs of future greenhouse gas regulations can be defined and evaluated.

5.2 Discussion

5.2.1 Limitations of the Alternative Plans Considered (Finding 1).

Natural Gas and "Base" Scenarios

GRU developed two scenarios that feature reliance on natural gas for future capacity expansion, and a "base" scenario that incorporates most of the features of GRU's preferred plan for capacity expansion that relies heavily on coal and petroleum coke. All three scenarios include the existing fleet of generators, and the current generator retirement schedule. All three scenarios are identical from 2004 through 2010 and all assume that the existing Deerhaven Unit #2 is retrofitted with pollution control equipment.

EPAC was supplied with the results of 3 sets of simulations of the three alternatives simulated: one without carbon penalties, one with low carbon penalties and one with high carbon penalties. Two additional sets of simulations were also conducted to explore the sensitivity of the results to assumptions about the relative costs of solid fuels and natural gas, but EPAC did not examine these.

The three scenarios diverge beginning in 2011. In that year, the "base" scenario adds the 220 MW circulating fluidized bed (CFB) generator, an "all gas" scenario adds a 243 MW natural gas combined cycle plant, and a "market rent" alternative begins renting 20-MW peaking units to supply needed reserve capacity, and generate electricity for local users.

Natural gas prices begin at $6.68 per million Btu in 2011, and rise to $11.76 in 2023[7]. The CFB unit in the simulated "solid fuel" scenario uses wood as the source of 13.7% of the energy it consumes; the remainder is a mixture of petroleum coke and high sulfur coal[8]. The price of this mixture ranges from $1.57 to $2.05 per million BTU. All

[6] In the fall of 2003 GRU offered four options for increasing capacity, two of which entailed building and operating very large coal-based generators at Deerhaven, and sharing their ownership with other municipal utilities in the state. The large generators were dropped in the face of community opposition to the pollution it would experience from generating energy to be delivered to distant communities.
[7] These natural gas costs are similar to those used by other utilities.
[8] This system is a simplified version of the one described in many documents supplied by GRU, including the reference in footnote 1 above. The ability of a CFB unit to some biomass is viewed as a major advantage of this kind of unit, but current plans are for a modest use of waste wood to supply an average of

scenarios assume that the existing coal-fired generator burns high sulfur fuel that ranges in price from $2.08 per million Btu in 2011 to $2.78 in 2023.

Methodology

GRU used a computer program developed by the Electric Power Research Institute[9] to simulate the operation of the three systems. This program specifies the new generators to be added in each scenario based on projections of the energy needs for each year, and representative curves that describe the energy use during each day and year[10]. Changing the lists of generating units the program can choose among causes it to simulate the different scenarios. The generator options offered to the program were those commercially available in 2003; no new technologies were included[11] Features common to all scenarios were (a) the estimated net energy production required over the years from 2004 through 2023, based on GRU projections, and (b) a load-demand curve that the EGEAS program used to define hourly demand during every day of each year of the interval simulated.[12]

The modeling program selected the details of each of the three scenarios that minimized the cost of producing electricity. Operations were simulated for the full 20-year interval from 2004 through 2023.

The EGEAS program is apparently not suited to comparing GRU's favored plan with an incremental approach to increasing capacity or any other strategy that differs radically from the one chosen by GRU. It is not suited to addressing the benefits of reducing energy needs by means through demand side management that reduces customer electricity needs. The program can compare the costs of alternative ways of meeting the energy needs described in the input, but it cannot readily compare systems that differ greatly from the solid fuel system GRU wants the community to approve. The EGEAS program used by GRU does not take into account the community costs of air pollution or any other social costs that are relevant to a final decision about new generation capacity. Although this model can choose from any specified set of different generators which ones are best suited to the tasks at hand, GRU confined the selection to generators that were commercially available in 2003, and ignored both near-term and intermediate-term technological improvements expected between now and 2018[13].

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30 MW of power, which is less than 5% of the planned total GRU capacity. The scenario evaluated in this exercise features wood as the source of 13.7% of the energy used in the CFB, the remainder to be supplied by high sulfur coal (31.5%) and petroleum coke (54.9%).

[9] This is the Energy Generation Economic Analysis System (EGEAS) program that GRU uses for much of its planning.

[10] The forecasts GRU used are for the "native load" which consists of all retail customers in the local service area plus the city of Alachua and Clay Electric Cooperative, to which GRU sells wholesale energy for resale to customers living near Gainesville.

[11] The full set of generators considered are listed in Tables L-1 and L-2 of "Alternatives for Meeting Gainesville's Electrical Requirements Through 2022: Base Studies and Preliminary Findings." Gainesville Regional Utilities, 2003.

[12] GRU's 1983 load-demand curve was used for this purpose. The sensitivity of the results to differences in load-demand curve is unknown.

[13] Users of models like the EGEAS typically run it a large number of times to explore the effects of different options such as generators from which the program those to be modeled, explicit cost criteria, an assumed load-demand curve and other factors. GRU provided EPAC with only one set of EGEAS outputs corresponding to (a) the 3 base runs that used GRU's base estimates of fuel costs (b) 3 additional runs that tested the sensitivity of the original results to carbon taxes of $50, and (c) one simulation of the GRU solid fuel plan using slightly higher coal/petcoke prices and lower natural gas prices than the base case.

The "Carbon Tax"

GRU used the EGEAS program to explore the sensitivity of is simulation methodology to increases in the cost of fuel that reflect a financial penalty for the emission of carbon dioxide. Two levels of "carbon tax" were programmed: one corresponds to a cost of $13.64 per ton of carbon dioxide, and the other to a cost twice that high. These figures are within the range estimated by a number of workers[14] .

5.2.2. Results: Natural Gas Costs More than Coal (Findings 2 and 3)

GRU evaluated the three scenarios by simulating their operations over a 20-year period, and extrapolating the costs in the 20th year through the next 30 years. The "present value" of the costs of each of the three calculated for the 20-year simulation interval is shown in **Table 5.1** and **Figure 5.1**.

Table 5.1 Present Value of Modeled Alternatives*

Scenario	Carbon Tax per Ton of CO2 None	$13.64	$27.28
CFB	$2.252	$3.119	$3.987
All Gas	$2.706	$3.477	$4.247
Market Rent	$3.110	$3.892	$4.674

***Billions of dollars for 2004-2023**

Present value calculations discount future costs by an assumed "discount rate" that reflects what money would earn were it invested differently. Discounting translates future sums of money into equivalent current sums, and reflects the fact that a dollar today translates (through interest) into more dollars in the future.

Present value analyses are valuable planning tools, but are not intended as predictors of future costs and benefits. They only project today's best guesses into a future known to be uncertain. They cannot take into account important costs and benefits that are not easily translated into dollar terms.

Some important benefits cannot be evaluated by the methods GRU uses. These include, for example, lowered costs of health care and lowered health risks that could result from using a cleaner fuel like natural gas as well as improved property values near Deerhaven. The many benefits of different strategies for expanding generating capacity and—importantly—extensive use of biomass as a fuel also cannot be specified or compared with this simulation system. New jobs and other important economic and social benefits to the community can be expected from purchasing fuel locally instead of from distant suppliers.

According to the text of the presentation on November 15, additional runs were performed to explore the sensitivity of the conclusions to differences in demand and the number of customers, but EPAC did not examine these. We do not know if any analyses were conducted of the advantages of radically different strategies using different approaches.

[14] See analysis of carbon prices by Johnson, et al.

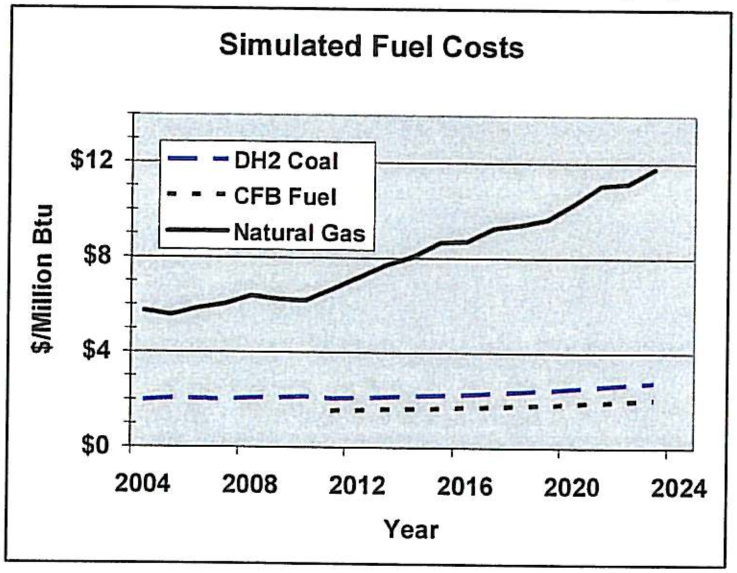

Figure 5.1. Projected natural gas and solid fuel costs used by GRU in its simulations of alternatives for expanding generating capacity. The coal is used in Deerhaven Unit #2, while the fuel for the proposed circulating fluidized bed generator is a combination of coal, petroleum coke, and biomass.

These simulation exercises confirmed that expanding the use of expensive natural gas for new generators costs more than expanding the use of low-cost coal and petroleum coke, but they do not confirm that the solid fuel option represents a wise choice.

5. 2. 3 Natural Gas Scenarios are Unrealistic (Finding 4)

Both natural gas scenarios are unrealistic, because they do not represent genuine available options, and because neither represents the most sensible way to expand the use of natural gas by GRU.

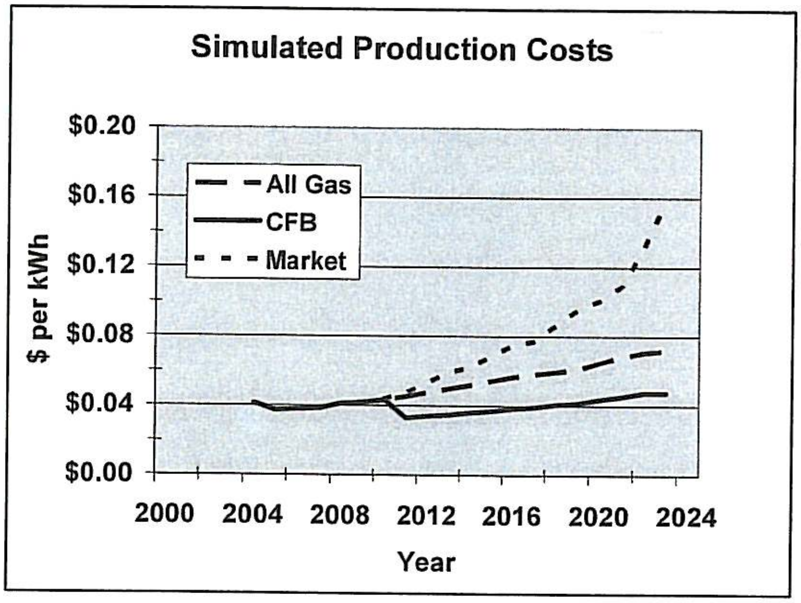

Figure 5.2. Average system costs of energy production for the three scenarios. These do not include fixed overhead, administrative costs, or transfer to the City treasury, all of which represent about 70% of the costs billed to ratepayers... The costs of the market rent scenario plotted above include the costs of capacity rental.

"Market Rent" Scenario

Under the "market rent" scenario, GRU rents peaking units. During the early years, these supply the reserve requirement imposed by the state[15]. Later they provide electric energy that is delivered to local customers. Under this scenario, GRU contracts for the use of small 20-MW peaking units located at a "merchant" utility. These units are inherently extremely inefficient. Merchant plants are for-profit companies that must recover all overhead costs and a profit on every sale. In contrast, municipal utilities do not need to recover overhead or other fixed costs for the energy they sell because these costs are borne by customers in the local service area.

Under the "market rent" scenario, GRU rents only this expensive capacity to fill its needs. GRU never buys any energy over the interchange when it is available at costs that are low compared to those charged by its merchant supplier. Consequently, average system energy production costs range from 5.2 cents per kWh in 2010, the year before capacity rental begins, nearly 16 cents per kWh in the final year simulated. (Production costs do not include fixed overhead items, or transfers to the City Treasury, which together total more than 70% of costs charged to ratepayers.). The market rent production costs in **Figure 5.2** include the annual cost of renting the peaking units. In

[15] Florida utilities are required to maintain a reserve capacity that exceeds their forecast peak loads by 15% or 20%. If GRU adopted the strategy described in the "market rent" scenario, it would have to buy two things under a purchase power agreement: reserve *capacity* to provide access to an amount of power equal to 115% of the peak load in each year, and *energy* that it purchases and resells to customers in the local service area.

spite of the extremely high cost of fuel and of capacity rental, GRU does not resort to energy conservation[16], which should be extremely cost-effective under this scenario.

"All Gas" Scenario

This scenario includes adding a large (243 MW) natural gas-fired combined cycle generator in 2011, which is larger than GRU needs through the year 2023. GRU owns a 110 MW combined cycle unit at the Kelly site[17]. Under this scenario, 38% of the capacity of the existing combined cycle plant at Kelly was used in 2010, but this drops to 5% of available capacity in 2011, when GRU adds the new larger combined cycle unit. The Kelly combined cycle plant remains largely unused through out the entire interval from 2011 to 2023; its capacity factor rising to a little less than 16% in 2023. During this interval, the new 243 MW unit also operates well below capacity (36% to 53%). Deerhaven Unit #2 operates at close to 80% of capacity during the entire interval, and contributes between 51% and 59% of all the energy needed in the local area. **Figure 5.3** shows the percent of available capacity used during each year of this simulation for the three largest generators. In spite of the burden of this costly new generator, overall fuel and energy production costs under the "all gas" scenario are less than 2 cents per kWh more than under the solid fuel scenario most of the time (**Figure 5.2**).

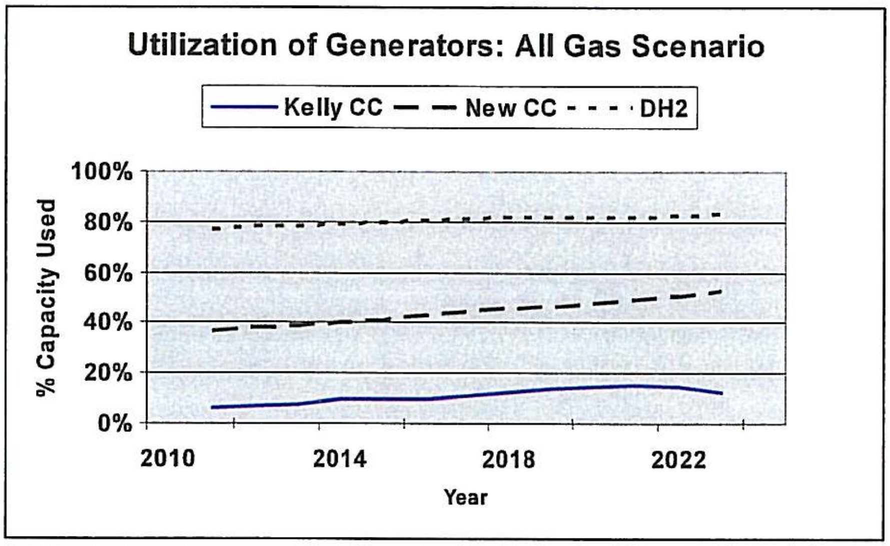

Figure 5.3. The "all gas" scenario adds a 243 MW combined cycle unit in 2011, but makes comparatively little use of it. Use of the Kelly combined cycle unit ranges from 6% to about 13% of available capacity. The coal-fired DH2 unit generates between 51% and 59% of the electricity used in the local area. It is possible that only about 100 MW of new capacity is needed to supply all the energy needs GRU forecasts for the local area through approximately 2018 or later.

[16] The scenario evaluated assumes that GRU spends $2 million dollars in 2011 to acquire 30 MW of peak shifting capability. This purchase ought to reduce the total capacity needs, but it has no effect on peak demand in each year. That is, peak-shifting costs to reduce peak load are included, but the cost benefits of those load shifts are not. Reducing peak demand by 30 MW should reduce reserve requirements by 35 MW, which, in turn, would save over $14 million per year in capacity rental costs.
[17] The Kelly combined cycle unit has never produced the amount of electric energy contemplated when it was built. It is presently not in operation due to equipment problems.

While the "all gas" scenario is more reasonable than the "market rent" scenario, it features none of the strategic advantages an incremental approach to deploying new capacity could provide. It also fails to incorporate reductions in demand and in energy use that were identified by GRU, or are being successfully applied by utilities elsewhere. It does not incorporate biomass fuels that could help to avoid greenhouse gas emission penalties[18]. An approach to a genuine alternative to GRU's proposal using biomass and conservation has been sketched in Chapter 8. Effective conservation (DMS) programs being undertaken elsewhere could also be incorporated into a genuine alternative. Some are discussed in Chapter 6 and its appendices.

5.2.4 Pollution Impacts

The EGEAS simulation of GRU's favored system is the only source of detailed information about the operation of that system that EPAC has been able to obtain. Examination of the outputs provides a useful picture of some impacts its operation will have on the local community. The most important of these pollution impacts is the production of carbon dioxide that will be subject to financial penalties under greenhouse gas regulations. **Figure 5.4** compares the simulated carbon dioxide emissions from the solid fuel system with those of the "all gas" scenario. The "all gas" scenario produces only about 30% less carbon dioxide than the solid fuel scenario, largely because it relies on coal-fired Deerhaven Unit #2 for a very large percentage of the energy consumed locally. EPAC did not calculate the NOx emissions of the "all gas" scenario because emission factors for the large combined cycle generator are not available. Sulfur dioxide emissions from the "all gas" scenario are likely to be about 40% lower than those from the solid fuel scenario. Very little sulfur dioxide is produced when natural gas is burned, but the intensive use of Deerhaven Unit #2 will contribute sulfur dioxide to the air. The emissions plotted in Figure 5.4 are those associated with filling the energy needs in the local area. GRU plans to operate both the retrofitted Deerhaven Unit #2 and the new coal/petcoke fired generator to generate extra energy to sell to utilities elsewhere in Florida. This is likely to increase local pollution by about 30% or more (see Chapter 7 below).

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[18] Although wood and other biomass fuels release carbon dioxide to the atmosphere when burned, this consists of carbon that was removed from the atmosphere relatively recently, or would enter it in any case if it were allowed to decay in a land fill, or burned as trash. This means that burning wood does not add to the greenhouse gas concentration in the atmosphere, and is "carbon-neutral". When trees and other plants remove carbon dioxide from the atmosphere and use it to produce wood and other plant tissue, they are in effect borrowing the gas from the atmosphere. Most of it is returned to the atmosphere when the wood is burned, or the plant matter decays. This carbon sequestration is a short term loan that does little to change the amount in the atmosphere. Under natural circumstances, the carbon in coal would remain underground for hundreds of millions of years. Mining and burning it causes a net addition of carbon dioxide that would not have occurred in the absence of humans and their industries. This added fossil fuel carbon dioxide is removed from the atmosphere by the ocean, which absorbs it from the air in cold polar regions. The water containing the carbon sinks into ocean depths, where it circulates for many hundred years or more before reaching the surface again. Locking carbon up in a forest for at least one hundred years is considered to balance the release of an equal amount of fossil fuel carbon dioxide, while shorter sequestration durations are not viewed as effective methods of balancing fossil GHG emissions to the atmosphere.

[20] Source: California Public Utilities Commission, "Draft Energy Action Plan II: *Implementation Roadmap For Energy Policies"* August 12, 2005, available for download at:http://www.cpuc.ca.gov/word_pdf/REPORT/48626.pdf

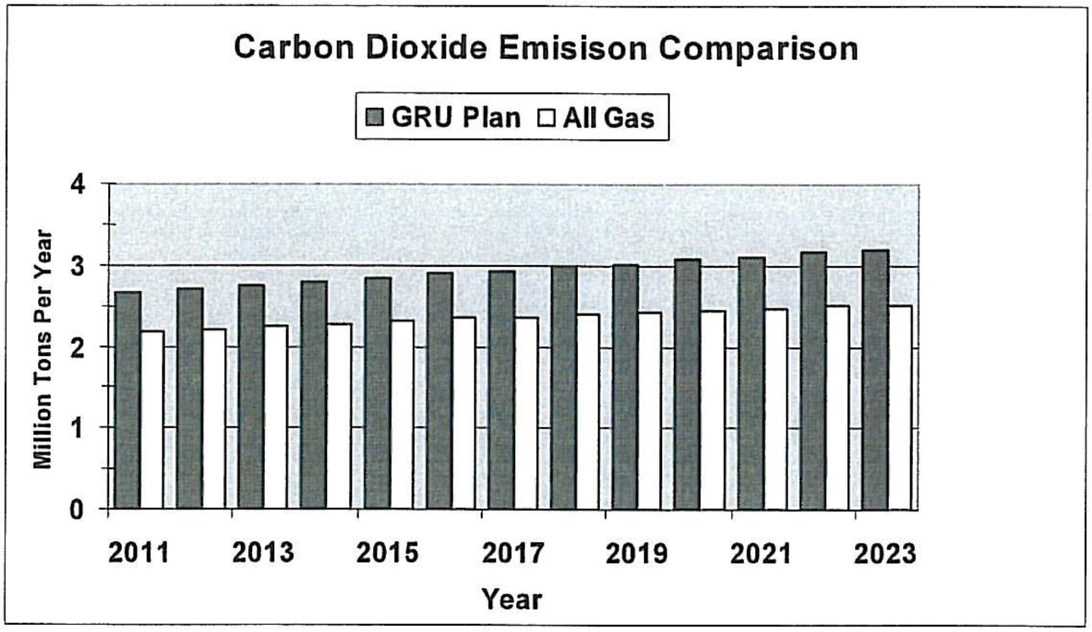

Figure 5.4. Carbon dioxide equivalent emissions from the GRU plan and the all gas alternative. Emissions shown here are about 27% to 30% higher for GRU's plan. They would be about 35% to 40% higher if wood were not co-fired in the CFB unit.

5.2.5 Policy Issues (Finding 6)

EPAC's examination of the alternatives compared and the comparison method suggests that the community may need to seek other means of appraising the plan GRU has proposed.

Risk Analysis

Financial risks associated with fossil carbon dioxide emissions are serious. Costly greenhouse gas regulations are likely to be imposed long before the retrofitted Deerhaven Unit #2 and the new CFB have reached the end of their useful lives. Evaluating the possible financial impact of these regulations, and reviewing new generation and other options in terms of those costs is the goal of carbon dioxide risk management.

A collection of generators and options for conservation and energy efficiency improvements is termed a "portfolio" of energy resources. GRU has proposed one such portfolio. This portfolio can be evaluated in terms of the financial risk it entails by exploring the effects of a number of different ways greenhouse gas regulations might impact it. Such an analysis can provide useful information, but it cannot guide the selection of an optimal portfolio. To do that, GRU needs to produce alternative portfolios implementing different strategies. One approach might consist of using the "loading order" recommended to California utilities, described as follows:

"The loading order identifies energy efficiency and demand response as the State's preferred means of meeting growing energy needs. After cost-effective efficiency and demand response, we rely on renewable sources of power and distributed generation, such as combined heat and power applications. To the extent efficiency, demand response, renewable resources, and distributed generation are unable to satisfy increasing energy and capacity needs, we support clean and efficient fossil fuel-fired generation.[20]

In any case, developing alternative portfolios and comparing them under different assumptions regarding the cost and timing of greenhouse gas regulations could be very helpful. Other utilities have found that carbon dioxide costs that reach or exceed about $20 per ton can have large effects on the financial risks associated with different portfolios[21].

Present value analyses are useful tools for exploring different courses of action, but they cannot capture all the relevant considerations. Net present value analyses always emphasize costs and benefits to be expected in the near future, and largely ignore those that will occur more than about 20 years in the future. Many stakeholders may feel that more emphasis should be placed on the 10 to 25 year horizon, which is the period when the combined financial impacts of higher costs for fossil fuels and penalties for greenhouse gas emissions are likely to be keenly felt.

The basic strategy of making an immediate commitment to two solid-fuel generators that forecloses the utility's ability to adapt to future changing energy environments cannot by evaluated by simulations of the kind used by GRU. If the utility is paying off the huge debt incurred to retrofit DH2 and build the CFB unit, it will not have financial resources to adapt to significant changes in regulations. This consequence is not normally considered in conventional risk analyses. But it is a very real concern, in view of the fact that the City government's bond rating and its ability to serve the needs of the community will be adversely impacted should GHG regulations make the solid fuel generators uneconomic to operate, or reduce the potential market for off-system energy sales expected by GRU management.

[21] See Bokenkamp, K., H. LaFlash, V. Singh, and D. Bachrach-Wang. "Hedging Carbon Risk: Protecting Customers and Shareholds from the Financial Risk Associated with Carbon Dioxide Emissions", The Electricity Journal, Vol. 16, Issue 6, July 2005, pp 11-24.

Chapter 6. Demand-Side Energy Resources

6.0 Introduction

The widespread use of technologies that reduce inefficient energy use is our community's cheapest and cleanest energy resource. Inefficient energy use wastes fuel and other resources and causes many economic and environmental problems. Simply using electric energy in a way that saves money would avoid most of them. A responsible energy policy should reduce unnecessary and inefficient electricity use, thereby lowering energy bills and delaying or avoiding the need to build a large new generator.

Many technologies are available to reduce consumer energy use. Most readers think of utility programs to promote these technologies as "conservation", but a more appropriate term is "Demand-Side Management (DSM)". Demand for electricity occurs on the customer's side of the meter, and demand-side management shapes the way customers use electric energy and how much they use. The other side of the meter is the "supply side", where the utility supplies generated electricity, usually from a central power plant, to customers.

Demand-side management involves three basic approaches: conservation, energy efficiency, and demand response. All use financial and other incentives to encourage customers to modify their electricity use. Demand response programs aim to shift in the time that electricity is consumed – away from periods of peak demand and encourage consumers to use less energy. Conservation programs aim to reduce energy use by persuading customers to get along with less of the things electricity supplies—heating, cooling, lighting, etc. With efficiency improvements, the same or more work is done with less energy. With conservation, less work is done with less energy. For example, using a compact fluorescent light bulb to read is an efficiency measure; whereas turning off the light and not reading is a conservation measure. Improving end-use efficiency --the efficiency with which customers use electric energy--reduces demand while the customer experiences no loss of amenity, whereas "conservation" involves the loss of an amenity. However, the public in general tend to call all these ways of reducing electricity demand "conservation".

Many studies confirm that demand side energy resources remain untapped and that reducing consumer demand for electric energy costs far less than building generators to produce that electricity. Reducing demand with DSM programs is equivalent to building a "virtual generator" that satisfies consumer needs with "Megawatts" while costing much less than "megawatts" from physical generators. Besides costing less than supply-side alternatives, the "virtual generator" keeps our air and water far cleaner, preserves coal region landscapes, and reduces economic risk represented by rising fuel costs or more stringent regulations – particularly those associated with carbon dioxide emission reductions.

Effective demand side programs reduce total energy use and the revenue utilities receive from electricity sales. Consequently, utility managers and owners often view them as threats.

GRU's proposal for meeting future community energy needs emphasizes the supply-side of the meter, and largely minimizes the role that increased investment in demand-side resources could play – foregoing DSM investments that would cost less than supply side alternatives. This approach is common among Florida's investor-owned utilities[1].

[1] The overall orientation of investor-owned utilities is discussed below in section 6.2.5.

Utilities that have more than enough generating capacity to fill the current customer needs have little economic incentive to implement DSM programs. DSM programs reduce customer energy purchases. The utility avoids the need to supply them with electricity, but this saves only the low overhead costs of producing electricity. The utility still has to pay its fixed overhead, service its debts, and transfer money to the utility owners. The small savings such a utility realizes are less than the income it foregoes.

The major economic value of DSM to a utility is that it can delay the need for new generators, and reduce the increased capacity that a utility might need to satisfy growing demand. "Demand side" approaches can play a key role in a balanced portfolio of energy resources.

EPAC's review of the role of DSM in GRU's proposal has focused on whether the potential benefits of DSM will be fully realized in the future, and on the constraints that currently reduce effective DSM implementations.

6.1 Key Findings

1. GRU's residential DSM programs are modest in scale and impact, and, absent policy direction from the commission, are likely to remain insignificant in the future. The current residential programs invest small amounts of money, achieve small reductions in peak demand and total energy consumption, and attract few participants.

2. Current residential DSM programs offer all but a tiny fraction of their benefits to builders, middle, and upper income residents. Less than 3% of DSM residential rebate program investments benefit low-income residents. A larger and better targeted investment in DSM programs could deliver valuable energy bill reductions to low income residents.

