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In the Matter of:

A REVIEW PURSUANT TO 807 K.A.R. 5:058 OF THE 2009 INTEGRATED RESOURCE PLAN FOR EAST KENTUCKY POWER COOPERATIVE, INC.	))))	CASE NO. 2009-106

SIERRA CLUB, KENTUCKY ENVIRONMENTAL FOUNDATION AND KENTUCKIANS FOR THE COMMONWEALTH'S COMMENTS ON 2009 EAST KENTUCKY POWER COOPERATIVE, INC.'S INTEGRATED RESOURCE PLAN

The Sierra Club, Kentucky Environmental Foundation, and Kentuckians for the Commonwealth [hereinafter "Intervenor Groups"] respectfully submit these comments on East Kentucky Power Cooperative's ("EKPC") 2009 Integrated Resource Plan ("2009 IRP") pursuant to the Public Service Commission's ("Commission") July 2, 2009 Order. In so doing, the Intervenors are mindful of the Commission's August 19 Order which held:

> Thus, any effort to compare EKPC's demand-side options to Smith 1 constitutes a challenge to the need for Smith 1, and any challenge to Smith 1 is a direct challenge to the CPCN authorizing its construction. As discussed in the July 13 Order, there are legitimate ways in which a challenge to Smith I could be pursued, but the use of an IRP case is not one of them. Any comparison of EKPC's demand-side options must be made to its projected supply-side resources that have not already been authorized to be constructed pursuant to a CPCN. EKPC's IRP, which covers the 15-year period extending through 2023, projects a need for six additional supply-side resources after Smith 1. It is those resources that are not yet authorized to be constructed by a CPCN and that are properly compared to EKPC's demand-side options. Since the need for Smith 1 is not within the scope of this IRP review, EKPC need not provide the Environmental Groups any non-public information related to Smith 1.

The Intervenor Groups will of course obey the Commission's order and only refer to resources that already have a CPCN as references to make points about options for future solutions involving resources which do not have CPCN. Thus, below are Intervenor Groups' truncated comments on various components of the 2009 IRP.

I. INTRODUCTION

EKPC is a utility that has done, and continues to do very poor resource planning. This fact gives the Intervenor Groups no pleasure because their members have to bear the brunt of EKPC's poor planning. Nevertheless, it is a harsh reality.

The proof of this poor planning should be evident. For example, EKPC is on the verge of financial catastrophe and have been so for a number of years. *See e.g.* Robert Marshall, President and CEO of EKPC and David Eames, Chief Financial Officer, *Statement of Reason for Rate Increase. 807KAR 5:001, Section 10(1)(b)(1),* PSC Case No. 2008-00409.

We are witnessing a fundamental change in electricity production in this country. Our use of coal is declining and our use of renewable and less dirty fuels such as natural gas is increasing. *See* Table 1 below. It is the beginnings of the transition to the Clean Energy Economy but EKPC's planning does not acknowledge, much less attempt to adapt to this change.

TABLE 1: NATIONAL GENERATION MIX TREND[1]

Year to Date Jan – June	Coal	Natural Gas	Renewables (excluding large scale hydro)
2007	49%	19%	2.5%
2008	49%	20%	3%
2009	45%	21%	3.5%

EKPC's poor planning is causing EKPC to miss out on this opportunity. For example, the average price for coal when up 6.7 percent between June 2008 and June 2009. In comparison, the average price for natural gas went down 63.7% during that same period.[2] June

[1] Source: US Department of Energy, Energy Information Agency, Electric Power Monthly (EPM) Chapter 1.1 available at: http://www.eia.doe.gov/cneaf/electricity/epm/epm_sum.html.
[2] Source: EPM Executive Summary, September 2009.

2009 is the most recent permanent data available from the U.S. Energy Information Agency but market data indicates that the price of natural gas has continued to drop.[3] Utilities that have planned well are able to take advantage of this change in price of fuel by generating more electricity with natural gas and less electricity with coal, thus saving money for themselves and their customers. This is in large measure what is responsible for the shifting national generation mix with coal generation decreasing and natural gas generation increasing. However, EKPC has no combined cycle combustion turbine generating units or even natural gas fired boilers for that matter and EKPC's IRP does not call for any during its planning horizon. In fact, EKPC did not even seem to consider natural gas fired combined cycle combustion turbines to meet base load in the 2009 IRP. *See* 2009 IRP at 5-12. Thus, EKPC has no way to efficiently generate electricity from natural gas to meet base load or intermediary load needs.

A large measure of EKPC's problem seems to be that it's planning is detached from current reality. For example, EKPC offers the demonstrably incorrect claim that "gas . . . prices have increased dramatically." *Id* at 5-3. As shown above, that is not the case.

In contrast to EKPC's IRP, Kentucky Power's recently filed IRP acknowledges the current state of affairs and reflects planning to address it. The Kentucky Power IRP states:

> The tempered load growth combined with additional renewable resources and other additional supply-side resources, and increased DR/EE initiatives reduce the need for new peaking capacity until 2018, with new base load capacity now not required until beyond the forecast period.
>
> ...
>
> the future, now more than ever before, is highly uncertain, particularly in light of the current economic conditions, the movement towards increasing use of renewable generation and end-use efficiency, as well as legislative proposals to control "greenhouse gases" which could result in the retirement or retrofit of existing generating units, impacting the supply of capacity and energy to Kentucky Power.

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[3] *See e.g.* http://www.oilnergy.com/1gnymex.htm#6mo

Kentucky Power IRP, Case No. 2009-339, at 1-2. While the Kentucky Power IRP calls for adding gigawatts of renewable energy and retiring gigawatts of fossil fuel fired generation, EKPC's IRP calls for simply continuing to build inefficient coal-fired power plants as far out as EKPC can see.

II. FINANCIAL POSITION

EKPC's 2009 IRP does not seem to evidence any serious consideration of EKPC's current financial situation, which is bleak. For example, EKPC's interest payments have doubled in the past 5 years so that EKPC now pays over $109 million per year in interest. *See* EKPC 2008 Annual Report at 2.[4] Moreover, EKPC overall financial health is poor. The Intervenor Groups recently had Tom Sanzillo evaluate EKPC's financial health based on EKPC's 2008 Annual Report. His report, "The Growing Unsustainable Debt Burden of the East Kentucky Power Cooperative's (EKPC) Capital Plan: A Case Study in Energy Debt Mismanagement" is attached as Exhibit 1. Tom is a Senior Associate with TR Rose Associates, a public policy and financial consulting firm in New York City. From 1990 to 2007, Tom served in senior management positions to the publicly elected Chief Financial Officers of New York City and New York State. For the period 2003 to 2007, he served as the First Deputy Comptroller for the State of New York. Tom was responsible for a $150 billion globally invested public pension fund; oversight of state and local budgets and debt offerings; audit programs for all state agencies, public authorities and local governments, and review and approval of state contracts. Due to an early resignation, Tom served for a short period as the New York State Comptroller from 2006-07.

[4] Available at http://www.ekpc.coop/publications/EKPC%20Annual%20Report.pdf

The Sanzillo report states that "[a]ccording to EKPC's 2008 Annual Report, three significant measures of the cooperative's financial health declined since the previous year." Ex. 1 at 1. The report concludes: "The best case strategy is for some debt reduction, or else EKPC risks losing its historic mission as an economic catalyst, and instead could become an impediment." Ex. 1 at 4. Yet, the IRP predominately focuses on acquiring new supply side fossil resources including capital intensive base load resources. See 2009 IRP at 5-9. There is no evidence that the resource selection considered EKPC's need to reduce its debt. Greater use of power purchase agreements, demand side management, load shifting measures and more realistic load forecasting could all help EKPC to reduce its debt in the future. EKPC should do this.

The very limited consideration of EKPC's financial situation in the 2009 IRP is unreasonable. The discount rate used by EKPC in its present value calculations is based on the weighted average cost of EKPC's outstanding long-term debt as of December 31, 2008. *See* 2009 IRP at 9-1. Yet the Sanzillo report explains:

> Due to changes in the credit markets in 2008, EKPC received a financial advantage from reduced interest rates. "The average annual rate on all debt decreased from 5.43 percent in 2007 to 4.81 percent in 2008."[8] This overall rate is the lowest interest rate the cooperative has achieved since 2003.
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> 8EKPC, 2008 Annual Report, *Interest Costs, p.12.*
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> . . .
>
> From the perspective of a debt analysis, EKPC's risk is clear. The national economy is likely to turn around and grow faster than rural Kentucky's economy. Interest rates, a tool of national economic performance, are also likely to rise. The interest rates charged to EKPC are likely to move back to EKPC's historic levels, if not higher, depending on long term RUS policy, other actions by federal lenders, and the private sector's reaction to EKPC's credit profile.

Ex. 1 at 2-4. EKPC's 2009 IRP is based on a series of long-term debt, interest rate and public policy assumptions that are not sustainable. A more realistic weighting of these factors would produce a more reliable estimate of EKPC's short and long term capacity to borrow funds to meet its capital commitments. As it stands, the only certainty in these estimates is the certainty that rates will have to rise appreciably to correct for the significant margin of error that they are based upon.

III. ENERGY FORECAST

EKPC's forecast of how much electricity it needs is flawed, resulting in EKPC planning to add supply side fossil fuel resources that it does not need. Our comments below address the total amount of electricity needed, sometimes referred to as total requirement, which is measured in megawatt-hours or gigawatt-hours. Demand or peak needs, which is measured in megawatts, is something different. Although EKPC often conflates the two, by for example, discussing its peak demand when addressing the need for base load supply side resources, the two concepts are distinct although they can be interrelated.

Historically, EKPC has over-estimated its energy needs. Over-estimation of energy needs results in spending more capital than necessary, causing rates to have to go up to pay for unused or under-utilized power plants.

The 2009 IRP demonstrates EKPC's historic over-estimation of energy needs. For example, page 5-5 of the 2009 IRP shows that EKPC's forecast for its energy requirements in 2020 decreased between 2004 and 2008 by 2,273,498 mwh per year or almost 12%. Notice also that the amount of electricity EKPC has over-estimated trends upward as a percentage over time. Notice also that the over-estimation is consistent. 2009 IRP at 5-5 Forecast Comparison.

The 2009 IRP's forecast is unrealistic because it is based on outdated data. EKPC admits that it conducted no load forecast since August 2008 even though EKPC did not file the 2009 IRP until April 21, 2009. *See* Public Interest Groups First Data Request Response 7. We are in a period of dramatic change for the electric industry because of a number of factors including the economic recession, the declining availability of cheap fossil fuels, the increased attention to climate change, the advancement of knowledge of health impacts from pollution, and the decrease in costs and increase in availability of renewable energy technologies. In the current situation, using load forecasts that are over seven months old leads to unreliable results in resource planning.

EKPC's forecast is very likely wrong and wrong for the first year in the forecast, that is 2009. This means that it will have a dramatic effect on energy requirements for later years in the IRP because of the lack of compounding. EKPC's actual total requirement for 2008 was 12,948,091 mwh. *See* 2009 IRP at 7-2. The 2009 IRP predicts that the total requirement for 2009 will be 13,647,057. This represents a predicted 5.4% increase in total requirements between 2008 and 2009. However, looking at the 2009 data that EKPC has supplied for actual energy requirements, thus far EKPC has experienced a 5.8% decrease in total energy requirements. *See* Public Interest Groups' First Data Request, Response 13. This calls into serious question the IRP's plan for future base load generating resources.

There are additional reasons to think that the 2009 IRP projection of future energy requirements are significant over-estimations. EKPC's load forecast fails to consider mandatory improvements in the efficiency of various appliances, including such large energy users as supermarket refrigeration, commercial HVAC systems and small electric motors. *See* Environmental Groups' Second Data Request, Response 83, Table 1. Furthermore, EKPC does

not include future efficiency savings from small commercial class. *See Id.* at page 3-4. EKPC's future energy and load projections should consider all required improvements in efficiency.

Furthermore, EKPC's analysis of one of its largest users appears to be largely based on guess work. EKPC admits that it does not consider the overall steel market in trying to predict Gallatin Steel's energy use. *See* Environmental Groups' Second Data Request, Response 85. Even for the factors that EKPC does consider, it makes a "qualitative determination." Before investing billions of dollars in future supply side resources, EKPC has a more objective analysis based on data. There are obviously professions that track the steel market. EKCP should get some profession help to make these sorts of judgments in the future.

IV. FUTURE SUPPLY SIDE FOSSIL RESOURCES

The 2009 IRP projects a continuing very heavy reliance for EKPC on coal-fired power plants. This is capped off with an additional 278 MW coal-fired CFB in 2022. *See* 2009 IRP at 8-106. This makes EKPC one of, if not the only utility in the country proposing to build additional, old-fashion coal fired power plants as far out as in the third decade of the 21st century. EKPC plans to be getting approximately 83% of its electricity from coal fired generation in 2023. See Corrected Table 8.(4)(b)-1 in Public Interest Groups First Data Request, Response 73 Attachment 1. This future does not look bright from EKPC customers when one considers that coal prices have gone up 50% in the past 5 years. *See* 2008 EKPC Annual Report at 3.

To begin with, the 2009 IRP is not very transparent or user friendly in general but especially when it comes to the supply side fossil generation sources. The 2009 IRP fails to provide the required information about planned future supply side resources. The unnamed table on page 5-9 lists seven planned new generating units in the scenario including DSM. 2009 IRP

at 5-9. One can infer that four of the planned units are actually not planned units but rather purchases. *See* 2009 IRP at 8-49. One can infer that the 200 MW Emission Free PPA mentioned on page 8-49 is a euphemism for purchasing energy from a nuclear power plant. Section 8.(3)(b) says that EKPC is to list all existing <u>and planned</u> electric generating facilities and then provide 11 pieces of information about <u>each</u> facility. 2009 IRP at 8-15. The 2009 IRP says this information is found on pages 8-100 through 8-106. However, EKPC does not provide the required information for the two of the planned units. *See* 2009 IRP at 8-100 through 8-106. One can speculate, although a decent IRP would not cause the reader to speculate, that the 2022 278 MW coal fired CFB on page 8-106 is the 300 MW base load capacity listed on page 5-9. EKCP should actually provide the required information.

One of EKPC most fundamental problems is EKPC using base load generating units to meet its peak demand. Base load units are much more capital intense than peaking or intermediary units. However, this is often justified by the fact that the base load units are used much more often, *i.e.* the capital invest is not sitting idle. However, EKPC does not distinguish between base load, intermediary load or peak load supply side resources in its planning model. *See* Environmental Groups' Second Data Request, Response 87.

