COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of the Application of The Union Light, Heat and Power Company for a Certificate of Public Convenience and Necessity to Acquire Certain Generation Resources and Related Property; for Approval of Certain Purchase Power Agreements; for Approval of Certain Accounting Treatment; and for Approval of Deviation from Requirements of KRS 278.2207 and 278.2213(6)	)	Case No. 2003-00252

DIRECT TESTIMONY OF

JUDAH L. ROSE

ON BEHALF OF

THE UNION LIGHT, HEAT AND POWER COMPANY

July 21, 2003

DIRECT TESTIMONY OF JUDAH L. ROSE

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Judah L. Rose. My business address is 9300 Lee Highway, Fairfax, Virginia 22031.

Q. WHAT IS YOUR CURRENT POSITION?

A. I am a Managing Director of ICF Consulting ("ICF"). ICF has about 1,000 employees and has been consulting in the power industry for 30 years.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL QUALIFICATIONS.

A. After receiving a degree in economics from the Massachusetts Institute of Technology (MIT) and a Masters Degree in Public Policy from the John F. Kennedy School of Government at Harvard University, I joined ICF in 1982. I have worked at ICF since then and now direct most of ICF's consulting for the electric power industry. For additional details, please see my resume, Attachment JLR-1.

Q. DO YOU HAVE PUBLIC SECTOR CLIENTS?

A. Yes. ICF has been the principal power consultant to the U.S. Environmental Protection Agency (EPA) continuously for 25 years, and I am currently performing work for the EPA. ICF recently conducted the Federal Energy Regulatory Commission's (FERC) study of electric transmission policy. We have worked with the US Department of Energy, and numerous foreign governments. We have also worked with state regulators and state energy agencies, including those in Kentucky, New Jersey, California, Texas, New York, and Michigan.

Q. DO YOU HAVE PRIVATE SECTOR CLIENTS?

A. Yes. ICF provides assistance to electric utilities, financial institutions, power marketers, fuel companies, and independent power producers. A list of private and public references is at Attachment JLR-2.

Q. WHAT TYPE OF WORK DO YOU TYPICALLY PERFORM?

A. I have extensive experience in assessing prices and supply and demand conditions in wholesale power markets, including the Midwest, and valuing power plants. This work often supports strategic decision-making for developers and investment decisions for the financial community. For example, we supported the financing of tens of billions of dollars of new and existing electric generating power plant investment and acquisition via the provision of due diligence independent market assessment services.

Q. DO YOU HAVE OTHER RELEVANT EXPERIENCE?

A. Yes, I have testified in many legal proceedings. For example, I testified in the largest stranded cost case in U.S. history and in the largest U.S. bankruptcy filing in terms of the amount of generation capacity. In addition, I have authored numerous articles in industry journals and spoken at scores of conferences.

Q. HOW SUCCESSFUL HAVE YOU BEEN IN FORECASTING WHOLESALE POWER PRICES?

A. As early as 1995 in a published article, I forecasted that prices would reach thousands of dollars per MWh and made numerous warnings that this was imminent in late 1997 and early 1998. As shown in Attachment JLR-3, Midwest power prices reached these historically unprecedented levels in 1998 and in 1999. I have a similar record in California and the West where I warned on national television in 1999 that the West was the single worst source of concern for power shortages and price spikes (*See* Attachment JLR-3).

Q. HAVE YOU TESTIFIED BEFORE, OR MADE PRESENTATIONS TO, OTHER STATE REGULATORS AND LEGISLATORS?

A. Yes. I have testified before or made presentations to state regulators and legislators in New Jersey, Indiana, Ohio, California, Louisiana, South Carolina, New York, Pennsylvania, Florida and Minnesota.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of The Union Light, Heat and Power Company (ULH&P).

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I have six objectives for my testimony:

- The first objective of my testimony is to present ICF's Base Case forecast of future wholesale power, natural gas, and NO_x allowance prices in the Midwest. This forecast was provided to Ms. Jenner as an input to ULH&P's Integrated Resource Plan (IRP) process. ULH&P's IRP process evaluates in detail the resource alternatives available to ULH&P for meeting its load, including construction of new power plants and purchasing power from the market.
- The second objective is to summarize the key implications of the Base Case price forecast for ratepayers. One implication is that there usually should be rough consistency between the IRP and the price forecast. This is because the IRP and price forecasting processes are similarly searching for the least cost options for meeting electricity demand. The

incremental or marginal cost of supply in the market equals the price under competitive conditions. Another implication is related to the dual use of prices. Not only is price an important benchmark for measuring resources attractiveness in an IRP, but it also determines the potential market value of resources. High market value resources are also likely to provide more benefits. Hence, ICF presents its estimate of potential market value for the portfolio.

- The third objective is to describe the key drivers of ICF's Base Case forecast of wholesale power prices. In addition to future prices for natural gas and coal, power prices are also determined by electricity demand, transmission and projections of the balance between system peak generation supply and demand. It is believed that an explanation of the drivers will help make the testimony and forecast easier to understand.
- The fourth objective is to describe the potential for volatility and uncertainty in future wholesale power prices. This has important implications for relying very heavily on purchase power in that ratepayer rates would be very uncertain. This also has important implications as to which resource mix is best for customers and the extent to which customer savings estimated in the Base Case will actually be realized. Power price uncertainty will be illustrated by the results of sensitivity cases including alternative fuel price and very high power plant overbuild scenarios.
- The fifth objective is to discuss future environmental regulations and their effects on the market prices for power and emission allowances.

Environmental regulations are a sufficiently important uncertainty for coal-fired power plants that separate treatment is warranted.

- The sixth objective is to compare the risks of purchase power with owning "iron in the ground," especially related to credit and transmission risks.

III. <u>SUMMARY</u>

Q. WHAT ARE YOUR PRINCIPAL CONCLUSIONS?

A. My principal conclusions are the following:

- **ICF's Base Case Forecast of Wholesale Power Prices** – ICF's Base Case forecast shows that wholesale prices will rise very significantly over the medium-term. All-hours firm prices (in real 2000$) rise from $[redacted]/MWh in 2003, to $[redacted]/MWh in 2010. The increase in prices in nominal dollars is [redacted] – *i.e.*, after general inflation is added, prices reach $[redacted]/MWh in 2010. [redacted] This [redacted] reflects two factors. First, wholesale power prices will strongly be driven by the natural gas market prices. Wholesale power prices in the Midwest will increasingly reflect the costs of generating with natural gas. This is because practically no new coal plants have been built in the Midwest for approximately 20 years and electricity demand continues to grow. This will constitute a major historical change for a region used to stable coal-based generation costs. This is already apparent during on-peak periods, but will be evident in an increasing percentage of the hours of the year. Second, Midwest wholesale power prices will also rise reflecting the eventual tightening in the supply and demand balance at the peak as electricity demand catches up with power plant supply. This will raise super-peak summer prices in particular.

- **ICF's Base Case Forecast of Natural Gas Prices** – Natural gas prices are an extremely important determinant of future wholesale electricity prices as well as a cost element for Woodsdale and other plants. Natural gas prices have been very high and volatile in the last three years – *i.e.*, since 2000. Natural gas prices year-to-date in 2003 at Henry Hub, Louisiana, the market location for natural gas in the U.S., have averaged nearly \$6/MMBtu through May 2003. As of May 21, 2003, natural gas price futures are \$4.5/MMBtu or higher for all months through early 2005. These are all time record levels even in comparison to the 1970s shortage in real terms. In contrast, the price of the principal competing fossil fuel, coal, has shown much less volatility and the average delivered coal price to the utilities is roughly \$1.25/MMBtu. This period of high natural gas prices is driven in large part by the large amount of new natural gas-fired power plant additions in the U.S. starting in 2000 which has increased U.S. natural gas demand. In ICF's Base Case, future natural gas prices are lower than they are today, but higher than they have been on average between 1989 and 2002. ICF's forecast of Henry Hub natural gas prices 2004 – 2010 in nominal terms is [redacted]. High gas prices increase the extent to which existing coal-fired power plants like East Bend and Miami Fort 6 can decrease ratepayer costs relative to relying on wholesale power market purchases.

- **ICF's Base Case Forecast of Generation Supply and Demand at the Peak** – Supply and demand balance is the second largest driver of power prices. After correcting for currently high natural gas prices, wholesale power market prices are below equilibrium levels due to excess generation capacity. Equilibrium is the level that allows new entrants to earn a reasonable return on their investment. However, this has resulted in a dramatic reduction in new power plant development activity, which is setting the stage for a recovery in the markets in the Midwest in the 2005 to 2008 time period. In ICF's Base Case forecast, "pure" capacity prices, a measure of scarcity related to revenue available to power plants during the summer peak, [redacted] in 2008 in nominal dollars. This forecast of recovery reflects ICF's expectations that electricity demand will grow at rates close to historical levels, and there will be a very significant slowdown in new power plant construction. In the past, many observers have been surprised at the rapidity of market turnarounds, available forecasts notwithstanding. This implies that very heavy reliance on wholesale power markets should only occur after carefully weighing the risk that the recovery in prices might be even stronger than expected.