3. DSM offers enormous benefits to the public and the utility alike, but the community could benefit if DSM played a larger role in GRU's plans. If GRU matched the achievements of many utilities in other states, new generator needs could be significantly delayed or avoided and energy bills could be lower. This strategy would require funding DSM programs in the same way supply-side resources are funded

4. Residential energy use by GRU customers is about average for the state and offers abundant opportunities for savings. While average electricity use is low, this is due to natural gas use by approximately 40% of GRU customers.

5. Income to the City of Gainesville from electricity sales is closely tied to the volume of those sales, but successful DSM programs reduce energy use and the volume of sales, thereby threatening City income. This conflict can be readily eliminated changing the way income is collected from the utility, removing the connection between the volume of electricity sales and City income, as has been done in other states.

6. GRU evaluates and selects DSM programs only when it is considering capacity expansion, and evaluates potential demand side resources using a cost-effectiveness criterion (Rate Impact Measure) with a built-in pro-

generator bias. The last comprehensive evaluation of DSM cost effectiveness potential in our community was performed in 1994. That evaluation guides program development today.

7. The Rate Impact Measure (RIM) test is biased against conservation, but it is the primary test used by GRU to evaluate DSM resources. Cost-effectiveness tests help to compare demand- and supply-side alternatives, but the ultimate selection requires informed judgment. The Total Resource Cost (TRC) test selects DSM resources that cost less than generation alternatives. The societal variant of the TRC test also weighs environmental and health costs of energy resource alternatives.

8. GRU now sets and implements DSM policy. The City Commission plays a passive role in setting DSM goals and policies[2]. It does not choose among alternative DSM programs but typically only ratifies those proposed by the utility. GRU makes its own selections among possible programs, decides what class of participants will benefit and how big the total budget will be, evaluates program cost-effectiveness, and then recommends to the Commission the programs GRU management prefers. In practice, GRU's choices add up to unarticulated DSM policy decisions.

6.2 Discussion

Background: Goals of Demand Side Management

The demand for energy in Gainesville and elsewhere varies over the hours of any single day, with low demand occurring late at night and in the early morning, and higher demand occurring during the day when most of the population is active. The daily pattern of energy use differs by season, as the need for heating or cooling changes. Like most other utilities, GRU matches the demand by using different kinds of generators. These are:

- *Base units*, which are designed to operate for long periods, take days to start. They are the cheapest units to operate, but the most costly to purchase, and may last up to 50 years or more with proper maintenance.
- *Intermediate units*, which can be started up within about 3 hours, are more costly to operate than base units. They are intermediate in cost, but have a only a 25 year lifetime; and,
- *Peaking units*, which can be turned on or off in 30 minutes or so, are extremely inefficient and very costly to operate, but least expensive to purchase.

GRU's generating units are listed in **Table 6.1**.

[2] And also in other policy decisions regarding the operation of the electric utility.

Table 6.1 Characteristics of GRU Generating Units

Unit	Capacity* (MW)	Heat Rate** (Btu/kWh1)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Fuel Type	Fuel Price ($/Million Btu)
Base						
Deerhaven Unit 2***	228	10,138	$21.23	$0.94	Low S Coal	$2.04
Crystal River Unit 3	11	10,500	$191.20		NUCC	$0.42
Intermediate:						
Deerhaven Unit 1	81	11,960	$15.54	$2.81	NG	$5.97
J R Kelly Unit 7	20	12,427	$16.69	$6.16	NG	$5.97
J R Kelly Combined Cycle	110	8,200	$15.52	$3.67	NG	$5.97
Peaking						
Deerhaven CT 1	18	14,814	$0.13	$6.24	NG	$5.97
Deerhaven CT 2	18	14,814	$0.13	$6.24	NG	$5.97
Deerhaven CT 3	75	11,989	$0.12	$0.58	NG	$5.97
J R Kelly CT 1	14	16,333	$2.10	$26.41	NG	$5.97
J R Kelly CT 2	14	16,733	$2.10	$26.41	NG	$5.97
J R Kelly CT 3	14	16,733	$2.10	$26.41	NG	$5.97

* Summer
**Corresponds to optimal operating conditions.
***Current configuration. Characteristics will change after new pollution control equipment is installed.
Source: Table L-2 in GRU "Alternatives for Meeting Gainesville's Electrical Requirements through 2022" Table L-2

Changing the Daily Load Shape

The daily load shape is the pattern of hourly energy use by a utility's customers. Residential and commercial customers tend to use energy during the day, in ways that depend on the season and temperature. Industrial customers generally impose steady demands that do not vary greatly with time of day. Hospitals and supermarkets also tend to impose steady demands. In Gainesville, demand is dominated by the residential and commercial sectors, which consume over 90% of the electric energy used in the local area.

Figure 6.1 shows the daily load experienced by GRU during the warm months of June through September in 2003, and indicates the base and intermediate capacity of GRU's generator fleet. Summertime demand is highest between about noon and 6 pm when air conditioning use is greatest, although it does not decline to below 239 MW—the capacity of GRU's two base units—until early morning. The maximum demand during the summer of 2003 did not reach 439 MW--the combined capacity of GRU's base and intermediate units—which suggests that peaking units were not needed, but this is misleading. The timing of the short daily intervals of high demand is an important factor in decisions about which units to use on a given afternoon. Cost is also critical. These and other factors must be juggled in deciding what unit will be used when demand is high. Peaking units can be started at shorter notice than intermediate units, and it will often be more economical to use them instead of an available intermediate unit. (Some relevant cost factors are included in **Table 6.1**. Peaking units are inefficient and generally quite costly to operate, though comparatively inexpensive to purchase.)

The high operating costs of peaking units result in very high energy production costs during peak use, but many utilities charge residential and small commercial customers the same rate per kWh around the clock. Consequently, these customers have no incentive to reduce electricity use when it is most expensive. GRU charges all customers the same rate regardless of the time at which the energy is used[3].

[3] In 2004 there was one residential customer on time-of-use rates, which are discussed below. (Source: Barney Capehart, personal communication, July 2004.)

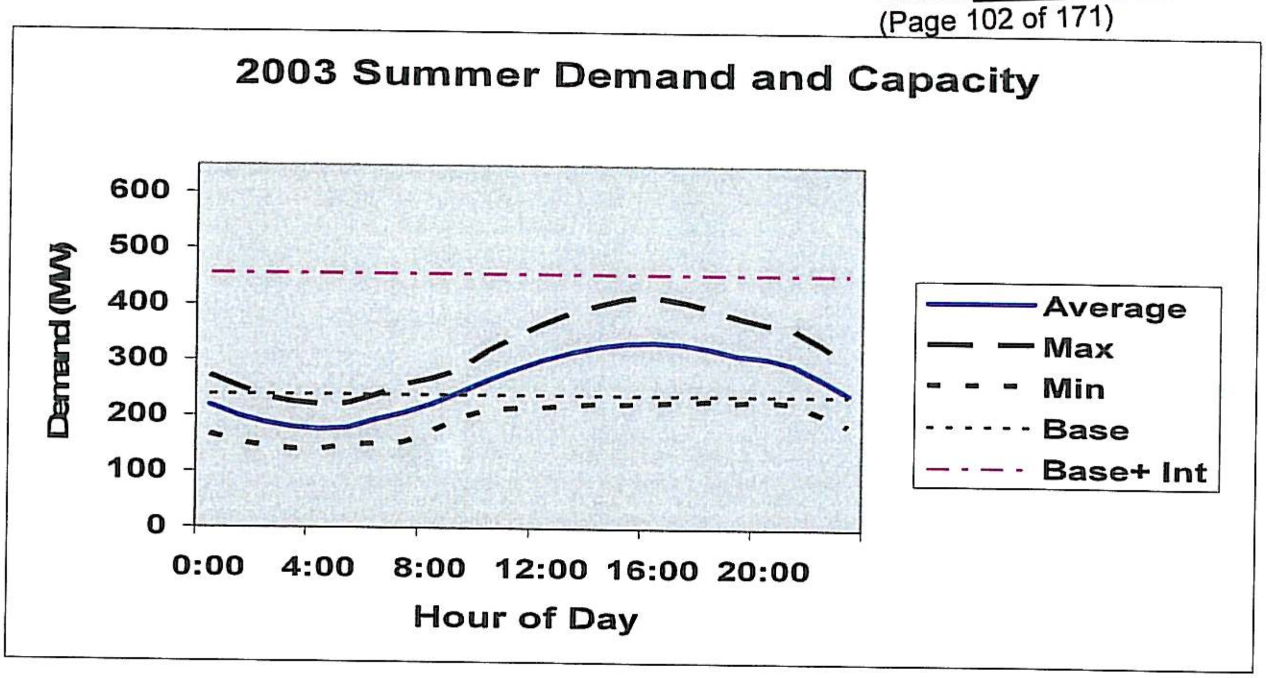

Figure 6.1. Distribution of GRU's daily load between June 1 and September 30, 2003. It is likely that peaking units were employed on some days, even though the maximum demand was always less than the combined capacity of the base and intermediate units owned by GRU. Demand was below base unit capacity for an average of 8 hours every night during these months.

Examining the cost of the last and most expensive generators turned on as demand rises during the day shows the cost advantage of reducing peak demand. This is termed the "marginal cost" of energy[4]. Marginal costs are very high on hot summer afternoons and much lower at off-peak times

Figure 6.2 is a plot of GRU's marginal cost of generating electricity on August 17, 2005[5]. Reducing demand by one MWh would have saved between saved between about $29 and $160 dollars, depending on the time of day at which the savings occurred. Most of the avoided cost is fuel cost. The lowest marginal cost experienced between about

[4] Capital and fixed overhead costs are not included.
[5] Source, GRU staff, August 22 2005 email to Dian Deevey from Rita Strother.

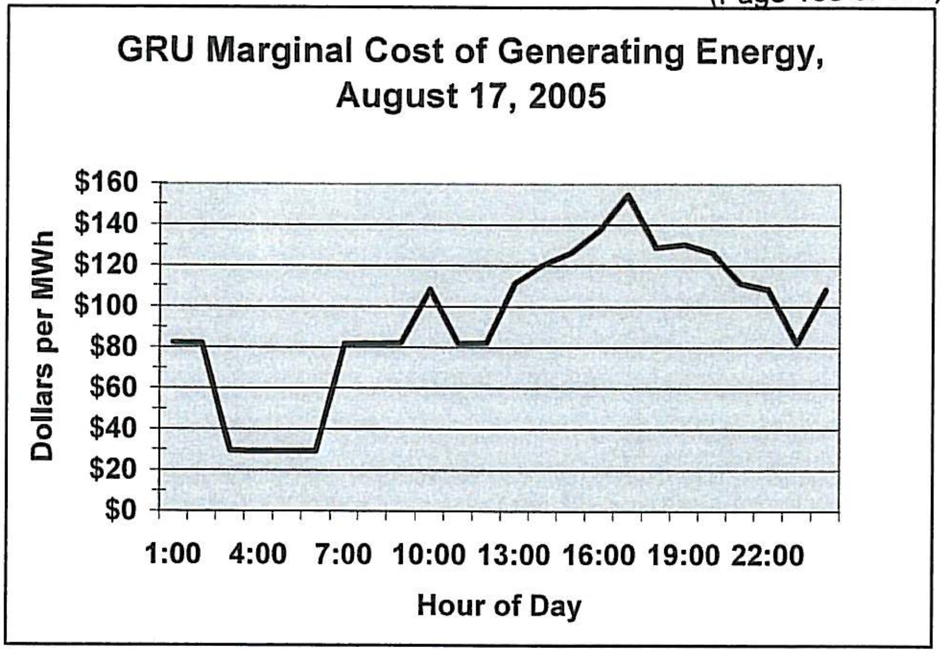

Figure 6.2. GRU's marginal cost of generating electricity on August 17, 2005. The marginal cost is the cost of the generator most recently put on line, the most expensive one in use during that hour. It is production cost avoided if demand drops by one megawatt for an hour. Most the cost represents the cost of the fuel in use.

3 AM and 6 AM reflects the fact that only the base units—Deerhaven Unit #2 and probably the nuclear plant at Crystal River—were in operation at that time. An important goal of GRU's proposal for a new solid-fuel power plant is to reduce the production costs of generating electricity for the local market to levels comparable to the lowest levels plotted in Figure 6.2.

The costs plotted here do not include the fixed overhead costs GRU must pay every year to cover staff, billing and collection, insurance, fixed maintenance costs, or service on existing debt, and the annual transfer of revenue to the Gainesville City Treasury.. In 2004 these totaled nearly $120 million, or nearly 70% of the costs paid by ratepayers, or almost $14,000 per hour during the entire year[6]..

How much money would GRU save if demand were lowered enough to dispense with the most expensive unit whose cost is shown in Figure 6.2? That depends on how much of that cost reflects the costs of fuel—which GRU passes on to the customer—and how much reflects the variable overhead and maintenance (O&M) costs that GRU could avoid if it could turn off a the peaking unit responsible for the highest costs shown in figure 6.2. A basis for estimating these O&M costs can be found in GRU simulations conducted in 2004[8]. These simulations imply that the variable O&M cost of the most expensive of GRU's peaking units—those at Kelly-- is about $26 dollars per 1000 KW. If enough customers reduced their demand so one of these units

[6] Source: Gainesville Regional Utilities Annual Report FY 2003-2004.
[8] See EGEAS Modeling Run: "Base 2 sigma L&E and Base FP Forecast, dynamic", Conducted by GRU 10/31/04, PDF pages 5 through 10 (report pages 7 and 108 through 111 through 116) Source Email from J. Womble to D. Deevey, 11/29/2004.

could be turned off, GRU would lose more than twice as much money in lost revenue as it saved in variable O&M.costs.

It is evident from Figures 6.1 and 6.2 that energy production costs to the utility could be reduced if customers were able to even out their use of electricity, imposing more of their utility demands in the late evening or early morning hours when there is capacity to spare and costs are low. But this reduction would not be economically attractive unless it could postpone the day on which the utility needed an additional generator, or lower the size of a new one.

Assuming a utility wanted to reduce electricity consumption to delay the need for a new generator, how could this be achieved? Costs could also be lowered by widespread use of technologies that improve customer's electricity use efficiency (i.e., efficiency measures). Persuading them to get along with less of what the electricity does for them—air conditioning, computer operation, swimming pool heating, and so forth could also lower costs. These are the goals of demand-side management programs.

Kinds of DSM Programs

There is no accepted way to classify DSM programs. One classification[9] results in the following categories:

- *Conservation* of electricity by reducing consumption, usually in ways that require specific actions by users, such as lowering thermostats, turning off lights, or avoiding the use of lighting or equipment. Conservation usually means going without.
- *Energy Efficiency* improvements entail using less electricity to do a job by substituting more efficient equipment. This usually requires purchasing more efficient equipment such as appliances, improving insulation, fixing leaks, and so forth. Building standards developed by EPA and other agencies are selected to reduce energy use in new structures, compared to the minimum standards incorporated in most building standards. Very significant energy efficiency improvements would result from adopting better building standards, and better standards for appliances, lighting, and other equipment.
- *Demand Response* encompasses a large variety of programs that reduce customer demand when generation costs are high:
  - *Load Management* is one kind of demand response program where the utility makes decisions about reducing load. The utility may turn off a customer's air conditioner, water heater, pool pump or other equipment for a short duration according to a scheme agreed on in advance.
  - *Price Response Programs* are based on voluntary customer actions in response to economic signals from the utility. The differences between Price Response and Load Response programs are a matter of degree. The most pronounced

[9] This classification roughly follows that used by the Peak Load Management Association described in: "Demand Response: Design Principles for Creating Customer and Market Value" PMLA February 2002. Available for download via links at: http://www.peaklma.com/i4a/pages/index.cfm?pageid=133

difference is that in price response programs, the utility communicates a price signal to their customers, and the customer has discretion about whether to respond to that signal, whereas in load management programs, the customer has much less freedom once they agree to terms of the system.

- *Time of Use Rates* charge participating residential or commercial customers a different rate depending on the time of day and season--higher rates corresponding to times when demand peaks, and lower ones at times of low demand. Most programs for residential and small commercial customers have a "shoulder" period between the two, when rates are moderate[10]. Time of use rates can be used by large numbers of customers with comparatively inexpensive meters, and little utility-to-customer communication.

Tiered and seasonal rates are not traditionally included in lists of Demand Response programs, but we include them here because their overall effect is to charge higher rates to customers that use the most electricity. These programs have the same goal as other demand response programs—getting the customer to use less electricity when it is more expensive to generate. Many conservation-oriented utilities have different rates for summer and winter, and some reduce the impact on low-income ratepayers by giving them different rates.

Patterns of Energy Use and Ways to Change Them

Developing sensible plans to achieve energy use reductions requires information about how electricity is used by consumers during each hour in the different seasons. **Figure 6.3** shows electric energy demand of different sectors on a hot day in California in 1999. This figure is probably representative of the impact of air conditioning load in many southern tier states, except that California has a large industrial and agricultural base load not found in Florida or in Gainesville[11]. Residential and commercial air conditioning and commercial lighting accounted for about 65% of energy demand during the peak. (These are the second, third, and fourth segments from the top in Figure 6.3). Making these more efficient could have large payoffs for consumers.

The effects of energy efficiency improvements and load control techniques that simply turn off some equipment during periods of peak use are illustrated in Figure 6.4. This figure compares the effects of reducing cooling by resetting thermostats (load control) and improving the efficiency of lighting or cooling in a large commercial establishment (energy efficiency improvements). Both techniques can play a useful role in any aggressive program of demand side management.

One very promising load control methodology, rejected by GRU as not cost-effective in1994 and 2004 (see below), may be implemented in the future. This program was pioneered by Austin

[10] GRU offers a time of use program that had only one participant in 2004. It has only two rates--"peak" and "off-peak"—in effect for 8 months of the year. Between May 15 and October 15, the peak lasts from noon to 9 pm. In January and February, peak hours are in the morning and the evening between 7 am and 11 am, and between 6 pm and 10 pm. EPAC's analysis of a member's bill confirmed that even in the unlikely event that 70% of electricity consumption could be confined to off peak hours during the 8 months in question, the customer would save only $1.73 over the whole sample-year, and risk very high monthly bills for using air conditioning in the summer. In practice, these rates are punitive.

[11] The 1994 report of GRU's study of energy use in the local area summarizes analyses of local energy uses, but does not does not report the details of energy use by the various retail sectors served.

Energy, who found it to be extremely cost effective[12]. The goal is to cut peak demand on summer afternoons by sequentially shutting down residential air conditioners briefly. Each participating customer is provided with a programmable, smart thermostat that allows the owner to set the temperature independently for four different time periods throughout the day. The thermostats are also equipped with FM receivers that allow the utility to remotely control the operation of the air conditioner by means of its FM signal. At times of peak usage, air conditioners are turned off for 10 minutes every half hour. Turning off a thousand air conditioners reduces demand by one megawatt; turning off three thousand in sequence reduces demand by one megawatt for an entire hour*. Austin Energy has 40,000 residential air conditioners which reduce peak demand by about 20 MW. This program has a long waiting list.

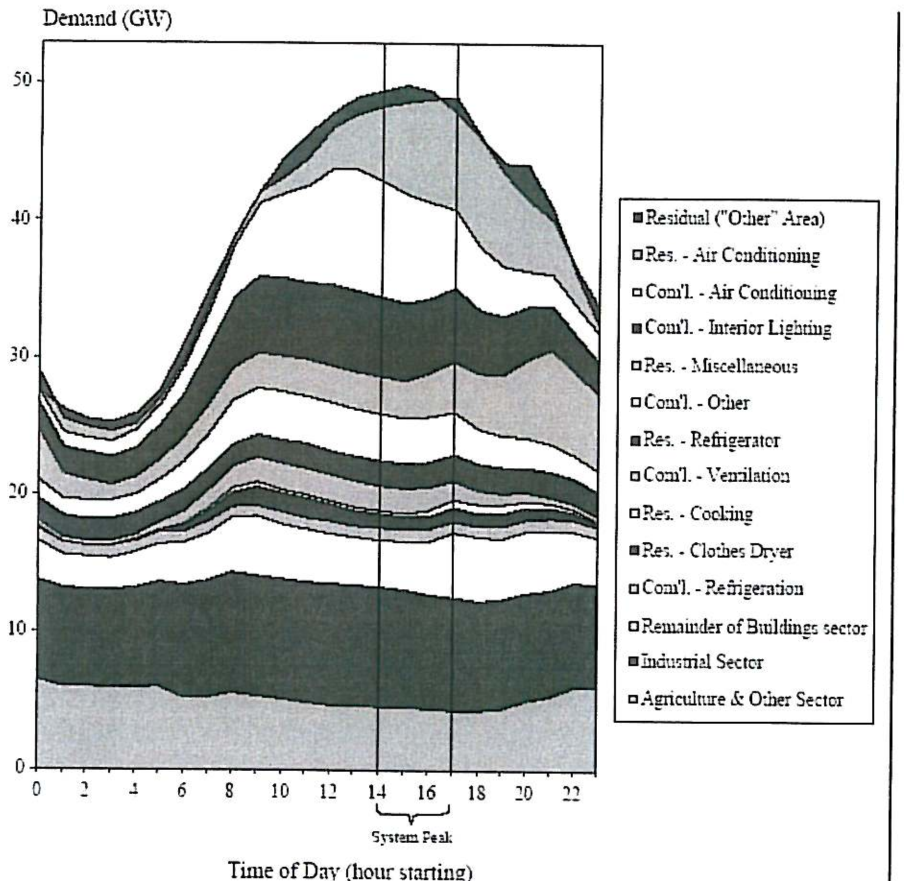

Figure 6.3. Energy uses at a California location for a day when total demand approached the peak for the year. Commercial and residential air conditioning and commercial interior lighting accounted for over a third of total energy use in mid-afternoon.

The program is extremely popular with residents, including apartment dwellers. The thermostats are installed free of charge, with no incentive payments to get customers to participate. The customers like the thermostats because they can program more efficient energy use with them—lowering the thermostat when they are away at work, or at night. Purchasing and installing the thermostats is very inexpensive and operational costs are reported

12 Gustafson, J. 2003.

by Austin Energy to be negligible. Other utilities have implemented residential load control of hot water heaters, air conditioners, and pool pumps and heaters.

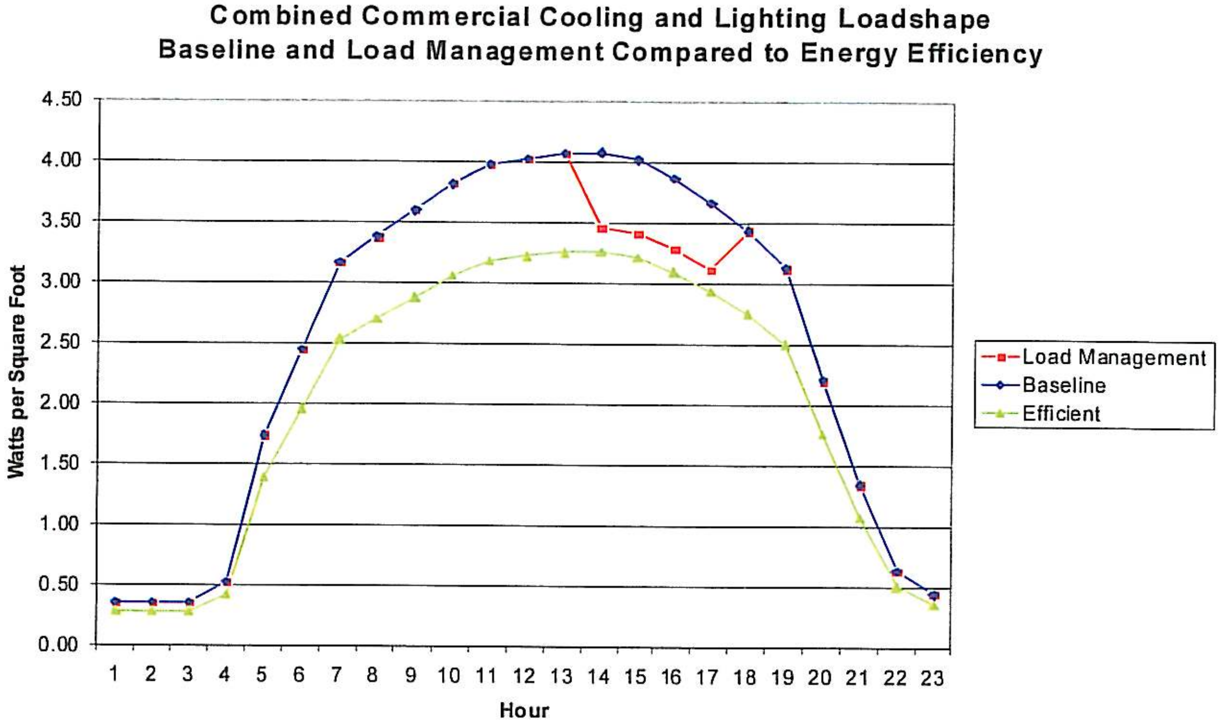

Figure 6.4 Effects of load management and energy efficiency. The base line shows energy consumption by hour without energy efficiency or load control. Load management sharply reduces consumption for a short duration between 12:30 PM and approximately 5:30 PM by manipulating the thermostat. In contrast, installing more efficient lighting and cooling achieves a much larger daily reduction in both peak energy use and continues to reduce consumption throughout the day and night.

Tiered Residential Rates

One of the most effective ways to reduce residential energy use is to charge higher rates to customers who use the most electricity, by increasing the rates for usage above specific set levels. In Gainesville, residents pay a basic charge of $4.66 per month and 4.613 cents for the first 750 kWh used during the month. For all usage above 750 kWh, the charge is 5.677 cents per kWh. (In addition, customers pay a fuel charge of 3.55 cents per kWh[13]). This is referred to as a tiered rate structure. It has two tiers, the first one being the first 750 kWh per month, and the second one all energy use above that. The more energy a customer uses in the second tier, the higher the average per kWh rate for that month.

Most conservation-oriented utilities use tiered rates, and many use different rates for different seasons. Austin Energy uses two tiers in each of two seasonal rates. **Figure 6.5** is a plot of the per kWh rate in Gainesville and in Austin Energy in 2004.

[13] A rate increase is scheduled for October, 2005.

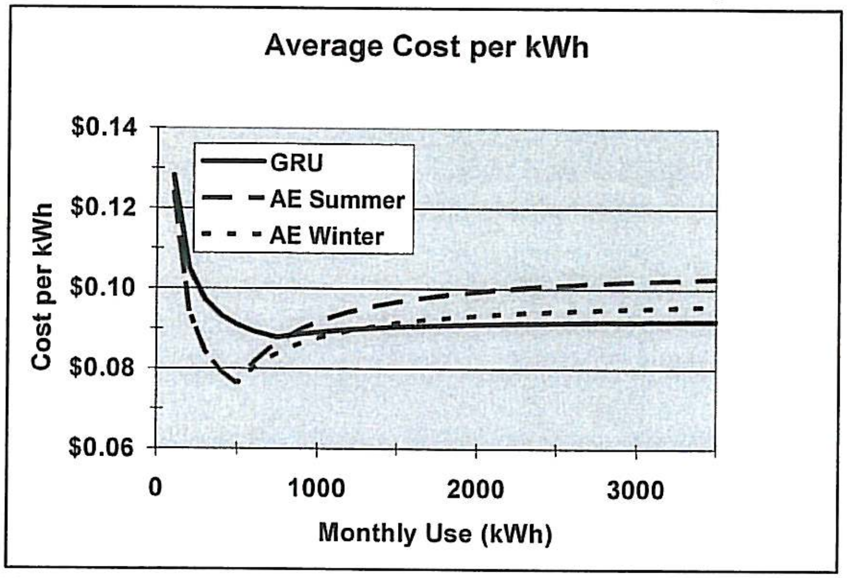

Figure 6.5 Residential tiered rates in Gainesville and Austin, Texas provide minimum rates at the point where the second tier begins to affect the bill (dollars per kilowatt hour). In Austin, rates are tiered more than in Gainesville to discourage high monthly consumption, especially in summer. Low income residents pay less in Austin than shown in this plot. The plotted data include a charge for fuel (See Figure 6.7).

In a single tier system, customers that use more energy, pay the same per kWh than customers who use less. This fails to discourage high energy use. **Figure 6.6** shows charges for three other municipal utilities in Florida: JEA, Tallahassee (TAL), and Orlando (OUC). JEA and Tallahassee have no second tier, and average per kWh costs decline with monthly usage, which encourages residential customers to use more energy. Orlando has a tiered residential rate structure, but it has little effect on monthly per kWh charges (Figure 6.5).

