agreement with local groups, ending a long battle over its Iatan 2 power plant project. Under KCP&L's agreement, the company will invest in renewable energy and energy efficiency, and reduce emissions of various pollutants, among other environmentally linked provisions. The cost to KCP&L of complying with the agreement is unknown but may be in the hundreds of millions.

Acting Locally

Not satisfied with waiting for a federal response, several states have taken action, and private industry is beginning to support market-based solutions. The Regional Greenhouse Gas Initiative (RGGI), comprising eight northeastern states, establishes a cap-and-trade system to stabilize CO_2 emissions by 2009 and reduce them 10% by 2019. California enacted and signed into law AB32, the "California Global Warming Solutions Act of 2006," which requires the reduction of greenhouse gases to 1990 levels by 2020. It has also passed SB 1368, the "Greenhouse Gases Emission Performance Standard," which prevents procurement of power from coal-fired plants, even if located outside of the state.

Twenty states and the District of Columbia have adopted renewable energy standards covering roughly 40% of the electricity used in the U.S. Washington, Oregon, New Hampshire, and Massachusetts have passed laws limiting CO_2 emissions, or requiring plant owners to purchase offsets. The Western Governors' Global Warming Initiative—a memorandum of understanding Arizona, New Mexico, Oregon, Washington and California signed in February of 2007--sets the end of 2007 for the development of details for targeted reduction, and the end of 2008 for the development of a cap and trade program.

While representing a step in the direction toward addressing global warming, most experts agree that, as local efforts, these initiatives will have a limited impact on an issue that's global in nature. Furthermore, they could impose competitive disparities, especially for entities operating in multiple markets. This would likely be more true for investor-owned utilities, as public power generally operates within set municipal boundaries or is confined to serving customers in a single state.

Lingering Uncertainties

In response to growing public concern about climate change, the public power market is bracing for possible moves by the U.S. Congress to address greenhouse gas emissions. Given the range of options and costs survey respondents are currently modeling, CO_2 reduction will likely represent a significant technological and financial challenge to the public power industry.

Standard & Poor's has begun to assess public power utilities' exposure to the potential new regulation in light of their operational and financial profiles, and we are focusing on management's efforts to evaluate the range of remedial options at its disposal. However, we have yet to factor into ratings the costs of addressing potential regulation given the uncertainties.

Click on this link to see other articles in "Special Report: The Credit Impact Of Climate Change."

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November 3, 2006

Washington State's Wind Initiative Presents A Mixed Credit Picture

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SAN FRANCISCO (Standard & Poor's) Nov. 3, 2006--Voters in Washington State's Nov. 7 election face an initiative that would impact most of the state's public power utilities, but may have only a marginal effect on credit quality.

On Tuesday, Washington voters will decide whether to approve Initiative-937, which would apply to any utility with more than 25,000 customers, including city electric departments, public utility districts and investor-owned utilities. According to the U.S. Energy Information Agency, Washington has 18 electric utilities with a combined 2.6 million customers that meet this definition.

Initiative-937 would mandate utilities to have 3% of their power portfolio in wind, or other renewable resources, by 2012, rising to 15% by 2020. Hydroelectric generation is not considered renewable in the language of the initiative due to issues with fish and wildlife. The measure would require public power utilities to either enter into contracts for wind resources or build their own generation assets to meet threshold targets set in the initiative. However, a key provision allows that once the cost differential of providing renewable resources can be demonstrated to add more than 4% to costs over and above the current cost structure, a utility would not be required to pursue more renewables for its portfolio.

From a credit standpoint, mandates are generally not favorable for credit quality because they represent the diminution of self-control of operational or financial policies and targets that may suit some individual utilities more than others. If the measure passes, Standard & Poor's Ratings Services would evaluate the effect on a case-by-case basis.

"But overall, the impact is expected to be marginal due to the extended timeframe for implementation, the incremental cost cap that reduces potential exposure, and the expectation that affected utilities will react to changing conditions and preserve their financial condition through rate increases or overhead adjustments," said Standard & Poor's credit analyst Ian Carroll.

The net effect for some public utilities, particularly those with sufficient resources or that are long on power, would be to displace some current resources to make room for the additional renewable energy capacity. Ultimately, this could add to cost structures and increased customer rates.

Several utilities are already spearheading renewables independently of the initiative, and wind projects are the fastest growing generation type in the region, accounting for 59% of new generation.

For example, the White Creek Wind Project in south central Washington is expected to provide 200 MW to project participants, consisting of four utilities, including Cowlitz County Public Utility District (rated 'A-'), and Klickitat County PUD when it becomes operational, initially projected to be 2008. Energy Northwest Nine Canyon Wind project, which delivers power to 10 public utilities, is embarking on its third phase, adding 32 MW by 2008 to the 64 MW from existing phases. In addition, more than half of the new energy resources under development or construction are wind projects.

The Northwest public power region has been experiencing strong load growth and is characterized by the predominance of low-cost hydropower from the Federal Power System, and from other projects along the Columbia River. While this has resulted in the northwest being one of the lowest cost regions in the country, the concentration in hydropower also results in vulnerability due to fluctuating hydrological conditions, as was experienced in the 2001 power crisis, and other drought years since then. And, its strong load growth poses a challenge, not only in terms of I-937, but also for Bonneville-reliant utilities that will likely be forced to find alternate forms of power for load growth when contracts change in 2011, or else fall into a higher cost structure.

Standard & Poor's currently rates 33 Northwest public power utilities and projects, with 10 in the 'AA' category, 20 in the 'A' category, and three in the 'BBB' category. In the overwhelming majority of ratings the outlook is stable, with only 6% negative. These current ratings represent an improvement since 2003, when 18% of the outlooks were negative. Also in 2003, there were only eight 'AA' category ratings in the Northwest, with 19 in the 'A' category and six in the 'BBB' category.

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October 12, 2005

Will Alternative Energy Finally Achieve Liftoff In The U.S.?

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Will Alternative Energy Finally Achieve Liftoff In The U.S.?

(Editor's note: As a part of our special series on energy, we've included this assessment of the U.S. alternative energy sector from the viewpoint of stock investors. For an assessment of this sector from a credit perspective, please see "Is Alternative Energy A Viable Alternative In The U.S.?" published Oct. 11, 2005, on RatingsDirect.)

By Tina Vital, Equity Analyst

It is a question that arises during every energy crisis: When will alternative energy technologies--and stocks--catch fire? The answer this time seems to be: expect a slow burn more than an explosion.

Certainly, recent increases in energy prices imply that renewable energy should be gaining momentum. Since the end of 2003, West Texas Intermediate oil spot prices have risen by $30 per barrel to above $60, primarily reflecting an inability to boost global oil production fast enough to meet demand. Based on data from independent economic forecasting firm Global Insight, we expect that they will remain above $45 through 2008.

We think the situation is more severe for U.S. natural gas. Supplies were tight even before Hurricanes Katrina and Rita hit the Gulf of Mexico. In their aftermath, cumulative natural gas losses from the storms could total 500 billion cubic feet (bcf) by year end, and gas supplies are expected to fall 300 bcf short of domestic needs this winter. Already, U.S. natural gas prices have climbed 141% this year, to more than $14 per million Btu, and Global Insight projects that homeowners will be paying $14 to $16 per million Btu this winter--up 40% from last year. Those heating customers dependent on Louisiana natural gas could see a 70% increase in their winter natural gas bills.

It's thus no surprise that Katrina and Rita, which initially shut in 100% of U.S. Gulf coast oil, 78% of Gulf gas, and 30% of U.S. refining capacity, have heightened interest both in energy conservation and alternatives to fossil fuels, including nuclear and renewable resources (such as hydroelectric, biomass, geothermal, solar, and wind).

Energy Act Of 2005

Coincidentally, just before the hurricanes arrived, President Bush signed the Energy Policy Act of 2005, the first such legislation in 13 years. It streamlined the federal permitting process and provided tax incentives for new projects--40% of which focus on efficiency and renewable energy. While we project these incentives will provide a short-term boost to certain renewable energy projects, particularly wind, over the next few years, we estimate they are not long lasting enough to improve the long-term economics of these renewable energy projects--or even boost oil and gas production beyond the levels stimulated by high market prices. A July study by the Energy Information Administration (EIA)--entitled "Impacts of Modeled Provisions of H.R. 6 EH: The Energy Policy Act of 2005"--predicts essentially no long-term (2010-2025) increase in renewable energy from the new legislation.

Greenhouse Gases And Climate Change

Concerns over climate change are also raising the profile of renewable energy, since it adds little if at all to greenhouse gases. Carbon dioxide emissions related to fossil fuel consumption represented approximately 84% of total U.S. greenhouse emissions in 2002, and the EIA projects energy-related carbon dioxide emissions will increase by 19% from 2002 to 2012 (or 1.7% annually), and by 40% from 2002 to 2025 (1.7%). However, the ratio of total U.S. greenhouse emissions to domestic economic output (called intensity) is projected to decline by 14% from 2002 to 2012 (minus 1.5% annually), and by almost 30% from 2002 to 2025 (minus 1.7%), reflecting the Bush Administration's 2002 Climate Change Initiative.

A similar EIA study predicts that world carbon dioxide emissions from the consumption of fossil fuels will increase 59% from 2002 to 2025 (or 2.0% annually) reflecting rapid increases by emerging economies (3.2%) and incremental usage increases in coal (which is highly carbon intensive), but that worldwide carbon dioxide intensity will decline by 33% from 2002 to 2025 (minus 2.0%) due to improved efficiency of energy use and a switch to less carbon-intensive fuels (such as natural gas). The Kyoto Climate Change Protocol, from which the U.S. withdrew in 2001, requires participating "Annex I" countries to collectively reduce their greenhouse gas emissions to about 5% below the 1990 level between 2008 and 2012. As of May 27, 2005, about 148 countries have ratified, accepted, acceded, or approved the Kyoto Protocol, which became a legally binding treaty on Feb. 16, 2005. As much as any other factor, Kyoto could influence the implementation of technology to raise energy efficiency, as well as which sources of energy grow the fastest in the near to medium term.

Alternative Power

Alternative sources of power to fossil fuels include nuclear and renewable sources (such as hydroelectric, biomass, geothermal, solar, and wind). However, since most renewable energy is not expected to be cost competitive with coal (the baseline fossil fuel, due to its availability and low relative cost) anytime soon, Standard & Poor's Equity Research projects only moderate growth for these renewable sources of power. As shown in the table below, only geothermal, wind, and biomass appear to offer competitive economics to coal, which operates at levelized costs (a comparable basis of projected capital and operating costs discounted back to the present year) of about 4-5 cents per kilowatt-hour. Still, some vendors believe that improved safety and new technology and economies of scale will reduce the costs of nuclear plants going forward.

Levelized Costs Of Conventional And Renewable Generation In The U.S.

Generation source	Reference case	PTC extension case
(2003 cents per kilowatt-hour)		
Combined cycle	4.70	4.50
Combustion turbine	7.00	6.80
Coal	4.30	4.30
Geothermal	4.40	3.60
Nuclear	6.00	N.A.
Photovoltaic	21.00	21.00
Solar thermal	12.60	12.60
Open-loop biomass	5.10	4.50
Wind	4.80	2.90

Source: U.S. Energy Information Administration (EIA), 2005. N.A.--Not available. PTC--Production tax credit.

According to EIA predictions, hydroelectricity and other grid-connected renewable energy sources should maintain an 8% share of worldwide energy use between now and 2025. Separately, we estimate that over the same time frame, the use of solar photovoltaic, wind, biomass, solar thermal, geothermal, and biofuels--which, combined, account for 1.5% of worldwide energy production--will grow 8% annually, compared with 2% to 3% for conventional energy sources. Meanwhile, the EIA predicts worldwide use of nuclear-generated power will grow less than 1% annually, with the U.S. total only inching up thanks to a dearth of new nuclear plant construction. By 2025, nuclear power consumption in the U.S. is projected to be only about 7% higher than consumption of power from other renewable sources--primarily wind and geothermal power.

Alternative Fuels

With oil prices soaring, alternative sources of fuel may replace the use of conventional gasoline and diesel, to some extent, in vehicles and industrial motors. While large-scale production of biofuels (such as corn-based ethanol) may not be practical due to the significant land usage required, they could find support as a fuel additive due to global efforts to reduce the carbon intensity of fuels. Also, the low relative resource cost of coal and stranded natural gas worldwide has improved the outlook for the conversion of coal to liquids and gases, and gas to liquids--at least over the short-to-medium term. Major oil companies involved in the conversion of gases into synthetic liquid fuels include Rentech Inc., Sasol Ltd., Chevron Corp., Exxon Mobil Corp., BP plc, Royal Dutch Shell plc, and Syntroleum Corp.

Longer term, hydrogen may become a viable alternative fuel, since it offers the potential for efficient, emission-free vehicles, and goes hand-in-hand with fuel cells, a technology that generates electricity with only heat and water as by-products. However, in our view, fuel cell systems must undergo substantial cost reductions before they can compete with conventional engines, and hydrogen as a fuel source must overcome challenges of safety and a relatively high cost of distribution and production.

Oil Companies Invest In Renewables

Among the integrated oil companies, supermajors such as BP, Chevron, Royal Dutch Shell, and Total S.A. are taking a long-term view and building renewable energy businesses. Most are focused on solar and wind, but Royal Dutch Shell also has interests in biofuels, geothermal, and hydrogen, Chevron in geothermal, and Total in biomass and hydropower. At the same time, some of these energy firms (such as Royal Dutch Shell) have written down certain of their investments in renewable energy, whose returns have lagged those from conventional fossil fuels. The challenge for these companies is how to turn energy and environmental problems into profitable business opportunities given current policy incentives.

Therefore, while certain renewable energy technologies have found a home in the marketplace, others are just beginning to emerge and depend on a supportive policy environment and improved technology to realize their potential. That leaves the future of the renewables business reliant on government support.

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California Public Power Utilities Wrestle With Competing Energy Demands And Global Warming Strategies

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California Public Power Utilities Wrestle With Competing Energy Demands And Global Warming Strategies

Utilities across the U.S. are facing long-term demands from carbon emissions, resource adequacy, price volatility, and pressure on retail rates. California's public power utilities have a heightened focus on these matters for several reasons, including:

- Growing load demand and a need to import large amounts of power from other states;
- Reliance on natural gas as a fuel source in new generation, and this commodity's inherent price volatility; and
- California's position as a leader among states in addressing concerns about "global warming" and carbon emissions through legislative and regulatory mandates, that will pressure the state's already high retail rates.

For more than a decade, the California electric industry has experienced a series of challenges, such as its unsuccessful attempt at deregulation, extreme power market price volatility, drought and, more recently, wildfires. California's public power utilities have nevertheless maintained strong credit quality, due to common characteristics such as good financial performance, management planning, and strong and stable customer bases. Currently, all of Standard & Poor's Ratings Services ratings in this sector and state are investment grade, ranging from 'BBB+' to 'AA+' (see table 1 and chart 1). We currently rate 28 of the state's public power credits. Of these, five are in the 'AA' category, 17 in the 'A' category, and six in the 'BBB' category. On balance, the rating distribution of California public power utilities is marginally better than U.S. public power utilities as a whole.

From a rating action standpoint, the past year has been relatively calm, with no ratings changing, and three rating outlooks improving from negative to stable (Lodi, and two transactions of Northern California Power Agency that are linked to Lodi's rating).

Although California public power utilities will continue to face challenges that could affect credit quality, we expect their rating stability to continue. Rating upgrades may be limited due to cost pressures associated with drought, natural gas supply, and demands on the utilities to address renewable energy targets and other environmental regulations unique to the state.