- **Implications of ICF's Base Case Price Forecast for ULH&P's Power Supply Proposal** – The proposal to transfer to ULH&P a portion of the existing East Bend coal-fired power plant for baseload (414 MW – Net Summer Capacity), the coal-fired Miami Fort 6 for base/mid-merit or intermediate service (163 MW – Net Summer Capacity), and the

Woodsdale natural gas-fired power plant for peaking capacity (500 MW – Net Summer Capacity) is reasonable for a number of reasons. First, the plants could provide significant savings to customers starting in 2007 relative to relying on the wholesale power market. Put another way, the costs of generating power from these plants are less than market prices. This reflects two main considerations. First, the most likely alternative to the two coal-fired coal plants is to rely on other natural gas plants which will set the wholesale power market price for intermediate and even for baseload supply. Second, the Woodsdale gas plant can provide savings relative to market since it economically meets ULH&P's peaking needs, which become significant in 2007. While these savings are likely to be significant, they are not guaranteed. The savings depend on future natural gas prices, electricity demand growth, the extent of any future power plant overbuilding, and other parameters. Third, these plants' potential market value exceeds the book value even after subtracting off-system sales revenues. ICF estimates the combined potential market value of these plants in the Base Case to be $[redacted] in 2007 or $[redacted] versus $358 million or $332/kW in book value as of January 1, 2007. While these savings are large, it is worth emphasizing that in order for a buyer to realize this value, future natural gas prices, industry cycles and other factors need to be consistent with the ICF Base Case wholesale price forecast.

- **ICF Sensitivity Case Forecasts and Power Price Volatility and Uncertainty** – Wholesale prices are uncertain in two respects. First, they will be very volatile year-by-year. Second, the long-term (*e.g.*, 20-year) trend also has significant uncertainty. For example, the ratepayer savings or potential market value in the Base Case may not be realized either in a given year or over the lifetime of the assets if natural gas prices are lower, excess capacity continues longer than expected or other events occur which lower wholesale power prices. For example, in one scenario examined, average 2004 – 2020 wholesale power prices (all-hours firm) were $[redacted]MWh (nominal dollars) versus $[redacted]MWh in the Base Case, and the potential value of the portfolio was [redacted] times the book value or $[redacted]/kW higher instead of [redacted] times book value in the Base Case. This case had low gas prices, low electricity demand growth, very high overbuild, and high supply from existing baseload units (*i.e.*, increases in availability). Conversely, if natural gas prices are higher than expected (*e.g.*, are at current levels again in the future) market prices and ratepayer savings could be higher than the Base Case.

- **Environmental Regulations** – Emission regulations on power plants are another important source of uncertainty when considering relying on coal plants. Emission regulations will most likely tighten over time. This reflects regulations already on the books, such as the federal acid rain program, which effectively become tighter over time, as well as potential new environmental regulations, such as the President's Clear Skies Act (CSA) program. This will primarily affect coal-fired power plants by increasing their costs. There will be some compensating increases in terms of higher wholesale power prices. However, on balance, costs can increase more than prices because natural gas generation will frequently set prices. Nonetheless, coal plants still can provide large savings to ratepayers since fuel savings offset environmental control costs. This is especially true for highly controlled power plants such as the East Bend coal plant, which has always been scrubbed for SO_2, and which has installed SCR (Selective Catalytic Reduction) NO_x emission controls. Indeed, we conclude that gas prices and industry boom-bust cycles are likely to be more important factors affecting the attractiveness to ratepayers of the ULH&P proposal than environmental uncertainties.

- **Volatility of Rates Under Proposal** – This variation and uncertainty in wholesale power prices is in contrast with the rates and costs under the proposed plan which will not vary much. This reflects the relatively low volatility of coal prices and stability of rate base assets compared to heavy reliance on a power market increasingly dominated by volatile natural gas generation. Thus, the ULH&P proposal has the twin virtues of expected ratepayer savings relative to market and lower rate volatility than market based alternatives.

- **Other Attractive Features of the Proposal** – Even if the proposal turns out to be comparable to market rather than providing savings to ratepayers, there are several attractive features to the ULH&P proposal. The principal alternative to using rate base coal and peaking power plants to meet ratepayer demand is to contract for purchase power. Heavy reliance on short-term (less than one year) spot purchases creates significant volatility relative to rate base regulation. Long-term purchases can limit volatility. However, long-term purchase power entails special risks and complexities not present in the current proposal. These special risks must be carefully weighed along with potential benefits. For example, the wholesale power industry has been experiencing a very high degree of turmoil and credit risk. In August 2002, it was reported that five of the top eleven wholesale power marketers were rated as sub-investment grade or having junk bond status and two more had substantially decreased their trading operations. Wholesale power trading volumes were down 70% nationwide and 39% Into Cinergy. Many are familiar with the bankruptcies or severe credit problems of such companies as Enron, NRG, Mirant, and Calpine. A key risk is that a purchase power deal is terminated due to credit problems at the supplier when power prices are high. In this situation, replacement power could be unexpectedly expensive, or in the extreme, not available. The risk of such problems is relatively low under the ULH&P proposal. Another special power purchase risk is transmission problems. Transmission under purchase power alternatives is likely to be a greater risk than under the current proposal. Transmission risk is roughly proportional to the distance between generation and load. The current proposal involves plants directly connected to the Cinergy transmission system. There have been significant transmission problems in the Midwest including actions to cut scheduled power flows and uncertainties associated with regulatory changes and problems.

- **Quantity Proposed** – The ULH&P proposal entails 1,077 MW (net summer rating) and implies a reserve margin of approximately 21% in 2007. The higher reserve is required because ULH&P is a small system and it is important to protect against any outages from one of the gas units. Reserves are required to the extent the costs of reserves are less than the savings they provide. The savings of peaking reserves, like Woodsdale, derive from the potential for price spikes or their equivalent in the market. By 2007, the market has the potential for scarcity at the system peak, and this will remain a long-term feature of the power generation business. Accordingly, the reserve plan appears appropriate.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. The remainder of my testimony is organized into three sections. The first presents ICF's Base Case forecast of future wholesale power prices. This section also discusses the implications of this forecast on the competitiveness of resource alternatives generally and the ULH&P proposal specifically. The second section discusses market uncertainties, which can create wholesale power price volatility. This section also discusses sensitivity cases (*e.g.*, high and low gas price sensitivity cases.) The third section discusses the effects of potential new environmental regulations.

IV. <u>ICF'S BASE CASE FORECAST</u>

Q. WHAT IS ICF'S BASE CASE WHOLESALE POWER PRICE FORECAST?

A. ICF's Base Case reflects ICF's view of what is most likely to happen in the future vis-à-vis key economic drivers (*e.g.*, fuel, electricity demand, power plant entry and exit) and reflects already promulgated air pollution regulations.

Q. WAS THE BASE CASE THE ONLY SCENARIO ANALYZED?

A. No. Since future developments are uncertain, the Base Case is supplemented by five main alternative scenarios. Each of the principal five scenarios is the same as the Base Case except as noted. These alternative cases are: (1) Low Natural Gas prices, (2) High Natural Gas prices, (3) very high supply or large overbuild in the second half of this decade, (4) CSA, and (5) Mercury Maximum Achievable Control Technology (MACT). In addition, in light of the uncertainty regarding future power prices, ICF ran a few other cases to assess the combined effects of downside events, *e.g.,* a case with low gas prices, very high overbuild, low demand growth, and high availability of U.S. coal and nuclear units. Note that these cases are distinguished from the above cases in that they are less likely, since they reflect a combination of non-Base Case events. Lastly, ICF also conducted its analysis entirely in real inflation adjusted dollars, and hence, alternative views of future general inflation can be easily simulated. For example, we report a case with 1.5% rather than 2.5% inflation.

Q. HOW IS ICF'S BASE CASE FORECAST OF WHOLESALE POWER PRICES DEVELOPED?

A. ICF developed this case using its proprietary IPM® model and associated database. This model projects future wholesale electricity prices by simulating future demand and supply conditions. Power prices are forecast simultaneously with power plant dispatch, transmission flows, new power plant construction, mothballing and retirement, and power plant fuel choice (*See* Attachment JLR-4). The model also is used to forecast environmental compliance, the prices of emission allowances, and the price of fuels (*i.e.*, coal and natural gas prices in conjunction with ICF's model of the North American natural gas industry (NANGAS.)

Q. WHAT REGIONS DOES THE MODEL COVER?

A. The model simultaneously forecasts prices in the Midwest marketplace and in most of the Eastern Interconnect (*See* Attachments JLR-5 and JLR-6). The Eastern Interconnect is the largest synchronous power grid in the world and extends from the Canadian Maritimes, to Saskatchewan, from Florida to New Mexico. This simultaneous modeling is performed to capture the interactions between regional marketplaces via transmission imports and exports. The modeling was conducted for the period 2003 to 2032, and uses a dynamic linear programming methodology that allows decisions to be based rationally on future conditions – *e.g.*, investments reflect future conditions.

Q. IS THIS MODEL WIDELY ACCEPTED AND USED?

A. Yes, this model is widely used in both the public and private sectors and both in the U.S. and internationally. This and predecessor ICF proprietary models and data bases have been the only models used by the U.S. EPA for 25 years in its analysis of the impacts of environmental regulations on the power industry. FERC has repeatedly used this model, including for its recent study of the effects of its transmission policy on the power industry. This model has also been used by public service commissions. The model is also used extensively in the private sector and is a major source of information used in due diligence review of financing. This model is used to model the power industries in North America, Europe and much of Asia.

Q. WHY IS IT APPROPRIATE FOR ULH&P TO USE THIS FORECAST IN THE IRP MODELING PROCESS?

A. An important alternative to meeting the power generation needs of ULH&P is buying power from the wholesale power market. Thus, the forecasts of market prices can be input into the IRP modeling process, which involves detailed analysis of the economics of resource alternatives available to ULH&P. These alternatives include new power plants.