While this approach could work in theory, EKPC uses absurd inputs into its model to get results out that pick base load units to meet peak demand. For example, capital cost of the future coal-fired CFB and the capital cost of a combined cycle natural gas plant that EKPC uses are absurd, both in absolute and relative terms. *See* 2009 IRP, Confidential Version, at 8-14, Table 8(2)(c)-1. EKPC cannot provide any data to support this position. One can compare the price of the future CFB provided in the IRP with the price that EKPC has told the Commission it expects to pay for the Smith 1 CFB to get an idea of the accuracy of the price of the future CFB. As to

the combined cycle plant, as explained below, Progress Energy Carolinas is building a combined cycle plant for approximately $947 / kw. The California Energy Commission's most recent estimate was $1329 / kw in 2009 but only $901 / kw in 2007, the year of EKPC's capital value. The California Energy Commission estimated that this price would hold steady through 2023, the year that EKPC is planning on adding its future coal fired CFB. *See* California Energy Commission, Comparative Costs of California Central Station Electricity Generation, Draft Staff Report at 6, 9.[5] Compare this to the capital costs EKPC used for combined cycle power plants in the 2009 IRP, Confidential Version, at 8-14, Table 8(2)(c)-1.

EKPC's use of these absurd capital costs means that the planning model "picks" a 300 MW coal-fired CFB to meet EKPC's needs in 2023. *See* EKPC IRP at 5-9, 8-106. In light of fundamental problem with EKPC's analysis, EKPC should identify whether it needs base load, intermediary load or peaking units and then only evaluate technology that is appropriate to meet that need.

EKPC problem of planning which results in excessive, and the wrong type of supply side resources in the future is exacerbated by the fact that EKPC does not do a reasonable analysis of its ability to sell its excess electricity off of its system. Supply side fossil fuel resources are "lumpy" meaning you have to purchase a unit that is of a certain minimum size for technology reasons, even if you do not need that much added capacity until later. Thus, sometimes a utility needs to sell energy off system.

Most of the states in the United States, including Ohio, have renewable portfolio standards, which are also called renewable electricity standards. In additional a national renewable portfolio standard is very likely coming. Furthermore, other states already have

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[5] Available at http://www.renewableenergyworld.com/rea/video/touring-unhs-ecoline-landfill-gas-project?cmpid=WNL-Friday-September18-2009.

greenhouse gas emission limits for their electricity. This means that in the future EKPC's market to sell its excess electricity generated from its fossil fuel units will shrink. However, EKCP does not consider these factors in its IRP. *See* Public Interest Groups First Data Request, Response 44a-c.

Other utilities are moving in the opposite direction of EKPC's 2009 IRP. For example, Progress Energy Carolinas is planning on shutting down three coal-fired units and building a new combined cycle natural gas power plant that is capable of meeting base load needs. *See* Ex. 2. Note that Progress Energy's combined cycle natural gas plant is expected to cost approximate $947 / kw. *See* Ex. 2 ($900,000,000 / 950 MW / 1000 kw per mw). Compare this to EKPC's estimate of the capital costs of a combined cycle power plant on page 8-14 of the 2009 IRP.

Kentucky Power, and its parent corporation, AEP, are also moving in the opposite direction of EKCP in terms of supply side resources. In Kentucky Power's recently filed IRP, there are no plans for additional coal fired generation, no plans for additional base load generation, there is retirement of old coal fired units, there is natural gas fired units to meet intermediary load, and sizeable amounts of DSM and renewable. *See* Kentucky Power Company Integrated Resource Plan, Case No. 2009-339, at page 1-2, Table 1.

In April of this year, in a proceeding in front of the Louisiana Public Service Commission, a utility dropped its plans to build a coal fired unit in favor of a natural gas fired combined cycle combustion turbine facility. *See* Ex. 4. This is further evidence of the unreasonableness of EKPC's future CFB.

Part of EKPC's reluctance to planning for base load or intermediary load generating units that burn fuels other than coal may be its lack of understanding or success in the natural gas market. EKPC buys natural gas on the spot market. Staff's Second Data Request, Response 30.

Poor planning ends up costing EKPC dearly. For example, EKPC paid $15.70 per MMBtu in May 2009 when the average price paid by power generators for the same month was $4.46. *See* Environmental Groups' Second Data Request, Request 98. When asked why EKPC was paying over three times the national average, EKPC incorrectly tried to claim that the U.S. Energy Information Agency average price does not include the hedge price. *See Id.*, Response 98. However, Rebecca McNerney, who is the person at the U.S. Energy Information Agency who deals with this data confirmed that their information is indeed intended to reflect the inclusion of the hedge price. *See* Ex. 3. EKPC should obtain outside professional assistance in evaluating projections of future fuel costs and the analysis of the outside professional assistance should be available to the Commission and the parties, albeit pursuant to a protective order if need be.

EKPC also lacks some basic understanding of coal-fired power plants and how they will be impacts by future regulation which means EKPC's evaluation of the its future CFB is unreliable. For example, EKPC claims that its coal-fired CFBs, Spurlock 3 and 4, meet and/or exceed Maximum Achievable Control Technology ("MACT") standards. *See* Staff's Second Data Request Response 29. This is simply not true. Although US EPA has a mandatory duty to promulgate one, there currently is no MACT standard for coal-fired Electric Generating Units. *See* New *Jersey v. EPA*, 517 F.3d 574, 578 (D.C. Cir. 2008). Thus, EKPC's claim that it is meeting or exceeding a standard that currently does not exist is obviously false. Spurlock 3 does have a case-by-case MACT limits but whether those are more or less stringent than the MACT standard that EPA will ultimately impose is not known or unknowable at this point. Spurlock 4 does not have a case by case MACT limit and US EPA will be issuing an order on the legality of that situation by September 21, 2009.

Another example is nitrous oxide (N_2O) which is a greenhouse gas, emissions of which will likely be regulated in future greenhouse gas regulations. Coal-fired CFBs, including the coal-fired CFB EKPC is planning for 2022 or 2023, are major sources of N_2O. In this proceeding, EKPC claims that Selective Catalytic Reduction ("SCR"), a pollution control device commonly used on coal-fired power plants, controls emissions of N_2O. *See* Public Interest Groups' First Data Request, Response 32. This is not so. The document that EKPC offers to support this assertion does not actual claim that SCR controls N_2O. *See* Environmental Groups' Second Data Request, Response 82, pages 2-8. Other EKPC personnel know this claim to be incorrect. The fact that EKPC's resource planners do not even know which pollution control device can or cannot control which pollutant bodes strongly towards EKCP being required to eliminate self-owned fossil supply side resources as future options.

EKPC's analysis also fails to realistically consider future environmental regulations. There are numerous environmental regulations that the U.S. Environmental Protection Agency (US EPA) is under a legal mandate to promulgate. For example, as mentioned above US EPA is required to promulgate emission limits for hazardous air pollutants, including but certainly not limited to mercury, from coal fired power plants. US EPA is also required to promulgate a rule that controls NOx and SOx emissions in light of the fact that its Clean Air Interstate Rule ("CAIR") has been struck down. EKPC's analysis shows no evidence of considering these future regulations which will almost certainly come to be. *See e.g.* Environmental Groups Second Data Request, Response 88 page 2 – 3 (evaluating cost of compliance with the CAIR rule that has been struck down by the D.C. Circuit); Response 99. To its credit, EKPC did consider CO_2 regulation. But it ignored possible N_2O regulation. EKPC should evaluate the

impact of all future environmental regulations including the possibility that it will simply not be able to obtain permits to build certain future fossil supply side resources.

V. SUPPLY SIDE RENEWABLES

As with the other topics discussed above, EKPC's 2009 IRP is difficult to understand but yet clearly indicates a lack of serious commitment to meeting its customers' needs with clean, renewable energy from sources like wind and solar. The 2009 IRP does include a "30MW Biomass PPA" but does not further elaborate. *See* 2009 IRP at 8-49. We can extrapolate, although again a good IRP would not require such extrapolation, that the Biomass PPA would be coming from a Non-Utility. *See* Corrected Table 8.(4)(b)-1 in Public Interest Groups First Data Request, Response 73 Attachment 1. This Biomass PPA would be meeting about 1.5% of EKPC's energy requirements in 2023. *Id.* Biomass is a very broad term that means different things to different people. Some energy sources that are considered biomass are not clean, some are not renewable and some neither. All we know is that at a time when whole states, because of their renewable portfolio standards, will be getting a quarter, a third or more of their electricity from renewable sources, this Biomass PPA will be contributing a very minor amount to EKPC's energy mix.

In contrast, while not as aggressive as it should be, AEP's IRP does include a significant amount of renewable. *See* Kentucky Power IRP, Case No. 2009-339, at 1-2. This includes meeting 3% of its capacity needs with solar in 2023, 7% with wind and 6% with biomass. *Id.*

Wind power is a mainstream source of electric generation in the U.S. and yet EKPC's 2009 does not include any plans for wind energy. In the last two years, wind power has been second only to natural gas power plants in terms of name plate capacity installed in the United States. Currently, there are approximately 30 gigawatts of installed wind power capacity in the

United States. *See* http://www.awea.org/projects/. Texas is the state with the most installed wind power capacity but Indiana is the state that is experiences the greatest relative growth of wind power capacity. As noted above, AEP's Eastern System plans on installing 3 gigawatts. Kentucky Utilities /Louisville Gas & Electric recently applied to the Commission for the inclusion of wind power on their system. *See* PSC Case 2009-353.

EKPC is oft heard to complain about its lack of ability to transmit wind power on to its system. Yet EKCP is perfectly capable of building high voltage transmission lines to accommodate new fossil fuel fired capacity. Furthermore, EKPC has chosen not to join a regional transmission organization.

Furthermore, in addition to the self-build option, there are a variety of efforts underway to provide market based transmission services for the delivery of wind power. *See e.g.* http://www.itctransco.com/projects/thegreenpowerexpress/thegreenpowerexpress-map.html. EKPC's 2009 IRP makes no mention of even considering these options.

EKPC's 2009 IRP also ignores solar photovoltaic ("PV") and solar thermal. *See* Public Interest Groups' First Data Request, Response 37. EKPC did this without any information or data regarding future costs. *See Id.*, Response 38. This is particularly shocking when one considers that most experts agree that solar PV will reach grid parity well before 2023. Grid parity is when solar PV costs the same as the current energy mix. The way EKPC's rates have been increasing, it will probably be much soon than that.

As mentioned above, AEP includes significant solar in its IRP. *See* Kentucky Power IRP, Case No. 2009-339, at 1-2. Furthermore:

> On June 17, the California Energy Commission (CEC) issued a landmark ruling that will undoubtedly figure prominently in this discussion. The CEC denied an application for a 100-megawatt natural gas-fired gas turbine power plant in part

> because rooftop solar PV could potentially achieve the same objectives for comparable cost.

Ex. 5 at 1.

Oddly, EKPC's 2008 Annual Report at 8 says up to 50 MW of renewable to be signed in 2009. However, this 50 MW of renewable does not show up in the 2009 IRP unless this 50 MW of renewable is the 30 MW Biomass PPA scheduled for 2017 in the 2009 IRP. *See* 2009 IRP at 8-49, Table 8.(4)(a)-2.

Although not mentioned in the 2009 IRP, EKPC apparently did take an option on 10 MW of 150 MW wind farm. Supplemental Response to Public Interest Groups Request 19 at page 23. However, we do not know enough about this to comment on it except to say that it does not appear to have come to be. Furthermore, it is such a small scale that the economics of it are highly doubtful.

EKPC received over 2,100 MW of interest in renewable even though they asked for only 300 MW. Supplemental Response to Public Interest Groups Request 19 at page 26. Thus, the renewable are likely there. Unfortunately, EKPC does not provide the information needed to make an effective analysis. Rather, EKPC hides its information even though there is a confidentiality agreement in this case. *See* Environmental Groups' Second Data Request, Response 100; Public Interest Groups' First Data Request, Response 62. There are no good inferences that one can draw from EKPC's disrespect for the truth finding function of this Commission. EKCP should be required to provide the requested information.

VI. DSM

Turning finally to what EKPC calls Demand Side Management "DSM," the 2009 IRP viewed in isolation is less aggressive than is reasonable but on the right track. The 2009 IRP predicts that after 10 years of implementation, EKPC's DSM program would save 455,519 MWh. 2009 IRP at 8-51. The Intervenor Groups had an expert develop a plan that resulted in 743,544 MWh of annual savings, or 63% more, that EKPC's new DSM programs. *See* "A Portfolio of Energy Efficiency and Renewable Energy Options for East Kentucky Power Cooperative," ("Portfolio") page 14, Table 4, provided on a CD in response to Staff's Supplemental Data Request, Response 5.

EKPC's DSM program could achieve significantly greater energy reductions, even within its current framework. For example, EKPC rejected 72 DSM programs based on subjective analysis. *See* 2009 IRP, Technical Appendix at DSM-1. Some of these subjectively programs are actually cost effective. For example, EKPC rejected a room air conditioner exchange program. *See id.* at DSM-8. However, the Intervenor Groups' Portfolio found the cost of this program to be 5.8 cents per kilowatt-hour. Portfolio at 38. This is probably less than the cost of new generation for EKPC and provides a hedge against future cost increases. In addition, this program would involve giving EKPC customers free air conditioners. It is difficult to see how the program would not be overwhelmingly supported.

EKPC also rejected a program of helping customers to install low flow showerhead and faucet aerator/pipe insulation. 2009 IRP, Technical Appendix at DSM-1. This program is highly cost effective because it has low capital costs. For example EKPC could buy faucet aerators at wholesale prices for very little money. The program also helps customers save money on their energy and water bills. The major expense in such a program comes from delivery of the program. However, EKPC plans to go ahead with other programs that could be very cheaply

combined with the low flow showerhead / faucet aerator / pipe insulation program. These include the low income weatherization, enhanced button up, and tune up programs. *Id.*

Thus, EKPC should conduct a quantitative analysis of all 103 programs including a consideration of the economies of scale that can be achieved by combining programs. In this quantitative analysis, EKPC should have to consider the true cost savings. For example, EKPC admits that it does not consider the cost savings to distribution cooperatives from avoided capital improvements or operation and maintenance costs because of reduce demand and energy requirements from DSM programs. *See* Public Interest Groups' First Data Request, Response 48. EKPC's analysis should evaluate all cost savings, not just selected ones.