Table 1

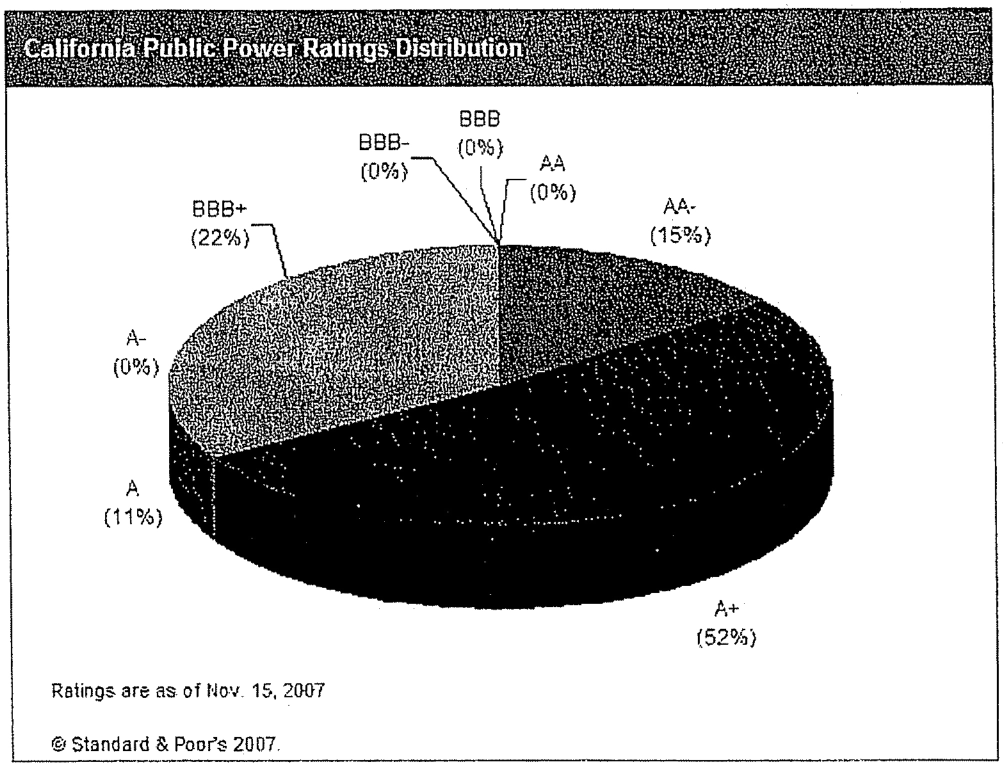
Calif Power Plants Online Since 2005

Project or Plant/Utility Name	County	Fuel	MW	Online
Donald Von Raesfeld Power Plant - Silicon Valley Power	Santa Clara	Oil/Gas	147	March 24, 2005
Pastoria Phase 1 & 2 - Calpine	Kern	Oil/Gas	750	Phase 1: May 4, 2005, Phase 2: Sept. 9, 2005
Metcalf - Calpine	Santa Clara	Oil/Gas	600	May 27, 2005
Kings River Conservation Dist Peaker	Fresno	Hydro	97	Sept. 19, 2005
Magnolia - Southern Calif Public Power Auth	Los Angeles	Oil/Gas	328	Sept. 22,2005
Malburg - City of Vernon	Los Angeles	Oil/Gas	134	Oct. 17, 2005
Mountainview - Southern Calif Edison	San Bernardino	Oil/Gas	1,056	Unit 3: Dec. 9, 2005; Unit 4: Jan. 19, 2006
SMUD Combined Cycle Phase 1	Sacramento	Oil/Gas	500	Feb. 24, 2006
Walnut Energy Ctr - Turlock Irrigation Dist	Stanislaus	Oil/Gas	250	Feb. 28, 2006
Palomar Escondido - Sempra	San Diego	Oil/Gas	546	April 1, 2006

Table 1

Calif Power Plants Online Since 2005(cont.)				
Riverside Energy Resource Ctr - City of Riverside	Riverside	Oil/Gas	96	Unit 1: June 1, 2006; Unit 2: July 26, 2006
Ripon Simple Cycle - Modesto Irrigation Dist	San Joaquin	Oil/Gas	95	June 21, 2006
Bottle Rock Geothermal - U.S. Renewables Group	Lake	Hydro	20	Oct. 1, 2007
Roseville Combined Cycle - City of Roseville	Placer	Oil/Gas	160	Oct. 1, 2007

Chart 1



Power Supply Challenges

California, due to its rising energy demand combined with the practical limits on building nuclear and coal-fired capacity locally, will remain a net importer of electricity. Its imported power comes mainly from coal and nuclear baseload projects in Utah, New Mexico, and Arizona, and from hydroelectric projects in the Pacific Northwest during the summer. In 2006, California's in-state capacity of 24,788 MW was dwarfed by its non-coincident peak demand of 56,191 MW. Peak demand rises by almost 1,000 MW per year, despite substantial conservation efforts and incentives in play. Total state energy capacity has risen just 2.7% annually during 2002-2006 versus peak load rising 1.2% on average per year, with a strong 3.2% peak load increase in 2003. With a growing population and per capita energy use rising, electricity demand in California will continue to increase. This growth, along with the normal pace of existing plant retirements, will require the state's electric utility industry to find additional new resources. During 2002-2006, electricity production in California showed strong growth, rising from 210,000 GWh to 231,000 GWh, a 10% overall increase versus imported generation, which grew just 3% from 63,000 GWh to 65,000 GWh. Both in-state and imported generation faces transmission-related challenges, however.

About 50% of California's power capacity is fired by natural gas or oil, while only 8% is coal fired (it was higher 14% in 2002). This is in marked contrast with national figures, where half of domestic generation capacity is coal-fired, and only 20% is from natural gas. Since 2005, almost 5,000 MW of new natural gas and hydro capacity has been installed, with about one-third coming from public power utilities (see table 2), at the expense of nuclear power which was 15% of capacity in 2006 versus 18% in 2002. Many of these natural gas power plants, such as the most recently operable plant in Roseville, are used for base and intermediate load, whereas traditionally natural gas plants were used for peaking capacity. The increased dependence on natural gas could be a dual-edged sword.

While cleaner than coal-fired plants—meaning they produce less sulfur dioxide, mercury, and nitrogen oxides--natural gas plants have more volatile cost structures due to the economics of the market. The installation of natural gas plants for baseload capacity, a recent trend in California that will continue, also pressures the supply of this commodity as well as pipeline capacity, which could exacerbate price volatility even further. Consequently, the state will need to continue to promote renewable energy projects within the state. Ongoing development of solar, geothermal, and wind generation will need to continue, in conjunction with expansion of the state's power grid capacity to keep up with energy demand.

Table 2

California Electric Data

Five-Year Historical Statistics

	2002	2003	2004	2005	2006
Generation Capacity by Type (MW)					
Coal	3,175	3,116	3,264	3,211	2,014
Gas	10,387	10,502	11,942	10,964	12,365
Hydro	3,564	4,126	3,924	4,554	5,529
Nuclear	3,922	4,063	3,452	4,127	3,657
Other Renewable (solar, biomass, wind)	1,217	1,143	1,245	1,230	1,224
Total	22,265	22,949	23,826	24,086	24,788
% Change	N.A.	3	4	1	3
Generation Capacity by Type as % of Total					
Coal	14	14	14	13	8
Gas	47	46	50	46	50
Hydro	16	18	16	19	22
Nuclear	18	18	14	17	15
Other Renewable (solar, biomass, wind)	5	5	5	5	5
Total (%)	100	100	100	100	100
Renewable Capacity (MW)					
Wind	405	379	486	466	505
Solar	97	87	85	75	70
Geothermal	1,583	1,572	1,598	1,642	1,510
Other (Organic Waste and Other)	745	706	702	688	649
Total	2,829	2,743	2,871	2,871	2,733

Table 2

California Electric Data(cont.)					
% Change	N.A.	(3)	5	0	(5)
Renewable Capacity as % of Total					
Wind	14	14	17	16	18
Solar	3	3	3	3	3
Geothermal	56	57	56	57	55
Other (Organic Waste and Other)	26	26	24	24	24
Total (%)	100	100	100	100	100
Renewable Energy (MWh)					
Wind	3,546,000	3,316,000	4,258,000	4,084,000	4,420,000
Solar	851,000	759,000	741,000	660,000	616,000
Geothermal	13,867,000	13,771,000	14,000,000	14,380,000	13,226,000
Other	6,522,000	6,184,000	6,149,000	6,027,000	5,682,000
Total	24,786,000	24,030,000	25,148,000	25,151,000	23,944,000
% Change		(3)	5	0	(5)
Renewable Energy (MWh) as % of Total					
Wind	14	14	17	16	18
Solar	3	3	3	3	3
Geothermal	56	57	56	57	55
Other	26	26	24	24	24
Total (%)	100	100	100	100	100
Average Retail Rate by Customer Type (Cents per KWh)					
Residential	12.64	12.23	12.2	12.51	14.33
Commercial	13.36	12.48	11.64	11.92	12.9
Industrial	9.81	9.59	9.27	9.55	10.09
Overall	12.19	11.78	11.35	11.63	12.82
% Change	N.A.	(3)	(4)	2	10
National Average Overall Rate (%)	7.20	7.44	7.61	8.14	8.90
Calif Overall Rate as % of National Avg Retail Rate (%)	169	158	149	143	144
Other					
Peak demand non-coincident (MW)	53,483	55,247	56,435	56,000	56,191
Forecasted Peak Demand (MW)	54,255	55,600	56,973	58,232	59,502
In-State Generation (MWh)	209,649,000	215,159,000	223,081,000	225,521,000	230,506,000
Imported Generation (MWh)	62,859,000	61,811,000	66,278,000	62,456,000	64,762,000

N.A. - Not available.

Environmental Regulatory Framework

In additions to federal regulations concerning Nox, SO2, Mercury, soot and other air-quality issues, California's utilities and power generators are subject to numerous environmental regulations imposed by state legislation. One of the most significant, established in 2002, is the requirement that utilities obtain 20% of their power supplies from renewable resources (see "Alternative Energy," below). In 2006, California passed two other landmark measures

(Senate Bill 1368 and Assembly Bill 32) that pushed the environmental envelope even further, and solidified California's position among U.S. states in regulating the impact utilities have on the environment.

SB 1368, established in 2006, applies to utilities' practices of procuring power. The law restricts utilities from entering into long-term financial contracts for base load generation for power that does not meet a certain environmental performance standard. The performance standard is likely to be set such that coal-based resources will not comply, but modern combined cycle gas-fired plants will. That level is established at 1,100 pounds of CO2 per megawatt-hour. California utilities are reacting to this legislation, and several public power utilities in Southern California consequently are not expected to renew long-term contracts for power from Utah's Intermountain Power Project, Units 1 and 2. In fact, SB 1368 led the Intermountain Power Agency (Utah) and its Southern California public power partners, Los Angeles Department of Water and Power being the largest, to end support for the development of a third unit, prompting a legal challenge by the Utah Association of Municipal Power Systems and Pacificorp. SB 1368 is intended to direct power utilities in efforts to comply with the 2006 legislation AB 32 (known as the Global Warming Solutions Act) as well as the governor's 2005 executive order (S-3-05), which establishes a goal of reducing greenhouse gas emissions to 1990 levels by 2020. AB 32 specifically requires electricity producers, among others, to reduce greenhouse gas emissions 25% by 2020. The California Air Resources Board (CARB) is charged with determining the specifics of how AB 32 will be implemented and how greenhouse gases are regulated. In conjunction with other state bodies, CARB will consider various options of granting emissions allowances, and what form a cap-and-trade program or other methodology might take.

It remains to be seen what effect these new standards will have on the credit quality of public power utilities, or what the financial penalties would be for failure to comply. California's public power utilities have been at the forefront of developing renewable portfolios, and some, as mentioned above, have independently taken steps away from adding more coal-fired electricity. However, mandates such as these will generally put upward pressure on utilities' cost of power by adding to or redirecting investments in generation, often to more expensive options.

Alternative Energy

Demand for alternative energy resources or "green" power is growing, although renewable power comprised just 5% of total energy capacity in California in 2006. Many utilities are either building, buying, or otherwise planning the acquisition of substantial amounts of renewable energy. The demand is due to several factors, including:

- The state-mandated renewable portfolio standard (RPS) for investor owned utilities (IOUs) that also have influenced many public power utilities to follow similar guidelines, or in many cases stricter internally-imposed requirements;
- The expectation that RPS standards will soon also apply to munis;
- Political pressure for more environmentally friendly local generation and imported energy resources;
- Continued strong load growth combined with increasingly limited ability to access additional traditional forms of generation such as coal or nuclear power; and
- The improving cost structure of renewable resources relative to traditional electricity sources, and increasing supply.

In 2002, California enacted a renewable portfolio standard that requires investor-owned utilities' energy portfolios to contain a certain percent of renewable energy over a certain period of time. Later amended and accelerated, the RPS requirement is 20% by the year 2010, with the governor endorsing this accelerated schedule and setting a goal of achieving a 33% RPS by 2020 for the state as a whole.

While currently not required to meet these standards, most public electric utilities in the state are adopting or working toward meeting these standards, with many even imposing accelerated requirements on themselves given public interest, but mainly given the expectation that the RPS will also eventually include public power, whether by state or federal fiat. Although the cost structure for renewable power is much higher than that of coal, nuclear, or natural gas, costs could gradually become more competitive as renewable energy resources continue to expand, and technologies improve, especially given the fact that for many renewable energy resources, the fuel (wind, sun, water) is free. Among wind, solar, geothermal and other resources such as renewable/approved hydro and other smaller resources, the wind "sector" grew the most from during 2002-2006 from 14% of all renewable capacity in 2002 to 18% in 2006, while geothermal and solar remained steady during those five years at close to 55% and 3% of renewable capacity, respectively.

Several utilities in the state have already begun ramping up their renewable energy portfolios in a number of different ways, including building their own projects or acquiring through purchase power agreements a stake in other utility-owned projects, and many more are in the planning stages. Examples include Riverside's electric utility and the Imperial Irrigation District (IID), both which have growing customer bases in Southern California.

Riverside Public Utilities' electric system has gained strong momentum when in comes to the acquisition of renewable energy capacity. As of 2006, 10% of Riverside resource portfolio was considered green, including landfill gas, hydropower and geothermal. Riverside has a formal internal goal of 20% by 2010, 25% by 2015, and 33% by 2020, with several renewable contracts in place totaling 58 MW in capacity, and almost 30 MW in additional capacity coming online from 2007-2009.

Imperial Irrigation District is in the process of developing its geothermal power resources located near the Salton Sea, and is about to bring online 70 MW that will allow it to achieve a 20% RPS. By 2011, geothermal will account for an estimated 10% of IID's capacity and will compliment its renewable hydro facilities along the All-American canal which currently total 12% of capacity (9% in 2011). IID is also exploring a 500 KW solar photovoltaic plant that could generate one million KWh of green energy per year.

Relative to solar energy mandates in the state, SB 1 passed in August 2006 and took effect in January 2007. The measure complements the California Solar Initiative established by the California Public Utilities Commission (CPUC) in January 2007, and puts the state on track toward building one million solar roofs over the next ten years. Provisions of SB 1 include a credit on retail electric bills; a mandate that solar panels become a standard option for all new homebuyers; directs the California Energy Commission to determine if or when solar energy should become a mandate; and requires that the state's municipal utilities create their own solar rebate program, among other items.

Prior to SB 1, California regulators approved the California Solar Initiative (CSI), the largest solar energy policy ever enacted in the U.S. and second only to Germany in terms of global solar policy. The CSI plan is monumental for the solar industry, allotting $3.2 billion for solar energy rebates in California over the next 10 years and providing for the installation of approximately 3,000 MW of solar energy, roughly the power equivalent of six large natural-gas fired power plants.

Lodi's electric utility is seeking to gain a foothold in the solar industry, with its new solar initiative called Lodi Solar Rebate Pilot project. The program offers an annual rebate/incentive budget of $600,000 for systems installed after

January 1, 2008. Customers may apply for a rebate starting at $2.80/watt (year 1), which decreases by 7% each year with a maximum rebate of $375,000 per system or $75,000 per customer per year until entire rebate commitment is paid.

Nearby, at Roseville's electric utility, customers that install a solar electric system receive a rebate from the utility. To qualify, customers must sign an interconnection agreement with the utility, and the photovoltaic modules and inverter must be on the California Energy Commission (CEC) list. Several other cities have or are developing solar initiatives as well.

Meeting Energy Needs And Preserving Credit Quality.

California's public power utilities have faced numerous challenges over the years, and as a group, exhibit strong credit quality. Management and governing bodies of these utilities have been effective in coping through various measures.

In reaction to commodity price volatility, for power and natural gas, utilities have incorporated physical or financial hedges to reduce seasonal market exposure. To combat increased volatility in the natural gas market, utilities, such as the members of the Southern California Public Power Authority (SCPPA), acting jointly, have purchased natural gas reserves in other states, including Wyoming or Texas. The electric system of Roseville, Calif., and the Sacramento Municipal Utility District have opted to enter natural gas prepay transactions to lock up future gas supplies while also obtaining a discount versus the market index price on their long-term natural gas purchases. Many other utilities have implemented hedging strategies that reduce market exposure with strict limits to "open" positions, usually declining as the relevant month, quarter or year approaches. Not all of these measures, however are risk-free, as the yields from natural gas fields or wells are uncertain, and counterparty risk is introduced in gas prepay transactions, power purchase agreements, and futures contracts.

Another financial hedge that has proven effective is found on the revenue side of the ledger, namely through rates. Since the power crisis in California in 2000 and 2001, many utilities have adopted automatic mechanisms whereby actual fuel and/or power costs are reviewed on a recurring basis with rates adjusted to reflect the utilities' actual cost, thus transferring the price risk to the customer from the utility. These mechanisms often bypass the normal ratemaking process that involves public hearings, and city council assent, which can result in long lead times and, often, under-recovery. We believe utilities—especially those that are gas-dependent--that have yet to implement some version of a variable cost recovery mechanism in their rate structures should certainly consider them, as these mechanisms can help to stabilize financial performance and debt service coverage ratios--two key factors in our credit analysis. Utilities are increasingly targeting reserve levels to match their specific exposures, which has resulted in higher balances in rate stabilization-type accounts.

On the operational side, utilities are increasingly focused on fuel or unit diversity, again aimed at reducing market exposures that occur when supplies are tight, or transmission or power plant outages arise unexpectedly. Incorporating renewable energy into a power supply portfolio contributes to power supply diversity, in addition to having benefits of reduced emissions, and meeting local, state or federal mandates.