Q. WHAT IS THE DIFFERENCE BETWEEN A FORECAST AND A FORWARD PRICE?

A. A forward price is a quote today which a counterparty would use as a basis for a contract. A forecast is not reflective necessarily of what can be transacted for today, but reflects what a going-forward fundamentals-based analysis shows as likely to occur. Often, the forward price reflects forecasts, but not always.

Q. WHY USE FORECASTS AND NOT FORWARD PRICES?

A. Both pieces of information can be helpful. However, the forward market is *especially liquid for short-term transactions* (*e.g.*, less than one-year), but is less liquid over time. This increases the importance of price forecasts as opposed to observable forwards only. Also, while forecasts are not problem-free, forwards have additional issues such as how to factor in credit risk.

Q. WHAT ARE THE MAIN CONCLUSIONS OF ICF'S BASE CASE ANALYSIS OF WHOLESALE MARKET CONDITIONS?

A. ICF's forecast is summarized in Attachment JLR-7. Power prices increase in real inflation-adjusted terms in the forecast period. Between 2003 and 2010, real prices [redacted] per year, though they [redacted] more slowly thereafter.

The rapid near-term increase is due to two factors. First, as electricity demand increases, natural gas plants become the marginal price-setting units more often. This raises prices because the variable costs of gas generation is much higher than for coal generation. It should be noted, long-term average electricity demand growth has been remarkably steady in this area (*See* Attachment JLR-8) in spite of consistently too low forecasts by the utility industry generally (*See* Attachment JLR-8a.) Also, almost no new coal capacity has been built in recent years. This transition to natural gas generation on the margin is facilitated by the de-pancaking of transmission rates associated with Regional Transmission Organization (RTO) implementation. As transmission is facilitated, coal power can be shipped further at lower costs. Second, as electricity demand grows, it catches up with past generation capacity additions and power prices rise to the levels needed to support and permit additional power plant construction. This increase in price largely stops in the mid to late 2000s. However, in nominal terms, prices continue to rise due to the effects of general inflation.

Q. IS THERE A WAY TO EXPRESS YOUR WHOLESALE POWER PRICE FORECAST CORRECTING FOR THE LEVEL OF NATURAL GAS PRICE FORECASTS?

A. Yes. In Attachment JLR-9, the implied system heat rate is shown in Btu/kWh. This parameter is a useful rule-of-thumb and is calculated by dividing the wholesale electricity price by the delivered natural gas price. In 2003, if one assumed that natural gas-fueled plants were always the price-setting unit and had a heat rate (*i.e.*, a thermal efficiency for converting fuel energy to electrical energy) of [redacted] Btu/kWh, then the electricity price would equal $[redacted]/MWh in real 2000 dollars. Of course, the actual IPM® modeling does not assume natural gas is on the margin setting prices all the time. Also, no natural gas power plant has an efficiency as low as [redacted] Btu/kWh. *Even the best units average no* lower than approximately 7,000 Btu/kWh, and most gas units average well above this level. Also, these units have other variable costs beyond fuel, *e.g.*, non-fuel O&M. Rather, coal generation costs are the marginal or incremental source of generation a large part of the time, and this depresses the implied heat rate. However, this index corrects for the effects of natural gas prices which is one of the more uncertain parameters. By 2010, the implied system heat rate rises to [redacted] Btu/kWh. This means that power prices will be higher for the same natural gas price. This increase reflects both increased reliance on natural gas generation instead of coal generation (*i.e.*, gas is on the margin in more hours of the year), but also a firming in the scarcity or reliability component of price.

Q. WHAT IS YOUR BASE CASE FORECAST OF NATURAL GAS PRICES?

A. In Attachment JLR-10, ICF's Base Case forecast of natural gas prices are shown for Henry Hub, Louisiana, the key U.S. market price for commodity and for delivery to the Midwest. They rise in nominal terms, but are relatively flat in real, inflation-adjusted terms. Natural gas prices between 2003 and 2010 are forecast to average $[redacted]/MMBtu (nominal $) for Henry Hub versus $[redacted]/MMBtu (nominal $) for 1989-2002 and versus $[redacted]/MMBtu (nominal $) between 2000 and 2003 YTD (through April).

Q. WHAT IS THE SOURCE OF YOUR NATURAL GAS PRICE FORECAST?

A. The source of ICF's forecast of natural gas prices is ICF's NANGAS Model. This model accounts for supply developments in over 17,000 reservoirs in the U.S.

and Canada, and for natural gas demand throughout North America. Demand for natural gas is forecast to increase substantially reflecting the huge increase in natural gas power plant generation capacity. Natural gas industry supply response lowers prices from current levels, but is not able to balance demand unless prices are above 1989 to 2002 average levels due to the need to attract capital for Liquefied Natural Gas investments, extended pipelines to frontier supplies (*e.g.*, Alaska), deep off-shore investments and higher risk on-shore investments (*e.g.*, less developed geologic plays in non-frontier areas).

Q. WHAT ARE YOU ASSUMING ABOUT COAL PRICES?

A. ICF's Base Case forecast shows declining real and flat nominal coal prices (*See* Attachment JLR-11). Coal prices are not expected to be above historical levels due to only modest coal demand growth, a robust resource base, and competition among multiple sources. This is especially true for plants on the Ohio River like East Bend and Miami Fort 6 with excellent access to multiple coal resources via barge. Unless otherwise noted, ICF used Cinergy estimates of delivered coal costs to East Bend and Miami Fort 6 when valuing these plants.

Q. WHAT ARE THE NEW RESOURCE OPTIONS CONSIDERED IN YOUR MODELING?

A. For each region in the Eastern Interconnect, the model has the option to build natural gas-fired simple cycle combustion turbines, natural gas-fired aero derivative combustion turbines (*i.e.*, LM 6000s), natural gas-fired combined cycles, natural gas-fired cogeneration with the quantity of cogeneration limited based on industrial sector boiler-by-boiler assessments of cogeneration potential, or coal-fired power plants. Over time, most of these options change and improve in terms of having lower real cost and/or higher performance (*See* Attachments JLR-11, JLR-11a, and JLR-12). Other new power plant options that were not explicitly considered in these runs because in previous runs they were found not to be economic to include except when required by law:

- Wind
- Solar
- Nuclear
- Distributed Generation

Q. WHAT TREATMENT HAS BEEN PROVIDED FOR DEMAND SIDE RESOURCES?

A. ICF has implicitly included them in our forecast by lowering future demand growth rates below historical levels (*See* Attachment JLR-12).

Q. WHAT NEW POWER PLANTS ARE BUILT IN THE MIDWEST IN THE BASE CASE FORECAST?

A. In the forecast, new power plants currently under construction are assumed to be complete and come on-line. In other words, no plants already under construction are cancelled in spite of the current excess capacity and depressed power prices for peaking plants. However, this means there will be a sharp-drop off in additions because almost no new plants under construction are scheduled for completion in 2005 or beyond. These plants under construction are referred to as firm additions. The model also builds new plants based on the economics of supply and demand. These new plant builds are referred to as non-firm or model builds. In the near term, the model chooses to primarily (*e.g.*, [redacted]) build new natural gas-fired peaking power plants through 2012 (*See* Attachment JLR-13).

[redacted]. Even though electricity demand is growing, [redacted]. In the 2013 to 2015 period, and especially thereafter, [redacted]

Q. DOES THIS MEAN THAT NEW COAL POWER PLANTS ARE NOT ECONOMIC IN THE BASE CASE?

A. Yes, new coal-fired power plants are not as economic as new natural gas-fired units. This is primarily because their capital investment costs are much higher than for gas-fueled power plants and this added cost is not offset fully by lower fuel costs. However, as natural gas prices have risen, the degree to which new coal plants are close to being economic has grown. In fact, if the capital costs of new coal power plant costs were decreased 13% (*i.e.*, to $[redacted]/kW, from $[redacted]/kW (2000$), they would be economic.

Q. ARE THERE SIGNS THAT THE CURRENT CONSTRUCTION PHASE WILL END SHARPLY IN THE NEAR-TERM?

A. Yes. As shown in Attachment JLR-14, there has been a dramatic increase in the cancellation of proposed new power plant projects. 2002 cancellations were more than twice 2001 levels and 2001 levels were about 3.5 times 2000 levels (*See* Attachment JLR-14). Financing new units has also become more difficult as the credit worthiness of power industry developers, marketers and some utilities have deteriorated (*See* Attachment JLR-15).

Q. WHAT ARE THE WHOLESALE POWER PRICING CONSEQUENCES OF THIS BUILD FORECAST?

A. As mentioned, the scarcity component of pricing is depressed in the near-term relative to equilibrium levels. This scarcity component is also known as the pure capacity price and equals on an annual per kilowatt basis the price spike revenue available to all units. Price spikes are prices above the marginal short run variable costs of plant operation. They are necessary to ensure sufficient capacity (hence the name capacity price) to provide customers reliable supply. In other words, a market without price spikes (or equivalent substitutes) forever will fail to provide reliable supply (*i.e.*, there will be blackouts.) Prices rise strongly over time as demand catches up with supply in the Midwest and elsewhere in the Eastern Interconnect. Attachment JLR-16 shows ICF pure capacity price forecast for the Base Case. Capacity prices are one of two components of firm prices and the smaller of the two. Capacity prices increase by more than a factor of [redacted], *i.e.*, a [redacted]% increase between 2003 and 2006 in real terms and by an additional [redacted]% between 2006 and 2009. This component is not observable in most markets since the transactions are bundled with a single $/MWh price. However, the capacity price is needed since the bundled firm price is analytically estimated as the sum of the capacity price and the electrical energy price or system lambda.