Once EKPC comes up with a comprehensive DSM plan of which programs to include, EKPC must also come up with an effective plan to implement it. For example, Glenn Cannon, an expert on DSM programs for public power entities, says that a utility needs one employee dedicated to DSM from approximately every 5,000 customers it has. Bluegrass Energy has one employee dedicated to DSM and over 50,000 customers. This is a formula for failure. Thus, it is not surprising that EKPC's energy audits and touchtone energy home certifications are reported in the single digits. *See e.g.* Supplemental Public Interest Groups Request, Response 19 at page 28.

One of the keys to achieving successful reductions in energy requirements through DSM programs is being able to pay for the DSM programs. EKPC said they were going to apply for a DSM surcharge. *See* Supplemental Public Interest Groups Request, Response 18, pages 29-31. However, the Intervenor Groups are not aware of EKPC making such an application. EKPC should do so or come up with an alternative funding mechanism.

VII. CONCLUSION

EKPC's 2009 IRP fails to consider EKPC poor financial health, is based on a forecast of energy requirements which is almost certainly a dramatic over-estimation, evaluated supply side fossil generating units based on unrealistic costs, fails to consider the most cost-effective supply side renewable energy option and includes under-utilized demand side management program that does not include a concrete explanation of how it will be implemented. In short, the 2009 IRP is unrealistic.

Respectfully submitted,

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Dated: September 18, 2009

CERTIFICATE OF SERVICE

I certify that I mailed a copy of the above by first class mail on September 18, 2009 on the following:

Hon. Mark David Goss
Frost Brown Todd LLC
250 West Main Street
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Lexington, KY 40507- 1749

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Robert Ukeiley

EXHIBIT 1

The Growing Unsustainable Debt Burden of the East Kentucky Power Cooperative's (EKPC) Capital Plan

A Case Study in Energy Debt Mismanagement
September 14, 2009

Tom Sanzillo
Senior Associate
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33 Park Drive
Woodstock, New York, 12498

Abstract

EKPC is engaged in a multi year, multi billion dollar capital plan to meet the needs of its members. The largest portions of the capital expenditures are to finance new coal-fired power plants and to bring existing coal-fired power plants into compliance with existing clean air requirements. To support this capital program EKPC is going deeply into debt in a manner that is unsustainable. Last year EKPC received $49.6 million more in revenue from its operations that the year prior, but this provided very little relief to EKPC's worsening credit profile. Instead, EKPC's other operational problems took priority. EKPC's customer base, like Kentucky's economy is changing and provides less robust economic performance than in the past. Taking on more debt at this time is imprudent. And, renewed economic growth may make the debt situation worse for EKPC and its customer base. EKPC runs the risk of going from a source of economic progress to that of an impediment.

EKPC's Multi Year Plan for Capital Expenditures

EKPC is engaged in a multi-year, multi-billion dollar capital plan to meet the needs of its members. To complete its generation, transmission and other projects it has increased capital spending aggressively. From 2004 through 2008 its long term debt has increased from $1.2 billion to $2.3 billion.[1] A significant segment of this program is dedicated to financing new coal fired generation and paying for compliance investments for existing coal fired power plants.[2] The recently released Integrated Resource Plan (IRP) includes four new additional base load power plant projects through 2023.[3]

Why This Investment Program Is Not Sustainable

The financial condition of EKPC has weakened as its borrowing has increased. Not unlike a household that goes into too much debt, it is showing considerable signs of financial trouble.

According to EKPC's 2008 Annual Report, three significant measures of the cooperative's financial health declined since the previous year. These 'technical' measures are used by banks and the Rural Utility Service – a federal funding agency for EKPC and others – to determine its health[4]. The three financial/credit reporting measures are:

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[1] East Kentucky Power Cooperative, 2008 Annual Report, *Five Year Statistical Summary,* p. 3.
[2] For a brief reference of each of the major investments through 2011 see: Sanzillo, Tom, TR Rose Associates, *Right Decision for a Changing Time*, April 7, 2009, p. 32. For a more detailed accounting of the various investments and debt implications see: EKPC, *Op Cit, Long Term Debt,* p. 33-36.
[3] EKPC, *Integrated Resource Plan,* Case No. 2009-00106, April 21, 2009.
[4] For a full discussion of EKPC's credit position and how it rates in relation to other cooperatives as well as it current financial health see Sanzillo, *Op Cit* (Full Report).

- The Cooperative's TIER Rating. It declined from a 2007 level of 1.43 to a 2008 level of 1.25.[5] This credit report measure represents the relative ability of the cooperative to pay its long-term interest payments. The higher the rating, the stronger the financial health of the cooperative. Earlier this year when EKPC was compared to other comparable cooperatives in the country on this measure, it scored last. According to EKPC's own experts the cooperative was in danger of losing its creditworthiness.[6]

- The DSC measure – or Debt Service Coverage ratio – is simply another credit measure, and it too has deteriorated. In 2007 the cooperative scored 1.17; in 2008 that score dropped to 1.04.

- Another important measure is 'net margin,' an accounting tool used to show generally the amount of cash available after all expenses and needs are met. The higher the margin, the healthier the cooperative. It too has declined since 2007. In 2007 EKPC's (restated) Net Margin was $44,493 million; in 2008 it was $27, 872 million.

There are two additional factors that help to understand the EKPC's 2008 financial year, and how, although some positive occurrences took place, credit conditions continued to deteriorate.

First, according to EKPC's 2008 Annual Report the cooperative received revenues of $795 million. This represents an increase of 6.6%, or $49.6 million from 2007.[7] Despite these additional revenues, pressing operational matters meant that almost no progress was made toward improving the cooperative's credit position.

Second, when recent trends in EKPC's interest costs are analyzed, the underlying problem of the cooperative's excessive indebtedness becomes clear. Due to changes in the credit markets in 2008, EKPC received a financial advantage from reduced interest rates. "The average annual rate on all debt decreased from 5.43 percent in 2007 to 4.81

[5] EKPC, 2008 Annual Report, *Op Cit*, p. 3.
[6] Sanzillo, *Op Cit, Appendix III, EKPC's Times Interest Earned (TIER) Ratio*, p. 38-41.
[7] EKPC, *Op Cit*, p. 2.

percent in 2008."[8] This overall rate is the lowest interest rate the cooperative has achieved since 2003. The 2008 Annual Report also shows *paradoxically that the actual cost of interest paid by the cooperative to its lenders in 2008 was also the highest paid since 2003.* The fact that the cooperative is borrowing at such a rapid rate eliminated any year over year cash savings to the cooperative gained from the lower interest rate. The interest cost went from $102 million in 2007 to $109 million in 2008.

The interest factor and some spending needs eroded the benefit of the revenue bump enjoyed by EKPC this year. It meant the cooperative postponed meeting its credit needs in order to meet operational ones. While the organization was able to make some progress on its member equity metric, its overall credit position deteriorated.

Background Economics

EKPC's growing reliance on debt and projections of greater use of debt through 2023 as outlined in the Integrated Resource Plan should also be analyzed against Kentucky's changing economic conditions.

The Integrated Resource Plan contains the following summary analysis

> An important variable that impacts the load forecast is regional population. Historical population grew rapidly during the seventies and slowed during the second half of the eighties. The growth increased during the late nineties and early two thousands and presently, has slowed down. Given the decline the economy is currently exhibiting, population growth is expected to be low for the next several years.[9]
>
> EKPC's peak and energy growth rates are projected to be 2% per year, much lower than historical growth rates. Should actual growth be higher than forecast, the reserve margin that has been designed into this plan will provide for reliable service. Should actual growth be lower than

[8] EKPC, 2008 Annual Report, *Interest Costs, p.12.*
[9] IRP, *Op Cit,* p. 5-15

> forecase, EKPC's expansion plan relies heavily on non-capital intensive resources like DSM, purchases, and combustion turbines. Therefore, EKPC's risk of stranded assets is low.[10]

From the perspective of a debt analysis, EKPC's risk is clear. The national economy is likely to turn around and grow faster than rural Kentucky's economy. Interest rates, a tool of national economic performance, are also likely to rise. The interest rates charged to EKPC are likely to move back to EKPC's historic levels, if not higher, depending on long term RUS policy, other actions by federal lenders, and the private sector's reaction to EKPC's credit profile. The impact of such interest rate changes on EKPC's cash position were explored in the last rate case.[11] Higher interest rates can have a dramatic and negative impact on the cooperative's cash flow.

Conclusion

The implication of effectively being 'stuck' with higher interest rates on sizable debt levels will compel the Public Service Commission to pass along more costs to EKPC members. Beside this set of fixed factors, the cooperative's IRP makes passing reference to new federal carbon regulation. This is another set of external fixed costs which come with any decision to invest in coal in the current climate. The best case strategy is for some debt reduction, or else EKPC risks losing its historic mission as an economic catalyst, and instead could become an impediment.

[10] IRP, *Op Cit,* p. 5-19.
[11] Sanzillo, *Op Cit,* p. 37.

EXHIBIT 2

TRADING MARKETS.COM

Progress Energy to shut down three coal-fired power plant units

Wednesday, August 19, 2009, Posted 09:35 AM

Aug 19, 2009 (Datamonitor via COMTEX) -- PGN | Quote | Chart | News | PowerRating -- Progress Energy Carolinas has announced a plan to permanently shut down three coal-fired power plant units near Goldsboro in North Carolina and seek state regulatory approval to build a new, natural gas-fueled facility at the site.

As proposed, the new plant will increase the amount of electricity that can be produced at the site by about 550MW, while reducing overall emissions, including CO_2. The additional generating capacity will be used to meet the demands of a growing customer service area and to provide for additional resource flexibility.

The company has filed for a certificate of public convenience and necessity from the North Carolina Utilities Commission, under legislation signed into law in July 2009. The petition seeks approval to build a 950MW combined-cycle natural gas plant that will replace the existing 397MW of coal-fired generation at the HF Lee Plant in Wayne County.

The project represents a total investment of about $900 million and is expected to be in service in early 2013. It is expected to create up to 500 construction jobs over the 24-month building process.

In addition to an estimated 60% reduction in the facility's CO_2 emission rate, the new units will decrease the facility's emission rates for mercury by 100%, sulfur-dioxides by nearly 100% and nitrogen oxides by more than 95%.

http://www.datamonitor.com

EXHIBIT 3

rukeiley

From: McNerney, Rebecca [Rebecca.McNerney@eia.doe.gov]
Sent: Thursday, September 17, 2009 3:21 PM
To: rukeiley@igc.org
Subject: RE: costs of natural gas

Good Afternoon, Robert,

Our instructions to our respondents are to include the hedge cost in their total delivered cost.

Please let me know if you have additional questions.

Becky

From: rukeiley [mailto:rukeiley@igc.org]
Sent: Wednesday, September 16, 2009 7:27 PM
To: McNerney, Rebecca
Subject: costs of natural gas

Dear Ms. McNerney:

In the EPM, when you report the cost of natural gas, is that price paid for spot gas purchases or does that reported cost also include the hedge cost?

Thanks

Robert

Robert Ukeiley
Law Office of Robert Ukeiley
435R Chestnut Street, Ste. 1
Berea, KY 40403
Tel: (859) 986-5402
Fax: (866) 618-1017

EXHIBIT 4

Redacted Public Version

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

***EX PARTE*:**	)	
APPLICATION OF	)	
ENTERGY LOUISIANA, LLC	)	
FOR APPROVAL TO REPOWER	)	
THE LITTLE GYPSY UNIT 3	)	**DOCKET NO. U-30192**
ELECTRIC GENERATING FACILITY	)	
AND FOR AUTHORITY TO COMMENCE	)	
CONSTRUCTION AND FOR	)	
CERTAIN COST PROTECTION AND	)	
COST RECOVERY	)	

REPORT AND RECOMMENDATION
CONCERNING THE LITTLE GYPSY UNIT 3 REPOWERING PROJECT

NOW COMES Applicant, Entergy Louisiana, LLC ("ELL" or the "Company"), and, pursuant to the Commission's Order No. U-30192-B dated March 13, 2009, respectfully submits this Report and Recommendation Concerning the Little Gypsy Unit 3 Repowering Project (the "Repowering Project" or the "Project"). For the reasons explained more fully below, ELL recommends to the Commission that ELL (i) continue the temporary suspension of the Repowering Project; and (ii) make a filing with the Commission seeking a longer-term delay (three years or more) of the Repowering Project as well as appropriate accounting for the Project costs until the Commission can determine the permanent ratemaking treatment of these costs. A longer-term delay of the Project is appropriate given the uncertainty of various key factors that drive the economics of the Project, including but not limited to:

1) The sharp fall off in natural gas prices, both in the short term but also as projected for the long term by many industry experts, which affects the economics of the Repowering Project;

2) The implementation of various new federal energy policies, including a mandatory Renewable Portfolio Standard and other policies that may affect the economics of the Project; and

3) The uncertainties caused by the recent financial crisis and its effects on the U.S. and global economies.

The longer-term delay will allow ELL to gain better clarity regarding these uncertainties and better understand the effects of these recent changes on the economic viability of the Repowering Project. This delay is consistent with the direction set forth in the Commission's Order Nos. U-30192, dated March 19, 2008, to monitor the economic viability of this Project as part of the Commission's Quarterly Monitoring Plan process.

I. Introduction

During the past few months, there have been dramatic and unforeseeable changes in the U.S. and world economies, the likelihood of various new federal energy policies, as well as a significant decline in the prices of various commodities, including natural gas and crude oil. While it is not possible to predict accurately what the future holds, the level of uncertainty associated with these issues causes concern and a need to pause when considering a commitment as significant as the Repowering Project.

Recognizing these changes, the Commission, at the March 11, 2009 Business & Executive Meeting, issued an Order requiring ELL to suspend, temporarily and to the extent practicable, the current development of the Repowering Project.[1] Specifically, the Commission adopted a Motion stating that:

[1] Order No. U-30192-B, dated March 13, 2009.

> *There have been significant changes that have occurred relating to the Little Gypsy Repowering Project during the past few months, including the recent structural change in the market for natural gas, changes in the capital and financial markets, and the general state of the economy.*
>
> *Given these changes, I move that the Commission direct that Entergy Louisiana, LLC immediately suspend, to the extent possible, on a temporary basis, the Repowering Project and take the steps reasonably necessary to minimize project spending during the period of suspension. I understand that ELL has issued letters formally suspending certain contracts associated with the Repowering Project, and I also move that the Commission direct that these suspensions shall remain in place during the period of suspension.*
>
> *ELL is directed to continue to review the current economics of the Repowering Project and develop a recommendation regarding whether it is appropriate for ELL to make a filing with the Commission to formally delay the Repowering Project for an extended time.*
>
> *By no later than the April 2009 B&E session, ELL shall inform the Commission whether ELL intends to make such a filing.*[2]

For the same reasons that the Commission noted in its Order, prior to the issuance of that Order, ELL proactively responded to the change in the risks and expected value of the Project by taking steps to minimize spending on the Project while the Company conducted further analysis with a view toward determining whether a longer-term delay of the Project would be in the best interest of customers. ELL's analysis shows that, although there are certain risks associated with the continued volatility of natural gas, the expiration of vendor contracts, and the potential expiration of existing environmental permits for the Project, a longer-term suspension and delay of the Project is nonetheless appropriate and would be a prudent action by ELL.