Table 3

Public Power Rating Distribution

Issuer	Rating	Outlook
Palo Alto (Combined Utility)	AA+	Stable
Anaheim	AA-	Stable
Los Angeles Dept of Wtr & Pwr	AA-	Stable
Southern California Pub Pwr Auth (Hoover Uprating)	AA-	Stable
Southern California Pub Pwr Auth (Southern Transmisson Proj) Senior Lien	AA-	Stable
Burbank	A+	Stable
Glendale	A+	Stable
Imperial Irr Dist	A+	Stable
Modesto Irr Dist	A+	Stable
MSR Pub Pwr Agy (San Juan Pwr Project - Unit 4)	A+	Stable
Pasadena	A+	Stable
Riverside	A+	Stable
Roseville	A+	Stable
Southern California Pub Pwr Auth Pwr (Palo Verde)	A+	Stable
Southern California Pub Pwr Auth (San Juan Pwr Proj - Unit 3)	A+	Stable
Southern California Pub Pwr Auth (Magnolia Pwr Proj A)	A+	Stable
Southern California Pub Pwr Auth (Multiple Projects)	A+	Stable
Walnut Energy Ctr Auth (Turlock Irrig. Dist)	A+	Stable
Turlock Irr Dist	A+	Stable
California Resource Efficiency Fin Auth (Azusa)	A	Stable
Sacramento Mun Util Dist	A	Stable
Santa Clara (Subordinate Lien) (dba Silicon Valley Pwr)	A	Stable
Alameda	A-	Stable
Banning	A-	Stable
California Dept of Wtr Resources (Pwr Supply)	A-	Stable
Northern California Pwr Agy (Hydroelec proj no. 1)	A-	Stable
California Infrastructure & Economic Development Bank (Cal ISO)	BBB+	Positive
Lodi	BBB+	Stable
Northern California Pwr Agy (Combustion turbine proj #1)	BBB+	Stable
Northern California Pwr Agy (Geothermal proj #3)	BBB+	Stable
Trinity Cnty Pub Util Dist	BBB+	Stable
Vernon	BBB+	Stable

STANDARD &POOR'S

RATINGSDIRECT®

May 10, 2007

Effects Of Warming, Efficiency Programs, And Conservation On Energy Usage And Credit Quality

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Effects Of Warming, Efficiency Programs, And Conservation On Energy Usage And Credit Quality

The credit concerns for utilities from global warming, caused by greenhouse gas emissions, are largely the result of financial pressures created by capital and variable costs of added emissions controls. However, the potential exposure of financial margins is not exclusively limited to these contingencies. In particular, Standard & Poor's Ratings Services expects a heightened regulatory and legislative focus on greenhouse gas emissions to lead to mandates directing utilities to implement additional energy efficiency and conservation programs. These programs are designed to reduce end-user electricity and natural gas consumption. As a result, utility margins may be affected, if revenues and profits decline along with consumption.

Energy Efficiency And Conservation Among Electric Utilities

Energy efficiency and conservation programs have been in place for some time, but the amount of avoided demand for electricity has been essentially constant for the past 10 years (see table 1). The extent of annual reduction has been very small relative to the one million MW or so of electric generation capacity in the U.S. Similar trends are found in electricity consumption data (see table 2)

Table 1

Demand-Side Management Actual Peak Load Reductions By Program Category (1994-2005)

(MW)

Item	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994
Total actual peak load reduction	25,710	23,532	22,904	22,936	24,955	22,901	26,455	27,231	25,284	29,893	29,561	25,001
Energy efficiency	15,351	14,272	13,581	13,420	13,027	12,873	13,452	13,591	13,327	14,243	13,212	11,662
Load management	10,359	9,260	9,323	9,516	11,928	10,027	13,003	13,640	11,958	15,650	16,347	13,340

Source: Energy Information Administration

Table 2

Demand-Side Management Program Energy Savings (1994-2005)

(Thousand MWh)

Item	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994
Total energy savings	59,897	54,710	50,265	54,075	53,936	53,701	50,563	49,167	56,406	61,842	57,421	52,483
Energy efficiency	58,891	52,662	48,245	52,285	52,946	52,827	49,691	48,775	55,453	59,853	55,328	49,720
Load management	1,006	2,047	2,020	1,790	990	875	872	392	953	1,989	2,093	2,763

MWh -- Megawatt-hours. Source: Energy Information Administration

The fairly static nature of the volume of reduction in demand and energy consumption, coupled with the heightened focus on global warming issues, leads us to expect that efficiency requirements will increase. Heightened efficiency and conservation might be accomplished by a utility in many different ways.

In the future, some methods could include the sale, distribution or promotion, of fluorescent light bulbs, energy audits, and the installation of "smart" electric meters to facilitate the implementation of time-of-use rates.

Time-of-use rates encourage customers to shift usage to off-peak periods for resource optimization. Other efficiency measures may not directly involve a utility. For example, California has been very successful in controlling energy demand through several means that do not directly involve utilities. Notably, California's building code regulations, which were first adopted in 1978 to reduce energy consumption, have played an important role in managing energy demand. The California Energy Commission reports that the state has the lowest per-capita electricity consumption among the 50 states (almost 50% below the national average), which bears out the effectiveness of its efficiency programs. California similarly exhibits low levels of per-capita carbon dioxide production relative to other states. California has also seen smaller growth in its per-capita electricity consumption, compared with the national growth rate in per-capita electricity consumption.

Achieving emissions reductions may require cuts in electricity consumption, including a need for programs to address the increasing demand for electricity (see table 3). Electricity consumption has increased by about 2% per year over each of the past 15 years, because of the growing population, increasing economic activity, and the introduction of more appliances that can be turned on in an instant or are rechargeable and draw power even when not in use. By some estimates, instant-on appliances now account for at least 5% of residential electric consumption.

Table 3

U.S. Electricity Consumption

Year	National end use electric consumption (MWh)	Change over previous year (%)
2005	3,813,359,194	2.6
2004	3,716,687,530	1.6
2003	3,657,517,424	0.7
2002	3,632,264,181	2.5
2001	3,544,740,202	(1.3)
2000	3,592,356,777	3.1
1999	3,483,716,365	1.7
1998	3,425,096,636	3.7
1997	3,301,849,322	1.5
1996	3,253,765,037	2.8
1995	3,163,963,129	2.7
1994	3,080,888,198	2.7
1993	3,000,700,217	3.6
1992	2,897,206,690	0.4
1991	2,886,060,219	1.7
1990	2,837,083,605	3.0

MWh -- Megawatt-hours Source: Energy Information Administration

Coal-fired generation is the largest source of carbon emissions in the electric production realm. Electric energy efficiency programs will not necessarily displace coal base load units and their emissions. Realistically, energy efficiency measures may have the effect of displacing gas units further along the dispatch curve relative to coal units, without reducing the electric and emissions output of low-cost, coal-fired base load units.

From a credit perspective, any directive with the goal of reducing retail customers' electricity consumption has the potential to create additional costs for a utility, especially if additional staffing or capital investments are necessary to implement efficiency and conservation. Reduced consumption also could erode the revenue stream of affected electric utilities. The combination of extra costs and eroded revenues could impair financial margins and credit quality. At the same time, energy efficiency and conservation might reduce the need for new capital investments in power plants, which could temper pressures on financial margins caused by these programs.

Such trends could affect vertically integrated electric utilities and utilities that have been transformed through market restructuring into transmission and distribution (T&D) systems, eroding return on investments made to develop generation and T&D facilities.

The exposure of financial margins to reduced consumption resulting from efficiency and conservation is founded in traditional ratemaking principles. Regulators often set utilities' retail electric rates at levels that provide for the recovery of fixed and variable costs, together with a return on the rate base. A utility's rate base typically closely approximates its undepreciated capital investments. If we set aside rate design objectives related to the allocation of costs among different customer classes, retail volumetric charges may be established by taking the overall revenue requirement and dividing it by the expected volume of electric consumption measured in kilowatt-hours (kWh). In rate proceedings, anticipated sales volumes are generally established with reference to a historical period's actual usage, a period referred to as the "test year."

Logically, utilities would take a negative view of programs whose objective is to reduce sales volumes that support their established retail rates. Diminished sales volumes could hinder the recovery of fixed costs and the return on capital investments. Consequently, the introduction of a program that reduces electricity demand runs counter to the financial interests of utilities and their investors.

Making Electric And Gas Utilities "Revenue Neutral" To Efficiency And Conservation

More frequent rate cases could address the financial and credit quality issues created by reduced sales resulting from efficiency. Yet, more innovative ratemaking tools such as rate decoupling and other rate structures that insulate fixed-cost recovery from changes in sales volumes are available to utilities and their regulators to tackle the financial pressures that might flow from emissions reduction programs. These tools can provide more predictable and stable financial margins than frequent rate filings can. Moreover, full-blown rate cases can become protracted, and a lengthy proceeding can delay needed rate relief. The outcome of a rate case is often difficult to predict and rate cases may even result in disallowances if regulators revisit expenses and performance.

Some of the rate-making tools that address the shortcomings of frequent rates cases are not accepted beyond a handful of jurisdictions. This is because some regulators fear that systems that protect utility financial performance from usage reduction may also present the danger of lulling management into a state of indifference to customers' interests. Some regulators also may be loathe to implement rate designs that might be perceived as transforming customers into hedging instruments, compelled to bear the financial responsibility for shielding earnings from volatility in sales volumes.

Revenue decoupling is one of the more progressive regulatory mechanisms for protecting a utility's financial performance and, in turn, its credit quality, as efficiencies and conservation levels increase. Under revenue decoupling, the regulator eliminates or diminishes the risk to financial performance presented by declining sales volumes between rate cases via the use of a tracking mechanism, such as a balancing account, to record deviations from targeted financial objectives. Trigger mechanisms ensure the recovery of shortfalls relative to authorized returns. The decoupling mechanism thus reduces or eliminates utility resistance to efficiency and conservation programs. Of course, for the decoupling mechanism to be effective in preserving financial metrics and credit quality, the financial thresholds that trigger an adjustment between the authorized and actual return must kick in while shortfalls remain reasonable. If the tracking mechanism could lead to sizable deferrals, it could negatively affect a utility's credit rating.

To date, a limited number of jurisdictions have provided for decoupling. California is the only U.S. jurisdiction that applies revenue decoupling to electric utilities. A handful of jurisdictions accord rate decoupling to natural gas utilities to insulate their financial performance from demand reductions caused by either efficiency and conservation programs, or demand elasticity that may be present in a rising gas price environment. In California, utilities earn a return on their investments in utility plants, but do not earn any margin on the sale of electric or gas commodities. Rather, commodity costs are recovered based on actual costs incurred. Variations in these costs are captured in balancing accounts and rates that are periodically adjusted to provide for the recovery of amounts recorded in those accounts. The balancing account mechanism in California can exhibit some delay in cost recovery, but a reasonable one.

While decoupling can remove disincentives for utilities to participate in efficiency and conservation programs, it does not create incentives for the participation in such programs. In fact, efficiency and conservation programs may decrease the future earnings potential that could have come from new power plants that might have been built and added to the rate base. Consequently, to encourage utilities to pursue such programs, it may be necessary to create financial incentives for achieving targeted objectives. Incentive ratemaking that is tied to efficiency and conservation might accomplish this. A combination of decoupling and incentives can encourage utilities to act in the public interest without concern for a negative effect on financial margins.

Another vehicle for limiting potential degradation of financial margins resulting from efficiency and conservation might be borrowed from water utilities and a few electric and gas utilities. To insulate financial performance from seasonal and weather-related fluctuations in consumption, many water utilities' rates include what is referred to as a ready-to-serve charge. This charge represents a base charge that is independent of usage and is set at a level that permits a utility to recover fixed costs, and possibly earn a return, regardless of consumption. The ready-to-serve charge is a tool that insulates financial performance from erosion if consumption declines. However, like decoupling, a ready-to-serve charge does not provide an incentive for a utility to actively promote conservation. So, once again, some form of incentive may be necessary to promote efficiency and conservation, if the ready-to-serve charge concept is extended to electric utilities.

The ratemaking principles relevant to mitigating the financial exposure of electric utilities' participation in conservation and efficiency programs are also relevant to natural gas utilities, whose sales volumes could be compromised by demand reductions from policies designed to curtail global warming. Like electric utility rates, the retail rates of natural gas distribution utilities are set at levels designed to recover costs through the sale of predicted volumes of gas. Whether our focus is on electric or gas utilities, it is clear that the response of regulators to reductions in sales and financial metrics from emissions-reduction efforts will be critical to the preservation of credit quality.

Temperature Volatility And Its Effect On Gas And Electric Revenues

Weather volatility, including a trend toward higher temperatures, can influence the revenues derived from retail customers of electric and gas utilities. The mechanisms for insulating utilities from the financial effects of consumption changes from efficiency and conservation are equally applicable to utilities that are experiencing declining consumption, possibly due to global warming.

Sales of natural gas have indeed slowed from 2003 to 2006 (see table 4). However, given this narrow window and other uncertainties, it remains unclear whether warming trends or the influence of sharp increases in natural gas prices were the cause. Yet, Standard & Poor's has reviewed data that demonstrates a clear pattern of declining heating-degree days for 25 geographically diverse cities over the past 30 years (see charts 1 and 2).

Table 4

U.S. Natural Gas Consumption

(Mcf)

Year	Residential and commercial	% Change	Total U.S.	% Change
2001	7,794,052	N.A.	20,495,108	N.A.
2002	8,032,988	3.1	21,227,015	3.6
2003	8,258,845	2.8	20,562,727	(3.1)
2004	7,997,769	(3.2)	20,724,883	0.8
2005	7,907,662	(1.1)	20,544,907	(0.9)
2006	7,283,182	(7.9)	20,152,149	(1.9)
Five-year change (2001-2006)		(6.6)		(1.7)

Mcf -- Thousand cubic feet. N.A. -- Not available. Source: Energy Information Administration.

Chart 1

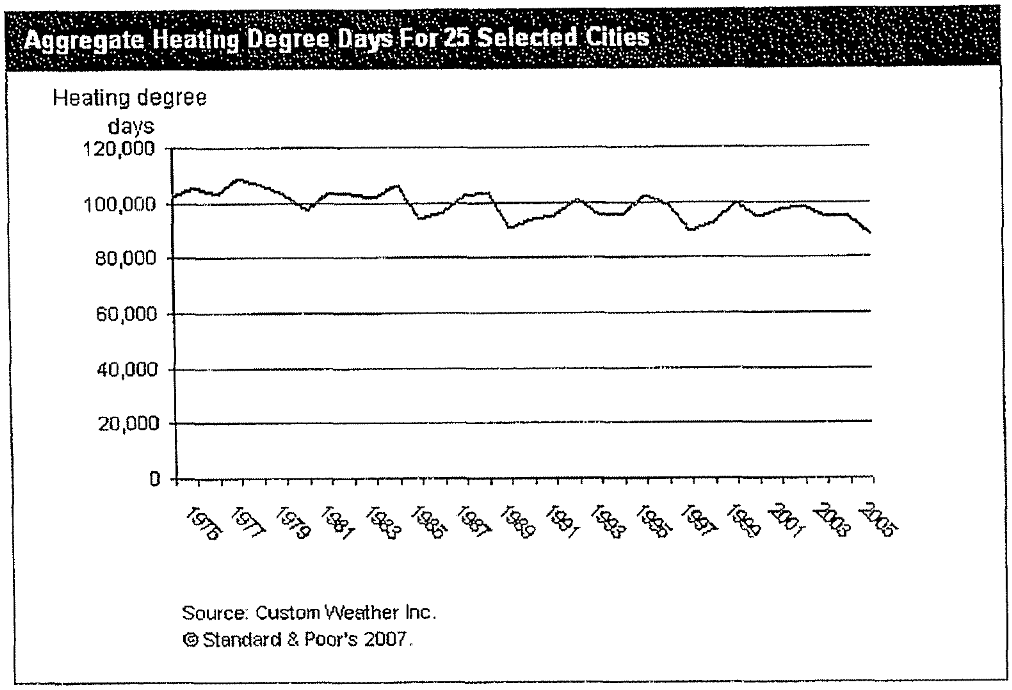
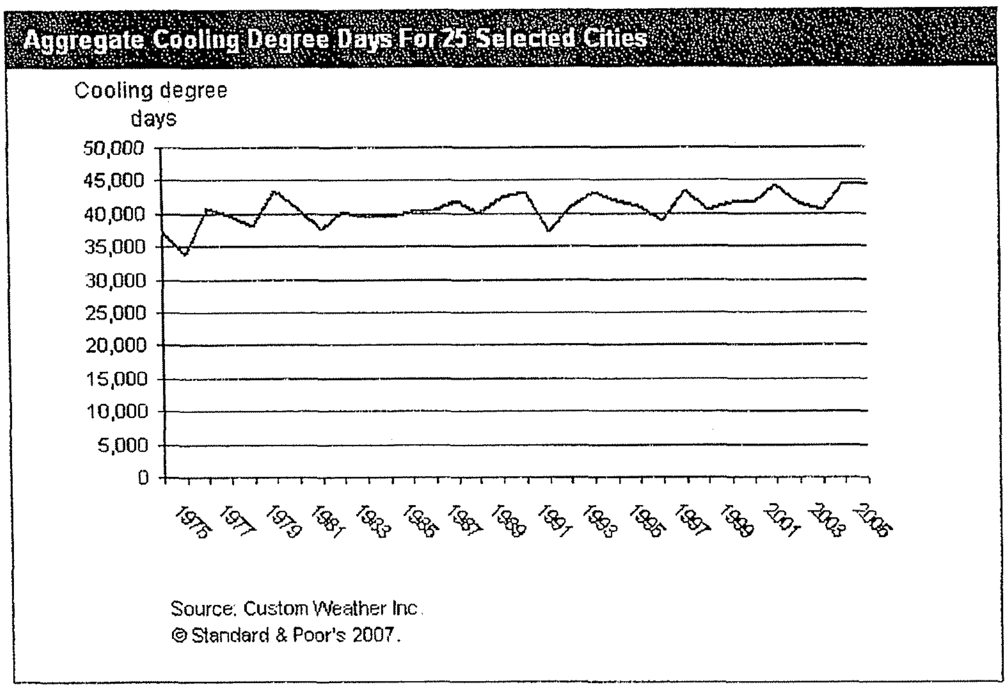


Chart 2



A corresponding increase in cooling-degree days accompanied this trend. On balance, electricity consumption has increased and gas consumption in recent years remained essentially unchanged (see tables 2 and 3). So, it remains unclear what the implications of warming trends on revenues may be over time. Increased summer electric load may offset a decreased winter demand, while gas distribution companies will likely suffer from lower revenues if the trend holds. In either case, the presence or absence of a regulatory response to changes that pressure financial margins could influence credit ratings of affected utilities.