To be effective, a second tier must affect a significant proportion of residential customers, which means that it must start at a low consumption level. How steeply electricity costs should rise depends on the difference between the second and the first tier costs. In Orlando, the second tier begins at 1,000 kWh per month, and is 20% greater than the first tier.

Comparisons of the costs to customers that use 1,000 or 2,000 kWh per month show how tiered rate structures can affect the costs of energy. If the cost per kWh were the same regardless of how much energy customers use, those using 2,000 kWh per month would pay exactly 200% of the amount those using 1,000 kWh pay. Without tiered rates, the monthly bill for users of 2,000 kWh is less than twice that for those who use 1,000 kWh. For JEA customers, the monthly cost of 2,000 kWh is 192% of the cost of 1,000 kWh. Tallahassee customers, it is 195%. If rates are tiered, the cost is more than 200% of the cost of 1,000 kWh. Among utilities that use tiered rates, the cost is: Gainesville, 203%; OUC, 204%, Austin Energy winter, 207%, summer 216%, City Service, (San Antonio, TX) 215%, and SMUD (Sacramento), winter 206%, summer 252%.

One serious problem with sharply tiered rates is that they are very hard on low-income ratepayers, who often struggle to pay monthly utility bills. Many utilities moderate this impact by giving special rates to low-income residents. Austin Energy eliminates the monthly fee for low-income residents, and allocates to them a fraction of their wind energy purchase, which costs only 1.7 cents per kWh for fuel, as opposed to the 2.79 cents charged regular customers. **Figure 6.7** shows the resulting average cost of energy for each kind of customer.

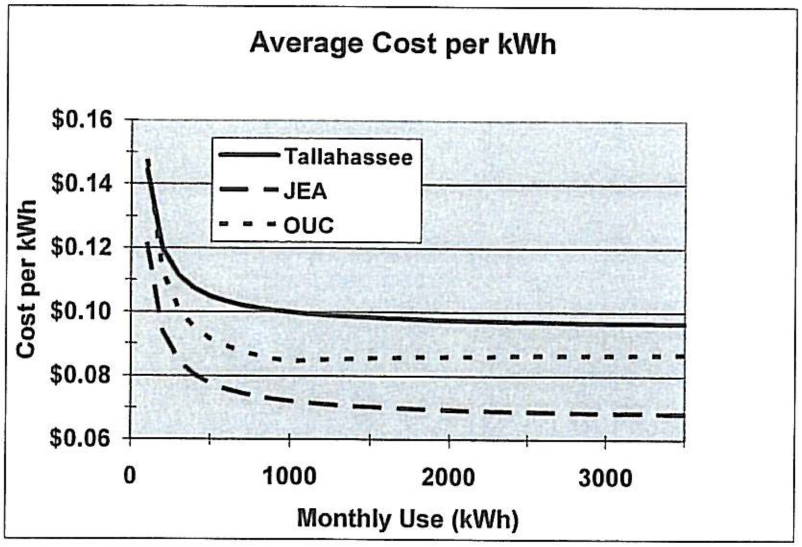

Figure 6.6. Cost per kWh in three Florida municipal utilities. Neither JEA nor Tallahassee have a second tier rate, and per kWh energy costs decline as residential customers increase their monthly consumption. Orlando has a second tier rate that begins at 1,000 kWh per month, but the increase is very small.

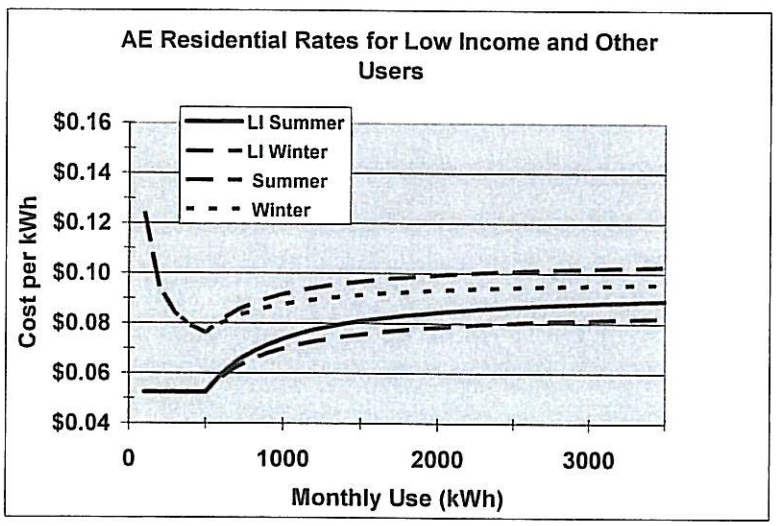

Figure 6.7. Comparison of Austin Energy residential rates for low income and other customers. Low-income ratepayers pay no monthly charge, and are allocated the energy from AE's wind turbines, which cost 1.7 cents per kWh, while other customers are charged 2.79 cents per kWh.

6.2.1 GRU's Conservation Programs are Modest and Offer Little to Low-Income Customers (Findings 1 and 2)

History

Conservation and other demand side management techniques to improve the efficiency of electricity use were heavily subsidized by Federal programs during the 1980's, a period when GRU and other utilities saw significant reductions in energy usage and in demand. This is apparent in **Figure 6.8** where summer and winter demand reductions since 1983[14] are plotted, together with forecasts for 2005-2013. In 1984 peak summer demand was 225 MW, and in 2003 it was 417 MW. According to recent GRU projections[15], it will rise to 560 MW by 2013 and to 673 in 2023.

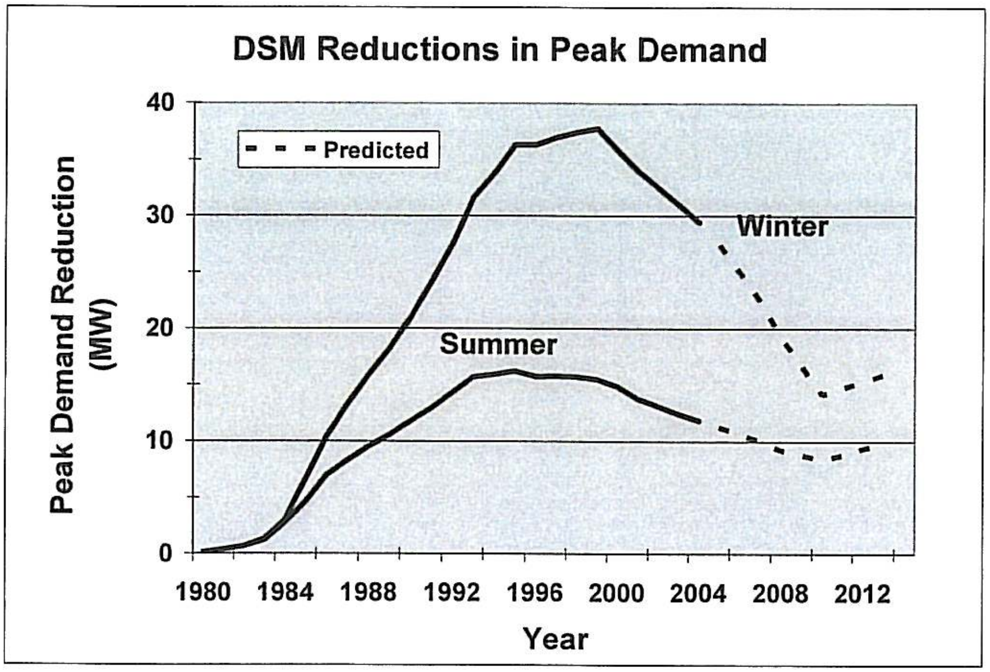

Figure 6.8 Demand reductions achieved by energy efficiency programs in Gainesville, as estimated by GRU in 2003. Only the summertime reductions impact peak demand, because GRU is a summer-peaking utility. Large winter peak reductions reflect subsidies for natural gas installations, which supply winter heating needs. Source: "Alternatives for Meeting Gainesville's Electrical Requirements through 2022 Base Studies and Preliminary Findings", Gainesville Regional Utilities December 2003.

It is difficult to estimate the impact of demand side programs on peak demand or total energy consumption. Utilities have to estimate what the usage would have occurred in the absence of the DSM programs. Often the cost of reliably confirming the impact of a DSM program can exceed the savings it achieves in avoided generation. About 20% of GRU's DSM achievement is in the form of behavioral changes resulting from consultation with customers[16].

[14] Data from Gainesville Regional Utilities' 2003 Ten-Year Site Plan, Table 3.1.
[15] Projections supplied by the GRU "Blue Book" in April, 2004. These projected slightly lower future peak demands than those presented in 2003, and further slight reductions are apparent in the Ten Year Site plan prepared by GRU in 2005.
[16] Neither Austin Energy nor Florida Power and Light count the effects on peak demand or energy consumption of such educational efforts, because they cannot be accurately or reliably verified. Austin Energy does not count any behavioral changes, removal or downsizing of equipment, or maintenance changes that may reduce energy consumption. They count only

DSM impacts on peak demand have declined markedly since the early 1990's, because programs started in the 80's reached the end of their effective lives as government funding was stopped. Figures 6.8 and 6.9 show this effect. **Figure 6.9** shows how little DSM programs influence peak demand, and how their impact has declined over the years since 1980.

Lack of Economic Incentive for DSM/EE at GRU

GRU has little economic incentive to invest in DSM programs. GRU has more capacity than needed to supply both its current retail customers plus some wholesale customers. GRU generators are all paid for, or are being paid for by means of bonds it issued in past years, and GRU cannot avoid their capital cost, no matter how little it operates them. Fuel cost is the only major expense that GRU avoids when customers conserve energy, but that is paid directly by the customer, so GRU does not benefit economically. A small variable overhead and maintenance cost for each generator can be partially avoided, but this avoided cost is small compared to the lost income from customers who reduce their energy consumption.

As long as GRU adds generators to ensure that it has significantly more capacity than it needs locally, DSM will offer few economic advantages. Under these circumstances the rational business choice would be to minimize conservation investments, and encourage consumers to use energy.

Current Residential DSM Programs

In 2004 and 2005 GRU offered residential customers a small number of DSM rebates and other programs to reduce electricity use. Seven of these include rebates for appliances and other measures that improve end-use efficiency, while two educate customers about energy-saving options. One program installed net metering whereby consumers with solar photovoltaic panels can sell their excess energy back to the utility, (but we could find no recent example of a consumer doing this). The more substantial remaining six programs offer rebates for new construction of single-family residences that use natural gas and for natural gas appliances. Additional limited rebate programs were established in 2005 to reduce energy needed for cooling residences, including a pilot program to repair air conditioning ducts.

By far the most important program is the new construction rebate for builders of single-family homes who include natural gas service in new residences. Builders can collect up to $650 in rebates, beginning with the installation of a new gas water heater ($200 rebate). This is part of the largest current GRU DSM program, namely, promotion of the installation and use of natural gas. Natural gas can be used very efficiently for space heating, water heating, cooking and so forth. Consequently promoting natural gas use is an effective way to reduce utility electricity demand.

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reductions based on equipment changes, which they confirm by inspection and consumption record. These are also independently verified.

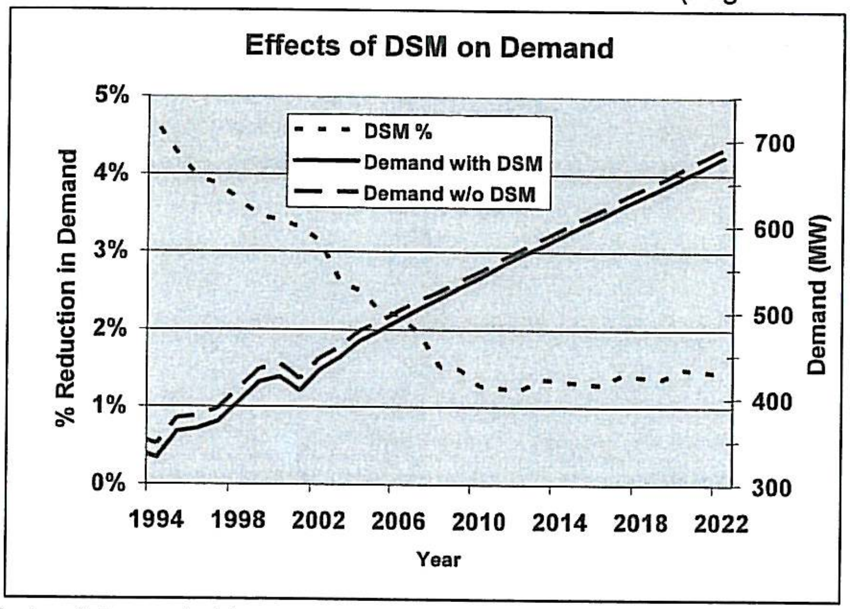

Figure 6.9. Effects of demand side management on peak summer demand, as estimated in GRU's 2003 planning documents. (Estimates of future peak demand have been reduced since the data plotted here were provided.)

Table 6.2 lists the averages of the natural gas rebate programs for the interval 2000-2004, and the current electric rebate program for 2005[17]. Taken together, rebates for the two listed years total about $350,000, with 78% going to gas new construction and over 11% to central air conditioning systems[18]. According to GRU estimates, the 2005 electric rebate programs shown in Table 7.3 and listed above will save approximately 0.33 MW of summer demand at a cost of about $400 per kW[19], which is quite low compared to the cost of new generating capacity ($1,200 / kW).

Builders and developers of new residential housing and individuals in the market for new appliances receive most of the benefits of GRU's current residential DSM programs.

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[17] The natural gas rebate program data were provided in an email from J. Womble to D. Deevey, 3/10/2005. The 2005 electric rebate program data were provided in an email from R. Strother to D. Harlos, Cite emails that were the source of this information. We requested information about costs of operating these programs, but were told that the data were unavailable. .

[18] The figures for the gas program in 2004 are representative of those in previous years, so adding the disparate years together is unlikely to introduce significant error.

[19] Calculated from data supplied by GRU in emails on the following dates:

Table 6.2 Residential Rebate Programs Costs in Dollars

Gas Rebates	2000	2001	2002	2003	2004	Average 2000-2004	Percent of Total
Gas, New Construction*	$183,700	229,800	315,500	327,900	262,000	$263,780	*74.0%*
Furnace, gas conversion	$7,500	11,000	6,500	2,003	1,000	$5,601	*0.3%*
Gas Water Heating	$6,800	7,900	7,900	8,400	1,350	$6,470	*0.4%*
Gas Cooling	$0	0	0	0	0	$0	*0.0%*
Gas $$ Subtotal	$198,000	248,700	329,900	338,303	264,350	$275,851	
Gas Percent of Total	*99.8%*	*98.3%*	*98.7%*	*98.6%*	*99.1%*	*77.9%*	*77.9%*
Electric & Other**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005 FY**	
Central Air	0	0	0	0	0	$40,200	*11.4%*
Room Air	0	0	0	0	0	$2,310	*0.7%*
Central AC Maintenance	0	0	0	0	0	$5,600	*1.6%*
Heat Recovery Units	0	0	0	0	0	$1,580	*0.4%*
HVAC Heat Pipes	0	0	0	0	0	$480	*0.1%*
Mobile Home Roof Coating	0	0	0	0	0	$720	*0.2%*
Duct Repair Pilot***	0	0	0	0	0	$25,000	*7.1%*
Solar Water Heater	$350	4,300	4,200	4,900	2,300	$2,300	*0.6%*
Electric & Other Subtotal	$350	4,300	4,200	4,900	2,300	$78,190	
ɘc & Other Percent of Total	*0.2%*	*1.7%*	*1.3%*	*1.4%*	*0.9%*	*22.1%*	*22.1%*
Grand Total Gas & Electric	$198,350	253,000	334,100	343,203	266,650	$354,041	*100%*

NOTES:

Gas New Construction* The final column uses the average of the preceding 5 years because expenditures planned for FY 2005 were not available. Rebates to builders of multifamily residences may not be included.

Electric and Other** These programs were reported as ongoing in 2003, but had no participants in the interval 1996 through 2003. They were re-activated in FY2004-2005.

Pilot Duct Repair*** This is not a rebate program. All costs of testing and repairing ducts are paid for by GRU. These are estimated to average $500 per unit, for 50 participants chosen at random.

SOURCE: The data in this table were supplied by GRU to EPAC in a series of emails in the months April, May, and September 2004, and January through May of 2005.

GRU's residential DSM program expenditures are very modest by comparison with its income from late payment fees (over $672,000 in 2004). .

Social Conservation Needs: Low Income Residents

Approximately 15% of GRU's residential customers have difficulty paying their utility bills[20], but few of them benefit from the DSM programs listed in table 6.2 except, possibly, the $70 rebate for reflective coatings on mobile homes. The coatings reflect sunshine and can reduce air conditioning needs, but the 2005 budget will coat only 10 mobile home roofs. Rebates for new appliances have little appeal for ratepayers who have difficulty in meeting their monthly bills.

[20] Alternatives for Meeting Gainesville's Electrical Requirements Through 2022: Base Studies and Preliminary Findings. Gainesville Regional Utilities, 2003.

In its original planning document[14] GRU listed two programs specifically designated for low-income families. One is the "Front Porch Florida" program that installed solar water heaters in homes in the Duval neighborhood in East Gainesville in 2003. The other consisted of extending natural gas to low-income homes. "Florida Fix", a weatherization program for low-income residents, has been a regular feature of GRU's DSM efforts. It consists of GRU staff volunteers who provide one day of free labor to a weatherization program run by the Community Action Agency, which receives Federal money[21]. GRU contributed $6,500 dollars to this program as rebates for air conditioners in 2004. We have not included this contribution in Table 6.2, as it was not listed in the materials supplied to EPAC.

GRU has a Project Share program that annually collects about $50,000 in charity contributions from ratepayers, and gives them to the Salvation Army to provide one-time help paying utility bills. This program focuses on the needs of low-income ratepayers who are elderly or disabled. (Many utilities throughout the country have similar Project Share programs, though the details of the aid they distribute are not all the same. For example, in Seattle, the Project Share program subsidizes the utility bills of some eligible customers.) GRU also counsels residents who cannot pay their bills and tells them about the Community Action Agency and helps them finance their bills.

In 2004, GRU funded the Community Energy Cooperative (CEC) to conduct a pilot program to develop information about the energy use and weatherization needs of low-income families in Gainesville[22]. This group has designed a GIS-implemented study that combines data from billing records, the Census Bureau, and the County Tax Assessor's to explore the use of electricity in GRU's load service area[23]. GRU is working with the consultant and plans to complete the study[24].

Improving energy efficiency in low-income homes is rarely cost-effective, as the homes are often old and difficult to improve. Before energy deregulation programs began in the mid-1990s, many states required utilities to aid low-income residents, and allowed cost recovery, but many of these programs have since lapsed. Florida requires most of its large utilities to participate in an energy efficiency program, but not Gainesville.

All states that have a wholly or partially deregulated electric utility industry have established system benefit funds that collect a fee for all energy sold and use it to fund DSM programs. Twenty-five states with system benefit funds earmark part of the surcharge they collect for assistance to low-income residents. Charges for low-income assistance in these states range around from less than one tenth of a cent ($0.001) per kWh up to five times that amount.[25].

If Gainesville instituted a public benefits surcharge on GRU's kWh sales, it could provide significant money to reduce electricity needs for low-income residents through energy efficiency improvements. A very small surcharge on retail energy sales equaling an increase of 0 .5% -

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[21] The Community Action Network administers a program that in 2004 provided about $92,000 for weatherization of homes of low income families (Weatherization Assistance Program) in Alachua County, and about $350,000 for aid in paying utility bills (Low Income Home Energy Assistance Program). The funds are from Federal programs. The weatherization program spends an average of $7000 per residence to fix roofs, improve insulation, replace windows and doors, etc.

[22] See CEC Draft Final Report, provided by GRU to D. Deevey under a Public Information Request.

[23] Source: Personal communications between D. Deevey and the staff of Community Energy Cooperative, Chicago, Ill, August 2005.

[24] Comments by M. Spiller, August 25, NAACP meeting at the Wilhelmina Johnson Center, Gainesville.

[25] See Database of State Incentives for Renewable Energy (DSIRE) at: http://www.dsireusa.org/

would produce nearly $1 million, and would cost the residential ratepayer an average of only about 25 cents each month. Depending on the cost per home, this sum could weatherize 100 to 200 residences each year if it were all devoted to weatherization. This would reduce energy demand, as well as the costs to residents who need the most financial help[26].

The state of Florida may soon add a public benefit fee to fund aid for low-income residents and DSM in general. Two recent reports on energy use in the state strongly recommend this course of action[27]

6.2.2 The DSM Potential at GRU (Finding 3)

Expected Future Peak Reductions by DSM

The peak load forecasts for the next 10 to 20 years used by GRU strategists include the effects of past DSM programs. Actually, three projections are made: a "base" projection using observations of the past roles of weather and population on peak demand and total local energy use, plus "high band" and "low band" projections that define the range of uncertainty of the forecasting method[28].

In discussing DSM, it is important to distinguish between the total expected peak demand in a future year, and the projected increase in total demand over some interval of time, like the next ten years. For example, Austin Energy reduced its peak demand by a net of over 550 MW between 1983 when it began a vigorous DSM program and the end of 2003. This corresponds to about 24% of its 2003 peak load of 2,350 MW. In contrast, GRU's net DSM impact totaled 12.4 MW in 2003, or about 3% of its peak 2003 load of 417 MW.

Every year utilities project the future local electricity needs for the next 10 years, and most find that demand is growing. Many utilities express DSM targets in terms of their impact on the demand growth rate, which is also called the incremental demand increase. In 2004, GRU projected a peak of 569 MW for 2014, which was 137 MW greater than its 2004 peak demand of 432 MW, and included 6 MW of DSM reductions during that 10-year period. According to these figures, the DSM programs were expected to cut the growth by a little over 4%. In December, GRU announced that planned DSM programs would further reduce demand by 4 MW. This brings the cut in the growth rate to about 6.5%.

Utilities in other states are achieving much greater reductions in peak demand growth. Deregulated investor-owned utilities in Texas are required to reduce the growth rate of their peak demands by 10% during the same ten-year period. Austin Energy, a municipal utility in Texas that is widely recognized as the US leader in energy conservation, plans to cut the rate of

[26] According to Austin Energy, this program costs approximately $1100 per kW demand reduction, which is about twice the avoided cost.

[27] Florida Solar Energy Center report "Florida's Energy Future: Opportunities for Our Economy, Environment, and Security". A report to the Florida Department of Environmental Protection: January 16, 2004, produced by the Florida Solar Energy Center and available at: http://www.fsec.ucf.edu/. See also "Report of The Environmental Technical Advisory Committee to the Florida 2020 Study Commission August 30, 2001", available for download at:
http://www.myflorida.com/myflorida/government/taskandcommissions/energy_commission/pdfs/environmental_tac_report.pdf.

[28] For example, in 2003 GRU forecast of summer peak demand in 2022 as 681 MW with low and high band range of 597 to 761 MW, or about plus or minus 12%. GRU uses linear multiple regression for forecasting purposes.

growth by 21.5% over this interval[29]. California recently announced a doubling of its budget for energy efficiency improvements over 2004-2013 to reduce the state peak summer demand by 5,000 MW, and annual electric energy consumption by 23,000 GWh[30]. This represents a reduction about 55% to 59% of peak demand growth over the next 10 years.

According to the Florida Solar Energy Center, Florida could implement an aggressive program of improving end use energy efficiency, and reduce state energy consumption by 15%.

Figure 6.10 illustrates how GRU's peak demand would be affected if GRU could match these goals. The rate reductions in the other utilities are applied to GRU's April 2004 peak demand forecasts, and are extrapolated through to 2023. The top line labeled "GRU 2004" is the summer peak demand forecast by GRU in April 2004. "GRU Recent" corresponds to the 6.5% growth rate reduction announced in December 2004.

The other lines in **Figure 6.10** show how demand would grow if GRU could match the goals mentioned above for Texas deregulated investor-owned utilities, Austin Energy, or California utilities. GRU's new peak demand forecast of 565 MW for 2014 would be reduced, respectively, to 561 MW, 549 MW, or 512 MW if it could match the Texas, Austin Energy, or California targets for the next decade. We have extrapolated these projections to the year 2023 just to illustrate the possibilities energy efficiency improvements and other DSM program offer. It seems likely that well before 2023, state and federal regulations and new technologies will greatly improve energy efficiency, and even greater demand reductions than those shown in Figure 6.10 will be achieved.

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[29] Source, Fred Yebra, Mgr of Austin Energy conservation services, email to Dian Deevey January 2005. Austin Energy was considering a far more aggressive program for this period, but we have not included the results in the figures presented in this section.

[30] See "Draft Energy Action Plan Ii: *Implementation Roadmap for Energy Policies"* August 12, 2005, available for download at: http://www.cpuc.ca.gov/word_pdf/REPORT/48626.pdf . See also: Decision 04-09-060 September 23, 2004, Before the Public Utilities Commission of the State Of California; "Interim Opinion: Energy Savings Goals for Program Year 2006 and Beyond" Available for download: http://www.cpuc.ca.gov/word_pdf/FINAL_DECISION/40212.pdfDRAFT

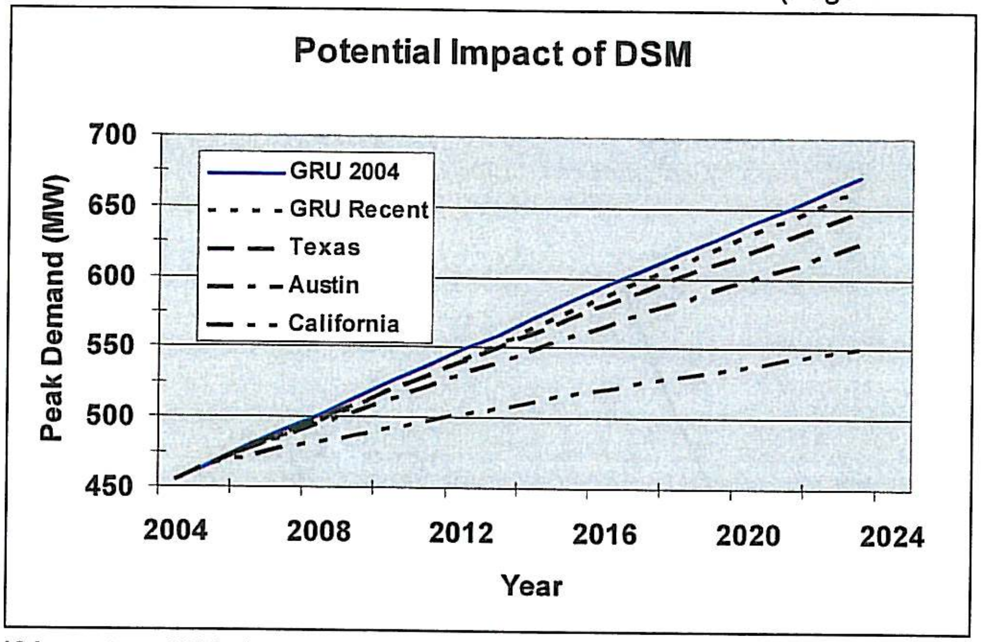

Figure 6.10 Impact on GRU of matching reductions in peak demand growth planned for other utilities. The reductions in peak demand growth rates targeted by Texas for regulated utilities (10%); Austin Energy (20.5%); and California (55%), are applied to the GRU growth rate of its 2004 projections. "GRU recent" reflects the plan announced in December 2004 to reduce the 2014 peak demand by approximately 6.5%. All reductions have been extrapolated to 2023, to demonstrate the impact of sustained reductions in the growth of peak demand.

Both Texas and California have public benefit funds they give to individual investor-owned utilities to fund approved DSM projects. (Austin Energy is not eligible for these funds, but it sometimes obtains grants from the state for specific demonstration projects). Austin Energy has a policy whereby it invests heavily in energy efficiency or other DSM programs if they reduce energy use more cheaply than electricity from new generators.

Unlike GRU, both Austin Energy and California utilities have achieved extremely large DSM energy demand reductions over the past 5 to 20 years. States have a major advantage over utilities in that they can improve building codes and appliance standards, and fund investments in energy efficiency with per kWh surcharges on all electricity use. Individual utilities usually cannot mandate improved building codes, or require that all appliances sold in the area be the most efficient available, though they can encourage builders to use higher building standards than the minimum required by the state, and encourage customers through rebates, education, and other measures. For this reason, Austin Energy and other conservation leaders among utilities are the more appropriate models for GRU than states like California, although many benefits from California's programs will be available to all consumers.