Q. DOES THIS MEAN THAT EXISTING COAL PLANTS ARE NOT ECONOMIC?

A. No. *In fact they can be very economic if they are transferred at levels below the* cost of a new unit (*i.e.*, less than $[redacted]/kW), and especially if they are transferred with a grandfathered allocation of emission allowances. Existing units can be very economic because their fuel costs are much lower than the fuel costs of natural gas-fired units. East Bend also has substantial coal choice flexibility due to its access to barge supply on the Ohio River (as does Miami Fort 6) and its air pollution controls which allow it to use even high sulfur coal.

Q. WHAT ABOUT ENVIRONMENTAL COSTS IN YOUR BASE CASE?

A. In general, coal power plants have higher costs for air emissions and pollution control than natural gas power plants. This reflects federal acid rain and the State Implementation Plan (SIP) Call NO_x cap and trade programs as well as power plant specific emission limits (*See* Attachment JLR-17). However, existing coal plants still have great value to ratepayers since the fuel cost advantage is larger than the disadvantage of greater environmental costs. This is especially so for the East Bend plant, which is highly controlled for air emissions. East Bend has flue gas desulfurization and is already installing SCR NO_x emission controls.

Q. WHAT ARE THE IMPLICATIONS OF YOUR PRICE FORECAST FOR RATEPAYERS?

A. There are two implications. First, the transfer of East Bend, Miami Fort 6 and Woodsdale combined with back-up power contracts will provide ULH&P ratepayers electricity at costs starting in 2007 below the costs of relying on the wholesale power market. The extent to which these savings are realized depends most heavily on future natural gas prices and the pattern of new power plant builds in the second half of this decade. Other uncertainties could also affect the amount of savings including environmental regulations, electricity demand growth, coal prices, and unit availability. Second, rates under the proposal will also be stable especially when compared to heavy reliance on short-term purchases.

Q. WHAT IS THE POTENTIAL MARKET VALUE OF THE PROPOSED PLANTS RELATIVE TO THEIR BOOK VALUE UNDER YOUR BASE CASE?

A. The potential market value of the three plants (*i.e.*, East Bend, Woodsdale, and Miami Fort 6) in 2007 is higher based on the results of ICF's Base Case forecast. In ICF's Base Case, the potential value of the portfolio of three plants is $[redacted] billion or $[redacted]/kW versus $358 million and $332/kW of book value.

Q. IS YOUR FORECAST SENSITIVE TO POWER PRICE FORECASTS?

A. Yes, very much so. As is discussed in the next section, lower potential values closer to book values are possible.

Q. HAVE YOU CONSIDERED THE EMISSIONS ALLOWANCES IN THE VALUATION OF THE PLANTS?

A. Yes, I have. The future value of the SO_2 and NO_x emission allowance allocation between 2007 and 2031 has been added to the value of the portfolio.

Q. DO YOUR CONCLUSIONS CHANGE SIGNIFICANTLY IF OFF-SYSTEM SALES ARE NOT CREDITED TO CUSTOMERS?

A. No. The savings relative to market are still likely to be significant. This makes the ULH&P proposal not to credit off-system sales revenues to customers reasonable. Indeed, the above assessment of potential market value does not include a credit of off-system sales to customers. Put another way, on system *sales are valued at the market price and they are the only sources of value in the* valuation.

Q. EVEN IF ULH&P COULD GET A SIMILAR OFFER, ARE THERE OTHER FEATURES THAT MAKE THIS OFFER ATTRACTIVE?

A. Yes. There are:

- **Credit Risk** – A power purchase agreement would increase credit risk that the counter party would not fulfill its conditions. As mentioned, credit concerns are very salient given the large problems facing the industry, including bankruptcies.
- **Transmission Risk** – These plants are directly interconnected into the Cinergy control area. If power is sourced further away, there are greater risks of transmission difficulties. These include Transmission Loading Relief procedures (TLRs) and/or higher costs.
- **Operations Costs and Risks** – The operations of the plants and market purchases and sales will benefit from the economies of scale of Cinergy operations under the Purchase, Sale, and Operation Agreement (PSOA).
- **Construction Siting and Permitting Risk** – Since the plants are operating, there is no construction or permitting risk.

Q. IS THE TOTAL AMOUNT OF CAPACITY BEING PROPOSED FOR ULH&P APPROPRIATE?

A. ULH&P's projected peak demand for 2003 is 848 MW. By 2007, its net load is forecast to be 889 MW. The total amount of capacity being transferred is 1,077 MW (net summer rating). Hence, the ratio of capacity to peak is 21%. Some of it is backed up by a supply contract with CG&E, but the rest is not (*i.e.*, the Woodsdale portion). In the event of outages at Woodsdale or higher than expected demand, ULH&P would have to go to market. The reserve level is consistent with the levels typical in the industry factoring in the size of ULH&P's system, the back-up contracts and transmission access. Reserves are appropriate to the point that the costs of the reserves are greater than the expected costs of relying on the market.

Q. ARE THERE ADDITIONAL UNDERLYING ASSUMPTIONS GUIDING YOUR APPROACH TO FORECASTING DEREGULATED WHOLESALE POWER PRICES?

A. Yes, as follows:

- First, the markets will be perfectly competitive and efficient (*See* Attachment JLR-18). Accordingly, prices will reflect the marginal costs of producing electricity including the costs of providing customers reliable supply. To the extent that the wholesale power market is not fully competitive, prices will be higher than shown. If the market is not fully competitive, large producers could withhold capacity (*e.g.*, drag out maintenance) or raise bid prices above short run marginal costs. This could have a large effect at system peak, exacerbating shortages and price spikes. This is assumed not to happen at all in our study.
- Second, the industry will tend to equilibrium, *i.e.*, when there are shortages, developers will build needed plants. Similarly, when there is too much plant capacity, plant owners will mothball or retire existing units. If the market tends to equilibrium less than assumed, prices can be more volatile as the market swings between extremes.

Q. WHAT ARE PRICE SPIKES?

A. Price spikes are defined as periods in which hourly prices are above the short run variable costs of the grid's most expensive unit. For example, if the most expensive unit's short-run variable costs (*i.e.*, mostly fuel) are $75/MWh, and the price is $1,075/MWh, the spike is $1,000/MWh. If this happens 100 hours per year, each kilowatt receives revenue of $100 (*i.e.*, $100/kW-yr).

Q. HOW DOES YOUR METHODOLOGY ADDRESS THE ISSUE OF PRICE SPIKES?

A. In a competitive market, the price spikes reflect the fact that in a given hour, there are not enough power plants available at a given location to meet demand without likely interruption of load. This usually occurs only at the summer peak. In such a situation, the price is set by an end user or its agent, (*e.g.*, integrated utility), retail marketer, agreeing for a price not to buy power, (*i.e.*, enough customers have to agree that at a high enough price,) buying electricity exceeds their costs of interruption. As mentioned, in the Midwest, these price spikes have been several hundred times average price levels.

These spikes create value for all plants competing in the market. Thus, the spikes are subject to the forces of supply and demand. If the money available from the spikes is too high, (*e.g.*, they occur too often or the price is too high,) then developers build more plants and decrease the spike frequency and/or the level of the price at the spike. If the revenues from the spikes are too low, plants will retire and new builds will be delayed even as demand grows. The equilibrium spike level (the sum of the spikes weighted by the costs of interruption) is equal to the pure capacity price calculated by the model.

Q. IS THERE A SEPARATE CAPACITY MARKET IN THE MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC. (MISO)?

A. No. Some other wholesale power markets have a separate market for capacity (*e.g.*, PJM (Pennsylvania, New Jersey, Maryland), NEPOOL (New England Power Pool), and NYPP (New York Power Pool)). This is because they automatically enforce a high reserve margin, which suppresses the peak prices and, as it turns out, eliminate the revenues needed to ensure construction of new plants needed to ensure reliability. Thus, a separate market has been set up to provide sufficient income to market participants as compensation for suppressing the spikes.

Q. DOES YOUR METHODOLOGY DEPEND ON HAVING SEPARATE ENERGY AND CAPACITY MARKETS?

A. No, we are not assuming there is or will need to be a separate capacity market. Our methodology calculates separate annual prices and fortunately, an annual sum of spikes is sufficient for valuation purposes.

Q. CAN YOU ENVISION A DEREGULATED MIDWEST WHOLESALE POWER MARKET THAT, FOR A FEW YEARS, DOES NOT HAVE SOME PRICE SPIKES OR THEIR EQUIVALENT?

A. No. Wholesale power price spikes might be suppressed by lower than average weather or outages temporarily or some slowness in power plant owners adjusting their mothballing/retirement programs. Rather, the question is not whether there will be price spikes, but how frequently they will occur and how high they will be.

Q. WHAT ASSUMPTIONS DO YOU MAKE REGARDING THE RETIREMENT OF EXISTING CAPACITY?

A. The model determines whether units should be retired economically. Units can also be mothballed by the model (*i.e.*, taken out of service temporarily.) Few units are mothballed and fewer are permanently retired in this analysis. If any major retirements occur, we would show even greater need for capacity.