Click on this link to see other articles in "Special Report: The Credit Impact Of Climate Change."

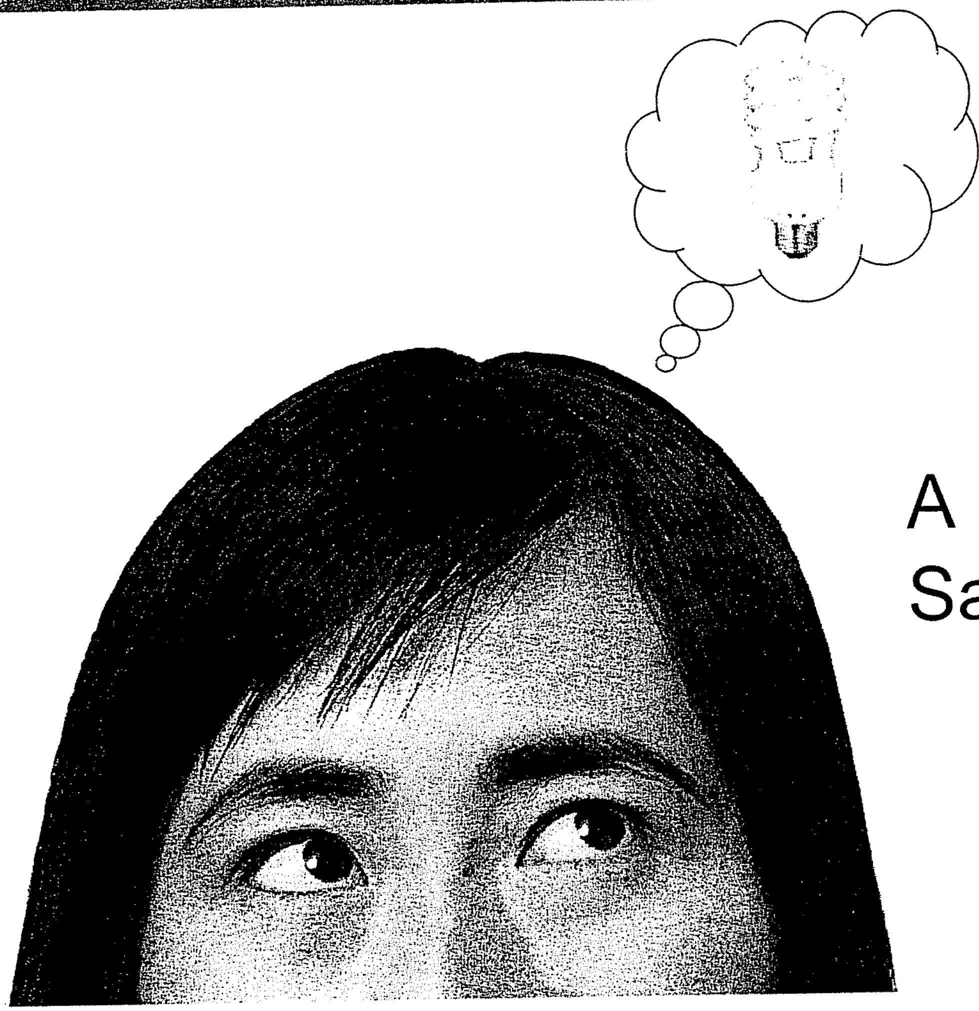
Click on this link to go to the Special Report Archive.

Changing minds.

Changing habits...

A New Approach to Energy Efficiency

December ____, 2007



A Discussion With Sandra Meyer

Duke Energy®

Changing minds. Changing habits...

Why Energy Efficiency?

- Customer demand is growing requiring new investment
  - DOE estimates a 50% increase in demand by 2030
  - Growth in consumer use – especially electronics
  - Duke Energy adding 40,000-60,000 customers per year
- Energy prices are increasing
  - Rising Fuel Costs
  - Needed investment in delivery systems
- Environmental issues need to be addressed
  - Greater environmental controls and carbon issues will add more upward pressure on prices for customers
- Advances in technology will make energy efficiency easier to obtain without disrupting customer's comfort and convenience

Changing minds. Changing habits...

Our Vision: Changing the Way We Think About Utilities & Energy Efficiency

What if Customers. . .

- had access to state-of-the-art energy efficiency services and technologies that allowed them more options in managing their bill?
- could participate in energy efficiency programs with minimal impact on their comfort and convenience?
- had lower bills and the environmental footprint reduced as a result of customers saving watts?

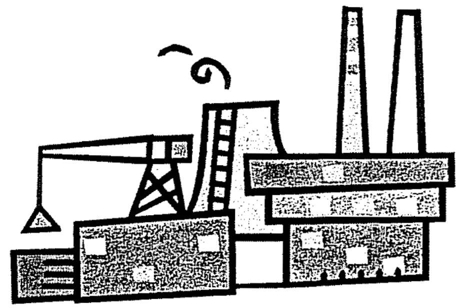
Changing minds. Changing habits...

Our Vision: Changing the Way We Think About Utilities & Energy Efficiency

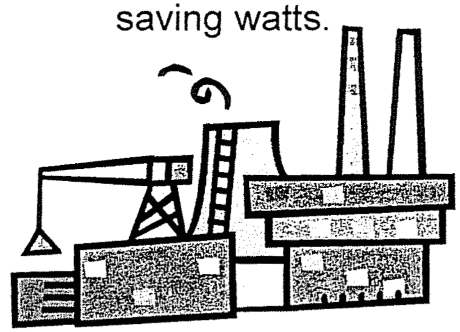
What if Utilities. . .

- were confident that energy efficiency was as reliable as power plants in meeting our growing need for electricity – a fifth fuel?
- were financially indifferent to meeting rising electricity demand with a new power plant or energy efficiency?
- were allowed to expand their business planning to include the "business" of saving watts (i.e: reducing megawatts)?
- created new energy efficiency service jobs and gave businesses in the state a competitive advantage?

Power Plant, made of steel and concrete, meets needs by making watts.



Save-A-Watt Plant, made up of hundreds of energy efficiency measures, meets needs by saving watts.



Changing minds. Changing habits...

The Fifth Fuel

- Much like other sources of generation, energy efficiency has its own reliability characteristics.
- There are two types of energy efficiency – demand response and conservation
- Demand Response Programs
  - Duke Energy has long relied upon demand response as an integral component of its resource mix.
  - History has shown that these programs can be counted upon as a reliable resource.
- Conservation Programs
  - Once conservation measures are installed they will be a reliable resources as well.
  - Conservation measures (e.g., insulation or high efficiency commercial lighting) are not subject to scheduled or forced outages.
  - Once implemented, they will provide resources with measured reliability,
  - While important part of any program, Education and awareness (such as campaigns to turn back the thermostat) do not qualify as a reliable resource in our model.

Changing minds. Changing habits...

Our Vision: Paid On Results, So Create Programs Customers will Value

RESIDENTIAL CUSTOMER PROGRAMS

- Residential Assessments
- Smart $aver® for Residential Customers
- Power Manager (Demand Response)
- Low Income Energy Efficiency and Weatherization Assistance Program
- Energy Efficiency Education Program for Schools

NON-RESIDENTIAL CUSTOMER PROGRAMS

- Non-Residential Assessments
- Smart $aver® for Non-Residential Customers
- PowerShare® (Demand Response)

RESEARCH

- Efficiency Savings Plan Program
- Advanced Power Manager Pilot Programs

Changing minds. Changing habits...

Energy Efficiency as a Resource

- Lowest cost alternative and emissions free
- Because it is a reliable resource, it should be treated as a production cost in the regulatory arena.
  - As energy savings accrue, electricity sales and generation additions will erode.
  - The pricing of watts saved should be tied to the utility's avoided cost of producing energy
  - Pricing these saved watts at a discount to new generation (avoided cost less 10%) guarantees a discount to customers over the cost of supply only resources
- Using an avoided cost model ties 3 traditional components of cost recovery (program cost, recovery of lost margins, shareholder incentives) into one simplified approach and puts the risk of performance on the utility

Changing minds. Changing habits...

Our Proposal:
Changing the Way We Think About Utilities & Energy Efficiency

Renewable Energy	100+%
New Generation	Avoided Cost of New Generation
Energy Efficiency Proposal	90%
Current Duke Rates	below national average

Proposal Assumptions:

1. In order to meet the growth in customer demand and reduce environmental impacts, energy prices are likely to rise over current rates;
2. Customers need help to better manage their electric bills in a rising price environment.
3. Working with customers to develop new approaches to energy efficiency programs can result in significant customer participation at a cost less than that of new generation.

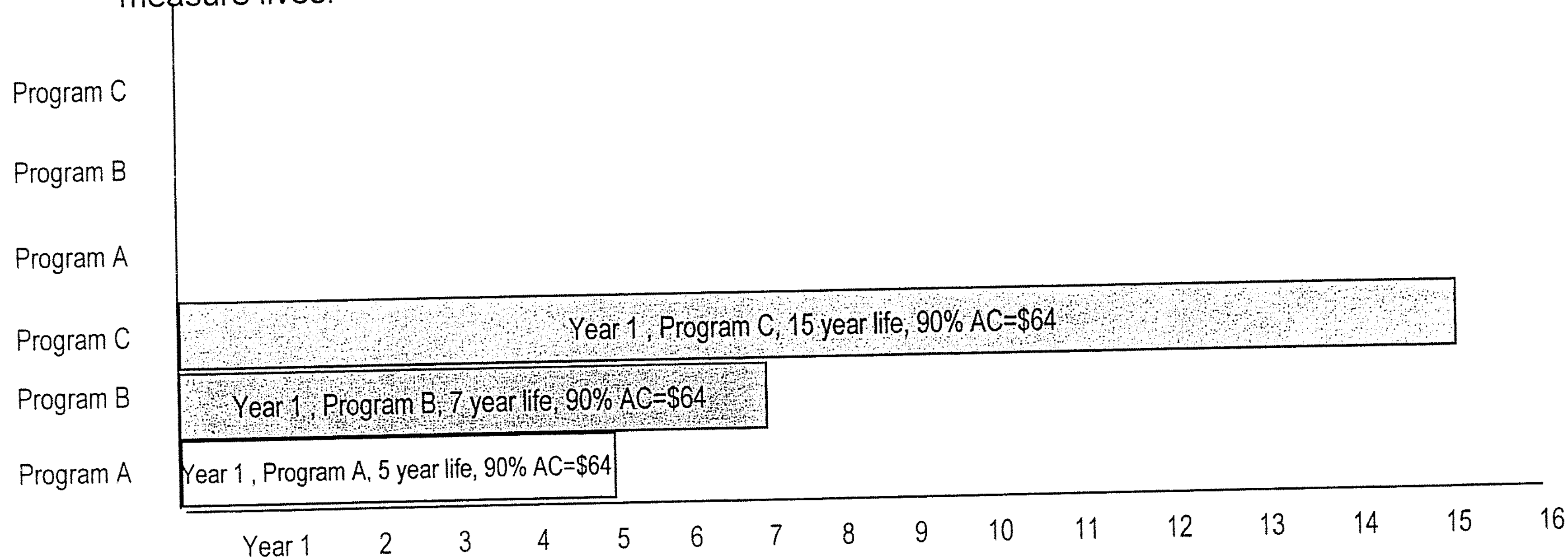
Changing minds. Changing habits...

Our Proposal:
Changing the Way We Think About Utilities & Energy Efficiency

- Best way to model the cost of new generation is to use the avoided cost of generation that is subject to Commission review;
- Determine an appropriate percentage of this avoided cost of generation that would
  - automatically produce savings for customers (given the supply alternative)
  - provide the utility with enough revenue to cover all program costs; education, awareness and administration costs; measurement & verification costs, research & development, and an appropriate return on the investment.
  - 90% recovery of and on avoided supply-side costs meets these requirements
- A rider that would provide for a kWh charge for retail electric customers
  - Third-party verification of results
  - Rider adjusted annually based on updated projections of results, including projected incremental avoided costs and actual results achieved by the Company. These annual adjustments ensure customers pay only for verifiable EE savings
- The energy efficiency plan will be updated annually based on the performance of programs, market conditions, economics, consumer demand and avoided costs.
- This approach ensures the utility will work to drive results up and costs down.

Example of How Avoided Cost Recovery Would Work

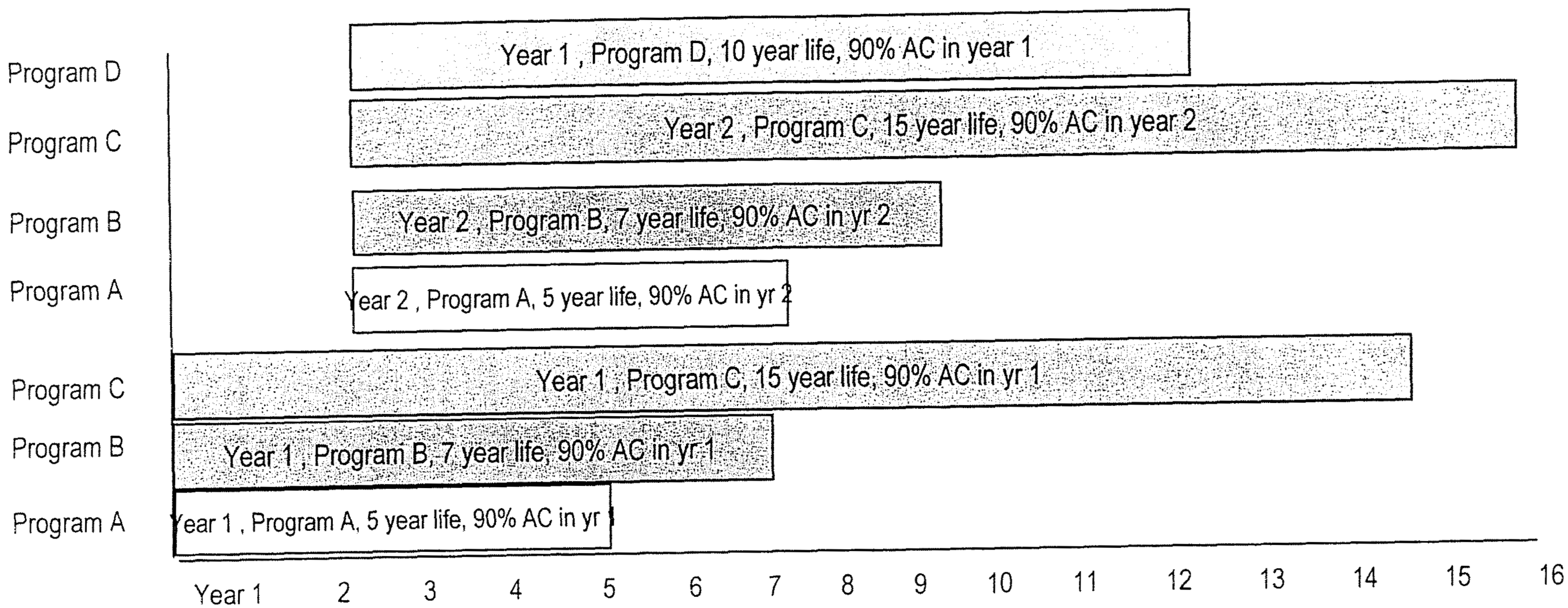
- In year one, the utility implements three programs: the programs include measures with expected lives of 5, 7, and 15 years respectively.
- There are expected numbers of participants for the first year, expected on-going impacts (demand and energy) per participant per year, and expected percentage of "free riders".
- Therefore there is an amount of avoided capacity and energy associated with the first year of the program that will continue into year 15.
- The value of the avoided capacity and energy can be calculated.
- The Rider will be calculated to recover 90% of these avoided capacity and energy costs over the measure lives.



Changing minds. Changing habits...

Simplified Example of How Energy Efficiency Rider Would Work

- In year 2, additional participants are added to the programs implemented in year one, plus the implementation of a new program.
- The value of avoided capacity and energy associated with these new participants can be calculated.
- The Rider for Year 2 will be calculated to recover 90% of these avoided capacity and energy costs of BOTH the second year of the Year 1 participants as well as the first year of the Year 2 participants.
- An independent third party will verify energy savings. If savings were less than anticipated, Duke Energy would have over collected and a downward adjustment would be made to the rider in the year following the evaluation. If savings were more than expected, Duke Energy would have under collected and the appropriate upward adjustment would be made to the rider in the year following the evaluation



Our Vision: Energy Efficiency Benefits All

Our Energy Efficiency model will benefit our customers, the public and the company by:

- Lowering bills for ALL customers, compared to the bills that would result from supply-side only investments
- Providing customers with universal access to energy efficiency
- Substantially lowering bills for customers who participate
- Producing a portion of needed capacity and energy to meet our customers' energy requirements with zero emissions
- Providing the company with the financial incentive to produce energy efficiency that saves watts
- Creating new energy efficiency service jobs

Changing minds. Changing habits...