Examination of the current and past programs at Austin Energy confirms that many clearly have application in Alachua County, and might be usefully adopted here[31]. Many utilities—including Austin Energy—charge large customers prices that reflect the true *cost of generating the electricity, and change over the day.* This approach very successfully reduces demand among large customers, if they are provided with feedback about their energy consumption, and have the flexibility to adapt energy use to coincide with low demand periods. It results in significant

[31] Many of these are discussed in Appendix 2.

money savings to customers, provided the rate structures permit them to share in the low generating costs achieved by the utility at off-peak times. GRU offers its large commercial users smart meters but does not have a rate structure that rewards customers for using them[32], so none are in use (except that employed in the City Administration building).

Impact of DSM on Generating Capacity Needs

How much new generation would GRU need if it could match the expected efficiency improvements of Austin Energy, or California utilities? GRU is required to maintain a 15% reserve relative to expected peak demand, to accommodate emergencies[33]. **Figure 6.11** shows how much capacity would be required if DSM programs succeeded in reducing peak demands in the ways plotted in **Figure 6.10**. It is apparent that a small addition of 50 to 100-MW capacity in about 2012 combined with a DSM program that matches the 20.5% goal adopted by Austin Energy could significantly delay the need for new generators at GRU until about 2016 or later, when new technologies are likely to be available at competitive costs[34]. A well-funded, very aggressive DSM program might do much better than the 20.5% goal chosen by Austin Energy with far less cost to consumers than a new generator.

6.2.3 Room for Improvement in Residential Energy Efficiency and Conservation (Finding 4)

GRU has often claimed that additional conservation or other DSM programs are not likely to achieve significant energy use reductions, supporting this claim by pointing out that the average electric energy consumption by residents is much lower than the state average[35]. In 2003, local residential electric utility customers used and average of 955 kWh per month, while the state average was 1,229 kWh per month.

GRU's comparison is misleading. GRU residential customers use less electricity than other state residents only because they use much more natural gas. The state average residential natural gas consumption is 0.05 therms per month, while in GRU's local service area it is 12.1 therms per month. When these figures are converted to kWh and added to electricity consumption, Gainesville residential energy consumption rises to 1,309 kWh per month, or about equal to the state average of 1,229 kWh per month (Figure 6.12). EPAC concludes that conservation and demand side management are still viable options for residential energy use reduction, and can delay the need for new capacity.

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[32] As of March, 2005, GRU offered no price break to large users who shifted loads into off-peak periods.
[33] This 15% reserve can be in the form of purchase contracts or on-site generating capacity
[34] See Chapter 8 on Biomass for an illustration that suggests that 100 MW of added capacity could supply all energy needed in the local area through about 2012 to 2014, assuming that there are no reductions in peak demand or energy consumption projected by GRU. It could delay need for a new generator longer if accompanied bay very aggressive DSM/EE program.
[35] Frequently Asked Questions: About Future Power Plans at the web address: http://www.gru.com/AboutGRU/NewsReleases/Archives/Articles/IRP_QA.jsp
"How are GRU customers doing in conserving energy?" Item 26. "GRU's customers have the lowest per capita electricity usage in the state, and have had for a number of years. This is one reason why additional conservation is hard to achieve, as our customers are already doing more than most."

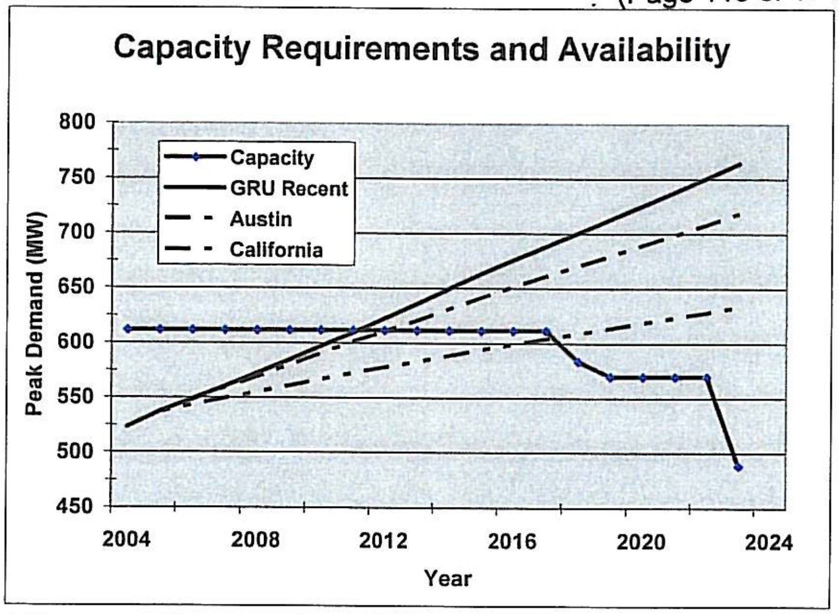

Figure 6.11. Existing generating capacity at GRU compared to capacity required under different assumptions about DSM effectiveness. Peak demands resulting from DSM as shown in Figure 6.10 have been incremented by the extra 15% to include reserve capacity required by state policy. The curve labeled "capacity" shows the existing capacity at GRU and the impact of planned retirements.

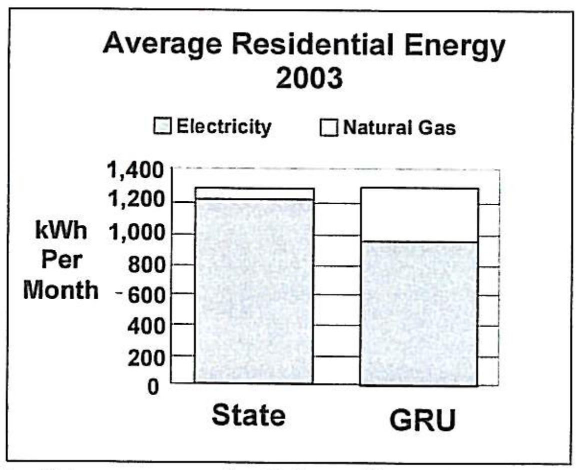

Figure 6.12 Average residential energy use by Gainesville customers was slightly more than the statewide average in 2003, due to use of natural gas which is available to approximately 38% of GRU residential customers. Overall, GRU residential customers are no more effective at conserving energy than the average state customer.

6.2.4 Barriers to Energy Efficiency at GRU (Finding 5)

The electric utility at GRU is a major source of income for the City of Gainesville. As owners of the utility, the city is entitled to an income from its operations. The utility pays no property taxes, so some of the return to the city corresponds to the taxes GRU would pay if it were privately owned. During most of the recent past, the utility transferred a specified percentage of its net revenues to the city treasury, but in 2000, the formula for determining the transfer was changed in anticipation of state electric utility deregulation then under consideration. A second goal was to make the magnitude of the transfer more predictable, to simplify city budgeting.

In deciding details of the new transfer formula, city staff used the Florida Public Service Commission model for profit allowed to investor-owned utilities when setting their rates, an exercise that occurs once every five or six years. This method bases the utility net revenue—and the city's income portion of it on the volume of local energy sales. This, in turn, establishes powerful disincentives for demand-side management and energy efficiency. Many utility experts discuss this problem, and propose solutions[36,37,38].

The IOU Model and Accompanying Utility Strategies

In return for a monopoly on electric energy sales in a specified geographical area, investor owned utilities (IOUs) are closely regulated by state utility commissions in those states that—like Florida--have not deregulated their electric utility industry. Utility regulators determine the customer utility rates, and act to keep rates low and fair for all ratepayers[39].

The Florida Public Service Commission establishes the utility rates for electrical service based on the amount of revenue needed to cover operating costs; to pay off assets used to produce, transmit and distribute electricity; and provide an appropriate level of investor profit.

Utility rate determinations occur through public rate-setting proceedings in which the utility, the FPSC staff and attorneys, and the utility's customers participate. In these hearings, utilities offer financial data to support their proposed rate requests, including forecasts of the expected future sales of energy to different sectors it serves, and expected inflationary increases in costs. Other parties can also present cost calculations upon which just and reasonable rates may be established. Utilities charge different rates to different classes of customers. The FPSC evaluates the cost of generating electricity and distributing it to each class, in an effort to insure that fair rates are set for all.

The allowed utility profit is based on the value of the capital invested in plant and equipment used to generate and deliver electricity. The value of this capital is termed the "rate base", and regulators allocate utilities an annual return on this rate base.

Every utility has to cover two kinds of costs of doing business. The largest are *fixed costs* that must be paid annually, no matter how much energy the utility sells. These include loan repayments, regular maintenance of major equipment, the personnel costs for the large staff needed to operate and repair equipment, read meters, bill customers, and so forth, insurance,

[36] Bachrach, D., S. Carter and S. Jaffe, "Do Portfolio Managers Have An *Inherent* Conflict of Interest with Energy Efficiency?" *The Electricity Journal,* Volume 17, Issue 8, October 2004, pp. 52-62.
[37] Shirley, Wayne, 2005 "Barriers to Energy Efficiency" Presentation by Wayne Shirley to 2005 Mid-Atlantic Conference of Regulatory Utility Commissions on Meeting on Barriers to Energy Efficiency. Available for Download from a link at: http://www.raponline.org/#top
[38] Bachrach, D., M Ardema, and A. Leupp, 2003 "Energy Efficiency Leadership in California: *Preventing the Next Crisis"* Natural Resources Defense Council, Silicon Valley Manufacturing Group April 2003
[39] Because they had a captive market, and assured recovery of costs, utilities had very good credit ratings during most of the last century, before deregulation became a reality. Utilities could obtain loans for new equipment at rates that were lower than the income they were allowed to collect on their rate base This difference between low interest costs on loans to build generators, and higher rates of return on the value of the generators once they were built and added to the rate base gave utilities an incentive to build generators, and established a strong pro-generation orientation among utility managers and owners

contributions to contingency funds that are used during emergencies of different kinds, and many administrative costs. There are also some minor costs associated with operating and maintaining equipment that depend on the amount of electricity generated and delivered to customers.

Fuel is the greatest *variable cost* of electric energy generation, but in Florida, it is not included in the rates approved by the FPSC. Fuel costs are charged directly to the customer[40]. The utility provides the FPSC with data about all these costs during the rate setting hearings. Rate setting hearings are extremely expensive for utilities and the FPSC, and occur only once every 5 or 6 years.

Once rates are set, the utility must make sure that the volume of sales is sufficient to insure that enough money will be collected each year to cover expenses and collect the allowed profit, some of which is sent to stockholders as dividend payments, and some retained by the utility to invest in ways to increase business income. Electricity sales are notoriously variable, and depend critically on the weather. In most of Florida, a warm winter and a cool summer will greatly depress electricity sales while hurricanes and tornados that black out sections of the service area will further reduce them, and cause damage the utility must repair.

A cold winter and a hot, storm-free summer will have the reverse effect. It will increase electricity sales, as well as the profits and fixed cost returns embedded in the rates.

The profit a utility actually realizes on its sales is the difference between the revenue collected and the costs of generating electricity, most of the latter being fixed costs that do not vary with the sales volume. Utility profits are extremely sensitive to the volume of sales. A reduction in sales of 5% could reduce profit by 20% to 25%. If sales are higher than expected, the utility collects more money than it needs to cover fixed and variable expenses, and keeps what is left over as profit. A small increase in sales can result in a large increase in profits collected[41]. These facts strongly influence the behavior of investor owned utilities.

Under the circumstances described here, all utilities - even those owned by municipalities - will seek to maximize their profit and net income by getting customers to use more electricity, not less. No utility manager or owner will be enthusiastic about investing in programs that threaten significant loss of the income needed to pay fixed costs or dividends to stockholders.

The perverse consequences of tying utility profit and recovery of fixed costs to the volume of sales are:

> When sales increase, the utility makes money, even if ratepayers waste electricity. When ratepayers become more efficient, the utility loses money, even though the customer saves money.

Basing utility profits on volume of sales establishes the conditions for strategies that work against the interests of the ratepayers that regulators ought to be protecting.

How the City Income is Tied to the Volume of Electricity Sales

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[40] In Gainesville, the current fuel charge is 3.55 cents per kWh.
[41] Appendix X from a paper by three utility experts gives simplified examples of how changes in the volume of sales impact the profitability of utilities and their ability to cover fixed costs

The income the City of Gainesville receives from the electric utility has two components. The largest of these is called the "base transfer". In 2000, when the current system was designed, staff determined the income that the Florida Public Service Commission would allow GRU if it were an investor-owned utility, and added the money from other sources that a utility could expect to receive on its equipment[42]. They calculated the rate base and the portion of the payments based on it that a conventional utility might pay out to stockholders as dividends. To this they added the property taxes the city would receive if GRU were an investor owned utility. The resulting sum was designated the "base transfer" for the year. The staff also devised a formula providing for regular increases in the base transfer in subsequent years based on past increases in sales volume.

GRU sells electric energy to other utilities, which resell it to their customers. These sales are termed "off system sales", and the City commission gets a portion of the resulting net revenue. The base transfer and the payments from off-system sales are now calculated in the following manner[43]:

Base transfer. The base transfer increases by 3% every year if sales have increased, as determined by a comparison of three-year averages of kWh sold in the local area. If sales have decreased, the city receives only the same base transfer it received the year before. If sales have increased by more than 3%, the city receives an extra share of the increase over 3%.

Off-System Sales Revenue Transfer. The net revenue from off-system sales is equal to the amount of money paid by the purchasers, less the cost of the fuel used to generate the sales. (Overhead costs are not subtracted from off-system sales revenues because the local retail ratepayers pay them). GRU sells energy by a purchased power agreement with the City of Starke. GRU also buys and sells energy on a spot market by means of which many utilities interchange energy. This market is referred to as "the interchange". Calculating the net revenue from off system sales requires subtracting costs of purchases from the receipts of sales. In most years, GRU sells more energy than it buys via the interchange, so there is net revenue to share with the city. The city receives a fixed 3% of net every year, except that in years when the net revenue exceeds the prior year's net revenue by more than 3%, the city receives a larger percentage of the net.

Basing city income on sales volume gives the city and the utility management the same disincentives for energy efficiency and demand side management as for investor owned utilities.

Under these circumstances, GRU's rational business strategy would be to oppose DSM, and encourage energy consumption by ratepayers. As the recipient of a "dividend" on utility operation, the City also has a strong incentive to increase its dividend by adding customers to the local service area, and promoting their energy consumption, even when it is wasteful.

The most invidious consequence of this tie between income and volume sales is that it establishes a strong pro-generator bias when utilities review the options to meet rising energy demand in their service areas. Investments in energy efficiency that could save ratepayers significant amounts of money are ignored in favor of investments in generators that could enable the utility to generate and sell more energy, a policy that is furthered by using the Rate Impact Measure test to evaluate energy efficiency and DSM programs.[44]

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[42] For example, the utility receives franchise fees for the use of its transmission lines.
[43] The details of the transfer are complicated. They are described in Appendix X.
[44] The RIM test and other cost-effectiveness tests used to evaluate DSM programs are discussed in more detail below.

Removing Disincentives by Revenue Decoupling

The Gainesville community has a clear interest in reducing the cost of electricity and delaying building expensive new generators as long as possible. The public has repeatedly expressed a strong preference for conservation and energy efficiency over building a new generator that will burn coal and petroleum coke. Can the interests of the public and those of the city and the utility be aligned?

Many experts have recognized this problem and proposed solutions[25, 26, 27], some of which have been adopted by state regulators, and could be adapted in Gainesville.

One clear statement of the problem summarizes California's actions to sever this connection as a step in implementing effective energy reduction programs. The following is a quotation from this insightful paper[27]:

> "ALIGNING CUSTOMER AND UTILITY INCENTIVES
>
> The first step to allow energy efficiency investments to compete on an equal footing with power plant investments is to ensure that utilities can profit—or at least be financially indifferent—when pursuing either supply- or demand-side resources. Although this was well-established regulatory practice in California for more than a decade, the Public Utility Commission put this policy on hold in the mid-1990s when California began its attempt at electric industry restructuring. The utilities reverted to an outmoded and counterproductive form of price regulation that directly links utility revenues to the amount of electricity sold. Under this form of price regulation, even when an investment in energy efficiency is the cheapest resource option for a utility and would reduce customer bills, the utility loses money. Naturally, no utility enthusiastically pursues resources that reduce the volume of electricity sold under these circumstances. Appendix III provides a simple illustration of the problem utilities face under this outmoded form of price regulation and the best solution to it[45]....
>
> ...
>
> Although it may not be immediately obvious, consumer-owned utilities in California face many of the same predicaments as the investor-owned utilities due to the use of outmoded mechanisms to determine revenues. Publicly owned utilities are not profit driven like the investor-owned utilities, but they still face significant financial pressures. With the same revenue mechanism that links financial health to sales volume; consumer-owned utilities are just as dependent on increasing kWh sales as investor-owned utilities and are penalized for taking advantage of least-cost resources that decrease electricity sales. Updating their revenue mechanism to break the link between financial health and the amount of electricity sold would greatly benefit California's consumer-owned utilities by increasing financial stability for the utility, assuring timely transfers to their associated city governments where relevant, and by reducing bills for their consumer-owners."

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[45] This appendix is incorporated with permission as an appendix to this chapter.

Severing the link between income and energy sales volume by insures that the city and the utility receive their needed income regardless of whether sales increase or decrease. Here are the essential steps[46]:

1. At regular intervals, the city decides how much income it should receive from the utility. The utility also decides how much income it needs to cover its fixed costs, including additions to reserves for emergencies, loan repayments, and contributions to various utility contingency funds it maintains.

2. Rates are set in the usual way, using forecast of sales of different kinds together with the total revenue needs decided in step 1 above to determine the total income and the per unit rates to be charged to each kind of customer.

3. Periodically, income from sales is reviewed to see whether the utility has collected more than it needs, or less. If it has collected more, rates are reduced and the extra income is returned to ratepayers. If it has collected less than it needs, rates are increased slightly to make up the needed difference. This process is called a "true-up", and it is routinely performed by electric co-operatives, which collect no profits from their ratepayers.

Changes similar to those suggested here could be adapted to removing the incentive to increase off-system sales. All that is necessary is to make sure neither the utility nor the city keeps the net revenue for itself. This revenue could be returned to the ratepayers by reducing rates in the next true up. Alternatively, it could be used in whole or in part to fund energy efficiency and DSM programs, especially social conservation programs aimed at low income ratepayers.

These steps will eliminate disincentives for DSM and energy efficiency, but they will not provide positive incentives to implement such programs. Many utility experts have proposed methods to reward utilities for reducing energy consumption, and share in the in the financial benefits that their customers experience[47]. In Gainesville, it might be possible to develop rules that fairly reward the city and the utility when customer costs are verifiably reduced through DSM programs. Such rewards could take the form of sharing savings with customers when rates are trued up.

One objection to revenue decoupling is that an ill-designed system would impose all the economic risk on the ratepayers, who must maintain the income to the city and continue to cover the fixed costs of the utility even in the face of a general economic downturn in the region. This could be avoided by designing safety valves that reduce ratepayer contributions, and require the city and the utility to share severe economic losses that affect the entire community.

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46 See Bachrach, Adema et al cited in footnote 25 above, and Shirley cited in footnote 26 for a fuller explanation of some features of this approach. Appendix 3 reproduces the Appendix III mentioned above.

47 See, for example C. Harrington, D. Moskovitz, W. Shirley, F. Weston, R. Sedano, and R. Cowart. 2002. *Portfolio Management:* A paper funded by the energy Foundation and available for download at: http://www.ef.org/energyseries_market.cfm. This paper discusses portfolio incentives in the context of portfolio management in deregulated markets, but some of the concepts may have application in a monopoly market like Gainesville's.

6.2.5. Finding and Evaluating DSM Programs: Bias in the Rate Impact Measure (RIM) and other Tests of Cost-Effectiveness (Findings 6 and 7)

All programs for reducing customer energy use cost the utility some money. The trick is to find those that are cost-effective and which would, if adopted, save the utility and the community money. There are many ways to find answers to this superficially simple question.

Utilities have developed a number of cost-effectiveness tests to compare the benefits of not generating electricity with the costs of instituting a DSM project. The DSM measure passes the test only if benefits exceed costs. Several cost-effectiveness tests can be applied in different ways. Each provides a different perspective on DSM programs under consideration. Four kinds of cost-effectiveness test are recognized:

The ***participant test,*** which compares the benefits to the participating customer with their costs, and determines if the program offers a financial benefit to its participants.

The ***utility revenue*** requirement test measures the net costs of DSM incurred by the utility, (including the benefit of not buying fuel and reducing maintenance costs) against the cost of losing sales income.

The ***rate impact measure*** determines whether the program would increase rates non-participants have to pay.

The ***total resource test*** combines all the benefits and costs calculated in the above tests to determine whether the benefits exceed the costs.

We may add a fifth test to these cost effectiveness tests discussed in various GRU documents, one required by the California Public Utilities Commission. This is the societal test, which incorporates the very real benefits and costs to society that are associated with electric energy generation or its avoidance, and those specific to the DSM program.

The ***societal test*** is a version of the total resource test that includes external benefits and costs to society. In California, these include the costs of pollutants and of greenhouse gas emissions, but in other jurisdictions societal costs and benefits could include anything the community deems important, such as the avoided cost of pollution or illness caused by pollution, the environmental cost of mining and transporting the fuel, the benefits, economic activity generated in the community by the DSM program and so forth. The societal test is used to choose among DSM programs that pass other tests.

There is an additional factor that can be evaluated, and is applicable to a group of DSM projects. The ***equity test***, asks whether the benefits of the family of adopted DSM programs are fairly distributed among all groups in the community, including the economically disadvantaged.

GRU presently uses two only benefit/cost tests:

(a) A participant test that evaluates each DSM program from the point of view of its attractiveness to the customers that might participate.

(b) The rate impact test, which determines whether implementing a DSM program would require the utility to raise rates for non-participating customers, which penalizes customers who do not participate.

Using each of the tests requires choices. These choices can make the difference between passing or failing a DSM program. In April 2004, GRU described the results of recent re-evaluations of some DSM programs, including the air conditioner load control system described above. This evaluation illustrates some of the ways different assumptions change the results of DSM tests:

1. Listing the costs of a DSM program. GRU assumed $300 per installation, whereas AE paid less than $250 (including radio transmitter). GRU assumed the customer would require a rebate totaling $90 per year, but AE found no rebates at all are necessary. GRU assumed high operating costs per participant, which AE says were very low.

2. GRU evaluates DSM programs only when it is contemplating purchasing a new generator, and then compares the cost of the DSM program options with the avoided cost of the new generator. If the generator is a base unit, it will be extremely cheap to operate. Comparing the cost of a DSM that reduces peak demand--like the AC load control program describe above does--with the avoided cost of a new base unit is comparing apples to oranges, because the air conditioning system avoids the use of expensive peaking units, not the base unit. Some states that fund DSM programs in utilities using public benefit funds specify what avoided cost is to be used. For example, in Texas, the avoided cost is specified as the cost of a combined cycle natural gas unit.

3. DSM programs operate for many years—up to 10 to 15 in some cases—and estimating their costs and savings often requires estimating the net present value of the benefits and the needed investment over this lifetime. The calculated cost effectiveness depends on the discount rate assumed in the net present value estimate. In 1994, when GRU evaluated the programs now in effect, they used a discount rate of 8.5%. In the current evaluations it has been reduced to 7.5%. The discount rate used is so critical in evaluating DSM programs that many states require all programs to be evaluated using the same discount rate. In California, for example, it is 5%. In general, the lower the discount rate, the more likely it is that a given program will prove to be "cost-effective".

The California Manual of Standard Practices[48] is a standard reference work that describes every commonly used DSM cost-effectiveness test and the different ways of expressing the costs and benefits. According to the Manual, all DSM tests are useful to utilities wanting to explore and compare various DSM programs. But it emphasizes that *all cost-effectiveness tests are crude screening tools that cannot elucidate all DSM program features that need to be considered* before selecting DSM programs for implementation. No single test and no single test application can evaluate all the relevant features of DSM programs.

Rate Impact Measure (RIM) Test

[48] . "California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects", October 2001. Available for download at: http://www.cpuc.ca.gov/static/industry/electric/energy+efficiency/rulemaking/resource5.doc.

GRU has adopted the very controversial Rate Impact Measure (RIM) Test as the single criterion for determining the cost-effectiveness of proposed DSM programs In one document, GRU suggests that doing so follows policies established by the Florida Public Service Commission (FPSC) [49, 50]. The FPSC does not regulate anything GRU does in the normal course of business. GRU has no obligation to use this or any other test when evaluating candidate DSM programs for implementation here[51]. But we believe that GRU would use the RIM test to support a claim that DSM programs cannot substitute for a new generator or significantly delay the need for one, should they ever seek certification of need[52] from the FPSC.

The RIM test has been widely criticized because it rules out all programs that require capital investment and precludes considering DSM costs on the same basis as the costs of new supply-side generation capacity. This is a major barrier to energy efficiency investments. No matter how beneficial to customers, or how effective in eliminating the need for new generators, no DSM program that raises rates to any group of ratepayers, or even any single ratepayer can pass the RIM test[53].

The RIM test is defended on the grounds that it prevents "cross subsidies" whereby non-participating customers pay higher rates to pay for DSM programs that benefit only participants. But many cross subsidies are already implicit in GRU rate structures, and are justified on policy grounds. For example, Gainesville commercial customers who are members of the utility's "Business Partners" program receive large discounts on their bills if they agree to remain customers in the event of deregulation. These discounts are not available to residential customers, who pay higher rates than they otherwise would if there were no "Business Partners" program. This program would not pass a RIM test-type evaluation. Residential and commercial customers increase demand during peak periods, but pay no more for electricity at these times it than at other times of the day, even though costs of supplying their energy are very high. These high costs are subsidized by commercial customers that have high base-load demands and purchase substantial proportions of non-peak period energy. They receive no price breaks at these times when there is spare capacity and generating costs are low.

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[49]. See "Staff Response to Long Term Electrical Supply Plan Questions, Issues, and Recommendations Made in November 2004 to the Gainesville City Commission" Prepared by GRU, December 2004.

[50] GRU is not regulated under Florida Energy and Efficiency Conservation Act (FEECA) and therefore the Florida Public Service Commission places no demands on GRU as to how it evaluates conservation. FEECA requires large utilities to submit conservation programs for PSC approval. The commission as a matter of policy often uses a RIM test to review these programs.

[51] If GRU decides to add a new generator with a capacity greater than 75 MW, it will have to apply to the FPSC to certify that there is a need for the new capacity. At this time it will be required to show that no energy efficiency or conservation programs can eliminate the need for the new generator, and it will have to submit evaluations of DSM programs in support of any claim it may make that none can substitute for the generator. GRU may choose to use the RIM test to rule out DSM, but the FPSC does not require the use of the RIM test for this purpose. (Personal Communication between M. Haff and D. Deevey)

[52] The FPSC determines whether a utility needs a new generator and whether the one proposed represents a prudent investment. If so, they certify the need for the new generator. State approval of new generators

[53] Consider a science fiction scenario in which invisible extraterrestrials arrived in Gainesville one night and installed a miraculously efficient solar PV collection and storage system on every roof in the city and connected it up to all the homes and commercial establishments, before silently departing. This free system would fail the RIM test, because GRU's revenue would drop precipitously, and rates would have to be raised to pay fixed overhead costs.

GRU's cost-effectiveness testing approaches can also be criticized because they ignore many important societal benefits that accrue to the community as a whole if less electricity is generated and sold. Reduced air pollution; avoidance of potential costs of greenhouse gas regulations; and economic benefits to the community in the form of jobs and sales of things like photovoltaic systems are among the major advantages that DSM programs could offer. Use of the RIM test implies a very narrow role for the municipal utility in the community, which is actually a publicly owned institution that strongly affects us all.

6.2.6 DSM Policy Considerations (Finding 8)

EPAC's review of conservation and DSM measures has revealed a number of areas where the City has not established explicit policies, but directly accepts the recommendation of the utility management. Viewed as a whole, these decisions reflect implicit policy decisions that the City may wish to re-examine. If so, then the following questions will deserve consideration:

1. **Should the City eliminate the tie between the volume of electric energy sales and the amount of money transferred to the City treasury, or retained by the utility to cover fixed costs in the manner describe above under section 6.2.4? This approach has been adopted by the California Public Utilities Commission, but as far as we know no municipal utility has explicitly adopted it.**[54] Options for achieving revenue decoupling could be developed and evaluated in the context of alternative rate structures that incorporate incentives and rewards for customers who reduce their energy needs by these means.

2. **What roles should DSM and energy efficiency play in meeting the energy needs of the community?** These programs are the cheapest way to meet electricity demand, and could delay the need for new base or peaking units at GRU, if aggressively pursued and effectively implemented. Critics have suggested that the City Commission adopt a policy that makes DSM the first priority for meeting needs for new capacity. Appendix 3 to this chapter contains sections from the Austin Energy strategic plan that provides such an example, together with some Austin City Commission resolutions that reflect important policy goals.