V. WHOLESALE POWER PRICE VOLATILITY AND LONG-RUN UNCERTAINTY

Q. DO YOU BELIEVE THERE IS SIGNIFICANT POTENTIAL FOR WHOLESALE POWER PRICE VOLATILITY AND UNCERTAINTY?

A. Yes. I believe significant potential exists based on model results, theoretical considerations and historical data. Further, regulators should be aware that heavy reliance on the market can pose risks.

Q. WHAT IS THE LARGEST SOURCE OF NEAR-TERM VOLATILITY IN THE MARKET?

A. The largest source of power market volatility is volatility in natural gas markets. This volatility reflects weather conditions, but also oil price volatility, business cycles, and uncertainty over the gas industry supply response to growing natural gas demand. This volatility is likely to increase as the Midwest wholesale power markets increasingly rely on natural gas power plants. For example, 2003 year-to-date (through May) Henry Hub natural gas prices have been \$5.92/MMBtu versus \$2.87/MMBtu for the same period in 2002. On-peak Into Cinergy wholesale power prices were \$48/MWh 2003 year-to-date (through April 21) versus \$23/MWh in year-to-date 2002 (through April 22). This power price increase reflects in large part higher natural gas prices.

Q. HOW CAN THIS HIGH NATURAL GAS PRICE VOLATILITY BE BEST UNDERSTOOD?

A. This volatility can be best understood by comparing coal and gas price volatility. As shown in Attachments JLR-18a, Attachment JLR-18b, and Attachment JLR-18c, coal price volatility has been low compared to gas price volatility. Thus, reliance on gas generation will involve substantial potential volatility.

Q. WHAT IS THE NEXT MOST IMPORTANT SOURCE OF POWER PRICE VOLATILITY?

A. Over time, shortages of generation capacity will re-emerge in the market. This will drive up wholesale power prices at least to the level needed to support new entry. The exact timing of this will be heavily influenced by future new build patterns. At this time, the pipeline of new firm plant additions is about to empty and construction of new plants is unlikely to resume until fuel-adjusted power prices start recovering. Indeed, there is potential that power prices could rise above equilibrium price levels before power plant supply responds. This reflects the financial difficulties facing developers which create investment lags. As a consequence, prices could skyrocket up to levels higher than forecast here.

Q. DID ICF CONDUCT NATURAL GAS PRICE SENSITIVITY CASE ANALYSIS?

A. Yes. ICF analyzed a high and low natural gas price forecast case (*See* Attachment JLR-19). In the low case, future gas prices were approximately equal to historical 1989 to 2002 natural gas prices in real inflation adjusted terms (*i.e.*, $[redacted]/MMBtu **at** Henry Hub in real 2000 dollars for 2003 – 2025). This is unlikely to occur in light of the large increases in natural gas demand forecast for the future. However, some individual years could reach this level. In the high case, [redacted] This represents a more pessimistic view of gas industry supply response from the perspective of buyers.

Q. WHAT WERE THE RESULTS?

A. Midwest (*i.e.*, Southern ECAR) wholesale all-hours firm (unit contingent firm) prices are shown in Attachments JLR-20 to JLR-24. Midwest power prices were $[redacted]/MWh (2000$) on average between 2003 and 2025 in the High Gas Price Case (plus [redacted]% versus the Base Case), and $[redacted]/MWh (2000$) in the Low Gas Price Case ([redacted] [redacted]%.) The average Midwest power price between 2003 and 2025 in the Base Case is $[redacted]/MWh (2000$.) The decrease is larger in the low gas price case for two reasons. First, the difference between the Base Case and Low Gas Price Case is modestly more than the difference between the Base and High Case. This reflects the lower likelihood of sustained very high gas prices. Second, the power industry responds by building many more new coal power plants to lower costs and prices and hence, the elasticity of power to gas prices is lower when gas prices go up than down.

Q. WHAT OTHER SENSITIVITY CASES DID YOU EXAMINE?

A. I also examined a scenario in which there were very large amounts of additional power plant construction in the Eastern Interconnect in 2006 and 2007 relative to the Base Case.

Q. WHY DID YOU DO THAT?

A. In the Base Case, power plant construction does not resume until market conditions warrant. In fact, the supply response might either be too fast or too slow. If it is too slow, prices could shoot up to even higher levels than shown in the Base Case. This is what happened in 1998 and 1999. Conversely, if the supply response is too fast, prices will be depressed relative to Base Case levels. Current low, fuel-adjusted prices reflect excess capacity which is a result of too fast a supply response.

Q. HOW WAS THIS CASE DEVELOPED?

A. I assumed that the amount of overbuilding would be roughly equal to the levels experienced in 2001 and 2002. The extent of the overbuild was distributed evenly among sub-regions.

Q. WHAT WAS THE RESULT OF THIS CASE?

A. Under the overbuild case or the high power supply case, firm 2003 to 2025 power prices were $[redacted]/MWh (2000$) versus $[redacted]/MWh in the Base Case. The effects are more pronounced in the 2006 to 2010 period where the implied system heat rate falls from [redacted] Btu/kWh in the Base Case to [redacted] Btu/kWh. Also, 2006 to 2010 power prices fall from $[redacted]MWh in the Base Case (2000$) to $[redacted]/MWh in this high overbuild case (2000$).

Q. IS THIS A LIKELY CASE?

A. No. This case is highly unlikely. In order for this case to occur, developers would have to seek financing for their new power plants almost immediately. This would be very difficult in today's environment.

Q. WHY DID YOU NOT ALSO RUN A SHORTAGE CASE?

A. A shortage case was not run for several reasons. First, it is difficult to estimate the consequences of a shortage since wholesale prices rise to what customers would be willing to pay to avoid being blacked-out. We know that the willingness is very high, but we are not sure about the exact level. Second, we do have the experience from 1998 and 1999, and hence a historical review can be a rough guide to how the proposed portfolio would perform in the event of a shortage.

Q. IS THERE A WAY TO SUMMARIZE THE SENSITIVITY OF YOUR POWER PRICE AND PORTFOLIO VALUATIONS TO GAS, ENTRY-EXIT AND OTHER UNCERTAINTIES?

A. Yes. Attachments JLR-25, 25a, 26, and 26a show the sensitivity of power prices and the value of the portfolio (*i.e.*, East Bend, Miami Fort 6 and Woodsdale) to alternative power price scenarios. These results include some combination cases, *e.g.*, low gas price, very high overbuild, low demand growth, and high U.S. availability for existing coal and nuclear units. These combination cases are relatively unlikely because so many items have to occur, but are shown to illustrate potential downside events. We are emphasizing the downside because it is important to realize that the value of the portfolio and ratepayer savings are not guaranteed.

Q. DOES A REVIEW OF THE RECENT HISTORY OF THE WHOLESALE POWER MARKET ALSO PROVIDE INFORMATION ABOUT THE RISKS OF RELIANCE ON THE WHOLESALE POWER MARKET?

A. Yes, the history of the wholesale power market emphasizes the need for the regulators to make decisions about the risks they are willing to accept via reliance on short-term purchase power. The 1998 to 2001 period repeatedly saw across the U.S. unexpectedly high prices and shortages and this issue has engaged regulators more than any issue. Also, history is important because episodes of shortages and high prices can unexpectedly recur.

Q. PLEASE DESCRIBE RECENT WHOLESALE MARKET PRICES FOR ELECTRICITY IN SOUTHERN ECAR (EAST CENTRAL AREA RELIABILITY COORDINATION AGREEMENT) WHERE THE PLANTS ARE LOCATED.

A. In 1998 and again in 1999, the Midwest had the highest wholesale spot prices in the U.S. Prices were particularly high as the result of extremely high price spikes during the summer when demand is the greatest. This was a huge reversal of historic conditions where the Midwest was known for reliable, low cost supply.

Q. WHY WERE WHOLESALE POWER PRICES SO HIGH IN THE 1998 AND 1999 PERIOD?

A. In the 1998-1999 period, wholesale power prices were high because the demand for electricity caught up and overtook supply (*See* Attachment JLR-27). As a result, there were shortages and/or the likelihood of imminent shortages during the super peak demand periods, a period of time when power is highly valued as communities struggle with extreme heat. The 1998-1999 shortages reflected the following:

- **Strong Electricity Demand Growth** – Electricity demand, adjusted to remove the effects of weather, was strong in the Midwest for many years. Electricity demand, especially peak demand can be resilient even during economic slowdowns as weather can overwhelm economic activity and because so much of demand is largely independent of economic activity (*e.g.*, residential use). In the U.S., electricity demand continues to grow on average even during recession as population growth, and the development of new uses for electricity continue.

- **Inadequate Construction of New Capacity** – Reserve levels declined greatly in the 1990's and new power plants were not added. In this environment, companies increasingly relied on purchasing power from others in the market. Ultimately, more and more buyers were chasing fewer and fewer sellers.

Q. WHAT HAPPENS TO WHOLESALE SPOT PRICES WHEN THERE ARE GENERATION CAPACITY SHORTAGES?

A. Prices reach extremely high levels as buyers (actual end users or their agents such as integrated utilities) pay to avoid having to do without electricity. The consequences of loss of supply create so much difficulty for end users they are willing to pay their suppliers a lot to ensure high levels of reliability. The high prices eventually cause some users to cut their demand and encourage additional supply, and frequently (but not always) this helps balance supply and demand. However, until this occurs, these high prices can have a huge effect on annual average prices even if their frequency is low. 100 hours per year (*i.e.*, about 4 days) of $1,000/MWh price spikes raises annual average prices by nearly $10/MWh, or about 33% of typical average wholesale power prices. As the supply and demand balance deteriorates the frequency and extent of the shortages increase on average. Ultimately, the price spikes combine with blackouts, as demand frequently does not adjust since most consumers are not exposed to market pricing. Lastly, suppliers can begin to go bankrupt as prices rise and they do not have adequate hedges.