Since the Commission voted to certify the Repowering Project in November 2007, ELL has, as required by Order No. U-30192 and U-30192-A[3], continually monitored the economics of

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[2] *Id.*

the Project to ensure that the Project would provide the benefits contemplated by the LPSC when it certified the Project. As part of the Commission-approved Monitoring Plan, ELL has performed and provided to the Commission, through its Staff, ongoing analyses concerning the projected net benefits of the Project to customers, using the latest information concerning a host of assumptions, including but not limited to the projected costs of natural gas, petroleum coke, coal, and carbon dioxide ("CO_2") regulation through allowances and/or taxes.

As recently as the January 8, 2009 Supplemental Monitoring Report, the Project continued to show positive net benefits to customers when compared to the alternative of a CCGT facility. In the Monitoring Report for the Fourth Quarter 2008, however, which was submitted to the Commission Staff and the Intervenors on February 16, 2009, the Repowering Project's economics, using the most recent assumptions, for the first time projected negative net benefits – indicating that the Repowering Project was projected to cost customers more than the hypothetical CCGT alternative on a net present value basis. At about this same time, on February 25, 2009, the LDEQ issued the final air permit for the Project, which otherwise cleared the way for ELL to commence on-site construction activities for the Project.

In view of the recent adverse change in the projected economics of the Project and given the significant changes in the economy and the uncertainty created by the potential development of new and in some cases more aggressive federal energy policies under the new Administration, the Company believed that it would be appropriate to further evaluate whether continuing with the Repowering Project at this time would be in the best interest of customers. Thus, the Company undertook steps to minimize spending on the Project while further analysis was performed, including, on March 4, 2009, suspending all activity under three of the four largest

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[3] LPSC Order No. U-30192-A, dated July 2, 2008.

contracts relating to the Project, pursuant to the suspension terms of the contracts, and directing the vendor under the fourth contract to take substantial steps to slow the rate of spending. While ELL believes these short-term suspension steps will not immediately delay the in-service date of the Project if the Company ultimately decided to proceed with construction in the near term, the suspension of these contracts allows ELL to minimize spending while it further analyzes whether the Project continues to satisfy the objectives set forth in the Commission's certification Order U-30192, dated March 19, 2008 given recent events.

Since suspending its largest contracts and minimizing the work performed by the Project contractor, ELL has determined that it is in the best interest of customers that the Project be placed into a longer-term delay, that is, a delay of three years or longer. To implement such a delay, it will be necessary for ELL to cancel its current contracts and otherwise terminate the Project activities. However, if total costs to customers are to be minimized under a long-term delay, such steps are immediately necessary. In addition, as ELL will discuss in the last section of this report, a longer-term delay may require ELL to start over in some or all of the permitting processes. Further, if the Project is delayed for an extended period, there is a material risk that one or more permits would not be granted or would be granted subject to conditions that make the Project less attractive economically.

II. Summary of the Recommendation

The Company recommends that the Project be placed in a longer-term delay in consideration of the significant uncertainty associated with this Project caused by the recent changes that have occurred in the commodity markets, the economy, and in U.S. energy policy. A longer-term delay will allow the Company to gain additional clarity regarding a number of these issues, thus mitigating the risk that the Project will not provide long-term benefits to customers.

Perhaps the largest change that has affected the Project economics is the sharp decline in natural gas prices, both current prices and those forecasted for the longer-term. The prices have declined in large part as a result of a structural change in the natural gas market driven largely by the increased production of domestic gas through unconventional technologies. The decline in the long-term price of natural gas has caused a shift in the economics of the Repowering Project, with the Project currently—and for the first time—projected to have a negative value over a wide range of outcomes as compared to a gas-fired (CCGT[4]) resource.[5]

The proposed changes in various energy policies by the Obama administration also could have significant effects on the future economics of the Repowering Project. While this administration has only been in office since mid-January, it is becoming more likely that a Renewable Portfolio Standard ("RPS") soon could be implemented. An RPS will require utilities such as ELL to incorporate various new technologies into their long-term resource

[4] The acronym "CCGT" refers to a Combined Cycle Gas Turbine, which is a relatively newer gas-fired technology.

[5] Prior to this time, the Project had consistently been expected to provide both fuel diversity benefits and positive net economic value on a present value basis relative to a CCGT. Although the LPSC recognized that the volatility of gas prices could cause the net benefits of the Project to become negative at times, all five of the Company's prior filings (direct and rebuttal, July 2008 Monitoring Report, December 2008 Supplemental Report, and January 2009 Supplemental Report) pointed to positive net benefits. As such, this was the first time in which the fuel diversity benefit from the Project was expected to come at an additional cost to ELL customers.

portfolios, including the potential for baseload resources such as biomass facilities and various other intermittent resources such as wind or solar powered generation. The effects of an RPS could mandate that up to 25% of a utility's total energy requirements be provided by renewable resources. Renewable resources are being evaluated by the Entergy System[6] and will be a key consideration in the 2009 Strategic Resource Plan.

With regard to CO_2 legislation, while the Commission and the Company certainly anticipated that CO_2 regulation would be in place over the life of this Project and incorporated CO_2 compliance costs into its evaluation, there seems to be an emerging momentum to implement CO_2 legislation during the next one to two years. If this occurs, it will allow the Company to gain much greater certainty regarding the cost of compliance with CO_2 legislation and how it will affect the Project economics. CO_2 costs, as the Company has always made clear, are an important factor in the Project economics, and while the possible implementation of CO_2 legislation is not a reason to delay the Project, one of the benefits of the longer-term delay will be greater level of certainty regarding this cost.[7]

In addition, the changes in the U.S. and world economies have caused great turmoil in the capital markets. This turmoil has affected both the cost of capital and the timing of its availability. As the Commission is aware, in addition to the Repowering Project, ELL is engaged in the Waterford 3 Steam Generator Replacement Project, which is estimated to cost

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[6] The electric generation and bulk transmission facilities of the six Entergy Operating Companies are planned and dispatched as a single, integrated electric system, referred to as the "Entergy System" or the "System." In addition to ELL, the six Entergy Operating Companies include Entergy Arkansas, Inc., Entergy Gulf States Louisiana, L.L.C., Entergy Mississippi, Inc., Entergy New Orleans, Inc., and Entergy Texas, Inc. Entergy Arkansas, Inc. and Entergy Mississippi, Inc. have provided notice of their intention to terminate their participation in the Entergy System Agreement.

[7] There have been recent updates suggesting that CO2 costs may be higher than expected at the time of certification. For example, the 2009 ICF Multi-Client Study reflects CO2 costs that are much higher than ICF predicted in the Multi-Client Study that was presented during the certification proceeding in this matter. A higher CO2 cost would adversely affect the Project economics.

approximately $511 million. ELL also is in need of acquiring additional CCGT capacity and expects to make various investments in its transmission system during the period of time that the Repowering Project is under construction. When engaging in a large project such as the Repowering Project, which will drive the timing of the need for capital, there could be a constraint in obtaining—at the time it is needed and at rates that are attractive economically—the capital that is needed to fund the Repowering Project as well as ELL's other resource needs. Given the uncertainties in the economics of the Repowering Project, it would seem to be a more prudent use of capital for ELL to plan to fund these other projects and retain additional liquidity while delaying the Repowering Project until the additional clarity can be gained regarding the Project economics.

These revised market outlooks, particularly the sharply lower gas price forecasts, and potential policy outcomes create significant uncertainty in the economics of the Repowering Project. The change in the long-term gas forecasts reduces the value of the fuel savings that the Company and the LPSC anticipated would be provided by the Project. Thus, the "small premium" that the LPSC contemplated could be associated with the Project relative to the cost of an alternative resource such as a CCGT could be much higher—a change from all prior economic analyses, even those performed as late as January 2009. On a more near-term basis, over the first five years of the Project, the net cost to customers of the Repowering Project was originally estimated to equal $145 million; however, the current analysis indicates the total net cost to customers over the initial five years of the Project has more than doubled and is approximately $350 million.

Considered together, the uncertainties associated with the recent changes in the Project economics and market forces driving them, as well as the developments in the federal energy policy and issues raised by the turmoil in the financial markets, suggest that ELL should delay the Repowering Project for a longer term (three years or more) in an effort to gain more clarity and certainty and allow ELL to better determine whether the Project reflects the lowest reasonable cost alternative for customers or whether other alternatives will be better suited to address customer resource needs. Accordingly, ELL recommends to the Commission that ELL make a filing seeking to delay the Project for an extended period of time.

In recommending to the Commission that the Project be delayed for a longer-term, the Company is mindful of the Commission's guidance in Order No. U-30192 that the volatility of natural gas prices could cause the net benefits of the Project to become negative at times during the construction schedule and that a significant part of the justification for the Project is the fuel diversity benefits it offers – benefits not available from a CCGT alternative. The recent structural change in the natural gas market, however, suggests that, across a reasonable range of assumptions, the economics of the Project will be negative relative to a CCGT. Thus, the small "premium" caused by short-term fuel price volatility that the Commission believed could be offset by the fuel diversity benefit provided by the Repowering Project appears, to be materially larger than reasonably could have been expected. A longer-term delay will allow ELL to determine whether the Project, in fact, represents the lowest reasonable cost alternative available to diversify ELL's fuel mix to protect customers from volatile natural gas prices.[8]

[8] Although this filing is made on behalf of ELL, it should be noted that these same factors also merit a delay in the decision of Entergy Gulf States Louisiana, L.L.C. ("EGSL") to participate in the Project at this time. The Commission is considering whether to allow EGSL to participate in the Repowering Project as part of Phase 2 of this proceeding.

III. Recommendation

As noted above, ELL bases its recommendation that the Project be delayed for a longer-term on the recent and significant changes in the Project's economics. This report therefore begins by setting forth the details concerning the change in the Project's economics and discusses the uncertainties raised by the current state of the economy and possible changes in federal policy under the Obama administration. Then, to ensure that the Commission is fully informed of the Project status and spending, the report discusses the current status in some detail. Finally, the report details the current status of the various environmental permits for the Project and the effect on these permits of a longer-term delay in the Project. A longer-term delay is likely to require ELL to seek new or significantly modified permit approvals for the Project, and ELL cannot know today whether such approvals will be obtainable or what conditions may be imposed. This risk is one that ELL has considered and the Commission must consider in deciding whether a longer-term delay of the Project is appropriate.

A. Project Economics

1. Previous Economics

The Repowering Project was undertaken in large part to add supply diversity to the ELL generation portfolio and reduce reliance on gas-fired resources. ELL's generation portfolio was and continues to be weighted toward natural gas-fired resources. Relative to other utilities, ELL's natural gas dependency is high. This dependency on natural gas-fired resources exposes customers to risk relating to changes in natural gas prices. Based on the information available at the time of the original decision to proceed, the Repowering Project was the lowest reasonable cost alternative for reducing reliance on natural gas-fired resources. The Commission recognized in its Order approving the Project that the Project may result in a "small premium" for customers over its useful life relative to the cost of a CCGT resource – that is, that the cost of the Little Gypsy Repowering Project over its useful life ultimately could exceed the cost of a CCGT.[9] Nevertheless, at the time that the Repowering Project was certified, the Company's analyses indicated that it was more likely than not that the Repowering Project would be a lower cost alternative than a CCGT. The Company's analysis did indicate that there was a risk that under certain sets of assumptions, the Repowering Project could become a more costly alternative than a CCGT. The Commission found, however, that the fuel diversity benefit provided by the Repowering Project was sufficiently important that the Project should be certified despite this risk.[10]

The positive economics of the Repowering Project continued through 2008, with each Monitoring Report and a supplemental report prepared by ELL reflecting benefits from the Project. These positive economics continued even though, in 2008, ELL was required to delay the Project in order to obtain additional environmental permitting. Because of then-increasing commodity prices and the additional financing costs for a longer construction period, this delay added to the cost of the Project, increasing the total cost, inclusive of AFUDC, from $1.55 billion to $1.76 billion. However, at this time, gas prices also were increasing and reaching record high levels. Thus, the July 2008 Monitoring Report indicated that the Repowering Project continued to be economic relative to the CCGT alternative. At that time, the Net Present Value of the Repowering Project relative to the CCGT was positive $236 million, similar to the benefit considered by the LPSC when the Project was certified. Gas prices continued to trend upward

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[9] *See* LPSC Order No. U-30192 (March 19, 2008) at 17, 24,

[10] *Id.* at 24.

for the remainder of the Summer of 2008, further affirming the economics of the Repowering Project.

2. Economics Today

Recent developments in natural gas market and resulting changes in projections for long-term natural gas price levels have decreased the value of the Little Gypsy Repowering Project since the Commission certification. Thus, while the Repowering Project would provide a physical hedge against high natural gas prices, there now appears to be significant uncertainty as to the value of this hedge relative to a CCGT alternative. Given current forecasts of natural gas prices, it now appears that the CCGT alternative may be more economic than the Repowering Project across a range of assumptions.

ELL has prepared several economic analyses of the Repowering Project during the first quarter of 2009. Consistent with prior analyses, the Company used the PROSYM production cost modeling tool along with the current estimate of total Project cost, "sunk" costs, and assumptions about key inputs (forecasted natural gas prices, forecasted petroleum coke, and coal prices, etc.). These analyses compare the 40-year life-cycle economics of completing the Repowering Project with the alternative of canceling the Project and initiating a project to construct a new CCGT facility of equivalent capacity and utilization. The analyses follows the same methodology utilized by ELL in the prior viability analyses as well as the economic analysis presented in Exhibit APW-28 in the Company's Rebuttal Testimony filed in October 2007 in Phase I of this proceeding. The table below reflects the results of the ongoing Project analyses.