3. **Should the City explore funding DSM programs from a small fee imposed for every kWh sold, in a way analogous to the Public Benefits Fees established in many states?** This one of many possible ways to fund vigorous DSM programs, but if the RIM test were abandoned, there would be no barrier to investing in DSM the way GRU now invests in new generators.

4. **Should DSM programs be evaluated for cost-effectiveness using a wide range of techniques that capture a wider range of community goals?** GRU rejects programs found to be cost effective by other Florida utilities, which suggests that they apply conventional benefit/cost measures differently. Many experts recommend using the total resource test and incorporating social costs and benefits to the community explicitly in benefit/cost evaluations, all of which the Rate Impact Measure test ignores. An aggressive program of DSM requires sensitive analyses of benefits and costs that could be illuminated by using more

[54] Austin Energy has adopted a "conservation first" policy that has the same practical impacts as the solutions discussed in section 6.2.4 above.

cost-effectiveness tests, but factors not explored in benefit cost analyses should also be considered. The many disadvantages of the RIM test may lead to its abandonment, which could clear the way for numerous community benefits.

5. How should priorities be assigned among classes of customers who might benefit from these programs? How do we prioritize between programs targeting different classes of customers? Right now, developers receive almost all GRU program benefits. Policy on this topic cannot be settled in the abstract.

6. Should the City Commission choose among the variety of programs that pass benefit cost tests, rather than GRU management? If so, more information about the benefit/cost analyses and data on the expected costs and savings will have to be provided so sound choices are made. This information should include cost per MWh saved, and cost per kW of capacity saved, and the impact on energy demand at off-peak as well as peak periods, and community economic and social costs and benefits..

7. Both the utility and the community need a clear policy statement regarding the importance of DSM/ Energy Efficiency. Ed Regan, manager for strategic planning has suggested that all DSM programs be farmed out to independent companies, so that GRU top management can focus on generating energy. Other utilities have found that they can help their customers more by expanding their activities and investing in ways to supply cooling, heating and other services that are difficult for individual customers to obtain for themselves. Some have found it beneficial to hire and supervise a trained staff of experts and inspectors who could guide consumers in ways to enhance efficiency, and confirm that contractors make needed improvements properly and for a reasonable cost.

Chapter 6, Appendix 1: Calculating the City's Share

The annual money transfer the city receives from the electric utility has two major components. Most of the transfer is based on total energy sales and increases in those sales. It is called the "base" transfer. An additional smaller component is based on the net revenues from off-system sales via the interchange or from contracts with other utilities.

Base Transfer

In 2000, when the current system was put in place, GRU and city staff determined how much money the City, as the owner of the electric utility, would receive if it were an investor-owned utility. They determined the rate base and the income from other fees and charges. To this they added the property taxes an investor-owned utility would pay and arrived at a total of $15,692,967 for the 2001 base transfer.

GRU calculates the rolling average of local energy sales (kWh) during the preceding 3 years and recalculates at the end of the fiscal year. This rolling average is compared to the preceding year's sales, and a new base transfer is calculated from these comparisons:

- If the rolling average not less than the rolling average calculated the year before, the base transfer is increased by 3%.
- If the rolling average is less than in the prior year, the base transfer remains the same as it was in the prior year.
- If the rolling average is greater than 3% more than the prior year, then the base transfer will be increased by the regular 3%, plus one half the percentage of the sales increase exceeding 3%. This extra is referred to as an "incentive" payment, and is a kind of bonus.

Off System Sales

Part of the annual city money transfer is based on the net profits from electricity sales to other utilities. GRU sells energy to other utilities in two ways: by means of contracts negotiated in advance, and via the "interchange" sales via a spot market.

In both cases, the net revenues from off system sales equal the gross revenues, less the cost of the fuel used to generate the electric energy. Other fixed or variable overhead costs are not charged to off-system sales, as these are paid by the GRU's local retail customers. The transfer of off-system sales net revenue is determined as follows:

- The city receives 3% of all net revenues from off-system sales calculated at the end of every fiscal year.
- The net revenues from off-system sales are compared with those of the preceding year, and if they have increased by more than 3%, the city receives an "incentive" payment equal to one half the amount by which the net revenues exceed the revenues of the preceding year by more than 3%. This can also be thought of as a kind of bonus the City receives from expanding off-system sales.

According to GRU, the off system sales on which these calculations are based consist only of sales made by means of purchased power agreements, or through the spot market mechanism. They do not include the "wholesale" sales to the City of Alachua and to Clay Electric

Cooperative. The latter two utilities purchase electricity from GRU and resell it to their customers[1]. In projecting peak demand, reserve requirements, and total energy needs for future years, GRU includes the sales to these two wholesale customers. In the past, GRU has increased its retail customer base by purchasing customers from Clay Electric Cooperative who are added to GRU's local service area.

[1] According to the City Chief Financial officer, Mark Benton, wholesale off-system sales to Alachua and Clay electric cooperative are included in the calculation of money due the city from off-system sales.

Chapter 6, Appendix 2: Austin Energy and GRU's Benchmarking Exercise

Austin Energy (AE), the municipally-owned electric utility in Austin, TX has repeatedly been identified as the country's leader in electric energy conservation and efficiency. GRU compared AE and other utilities in a benchmarking exercise[1] comparing electric rates, bond ratings, and energy efficiency programs with those planned for GRU.

GRU's benchmarking methodology does not lend itself to identifying and discussing the most important factor responsible for Austin Energy's premier status as the country's leader in energy efficiency and DSM. In 1999, the Austin City Council adopted the following resolution:

> "Cost-effective conservation shall be the first priority in meeting new load growth requirements of Austin energy"

Complying with this requirement largely eliminates the barriers to effective DSM discussed in section 6.2.4 of this chapter, as it frees the utility to make investments in DSM programs as alternatives to investments in generators. In compliance with this resolution, Austin Energy requires that all proposed DSM projects pass a version of the rate impact measure test, but one that estimates the electricity generating costs more appropriately than GRU's version of this test. DSM projects are also required to pass a participant test, the utility test, and a total resource test as well as a RIM test. AE then chooses which DSM projects to implement based on many factors, including the cost advantages that accrue to the participant[2].

Using the participant's test to choose DSM projects reflects the high priority AE assigns to saving its customers money. Where energy use can be improved, but the techniques are beyond the customer's capability, Austin energy may make the investment, and provide the resulting savings at an attractive cost to the customer. AE built a thermal energy storage unit in downtown Austin to supply chilled water to commercial customers. Ice is made during off-peak hours for cooling buildings during peak hours in summer. The first of these units reduced on-peak demand by 20 MW while supplying 8,000 tons of cooling capacity to commercial customers. A third unit is under construction and will open in 2006.

Austin Energy has also invested in a 4.5 MW combined heat and power (CHP) unit located in an industrial park where it generates electricity and supplies thermal energy close to its customers at greater efficiency than a central plant. Because this unit is near customers, the heat generated during energy production can be used to provide cooled water for cooling purposes. This efficient use of waste heat achieves overall system efficiency above 70%, higher than that achieved even by modern natural gas-fired combined cycle located at central power plants where some heat is wasted. The income from the sales of cooling makes Austin's CHP project cost-effective. The unit is owned and operated by the utility.

The Austin City Council energy policy includes using the utility to attract new clean energy industries to the area, a policy that is furthered by AE's business-friendly investments and utility services. The latter include free installation of "energy miser" equipment that saves energy by

[1] "Benchmarking Electric Utilities: Energy Conservation Leadership and Financial Strength" Final Report, GRU October 2004. Delivered to City commission on November 15, 2004.
[2] This emphasis on benefiting the consumer reflects the "Vision" of the City: "we want Austin to be the most livable community in the nation".

turning off vending machines or coolers. These use IR detection systems, and turn off lights and cycle down refrigeration, which allows owners to save about $100 per year in electricity charges per refrigerated vending machine or up to $40 for units that hold non-perishable food items.

AE offers design guidance, inspection services, and large rebates to commercial customers, including apartment owners/managers. The "Green Building" program has partnered with developers to produce attractive energy- and water-efficient multifamily housing developments, in which efficient water and energy use, and other sustainable environmental goals are realized.

AE has a special residential program for homes ten years old or older.. AE advises homeowners on tests of cooling systems, and shares the cost of the tests with the homeowner. Independent contractors conduct the tests, and AE reviews test results to determine requirements to improve house systems to Energy Star standards. Rebates of up to $1,400 dollars are available under this program, but are given only after the work is completed and inspected by AE inspectors who work directly for the utility. Having AE's own experts interface between the consumer and the contractor protects the customer by assuring that the right work is done correctly.

AE has too many and too various conservation and energy efficiency programs to list here. Some of them integrate other City services. Readers are urged explore the programs at the Austin Energy web site. The URL is http://www.austinenergy.com.

GRU's Utility Benchmarking

GRU's benchmarking project provides useful comparative information about many utilities. GRU divided municipal utilities into two groups according to their financial strength as indexed by their bond ratings and whether they have been identified as "conservation leaders". With one exception, the "financially strong" group with high bond ratings included only utilities that are not conservation leaders.

Utility bond ratings are judgments of whether a utility is likely to meet bond repayment obligations. Many factors enter into the bond rating. One very important factor is whether the utility maintains cash and other reserves to handle emergencies like downed transmission lines, unanticipated and expensive equipment outages or other eventualities. GRU has an excellent credit rating in part because it has agreed with the bond underwriters to maintain a "rate stabilization fund" that insures that it has plenty of money put aside for these unforeseen circumstances. Consequently it will be able to make the required bond payments. The other two Florida municipal utilities characterized in this report as financially stable also maintain rate stabilization funds. But Austin Energy does not.

Benchmark Data for Austin Energy

Austin Energy (AE) is widely recognized as a DSM leader and the originator of a number of DSM approaches copied elsewhere. But the details in GRU's Benchmark report reveal few reasons why Austin Energy is so recognized. GRU's report contains some errors in its characterization of AE's operations, probably at least in part because the authors used standard reference sources for much of the material, and did not check its accuracy. Some of areas where comparisons appear to have been marred by inadequate information sources include the following:

1. Only 57% of residents in Austin Energy's service area use natural gas, not 80% as specified in the benchmarking report[3]. The meaningfulness of comparisons of residential customer energy use depends on whether customers have access to natural gas for heating and how much they use. According to the Texas State Railroad Commission, 57% of Austin residents used natural gas in 2003, a figure which we may assume is also representative of the small number of Austin Energy residential customers that live outside the city boundary. The implications of the customer natural gas use are discussed further below.

2. Austin fuel costs are higher than listed in the benchmark comparisons. GRU reports that AE paid only $14.63 per MWh for fuel[4], but in fact, the average cost for the fuel for almost all the energy AE generates was $27.89 per MWh in 2003, and only a little less than GRU's quoted local cost of $33.13. AE purchases renewable wind energy at an attractive price that is passed on to participants in a "GreenChoice" program. The latter customers obtain all their power from this program. They pay a monthly premium to belong, but their rates will not be affected by future increases in natural gas costs.

3. Gainesville income data are distorted by the very large number of non-working college students who live in the city. The benchmarking study compared the per capita income of the areas served by all the utilities studied[5], and the percentage of the population living in poverty. There is reason to believe that the GRU data are seriously skewed by college students who are recorded by the Census Bureau as having no income, when in fact their bills are paid by their parents. There were approximately 40,000 UF students from out of town living in Alachua County in 2000 (about 18% of the total population). This student population is probably partly responsible for the low per capita income and the high proportion of residents living in poverty reported by the National Census Bureau. Given the biased nature of the census bureau estimates of per capita income and poverty in Alachua County, few conclusions can be drawn from comparisons of these figures with comparable data for other utilities.

4. Comparison of monthly electric energy consumption by residential customers is questionable. GRU compared electricity consumption between average residential utility customers. This comparison is not meaningful unless the data are corrected for natural gas use. Using data available from GRU and (for Austin from the Texas Railroad Commission), EPAC has calculated the average total energy consumption by residential customers of both utilities. These calculations yield an average of 1,611 kWh per month per residential customer in Austin, compared to the average of 1,309 kWh per month calculated for GRU customers. Austin customers use 23% more energy for heating and cooling their residences than GRU customers. Considering that there are 12% more heating degree days and 44% more cooling degree days in Austin than in Gainesville, these data suggest that Austin customers are significantly more efficient in their use of energy than GRU customers.

5. AE residential rates are among the lowest in the Texas, not the highest. The GRU Benchmarking Study compared utilities in terms of the ratio of their price of electricity,

[3] Figure 5 and page 17.
[4] Table 4 and page 18.
[5] Figures 6 and 7, pages 19 and 20.

and the average in the state, using for this comparison the average monthly residential consumption of electricity[6]. According to the benchmarking report, Austin Energy rates are higher than the average in the state, but according to the figures listed in Appendix A of GRU's Benchmarking Study, the state average is $78.03 while the average for Austin Customers is $71.95, (92% of the average). EPAC examined rates from the point of view of the costs per kWh, and concluded that AE rates are among the lowest in the state.

Some Texas utilities are deregulated and compete with one another for customers, and others have opted to remain regulated load-serving utilities serving geographical areas where there is no competition. The latter group includes only 5 investor-owned electric utilities, plus 9 electric cooperatives and 4 municipal utilities, including AE. Examination of the monthly reports for the latter utilities shows that in every month in 2002 through the end of 2004, AE had either the lowest or the second lowest rates listed for the benchmark categories 500 kWh per month and 1,000 kWh per month.

Detailed rate data for utilities in the competitive markets in Texas are not available at the Texas Public Utilities Commission website. However, according to Texas Rose[7], costs charged by deregulated utilities in 2003 ranged between about 10.5¢ per kWh to almost 12.0¢ per kWh, while consumers living in unregulated areas paid an average of 8.9¢ per kWh. These conclusions are substantiated in the Austin Energy Annual Report of 2003[8].

Austin Energy uses a tiered residential rate, with lower prices for the first 500 kWh month, and higher charges for additional energy. The cost of the first 500 kWh in 2003 is listed as 6.35¢ per kWh, while the average annual cost of the remaining kWh used each month is 9.72 ¢ per kWh[9]. These charges include a fuel charge of 2.79 ¢ per kWh. The monthly cost to the consumer depends on the monthly energy use, so comparison of average bills can be misleading because whether a bill seems high or low will depend on the amount of energy consumed and how sharply tiered the rates are. For an "average" month, with 968 kWh consumption, the average cost per kWh would be 8.8 ¢, consistent with the claim that AE rates are low compared to the state average.

6. General Fund Transfers per residential customer. GRU compares utilities in terms of the general fund transfer per residential customer, but as all utilities have additional kinds of customers that also contribute to transfer revenues, it is not obvious what this comparison shows. For example, if the analysis were based on the proportion of revenue paid by residential customers, GRU customers would be credited with a contribution of approximately $122 each, while AE customers would be credited with contributing approximately $93 each.

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[6] These data are plotted for all utilities studied in Figure 8, page 21, but not discussed in the body of the report. The figures for individual utilities are in the summary tables in Appendix A. The Austen data are found on pages A13 and A14.

[7] Ratepayers' Organization to Save Energy, which describes itself as "A nonprofit organization dedicated to affordable electricity and a healthy environment."

[8] Austin Energy Annual Report 2003. Available for download at: http://www.austinenergy.com/About%20Us/Newsroom/Reports/annualReport2003.pdf

[9] These results were taken from the TUC web site. They do not appear to include the basic monthly fee.

7. AE is reported by GRU to use the Participant Test to choose DSM projects, which GRU seems to suggest is the only test used by the utility[10]. In fact, AE uses all four of the cost effectiveness tests--the participant test, the utility test, the total resource test, and its version of the rate impact measure (RIM) test. All programs considered for implementation must pass AE's version of all these tests.

There are two exceptions to this rule: the low-income weatherization program loses money, as does a program that upgrades city-owned buildings. The latter is justified because the utility is part of the city government, and reducing the bills of government buildings is a legitimate investment of utility revenues. AE is not paid for energy used by the City. What it spends to reduce bills of government buildings reduces its cost of supplying their energy. The use of the Participant test as a guide for selecting among DSM programs reflects the City's emphasis on saving money for their customers by making their energy use more efficient. This is not the only criterion the utility uses[11].

8. GRU compares 10-year incremental conservation goals of utilities as a % of the 2003 summer or winter peak demand[12], but does not give Austin's, identifying it only as "<15%". GRU lists its own incremental conservation goal as 1.7 % of the 2003 peak demand, which corresponds to a little more than 7 MW, and includes some net cumulative demand reduction initiated in prior years. Some of the latter consist of unconfirmed consumer behavioral changes assumed to result from energy audits or other educational outreach by the utility. Austin Energy also has cumulative demand reductions derived from prior years, but the utility specifically does not count behavioral changes. All demand reductions claimed by AE are based on permanent equipment changes, and all have been independently verified. If these are added into the demand reductions of about 200 MW planned over the 10-year interval, the total would be approximately 10% of the 2003 summer peak.

9. Appendix D of the GRU Benchmarking Study contains a residential and a commercial DSM checklist of programs offered by the reviewed utilities. Examination of the residential checklist shows that GRU offers a total of 24 programs, of which 4 are for natural gas users and hence irrelevant to utilities that, like Austin Electric, do not supply natural gas to customers. Many of the listed GRU programs have had no participants for several years. A total of 26 programs are identified by GRU as offered by Austin Energy, but EPAC finds that an additional 11 or 12 are offered by AE, bringing its total to 37 or 38.

[10] Table 6, page 24 and page A 13 of the Benchmark report cited above.
[11] The Austin City Council sets policy with respect to some choices among DSM. It has placed considerable emphasis on renewable energy and on solar energy, and on using the utility to attract clean new industry. See the Austin Energy Strategic Plan and comments in Appendix 3 of this Chapter.
[12] Table 7 and pages 23 to 25.

Chapter 6, Appendix 3: Austin City Council Resolutions

Two energy policy resolutions adopted by the Austin City Council in 2003 guide their strategic planning. Both are available in the Austin Energy Strategic Plan[1].

The impact of these resolutions on strategic planning is discussed in the current strategic plan in the following words (ref.1, page 26):

AUSTIN ENERGY'S COMPLIANCE WITH CITY COUNCIL STRATEGIC PLANNING POLICY

> Austin Energy produced the 2003 Strategic Plan to position itself in a rapidly changing electric utility environment. The most important element of the change facing Austin Energy will be the challenge to traditional energy sources. Supply availability and environmental impact issues surrounding traditional fossil fuel resources pose major questions. The answers to these questions will fundamentally change the utility industry over the next twenty years.
>
> In recognition of the significant change that is underway in the energy sector worldwide and in keeping with Austin's long-standing commitment to environmental stewardship, the Austin City Council has established a strategic energy policy for Austin Energy in its adoption of Resolutions 030828-38 and 030925-02 ("the Energy Policy Resolutions").
>
> **Resolution 030838-38** calls on Austin Energy to develop and incorporate strategies in its Strategic Plan that will ensure Austin remains a national and international leader in the development and use of clean energy. Specifically, Council has directed Austin Energy to develop strategies that at a minimum (1) produce a strategic planning process that includes progressive and ambitious renewable energy and energy conservation programs and, the nation's leading Renewable Portfolio Standard; (2) place emphasis on economic development for successful development, recruitment and retention of clean energy business enterprises; (3) pursue a risk management approach, which positions Austin Energy for a transition to a clean energy future through the successful identification and incorporation of promising energy technologies; and (4) include mitigation of carbon emissions from current and future fossil fuel facilities to reduce the negative effects of global warming.
>
> **Resolution 030925-02** directs Austin Energy to negotiate and execute a Memorandum of Understanding (MOU) with the World Wildlife Fund (WWF), to partner with them and other utilities in taking a responsible approach to global warming by supporting essential CO_2 emission reduction policies, including a switch from fossil fuel to more renewables within the electric generation portfolio. As part of the MOU, Council has charged Austin Energy to (1) establish a goal to achieve a minimum of 20% of the energy in its portfolio mix from renewable sources by January 1, 2020; (2) set an energy efficiency goal of 15% by 2020; and (3) support binding limits on national power sector CO_2 emissions.

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[1] Available for download at:
http://www.austinenergy.com/About%20Us/Newsroom/Reports/strategicPlan.pdf

Austin Energy believes that the 2003 Strategic Plan is in full compliance with the Energy Policy Resolutions. It accomplishes the majority of what Council has called for immediately and creates the framework to achieve the remainder; more specifically, the 2003 Strategic Plan emissions and their impact on global warming. The 2003 Strategic Plan also sets the stage for Austin Energy to participate in the advancement of a Clean Energy Industry in Austin.

Resolution 030925-02 is also addressed by the 2003 Strategic Plan. The resolution calls for Austin Energy to pursue a responsible approach to "switch" from fossil fuels to more renewable energy sources. For Austin Energy, the 2003 Strategic Plan represents a starting point for the transition from a traditional electric utility to a clean energy future. Additionally, the renewable energy and energy efficiency goals set forth in 030925-02 are key strategic objectives within the plans energy resource strategy. Further, the strategies and commitments in the 2003 Strategic Plan will serve as a framework for the development of a MOU with the WWF addresses 030838-38 in that it embraces ambitious strategies and objectives that will ensure Austin's clean energy leadership role in the future. The plan sets out robust conservation objectives and adopts the nation's leading Renewable Portfolio Standard. It also incorporates a risk management strategy aimed at moving Austin Energy successfully toward a clean energy future. The Renewable Portfolio Standard and energy efficiency objectives will mean that Austin will meet 35% of its energy needs from renewable sources (20%) for energy efficiency measures (15%) by the year 2020. Achievement of these objectives will help mitigate carbon.

Austin City Council RESOLUTION NO. 030828-38

WHEREAS, Austin's environmental stewardship is a community priority and is a major reason for our renowned quality of life; and,

WHEREAS, Austin's community-owned electric utility, Austin Energy, is a national leader in promoting and using environmentally-friendly renewable energy and energy efficiency programs: and,

WHEREAS, Austin Energy can play a strategic economic development role by helping create new jobs in Austin; and,

WHEREAS, Austin Energy's GreenChoice program ranks number one in the nation in green power sales according to the U.S. Department of Energy, with 2002's sales double the amount sold by second place Sacramento and third place Denver combined; and,

WHEREAS, Austin Energy has sold more than half a billion kWh of green power to customers since the GreenChoice program's inception in 2000; and,

WHEREAS to meet the community's demand for clean energy, Austin Energy has purchased approximately 100 MW of renewables, about three percent of its overall energy resources, well on the way to meeting the 1999 Council-established goal of 5 percent renewables by 2005; and, WHEREAS, Austin is extremely well positioned to become the future Clean Energy Capital of the World; NOW THEREFORE,

BE IT RESOLVED BY THE CITY COUNCIL OF AUSTIN:

That the City Council directs the City Manager to have Austin Energy develop and incorporate strategies in its Strategic Plan that will ensure Austin remains a national and international leader in the development and use of clean energy; and,

BE IT FURTHER RESOLVED:

That Austin Energy's clean energy strategies shall feature at a minimum:

1. A strategic planning process that includes progressive and ambitious renewable energy and energy conservation programs and, the nation's leading Renewable Portfolio Standard.

2. An emphasis on economic development for successful development, recruitment and retention of clean energy business enterprises,

3. A risk management approach, which positions Austin Energy for a transition to a clean energy future through the successful identification and incorporation of promising energy technologies.

4. Mitigation of carbon emissions from current and future fossil fuel facilities to reduce the negative effects of global warming.

Adopted August 28, 2003

Austin City Council RESOLUTION NO 030924-02

WHEREAS, Austin's environmental stewardship is a community priority and is a major reason for our renowned quality of life; and,

WHEREAS, Austin's community-owned electric utility, Austin Energy, is a national leader in promoting and using environmentally-friendly renewable energy and energy efficiency programs; and,

WHEREAS Austin Energy's GreenChoice program ranks number one in the nation in "green power" sales, with clean energy sales of more than half a billion kWh to customers since the program's inception in 2000; and,

WHEREAS, to meet the community's demand for clean energy, Austin Energy has purchased approximately 100 MW of renewables, about three percent of its overall energy resources, well on the way to meeting the 1999 Council-established goal of five percent renewables by December 31, 2004; and,

WHEREAS, deriving a large portion of Austin's electric power needs from sources such as natural gas, coal, and nuclear fission—which produce large amounts of either carbon dioxide or other environmental pollutants—may be considered inconsistent with Austin's environmental values and with the City's goal to become the Clean Energy Capital of the World; and,

WHEREAS, burning fossil fuels—coal, natural gas, and oil—emits carbon dioxide (CO_2) into the atmosphere where it builds up, blankets the earth, and traps in heat, causing global warming; and,

WHEREAS, global warming is arguably the most pervasive environmental problem with the potential for widespread damage to habitats, biodiversity, and life on earth; and

WHEREAS, on August 28, 2003, Council directed the City Manager to have Austin Energy develop and incorporate strategies in its Strategic Plan that will ensure Austin remains a national and international leader in the development and use of clean energy; and,

WHEREAS, Council directed that those clean energy strategies would feature the nation's leading Renewable Portfolio Standard ant mitigation of carbon emissions from current and future fossil fuel facilities to reduce the negative effects of global warming; NOW, therefore,

BE IT RESOLVED BY THE CITY COUNCIL OF THE CITY OF AUSTIN:

That Austin Energy shall negotiate and execute a Memorandum of Understanding (MOU) with the World Wildlife Fund (WWF) to partner with them and other utilities in taking a responsible approach to global warming by supporting essential CO_2 emission reduction policies, including a "switch" from fossil fuels to more renewables within the electric generation portfolio; and,

BE IT FURTHER RESOLVED:

That as part of the MOU, Austin Energy will:

1. Establish a goal to achieve a minimum of 20 percent of the energy in its portfolio mix from renewable sources by January 1, 2020; and,

2. Set a goal of increasing energy efficiency by 15 percent by 2020; and,

3. Support binding limits on national power sector CO_2 emissions.

Adopted September 25, 2003

Chapter 7. Off-System Sales

7.0 Introduction

GRU has proposed building a new Deerhaven Unit #3 generator with a circulating fluidized bed (CFB) boiler.[1] The stated purpose of building a new generator is to provide additional base capacity[2]. Together with the Crystal River nuclear plant, the new CFB unit and the retrofitted Deerhaven #2 will provide a total base capacity of 447 MW (including the nuclear unit at Crystal River). Summertime intermediate capacity will be about 270 MW in that year, while the existing peaking units add another 78 MW of capacity.

These units will supply more base capacity than will be needed in the local service area and the adjacent areas to which GRU supplies energy for resale, so the utility plans to operate the base units to produce energy for "off-system" sales to other utilities in Florida

Off-system sales are viewed as critical to the overall financial success of GRU's capacity expansion proposal. According to the Executive Summary of the IRP document:

> ..." *The ability to structure appropriate PPA sales agreements for some of this excess capacity is an important consideration for the financial success of this option*".[3]

GRU has not shared any details of anticipated off-system sales with the public, nor have they explained how these sales will affect the financial success of their plan.

Successful sales of excess energy could play a role in several ways, including: (a) providing a cost-free way of keeping the two plants in operation under optimal loads to achieve the planned operating economies; and/or (b) providing net revenues to repay the $550 million loan needed to implement GRU's proposal[4].

EPAC's review has examined the manner in which regulatory and technological responses to the climate crisis may affect future markets for off-system sales, (2) the impact of generating electricity for off-system sales on pollution exposures to nearby residents, and (3) implications for the financial stability of the utility and the City.

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[1] GRU will have a 215 MW Deerhaven Unit #2 fitted with updated pollution control equipment as well as the new 220 MW CFB unit.

[2] Generators are classified as base, intermediate, and peaking units according to their cost to operate, the speed with which they can be turned on and off, and the proportion of time they are in operation. Base units are the cheapest and typically slow to turn on and off, so they are usually operated for more than 50% of hours each year and operate round the clock for much of the time. Intermediate units are more flexible and usually more costly, and are used less than 50% of hours. Peaking units are small, flexible, and extremely costly, so they are used only when demand is very high. The Kelly combined cycle plant was originally planned as a base unit, but it has always been used as an intermediate unit.

[3] Executive Summary page 4 in "Alternatives for Meeting Gainesville's Electrical Requirements Through 2022: Base Studies and Preliminary Findings" Gainesville Regional Utilities, December 2003, See also Chapter N, page N-8.

[4] GRU plans to borrow money for the initial design and the preparation of the site application for the Florida Public Service Commission, but not pay back the interest or principle until site approval is obtained. Then, after the new plants come on line, it will issue bonds that include the money needed to pay back the interim loans and interest payments. We do not know whether this total includes commissions to the bond-issuers. If not, the bonds needed may total more than $550 million.