Q. **WHAT ELSE HAPPENS OVER TIME AS A RESULT OF THE SHORTAGES?**

A. Ultimately, sellers will respond by building more capacity moving toward an equilibrium level of price spikes. Note, on average the deregulated wholesale power industry has some price spikes which are necessary to provide compensation to new entrants. Further, as mentioned, these spike levels in a given year are not entirely predictable since they depend on weather and system outages, which cannot be predicted fully. Lastly, the situation can change fairly quickly, potentially more quickly than new plants can be added. As an example and to follow up on the description of causes of unexpected spikes, two years of unexpected demand growth or the retirement of one large nuclear unit or unexpected slowness in planning for retrofit of new pollution control equipment somewhere on the grid (*e.g.*, outside of Kentucky) can combine with hot weather and outages to cause above equilibrium spike levels.

Q. **HAS THIS PATTERN OF EXTREMELY HIGH PRICES OCCURRED ELSEWHERE?**

A. Yes. The same phenomenon occurred in California and throughout western North America in 2000 and 2001. This was in spite of the experience of the Midwest only months earlier. Price spikes have also occurred in the Northeast and elsewhere (*e.g.*, New York, New England, Mid Atlantic, Gulf Coast, Southeast).

Q. **WERE THE EFFECTS IN CALIFORNIA EVEN MORE SEVERE?**

A. Yes. Since the utilities in California relied even more on purchased power, the costs of supply to customers rose, the largest utility in the state went bankrupt, the state stepped in to buy power and state finances were adversely affected, and the bankrupt utility is now attempting to be permanently regulated by the federal government.

Q. PLEASE DESCRIBE POST-1998/1999 DEVELOPMENTS IN THE MIDWEST.

A. In response to higher prices, suppliers have added additional generation capacity in the Midwest. This has helped alleviate some of the extreme shortages of generation capacity, but prices for around-the-clock supply have never returned to the pre-1998 levels (*See* Attachment JLR-27). Indeed, 2001 average prices equaled 1999 levels. Even though 2001 prices on average were high, after September 11, 2001, prices were lower than the average, and as of this moment, they are still lower.

Even though prices have fallen on a fuel price adjusted basis, there have been some additional recent developments which highlight the need for additional capacity:

- **Electricity Demand Growth is Continuing** – In the light of the large size of the Midwest market, peak requirements are growing (in ECAR) close to 3,000 MW per year. If there are any plant retirements, these needs will be even larger. Thus, a hiatus in construction could quickly return the grid back to greater price spikes.
- **Retrenchment** - Credit concerns arising in the aftermath of the Enron bankruptcy have contributed to a significant cancellation of proposed power plant projects. The amount of power plant cancellations over the past year is greater by far then in any period since deregulation started. Also, companies like Enron, Power Corporation of America, and others are not honoring long-term commitments due to bankruptcy. The concern

is that these developments will contribute to an even more extreme industry cycle than would otherwise occur.

- **Transmission Concerns** - For the first time in the industry's history, significant amounts of new power plants are being added without the simultaneous addition of major new *transmission lines. Indeed,* transmission investment in the U.S. is falling precipitously (*See* Attachment JLR-28). This raises questions about the ability of the transmission grid to function, especially to deliver power over long distance. This also can increase the costs of obtaining firm transmission rights. *This concern relates in part to the significant* bottlenecks *in recent* years in the Midwest. As shown, the number of bottlenecks has greatly increased in the Midwest (*See* Attachments JLR-29 and JLR-29a). This also relates to the fact that power flows cannot be controlled as in most networks and flows are limited by the system's weakest link even if that *means turning off some plants.* Further, there is an inherent "catch-up" process at play in the transmission sector. Until very recently, after the new plants were actually brought on-line, the specific location and the exact size of the new units could not be determined. Since the transmission flows can only be assessed knowing specific locations, only now can the effects of these generation additions on power flow pattern be modeled. Also, this modeling is inherently complex due to the multi-state and international nature of the grid. This first time modeling is now revealing substantial bottlenecks which could limit the ability of companies

- to rely on long distance power purchases and additional problems may be uncovered in the near future.

- **Transmission Regulation** - Further, the reorganization of the transmission grid under deregulation has proceeded slowly compared to the generation sector. It could be several years before new regional transmission organizations are fully functional in terms of congestion management, transmission investment, and planning. This is in spite of efforts of Cinergy, one of the leaders in the Midwest Independent System Operator, Inc. regional transmission organization. Thus, there is the possibility of a difficult shake down period, which adds to volatility.

VI. ENVIRONMENTAL REGULATORY UNCERTAINTIES

Q. WHY ARE ENVIRONMENTAL REGULATORY UNCERTAINTIES IMPORTANT?

A. There are two reasons. First, there is a significant chance that environmental regulations will tighten over time. This reflects proposed new legislation by the President and others. This also reflects existing regulations which call for further tightening. Second, the effects of these regulations are concentrated on coal plants in general and the ULH&P proposal involves 54% coal capacity.

Q. WHAT ALTERNATIVE ENVIRONMENTAL REGULATIONS DID YOU ANALYZE?

A. ICF analyzed the President's proposed CSA (*See* Attachment JLR-30). This proposal would tighten the caps on SO_2 and NO_x emissions already in place and impose controls for the first time on mercury emissions. At the same time, the CSA eliminates the need for the imposition of mercury MACT. ICF also modeled a case which is the same as the Base Case except for mercury MACT to illustrate the effect of not enacting CSA. MACT is not a cap and trade system, but is implemented as a station specific limit. There is uncertainty regarding how MACT might be implemented beyond whether it will be implemented.

Q. HOW DOES ICF ANALYZE ENVIRONMENTAL REGULATIONS?

A. ICF uses its proprietary IPM® model to analyze the impacts of the program on every power plant in the U.S. The model forecasts environmental compliance (*e.g.*, retrofit installations fuel switching, changed dispatch) with the cap and trade plan for each unit and forecasts environmental allowance prices. The analysis also factors in effects on wholesale power prices and fuels markets. This and predecessor proprietary ICF models have been used by EPA for similar analysis for 25 years.

Q. WHAT HAPPENED IN THE CASE OF MERCURY MACT CONTROLS?

A. ICF analyzed the imposition of mercury MACT controls (*See* Attachment JLR-31). These controls were assumed to require [redacted]% reduction by station that burn bituminous coal, [redacted]% reduction for sub-bituminous coal, and [redacted]% reduction for lignite.

Q. DO THESE CASES REPRESENT A REASONABLE RANGE OF ENVIRONMENTAL REUGLATORY UNCERTAINTIES?

A. Yes. Other regulations (*e.g.,* CO_2 control) are possible, but the range is reasonable.

Q. WHAT ARE THE EFFECTS OF CSA AND MERCURY MACT ON THE VALUE OF THE PORTFOLIO?

A. In the CSA case, the potential portfolio value will be lowered by $[redacted]/kW relative to the Base Case and the value increases slightly under the mercury MACT case. The changes in potential portfolio value reflect the net effect of higher pollution control costs including higher prices for emission allowances, and higher power prices.

Q. WERE ATTACHMENTS JLR-1 THROUGH JLR-31 PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

ATTACHMENT JLR-1
JUDAH L. ROSE

EDUCATION

1982 M.P.P., John F. Kennedy School of Government, **Harvard University**

1979 S.B., Economics, **Massachusetts Institute of Technology**

EXPERIENCE

Mr. Rose has over 20 years of continuous experience at ICF Consulting and currently serves as *Senior Vice President of ICF Consulting Group and Managing Director* of ICF Resources Incorporated, the energy consulting practice. Mr. Rose's practice covers Wholesale Power, Litigation Support, Transmission, Environmental, Power Marketing, Power Sector Modeling, Risk Management and Natural Gas work in North America, Europe and Asia. Mr. Rose's clients include financial institutions, utilities, law firms, industrial power users, government agencies, public service commissions, GenCos and IPPs. Also, Mr. Rose is the Product Director for ICF's IPM© (Integrated Power Model).

Mr. Rose has publicly testified in state and other legal proceedings, addressed numerous major energy conferences, served as lead negotiator for the Hopi Tribe, authored numerous articles published in Public Utilities Fortnightly, the Electricity Journal, Project Finance International, Enron, and written numerous company studies on power, coal, and gas related issues, and managed large consulting projects. Mr. Rose holds a Masters Degree in Public Policy from the John F. Kennedy School of Government at Harvard University and a Bachelor of Science Degree in Economics from the Massachusetts Institute of Technology.

PRESS INTERVIEWS

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Newspapers: Denver Post

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"Cause No. 42196 - in support of PSI's petition for interim purchased power contract. Filed on 4/26/02."

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Rose, J.L., PSEG Off-Site Meeting Panel Discussion, February 6, 2003.

Rose, J.L., "The Merchant Power Market—Where Do We Go From Here?" Center for Business Intelligence's Financing U.S. Power Projects, November 18-19, 2002.

Rose, J.L., "Assessing U.S. Regional And The Potential for Additional Coal-Fired Generation in Each Region," Infocast's Building New Coal-Fired Generation Conference, October 8, 2002.