Moving Energy Efficiency Forward

- This new regulatory approach filed in North Carolina May 7, 2007
  - Implementation rules for Senate Bill 3 due by year-end
  - Procedural schedule expected early 2008
- South Carolina filing September 28, 2007
  - Procedural schedule set (testimony due Dec. 10)
- Indiana filing October 19, 2007
  - Procedural schedule set (testimony due Dec. 17)
- Ohio & Kentucky – To be determined

KyPSC-DR-01-007

REQUEST:

Identify the person having primary responsibility for the utility resource plan.

RESPONSE:

Diane L. Jenner

WITNESS RESPONSIBLE: Diane L. Jenner

KyPSC-DR-01-008

REQUEST:

Identify the person or persons having primary responsibility for the utility financial forecasts and strategic plan or strategic planning documents.

RESPONSE:

Brian P. Davey / Christopher M. Fallon

WITNESS RESPONSIBLE: Brian P. Davey / Christopher M. Fallon

KyPSC-DR-01-009

REQUEST:

Identify the person or persons within the utility having primary responsibilities for siting new generation.

RESPONSE:

Power plant siting is generally undertaken by a multi-disciplinary team utilizing an organized decision analysis process to arrive at the best decision, considering several differing objectives, for the location of a new power plant. The individuals on the team depend on the jurisdiction the power plant is to be located, as well as the generation technology type being considered, i.e., nuclear, coal, natural gas, etc.

WITNESS RESPONSIBLE: John G. Bloemer / Robert D. Moreland

KyPSC-DR-01-010

REQUEST:

Identify the person or persons within the utility having the primary responsibility for conservation, energy efficiency, and demand-side management programs.

RESPONSE:

Theodore E. Schultz, Michael Goldenberg, and Richard G. Stevie

WITNESS RESPONSIBLE: Theodore E. Schultz, Michael Goldenberg, and Richard G. Stevie

KyPSC Staff First Set Data Requests
Duke Energy Kentucky
Case No. 2007-00477
Date Received: November 20, 2007
Response Due Date: December 7, 2007

KyPSC-DR-01-011

REQUEST:

Identify and discuss all portions of the utility's current integrated resource plan which discuss future plans for implementation of demand-side management, renewable energy resources, and energy efficiency.

RESPONSE:

The most current filed Integrated Resource Plan ("IRP") for Duke Energy Kentucky, Inc. is the 2003 IRP, filed on April 1, 2004. Demand-side management and energy efficiency are discussed extensively in Chapter 4. Renewable resources are discussed in Chapter 5 and the General Appendix. These portions of the IRP are provided at Attachment KyPSC-DR-01-011.

WITNESS RESPONSIBLE: Diane L. Jenner

4. DEMAND-SIDE MANAGEMENT RESOURCES

A. INTRODUCTION

Since the previous Integrated Resource Plan filed in 1999, ULH&P has devoted its demand-side management (DSM) efforts to the implementation of the following four programs:

Program 1: Residential Conservation and Energy Education

Program 2: Residential Home Energy House Call

Program 3: Residential Comprehensive Energy Education Program

Program 4: Residential New Construction

The Kentucky Public Service Commission has been kept appraised of the activities and progress made on these programs through annual status reports filed with the Commission on or about October 1 of each year.

As a result of the Commission's review of the 2001 status report, the Commission approved the Home Energy Assistance Plus pilot program. In the 2002 status report, ULH&P provide detailed results on the cost effectiveness of the four programs and summary evaluation of the Home Energy Assistance Plus pilot program. Based upon the analysis, ULH&P recommended that the Residential New Construction Program be discontinued and that the Home Energy Assistance Plus pilot program be extended for two more years.

In the Commission Order in Case No. 2002-00358 dated December 17, 2002, the Commission approved the continuation of and cost recovery for the Residential Conservation and Energy Education, Residential Home Energy House Call, and Residential Comprehensive Energy Education programs for a 3-year period, through December 31, 2005. The Commission approved the termination of the Residential New Construction/Renovation program. Finally, the Commission approved the implementation of a revised low-income home energy assistance program (Payment Plus) as a pilot through May 31, 2004.

B. CURRENT DSM PROGRAMS

This section provides a description of each current program and a review of the cost-benefit analyses..

Program 1: Residential Conservation and Energy Education

The Residential Conservation and Energy Education program was designed by the ULH&P DSM Collaborative to help the Company's income-qualified customers reduce their energy consumption and lower their energy cost. This program specifically focuses on customers that meet the income qualification levels of 150% of federal poverty level. This program uses the LIHEAP customer list as well as other community outreach to improve participation. The program provides direct installation of weatherization and energy-efficiency measures and educates ULH&P's income-qualified customers about their energy usage and other opportunities to reduce energy consumption and lower their cost.

The Company estimates that at least 6,000 customers (number of single family owner occupied households with income below $25,000) within ULH&P's service area would qualify for services under this program. The program has provided weatherization services to 251 homes in 2000, 283 in 2001, 203 in 2002, and 224 in 2003.

At the end of 2002, the processes and impacts of the program were evaluated to identify additional areas for improvement. This evaluation showed that the overall program structure was cost effective. However, the Tier 2 level (basic services and air sealing) was the least cost effective alternative. Thus in early 2003 another modification to the program was made to further improve cost effectiveness. The Tier 2 and Tier 3 levels were combined into one new level (Tier 2) which, using the National Energy Audit Tool (NEAT) audit, expanded the offering of services to include insulation (previously in the old Tier 3 service level). The average amount spent and maximum amount allowed are listed below for each tier.

> TIER 1 Spending = Average $350 including administration, not to exceed $550
>
> TIER 2 Spending = Average $1,370 including administration, not to exceed $4,000

The services provided within each new modified tier are described below.

The tier structure is defined as follows:

	Therm / square foot	kWh use/ square foot	Investment Allowed
Tier 1	0 < 1 therm / ft2	0 < 7 kWh / ft2	Up to $550
Tier 2	1 + therms / ft2	7 + kWh / ft2	All SIR ≥ 1.5 up to $4K

SIR = Savings - Investment Ratio

Tier One Services

ULH&P, through its subcontractors, provides Tier One services to a customer, if they use less than 1 therm per square foot per year and less than 7 kWh per square foot per year based on the last year of usage (weather adjusted) of Company supplied fuels. Square footage of the dwelling is based on conditioned space only, whether occupied or unoccupied. It does not include unconditioned or semi-conditioned space (non-heated basements). The total program dollars allowed per home for Tier One services is $550.00 per home.

Tier One services are as follows:

- Furnace Tune-up & Cleaning
- Furnace replacement if investment in repair over $500 (leveraged through the Gas Weatherization program)
- Venting check & repair
- Water Heater Wrap
- Pipe Wrap
- Waterbed mattress covers
- Cleaning of refrigerator coils
- Cleaning of dryer vents

- Compact Fluorescent Light (CFL) Bulbs
- Low-flow shower heads and aerators
- Weather-stripping doors & windows
- Limited structural corrections that affect health, safety, and energy up to $100
- Energy Education

Tier Two Services

ULH&P will provide Tier Two services to a customer, if they use at least 1 therm and/or 7 kWh per square foot per year based on the last year of usage of ULH&P supplied fuels.

Tier Two services are as follows:

- Tier One services plus:
- Additional cost-effective measures (with SIR $\geq$ 1.5) based upon the results of the NEAT audit. Through the NEAT audit, the utility can determine if the cost of energy saving measures pay for themselves over the life of the measure as determined by a standard heat loss/economic calculation (NEAT audit) utilizing the avoided cost of gas and electricity. Such items can include but are not limited to attic insulation, wall insulation, crawl space insulation, floor insulation and sill box insulation. Safety measures applying to the installed technologies can be included within the scope of work considered in the NEAT audit as long as the SIR is greater than 1.5 including the safety changes.

Regardless of placement in a specific tier, ULH&P provides energy education to all customers in the program.

Refrigerators

To increase the cost-effectiveness of this program and to provide more savings and bill control for the customer, the DSM Collaborative and ULH&P proposed and gained Commission approval in Case No. 2002-00358 to expand this program to include refrigerators as a qualified measure in owner occupied homes. Refrigerators consume a very large amount of electricity within the home. Through replacement of poor-performing units, customers can save an average of $96 per year. To determine replacement, the program weatherization provider performs a two-hour meter test of the existing refrigerator unit. If it is a high-energy consumer as determined by this test, the unit is replaced. Results from a similar program operated by Cinergy in Ohio have shown that the average unit replaced consumes 1,620 kWh per year. Replacing with a new Energy Star qualified refrigerator, which uses approximately 400 kWh, results in an overall savings to the average customer of 1,200 kWh per year. In the Ohio program, Cinergy has been replacing 36% of the units tested. Given the size of the KY Residential Conservation and Energy Education program, that would equate to approximately 100 refrigerators being replaced per year. Ramp up for this program began in March 2003 and in 2003 there were 121 refrigerators tested and 47 units replaced. The existing refrigerator being replaced is removed from the home and destroyed in an environmentally appropriate manner to assure that the units are not used as a second refrigerator in the home or do not end up in the secondary appliance market. The refrigerator program has been found cost-effective elsewhere.

The Commission gave approval for continuation of the Residential Conservation and Energy Education program under the requirement that efforts be made to improve the cost-effectiveness and increase the level of co-funding or leveraging with other sources of funding. ULH&P, with the cooperation of the service providers, has worked very hard to make this program cost-effective. The leveraging of other funds has increased significantly. In addition, the program was re-designed such that each measure would be installed only if cost-effective.

ULH&P believes this program is cost-effective as a DSM program. In addition, continuation of this program ensures that the Company's disadvantaged customers can participate in ULH&P's portfolio of DSM programs and other funds are leveraged.

Program 2: Residential Home Energy House Call

The Home Energy House Call (HEHC) program consists of three major components:

- Home Energy Survey
- Comprehensive Energy Audit & Review
- Measures Installation Opportunity

When a customer requests a HEHC service, a qualified home energy specialist visited the home to gather information about the household's energy usage. A questionnaire about the energy usage, including appliance efficiencies, was completed. The specialist also performed a walk-through audit and checks the home for air infiltration, inspected the HVAC filter, and surveyed the insulation levels in different areas of the home. A detailed report was generated on site that explained how energy is used each month and a list of prioritized action items was compiled based on energy savings and costs.

In January 2003, ULH&P signed a two-year contract with Enertouch Inc. (dba GoodCents Solutions) to implement the Home Energy House Call program. By doing so, ULH&P is able to provide a more comprehensive program to customers for less than it cost in prior years under the previous contractor. The audit process, itself, remains much the same. Enhancements to the program include a more comprehensive audit report with a stronger focus on the building envelope, and the installation of several energy saving measures at no cost to the customer. The measures include a low-flow showerhead, two aerators, outlet gaskets, two compact fluorescent bulbs, and a motion sensor night-light. Customers can begin realizing an immediate savings on their electric bill by participating in the program. The program has also taken on a more professional look. Auditors are equipped with uniforms, marked trucks, and better equipment necessary to facilitate the audit.

In 2003, a total of 507 audits were completed in Kentucky, just above the goal. The goal was achieved even though ULH&P had to shut down the program for the first two months of 2003 to allow time for putting the new audit processes in place. In September and October 2003, HEHC piggybacked on the work of some 500 students participating in the Kentucky National Energy Education Development (NEED) program. As part of the curriculum on energy conservation in the Kentucky NEED program, Home Energy House Call audits will be offered on a first-come, first-served basis. With the increased response rate to the program this year and the strategy GoodCents proposed to "catch up", the program just exceeded the 2003 annual goal of 500 audits.

Customer satisfaction ratings for the new program to-date are very positive with a rating of 4.8 on a five- point scale for program.

Since the beginning of the program in 1996, over 2,800 customers have participated of which there were 485 in 2000, 500 in 2001, 513 in 2002 and 507 in 2003.

ULH&P believes this program is cost-effective as a DSM program and that it provides tremendous value to the ratepayers.

Program 3: Residential Comprehensive Energy Education

This energy education program was developed by the DSM Collaborative and implemented in late 1997. The contract for implementation of this program was awarded to Kentucky NEED (National Energy Education Development). NEED was launched in 1980 to promote student understanding of the scientific, economic, and environmental impacts of energy. The program is currently available in 36 states, the U.S. Virgin Islands, and Guam.

The program has provided unbiased educational information on all energy sources, with an emphasis on the efficient use of energy. Energy education materials, emphasizing cooperative learning, are provided to teachers. Leadership Training Workshops are structured to educate teachers and students to return to their schools, communities, and families to conduct similar training and to implement behavioral changes that reduce energy consumption. Educational materials and Leadership Training workshops are designed to address students of all aptitudes and have been provided for students and teachers in grades 5 through 12.

The KY NEED program follows national guidelines for materials used in teaching, but also offers additional services such as: hosting teacher/student workshops, sponsoring teacher attendance at summer training conferences, sponsoring attendance at a National Youth Awards Conference for award-winning teachers and students, and providing curricula, free of charge, to teachers.

Since October 1999, 414 Teachers enrolled in the program with 127 Teacher/Student presentations, 240 Teachers attending Teacher workshops and over 2,000 students attending workshops. Overall, the program has reached teachers and students in 71 schools in the six counties served by ULH&P. There are currently 158 teachers enrolled in the program. At a minimum, these teachers have impacted over 4,000 students. In addition, many of the teachers have multiple classes, so the number is potentially higher. Students who attend workshops are encouraged to mentor other students in their schools – further spreading the message of energy conservation. Teams of high school students serve as facilitators at workshops. Through this approach, all grade levels are either directly or indirectly presented the energy efficiency and conservation message. Several of the student teams have made presentations to community groups, sharing their knowledge of energy, promoting energy conservation and demonstrating that the actions of each person impact energy efficiency. It is intended that these students will share this information with their families and reduce consumption in their homes.

As noted in ULH&P's Case No. 2002-00358, the cost-effectiveness of this program is difficult to quantify. To get a better understanding of the impacts of this program, the last evaluation recommended that a better data collection instrument be employed. This data instrument has been developed and will be used in the classroom.

An additional improvement recommended by the evaluation is the addition of energy savings "kits" as a teaching tool. These kits include actual weatherization and conservation measures for the students to install in their homes to get their families directly involved in application of conservation concepts. The actual installation of measures helps increase the directly measurable savings from this program and should increase cost effectiveness. The Collaborative recommended and received approval to include 500 kits for inclusion in the energy curriculum of selected classrooms to increase savings and to improve tracking. These kits were tested in the Spring of 2003 for full implementation in the Fall of 2003 when the science curriculum deals with these issues.

Program 4. Pilot Program: Home Energy Assistance Plus

From January to April 2002, ULH&P and the Northern Kentucky Community Action Commission (NKCAC) implemented a pilot home energy assistance program, Home Energy Assistance Plus. This pilot program was structured to test and evaluate the process and design of a home energy assistance program. The pilot program was designed to impact participants' behavior (e.g. encourage meeting utility bill payments as well as eliminate arrearages) and to generate energy conservation impacts. As reported in the previous filing, in Case 2002-00358, a process evaluation completed for the pilot revealed that it was very labor intensive with limited results.

To address these findings, the DSM Collaborative recommended and received approval for another test program that has a less labor-intensive form of energy education, budget counseling, and bill assistance. A new pilot program for 2003-2004 is in progress to help these low-income customers. The pilot program was established with three parts:

1. Energy & Budget Counseling – to help customers understand how to control their energy usage and how to manage their household bills, a combined education/counseling approach will be used.
2. Weatherization – participants in this program are required to have their homes weatherized as part of the normal Residential Conservation and Energy Education (low-income weatherization) program unless weatherized in past program years.
3. Bill Assistance – to provide an incentive for these customers to participate in the education and weatherization, and to help them get control of their bills, payment assistance credits are provided to each customer when they complete the other aspects of the program. The credits are: $200 for participating in the energy efficiency counseling, $150 for participating in the budgeting counseling, and $150 to participate in the Residential Conservation and Energy Education program. If all of the requirements are completed, a household could receive up to a total of $500. This will allow for approximately 100 homes to participate per year.

This program is offered over six winter months per year starting in November. However, for the first year after approval, the program runs February through July and November through December. Customers will be tracked and the program evaluated after two years to see if customer energy consumption dropped and changes in bill paying habits occurred.

In the first round, through August 2003, 78 customers participated in the Energy Education segment while only 60 customers continued on to receive Budget Counseling. At this point, 17 customers have completed the weatherization component and 13 additional homes are in process. The additional homes should be completed later this year. A second round of classes are scheduled to begin in November, 2003. ULH&P and NKCAC will work to acquire more customers to attend these classes for this second round to make up for the shortfall in the first round. The Company expects to provide detailed information on the impact of this pilot program in the Fall 2004 DSM status report.

C. PRICING PROGRAMS

ULH&P's innovative pricing programs fall into three categories: Interruptible Contracts, PowerShare®, and Real Time Pricing. ULH&P has one contract for interruptible service for 3 MW.

The PowerShare® program is offered under ULH&P Rider PLM. This program was implemented on January 1, 2000, following the success of a 1990s program, Energy Call Options. The PowerShare® program is a market-based program that provides financial incentives in the form of bill credits to our industrial and commercial customers to reduce their electric demand during periods of peak load on the ULH&P system. Customers may choose to participate in either CallOption or QuoteOption.

CallOption requires customers to commit to a pre-selected load reduction, based on historic or usual demand, at a selected strike price. The strike price is selected by the customer based upon the customer's willingness and ability to comply with the call for a load reduction. In return for a commitment to reduce load when called, CallOption customers receive a monthly premium payment from ULH&P as a credit to the bill; in addition, when they are called to reduce load, the customers receive an energy credit based upon the strike price. Customers are offered a day-ahead and same day notification option. The level of incentive depends upon the selected parameters: the contracted for option load and the strike price. The term of the CallOption agreement is four months, June through September, with "built-in" limitations on the number of occurrences (hours) the CallOption can be invoked during the time period.