Table – Results of PROSYM Economic Analyses At Points in Time ($'MM)*

EFFECT ON TOTAL SUPPLY COST LG3 COMPARED WITH CCGT ($MM)	Direct Testimony (July 2007)	Rebuttal Testimony (Oct 2007)	Quarterly Monitoring Report (July 2008)	Supplemental Monitoring Report (Jan. 2009)	Sensitivity ICF Fuel / Emission Outlook (2008 / 2009)	Quarterly Monitoring Report (Feb. 2009)	Current Analysis (March 2009)
With LG3 Repowering Project							
Total PROSYM Fuel and Purchased Power	$81,821	$147,107	$166,300	$163,288	$166,900	$150,660	$155,267
Incremental Non-Fuel Revenue Requirement	$2,174	$2,237	$2,420	$2,403	$2,403	$2,403	$2,399
Total	$83,995	$149,343	$168,720	$165,691	$169,303	$153,062	$157,666
With Equivalent CCGT							
Total PROSYM Fuel and Purchased Power	$83,575	$149,093	$168,214	$165,027	$168,295	$151,964	$156,521
Incremental Non-Fuel Revenue Requirement	$514	$594	$694	$691	$691	$691	$792
Total	$84,089	$149,687	$168,908	$165,717	$168,985	$152,655	$157,313
Net Benefit / (Cost) of LG3RP over CCGT	**$94**	**$344**	**$188**	**$26**	**($317)**	**($408)**	**($354)**
Less Value of Existing LG3 Unit		($31)	($31)	($31)	($31)	($31)	($31)
Add: Committed Cost			$80	$220	$243	$274	$291
Net Present Value	**$94**	**$313**	**$236**	**$215**	**($106)**	**($165)**	**($94)**

* Values for direct testimony represent 25-year NPV. All other analyses reflect 40-year NPV values.

The current economic analysis indicates that the Net Present Value of the Repowering Project relative to the CCGT is negative $94 million. That is, as compared to July 2008, the Project economics have deteriorated by $330 million even after taking increased committed costs into consideration.

The decrease in projected Project economics between July 2008 and today is driven by an assumption of lower long-term gas prices. The July 2008 analysis assumed long-term gas prices of (2007$ levelized 2013 – 2036). The current analysis assumes long-term gas prices of (2007$ levelized 2013 – 2036). Although there has been some movement in other assumptions, which, in combination, partially offset the decrease in the gas prices, the reduction in gas prices of $1.41/mmBTU is the principal driver of the change in the overall projected economics. The table below reflects the key assumptions used in the economic analysis and how those assumptions have changed over time.[11]

Table – Key Assumptions Used In Economic Analyses

KEY ASSUMPTIONS (Levelized 2007$)							
	Direct Testimony (July 2007)	Rebuttal Testimony (Oct 2007)	Quarterly Monitoring Report (July 2008)	Supplemental Monitoring Report (Jan. 2008)	Sensitivity ICF Fuel / Emission Outlook (2008 / 2009)	Quarterly Monitoring Report (Feb. 2009)	Current Analysis (March 2009)
All in Fuel Costs for LG3 ($/mmBtu)							
Henry Hub Natural Gas ($/mmBtu)							
CO_2 Emission Cost ($/ton)							

* Included in the fundamental analysis only.

ICF International, a global professional services firm that is recognized as one of the leaders in providing expert opinions regarding the outlook with respect to fuel and emissions pricing, updated its long-term natural gas and CO_2 emissions forecast in early 2009. ELL utilized ICF's 2006/2007 Multi-client previous natural gas and CO_2 forecasts in its Rebuttal testimony in October 2007 and, therefore, has presented a sensitivity analysis of the Project economics using the updated ICF Multi-Client information. As shown in the table above, ICF's

[11] The Table reflects the 40 year analysis period used to evaluate the Project economics. Because 40-year commodity price assumptions are not generally available to the Company, ELL simply trends the cost up at an assumed rate of inflation for the years not available through the forecast.

updated 2008/2009 forecast for CO_2 emission cost is more aggressive than ELL's forecast for CO_2 costs on a long-term basis for the period extending through 2052. This higher forecast has a negative effect on the Project economics.

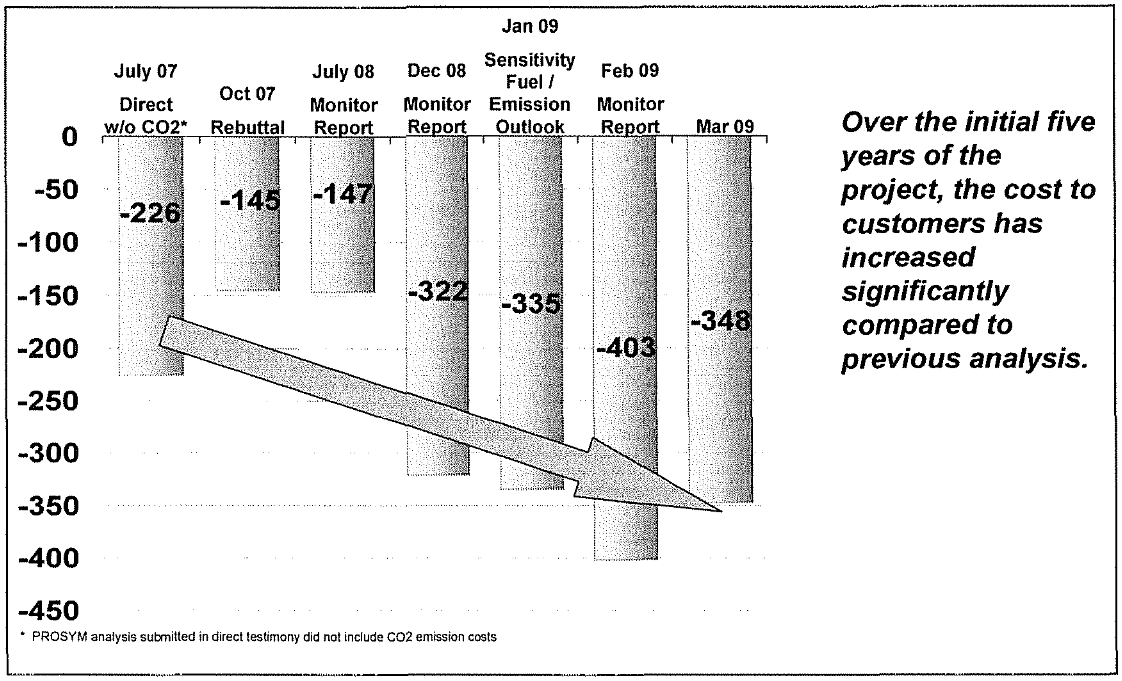
It should be noted that, in one sensitivity analysis the Company has prepared, the Project continues to reflect a break even or possibly positive economic value. This scenario assumes that the fuel mix for the Project is 80% pet coke and 20% coal, instead of the 60%-40% fuel mix that the Company has used as the reference case in all of its analyses. Utilizing a fundamental analysis consistent with the methodology used in Direct and Rebuttal testimony, if the Project burned 80% pet coke, the net benefit would improve by approximately $160 million and would, therefore, approach breakeven or, based on the recent PROSYM, be slightly positive.

ELL's most recent analysis suggests that the Repowering Project may no longer be economic relative to a CCGT alternative and addresses the effects of new and significant uncertainties that have emerged in the wake of the current economic crisis and changes that are being contemplated in federal energy policies. Although the economic results of the Project analysis are based largely on the assumed price of natural gas, as discussed subsequently, it appears that it is not unreasonable to assume that natural gas prices will remain significantly lower than the historic highs experienced in 2008. This means that the Project could, in fact, be a relatively costly physical hedge against high natural gas prices, as opposed to the "small premium" that the Commission contemplated as the possible cost of this hedge when it certified the Project. Further, one must consider these economics in light of the uncertainties caused by the current economic and policy changes.

3. Changes to the Early Year Project Economics

In assessing the potential effect of a long-term delay on the relative economics of the Project, the Company has reviewed the projected customer savings benefit or cost (when negative) over the initial five years of the Project and has compared this metric to previous analysis. As shown in the table below, the net cost to customers over the first five years has increased significantly when compared to the October 2007 Rebuttal testimony analysis.

Customer Benefits / (Costs) Over the First 5 Years of the Project ($MM)*



* Based on PROSYM analysis.

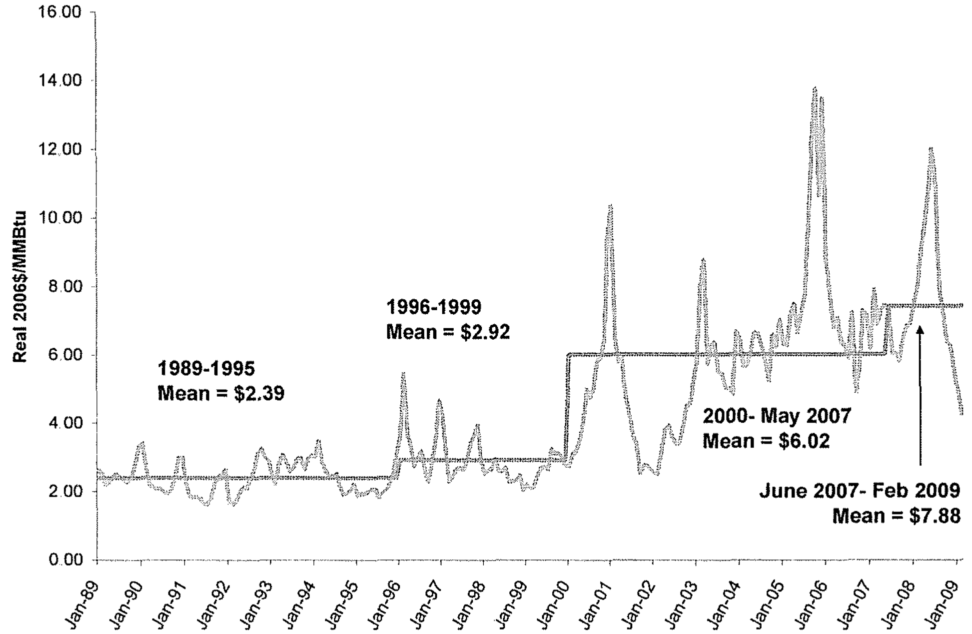
Whereas the net cost to customers was originally estimated to equal $145 million over the first five years, the current analysis indicates the total net cost to customers over the initial five years of the Project has more than doubled and is approximately $350 million. The Company recognizes this metric is not applicable when evaluating the overall life-cycle benefits of a resource; however, similar to the upward trend seen in the following discussion of the breakeven natural gas price, the trend in this metric indicates there is more risk in relying on the back-end cost benefits of the Project to produce benefits over its life-cycle. The higher customer costs in the first five years of the Project life, stemming mainly from lower expected natural gas prices in these years, supports the rationale for a longer-term delay in the Project. Delaying the Project provides headroom by avoiding substantial costs during the periods when gas prices are projected to be lower, and the Project does not provide customers with total savings.

4. Recent Natural Gas Developments

Until very recently, natural gas prices were expected to increase substantially in future years. For the decade prior to 2000, natural gas prices averaged below $3.00/mmBtu (2006$). From 2000 through May 2007, prices increased to an average of about $6.00/mmBtu (2006$). This rise in prices reflected increasing natural gas demand, primarily in the power sector, and increasingly tighter supplies. The upward trend in natural gas prices continued into the summer of 2008 when Henry Hub prices reached a high of $13.32/mmBtu. Since that time, natural gas prices have declined sharply, with recent Henry Hub prices $3.63/mmBtu (nominal).[12] The decline in natural gas prices since the summer of 2008 reflects, in part, a reduction in demand resulting from the downturn in the U.S. economy.

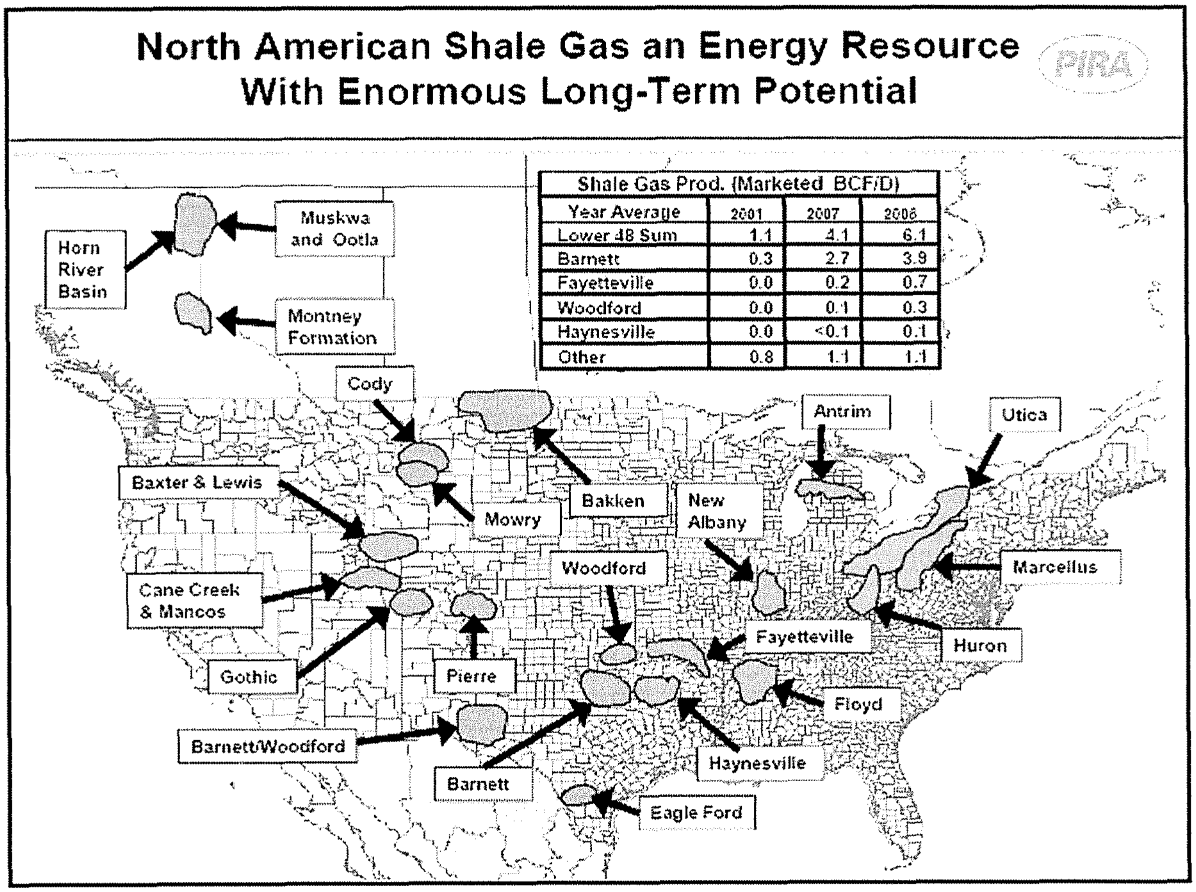
[12] NYMEX settlement for Henry Hub contracts for April 2009

Historical Natural Gas Prices and Volatility



However, the decline also reflects other factors, which have implications for long-term gas prices. During 2008, there occurred a seismic shift in the North American gas market. "Non-conventional gas" – so called because it involves the extraction of gas sources that previously were non-economic or technically difficult to extract – emerged as an economic source of long-term supply. While the existence of non-conventional natural gas deposits within North America was well established prior to this time, the ability to extract supplies economically in large volumes was not. The recent success of non-conventional gas exploration techniques (e.g., fracturing, horizontal drilling) has altered the supply-side fundamentals such that there now exists an expectation of much greater supplies of economically priced natural gas in the long-run. From 2001 to 2008, shale gas production in the lower 48 states increased from 1.1 billion cubic feet per day (BCF/D) to 6.1 BCF/D, an increase of more than 450%.