Rose, J.L., "Predicting the Price of Power for Asset Valuation in the Merchant Power Financings, "Infocast's Product Structuring in the Real World Conference, September 25, 2002.

Rose, J.L., "PJM Price Outlook," Platt's Annual PJM Regional Conference, September 24, 2002.

Rose, J.L., "Why Investors Are Zeroing in on Upgrading Our Antiquated Power Grid Rather Than Exotic & Complicated Technologies," New York Venture Group's *Investing in the Power Industry—Targeting The Newest Trends Conference*, July 31, 2002.

Rose, J.L., Panel Participant in the Salomon Smith Barney Power and Energy Merchant Conference 2002, May 15, 2002.

Rose, J.L., "Locational Market Price (LMP) Forecasting in Plant Financing Decisions," Structured Finance Institute, April 8-9, 2002.

Rose, J.L., "PJM Transmission and Generation Forecast", Financial Times Energy Conference, November 6, 2001.

Rose, J.L., "U.S. Power Sector Trends", Credit Suisse First Boston's Power Generation Supply Chain Conference, Web Presented Conference, September 12, 2002.

Rose, J.L., "Dealing with Inter-Regional Power Transmission Issues", Infocast's Ohio Power Game Conference, September 6, 2001

Rose, J.L., "Where's the Next California", Credit Suisse First Boston's Global Project Finance Capital Markets Conference, New York NY, June 27 2001

Rose, J.L, "U.S. Energy Issues: What MLA Members Need to Know," Multi-housing Laundry Association, Boca Raton Florida, June 25, 2001

Rose, J.L., "How the California Meltdown Affects Power Development", Infocast's Power Development and Finance Conference 2001, Washington D.C., June 12, 2001

Rose, J.L., "Forecasting 2001 Electricity Prices" presentation and workshop, What to Expect in western Power Markets this Summer 2001 Conference, Denver, Colorado, May 2, 2001

Rose, J.L., "Power Crisis in the West" Generation Panel Presentation, San Diego, California, February 12, 2001

Rose, J.L., " An Analysis of the Causes leading to the Summer Price Spikes of 1999 & 2000" Conference Chair, Infocast Managing Summer Price Volatility, Houston, Texas, January 30, 2001.

Rose, J. L., " An Analysis of the Power Markets, summer 2000" Generation Panel Presentation, Financial Times Power Mart 2000 conference, Houston, Texas, October 18, 2000

Rose, J.L., "An Analysis of the Merchant Power Market, Summer 2000" presentation, Conference Chair, Merchant Power Finance Conference, Atlanta, Georgia, September 11 to 15, 2000

Rose, J.L., "Understanding Capacity Value and Pricing Firmness" presentation, Conference Chair, Merchant Plant Development and Finance Conference, Houston, Texas, March 30, 2000.

Rose, J.L., "Implementing NYPP's Congestion Pricing and Transmission Congestion Contract (TCC)", Infocast Congestion Pricing and Forecasting Conference, Washington D.C., November 19, 1999.

Rose, J.L., "Understanding Generation" Pre-Conference Workshop, PowerMart, Houston, Texas, October 26-28, 1999.

Rose, J.L., "Understanding Capacity Value and Pricing Firmness" presentation, Conference Chair Merchant Plant Development and Finance Conference, Houston, Texas, September 29, 1999.

Rose, J.L., "Comparative Market Outlook for Merchant Assets" presentation, Merchant Power Conference, New York, New York, September 24, 1999.

Rose, J.L., "Transmission, Congestion, and Capacity Pricing" presentation, *Transmission The Future of Electric Transmission Conference*, Washington, DC, September 13, 1999.

Rose, J.L., "Effects of Market Power on Power Prices in Competitive Energy Markets" Keynote Address, The Impact of Market Power in Competitive Energy Markets Conference, Washington, DC, July 14, 1999.

Rose, J.L., "Peak Price Volatility in ECAR and the Midwest, Futures Contracts: Liquidity, Arbitrage Opportunity" presentation at ECAR Power Markets Conference, Columbus, Ohio, June 9, 1999.

Rose, J.L., "Transmission Solutions to Market Power" presentation, Do Companies in the Energy Industry Have Too Much Market Power? Conference, Washington, DC, May 24, 1999.

Rose, J.L., "Repowering Existing Power Plants and Its Impact on Market Prices" presentation, Exploiting the Full Energy Value-Chain Conference, Chicago, Illinois, May 17, 1999.

Rose, J.L., "Transmission and Retail Issues in the Electric Industry" Session Speaker, Gas Mart/Power 99 Conference, Dallas, Texas, May 10, 1999.

Rose, J.L., "Peak Price Volatility in the Rockies and Southwest" presentation at Repowering the Rockies and the Southwest Conference, Denver, Colorado, May 5, 1999.

Rose, J.L., "Understanding Generation" presentation and Program Chairman at Buying & Selling Power Assets: The Great Generation Sell-Off Conference, Houston, Texas, April 20, 1999.

Rose, J.L., "Buying Generation Assets in PJM" presentation at Mid-Atlantic Power Summit, Philadelphia, Pennsylvania, April 12, 1999.

Rose, J.L., "Evaluating Your Generation Options in Situations With Insufficient Transmission," presentation at Congestion Management conference, Washington, D.C., March 25, 1999.

Rose, J.L., "Will Capacity Prices Drive Future Power Prices?" presentation at Merchant Plant Development conference, Chicago, Illinois, March 23, 1999.

Rose, J.L., "Capacity Value – Pricing Firmness," presentation at Market Price Forecasting conference, Atlanta, Georgia, February 25, 1999

Rose, J.L., "Developing Reasonable Expectations About Financing New Merchant Plants That Have Less Competitive Advantage Than Current Projects," presentation at Project Finance International's Financing Power Projects in the USA conference, New York, New York, February 11, 1999.

Rose, J.L., "Transmission and Capacity Pricing and Constraints," presentation at Power Fair 99, Houston, Texas, February 4, 1999.

Rose, J.L., "Peak Price Volatility: Comparing ERCOT With Other Regions," presentation at Megawatt Daily's Trading Power in ERCOT conference, Houston, Texas, January 13, 1999.

Rose, J.L., "The Outlook for Midwest Power Markets," presentation to The Institute for Regulatory Policy Studies at Illinois State University, Springfield, Illinois, November 19, 1998.

Rose, J.L., "Developing Pricing Strategies for Generation Assets," presentation at Wholesale Power in the West conference, Las Vegas, Nevada, November 12, 1998.

Rose, J.L., "Understanding Electricity Generation and Deregulated Wholesale Power Prices," a full-day pre-conference workshop at Power Mart 98, Houston, Texas, October 26, 1998.

Rose, J.L., "The Impact of Power Generation Upgrades, Merchant Plant Developments, New Transmission Projects and Upgrades on Power Prices," presentation at Profiting in the New York Power Market conference, New York, NY, October 22, 1998.

Rose, J.L., "Capacity Value – Pricing Firmness," presentation to Edison Electric Institute Economics Committee, Charlotte, NC, October 8, 1998.

Rose, J.L., "Locational Marginal Pricing and Futures Trading," presentation at Megawatt Daily's Electricity Regulation conference, Washington, D.C., October 7, 1998.

Rose, J.L., Chairman's opening speech and "The Move Toward a Decentralized Approach: How Will Nodal Pricing Impact Power Markets?" at Congestion Pricing and Tariffs conference, Washington, D.C., September 25, 1998.

Rose, J.L., "The Generation Market in MAPP/MAIN: An Overview," presentation at Megawatt Daily's MAIN/MAPP – The New Dynamics conference, Minneapolis, Minnesota, September 16, 1998.

Rose, J.L., "Capacity Value – Pricing Firmness," presentation at Market Price Forecasting conference, Baltimore, Maryland, August 24, 1998.

Rose, J.L., "ICF Kaiser's Wholesale Power Market Model," presentation at Market Price Forecasting conference, New York, New York, August 6, 1998.

Rose, J.L., Campbell, R., Kathan, David, "Valuing Assets and Companies in M&A Transactions," full-day workshop at Utility Mergers & Acquisitions conference, Washington, D.C., July 15, 1998.

Rose, J.L., "Must-Run Nuclear Generation's Impact on Price Forecasting and Operations," presentation at The Energy Institute's conference entitled "Buying and Selling Electricity in the Wholesale Power Market," Las Vegas, Nevada, June 25, 1998.

Rose, J.L., "The Generation Market in PJM," presentation at Megawatt Daily's PJM Power Markets conference, Philadelphia, Pennsylvania, June 17, 1998.

Rose, J.L., "Market Evaluation of Electric Generating Assets in the Northeast," presentation at McGraw-Hill's conference: Electric Asset Sales in the Northeast, Boston, Massachusetts, June 15, 1998.

Rose, J.L., "Overview of SERC Power," opening speech presented at Megawatt Daily's SERC Power Markets conference, Atlanta, Georgia, May 20, 1998.

Rose, J.L., "Future Price Forecasting," presentation at The Southeast Energy Buyers Summit, Atlanta, Georgia, May 7, 1998.

Rose, J.L., "Practical Risk Management in the Power Industry," presentation at Power Fair, Toronto, Canada, April 16, 1998.

Rose, J.L., "The Wholesale Power Market in ERCOT: Transmission Issues," presentation at Megawatt Daily's ERCOT Power Markets conference, Houston, Texas, April 1, 1998.

Rose, J.L., "New Generation Projects and Merchant Capacity Coming On-Line," presentation at Northeast Wholesale Power Market conference, New York, New York, March 18, 1998.