The second option, QuoteOption, allows customers to elect whether or not to reduce load when called, at a selected minimum price. No monthly premium is paid to QuoteOption customers since they can elect not to respond when called, but an energy credit is paid for load reductions made in response to ULH&P calls.

Because customers have the right to elect whether or not to respond to a call, the QuoteOption essentially offers customers a no risk proposition. While this election feature gives us less control over, and certainty of, load reductions, it also provides us with load reduction from a group of customers that would not participate if they had to contractually commit to mandatory load reductions.

Within the current environment of lower market prices and reduced price volatility, our goal is to maintain the flexibility and optionality that the PowerShare® program provides. Our main emphasis will be retaining the existing PowerShare® base and to continue to cost-effectively add new Customers. We have positioned PowerShare® as a year round program in order to keep Customers engaged and interested in the program. We have simplified the enrollment process through the use of the PowerShare® Web site.

With the reduction of up-front premiums under CallOption due to the drop in market prices, the amount of CallOption load reduction for summer 2003 was only 100 kW. Our primary focus for the future is maintaining customers under the QuoteOption as a hedge against unforeseen changes in market prices and available supply.

ULH&P's RTP program (see Rate RTP) consists of a two-part rate: an access charge for the customer's historic or usual load, billed at standard tariff rates; and an energy charge, for the customer's incremental or decremental energy usage, billed at a real time price. The RTP rate sends price signals to participating customers that encourage usage during low cost periods and discourage consumption in high cost periods. Currently, 25 ULH&P customers participate in RTP with an expected peak load reduction for summer 2003 of about 2 MWs. While this program is scheduled to end in 2004, it was assumed to continue throughout the IRP planning horizon.

D. PLANNED NEW DSM PROGRAM

ULH&P is implementing a new program (Power Manager) that will allow the Company to shave the peak load on hot summer days. Power Manager is a direct load control (DLC) program for the cycling of residential air conditioning during the summer months. Under Power Manager, a load management control device (LM Device) will be installed on the customer's house and connected to the outside central air-conditioning compressor unit (A/C system). This LM Device will allow ULH&P to remotely cycle the A/C system during summer peak load periods (usually during a span from mid-day to early evening) thus reducing the amount of summer peak load. The program will be in effect during the period from May 1 to September 30. A paging system will be used to send load control instructions to the LM Device. It is expected that individual customers will be cycled for approximately 80-100 hours per summer, or on average about 10-12 times per summer.

Power Manager will be offered to residential customers who have a functional central air-conditioning system with an outside compressor unit. The customer (or the owner in the case of customers who rent) must agree to have the LM Device connected to their A/C system and to allow ULH&P to cycle their A/C system. The customer also must be located within the coverage area of the communication system that will be used to control the LM Device.

The initial design of Power Manager has been structured on the same basic principles as the Company's innovative PowerShare® program. Power Manager will couple direct load control with a flavor of "real time pricing" through the Variable Daily Event Incentive structure described below.

Customers who own their home (Owners) will select from two Control Options based on the amount of load reduction they agree to supply: Option A, 1 kW reduction and Option B, 1.5 kW reduction. Owners will receive an installation payment for agreeing to have the LM Device installed which will initially be set at $25.00 for Option A and $35.00 for Option B.

Customers who rent (Renters) will only be offered Option A because of the smaller-sized A/C systems that are typically installed. Additionally, in order to maintain the cost effectiveness of the program due to the high turnover rate for Renters and the fact that Renters do not own the central A/C system, Renters will not receive an installation payment.

Both Owners and Renters will receive a Variable Daily Event Incentive for each day that the A/C system is cycled. For any given day, the Variable Daily Event Incentive will be based on the kW reduction selected by the customer, the number of hours that the A/C system is cycled on any given day and the real time value of electric energy during the control event. For any given control season, the total payments for the Variable Daily Event Incentives will be at least $5.00 for Option A and $8.00 for Option B. The following illustrates the Variable Daily Event Incentive calculation assuming the value of the load reduction is $0.10:

Control Option	***Variable Daily Event Incentive***
Option A	1.0 kW X 8 Hours X $0.10 = $0.80
Option B	1.5 kW X 8 Hours X $0.10 = $1.20

Customers will be able to enroll in the program though a toll-free number and mail-in post cards. As an added benefit, customers will be offered an Event Opt-Out option that will allow them to pre-schedule a limited number of times that they are excluded from a control event under non-system emergency conditions. Customers will have one Opt-Out per month during the summer season. The Event Opt-Out will be implemented through the program's Customer Service Center via a toll free number. ULH&P also plans to have a recorded message via a toll-free number and a message on the Internet to inform customers when a control event may occur and what the price for the event incentive may be.

The enrollment of customers and the installation of the LM Device will be done by GoodCents Solutions out of Atlanta, Georgia. GoodCents currently provides customer support services for other ULH&P DSM programs and is providing customer and installation services for the IP&L and LG&E direct load control programs. Corporate Systems Engineering based in Indianapolis, Indiana, is the supplier of the LM Devices and is providing the software system used to cycle the A/C system.

The installation payment and the Variable Daily Event Incentive will be given to the customer in the form of credits on their bill. The tracking and the calculation of the bill credits will be done by GoodCents and transferred electronically to ULH&P's billing system.

E. DSM PROGRAMS AND THE IRP

The projected impact of the DSM programs discussed above have been included in the least-cost supply plan for ULH&P. The conservation DSM programs are projected to reduce energy consumption 3,100 MWH and 1 MW by the end of 2005. These impacts are included in the IRP analysis. The direct load control program is projected to reduce peak demand 12 MW by the end of 2007. Combining the direct load control projected impacts with those for the interruptible, PowerShare®, and RTP programs produces a projected load management impact of 17 MW by 2007. The following table summarizes the projected load management impacts included in this IRP analysis.

Projected Load Management Impacts
(MW)

Year	Interruptible	RTP	CallOption	Direct Load Control	Total
2003	3	2	0.1	0	5
2004	3	2	0.1	1.5	7
2005	3	2	0.1	4.6	10
2006	3	2	0.1	7.7	13
2007	3	2	0.1	10.8	16
2008	3	2	0.1	12.4	18
2009	3	2	0.1	12.4	18
2010	3	2	0.1	12.4	18
2011	3	2	0.1	12.4	18
2012	3	2	0.1	12.4	18
2013	3	2	0.1	12.4	18
2014	3	2	0.1	12.4	18
2015	3	2	0.1	12.4	18
2016	3	2	0.1	12.4	18
2017	3	2	0.1	12.4	18
2018	3	2	0.1	12.4	18
2019	3	2	0.1	12.4	18
2020	3	2	0.1	12.4	18
2021	3	2	0.1	12.4	18
2022	3	2	0.1	12.4	18
2023	3	2	0.1	12.4	18

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5. SUPPLY-SIDE RESOURCES

A. INTRODUCTION

The phrase "supply-side resources" encompasses a wide variety of options. These can include existing generating units on a utility's system, repowering or refurbishing options for these units, existing or potential purchases from other utilities, IPPs and cogenerators, and new utility-built generating units (conventional, advanced technologies, and renewables). The evaluation of these options considers technical feasibility, fuel availability and price, length of the contract or life of the resource, construction or implementation lead time, capital cost, O&M cost, reliability, and environmental effects. This chapter will discuss in detail the specific options considered, the screening processes utilized, and the results of the screening processes.

B. EXISTING UNITS

ULH&P does not currently own any generating units. Instead, it is served via a wholesale Power Sales Agreement (PSA) from CG&E as discussed in Section D below.

C. EXISTING NON-UTILITY GENERATION

ULH&P does not currently have any contracts with non-utility generators.

Some of ULH&P's customers have electric production facilities for self-generation, peak shaving, or emergency back-up. Non-emergency self-generation facilities are normally of the baseload type and are generally sized for reasons other than electric demand (e.g., steam or other thermal demands of industrial processes or heating). Peak shaving equipment is typically oil- or gas-fired and generally is used only to reduce the customer's peak billing demand. Depending on whether it is operated at peak, this capacity can reduce the load otherwise required to be served by ULH&P which, like DSM programs, also reduces the need for new capacity. The relationship of these facilities to the load forecast was discussed in Chapter 3. Some of these customers are participants in ULH&P's PowerShare® program which was discussed in Chapter 4. In compliance with the standards of conduct in FERC Order 889, any effects of these facilities on transmission and distribution planning are discussed in the Transmission Volume of this report, which was prepared independently.

D. EXISTING POOLING AND BULK POWER AGREEMENTS

At present, ULH&P does not participate in any type of power pooling because it does not own any power generating units.

ULH&P is currently a 100% wholesale requirements customer of CG&E. In recent times, up until January 1, 2002, ULH&P received its full requirements of electric power from CG&E under a FERC-approved cost-of-service-based wholesale power tariff. Under this wholesale power tariff, ULH&P paid a bundled price for transmission and generation services from CG&E. This bundled price was based on the FERC-approved costs of owning, operating and maintaining the FERC-jurisdictional portion of CG&E's transmission and generation assets.

Since January 1, 2002, ULH&P has received its full requirements of electric power to serve its retail customers from CG&E pursuant to a Power Sales Agreement approved, subject to certain conditions, by the Kentucky Public Service Commission in Case No. 2001-00058. This Power Sale Agreement is a market-based, fixed price agreement under which ULH&P is assessed a monthly demand charge of $7200 per megawatt (MW) based on its peak demand for the month, and an energy charge of $24 per megawatt-hour (MWH). ULH&P contracts separately with the Midwest Independent Transmission Operator, Inc. (MISO) through Cinergy Services, Inc. (Cinergy Services), for bulk transmission service to transport electric power from CG&E's plants and from outside the Cinergy system through the Cinergy transmission system to ULH&P's transmission system for ultimate delivery to ULH&P's distribution system and end-use retail customers. The contract for this service expires on 12/31/06. The modeling in this IRP consisted of modeling this PSA through its expiration date and then considering a number of supply-side and demand-side alternatives from 2007 forward.

Cinergy is interconnected directly with East Kentucky Power Cooperative, Inc., LGE Energy/Kentucky Utilities, American Electric Power, The Dayton Power and Light Company, Ohio Valley Electric Corporation, Ameren, Hoosier Energy, Indianapolis

Power and Light, Northern Indiana Public Service, and Southern Indiana Gas and Electric, and indirectly with the Tennessee Valley Authority.

As a matter of routine operation, Cinergy contacts neighboring utilities, utilities beyond them, power marketers, and power brokers on a daily basis in the interest of promoting opportunistic purchases and sales. Cinergy also routinely meets with utilities in the region generally to discuss the daily interconnection operations, opportunities for short-term energy transactions which may be beneficial to both parties, and the long term purchase/sale of capacity as an alternative to the construction/operation of additional generation facilities.

Cinergy has numerous single and multi-year contracts to buy and sell power. However, since these power transactions do not contractually obligate Cinergy to either build generation to serve them, or to be forced to take the power to supply jurisdictional customers, the capacity associated with these contracts has not been included in the expansion plan modeling. Further information on power contracts not associated with franchised service territory jurisdictional loads is considered to be trade secrets and proprietary competitive information.

E. NON-UTILITY GENERATION AS FUTURE RESOURCE OPTIONS

It is Cinergy's practice to cooperate with potential cogenerators and independent power producers. A major concern, however, exists in situations where either customers would be subsidizing generation projects through higher than avoided cost buyback rates, or the safety or reliability of the electric system would be jeopardized. Cinergy typically receives several requests a year for independent/small power production and cogeneration buyback rates. ULH&P does not currently have any contracts for cogeneration. However, ULH&P has two cogeneration tariffs available to customers and is in the process of updating these tariffs. ULH&P will supply any customer interested in cogeneration with a copy of these tariffs and will discuss options with that customer. ULH&P is currently in discussions with one customer.

A customer's decision to self-generate or cogenerate is, of course, based on economics. Customers know their costs, profit goals, and competitive positions. The cost of electricity is just one of the many costs associated with the successful operation of their business. If customers believe they can lower their overall costs by self-generating, they will investigate this possibility on their own. There is no way that a utility can know all of the projected costs and/or savings associated with a customer's self-generation. However, during a customer's investigation into self-generation, the customer usually will contact the utility for an estimate of electricity buyback rates. With ULH&P's comparatively low electricity rates and avoided cost buyback rates, cogeneration and small power production are generally uneconomical for most customers.

For these reasons, Cinergy does not attempt to forecast specific Megawatt levels of this activity in its service area. Cogeneration facilities built to affect customer energy and demand served by the utility are captured in the load forecast. Cogeneration built to provide supply to the electric network represent additional regional supply capability. As purchase contracts are signed, the resulting energy and capacity supply will be reflected in future plans. The electric load forecasts discussed in Chapter 3 do consider the impacts on electricity consumption caused by the relative price differences between alternate fuels (such as oil and natural gas) and electricity. As the relative price gap favors alternate fuels, electricity is displaced, lowering the forecasted use of electricity and increasing the use of the alternate fuels. Some of the decrease in forecasted electricity consumption may be due to self-generation/cogeneration projects, but the exact composition cannot be determined.

Cinergy has direct involvement in the cogeneration area. Cinergy Solutions, an affiliate of ULH&P, builds, owns, and operates cogeneration and trigeneration facilities for industrial plants, office buildings, shopping centers, hospitals, universities, and other major energy users that can benefit from combined heating/cooling and power production economies.

Other supply-side options such as simple-cycle Combustion Turbines, Combined Cycle units, Fuel Cells, coal-fired units, and/or renewables (all discussed later in this chapter) could represent potential non-utility generating units, power purchases, or utility-constructed units. At the time that ULH&P initiates the acquisition of new capacity, a decision will be made as to the best source.

F. SUPPLY-SIDE RESOURCE SCREENING

A list of over one hundred supply-side resources was developed as potential alternatives for the IRP process. Due to the size and run time limitations of the STRATEGIST® integration model (described in detail in Chapter 8), it was necessary to determine, through a screening process, which of these resources were the most viable and cost-effective.

1. Process Description

Information Sources

Most of the specific technology parameters used in the screening process were based on information taken from the Technical Assessment Guide® (TAG®) - Central Stations report dated December 2000 and the Technical Assessment Guide Supply-Side Technologies program (TAG-Supply™), Version 3.11, produced by the Electric Power Research Institute (EPRI) of Palo Alto, California. The TAG® is proprietary to EPRI and provides up-to-date information for use in the preliminary stages of supply-side planning analyses and studies. It contains conventional and advanced power generation technologies, including their current status and trends for future development, estimated cost and power performance data, economic factors, and environmental emissions data. In addition to the EPRI information, Sargent & Lundy (S&L) prepared a study for Cinergy that contained cost and performance data for potential new pulverized coal and fluidized bed plants. Cinergy considers the S&L study to be confidential and competitive information. The

2001 report "Repowering the Midwest" by the Environmental Law & Policy Center and other groups was the source for additional renewable cost information. Cinergy-specific price estimates for Combustion Turbines and Combined Cycle Units provided by Cinergy's engineering department were also used to supplement the EPRI data. Cinergy also considers these estimates to be confidential and competitive information.

Technical Screening

The first step in the screening process was a technical screening of the technologies to eliminate those that are not feasible in the Cinergy service territory. The two general categories of resources that were eliminated were Geothermal, because there are no suitable geothermal sources in this area, and Nuclear, because of current regulatory/political/environmental concerns. Further technical screening involved determining which technologies to consider within each of the two time periods: 2003-2012 and 2013-2023. Because the TAG® contains emerging technologies that are not yet commercially viable, only technologies whose Technical Development Rating was either Mature or Commercial were considered available to go in service between 2003 and 2012. All technologies (Mature, Commercial, Demonstration, and Pilot) were considered to be available beginning in 2013. The costs contained in the TAG® are intended to represent mature plant costs, so the estimated costs for Demonstration or Pilot technologies may differ substantially from those achieved at the time the technology is commercially available.

Economic Screening

The next step in the screening process was to screen economically the specific technologies within each general technology class against each other to determine the "Best in Class." Additional screening of these survivors across classes would occur later in the analysis. The ten general technology classes were:

Pulverized Coal

Fluidized Bed

Integrated Coal Gasification Combined Cycle

Combined Cycle

Simple Cycle Combustion Turbines

Fuel Cells

Wind

Solar

Other Renewables

Storage

The fuel prices used for the specific technologies within each class were representative fuel costs for Cinergy's service territory. The technologies were then screened using relative dollar per kilowatt-year versus capacity factor screening curves. The screening within each general class as well as the final screening across the general classes used a spreadsheet-based screening curve model developed by Cinergy.

This screening curve analysis model calculates the fixed costs associated with owning and maintaining a technology type over its lifetime and computes a levelized fixed $/kW-year value. This value represents the cost of operating the technology at a zero capacity factor or not at all, i.e., the Y-intercept on the graph (see the General Appendix for individual graphs). Then the variable costs, such as fuel, variable O&M, and emission costs associated with operating the technology at 100% capacity factor, or at full load, over its lifetime are calculated and the present worth is computed back to the start year. This levelized operating $/kW-year is added to the levelized fixed $/kW-year value to arrive at a total owning and operating value at 100% utilization in $/kW-year. Then a straight line is drawn connecting the two points. This line represents the technology's "screening curve". This process is repeated for each supply technology to be screened resulting in a family of lines (curves). The lower envelope along the curves represents the least costly supply options for various capacity factors or unit utilizations.