North American Shale Gas



Shale Gas Prod. (Marketed BCF/D)			
Year Average	2001	2007	2008
Lower 48 Sum	1.1	4.1	6.1
Barnett	0.3	2.7	3.9
Fayetteville	0.0	0.2	0.7
Woodford	0.0	0.1	0.3
Haynesville	0.0	<0.1	0.1
Other	0.8	1.1	1.1

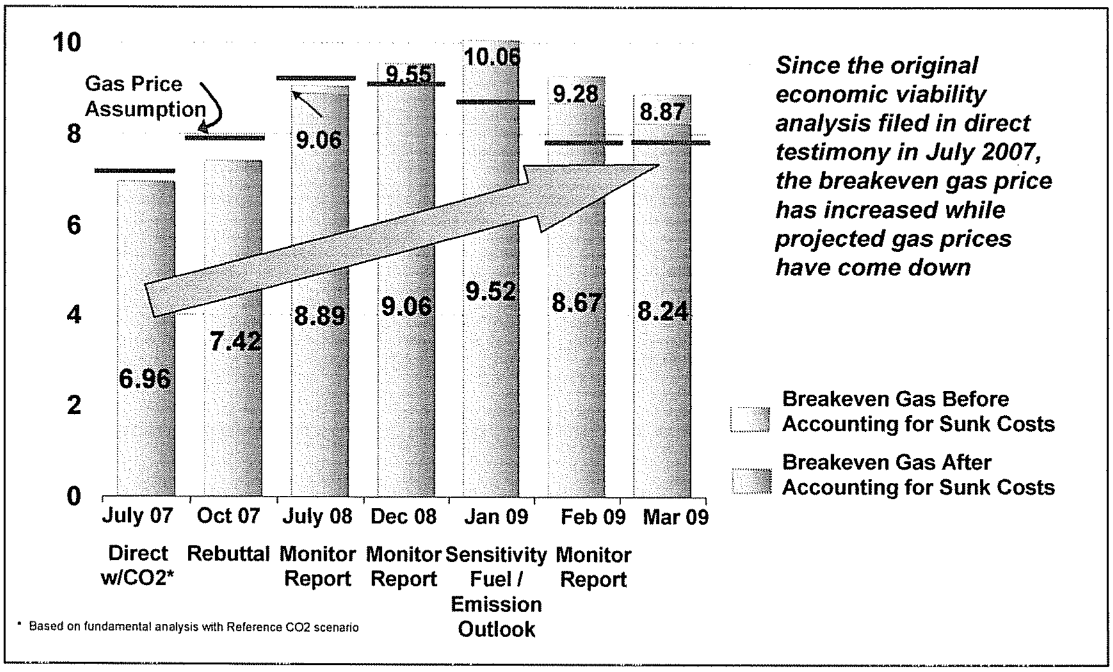
Source: PIRA

5. Breakeven Gas Price

In order to assess further the implications of current gas price projections on the long-term Project economics, the Company has assessed the "breakeven" gas price for the Project over the course of the Project. The "breakeven" gas price is the gas price at which the economics of the Project would match those of a CCGT alternative, that is, the gas price that would give the CCGT alternative the same net present value as the Repowering Project. If the price of natural gas is expected to exceed the breakeven price, then the Project would be economic (less expensive) relative to a CCGT alternative. If the price of natural gas is below the breakeven price, then the Project would be uneconomic (more expensive) relative to a CCGT.

The breakeven analysis relies on a fundamental analysis consistent with the methodology used in ELL's Direct and Rebuttal Testimony. The analysis indicates that, given current assumptions, including accounting for the Project's sunk cost, the breakeven gas price is approaching $8.24/mmBtu (in real 2007 $s). In other words, the Repowering Project is economic relative to the CCGT only if gas prices average above this level on a real, levelized basis over the life of the Project. Below is a chart comparing the breakeven price of natural gas that is required to cause the Project to be economic relative to a CCGT alternative across several different points in time.

Breakeven Gas Price ($/mmBtu)



Notes:
1. All gas prices quoted in real 2007 dollars.
2. Direct and Rebuttal Testimony based on 30-year fundamental analysis for 2012 – 2041. All other analysis based on 40-year analysis for 2013 – 2052.

As shown in the above chart, the analyses conducted over the course of the Project indicated that long-term gas price projections were above the Project's breakeven gas price until early 2009. This relationship suggested that the Repowering Project was likely to be economic relative to a CCGT alternative in the long-run. In the current analysis, however, the relationship has reversed. The breakeven gas price is now above projected long-term gas prices. Moreover, the gap between projected long-term gas prices and the breakeven gas price is $0.45/mmBtu ($7.79 projected compared with $8.24 breakeven) in real 2007 dollars when including sunk costs and over $1.00/mmBtu when excluding sunk costs.

The conclusion from the breakeven analysis is that one must believe that the levelized price of natural gas must remain higher than $8.24 (real 2007 dollars) over the life of the Project if it is to provide economic benefits to customers. In this case, however, as discussed previously, there is a reasonable basis to question this assumption due to the enormous potential of non-conventional resources and other forces that will help to lower natural gas prices. Thus, the breakeven analysis supports a longer-term delay of the Project.

6. Conclusions Regarding Economic Analysis

The cost of the Repowering Project and that of other baseload generation alternatives are subject to significant uncertainties that can change materially their relative economics. In the case of the Repowering Project, a chief uncertainty is long-term natural gas price levels, but the Project also is influenced by the effects of potential energy, environmental and policy issues, which are discussed in the next section, and by whether the timing of this investment is appropriate given the current capital markets. As recognized in the Commission's Order certifying the Project, "the cost-effectiveness of the Repowering Project remains very uncertain because one cannot predict with certainty the ultimate cost of possible CO_2 regulation and natural gas prices over the next 30 years."[13]

At the time of the certification proceeding and through the beginning of 2009, the Project was expected to produce both fuel diversity benefits as well as net economic benefits relative to a CCGT supply alternative. Thus, the important fuel diversity benefit of the Project was expected, under most assumptions, to be economic relative to a CCGT alternative.

Today, this conclusion is uncertain, and this uncertainty is the reason that ELL seeks a longer-term delay of the Project. Recent significant changes in the natural gas market and resulting structural declines in projections of long-term gas prices now make the expected economics of the Repowering Project less attractive relative to a CCGT alternative. Given the current cost of the Project and projected long-term natural gas prices, the Repowering Project does not appear to represent the lowest reasonable cost alternative for meeting ELL's baseload needs at this time. Further, there are new risks to the Project's long-term economics raised by the structural change in the natural gas market and ongoing economic crisis and emerging federal response and potential policy initiatives and timing, which were not knowable at the time of the earlier Project decisions. These new uncertainties pose additional risks to long-term electricity demand and supply requirements that suggest the timing of the Project should be reconsidered.

Of course, it should be noted that it is not possible to predict natural gas prices with any degree of certainty, and ELL cannot know whether gas prices may rise again. Rather, based upon the best available information today, it appears that gas prices will not reach previous levels for a sustained period of time because of the newly discovered ability to produce gas through non-traditional recovery methods. Thus, the cost premium that the LPSC believed might be

[13] Order No. U-30192 (March 19, 2008) at 28 (referring to testimony of Staff witness Matthew Kahal).

"small," as stated in its Order,[14] could be much higher. Under these circumstances, ELL believes that it is appropriate to delay the Repowering Project at this time and revisit this option in the future.

C. Uncertainties that May be Resolved During the Longer-Term Delay

Although changes in the natural gas market (and the associated changes in the expected future path of natural gas prices) is a key driver of the Company's recommendation at this time, the ultimate economics of the Repowering Project are also a function of the outcome of a variety of additional factors, each of which is highly uncertain. These include the long-term effects of the current global recession on the demand for energy; the possible imposition of federally-mandated RPS, which could change the structure of ELL's portfolio and further depress the long-term price of natural gas; the sustainability of the long-term non-conventional natural gas supply, which is a key driver of the expected lower natural gas costs; additional clarity regarding the cost of CO_2 compliance; the possibility of capturing lower long-term commodity costs in a future project; and, other factors. Continuing with the Repowering Project at this time would result in an irreversible investment decision based on the significant capital requirements associated with this Project, yet the resolution of the various uncertainties could produce scenarios in which the outcome of a decision to proceed would not benefit the Company's customers.

At this time, because of lower natural gas prices, the Commission and the Company have the ability to mitigate the effects of these uncertainties by exercising flexibility and delaying decisions that otherwise would result in irrevocable capital expenditures. Delaying a final

[14] Order No. U-30192 (March 19, 2008) at 24.

investment decision can create value for ELL customers by providing time to clarify and resolve uncertainties, increasing the likelihood that the Project, if ultimately undertaken, will produce net benefits for ELL customers over its lifetime. For instance, during a two or three year delay period, ELL is likely to learn whether we are in a severe but short recession or a long-term period of slow growth; whether the U.S. Congress will pass RPS and/or CO_2 legislation and, if so what the cost of compliance might be and the effect on ELL's resource needs; and, the extent to which the development of North American non-conventional gas reserves will constrain domestic natural gas prices for an extended period of time. Greater clarity on all of these uncertainties, about which much will likely be learned over the next two to three years, will allow a better final investment decision to be made. Because it is reasonable to expect that at least some additional clarity regarding these key issues will emerge over the next few years, a decision to delay is reasonable and prudent.

D. <u>Capital Considerations</u>

As the Commission is no doubt aware, the United States and world are in the midst of a severe economic crisis. The capital markets have become increasingly constrained, and investors are charging large premiums to invest in bonds, even in the case of utilities, which traditionally have been considered so-called "safe harbor" investments. While ELL cannot know today how the financial turmoil will affect the funding of the Project, it is reasonable to expect challenges and possibly added cost, which would weaken further the Project economics. Given the uncertainties in the economics of the Repowering Project, it would seem to be a more prudent use of capital for ELL to plan to fund these other projects and preserve its liquidity for unexpected events while delaying the Repowering Project until the additional clarity can be gained regarding its economics.

ELL discussed issues involving access to capital in its Direct Testimony in Phase 2 of this proceeding. However, at the time of that filing, ELL did not know whether the current tightening of the credit markets would be sustained. It now appears that it could take several years for the financial markets to recover.

The turmoil in the financial markets must cause ELL to consider the timing of investing in a capital project of the size of the Repowering Project given its uncertain economics and ELL's need to fund a number of other large investments. ELL is engaged in the Waterford 3 Steam Generator Replacement Project, which was recently certified by the Commission, and is estimated to cost approximately $511 million. ELL also is in need of acquiring additional CCGT capacity and has opportunities currently available to it. ELL expects to make various investments in its transmission system during the period of time that the Repowering Project is under construction. On top of these capital needs, ELL must seek recovery for its costs associated with the 2008 Hurricanes Gustav and Ike. The current estimated cost of these storms to ELL is $390 to $405 million, and there is a need to fund the depleted storm reserve. Although ELL expects that it will be permitted to recover its prudently incurred storm costs, that recovery is not likely to begin until 2010, and ELL is, therefore, entering the 2009 hurricane season with no storm reserve and no funding in place for its outstanding storm costs. Taken together, the projects that ELL needs to complete and ELL's need to ensure that it has adequate liquidity to address storm events counsel against undertaking an investment of the size of the Repowering Project at this time given its declining economics.

The longer-term delay of the Repowering Project will allow ELL to concentrate its financial resources on projects such as the Waterford 3 Steam Generator Replacement Project and on CCGT and transmission investment, all of which will provide benefits to customers. The delay also will permit ELL to resolve its cost recovery for Hurricanes Gustav and Ike. Given the uncertain economics of the Repowering Project, ELL believes that it is prudent to concentrate its resources on these other projects and preserve its liquidity for unexpected events until additional clarity can be gained regarding the economics of the Repowering Project.

E. Potential Supply Options

As part of the ongoing supply planning process and in light of the uncertainty associated with this Project, the Entergy System currently is pursuing the following initiatives to evaluate other supply options:

- Renewable Resources – The Entergy System issued a Request for Information ("RFI") for Renewable Resources to the market on March 31, 2009 in an effort to obtain information from third parties regarding the potential for the development of renewable generation resources in the area in which the Entergy System provides service. This information will prove valuable as ELL assesses the effects of a likely RPS as discussed herein and which technologies may be most appropriate to meet the needs of customers as well as the RPS.
- Energy Efficiency – The System currently is pursuing various initiatives regarding energy efficiency, including fulfillment of a commitment in this proceeding to complete a study of the DSM potential in the areas served by

ELL and Entergy Gulf States Louisiana, L.L.C ("EGSL").[15] The role of DSM in long term planning also is included in the LPSC's ongoing Integrated Resource Planning ("IRP") Docket. Finally, demand response programs and time-of-use rates were piloted by EGSL in 2008 and will be further evaluated in 2009 as part of the second phase of the advanced metering infrastructure (AMI) pilot in Baton Rouge.

- Long Term CCGT Resources – The System continues to evaluate opportunities for the procurement of long-term CCGT resources and, on March 31, 2009, posted notice that it intends to move forward with a long-term RFP for these resources. This RFP will include a self build CCGT option at the Company's Ninemile site, which will be compared against other market alternatives. In addition, the System continues to be in discussions with various suppliers for resources that may provide compelling benefits to customers.