7.1 Key Findings

1. Energy needs in the local area will be low compared to the capacity of the new base units for the interval 2011 to approximately 2018, and GRU plans to use the units to generate electricity for sales to other Florida utilities. GRU has stated that off-system sales will be critical to the success of its plan. However, it has not evaluated the opportunities for off-system sales, nor has it forecast the likely range of net revenues they might produce.

2. Operating the two base units to maximize off-system sales will subject the community to very large additional pollutant emissions.

3. GRU's potential market for off-system sales within Florida may be reduced by state-wide increases in efficiency, significantly increased energy prices to state retail consumers, and/or by mandated reductions in power-plant greenhouse gas emissions, any or all of which could occur within the coming decade or sooner. Even small reductions in anticipated energy use per customer, or increased efficiency in electricity end-use could have a major impact on state energy needs and on the market for off-system energy sales.

4. Bond rating agencies warn municipal utilities against the risk of overbuilding at the present time. Compared with other Florida municipal utilities planning new coal-fired powered plants, GRU's proposed commitment is extremely large relative to net revenues and existing rate base. This makes GRU's financial situation more vulnerable to errors in forecasts of fuel costs, energy sales, and regulatory action than other utilities in Florida.

7.2 Discussion

7.2.1 Introduction

Utilities in Florida regularly exchange energy among themselves. Utilities that have no generators, or not enough to supply their needs, contract with others for the delivery of wholesale energy, which they resell to their retail customers. There is also a spot market for wholesale electricity that operates to facilitate exchanges of energy between utilities that are producing more than they need, and other utilities purchase when the asking price is less than their own generating costs.

At present, GRU has excess capacity, and it regularly sends energy to the three other utilities with which it has wholesale contracts. In addition, GRU buys and sells energy on a spot market[5] [6]. These off-system sales fall into three categories:

1. Sales for resale (wholesale) to the City of Alachua and Clay Electric Cooperative. GRU delivers energy to the City of Alachua and the Clay Electric Cooperative for resale

[5] Many of these sales and deliveries are facilitated by a company called The Energy Authority (TEA). TEA is jointly owned by municipal electric utilities around the country. It operates a spot market for interchange energy sales and arranges for electricity delivery. JEA, OUC, GRU and other municipal utilities in Florida and elsewhere are also co-owners of TEA.

[6] In most years, GRU sells more energy to other utilities than it buys, but 2003 was an exception. In that year, Deerhaven Unit #2 was off-line for longer than usual, and electricity purchases from other utilities exceeded sales to them. Coal use and carbon dioxide emissions dropped in 2003, but in spite of this abnormality, it was used as a base reference for the examination of some features of the new systems.

to their retail customers. GRU's annual forecasts include the peak demands of each of these customers, and the amount of reserve margin their demand requires, adding both to its own estimates of peak demand and expected energy sales. The purchasers pay a fee based on actual kWh deliveries and the cost of the fuel used to generate the electricity they buy.

2. GRU sells energy to the City of Starke under a purchased power agreement (PPA) that includes two components: capacity rental and delivered electricity. The capacity rental gives Starke priority access to three megawatts of GRU capacity at any time it is needed, for which Starke pays a fixed amount. In FY 2003 the capacity charge was $56,000 per MW. Capacity charges increase annually, and by 2006 will be $60,000 per MW. In addition to capacity charges, Starke pays for every kWh of electricity delivered to its transmission system. These totaled a little over 13,000 MWh in 2004. When fuel costs are subtracted, the net revenue from energy sales to Starke was approximately $150,000 in 2004, while capacity charges were $171,000. Purchased power agreements can be very remunerative to the seller if they include capacity rental as well as sale of electric energy.

3. GRU buys and sells energy for immediate delivery via an interchange sales system. Utilities that are generating more electricity than they need, or expect to do so in the near future, offer the excess for sale via a spot market, specifying the amount available for sale and delivery terms. Other utilities bid on this energy and an auction-like process ensues. The highest bid sets the market price for that interval. Prices change every hour or, in some cases, every 15 minutes. Prices are high during periods of peak demand, and costly electricity generated from expensive fuels can find a market. During off-peak periods, few utilities are interested in purchasing expensive energy and prices are low.

The lowest cost energy offered for sale in this spot market is said to be "on the margin". Analyses of the changes in Florida wholesale spot market prices over a year have been used to estimate the proportion of time during which energy generated from cheap coal will be "on the margin".

The IRP document briefly discusses potential for off-system energy sales[7] and shows that coal-derived energy was expected to on the margin in Florida about 98% of the time in 2012. These conclusions are based on 2002 forecasts of statewide generating resources and increases in population and in per customer energy usage. They do not take into account the consequences of greenhouse gas (GHG) regulations, sharp increases in all electricity prices due to fuel cost increases, or changes in hourly use that aggressive energy efficiency programs could effect. They also do not consider the plans for new coal-fired generators under consideration by other Florida utilities.

[7] See Figures E-1 and E-2 of "Alternatives for Meeting Gainesville's Electrical Requirements Through 2022: Base Studies and Preliminary Findings" Gainesville Regional Utilities, December 2003.

7.2.2 Off-System Sales and Excess Capacity (Finding 1)

GRU has performed no analyses of potential sales or net revenues from sales. Many in the community believe that building a coal-fired generator to produce saleable electricity will result in large windfall profits that could pay off the bonds needed to implement GRU's plans. The total revenue available from off system sales after the new unit and the retrofitted Deerhaven Unit #2 go online depends on the energy remaining after local needs are satisfied, and whether this energy can be sold and delivered to other utilities.

GRU has presented little information about the how much excess energy it expects to generate and sell to off-system purchasers. Lacking detailed information from GRU, EPAC explored potential sales using a simulation of future operations that GRU produced to compare alternative generator expansion alternatives[8]. EPAC used the results of this simulation as a basis for estimating the amount of time base new units will be used to generate energy for sale in the local retail area, and the amount of excess energy that could potentially be generated for off-system sales[9]. According to these simulations, retrofitted Deerhaven Unit #2 will be needed to generate energy for local needs 48% of hours in 2011, rising to 62% in 2023. The corresponding figures for the CFB unit are 70% in 2011 rising to 80% in 2023. Assuming that 1 15% of each year is used for routine maintenance; these two units could be available to generate about 1100 GWh of excess electric energy in 2011, declining to 650 GWh in 2023. This represents about one third of the combined annual energy generation by the 2 units in 2011, and about one fifth in 2023. (**Figure 7.1**)

It is evident from **Figure 7.1** that if GRU's plans are implemented, there will be opportunities to generate significant amounts of energy for off-system sales. This is confirmed by an analysis of estimated hourly demand for the year 2015. **Figure 7.2** shows the average demand at each hour estimated for the six warmest months of the year and the six coolest ones, together with the average base capacity represented by Deerhaven Unit #2, the new CFB unit and the Crystal River nuclear generator.

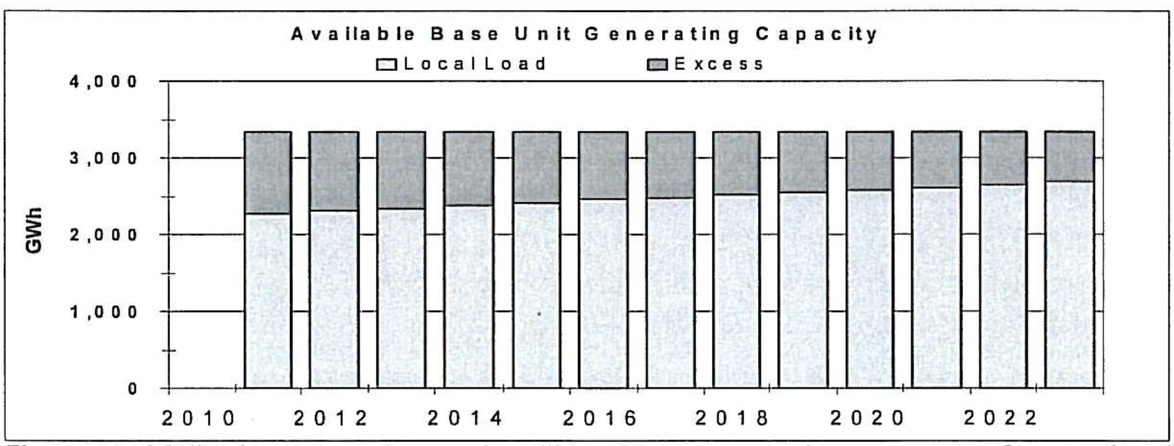

Figure 7.1 GRU's planned new base units will be able to generate large amounts of energy for off-system sales after 2011. This plot assumes 85% capacity factors for all years.

[8] These simulations are discussed in Chapter 5 below.
[9] The simulations GRU conducted provide helpful illustrations of planning issues, but incorporate a number of simplifications that must be noted. For example, they assume that the retrofitted Deerhaven Unit #2 and the new CFB are available for the whole of the first year they come on-line and can operate satisfactorily about 85% of hours in each year, with a minimum of time off-line for routine maintenance. In fact, it is likely to be many months before each unit is operating reliably at maximum capacity, and a capacity factor of 85% or better may be attainable only during the early life of each.

To simplify the analyses, we have assumed that the solid-fuel units are operated on average about 85% of hours in the year. The effects of climate on demand are evident in this figure, as is the fact that the planned 447 MW base capacity will be able to supply local needs most of the time. But this figure is somewhat misleading in that it shows the average demand in each hour, and not the excursions that contribute to the rare but important peaks. For example, the maximum demand expected in 2015 is 601 MW, which is far above the combined capacity of the base units. Intermediate and peaking units are needed when demand exceeds about 445 MW.

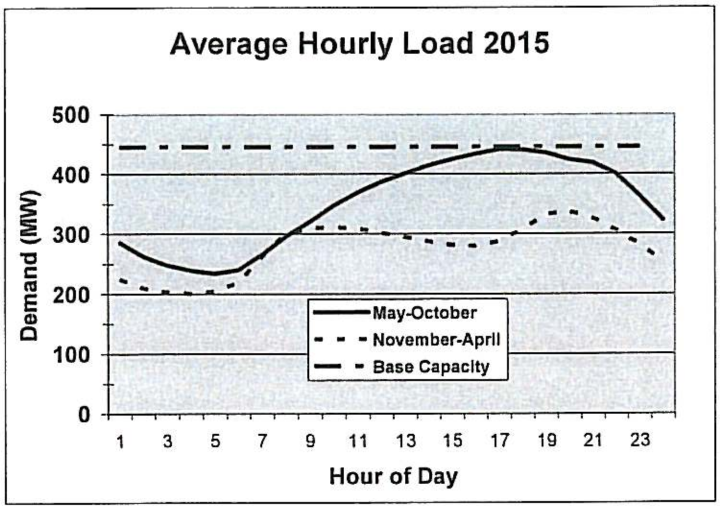

Figure 7.2 Average hourly demand in warmest and coolest 6 months of the year estimated for the year 2015, together with the maximum capacity of the planned base units. This will drop by 215 to 220 MW during a few weeks each year. This plot shows that demand will exceed base capacity only a very small proportion of the time.

Figure 7.2 shows the average hourly demand expected for summer and winter of the year 2015, together with the base capacity the utility will have if its proposal for a new power plant is implemented. The plotted line is the average demand by hour for the months indicated. On the few days when demand exceeds base capacity, intermediate or peaking units will be assigned to supply the demand. **Figure 7.3** shows the total consumption in the year 2015 plotted by hour, as well as the kind of generator that supplies the energy. Only about 2% of the energy expected to be used in 2015 would exceed the capacity of the base units.

7.2.3 Additional Pollution from Generating Excess Electricity

Generating excess energy for off-system sales would significantly increase local pollutant emissions. The maximum potential increase in emissions of SO_2 and NO_X for the year 2015 is shown in **Figure 7.4**, where the quantities sulfur dioxide and oxides of nitrogen have been added together to simplify the plot[10]. The plot shows pollution emissions for the whole year, plotted by hour of the day.

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[10] This analysis assumed that both units would be operated at maximum load for 94% of hours in the year, and that the energy generated by each for on-system sales will be that determined by the simulations GRU ran. All the remaining available capacity was assumed to be used for off system sales, allocated by hour as shown in Figure 3.3. Expected per-unit pollutant emission rates are based on the input used in modeling the dispersion of pollutants

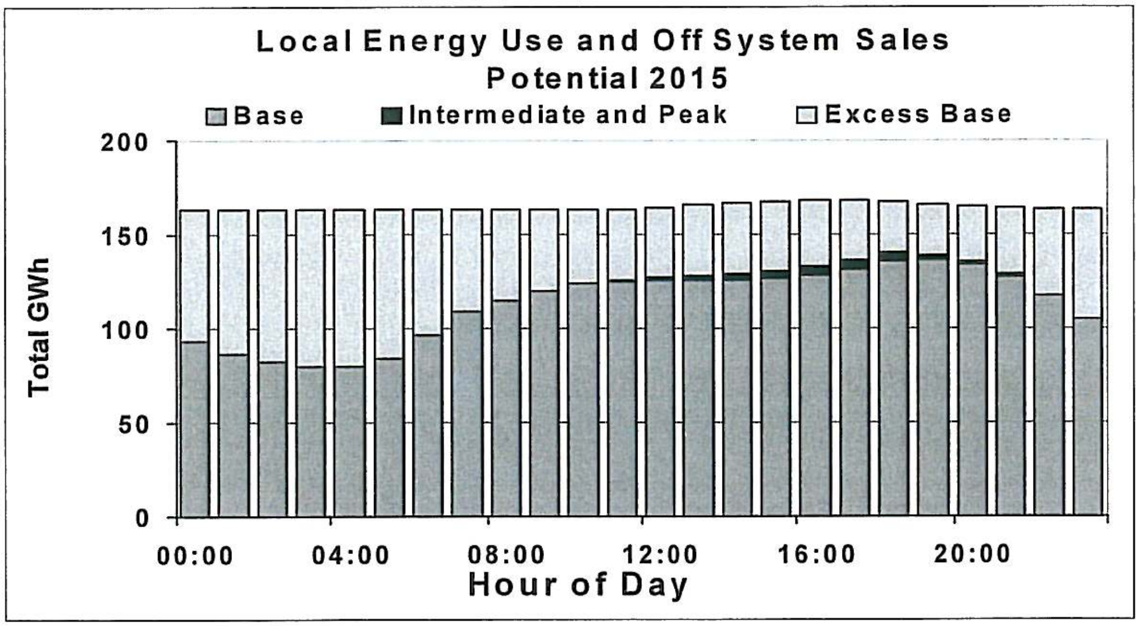

Figure 7.3. Energy from base and other units needed to supply consumption in the local area and the total base capacity available. Each bar corresponds to the total GWh sold at that hour throughout the year 2015. Base units supply all but 2% of total local energy needs. About 1000 GWh would be available in this year for off-system sales.

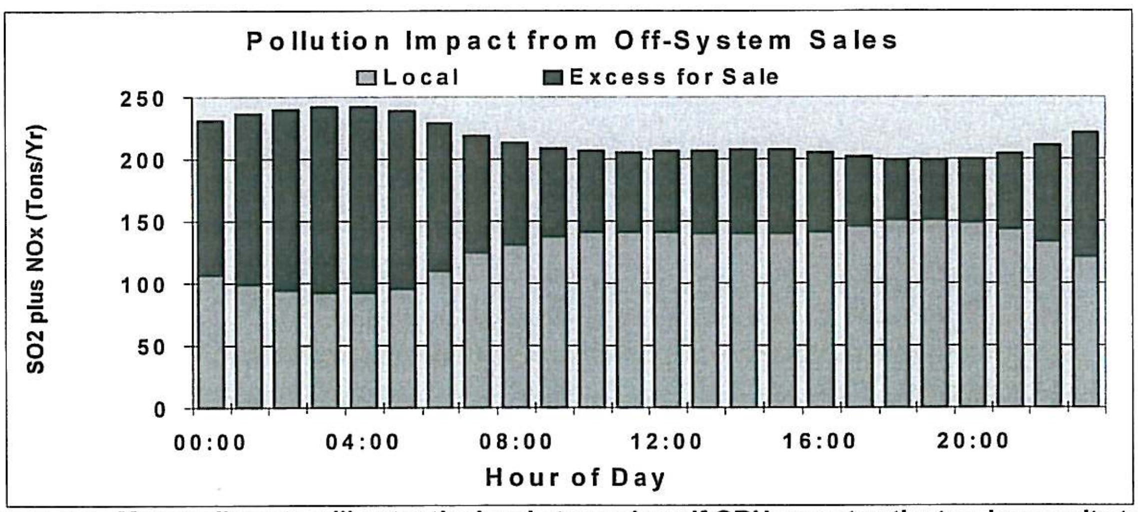

Figure 7.4. More pollutants will enter the local atmosphere if GRU operates the two base units to generate electricity for off-system sales. The columns show the total SO2 plus NOx produced throughout the year 2015 at each hour of the day. The retrofitted Deerhaven Unit #2 will supply most of the off-system purchasers. It will produce more pollutants and carbon dioxide per unit energy produced than the CFB unit. This plot assumes all both units are operating at 95% capacity, but in some months each will be offline for scheduled maintenance.

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reported in "Gainesville Regional Utilities Final Pm2.5 Air Quality Modeling Study: Assessing Past Actual Annual Emissions and Expected Future Actual Annual Emissions." Prepared by Black & Veatch, June, 2004.

The pollution calculations shown here assume that all available excess capacity is used for off-system sales. The new CFB unit will be preferentially used to serve local needs, which means that excess electricity for off-system sales will be generated mostly by the refurbished DH2 unit, which is dirtier than the CFB. It produces considerably more SO_2 and PM_{10} per unit energy generated than the CFB unit, which accounts for the obvious bulges in the plotted data (**Figure 7.4**). Operating the two solid fuel base units in this manner to maximize off-system sales would increase pollution emissions in the local area during some hours by about 50 to 72%, not including the added secondary particulate matter.

7.2.4 Future Florida Markets for GRU Excess Energy

If past population, per customer energy use, and fuel price trends in Florida continue for the next decade, then there will be an in-state market for off-system sales that could provide net revenues of \$20 to \$30 per MWh[11] for energy sales and perhaps much more if income from capacity rental can be guaranteed by purchased power agreements.[12]. Net revenue from such sales could total between about \$224 million and \$340 million between the time the units go on line and the end of 2023.

Under the optimistic market assumptions discussed here, off-system sales could generate significant income for the city at the cost of large increases in pollution exposures to the population of the county and surrounding areas. However, even under such optimistic assumptions, off-system sales are unlikely to provide sufficient income to service the bonds issued to pay for GRU's plans. Depending on the terms of the bond issue, the annual payments could range from about \$35 to \$45 million dollars. Furthermore, there are grounds to question the optimistic assumptions.

EPAC has reviewed forecasts of future state energy needs published annually by the Florida Reliability Coordinating Council (FRCC)[13]. These forecasts are straightforward extrapolations of current and past trends in the growth of the number of customers and energy use per customer. According to the most recent FRCC report, energy demand in the state will grow by 27% in the next ten years, due largely to migration of residents into the state. Migration into the state will increase both the number of residential customers and the number of commercial customers that serve them and non-resident visitors.

Based on past experience, the FRCC predicts that the 2004 residential and rural customer base of 7.4 million will grow by nearly 17% to 8.6 million in 2013, and approximately 90% of that growth will be from new residents moving to Florida from outside the state. Average electricity use per residential customer has risen steadily from 12.4 MWh per year in 1994 to 14.5 MWh in 2004. It is expected to increase to 15.8 MWh (8%) by 2013. Commercial usage will increase even more. The number of commercial customers will rise by 20%, but total commercial energy

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[11] Burns and McDonald, (October 23, 2003) "Coal Fired Generation Workshop".

[12] There is an important difference between renting capacity that the purchaser can call on when needed, and selling electricity. Under state law, Florida utilities must maintain a reserve capacity equal to 15% of their annual peak power demand. This reserve must be available on very short notice in case they experience, or other utilities in the state experience emergencies. Consequently, utilities that do not have the capacity to serve their usual load need to buy electricity to resell to their users, and these utilities also need to rent the capacity to satisfy the reserve margin requirement. Purchased power agreements are typically used to contract for capacity rentals. Contracts to rent capacity also usually include purchase of energy. The difference between capacity rental and electric energy purchase is further discussed in Chapter 5 of this report.

[13] "Regional Resource Plan: Regional Reliability and Resource Plan". Florida Reliability Coordinating Council July 2004.

use will increase by nearly 30% due to increases in consumption per customer. The residential "business as usual" projections are plotted in **Figure 7.5**.

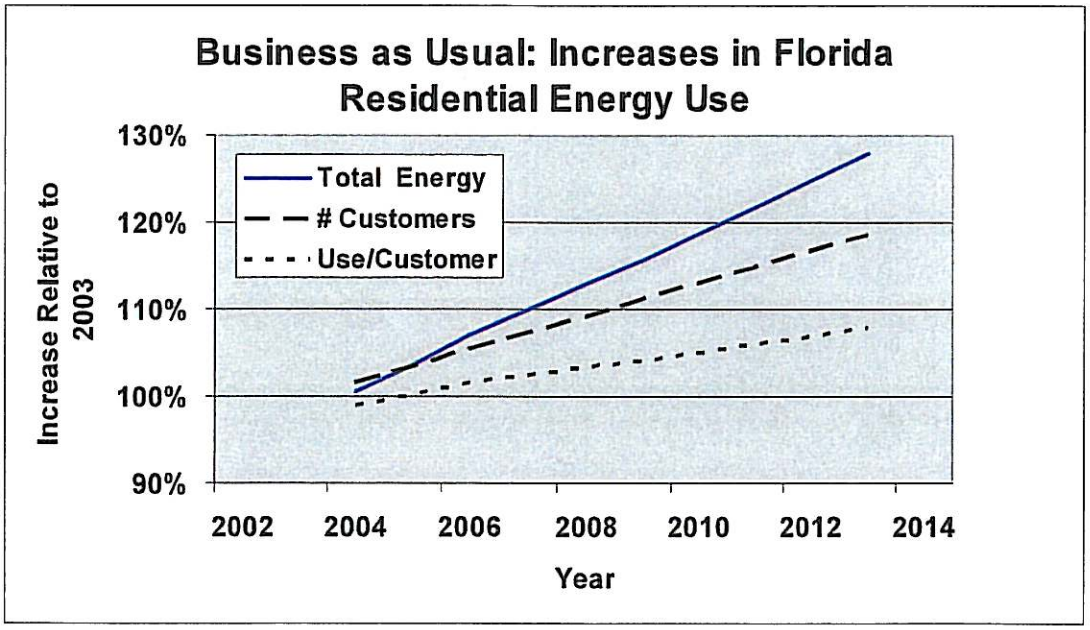

Figure 7.5. Residential energy use in Florida is predicted to be 27% higher in 2013 than in 2003. Consumption increases by commercial customers will parallel those for residential customers.

Although the details of this country's response to the climate crisis cannot now be predicted, it is abundantly clear that GHG reduction mandates will be imposed, probably within about a decade[15]. Extremely large increases in the efficiency of energy end-use are likely to be a prominent part of any response to the crisis, along with effective public education campaigns. Recent history indicates that energy prices will increase, and this will also make consumers conscious of the need to reduce electricity use.

In Florida even small changes in per customer energy use will have very significant impacts on the total energy needed in the state. This is illustrated in **Figure 7.6**, which contrasts the business as usual state forecast with two alternative scenarios. The first is labeled "conservation". It assumes that residential, commercial, and industrial customers simply cease to increase annual energy use in 2007, average use being constant after that year. The second strategy assumes that energy efficiency measures are adopted and that their net effect is to reduce per customer energy use beginning in 2007. As a result, per capita energy use declines steadily to the levels characteristic of 1994, which is reached in 2013. This scenario actually reverses the steady increase in state energy need observed over the past 20 years.

The two scenarios plotted in **Figure 7.6** illustrate the dramatic impact that even small electricity usage changes could have on generating needs in the Florida market. Note that continued increases in natural gas prices during the next 5 years may lead consumers to decrease their energy usage voluntarily and the results could approach the "conservation" impacts plotted in **Figure 7.6**.

[15] See Chapter 3.

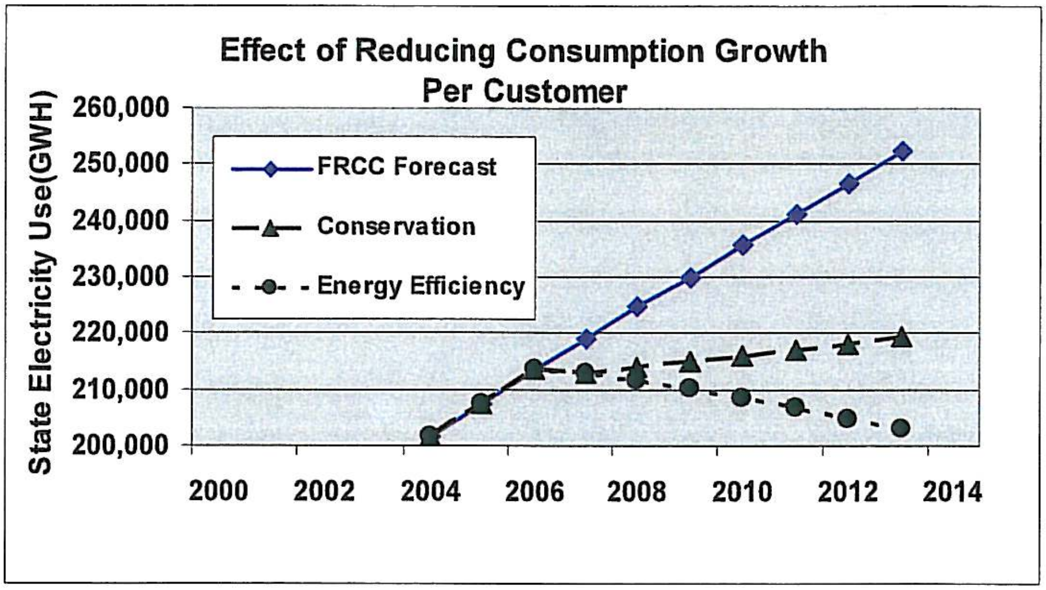

Figure 7.6 Florida electric energy growth under three scenarios. The business as usual FRCC forecast assumes large increases in state population and in per customer energy use over the decade. The conservation scenario assumes that all per customer energy use stops increasing in 2007 and remains constant for the remainder of the decade. The energy efficiency scenario assumes that per customer usage declines to the levels of 1994 by the end of the decade. In all cases, the Florida population is assumed to increase by 17% over the decade.

7.2.5 Overbuilding Risks (Finding 5)

GRU is one of three Florida municipal utilities that in 2004were planning to build a new solid-fuel generator. The others are JEA and Orlando Utilities Commission (OUC). Comparison of the plans and resources of these two utilities with GRU suggests the program proposed for Gainesville is far more ambitious and probably significantly more risky than the programs of the other two utilities.

JEA plans to add a new 275-MW CFB unit to its existing generator fleet by 2011. EPAC has estimated the capital cost of this project as $400 million, basing this estimate on a comparison with the expected $415 million cost of GRU's project (2005 dollars) corrected for an estimated $95 million dollar cost of the retrofit of Deerhaven Unit #2[16]. We do not know the total cost of the proposed generator, but have estimated it at $350 million for the purposes of this comparison.

Orlando Utilities Commission (OUC) plans to add a 285-MW coal-gasifying system[17] that will be built on OUC property and jointly owned by OUC and the Southern Company. The cost of this

[16] GRU estimated the total cost in "Affordability in an Uncertain Future: Presentation to the Gainesville City Commission November 15, 2004". Performing the DH2 retrofit, obtaining site approval, and designing, and building the CFB will require a bond issue of approximately $550 million in 2011, for a total cost including interest of about $1.5 billion. The estimate of the DH2 retrofit given here is based on the 2011 costs incorporated in the EGEAS modeling exercise, corrected to 2004 dollars. See Chapter 5 for a discussion of the modeling program and outputs.
[17] Coal is converted to a gas by heating in a special atmosphere. The gas is then burned to produce energy. Sulfur oxides, carbon dioxide and other pollutants produced during the heating process can be separated. Gasification provides a stream of nearly pure CO_2 that could possibly ultimately be sequestered in saline brine aquifers 6,000 or more feet deep. Sequestration in brine aquifers or other geological structures is the subject of research sponsored by the power industry and the Department of Energy.

project has been estimated at $557 million. The Department of Energy contributed a grant of $235 million for this project, while the remaining $322 million will be contributed by the Southern Company. OUC's contribution is the land on which the generator will be built.