Lines that never become part of the lower envelope, or those that become part of the lower envelope only at capacity factors outside of their relevant operating range, probably will not be part of the least cost solution, and therefore can be eliminated from further analysis. Whenever the screening curves for technologies with generic cost estimates were essentially the same as technologies with more detailed Cinergy cost estimates, the technology with the more detailed cost estimate was chosen.

2. Screening Results

Figures 5-1 through 5-11 show the technologies screened within each of the ten classes and identify which candidates within each class were the least cost, "Best in Class." As mentioned earlier, these survivors were passed to the next screening step involving across-class screening. The results of the screening within each class are discussed in more detail below.

Pulverized Coal

Figure GA-5-12 in the General Appendix shows the screening curve for the pulverized coal units. The Brownfield 467 MW Supercritical coal unit was the "Best in Class" in the relevant capacity factor range.

Fluidized Bed

Figure GA-5-13 shows the screening curve for the period 2003-2012, and Figures GA-5-14 through GA-5-16 show the results for the period after 2012. The Brownfield 459 MW unit was the "Best in Class" in the first ten years and the 350 MW PFBCPCFB unit was the "Best in Class" for installation after 2012.

Integrated Coal Gasification Combined Cycle

There were no Mature or Commercial technologies in the 2003-2012 time period. Figure GA-5-17 shows the screening curve for the time period after 2012. The "Best in Class" technology was a 460 MW Advanced GCC unit.

Simple Cycle Combustion Turbines

Cinergy's engineering department provided estimates for 156 MW (summer rating) 7FA CTs to be screened along with the TAG® technologies. Figures GA-5-18 and GA-5-19 show that the "Best in Class" CTs were the Cinergy-specific 7FA units for both time frames.

Combined Cycle

As with the Simple Cycle CTs, Cinergy's engineering department provided Cinergy-specific prices for a 477 MW (summer rating) Brownfield CC and for repowering Edwardsport as a natural gas CC plant to be screened along with the TAG® technologies (although a Brownfield CC and repowering Edwardsport are not resources that are available to ULH&P). The cost of a 477 MW Greenfield CC was also extrapolated from these estimates and used in the screening. For the period 2003-2012, the Cinegy-specific Greenfield CC, Brownfield CC, and Repowering Edwardsport units were the "Best in Class" as shown in Figure GA-5-20. For 2013-2023, the "Best in Class" Combined Cycle units were the Cinergy-specific Greenfield and Brownfield CC units, as shown in Figure GA-5-21.

Fuel Cells

The 2 MW Phosphoric Acid Ambient Pressure Fuel Cell was the only viable alternative for the 2003-2012 time frame. For the period after 2012, the Phosphoric Acid, Molten Carbonate, and the Solid Oxide Fuel Cells (including the Hybrid Fuel Cell from "Repowering the Midwest") were screened against each other as shown in Figure GA-5-22. The "Best in Class" unit was a 25 MW Pressurized Solid Oxide Pressurized Fuel Cell.

Alternative Technologies - Overview

The information obtained from a continuing review of available alternative energy technologies was considered in the preparation of the 2003 IRP. There is a very limited opportunity to apply renewable resource technologies in the Cinergy service territory. With most wind speeds averaging less than what is needed for a Class 3 wind site, generation of significant amounts of electricity using wind energy is not cost-effective relative to more conventional technologies. In addition, the actual capacity that would be available from wind resources at the time of summer peak (when the capacity is needed the most) is, at best, significantly less than the installed capacity. This means that considerably more capacity (at a correspondingly higher capital cost) would need to be installed for the wind capacity to be equivalent to the dependable capacity of a conventional technology resource. With regard to solar power, there is relatively low solar power density in this area, so generation of significant amounts of electricity using solar energy is not cost-effective relative to more conventional technologies. This is not to say that these technologies may not be feasible in supplying limited amounts of power in remote locations or in other special applications. However, under current assumptions, they continue to be not as cost competitive or as reliable in this part of the Midwest as the more conventional power supply technologies.

Biogas, or landfill gas, generally has both high levels of contaminants and a low-heat content resulting in an overall quality far below that required for pipeline quality natural gas. It is possible to process the gas to pipeline quality standards but doing so increases the cost. This low grade gas may be collected, transported short distances, and used in various manufacturing processes, but this activity is generally best suited to private enterprise ventures, not utility-scale projects. To Cinergy's knowledge, a small number of private companies currently collect landfill gas to burn in on-site CTs at a few different landfills within Cinergy's service territory.

At the present time, the use of tire-derived fuel is not a significant utility-scale energy source. Over time, as operational and environmental issues are resolved, tires or tire residue may become a competitive, but limited, fuel source.

Municipal solid waste (MSW) burning to produce energy is rarely economical from the energy production standpoint. The technology to burn this waste cleanly and reliably is very expensive. Generally, when communities resort to MSW burning it is to dispose of the waste more economically than alternative methods, not to generate low-cost energy. In most instances, the energy sales help to offset some of the costs associated with burning the waste. Siting a MSW burning facility is also a challenge. Concerns abound about truck traffic, odors, vectors, and air toxins. The Public Utility Regulatory Policies Act of 1978 (PURPA) obligates the Cinergy utilities to purchase power and energy from a MSW facility within its franchised service territories. However, Cinergy will defend electric customers against subsidizing the disposal costs of municipal solid wastes.

Biomass energy production facilities are generally limited by the availability of fuel within about a 50-mile radius. This is a result of the bulk material handling problems due to the low heat content of current biomass fuels. This limitation negatively impacts both the size and economics of biomass energy facilities. Development of specialized energy crops and further technology developments will be necessary to permit expansion of biomass-generated energy.

Storage technologies such as Pumped Hydro and Compressed Air Energy Storage (CAES) generally have limited application due to the need for suitable geologic formations. Other storage technologies such as Batteries and

Superconducting Magnetic Energy Storage (SMES) are applicable to more areas, but the storage time (one to five hours) is a limiting factor. Presently, batteries perform best in systems that require relatively short bursts of energy on an infrequent basis. Demonstration plants such as the 10 MW CHINO Battery Plant at Southern California Edison have been difficult to maintain and have proven to be more suitable for power delivery system stabilization than as a capacity resource. Other demonstration projects, such as EPRI's Transportable Battery System, should further quantify the benefits and appropriate applications of battery storage systems. However, at this point in time, large utility scale battery storage systems are not commercially viable.

The focus of Cinergy's R&D efforts with regard to Alternative Technologies is to provide planning and evaluation methods to assure a strategic advantage in the deployment of emerging technologies and the use of storage to manage energy supply. Despite the fact that Alternative Technologies are generally not economic in comparison to more traditional technologies, they were included nevertheless as part of the screening process to allow an economic comparison between the different technologies and to allow sensitivity analysis around base assumptions to be performed. The specific Alternative Technologies included in the supply-side screening are discussed below:

Wind

The only Mature or Commercial wind technology available during the 2003-2012 time period was a 50 MW plant in "Repowering the Midwest". The 100 MW Wind plant contained in "Repowering the Midwest" was selected for final screening for the 2013-2023 time frame as shown in Figure GA-5-23.

Solar

The flat plate Solar units in "Repowering the Midwest" were the only technologies that were either Mature or Commercial during the 2003-2012 period. During the 2013-2023 period, the "Best in Class" technology was also the Solar unit from "Repowering the Midwest" as shown in Figure GA-5-24.

Other Renewable Resources

For both time periods, the technologies were divided into the groupings of Municipal Solid Waste and Biomass-Fueled units. The screening curves for 2003-2012 and for 2013-2023 are shown in Figures GA-5-25 through GA-5-26. The 75 MW and 100 MW Biomass GCC from "Repowering the Midwest" were the "Best in Class" units for the 2003-2012 and 2013-2023 time frames, respectively.

<u>**Storage**</u>

The categories of Batteries, Pumped Hydro, Compressed Air, and Superconducting Magnetic Storage were used. The screening results for 2003-2012 are shown in Figure GA-5-27. The 20 MW Light Duty Lead Battery was the most economical. The screening curve for 2013-2023 is shown in Figure GA-5-28. The 20 MW Light Duty Lead Battery and the 350 MW Compressed Air Storage unit using Porous media unit were the most economical over their respective capacity factor ranges.

3. Other Technologies Considered

<u>**Other Hydro Resources**</u>

Hydro resources tend to be site-specific; therefore, Cinergy normally evaluates both pumped storage capacity and run-of-river energy resources on a project-specific basis.

<u>**Repowering Resources**</u>

Cinergy's 1995 IRP filing contained an extensive screening of repowering options at Cinergy's generating stations (see Cinergy 1995 IRP, Chapters 5 and 6). As discussed earlier, a specific cost estimate for repowering Edwardsport was included in the CC screening. In addition, since the cost estimate for Combined Cycle repowering at Edwardsport was similar to the cost of a new Combined Cycle plant, the characteristics of the new plant can act as a proxy for repowering in the planning analysis. If this technology is consistently selected as an economic alternative in the final integration process, repowering existing sites will be thoroughly investigated prior to initiating construction of a combined cycle facility at a new site. However, as discussed earlier, ULH&P does not currently own any generation.

4. Final Supply-Side Alternatives

The "Best in Class" technologies that survived the above screening process within each of the previous technological categories are listed in Figure 5-29. These technologies were then screened against each other, or across all classes, to develop the final supply-side alternatives to be carried into the integration model.

The resultant final screening curve for 2003-2012, Figure GA-5-30, shows that the 7FA CT, the Greenfield CC, the Brownfield CC, Repowering Edwardsport, and the Brownfield Pulverized Coal units make up the lower envelope of the final curve. The curve for the 2013-2023 period, Figure GA-5-31, shows that the Combustion Turbine, the Combined Cycle, Solid Oxide Fuel Cell, and 350 MW fluidized bed units make up the lower envelope of the final curve over their respective capacity factor ranges. While the screening curve shows that the Wind resource might be economical relative to Combined Cycle units if it can achieve capacity factors greater than about 30%, in reality the screening curve analysis greatly overstates the value of Wind due to the reduced level of capacity actually available on peak, as discussed earlier.

As a result of the screening process, the following supply technologies were selected to be utilized as candidate supply-side resources in the STRATEGIST® dynamic integration computer runs: 1) 156 MW 7FA CT units for the 2007-2023 time period, 2) 477 MW Greenfield Combined Cycle units for the 2007-2023 time period, 3) 467 MW Brownfield PC units for the 2008-2012 time period, 4) 350 MW PFBCPCFB units for the 2013-2023 time period, and 5) 25 MW Fuel Cells for the 2013-2023 period. More detailed information on the final supply side technologies screened can be found in Figures GA-5-32 and GA-5-33. Since the SO_2 and NO_x emissions of each of these potential resources will be modeled in the integration process, their effects on compliance with the Clean Air Act Amendments of 1990 and the NO_x SIP Call were factored into the analysis.

5. Screening Sensitivities

The screening model also can provide useful information concerning how much certain input parameters would need to change to make a technology that is not in the lower envelope under base assumptions become economical. Sensitivities were performed on each "Best in Class" final technology type in the 2003-2012 time period to determine what data input and/or assumption changes would be necessary to move it into the lower envelope (i.e., become an economic choice) within the relevant capacity factor range. Sensitivities were not performed for the 2013-2023 time frame because little additional information relevant to immediate resource decisions would be gained.

This methodology using the screening model (rather than performing all sensitivities at the end of the analysis) is more efficient and provides a better understanding of the magnitude of changes in fuel prices, Emission Allowance prices, capital costs, etc., that will affect resource decisions. In addition, it allows the most economical technologies from each individual class to be included in the sensitivity analysis.

Fluidized Bed

The parameters that should have the greatest impact on fluidized bed unit economics are relative fuel prices (coal prices versus gas prices), capital cost, and emission allowance prices. A sensitivity study showed a reduction in coal prices of 30% is necessary before the fluidized bed unit would become competitive at between 60% and 65% capacity factor (see Figure GA-5-34). An increase of 10% in gas prices is necessary before the pulverized coal unit and fluidized bed unit would become competitive at between 60% and 65% capacity factor (see Figure GA-5-35). However, the PC unit still slightly dominates the CFBC unit, so that the CFBC unit never becomes economic. Figure GA-5-36 shows that the estimated capital cost of the fluidized bed unit would have to decrease by 15% to make the unit economical at between 60% and 65% capacity factor. The unit is insensitive to emission allowance price changes in that it did not become economical even when reducing SO_2, NO_x, or both SO_2 and NO_x allowance prices to $0/ton (see Figures GA-5-37 through GA-5-39).

Fuel Cell

The parameters that should have the greatest impact on Fuel Cell economics are relative fuel prices (coal prices versus gas prices), and capital cost. The Fuel Cell was insensitive to changes in gas prices because the CT, Greenfield CC, Brownfield CC, and Repower Edwardsport units, which also use gas, were already more economical and continued to dominate it. The estimated capital cost had to be reduced by at least 90% to make the Fuel Cell competitive with the CT and CC units (see Figure GA-5-40).

Wind

For wind to be economical in a relevant capacity factor range, the estimated capital cost must be reduced by at least 20% to compete with CT and Combined Cycle units, and, even then, the wind resource is limited in Cinergy's service area as discussed earlier (see Figure GA-5-41). Because of the high capital cost of wind units, gas prices would have to be double their base case levels before the technology would be marginally competitive (see Figure GA-5-42).

Solar

For solar to be economical in a relevant capacity factor range, the estimated capital cost must be reduced by 75% to compete with Combined Cycle units, and, even then, the insolation is limited in the Midwest as discussed earlier (see Figure GA-5-43). Because of the high capital cost of solar units, even if gas, prices were 6 times their base case levels, the technology would not be competitive (see Figure GA-5-44).

Biomass

For the Biomass unit to become competitive with a Combined Cycle unit, a 70% decrease in the estimated capital cost would be necessary (see Figure GA-5-45). Alternatively, gas prices would have to be double their base case levels for the Biomass unit to be competitive (see Figure GA-5-42).

Battery

The major shortcoming of the Battery is its lack of flexibility due to its one-hour storage time in comparison with the allowable runtime of the CT. Given that the load during the hours immediately prior to and after the system peak can be almost the same magnitude as the system peak, these resources will not be able to compete with more conventional technologies for serving the system peak load until the storage times of Battery resources are increased.

6. Environmental Sensitivities

The "Best in Class" Technologies also were screened using more stringent environmental regulation assumptions to determine the resulting changes in their relative economics. To perform this analysis, the Cinergy screening curve model was modified to incorporate CO_2 emissions from each unit as well as the estimated emission allowance price for CO_2 emissions. The costs of the CO_2 emissions were then added to the other unit costs to develop the screening curves.

CO_2

The allowance price assumed for the CO_2 sensitivity was $23.64/ton ($21/ton in 1999 dollars escalated at 3% per year), which was derived from the U.S. Energy Information Administration (EIA) study "What Does the Kyoto Protocol Mean to U.S. Energy Markets and the U.S. Economy?". This is equivalent to $87.05/metric ton of carbon. Figure GA-5-46 shows the results of the screening for 2003-2012. As expected, renewable technologies became relatively more economical, especially in comparison to coal-burning technologies, but CTs and CCs continued to be the most economical overall. Figure GA-5-47 shows the results of the screening for 2013-2023, which utilized an allowance price of $31.76/ton in 2013 dollars ($21/ton escalated at 3% per year). Again, renewable technologies became more economical in comparison to coal-burning technologies, but CTs, CCs, and Fuel Cells were still the most economical choices. Although the Wind resource appears to be marginally economical according to the screening curve, this analysis is misleading due to its capacity problems that have been discussed previously.

<u>**Summary of Screening Sensitivities**</u>

Since the most economical technologies did not change for the 2003-2012 period, no additional technologies were passed to the Integration stage of the IRP process. However, Cinergy will continue to monitor the renewable and storage technologies that looked more promising under the more stringent environmental assumptions for possible inclusion in future planning scenarios. In addition, if specific proposals for these types of technologies are received, Cinergy will analyze them in more depth.

7. Unit Size

As described previously, various unit sizes were screened for most of the technology classes. The unit sizes selected for planning purposes generally are the largest technologies available today because they generally offer lower $/kW installed capital costs due to economies of scale. However, the true test of whether a resource is economic depends on the economics of an overall resource plan that contains that resource (including fuel costs, O&M costs, emission costs, etc.), not merely on the $/kW cost.

8. Cost, Availability, and Performance Uncertainty

Supply-side alternative costs used for planning purposes for conventional technology types such as Simple Cycle Combustion Turbine units and Combined Cycle units are relatively well known and are estimated in the TAG® and can be obtained from vendors. Cinergy's experience also confirms their reasonability. The TAG® costs include step-up transformers and a simplified substation to connect with the transmission system. Since any additional transmission costs would be site-specific and since specific sites requiring additional transmission are unknown at this time, the screening process did not include other transmission costs. However, the Cinergy-specific alternatives did include all costs. A listing of the projected generating facility costs from the screening curves can be found in Figures GA-5-32 and GA-5-33. The availability and performance of conventional supply-side options is also relatively well known and the TAG® contains estimates of these parameters.

9. Lead Time for Construction

The estimated construction lead time and the lead time used for modeling purposes for the proposed Simple Cycle Combustion Turbine units is about two years. For the Combined Cycle units, the estimated lead time is about two to three years. For coal units, the lead time is approximately five years. However, the time required to obtain regulatory approvals and environmental permits adds uncertainty to the process, so judgment is used also.