IV. Status of Project Development and Spending

ELL has incurred approximately $160 million of cost through February 28, 2009 on a life-to-date basis for the Repowering Project. ELL estimates that, should it cancel the Project, the total cost of the Project would be approximately $300 million, including actual spending and estimated contract cancellation costs, although the total cost could be higher depending upon when the contracts are cancelled. The portion of this figure attributable to contract cancellation

[15] As previously discussed in testimony before the LPSC, DSM is not a substitute for the supply role that would be provided by the Repowering Project. However, it will help meet the Companies' resource needs and may, with other initiatives, affect the total resource portfolio.

costs is only an estimate, as ELL must negotiate with many of the Project vendors in order to determine the actual cancellation costs. ELL has necessarily focused its discussions to date with vendors on issues surrounding the temporary suspension of the contracts; as such, ELL is not yet in a position to report on the status of the negotiation of cancellation costs for those contracts. ELL plans to begin canceling these contracts over the next few weeks and will be able to develop a complete cost estimate after it completes these cancellations and can determine the full costs to which it is obligated.

During February 2009, the Company determined that, in light of the deterioration in the Project's projected economics and other factors, including recent changes at the federal level, it would be appropriate to slow the rate of spending on the Project while further analysis was undertaken concerning the continued viability of the Project. During this time, the Company directed the Project Team to take necessary steps to minimize the costs incurred for the Project while also balancing the necessity of maintaining the projected in-service date. The Project Team analyzed the four largest contracts where the majority of dollars were being expended and identified discretionary steps that it could take to minimize spending during this period without immediately affecting the Project's construction schedule or projected in-service date. The Project Team also suspended entering into any new contracts unless they were required to maintain the construction schedule. For those that were required to maintain the construction schedule, when feasible, the Project Team bifurcated the new contracts to enter into only the required portions and to defer the remainder.

On March 4, 2009, as part of the above-described effort to slow Project spending, the Company instructed the Project Team to suspend substantially all activity under three of the Project's four largest contracts in order to minimize cost. The terms of these contracts permit

ELL to suspend activity under the contracts for a limited period of time, as it deems necessary, without having to cancel the contracts and renegotiate new contracts if the Project were to move forward. In addition, as of early March 2009, work under each of these contracts had progressed to a point that suspension would not be expected to affect the construction schedule significantly. However, the maximum time that these contracts may remain under suspension ranges from three months to one year. If the suspension exceeds the maximum time allotted, the contracts accord the vendors a right either to cancel their contracts or require a renegotiation of terms. Suspensions longer than three months are therefore impracticable, as the resulting contract cancellations would require that new contracts be negotiated and priced with either the same or new vendors.

Further, ELL is generally responsible under the contract terms for reimbursing incremental costs incurred during suspension. These incremental costs could include costs of storage, transportation to storage, and corrosion protection, among other items.

In addition to the above efforts to suspend activities under significant contracts, ELL directed its Engineering, Procurement, and Construction ("EPC") contractor, which is the principal contractor for the Project, to slow spending, including, specifically to do the following:

- defer any planned personnel moves, site mobilization, or additions to the project team;

- allow project team reductions for all personnel not listed as key personnel (reduction in key personnel must have ELL approval, per the contract);

- continue requests for proposals and evaluations of pending purchase orders and subcontracts, but not to approve any additional subcontracts or purchase orders without ELL approval;

- demobilize the site preparation subcontractor as required to limit activities to returning the site to an acceptable condition, and, further, to demobilize all personnel and equipment not required for this activity; and

• work with ELL to determine other cost control actions to reduce cost commitments and evaluate the requirements to maintain Work and Agency Orders that ELL suspends.

ELL believes that it should manage the Project spending consistently with the objective of obtaining a longer-term delay and further minimizing costs to customers, unless otherwise directed by the Commission. Thus, ELL plans to take immediate steps to minimize spending further on the Project, including the termination and/or cancellation of current contracts with vendors.

The timing of the cancellation of the contracts is important; in general, the sooner the contracts are cancelled, the lower the cancellation costs. The Project contracts have limited suspension periods, generally ranging from three months to one year, and contract provisions allow vendors to be compensated to maintain the suspensions. Thus, ELL must establish a timely suspension management plan. As part of this plan, ELL intends to cancel its contracts in April 2009.

It is important to understand that the management of the Project spending and contracts would differ if the contracts were being managed with a view to being able to restart the Project in the next three months to one year and that, if the Project were to be restarted within this time, there could be additional costs beyond those contemplated by the current Project estimate such as, for example, storage costs and costs to treat and protect fabricated materials so that they would be available for use when the Project resumed. However, given the high probability that the economic viability of the Project will not materially improve over the near term and considering the need to minimize overall costs for ELL and its customers, ELL believes that it is appropriate to implement a longer-term delay and immediately begin the orderly winding down of Project activities

V. Status of Environmental and Other Permits

ELL has obtained all major environmental permits required to begin construction of the Project. As detailed below, however, a delay in the Project places these permits at risk and may adversely affect the Project's economics and technological feasibility in the event the Project were later re-initiated. Below is a list of the major environmental permits that it needs to commence construction, including the following:

Type	**Permit**	**Issuer**
Air	Prevention of Significant Deterioration Permit To Construct	Louisiana Department of Environmental Quality ("LDEQ")
Air	Title V Operating Permit, including case-by-case Maximum Achievable Control Technology ("MACT") analysis	LDEQ
Air	Title IV Acid Rain Permit	LDEQ
Water	Section 404 Dredge and Fill ("Wetlands") Permit/Section 10 Rivers and Harbors Act Permit	U.S. Army Corps of Engineers
Water	Section 401 Water Quality Certification	LDEQ
Water	Coastal Use Permit	Louisiana Department of Natural Resources ("LDNR")
Water	Stormwater Control Permit/General Permit Coverage	LDEQ
Land Use	Project Approval	Lake Ponchartrain Levee Board

In addition to the above permits, which have been obtained, additional permits – (i) for modifications to wastewater discharges (Louisiana Pollutant Discharge Elimination System permit modification) and (ii) for the proposed post-combustion product landfill (solid waste permit) –must be obtained. These last two permits are not required to commence construction on the Project but would be required prior to operation of the new generating unit (for the wastewater permit) and prior to the start of landfill construction (for the solid waste permit).

Importantly, a short-term or longer-term delay in the Project would affect the above-described permits in a variety of ways. A short-term delay in the Project – lasting approximately 60-90 days – would affect only the Prevention of Significant Deterioration Permit To Construct. Specifically, if construction on the Project does not begin by May 30, 2009, an extension of the required start-by construction date included in the Prevention of Significant Deterioration Permit To Construct would be required. LDEQ originally issued this permit on November 30, 2007, and it expires on May 30, 2009 unless construction has begun or binding commitments to begin construction have been entered by that date. However, an extension of the construction start date requirement can be requested from LDEQ. Nonetheless, this is the most pressing deadline related to the environmental permits.

A suspension or multi-year delay in the Project would affect the permits in other, more significant ways. ELL would be required to seek renewal of existing permits, permit extensions, or new permits for the Project, including new air permits. Moreover, it is possible that any extensions, renewals, or new permits would contain new provisions that would have a significant effect on the economics or technological feasibility of the Project. If it proceeds with implementing a longer-term delay in the Project, ELL would seek extensions or renewals of the permits, when allowed by law or regulation and when beneficial to continuing Project viability, but it is not possible to know whether such extensions would be granted or for what period of time. Thus, if a decision is made to delay the Project for an extended period, that choice should be made with an awareness and acceptance of the fact that, as a result, ELL may be required to start over in some or all of the permitting processes. Further, if the Project is delayed for an extended period, there is a material risk that one or more permits would not be granted or would be granted subject to conditions that make the Project less attractive economically.

In particular, and in addition to the effects described above, the longer-term delay of the Project would affect the various permits as follows:

- Title V Operating Permit: LDEQ issued this permit initially on November 30, 2007 (without the MACT determination, which was added later as a modification). The permit expires on November 30, 2012 unless an application for renewal is filed on or before May 30, 2012. The permit also requires that construction begin within two years of permit issuance, or by November 30, 2009. ELL can request an extension of this deadline.

- New Regulatory Requirements: ELL may be required to comply with new regulatory requirements relating to air emissions that become effective before the onset of construction or before permits are extended or renewed. Examples of these requirements are limits on the emission of carbon dioxide and other greenhouse gases, technological standards for mercury and similar emissions, and additional controls required by tightened national ambient air quality standards for ozone that may affect St. Charles Parish. In particular, a designation of St. Charles Parish as not in attainment of EPA's new ozone standard could require LDEQ to deny an extension of the construction start-date requirement in the PSD permit in favor of requiring a new permitting process.

- Wetlands Permit/Section 10 Rivers and Harbors Act Permit: The Corps of Engineers permit expires on February 28, 2014. ELL would require an extension to continue construction operations regulated by this permit after that date.

- Coastal Use Permit: This permit expires on January 9, 2014. Extensions are not provided for this type of permit, so a new permit may be required if construction activities allowed by the permit are not completed by that date. The permit requires that "reasonable progress" continue to be made on the project during the life of the permit. If a new permit were required, new proposed regulations that would require the "beneficial use" of dredged materials could apply to the project, increasing mitigation costs.

Recently, new issues have arisen regarding EPA's jurisdiction over CO_2 emissions. In the wake of the United States Supreme Court's decision in *Massachusetts v. EPA*, EPA is expected to publish a determination in April 2009 that CO_2 emissions cause or contribute to an endangerment to human health and welfare. This "endangerment finding" is a condition precedent to EPA's regulation of CO_2 emissions from mobile sources, such as automobiles and trucks, under Title II of the Clean Air Act, § 201(a)(1). Once EPA makes the endangerment finding, the agency must then develop applicable emissions standards for mobile sources. These emission standards are not to take effect, however, until "after such period as the Administrator finds necessary to permit the development and application of the requisite technology, giving appropriate consideration to the cost of compliance within such period." CAA § 202(a)(2). It is unknown whether the endangerment finding would have an effect on the pending permit; however, assuming that the Company was able to gain an extension of the PSD permit, if construction did not begin by the expiration of the extension period, and a new PSD permit was required after the promulgation of CO_2 regulations, that permit likely would include CO_2 limits or technology requirements that differ from those present under the existing PSD permit.

VI. Conclusion and Recommendation

For the reasons set forth above, ELL recommends to the Commission that ELL (i) continue the temporary suspension of the Repowering Project; and (ii) make a filing with the Commission seeking a longer-term delay (three years or more) of the Repowering Project as well as appropriate accounting for the Project costs until the Commission can determine the permanent ratemaking treatment of these costs.

Respectfully submitted,

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EXHIBIT 5

CEC Cancels Gas-Fed Peaker, Suggesting Rooftop Photovoltaic Equally Cost-Effective

Bill Powers

An emerging discussion in the climate-change debate is whether our renewable energy should come primarily from remote utility-scale wind and solar plants, connected to urban centers by a vast new network of transmission lines, or whether local renewable energy should play a much more prominent role. The rooftop solar photovoltaic (PV) array is among the most recognized forms of local renewable energy.

On June 17, the California Energy Commission (CEC) issued a landmark ruling that will undoubtedly figure prominently in this discussion. The CEC denied an application for a 100-megawatt natural gas–fired gas turbine power plant in part because rooftop solar PV could potentially achieve the same objectives for comparable cost.

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This decision implies that any future applications for gas-fired generation in California, or any other type of generation including remote utility-scale renewable energy generation that may require public land and new transmission to reach demand centers, will be measured against using urban PV to meet the power need.

The CEC decision said the following:

> Photovoltaic arrays mounted on existing flat warehouse roofs or on top of vehicle shelters in parking lots do not consume any acreage. The warehouses and parking lots continue to perform those functions with the PV in place. (Ex. 616, p. 11.) . . . Mr. Powers (expert for intervenor) provided detailed analysis of the costs of such PV, concluding that there was little or no difference between the cost of energy provided by a project such as the CVEUP (gas turbine peaking plant) compared with the cost of energy provided by PV. (Ex. 616, pp. 13–14.) . . . PV does provide power at a time when demand is likely to be high—on hot, sunny days. Mr. Powers acknowledged on cross-examination that the solar peak does not match the demand peak, but testified that storage technologies exist which could be used to manage this. The essential points in Mr. Powers' testimony about the costs and practicality of PV were uncontroverted. (CEC Decision, pp. 29–30)

The CEC concluded that PV solar arrays on rooftops and over parking lots may be a viable alternative to the gas turbine project, and that if the gas turbine project proponent opted to file a new application, a much more detailed analysis of the PV alternative would be required. The use of the urban PV alternative as the litmus test that must be passed before a new gas turbine

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plant, or a new remote utility-scale wind or solar plant, can be approved should move the rooftop solar PV option onto center stage of the national renewable energy debate.

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URBAN PV IS COST-EFFECTIVE ALTERNATIVE TO PEAKING GAS-FIRED POWER

The CEC identified the low-end levelized cost of energy (COE) for PV as $114 a megawatt-hour in an August 2008 report that includes the comparative costs of different renewable energy technologies.[1] This $114 a megawatt-hour is based on "thin-film" PV and conservative assumptions regarding the installed cost and the direct-current-to-alternating-current conversion factor. The thin-film PV technology upon which the CEC estimate is based is manufactured by First Solar. First Solar stated an expected COE of $90 a megawatt-hour in its April 2008 comment letter to the CEC.

The thin-film PV capacity factor identified by the CEC and California's investor-owned utilities is 18 percent. Capacity factor is a measure of the amount of power produced by a system compared to its maximum potential output. Maximum potential output would be achieved if the system produced its rated power output 24 hours a day, every day of the year. Operating continuously at maximum output is equal to a 100 percent capacity factor.

The CEC identified the COE of a 50-megawatt simple-cycle gas turbine as $647 a megawatt-hour in its December 2007 report, *Comparative Cost of Electric Generation Technologies*. The turbines proposed for the gas turbine project were two turbines of approximately 50-megawatt capacity. The CEC assumed a 5 percent annual capacity factor for simple-cycle gas turbines in calculating the $647-a-megawatt-hour figure. This level is consistent with the level of operation anticipated by the project applicant. The applicant stated that the expected capacity factor would be 5 percent.[2]

Adjusting the peaking gas turbine COE to reflect an 18 percent capacity factor, equivalent to the annual capacity factor of thin-film PV, gives a simple cycle gas turbine COE of $180 a megawatt-hour.

The local utility assigns PV without storage a capacity factor of 50 percent for peak demand reliability purposes.[3] The reason for this is that PV system output peaks at midday, and the daily summertime demand peaks are typically around 3:00 p.m. or 4:00 p.m. State-of-the-art peaking gas turbines achieve only about 75 percent of their nameplate capacity at 100°F due to the relatively low density of ambient air at 100°F. Older peaking turbines achieve as little as 65 percent or less of nameplate capacity at 100°F.