Both JEA and OUC are far larger than GRU, have far more commercial customers, and far larger net revenues from energy sales. JEA has the income and ratepayer base to weather adverse regulatory or other future eventualities that could make their new CFB generator extremely costly to use (**Tables 7.1** and **7.2**).

Table 7.1 Comparison of Florida Municipal Utiliites Planning New Solid Fuel Generators in 2004

	Residential	Commercial	Total Sales
A. Sales (GWh)			
JEA	**5226**	**6789**	**12982**
Orlando Utility Commission	**1688**	**1611**	**5043**
Gainesville Regional Utilities	**854**	**908**	**2015**
B. Number of Retail Customers			
JEA	**332492**	**37392**	
Orlando Utility Commission	**131350**	**10363**	
Gainesville Regional Utilities	**74456**	**8978**	
C. Peak Demand MW	**Summer**	**Winter**	
JEA	**2530**	**2610**	
Orlando Utility Commission	**1121**	**1086**	
Gainesville Regional Utilities	**417**	**394**	
D. Generating Capacity (MW)	**Summer**	**Winter**	
JEA	**3257**	**3476**	
Orlando Utility Commission	**1047**	**1092**	
Gainesville Regional Utilities	**612**	**631**	

All three municipal utilities are significantly more dependent on coal to fuel their generators than Florida's electric power industry as a whole. In 2003, approximately 38% of all energy produced in Florida was produced from coal[13]. But in that year JEA produced 52% of its energy from coal, OUC 75%, and GRU 68%. When the new plants are in operation in 2012, JEA will be less dependent on coal (44% in 2005), OUC will remain about 75% dependent on coal, while in 2012 when its new plant opens, GRU will be nearly 93% dependent on coal. We conclude that all three municipal utilities could be seriously adversely affected if, as is possible, coal-using utilities are financially penalized under mandatory greenhouse gas regulations, but GRU will suffer more.

Table 7.2 New Capacity and Financial Comparisons

	New Unit Capacity MW	Capacity Increase %	Approximate $ Cost $ Million	Gross Revenue $ Million
JEA	275	11%	$400**	$713
Orlando Utility Commission*	143*	14%	NA***	$503
Gainesville Regional Utilities	220	36%	$330	$225

*Half the total 285 MW of the new plant
**Estimated total cost of $415 million system reduced for DH2 retrofit costs of $95 million
***Not applicable. OUC contributes the use of its site but no money.

The overbuilding risks to GRU would be further exacerbated if deregulation were to become a reality. Officially, Florida still plans to deregulate the electric energy market to promote competition among utilities. When deregulation occurs, major utilities like Southern Company and Florida Light and Power could have access to the Gainesville market, and many electricity users may switch to new suppliers if they are offered better deals than they now obtain from GRU via its "Power Partners Program"[18]. Although these customers have contracted with GRU to remain as GRU customers, buy-out provisions in the contracts could be invoked if GRU competitors offer them better deals. The two hospitals and the large supermarkets in town are the largest users. All use large quantities of energy during off-peak periods. They are the most likely to switch to alternative suppliers under deregulation. It is not clear how their loss would affect GRU's need for base capacity.

Bond Ratings

There are other reasons to be cautious about investing in increased capacity. According to Moody's Investor Service analyst, Dan Aschenbach, excess capacity and the absence of long-term transmission rights and price-certainty contracts could pressure the credit strength of municipal utilities, which now appear to be entering a new building cycle[19].

Citing defaults by publicly owned utilities in the 1980's and early 1990's, Aschenbach noted that utility managers learned a lesson reflected in the motto "Don't risk, don't build", but that the lessons are now being forgotten. He urged public power executives to avoid bad experiences of the past by answering several important questions including the following:

(1) Is too much capacity being built?
(2) How much leverage is too much leverage?
(3) What is the technology risk in the project? And
(4) Is there certainty in environmental regulation?"

[18] Customers who contract with GRU to remain customers under deregulation obtain a significant cut in their monthly bills. Small non-demand commercial customers receive a discount of 7%, larger demand commercial customers get a 10% discount, and the 18 largest retail users receive a 13% discount.
[19] Aschenbach D, "Credit Issues Resurface as New Electric Generation Projects by Public Power Utilities Take Center Stage", Report issued by Moody's Investor Service, and described in Foster's Electric Report, October 10, 2004. Unless attributed directly to Mr. Aschenbach, the quotes in this section are from the Foster report.

Chapter 8: Generating Electricity from Biomass

8.0 Introduction

Florida currently has only three practical renewable energy resources: solar energy, municipal waste, and biomass[1]. Until offshore tidal, current or wind energy electricity production becomes economical, solar energy, biomass and municipal waste are our most significant regional renewable energy sources, but Gainesville citizens have rejected burning municipal waste in conventional generators[2, 3]. GRU may fuel its proposed new 220-MW CFB generator with up to nearly 14% of biomass fuel, if it is built, but the utility has made no firm commitment to use this amount of biomass energy[4].

Gainesville is located in the midst of extremely rich wood resources. Pulpwood production has long been a major regional industry but a recent drop in prices has made it regionally uneconomic. GRU's consultant Black & Veatch reviewed biomass sources and energy conversion technologies in 2004 and reported the existence of large local biomass resources[5].

Biomass fuels have many advantages from the point of view of greenhouse gas emissions and local air pollution. Consequently, EPAC reviewed GRU's plans to determine whether greater biomass fuel use is an option, and its attendant advantages and costs.

EPAC's review of GRU's biomass plans included an analysis of GRU's initial screening procedure that caused it to reject significant biomass use, and a review of the environmental advantages of increased use of biomass.

8.1 Key Findings

1. **Most of the increased local need for electricity projected to about 2019 or beyond could be supplied by adding approximately 100 MW of biomass-based generation, and by making increased use of the existing natural gas-fired combined cycle generator at Kelly. Demand-side management and energy**

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[1] See "An Assessment of Renewable Electric Generating Technologies for Florida, January 2003" prepared by the Public Service Commission and the Department of Environmental Protection, available at: http://www.psc.state.fl.us/industry/electric_gas/Renewable_Energy_Assessment.pdf

[2] Biomass was the source of approximately 21% of the 1,068 MW of installed capacity fueled by renewable fuels documented in a 2003 report, while municipal waste supplied 42%, as reported in the Public Service Commission report cited above.

[3] Thermal solar water heating that may be economically competitive with electric energy and has been proposed by Dr. Barney Capehart as part of a program to reduce demand. (See "The Potential for Cost-Effective DSM Programs: An Evaluation of the Cost-Effective DSM Programs of the IOU's in Florida" Prepared for Gainesville Regional Utilities by Barney L. Capehart, PhD, CEM Gainesville, Florida 32605 October 31, 2003). Photovoltaics appear currently to be uneconomic, according to GRU analyses of power costs, although they may be desirable under a more comprehensive cost-effectiveness analysis.

[4] Whether the design GRU chooses will allow co-firing with this much wood is uncertain. Some CFB designs use only very limited amounts of biomass, and GRU has refrained from making a commitment to any specific amount of biomass. The biomass potential has been discussed by GRU in "Alternatives for Meeting Gainesville's Electrical Requirements Through 2022: Base Studies and Preliminary Findings" Gainesville Regional Utilities, 2003. If GRU does meet this target, biomass will supply approximately 7 to 7.5% of total energy used in the local service area.

[5] Black & Veatch Corp. "Supplementary study of Generating Alternatives for Deerhaven Generating Station" B&V Project No. 137196, March 2004. This report was released to the public on December 13, 2004. GRU did not modify its CFB proposal in response the advice contained in this study.

efficiency programs could reduce both the fuel cost of this option and the need for additional capacity to meet reserve requirements.

2. **Use of about 100 MW of biomass could contribute over 20 to 30 million dollars to the local economy in the interval 2011 to 2023. Timber producers and small landowners would benefit economically if GRU provided a market for thinnings and small diameter pulpwood that has recently lost its market.**

3. **Costs of a new biomass-based generator might be partly funded by the Department of Energy.**

4. **Biomass use eliminates highly polluting open burning of woody wastes from land clearing, forest thinning, and storm debris, and the cost of the disposal of these biomass fuel sources.**

5. **Biomass use does not increase the amount of fossil CO_2 in the atmosphere, and its use will not be penalized by future greenhouse gas regulations. Biomass use may produce tradable renewable energy credits.**

6. **Wood contains far less SO_2, mercury and other toxic materials than solid fossil fuels, so substituting it for coal or petroleum coke would reduce harmful toxic air pollutants. Biomass is less environmentally damaging compared to coal mining and does not require limestone scrubbing with resulting large tonnages of hazardous sludge wastes.**

7. **Biomass is a sustainable energy source, readily available year round, and locally available in large quantities.**

8. **Sustainable use of biomass fuel requires management safeguards to protect numerous environmental, economic and social advantages supplied by public and private forests.**

8.2 Discussion

Biomass has many compelling advantages, although GRU ranked it near the bottom in its initial alternative fuel screening exercise[6]. EPAC found that some of GRU's screening rankings seemed to be in error, or due to inappropriate combinations of fuels and technologies that were evaluated as a single option[7]. When these errors are eliminated, biomass appears to be a superior fuel to coal/petcoke. The only disadvantage relative to these other two fuels was that it could not supply a 220-MW base unit, a criterion GRU used to screen technologies, and one that implies a prior decision to add 220-MW to GRU's system.

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[6] Section I of "Alternatives for Meeting Gainesville's Electrical Requirements Through 2022: Base Studies and Preliminary Findings" Gainesville Regional Utilities, 2003.

[7] For example, biomass was apparently assumed to be used in an extremely inefficient 7-MW thermal boiler configuration that has a full-load heat rate of 15,000 Btu/kW, 15% mature forced outage, and costs $2,250 per kW and has fixed operation costs of over twice those of the competing CFB system. The CFB was ranked high on local economic impact because building the CFB generator will supply local jobs, although any new generator would do so and a biomass generator provides added fuel-related jobs in comparison to a CFB.

8.2.1 Supplying Projected Local Electric Energy Needs by Adding a 100-MW Biomass-based Base Unit (Finding 1)

EPAC developed a simple model of biomass use in a 100-MW base unit, using one of the models developed by GRU for its consideration of "alternatives" to the CFB system (Chapter 5 above)[8]. EPAC's model features a hypothetical 100-MW biomass base generator and is used solely to illustrate the advantages of biomass-based generation.

EPAC used GRU's simulations of an alternative system that features a 243-MW natural gas-fired combined cycle system to supply expected future increases in demand during the interval 2011 to 2023. EPAC used this "all gas" scenario, substituting a hypothetical 100-MW biomass-fired unit to supply the energy provided by the GRU modeled combined cycle unit. A 100-MW biomass replacement unit cannot supply all the energy generated by the 243-MW unit. EPAC assumed the existing natural gas-fired combined cycle plant at Kelly would make up energy shortfalls.

In GRU's "all gas" simulation model, the Kelly plant produced only a small fraction of the total local annual electric energy. In EPAC's model the Kelly proportion increased but not substantially.

EPAC assumed that the biomass unit generated approximately 796 GWh of electric energy every year, which roughly corresponds to an 85% capacity factor. The capacity factor for the Kelly plant ranged from 16% to about 52%. Biomass fuel costs were assumed identical to the high-sulfur coal costs projected by GRU, and GRU's natural gas cost estimates were used.

EPAC found that all the predicted energy needs of the local service area through the year 2019 could be supplied by a combination of the100-MW biomass-fired base unit and the 110-MW combined cycle unit at Kelly. But an unknown amount of additional capacity could be needed to supply the required 15% reserve. This would depend on reductions in peak demand achieved by conservation and other demand site management programs.

EPAC's modeling exercise is the source of the data presented in the remainder of this section. It illustrates the advantages of adding a small generator fired by biomass from local sources, and confirms that a capacity expansion of about 100 MW could supply local needs through approximately 2018 or even later but would probably have to be supplemented with additional generation to satisfy reserve capacity requirements. However, further detailed studies of real biomass systems and their potential use are clearly needed.

8.2.2 Economic Advantages of Biomass Use (Findings 2 through 4)

Purchasing biomass locally keeps money for power plant fuel in the local economy. Increased biomass use will increase this important benefit. Money spent on fossil fuel leaves the state, and sales taxes for these purchases benefit other state and local governments.

GRU's current proposal incorporates biomass fuel for about 30 MW of energy (about 7% to 7.5% of all fuel) after 2011. Under this plan, and assuming the biomass costs are identical to those of high sulfur coal, the utility would contribute about $3.8 million dollars to the local

[8] This model is described in Appendix 8.5 to this Chapter 8.

economy in the first year, rising to about $11 million in 2023. Exported fossil fuel dollars would range from $45 million up to $90 million during the same interval (**Figure 8.1**)[9].

If GRU used biomass for a total of 100-MW of generating capacity instead of 30-MW, the increased economic impact on the local community would be very impressive. According to EPAC's model, local biomass purchases could add between $20 million and $27 million to the local economy. But dollar exports for natural gas purchases would be higher than if the solid fuel generator were built. How much higher depends on the effectiveness of energy efficiency and demand reduction programs the utility adopts. EPAC explored the possible consequences of such programs by assuming that GRU adopts programs that gradually reduce the energy consumed in the local community, achieving a total 9% reduction by 2023. In this case, fuel dollars exported would range from about $45 million to about $97 million (**Figure 8.2**). Total fuel costs would be up to 24% higher under this option than under GRU's solid fuel option (**Figure 8.4**).

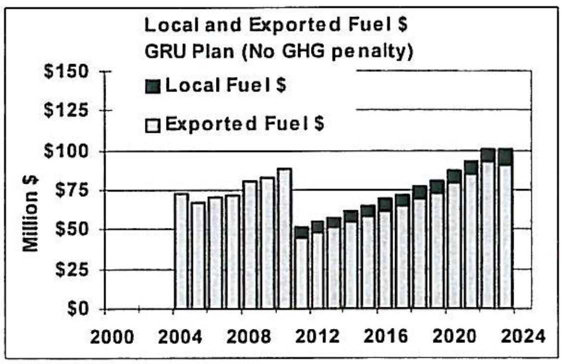

Figure 8.1 - Fate of Fuel Dollars Under CFB Plan; Money exported out of state to pay for fossil fuel compared to that retained locally under GRU's plan for 30 MW of biomass in its new CFB generator, beginning in 2011.

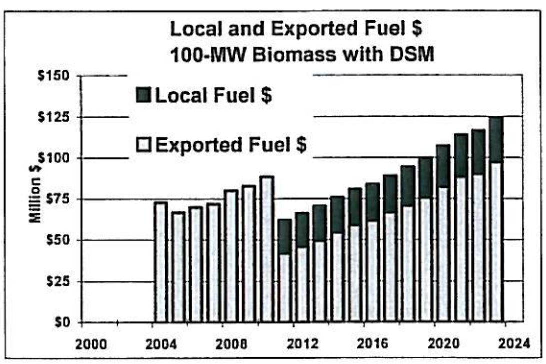

Figure 8.2 – Fate of Fuel Dollars under Biomass/DSM Plan: Money exported out of state to pay for fossil fuels compared with that retained in the local economy if GRU substitutes 100 MW of biomass to fuel electric energy generation for the proposed 220-MW CFB unit.

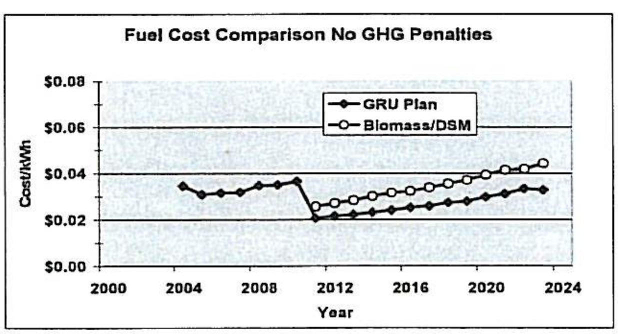

Figure 8.3 Comparison of GRU fuel costs. Fuel costs under the 100-MW biomass option exceed those of GRU's solid fuel proposal by about 25% if we implement a DSM program that reduces total demand by 9% in 2023. The differences plotted here correspond to between $0.005 and $0.011 per kWh, and reflect the high assumed future costs of natural gas. Note that Figure 8.3 includes no carbon dioxide emission penalty (see below).

[9] These calculations assume that Deerhaven Unit #2 is retrofitted and burns high sulfur fuel and in all other respects GRU follows the solid fuel scenario discussed in Chapter 4 above. The assumptions used by EPAC to develop these estimates are discussed in Appendix to Chapter 8.

DOE might pay a large part of the capital costs for a renewable fuel (biomass) generator. GRU's assumed capital costs for the CFB unit (about $350 million plus interest) will be paid entirely by local ratepayers. A biomass approach, representing a viable, local renewable energy source, could very likely attract capital cost sharing from DOE as a demonstration project[10, 11]. The community loses this opportunity to save up to half of capital costs *and* the resulting difference in loan interest if the City chooses GRU's conventional solid fuel-fired CFB.

Other economic advantages of increased use of biomass fuels to generate electricity include the following:

- **Biomass use adds local sales taxes** from the fuel sales as well as associated taxable business activities.
- **Biomass opens a lucrative market for small dimension timber** that would help forest owners manage their forests for high-value saw timber because they can count on intermediate biomass sale income of their thinnings and undesirable species.
- **Biomass burning creates wood ash, a valuable commodity** at $50 – $60 / ton as a soil fertilizer, rather than coal ash which is laden with heavy metals (page 3-2, Black & Veatch). This advantage applies *only* to units burning *solely* biomass, because coal and petcoke contaminate ash with toxic metals.
- **Biomass burning could produce tradable renewable energy credits prior to the imposition of mandatory greenhouse gas reductions.** Renewable energy credits for biomass use could be sold on the open market. This would further increase the biomass cost advantage relative to coal and petroleum coke. JEA and Progress Energy have already expressed interest in this approach[12]. The market for such renewable energy credits is reviewed in a recent NREL report[13].

8.2.3 Climate Change/Greenhouse Gas Issues (Finding 5)

If GRU used more biomass fuels, it would significantly reduce its atmospheric fossil fuel carbon dioxide emissions. **Figures 8.4** and **8.5** compare total fossil carbon dioxide emissions and carbon intensity changes that would result if GRU substituted 100 MW of biomass-based capacity for its proposed 220-MW CFB unit. Annual fossil carbon dioxide emissions drop over a million tons under the 100-MW biomass option, compared to GRU's current proposal (**Figure 8.4**). (Although biomass produces the greenhouse gas nitrous oxide, as does the CFB, the totals are insignificant in comparison to coal/pet coke carbon dioxide).

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[10] Black & Veatch Corporation. "Supplementary study of Generating Alternatives for Deerhaven Generating Station. B&V Project No. 137196, March 2004.
[11] Orlando Utilities Commission is now engaged in a joint effort with Southern Company to build a-coal fired merchant plant on land owned by OUC. Forty percent of the cost is being paid by the Department of Energy, and Southern Company is supplying the rest of the capital. OUC's is contributing the generator site.
[12] Black & Veatch Corporation 2004.
[13] See Holt, E. and L. Bird Emerging Markets for Renewable Energy Certificates: Opportunities and Challenges NREL/TP-620-37388, January 2005.

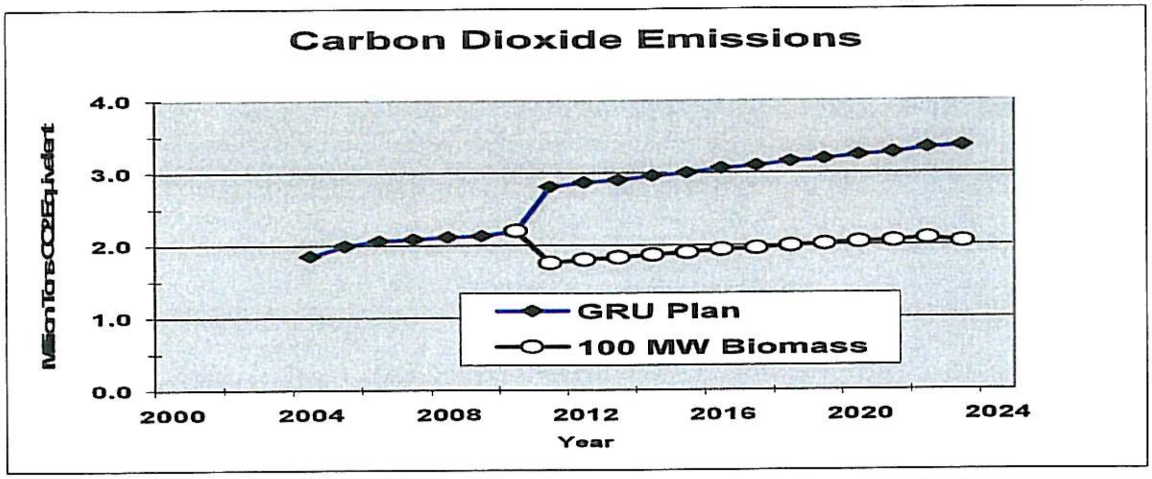


Figure 8-4. Comparison of fossil CO_2 resulting from substituting a 100-MW biomass based generator for the 220-MW coal/petcoke-fired CFB proposed by GRU and employing demand side managements to reduce peak demand. The data were derived from GRU simulations of its preferred plan and two alternative plans, and from modification of one of the latter by EPAC.

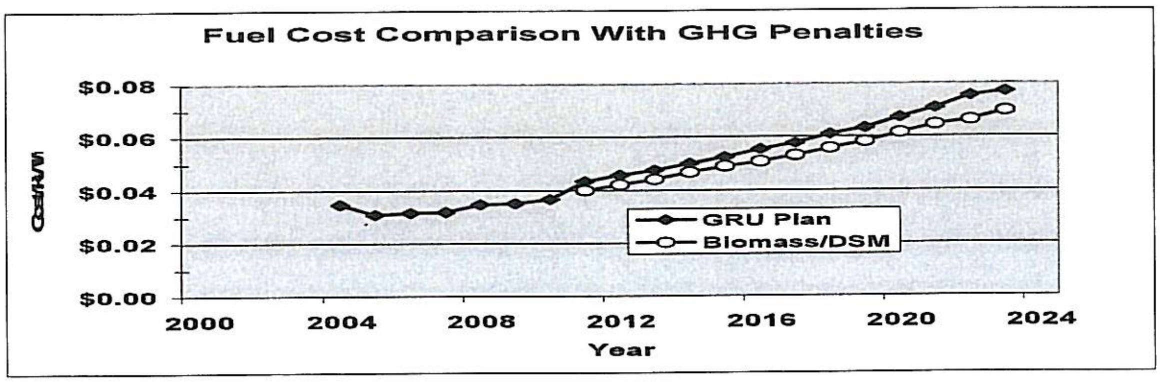


Figure 8- 5. Comparison of fuel costs assuming a greenhouse gas penalty that begins at $20 per ton of carbon dioxide and increase 5% per year in nominal dollars.

Figure 8.5 shows the effect of greenhouse gas penalties of $20 per ton on carbon dioxide in 2011, increasing at 5% per year. Fuel costs are high because large quantities of coal and natural gas are used by GRU, with or without the 100-MW biomass-fired base unit. If greenhouse gas regulations are enacted, a more serious consequence of the GRU plan—not illustrated in this chapter—is that solid fuel generators would have to be retrofitted to accommodate capture and sequestration, assuming suitable techniques are available. This would also be extremely costly, perhaps more costly than the hypothetic carbon penalties listed here. All utilities that depend heavily on coal would suffer under greenhouse gas regulations.

Projecting analyses beyond the point at which greenhouse gas regulations are imposed is extremely unrealistic. Under such circumstances, the community would begin to implement much more aggressive conservation and energy efficiency measures than those considered in this document. At that point it might be too late to take advantage of the rich local renewable wood fuel resources, if the City chooses to build the proposed GRU generator. Other Florida utilities may in the mean time contract for local biomass resources, leaving GRU few biomass options.

8.2.4 Pollution and Environmental Damage (Findings 6 and 7)

Biomass pollutes less than fossil fuel

Biomass contains almost no sulfur and has very low toxic metal levels compared to coal or petcoke[14]. GRU ranked biomass as inferior to coal under the screening criterion of local pollutant emissions, but this seems to be an error. Coal cannot match biomass emissions *even if* pollution controls are used. Biomass requires smaller, less expensive air pollution control equipment. The concentrations of mercury and other toxic metals are low in biomass[15], much lower than in coal. Unlike coal, biomass combustion emits no radioactive uranium and thorium. SO_2 scrubbing is not required because biomass sulfur concentrations are very low (see more associated advantages later in the list), which means that less dangerous $PM_{2.5}$ is created, because biomass combustion releases much less sulfur dioxide to the atmosphere—the chief source of secondary particulate matter.

Biomass fuels are far less environmentally damaging

Coal mining by mountaintop removal and strip mining devastate the regional mining environment and leave large permanent environmental deficits. Local biomass sources provide the opportunity to integrate local forest management to achieve sustainable fuel provisions with minimal environmental impact. Storm debris such as from 2004 hurricanes would be diverted to a biomass boiler rather than open incineration, which greatly increases local air pollution.

Biomass use and the production of ecologically dangerous SO_2 scrubber sludge

The CFB SO_2 scrubber produces huge daily tonnages of spent limestone waste (highly acidic calcium sulfate, laden with heavy metals). GRU did not consider this biomass cost benefit in its screening exercise. Reducing the production of hazardous scrubber sludge also reduces the risks of water supply contamination.

Biomass is an indefinitely sustainable fuel

Black and Veatch[16] rated the GRU-specified 30-MW biomass supply as sustainable. Biomass is indefinitely sustainable in properly managed forestry operations. Biomass fuel volumes considerably in excess of those projected by GRU could be sustainably produced, according to representatives of the University of Florida's School of Forest Resources and Conservation[17].

The biomass industry in North Central Florida is large, and most of it is well within the 50 to 100 miles considered reasonable for transport of biomass (See **Figure 8-6** below). Black & Veatch's March 2004 report also suggests regional availability is high enough for significantly more than

[14] See report by Friedli, H. R., L.F. Radke, J.Y Lu, C.M. Banic, W.R. Leaitch, J.I. MacPherson, 2003 "Mercury emissions from burning of biomass from temperate North American forests: laboratory and airborne measurements" Atmospheric Environments, vol. 37, pp 2 53-267, and Friedli, H.R., Radke, L.F., Lu, J.Y., 2001. "Mercury in smoke from biomass fires." Geophysical Research Letters 28 (17), 3223–3226.
[15] Particulate mercury is deposited from the atmosphere onto leaves and twigs, and enters the stems from soil sources, but the measured concentrations in wood fuels are quite low. Also, see report cited in footnote 14 above.
[16] Black & Veatch 2004 "Supplementary Study of Generating Alternatives for Deerhaven Generating Station" March
[17] Presentation by Don Rockwood to EPAC in January 2005.

30-MW[18]. EPAC believes significantly more biomass use may be possible, but additional independent studies of sustainability and availability are needed. Short rotation woody crops specifically grown to generate electricity are an attractive possibility. These must be carefully evaluated.

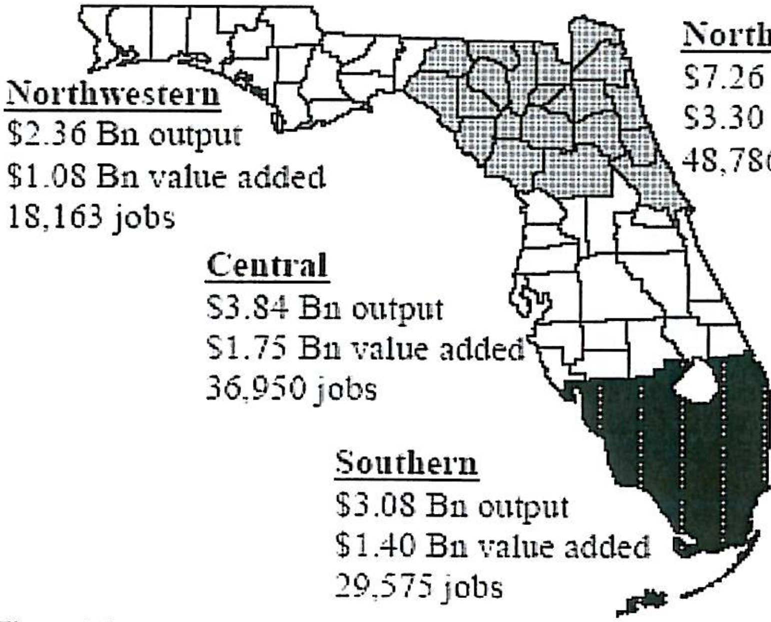


Figure 8.6. *Regional Annual Forestry Economic Value in Billions of Dollars* (Source: "Economic Impacts of the Forest Industry in Florida, 2003: Final report to the Florida Forestry Association" Hodges AW, Mulkey WD, Alavalapati JR, Carter DR, and CF Kiker. University of Florida 7 Jan 05).