10. RD&D Efforts and Technology Advances

New energy and technology alternatives are needed to ensure a long-term sustainable electric future. Cinergy's research, development, and delivery (RD&D) activities enable Cinergy to track new options including modular and potentially dispersed generation systems, Combustion Turbines, and advanced fossil technologies as well as enhancements to existing fossil power facilities. Emphasis is placed on providing information, assessment tools, validated technology, demonstration/deployment support, and RD&D investment opportunities for planning and implementing projects utilizing new fossil power generation technology to assure a strategic advantage in electricity supply and delivery. Cinergy is also a member of EPRI.

Within the 20-year horizon of this forecast, it is expected that significant advances will continue to be made in Combustion Turbine technology. Advances in stationary industrial Combustion Turbine technology should result from ongoing research and development efforts to improve both commercial and military aircraft engine efficiency and power density.

Cinergy's RD&D activities also involve Fuel Cell technology. For example, by joining forces with the U.S. Government and Ballard Generation Systems, Cinergy installed one of the world's first 250 kW class, natural gas-powered Fuel Cells. This unit was installed in 1999 at the Naval Surface Warfare Center located in Crane, Indiana. Cinergy also licensed a 3 kW hydrogen Fuel Cell from Ballard to help develop military and civilian applications. In addition, Cinergy participates in the IEEE Fuel Cell Standards Committee to establish national standards for stationary deployment.

11. Coordination With Other Utilities

Decisions concerning coordinating the construction and operation of new units with other utilities or entities are dependent on a number of factors including the size of the unit versus each utility's capacity requirement and whether the timing of the need for facilities is the same. To the extent that facilities that are too large to fit well into the resource plan become economically viable in a plan, co-ownership can be considered at that time. Coordination with other utilities can also be achieved through purchases and sales in the bulk power market.

G. ADDITIONAL SUPPLY-SIDE RESOURCES CONSIDERED

In this IRP, ULH&P also considered the acquisition of CG&E's ownership of East Bend 2, Miami Fort 6, and Woodsdale 1-6, in conjunction with a Back-up Power Sales Agreement (PSA) for East Bend 2 and Miami Fort 6, as potential supply-side resources.

1. Description

Figure 5-48 contains information concerning these CG&E generating units. This includes the station name and location, unit number, type of unit, installation date, tentative retirement year, net dependable summer and winter capability (CG&E share), and current environmental protection measures. For those units which are jointly owned with other utilities, Figure 5-49 shows the total capability of the unit and the share owned by each company. The approximate fuel storage capacity at each of these stations is shown in Figure 5-50. The specific analyses including these units is discussed in Chapter 8.

2. Availability

The unplanned outage rates of the units used for planning purposes were derived from the historical Generating Availability Data System (GADS) data on these units. Planned outages were based on maintenance requirement projections as discussed below. This IRP assumes that these generating units generally will continue to operate at their present availability and efficiency (heat rate) levels.

3. Maintenance Requirements

A comprehensive maintenance program is important in providing reliable low cost service. The following tabulation outlines the general guidelines governing the preparation of a maintenance schedule for existing units operated by Cinergy. It is anticipated that future units will be governed by similar guidelines.

Scheduling Guidelines for Cinergy Units

1. Major maintenance on baseload units 400 MW and larger is to be performed at about six to ten year intervals (East Bend 2).
2. Major maintenance on intermediate-duty units between 140 MW and 400 MW is to be performed at about six to twelve year intervals (Miami Fort 6).

3. Due to the more limited run-time of other units, judgment and predictive maintenance will be used to determine the need for major maintenance (Woodsdale 1-6).

In addition to the regularly scheduled maintenance outages, beginning in 1999, a program of "availability outages" was instituted. These are unplanned, opportunistic, proactive short duration outages aimed at addressing potential summer failure situations. At opportune times, when it is economic to do so, units not scheduled for a maintenance outage may be taken out of service for up to a week in order to perform preventive maintenance activities. This enhancement in maintenance philosophy reflects Cinergy's focus on having the generation available during peak periods (e.g., the summer months). Generating station performance is now measured primarily by reference to hours of availability for the peak hours of the day. Moreover, targeted, plant-by-plant assessments of the causes of all forced outages that occurred during 1999, 2000, 2001, and 2002 have been performed to further focus actions during maintenance and availability outages. (The 2003 assessment is not yet complete). Finally, in 2000, system-wide and plant-specific contingency planning was instituted to ensure an adequate supply of labor and materials when needed, with the goal of reducing the length of any forced outages.

The general maintenance requirements for all of the existing generating units were entered into the STRATEGIST® model (described in Chapter 8) which was used to develop the IRP.

4. Fuel Supply

Coal

The goal of Cinergy's Fuels Department is to provide a reliable supply of fuel in quantities sufficient to meet generating requirements, of the quality required to meet environmental regulations, at the lowest reasonable cost. The "cost" of the coal is the evaluated cost which includes the purchase price of the coal FOB the shipping point, transportation to the stations, sulfur content, and the effects of the coal quality on boiler operation and station operation.

Cinergy has set broad fuel procurement policies such as contract/spot ratios and inventory levels that aid in contract negotiations. Cinergy generally will seek the expertise of an independent consultant to review such policies. The policies are then combined with economic and market forecasts and probabilistic dispatch models to provide a five-year strategy for fuel purchasing. The strategy provides a guide to meet the goal of having a reliable supply of low cost fuel.

To provide fuel supply reliability, Cinergy purchases coal from a widely dispersed supply area, uses a mix of term contract and spot market purchases, and purchases from a variety of proven suppliers. Cinergy also maintains stockpiles of coal at each station to guard against short-term supply disruptions.

Coal supplied to Cinergy currently comes primarily from the states of Ohio, Indiana, Kentucky, Pennsylvania, West Virginia and Illinois. These states are rich in coal reserves with decades of remaining economically recoverable reserves.

East Bend and Miami Fort 6 customarily receive approximately 70% to 80% of their annual coal requirements under long-term coal supply agreements. Contract commitments offer Cinergy greater reliability than spot market purchases. The financial stability, managerial integrity, and overall reliability of the suppliers is evaluated prior to entering into a contractual commitment. Dedicated, proven reserves assure coal supply of the specified quantity and quality. Specified pricing, delivery schedules, and length of contract provide suppliers with the financial stability for capital investment and labor requirements and guard Cinergy against primarily upward price fluctuations in the market while allowing Cinergy to take advantage of price reductions in the market. This is accomplished using a combination of low fixed escalation, market re-openers at Cinergy's sole option, contract extension options and volume flexibilities.

The remainder of its fuel needs at East Bend and Miami Fort 6 is filled with spot coal purchases. Spot coal purchases are used to 1) take advantage of low priced incremental tonnage, 2) test new coal supplies, and 3) supplement coal during peak periods or during contract delivery disruptions.

Cinergy also maintains coal stockpiles at the stations in order to assure fuel supply reliability. In general, disruptions that could affect the coal supply are evaluated along with their potential duration, and the probability that they will occur. Sufficient coal is then kept on hand to meet those potential supply disruptions.

Natural Gas

Cinergy's use of natural gas for electric generating purposes has generally been limited to peaking applications. This natural gas is currently purchased on the spot market and is transported (delivered) using interruptible transportation tariffs. The high hourly demand combined with the low capacity factor associated with this type of application make contracting for firm gas and transportation non-economic. The gas supply for Woodsdale is managed under a Gas Supply and Management Agreement with Cinergy Marketing & Trading (CM&T), an affiliate of ULH&P. CM&T supplies the full requirements of natural gas needed by Woodsdale either by selling the gas from supplies owned or controlled by CM&T or by purchasing gas from third parties as an agent. The price paid is the market price, and then CM&T is reimbursed for the cost to transport the gas from the point where CM&T acquires the gas to Woodsdale. There is an administrative fee paid to CM&T for this service. The Gas Supply Management Agreement allows Woodsdale to obtain natural gas more economically by using CM&T as the supplier versus obtaining its own supply and paying for transportation service at CG&E's tariffed rate.

Propane

At Woodsdale, propane is used as the back-up fuel, which provides a hedge against high natural gas prices when gas is needed there. A Propane Supply Management Agreement is similar to the Gas Supply Management Agreement and provides for CM&T to supply the full requirements of propane needed by Woodsdale either from CM&T's own supplies or from supplies purchased by CM&T from third parties. Woodsdale has 100,000 barrels of propane storage space available under two separate agreements.

Oil

At East Bend and Miami Fort 6, Cinergy uses fuel oil for starting coal-fired boilers and for flame stabilization during low load periods. Oil supplies are expected to be sufficient to meet these needs for the foreseeable future.

Opportunity Fuels

Cinergy uses available non-conventional fuels where feasible to reduce generation costs. Examples of opportunity fuels include petroleum coke, "synfuels" derived from coal, waste paper, railroad ties and agricultural wastes. Cinergy has actively pursued the use of opportunity fuels for many years, having used or tested petroleum coke, synfuels, waste tires, cellulose derived from municipal solid waste, and paper pellets in various plants, always in a blend with coal. In the proposed experimental program to burn railroad ties, there would be no cost for the actual ties, thereby potentially reducing the fuel cost to the benefit of customers.

Cinergy's Fuels Department monitors potential changes in the fuel industry including mining methodologies, and the availability of different fuels. To the extent that any of these potential changes has an influence on the IRP, they have been incorporated.

The focus of Cinergy's fuel-related R&D efforts is to develop leading-edge technologies and provide information, assessments, and decision-making tools to support fossil power plants in reducing their costs for coal utilization and managing environmental risk.

5. Fuel Prices

The coal and oil prices for both existing and new units utilized in this IRP were developed using a combination of consultants and in-house expertise and judgment. Gas prices were provided by ICF Consulting. Cinergy's and ICF's projected fuel prices are considered by them to be trade secrets and proprietary competitive information.

6. Condition Assessment

In the past, Cinergy has had engineering condition assessment programs. Cinergy continues these types of programs, and with them intends to maintain its generating units, where economically feasible, at their current level of efficiency and reliability. In fact, many of the steps necessary to preserve the existing performance have been taken already.

7. Efficiency

Cinergy evaluates individual potential repairs or replacement of components on the existing generating units for their cost-effectiveness. If the potential changes prove to be cost-justified, they are budgeted and generally undertaken during a future scheduled unit maintenance outage. However, due to modeling limitations, the large number and wide-ranging impacts of these individual options made it impossible to include these numerous smaller-scale options within the context of the IRP integration process. The routine economic evaluation of these smaller-scale options is consistent with that utilized in the overall IRP process. As a result, the outcome and validity of this plan have not been affected by this approach.

Also, Cinergy generally pursues opportunistic power sales which enhance the efficient utilization of the generating facilities.

8. Environmental Regulations

The technology available to meet environmental regulations has added constraints to the power plant fuel cycle and also expends energy to operate. The net result is a reduction in the "energy and capacity for load" capability and a lower overall efficiency. This loss in capability must be replaced by newly acquired resources, by off-system purchased power, or by the increased operation of less efficient units. On either a system or regional basis, lost capacity ultimately translates into a cost (to replace the reduction in capacity) for new resource acquisitions.

Likewise, one potential effect of meeting environmental regulations can be to degrade the reliability (i.e., the "availability") of each generating unit by increasing the complexity of the overall system. This could translate into a "cost to replace the unavailable capacity" in terms of new resource acquisitions.

The technology to meet environmental regulations for fossil-fueled generation generally includes: 1) flue gas scrubbers for SO_2 control; 2) larger or upgraded electrostatic precipitators with flue gas conditioning, baghouses or wet electrostatic precipitators for particulate removal; 3) selective noncatalytic reduction (SNCR) technology, selective catalytic reduction (SCR) technology, boiler optimization technology, and low NO_x burners (or modifications of existing combustion systems) for NO_x control; 4) sorbent injection (such as activated carbon) and baghouses for mercury control; and 5) cooling towers or closed cycle cooling systems for reducing the potential impact of thermal discharges. In addition to these emission specific control technologies, there are some synergistic emission control benefits across technologies. For example, an SCR for NO_x control together with a flue gas scrubber for SO_2 control is a very effective combination in reducing mercury emissions as well. Similarly, baghouses with carbon injection for mercury control are also effective in reducing particulate emissions.

East Bend 2 was constructed originally incorporating a flue gas scrubbing system. This unit has been in commercial operation since 1981. The flue gas scrubber reduces the net output capacity of these units by about 1.2% to 1.6%.

The environmental standards limiting the stack discharge of particulates have necessitated retrofitting precipitators on several existing generating units. The upgraded precipitators will generally require more "energy to function". While a detailed study has not been performed, the projected effect of these precipitators on the efficiency of the fuel cycle is a decrease in the efficiency of approximately 0.75% to 1.00%.

While detailed studies are required to determine the specific impacts of new control technologies on generating unit output and the efficiency of the fuel cycle, the following are the approximate impacts: 1) SCRs (selective catalytic reduction systems) require approximately 0.6% of the unit output and decrease the efficiency by about 0.6%; 2) SNCRs (selective non-catalytic reduction systems) require approximately 0.1% of the unit output and decrease the efficiency by about 0.1%; 3) current design FGDs (flue gas desulfurization systems) require approximately 1.8% of the unit output and decrease the efficiency about 1.8%; and 4) ACI plus PBH (activated carbon injection and polishing baghouse) systems require approximately 0.5% of the unit output and decrease the efficiency about 0.5%.

The capital cost required for the construction of thermal pollution control equipment in modern steam-cycle power plants has increased over the conventional methods for generating plants sited on major inland waterways (e.g., once-through cooling). The cooling systems cause an overall reduction in the efficiency of the energy cycle of about 2% in the summer season and 1% in the winter season. For a system which has its greatest generation capacity requirement in the summer, the 2% reduction in available output at peak load must be replaced by additional capacity, and the efficiency reduction must be replaced by the purchase and burning of additional fuel.

Compliance with the Clean Air Act Amendments of 1990 and the NO_x SIP Call (see Chapter 6) has increased, and will continue to increase, the cost of producing electricity. Possible future regulations such as Mercury MACT, the Interstate Air Quality Rule, the Clear Skies Initiative, or other proposed legislation to reduce air emissions will also increase the cost of electricity production (see Chapter 8). In addition, depending on the schedules and timetables associated with the implementation of any new emission control regulations, equipment availability, construction and cut-in may adversely impact both reliability and electricity prices during compliance implementation.

Cinergy supports R&D efforts concerning products and processes that cover: 1) air toxics measurement and control; 2) NO_x, SO_2 and particulate (including PM2.5) control; 3) heat rate improvement; 4) waste and effluent management; 5) pollution prevention; 6) greenhouse gas reduction; and 7) combustion by-product use.

Figure 5-1

SCREENING: PULVERIZED COAL TECHNOLOGIES

2003-2012 and 2013-2023

1.1B Limestone Forced Ox. Sub. 500MW
1.1C Limestone Forced Ox. Sub. 400MW
1.1D Limestone Forced Ox. Sub. 300MW
1.1E Limestone Forced Ox. Sub. 300MW
1.1G Limestone Forced Ox. Sub.200MW
1.1H Limestone Forced Ox. Sub. 2X300MW
1.1I Limestone Forced Ox. Sub. 200MW
1.1J Limestone Forced Ox. Sub. 2 X 275MW
Greenfield 2960MW PC Sub.
Greenfield 467MW PC Sup.
Brownfield 2960MW PC Sub.
Brownfield 467MW PC Sup.

→ Brownfield 467MW PC Sup.

Figure 5-2

SCREENING: FLUIDIZED BED TECHNOLOGIES

2003-2012

Atmospheric Fl.-Bed Combustion (AFBC):
5.2A Circulating AFBC 200MW
5.3A Circulating AFBC 200MW
5.4A Circulating AFBC 200MW

Circulating Fl.-Bed Combusion (CFBC):
Greenfield 113MW
Greenfield 226MW
Greenfield 226MW (2X1)
Greenfield 459MW (2X1)
Brownfield 113MW
Brownfield 226MW
Brownfield 226MW (2X1)
Brownfield 459MW (2X1)

→ Brownfield 459MW (2X1)

Figure 5-3

SCREENING: FLUIDIZED BED TECHNOLOGIES (Cont.)

2013-2023

Atmospheric Fl.-Bed Combustion (AFBC):
5.2A Circulating AFBC 200MW
5.3A Circulating AFBC 200MW
5.4A Circulating AFBC 200MW

Bubbling Pressurized Fl.-Bed Comb. (PFBC):
6.1 Subcr. Reheat 80MW
6.2 Subcr. Non-reheat 2 X 80MW
6.3 Subcr. 350MW
6.8 Supercr. 350MW
6.9 Supercr. 350MW

Circulating Pressurized Fl.-Bed Comb. (PFBC):
Brownfield 226MW
Brownfield 226MW (2X1)
Greenfield 459MW (2X1)
Brownfield 459MW (2X1)

→ 6.9 Supercr. 350MW

Circulating Pressurized Fl.-Bed Comb. (PFBC):
7.1 Subcr. Reheat 80MW
7.2 Subcr. Non-reheat 1 X 160MW
7.3 Subcr. Non-reheat 1 X 350MW
7.7 Subcr. Reheat 350MW
7.8 Supercr. Non-reheat 350MW
7.9 Supercr. 350MW
8.0 Subcr. 1 X 350MW
8.1 Adv Subcr. 688MW
New Case 677MW

→ 7.9 Supercr. 350MW

→ 7.9 Supercr. 350MW