If only 50 percent of the installed PV capacity is considered available for peaking reliability purposes per San Diego Gas & Electric's (SDG&E's) assumption, then 150 megawatts of PV without storage would have to be installed to assure 75 megawatts of state-of-the-art peaking gas turbine power reliability at 100°F. In other words, 50 percent more PV nameplate capacity must be installed to achieve the same reliable capacity achieved by the gas turbine at 100°F.

If the value of the peaking power available from the PV array is limited exclusively to its ability to provide peaking power (for the sake of argument), it is reasonable to multiply the levelized COE by 1.5 to reflect the relative output compared to a peaking gas turbine on a summer afternoon. Multiplying the base case PV COE range of $90 a megawatt-hour (First Solar) to $114 a megawatt-hour (CEC) by 1.5 gives a peaking power PV COE range of $135 a megawatt-hour to $171 a megawatt-hour.

There is little difference between the COE of a 150-megawatt thin-film PV. . . and 100 megawatts of state-of-the-art gas turbine capacity at the same conditions. This is without considering the . . . renewable energy credits . . . , the elimination of air emissions, or the lack of dependence on a secure supply of natural gas.

Thus, there is little difference between the COE of a 150-megawatt thin-film PV array to assure 75 megawatts of net reliable summer afternoon peaking power at 100°F and 100 megawatts of state-of-the-art gas turbine capacity at the same conditions. This is without considering the green economic benefits of renewable

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energy credits generated by PV, the elimination of air emissions, or the lack of dependence on a secure supply of natural gas.

The addition of limited storage to each PV system ensures that the PV nameplate capacity is firm on-peak capacity. Commercial-scale demonstration projects are under way.[4] The battery systems are fully controllable by the utility as peaking units. The addition of energy management and battery storage allows the PV system to supply the utility grid with its peak output through the late afternoon summertime demand peak. The batteries mean that a 75-megawatt PV array with limited storage can provide the same reliable output at 100°F as a 100-megawatt peaking gas turbine plant. Adding limited storage capacity is a cost-effective approach to assuring the entire PV capacity is available during peak demand periods.

On June 18, Southern California Edison (SCE), California's largest investor-owned utility, received approval from the California Public Utilities Commission to construct a 500-megawatt urban PV project on warehouse rooftops. SCE states in its March 2008 project application that it

> can coordinate generation or storage technologies at the substation level to moderate the inherent weather-caused variability in solar PV production before such intermittency cascades into the higher voltage transmission system. Such coordination will reduce system costs. ([2008, March 27]. SCE application to CPUC for commercial PV program—Testimony, p. 17.)

SCE envisions large-scale storage as a viable and complementary element to its PV program. Maintaining rated power of the PV system through the afternoon peak load with energy storage would only be necessary on hot summer days.

ROOFTOP PV COULD PROVIDE RELIABLE POWER IN MANY PLACES NATIONWIDE

The U.S. solar energy approach to date has been almost completely focused on remote utility-scale solar energy resources and the transmission associated with such projects. This approach had merit in the 1980s when California became the world leader in solar power development using parabolic trough solar thermal technology at a time when solar PV cost $12 to $15 a watt (2008 dollars). However, the world has changed. Commercial PV installations now cost less than $4 a watt.

"Land-Intensive" Argument No Longer Correct

The current national focus on utility-scale desert solar power in the Southwest presumes this solar resource is so much more cost-effective than the urban PV alternative that it justifies the transmission cost, environmental trade-offs, and controversy of such remote solar development. This may have been true in the 1980s. It is not true in 2009.

The least-cost solar resource in 2009 is in California's developed urban and suburban areas, and this resource is vast. Urban solar deployments would be compatible dual use of existing rooftops and parking lots, avoiding the often-cited dilemma that "solar power is very land-intensive, and siting a solar plant means that most if not all of the other uses of that land are precluded."

It is true that some of the largest solar resources are to be found on public lands in the Southwest. However, these large solar resources are only useful to the extent that they are cost-effective in their own right and can be delivered efficiently to population centers. The cost of delivery via new transmission can be very high, without even addressing the environmental compromises necessary to construct the transmission lines or the utility-scale solar plants themselves.

No Line Loss nor Significant Additional Transmission

California's ongoing renewable energy transmission siting process, known as the Renewable Energy Transmission Initiative (RETI), indicates the least-cost solar solution to reaching California's target of 33 percent renewable energy by 2020 would consist predominantly of local distributed PV. Why? Because state-of-the-art PV is more cost-effective than solar thermal, and tens of thousands of megawatts of PV could be added at the local level with little or no upgrading to the existing transmission system required. RETI makes the following points about state-of-the-art PV:

> There is considerable commercial interest in utility-scale "thin film" (PV) systems. This sensitivity tests an alternate thin film technology for solar with capital costs of about $3,700/kWe (AC), roughly half that of tracking crystalline (PV). Notably, these (PV) capital costs are also lower than the large-scale solar thermal projects; therefore thin film solar is assumed to occur both at the distributed scale (20 MW) and also in large scale blocks (150 MW). (California Energy Commission. [2009, January 5]. RETI Phase 1B Final Report, pp. 5-27, 5-28.

PV can be deployed in urban and suburban areas in compatible dual-use applications that require no environmental trade-offs.

Unlike solar thermal technologies, PV can be deployed in urban and suburban areas in compatible dual-use applications that require no environmental trade-offs. Urban/suburban PV is more cost-effective than remote PV because it avoids the (1) high cost of new transmission lines and (2) high line losses, in the range of 15 percent, during peak demand periods.

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Could Fulfill 75 Percent of California's Renewables Target

The RETI report goes on to say that distributed PV at a current state-of-the-art capital cost of $3.70 a watt can provide two-thirds of what California needs going forward to reach 33 percent renewable energy by 2020:

> The results of this sensitivity run are dramatic. More importantly, the cost-competitive in-state (distributed PV resources) increase by more than 20 times to about 45,000 GWh/yr. This figure is over two-thirds of the net short requirement. The large majority of these (distributed) resources are 20 MW solar PV projects assumed to connect to the distribution system.

In February 2009, RETI reduced its estimate of the gap that must be filled to reach 33 percent by 2020, such that 45,000 gigawatt-hours a year (GWh/yr) from distributed PV could meet 75 percent of the need.

The November 2008 Los Angeles Department of Water & Power (LADWP) "Solar Los Angeles" strategic plan is a good real-world example of a renewable energy future that leads with distributed urban PV. The plan consists of 780 megawatts of urban PV and 500 megawatts of remote solar. This is two-thirds urban solar, one-third remote solar. With this urban/remote balance, little if any new transmission will be necessary for Los Angeles to go solar. LADWP is a public utility, and "Solar Los Angeles" reflects the intent of the city of Los Angeles to become a leader in smart and urban renewable energy development.

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San Diego Gas & Electric's service territory offers another example of the large role urban PV could and should play in California's, and the nation's, renewable energy portfolio:

- There are approximately 4,500 megawatts of commercial rooftop and commercial parking lot PV potential in SDG&E territory.
- Peak load in SDG&E territory in 2008 was 4,348 megawatts, and the average load over the course of the year is approximately 2,500 megawatts.
- 4,500 megawatts of PV are equivalent to approximately 900 megawatts of continuous power generation over the course of a year.
- The San Diego area could generate approximately 40 percent of its year-round power demand from urban commercial rooftop and commercial parking lot PV alone.
- That is without considering approximately 2,500 megawatts of PV potential on residential rooftops in SDG&E territory.

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- If the residential PV resource is fully developed in addition to the commercial PV resource, 60 percent of the San Diego area's year-round power demand could be met with urban PV.
- This large solar resource has no land-use requirements, as it is all compatible dual-use, and has no environmental impacts.

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Argument That Insufficient Manufacturing Capacity Exists Is False

RETI has attempted to minimize the distributed PV solution to California's renewable energy goal by stating that there is no way PV manufacturers could mobilize quickly enough to provide 2,000 to 3,000 megawatts of PV per year to realize the potential of the distributed PV alternative for California. This is not a valid concern. Spain, with about the same population as California and a less productive economy, added nearly 2,500 megawatts of PV in 2008.

More than 5,000 megawatts of PV were installed worldwide in 2008.[5] Worldwide thin-film PV production capacity reached 3,600 megawatts a year in 2008. It is projected to reach 7,400 megawatts a year in 2010. Worldwide conventional polycrystalline silicon PV production capacity reached 13,300 megawatts a year in 2008. It is projected to reach 20,000 megawatts a year in 2010. The 2010 projections were made just as the economic slump began in late 2008. It is likely there will be some scale-back on the 2010 capacity projections due to the state of the world economy. However, there is a tremendous amount of available worldwide PV manufacturing capacity.

Worldwide PV manufacturing, either thin-film alone or thin-film and conventional polycrystalline silicon, could readily supply a 3,000-megawatts-a-year PV demand in California and a much higher PV demand for the United States as a whole. The *Wall Street Journal* recently reported that conventional solar panel prices have fallen by $2 a watt since 2008, due to too much solar manufacturing capacity chasing too few solar projects.

New Transmission Line Buildout Could be Minimized

Investor-owned utilities make far more profit on transmission lines than any other types of infrastructure they build. This reality is often lost in the debate over whether it is preferable to generate renewable energy remotely and transmit it to demand centers or generate it locally. For example, a 1,000-megawatt transmission line being proposed by a western utility ostensibly to transmit renewable energy, with an estimated cost of $1.9 billion, will generate at least $1.3 billion in profits (in current dollars) for the utility shareholders over the financial life of the project. A total of $700 million of those profits will be credited to the company in the first eight-and-a-half years. Remote renewable energy generation requires transmission. Local renewable energy generation does not.

The nation has over 527,000 miles of existing high-voltage transmission.[6] This transmission infrastructure serves a declining demand for electricity. U.S. electricity demand declined approximately 2 percent in 2008 and is expected to decline another 1 percent in 2009.[7]

Southern California, with an average electrical demand of approximately 14,000 megawatts, has approximately 20,000 megawatts of import capacity on existing transmission lines. Southern California can already import 100 percent of its average electrical load. There may be some need to upgrade older lines so they can continue to provide decades of reliable service. However, neither California nor the United States as a whole is experiencing a shortage of transmission capacity as a general matter.

The policy challenge is the difficult work of ramping down the existing flow of fossil power on existing lines and methodically replacing it with renewable energy generation. A reasonable proposal of this sort was presented to the California Energy Commission in early 2007 by a major solar thermal developer. Called the Mojave Solar Development Zone, it would preferentially locate solar thermal projects along the rights-of-way of major existing highways with existing high-voltage transmission lines in the Mojave Desert. These highway corridors already have a combined 6,000 megawatts of existing transmission capacity.

In reality, the zone identified by the solar thermal developer is far larger than it needs to be to generate 6,000 megawatts, or even 10,000 megawatts of solar power. Solar thermal or PV can produce about 100 megawatts a square mile. One hundred square miles would produce about 10,000 megawatts. One-half mile solar rights-of-way on each side of the highway for only 100 miles would suffice to provide 10,000 megawatts of solar power.

This commonsense proposal predates the RETI process and apparently gained little or no traction within the RETI process itself. One likely reason is that the desert solar land rush had already begun, and restricting solar development to a limited Mojave Solar Development Zone would have inconvenienced developers with more remote and undeveloped properties in some phase of negotiation.

Another likely reason is that it made use of existing transmission and presumed that existing fossil transmission rights would be transferred to the solar projects. This is a reasonable presumption, but it is also a strategy the affected investor-owned utilities have steadfastly opposed. The California Energy Commission and the state of California missed an opportunity in 2007 to gain a measure of control of the desert land rush through some form of the Mojave Solar Development Zone and failed to act.

There is a better, more cost-effective, and less damaging solution that is being ignored or dismissed for reasons of political convenience.

The easiest pathway from a political standpoint—to give investor-owned utilities a mandate to overlay public lands and the United States with new transmission—would result in tremendous controversy and probable gridlock in moving forward on the development of renewable energy generation. The affected citizens and interest groups will oppose many of these projects for the right reasons—that there is a better, more cost-effective, and less damaging solution that is being ignored or dismissed for reasons of political convenience.

It is understandable why an investor-owned utility would see renewable energy solutions through a transmission lens. However, that lens is costly, inefficient, and controversial. The fact that a solar strategy with heavy reliance on remote sites and attendant new transmission would be very costly is positive financial news to an investor-owned utility. Yet it is an unnecessary and largely avoidable financial burden on everyone else.

CONCLUSION

The CEC made the right decision when it identified urban PV as a potentially viable alternative to a conventional peaking gas turbine. The CEC, through the RETI process, had already identified state-of-the-art PV as more cost-effective than utility-scale solar thermal technology. The net effect of these developments is to place more focus on urban PV to carry a much bigger share of the nation's renewable energy load than had been previously contemplated by policymakers.

NOTES

1. RETI Phase 1B draft report. (2008, August). PV cost comparison table, pp. 6–7. Retrieved July 2, 2009, from http://www.energy.ca.gov/reti/documents/2008-08-16_PHASE_1B_DRAFT_RESOURCE_REPORT.PDF.
2. CH2MHill. (2008, February). Response to Environmental Health Coalition Data Requests 1 to 35, p. 11.
3. SDG&E. (2006, August 4). Application A.06-08-010 for 500 kV Sunrise Powerlink transmission line, p. II-32: "This (PV) alternative proposes the installation of rooftop photovoltaic ("PV") technologies on houses, commercial facilities and industrial complexes within the San Diego area. Assuming 10% of the 3000 MW statewide target was achievable in the San Diego area, and—as described below—that 50% of this amount can be reliably assumed to be available during peak load hours, the maximum effective contribution of solar rooftop PV technology in reducing the need for conventional generating sources would be 150 MW."
4. CPUC A.06-08-010 Sunrise Powerlink Phase II proceeding hearing transcript at p. 3943, ln 10–16.
5. Schreiber, D. (2008, December 1–2). PV thin-film markets, manufacturers, margins. presentation at 1st Thin-Film Summit, San Francisco.
6. (2009, February 6). Hurdles (not financial ones) await electric grid update. *New York Times*. Retrieved July 2, 2009, from http://www.nytimes.com/2009/02/07/science/earth/07grid.html.
7. Energy Information Administration. (2009, May). *Short-term energy outlook—U.S. total electricity consumption, 1998–2010* (graph).

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