8.2.5 Need for Ecologically Sound Management Practices in Forests that Supply Biomass to GRU (Finding 8)

The advantages of biomass fuels are widely appreciated by other utilities in the state, and the resources of North Central Florida are likely to be extremely attractive to other Florida electric utilities. One concern is that GRU—by ignoring the biomass potential—may have opened the door for other purchasers to exploit resources in the county and surrounding counties in a manner that is ecologically destructive or worse. At present there are no regulations in the city or the county that mandate forestry practices to protect the ecological health of local forests, or preserve the many important ecological functions they provide. Commercial exploitation of the fuel resources by other utilities might include clear-cutting native or even commercial forests.

Clear cutting exposes soils to erosion, and which could deliver large quantities of silt to local creeks and lakes, destroying wildlife habitat, bottom dwellers, aquatic plants and other resources. Not all harvesting techniques are benign, but they can be made so, given education and inspection of the kind GRU could facilitate, with guidance from the many local forestry and wildlife experts present in the County.

Any program of GRU biomass use must be accompanied by outreach to both commercial and non-commercial forest owners to insure that they understand and follow appropriate guidelines for protection of the local environment as well as a program of inspection and certification. The

[18] Black & Veatch, 2004 page 3-13.

potential use of biomass as a GRU fuel increases the value of local forest resources, and offers the opportunity to effect environmental protection otherwise unavailable (See Appendix 8.1).

Chapter 8, Appendix 1: Biomass for Power Generation

(Prepared by Josh Dickinson[1])

Questions:

1. Is there sufficient biomass in north central Florida to sustain a power plant indefinitely?
2. Can biomass be obtained at a competitive price in the region?
3. Can forests of the region be harvested in an environmentally sustainable manner?
4. What are the advantages of using biomass compared to burning coal/petcoke?

1. *Is there sufficient biomass in north central Florida to sustain a power plant indefinitely?*

Yes. A look at a satellite image of north central Florida will reveal the enormous extent of natural and planted forest in the region. The area increases by the square of the radius. The area within 25 miles of Gainesville is 1962 square miles; within 50 miles, 7850 square miles; a fourfold increase in area. These forests are in private non-industrial, corporate and public ownership. In addition to natural forests, there are planted forests either on land previously in crops or pasture, or on land where natural forests have been converted to plantations. There are three common sources of biomass from forests: a) forests planted to produce pulpwood can be harvested instead for biomass, b) natural forests being managed for long-term production of saw timber can be thinned for biomass, and c) natural forests being restored to pine woodlands (the type of forest covering much of the coastal plain when Europeans arrived) where large volumes of laurel oak and other hardwoods are removed. In addition to the biomass growing in forests, large numbers of trees are cut due to urban expansion, fallen trees following storms are picked up and either burned or dumped in landfills, and tree branches are periodically trimmed from trees along electrical transmission lines.

2. *Can biomass be obtained at a competitive price in the region?*

Yes. Forests of the southeastern United States, including north Florida, are producing pulpwood dimension wood in volumes well in excess of consumption by the paper industry. This is due to the rapid growth of forests in our moist, warm climate and to the shift of the paper industry offshore. As a result, pulpwood prices are likely to remain relatively low for the foreseeable future (currently around $10 per ton at the mill). Vertically integrated paper producers will continue to use pulpwood from their own land and from other forest owners who have no other market. Some non-industrial landowners will shift to long-term rotation production of saw timber (worth over $40 per ton), while continuing to produce thinnings suitable for either pulpwood or fuel. Other forest owners, particularly those with plantations, will become potential sources of fuel wood. They may shift to hardwoods with higher Btu values in response to a fuel wood market. At $54 per ton for coal and $20 per ton for wood, the cost per million Btu is

[1] Josh Dickinson is a member of the Board of the U.S Forest Stewardship Council. He is also Executive Director of the Forest Management Trust, a nonprofit organization he founded in 1992. In addition to work in Madagascar, Bolivia and Mexico, the Trust has led the FSC regional standard process in the Southeast; has served as a catalyst, together with the Forest Stewards Guild, in establishing the SE Sustainable Forests Network with the goal of promoting sustainable forest use in the region; and sponsored the first certification of a forest in Florida.

equal ($2.10 per million Btu) according to figures provided by Tom Cunilio. The $20 figure for wood is double the current pulpwood price and therefore should be attractive to the forest owner. Long-term contracts may yield lower coal prices while imposition of a carbon tax could significantly increase the cost of coal.

3. *Can forests of the region be harvested in an environmentally sustainable manner?*

Yes. Wood is essentially a form of solar energy produced through photosynthesis by plants and is therefore renewable. Trees planted on land previously in pasture, corn or tobacco are just another crop, but one requiring far less cultivation, agricultural chemicals and labor. Therefore erosion and runoff of chemicals from plantations will be less than from cropland. Harvest as biomass fuel (or pulpwood) may occur in two cuts, a thinning and a final cut at about 25 years, followed by replanting. The common practice of the timber industry of windrowing and burning slash (tree limbs and sometimes roots) should be avoided because of the loss of nutrients that are concentrated in the leaves and small branches. Slash should be spread out to rot and enrich the soil.

The situation with natural forests is more complex. Management of a natural forest has the dual objectives of producing wood and other products while also maintaining the integrity of the forest ecosystem. This requires a variety of management decisions and actions such as cutting no more than the annual growth increment of the trees care in use of machinery so as to not destroy ground cover, controlled burning, protection of endangered species, etc. Fortunately, safeguards are available that can be required by the wood purchaser to assure the public that management is sustainable. The Forest Stewardship Council (www.fscus.org) has developed a set of regional standards specifically for forests of the southeastern United States, which if followed, will assure that forest management is ecologically, socially and economically sustainable. The standards apply to both natural and planted forests. A GRU requirement that forest biomass fuel be from FSC certified properties would assure the public that environmental concerns are effectively met.

4. *Are the advantages of using biomass compared to burning coal/petcoke?*

Yes. Biomass is by definition "carbon neutral", involving no new carbon to be mined from deposits millions of years old and released to the atmosphere. Wood does not contain such dangerous pollutants as mercury and vanadium. Using biomass will not trigger a carbon tax or other disincentive to the use of fuels that are a source of carbon dioxide and health-threatening pollutants. On the positive side, an assured market for biomass would economically benefit forest owners (who are also tax payers) in the counties surrounding GRU. In addition to the cash entering the local economy and paid in sales taxes, the addition of a lucrative market for small dimension timber would better enable forest owners to manage their forests for high-value saw timber because they can count on intermediate income from biomass sales. This increased value of forest holdings decreases the temptation to sell off land for development.

Caveat**:** New generation capacity based on biomass, in combination with existing generation capacity, should be sufficient to meet GRU's projected needs for decades to come if combined with a) aggressive demand side management, b) meaningful conservation incentives to consumers, and c) alertness to new technologies such as lower cost photovoltaics.

Chapter 8, Appendix 2: Letter to GRU from Josh Dickinson

Edward J. Regan

Strategic Planning

GRU

Dear Mr. Regan,

If we had the capacity to burn biomass for energy generation the current storm debris problem would be a bonanza!

Why should GRU commit to studies that could lead to significant use of biomass in its future power generation plans? With a few strict caveats, biomass fuel offers several advantages to our community and to GRU. These include:

Each MW generated using biomass represents one less MW generated with fossil fuels, effectively reducing new CO_2 entering the atmosphere, as well as reducing emission of other pollutants including NO_x, mercury, SO_x, heavy metals, and complex fine particulates. Health and environmental benefits are obvious.

A concomitant decrease in the large volume of highly acidic calcium sulfate used in scrubbing that would have to be stored near wetlands on and off site.

Use of biomass offers an economic use for waste wood, which would otherwise represent a cost to mills generating the waste.

Use of biomass from managed forests would contribute to the North Florida economy, benefiting forestland owners. A robust fuel wood economy would reduce pressure on landowners to sell out to developers.

A number of studies will be required. Topics include:

Determination of the potential sources of waste wood; the volume available on an annual basis, factors affecting future supply reliability, processing required, and costs of purchase, shipping and processing for use as a fuel.

Factors affecting potential fuel wood supply within the GRU woodshed; volumes potentially available as fuel wood associated with different management strategies including both plantations and natural forest management, competing uses of wood, and costs for purchase, shipping and processing.

A thorough assessment of potential environmental impacts of different levels of biomass use and a definition of strategies to mitigate adverse impacts.

Identification and assessment of technologies for processing and utilizing waste and forest biomass - these may include chipping or pelletizing of pine and hardwood fuel, and gasification versus CFB technologies for power generation. In New England wood pellets are competitive with fuel oil for home heating.

Assessment of the potential of solid waste as fuel a la Hawaii - a subsidized technology that drastically reduces landfill growth.

Discussion:

With foreign competition, consolidation and movement offshore by the paper industry, the production of pine as a source of pulpwood has outstripped the current and projected market. The result is a depressed market with prices running $5 to $11 per ton. Some of the major paper producers such as Georgia Pacific have sold off their forest holdings. Much of this forestland has been picked up by speculative enterprises such as Plum Creek (a REIT), John Hancock and Wachovia (TIMOs). Non-industrial private owners still hold most of the forestland in the region, the bulk in parcels of 100 to 500 acres. Private owners and some corporate owners are likely to shift to longer-term forest management for saw timber ($40+ per ton). However, in addition to remaining short-rotation plantations, a large volume of thinnings will be continually available as a potential fuel wood supply from forests managed for saw timber. Partial restoration of the historic extent of longleaf pine woodlands can yield large volumes of culled hardwoods (largely laurel oak).

A significant concern is the environmental impact of large volume use of wood biomass for power generation. The clear cutting of natural forests and conversion of natural forests to fuel wood plantations is matter of great concern to foresters, ecologists and environmentalists. The target volume of biomass that GRU should consider is that supply of wood that can sustained over the long term from forests that are managed according to ecologically economically sound principles of forest management. By requiring that all wood supplied for biomass power generation be certified by the *Forest Stewardship Council* as coming from well-managed forests, GRU can assure the public that forests are being managed according to principles accepted by major environmental groups around the world (www.fscus.org).

Several knowledgeable people are available to discuss wood biomass sourcing and utilization with GRU. Several have already had discussions with GRU. These include:

Wayne Smith, recently retired Director of the UF School of Forest Resources and Conservation, a world-recognized expert on biomass utilization.

Jack Putz, forest ecologist with long experience and interest in longleaf pine ecosystem restoration.

Jib Davidson, Columbia Timber Company, manager of Public Works Balu forest (management certified by FSC) and expert on timber supply in north Florida.

Richard Schroeder, officer with a Florida-based biomass company.

Josh Dickinson, advocate of sustainable forest management, member of the FSC national board and EPAC member.

I hope this is a useful contribution to the ongoing discussion of how to meet Gainesville's future energy needs.

With best regards,

Josh Dickinson

Chapter 8, Appendix 3:
Screening Biomass and New Generation Options

GRU evaluated alternative fuel-generator combinations in 2003 in two ways: (1) They estimated the cost of fuel, capital cost of each of several combinations, and the dollar costs of societal and environmental impacts, expressing the result as a cost per kWh; and (2) they compared alternative fuel and generator combinations in a screening exercise based on 8 characteristics.

Biomass currently plays only a minor role (about 7%) in GRU's plan for meeting future electric energy needs, and at present there is no firm commitment to biomass use[2].

EPAC found that biomass offers many benefits, and merits consideration as a very attractive alternative energy source. In this appendix we list questions about the initial biomass screening, and conclude that biomass fuels warrant a higher priority that that assigned by GRU. The community will miss numerous financial, economic, environmental, technical, and strategic advantages unless it is re-examined.

GRU reported the conclusions of its screening exercise and other conclusions regarding biomass fuel use to the Gainesville City Commission in a December 2003 report[3]. This report included few details of the screening methodology or the selection of screening criteria, and consequently the significance of the assigned ratings is hard to determine.

Table I-5 below is a summary of the reported screening analyses. Seven "generating alternatives" consisting of various combinations of fuel and generator were compared. Each was assigned a rank of 0 (worst) to 2 (best) for each of 8 screening criteria. The final ranking was based on the total score earned by each ranked alternative. Figure I-1 and 1-3 below[4] show the cost of each option estimated by GRU. The origin of the cost data in this plot is not clear[5].

Externalities

Evaluations of alternative electricity generating options often take into consideration social costs, by assigning a dollar figure to different kinds of impacts that affect society but are not a matter of the direct cost of fuel or the required generator.

[2] Details of the final design will determine whether biomass is co-fired with other fuels in the proposed new circulating fluidized bed generator.

[3] "ALTERNATIVES FOR MEETING GAINESVILLE'S ELECTRICAL REQUIREMENTS THROUGH 2022: Base Studies And Preliminary Findings" Gainesville Regional Utilities, December 2003. This document is also referred to in the text as the IRP, which stands for Integrated Resource Planning. Biomass is considered chiefly in Sections I and H of this report.

[4] Reproduced below

[5] Table L-2 in the IRP document provides some operational and cost estimates for GRU's existing fleet of generators and for several commercially available generators alternative build options under consideration .The biomass costs shown in Figure I-3 do not appear to be derived from Table L-2. Information from GRU indicates that the plotted costs reflect the assumption that the cost of biomass is identical to that of natural gas. Biomass fuel costs plotted in Figure I-3 are high compared to the $0.91 per million Btu listed in Table L-2 of the document.

TABLE I-5

SCREENING SUMMARY
FOR DISCUSSION

Rating Scale
0 = Worst
1 = Good
2 = Best

EVALUATION FACTORS	Leased Capacity	Energy Conservation	Photovoltaic	Gas-CT	Gas-CC	Biomass*	Coal-S. FL	Coal-Deerhaven**	Nuclear
Long-Term Capacity	2	0	0	1	2	0	2	2	2
Economic $/MWh	1	2	0	0	1	1	2	2	1
Econ.+Societal $/MWh	1	2	0	1	1	2	1	1	1
Fuel Price Volatility	0	2	2	0	0	1	2	2	2
Fuel Trans. Security	0	2	2	0	0	2	2	2	1
Fuel Storage Ability	0	2	0	0	0	2	2	2	2
Grid Independent	0	2	2	2	2	2	0	2	0
Reduce Local Emissions	2	2	2	0	1	1	1	2	1
Local Econ. Benefits	0	2	2	2	2	2	0	2	0
Number of Ones:	2	0	0	2	3	3	2	1	4
Number of Twos:	2	8	5	2	3	5	5	8	3

*Fuel supply price very uncertain and assumes zero societal cost for CO_2
** Includes Deerhaven 2 retrofit

GRU's evaluation considered societal costs of some air emissions based on a compilation of costs used in other states[6]. Pollution effects are comparatively easily assigned dollar costs, but other social value externalities are difficult to cost. For example, adverse respiratory and cardiac health effects, and the environmental damage of coal mining (acid mine drainage, erosion from mountain-top removal, water pollution, land reclamation costs) are typical adverse effects that are hard to translate into monetary terms.

EPAC found monetary values for benefits of biomass-fired generators in a 1999 report[7], to range from 4.7 to 24.8 cents per kWh. These derive from the high cost of landfill disposal of wood, and the pollution costs of particulate, methane, carbon monoxide and organic emissions from controlled forest burns, and waste wood burning. GRU did not include these dollar costs during its screening 2003 exercise[8]. Benefits such as local employment opportunities, economic development, and energy diversity and security provided by biomass-based energy production were also ignored.

[6] FY2001 Sustainability Report September 2001. Available via a link at: http://www.nrel.gov/sustainable_nrel/fy2001.html
[7] NREL, 1999: NREL/SR-570-27541 "The Value of the Benefits of U.S. Biomass Power" 1999
[8] In a report to the City Commission on December 13, GRU noted that using waste wood as fuel reduces pollutant emissions that would occur if it were burned, but apparently this advantage was not considered in the earlier screening process.

Criteria used in Comparisons - Undervaluing Biomass Fuel

Table I-5 shows the scores assigned by GRU to each generation option considered.

The highest overall score was earned by conservation, which ranked in the highest category on every criterion except one: the requirement that the option be capable of satisfying long-term generation needs, that is, supply the equivalent of 220 MW of capacity. Inclusion of this criterion in the screening suggests that GRU had decided in advance that acceptable new generation capacity options should be confined to large generators, presumably to realize economies of scale. This requirement is not explicitly discussed in the document[9].

Biomass and conservation options can be combined to reduce the need for a large generator, at least in the short term. Screening options for their ability to supply a full 220-MW generator is questionable. A more appropriate approach might have consisted of examining the fuel options and generator options first, and screening them for advantages, and then deciding whether they could be combined in useful ways—including incremental addition of generating capacity—and then exploring the resulting costs.

Biomass appears to be undervalued in this screening process, at least as far as can be determined from the data supplied in Chapter I of GRU's report. An examination of the factors GRU used suggests the following score changes on some of the criteria:

- **Long-Term Capacity**. This criterion should be eliminated, as it biases all results to favor a large coal-fired power plant.
- **Economic $MWh**. These scores are based on Figure I-1, and the low score for biomass reflects the erroneous assumption that wood costs as much as natural gas cost in 2003. More realistic fuel costs identical to that of HS coal would earn biomass a score of 2 on this criterion.
- **Economic and Societal Value**. These scores are based on Figure I-3. Biomass scores a 2, and Coal at Deerhaven a 1, a conclusion that ignores some serious societal costs associated with coal and some major benefits of biomass. An appropriate adjustment would lower coal at Deerhaven from 1 to 0.
- **Fuel Price Volatility**.; Biomass is assigned a 0 on this criterion, but we know of no logical or factual basis for this. According to Black & Veatch[10] biomass fuel costs are lower than those of coal, and probably will not be subject to significant price volatility, so a rank of 2 on this criterion is justified.
- **Reduce Local Emissions**. Biomass is assigned a score of 1 on this criterion and coal at Deerhaven is assigned a score of 2. A higher score for biomass can be justified because it contains no sulfur, has extremely low trace metal contents, leaves a small residue of ash (which is not toxic and can be sold as a fertilizer), and it produces fewer

[9] Chapter N of the IRP contains an analysis of the timing of increases in the needs for new generation, under the assumption that a large jointly-owned solid fuel generator would be constructed at Deerhaven, and GRU could acquire capacity from it in incremental steps during the interval 2010 to 2019, shown in Table N-2 and also in A-1. This option of the large jointly owned generator has been abandoned, and the peak load forecast has been revised downward since these analyses were conducted.

[10] Black & Veatch Corp. "Supplementary study of Generating Alternatives for Deerhaven Generating Station" B&V Project No. 137196, March 2004.

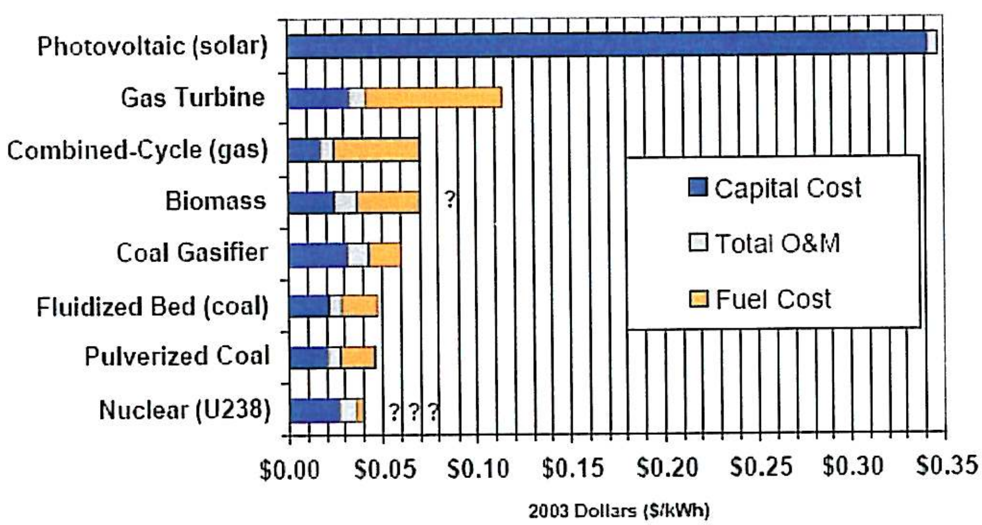
particulate emissions. Very significant advantages derive from the fact that using it to fuel a generator avoids open burning of waste wood, which avoids its great potential for smoke production and other local pollutants and does not require expensive, energy-consuming SO_2 scrubbing. Biomass deserves the highest rank on pollution emissions, and a much higher one than coal at Deerhaven, which produces air pollutants, toxic ashes, and toxic scrubber sludge. Biomass should be assigned at least 2, and coal at Deerhaven dropped to 1 or zero.

- **Local Economic Benefits**. High scores were assigned to coal at Deerhaven and other fossil fuel options, but the justification for these high scores is obscure[11]. Purchasing these fuels exports large amounts of money to other states. Using biomass would reduce the export of money, create sustainable local jobs, increase local sales taxes, and increase forest land values. This criterion can be rescored to give biomass a score of 2 and reduce coal at Deerhaven to 0.

GRU did not include a criterion related to greenhouse gas emissions. These emissions will have a large impact on the financial viability of coal at Deerhaven, and adding a screening criterion that scores options on the basis of their fossil CO2 emission could be justified. The score for biomass on such a criterion would be 2, while that for coal at Deerhaven would be 0.

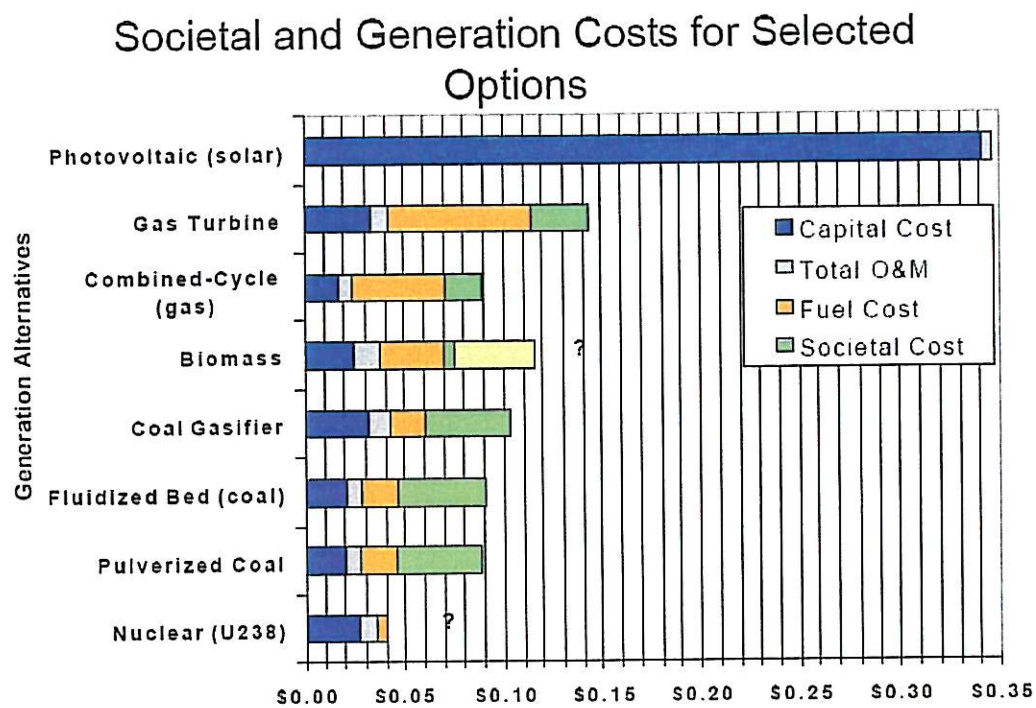
Rescoring the criteria in this manner yields 7 twos for biomass (total of 14) and 4 for coal at Deerhaven (8). Adding a greenhouse gas criterion changes this to 8 twos for biomass (16) and 4 for coal at Deerhaven (8).

FIGURE I-1
Generation Cost For Selected Options



[11] It could be due to the fact that GRU compared generators, not fuels independently of generators. Thus, coal and Deerhaven 2 retrofit are combined into a single option. Any local economic benefits of retrofitting Deerhaven Unit 2 would make coal score high. Had coal been compared directly with biomass, the major advantage associated with biomass would have been obvious.

FIGURE I-3



Chapter 8, Appendix 4, EPAC Biomass System Model

EPAC's biomass model was developed to illustrate the advantages and disadvantages that biomass might offer the community. It is not based on any specific generator design and it is not offered as a realistic option. Its sole purpose is to provide a tool for illuminating important features of GRU's CFB proposal and comparing those to renewable fuels..

1. **Methodology** EPAC used GRU's simulated operation of an "all gas" system as the basis for this biomass exercise[12]. The scenario for the "all gas" system assumed that GRU acquires a 243-MW (net) combined cycle, natural gas-fired generator that begins operation in 2011. In all other respects, electric energy demand in the local area, the other generators in the GRU fleet, and the retirement schedule are identical to the "solid fuel" system whose operatioacquisition of additional units. These are a 77.5-MW combustion turbine added in 2022 and the rental of a 20-MW combustion turbine in 2023. The added units supply less than 1% of the electric energy used in system.

[12] Discussed in Chapter 5.

GRU's simulation program produced a summary of the amount of energy generated by each unit in operation, the quantity of fuel used, the heat rate, and a number of other features for each year in the interval 2004-2023. Under the "all gas" scenario, about half the energy consumed in the local area was generated by the retrofitted Deerhaven Unit #2 and most of the remaining energy was generated by the new 243 MW combined cycle unit[13]. For example, this combined cycle unit produced over 845 GWh of energy in 2011, under the GRU simulation. This contribution increased steadily throughout the interval simulated until 2023, when this unit was assumed to provide 1,203 GWh to the local area.

EPAC's model eliminated the new 243-MW combined cycle unit and substituted a smaller biomass base unit that contributed a total of 796 GWh per year. EPAC assumed that the existing Kelly combined cycle unit supplied whatever energy the biomass unit cannot supply is provided. This extra contribution ranged from approximately 61 GWh in 2011 to about 414 GWh in 2023.

In the original "all gas" simulation, the Kelly combined cycle unit is seldom used; its capacity factor ranging from about 6% in 2011 to 13% in 2023. EPAC's changes increased this to 16% in 2011 up to 52% in 2023. The Kelly unit was assumed to operate at its maximum efficiency (8,200 Btu / kWh).

2. **DSM** The fuel cost of the EPAC biomass system is heavily dependent on the amount and cost of natural gas consumed by the Kelly combined cycle unit. EPAC's model calculated that this cost ranged from $8 million dollars in 2011, up to a peak of nearly $51 million in 2022. Natural gas costs ranged from $6.65 per million Btu in 2011 to $11.73 per million Btu in 2023. The use of the Kelly plant could be significantly reduced by demand-side management techniques that reduce peak usage. For example, load management, and rate structures that promote the use of thermal energy storage or other machinery at off-peak times could help to reduce peak demand. Many kinds of DSM programs could achieve a major reduction in the amount of consumed energy.

   We have assumed DSM programs will be adopted by GRU and can reduce the rate of increase of total electric energy consumption. How much would such programs reduce the need to buy costly natural gas to fuel the Kelly combined cycle plant? The answer depends entirely on the specific mix of programs and their individual impacts, and could not be estimated from the data available to EPAC. We simply assumed that DSM programs initiated in 2007 reduced the total electric energy consumed in 2023 by 9.2% from 3,072 GWh to 2,811GWh. The corresponding peak demand reductions could be about 50 MW. The model used here assumes that the biomass unit is a base unit that operates all the time, but that the Kelly combined cycle unit can be dispatched in a way similar to that of the hypothetical new combined cycle unit which it replaced in our model.

3. **Features of a hypothetical biomass unit** EPAC assumed that the hypothetical biomass unit has a net generating capacity of 100 MW and a heat rate of 11,000 Btu per

[13] In 2011, Deerhaven Unity #2 produced 1424 GWh, which represented about 52% of the total; while the added combined cycle unit produced 845 GWh, which was 34% of the total, which together contributed about 92% of the total. In 2023 the figures are 50% for Deerhaven Unit #2 and 44% for the combined cycle plant, for a total of 94%.

kWh. It is assumed to supply 796 GWh of electricity annually and its fuel is assumed to cost exactly the same as the high sulfur coal used in Deerhaven Unit #2 ($2.08 per million Btu in 2011, rising to $2.78 in 2023).