Rose, J.L., "Projecting Market Prices in a Deregulated Electricity Market," presentation at conference: Market Price Forecasting, San Francisco, California, March 9, 1998.

Rose, J.L., "Handling of Transmission Rights," presentation at conference: Congestion Pricing & Tariffs, Washington, D.C., January 23, 1998.

Rose, J.L., "Understanding Wholesale Markets and Power Marketing," presentation at The Power Marketing Association Annual Meeting, Washington, D.C., November 11, 1997.

Rose, J.L., "Determining the Electricity Forward Curve," presentation at seminar: Pricing, Hedging, Trading, and Risk Management of Electricity Derivatives, New York, New York, October 23, 1997.

Rose, J.L., "Market Price Forecasting In A Deregulated Market," presentation at conference: Market Price Forecasting, Washington, D.C., October 23, 1997,

Rose, J.L., "Credit Risk Versus Commodity Risk," presentation at conference: Developing & Financing Merchant Power Plants in the New U.S. Market, New York, New York, September 16, 1997.

ATTACHMENT JLR-2
Select ICF Wholesale Power Practice Client References

ABB Energy Ventures	JP Morgan Securities, Inc.
AES	Lehman Brothers
Air Pollution Prevention Directorate	Mirant Americas Energy Marketing
Akin, Gump, Strauss, Hauer & Feld	Moody's Investors Service
Allegheny Power	Natural Resources of Canada
ABB Energy Ven	NiSource Corporate Services Co.
ATCO Power	Office of Energy Efficiency, Canada
Bank of America	PNGTS Operating Co., LLC
Bechtel Services	Portland General Electric
Calpine-SkyGen	PPL
Central and Southwest	PSEG Power
Cinergy	Royal Bank of Canada
Coastal Power Company	S&P
Conectiv Energy	SkyGen
Constellation Energy	Sonosky, Chambes, Sachse, Endreson & Perry
Consolidated Edison (ConEd)	TD Securities
Credit Suisse First Boston	TECO Energy
Dominion Energy	Tractebel Power
Duke Capital Partners	UAE
Exxon/Mobil Gas	USEPA
FirstEnergy Corp	USDOJ
The Hopi Tribe	West LB
Invenergy	Western Regional Air Partnership
Iowa Utilities Board	Wilkinson, Carmody & Gilliam
Iroquois Gas Transmission System	Winthrop, Stimson, Putnam & Roberts

ATTACHMENT JLR-3
ICF Forecasting Success

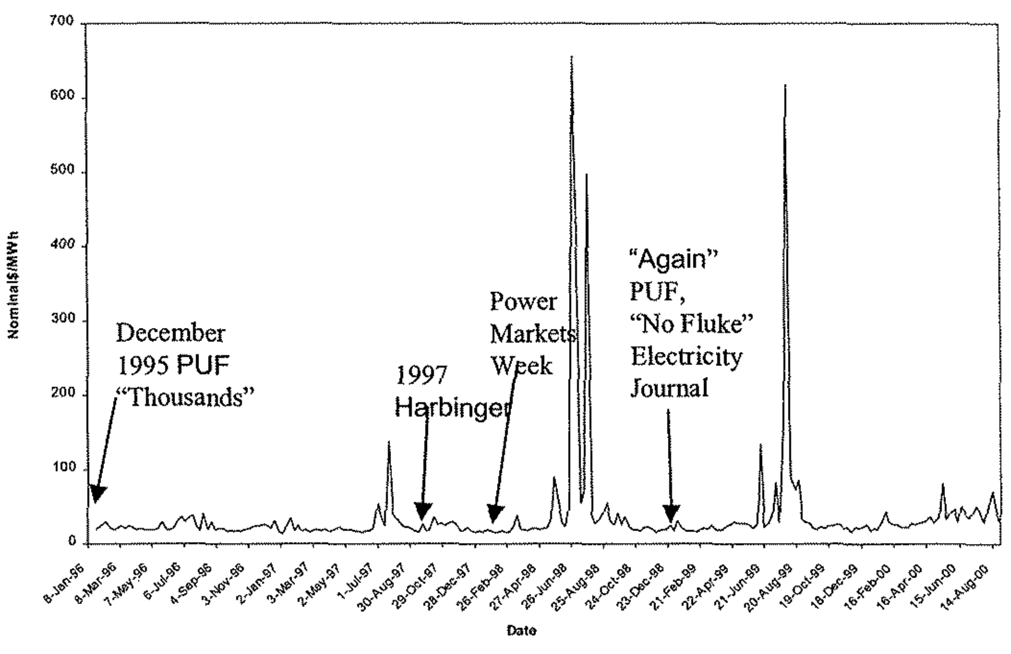
Forward Price Forecasts

ICF CONSULTING

Accurate Electricity Price Forecasts

ICF Consulting is the only forecasting group with a proven track record in supplying credible, forward wholesale power price forecasts to its clients. Among all forecasters, ICF Consulting alone accurately forecasted every major turning point in the U.S. wholesale deregulated power prices in North America. This information has been of unparalleled value to our clients. The lack of credible forward price forecasts can have extreme consequences for market participants.

Power Market Weekly On-Peak Index in Northern ECAR Spot Electricity Market



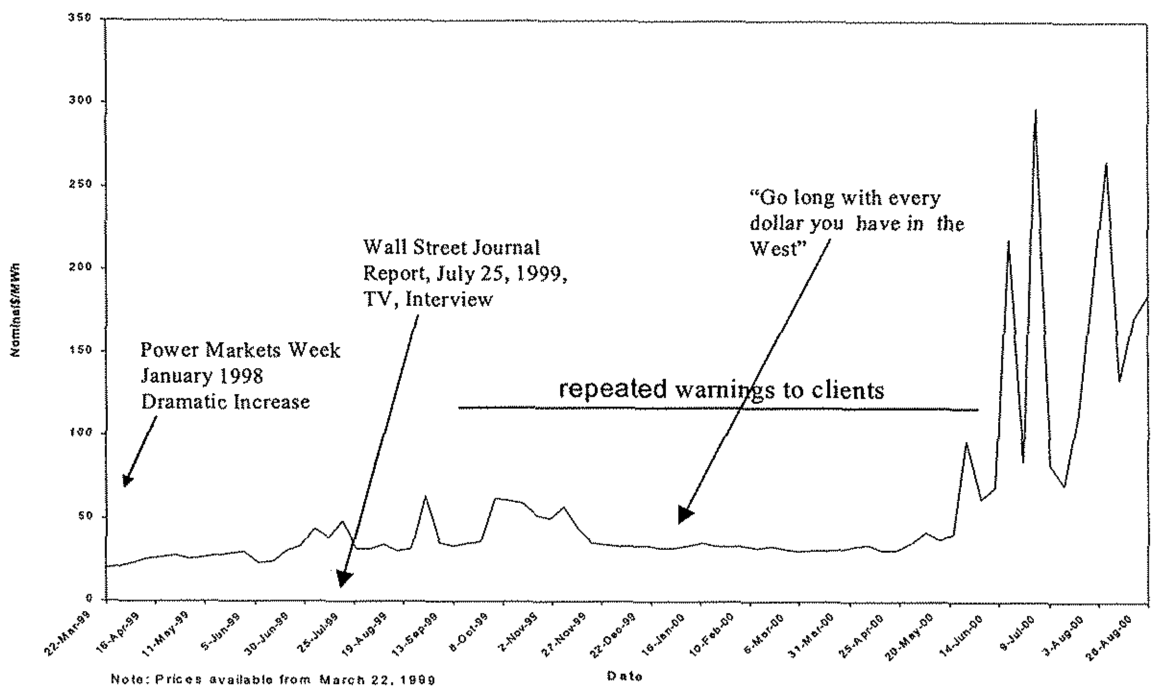
ICF Consulting documentation for this claim is contained in a series of public articles in which ICF shared its forecasts. In the two figures (see above and below), the timing of the published forecast is shown (via arrows) against actual prices.

YAG1204

Forward Price Forecasts

ICF CONSULTING

Power Market Weekly On-Peak Index in North Path Spot Electricity Market



The value of this information is heightened by the failure of others to provide credible forecasts. Below are some quotes from industry sources that documents the rarity of ICF Consulting's view. While public information reported that all was well, ICF stood alone forecasting imminent price explosions.

YAG1204

Forward Price Forecasts

ICF CONSULTING

Industry and Regulators Were Quiet Until It Was Too Late – Only ICF Consulting Provides Consistent Accuracy

"Resources will be adequate to meet projected demands in most areas of North America this summer. Reliability Assessment Sub-Committee (RAS) does not have particular concerns about reliability of the Western States Coordinating Council (WSCC) Region this summer."

1998 Summer Assessment, NERC, May 1998.

"The projected capacity margins and fuel supplies are anticipated to be adequate to ensure reliable operation in all areas of the region."

WSCC 10-Year Coordinated Plan Summary 1999-2008, page 39, October 1999.

"The southwest portion of WSCC (New Mexico, Arizona, southern Nevada, California, and Baja California Norte, Mexico) may not have adequate resources to accommodate a widespread severe heat wave or higher than normal generator forced outages. The possible inability to serve all firm peak demand under higher than normal temperatures or higher than normal anticipated forced outage conditions is a result of the continuing trend where peak demand growth has significantly exceeded the amount of new generation facilities being installed."

Western Systems Coordinating Council Assessment of the 2000 Summer Operating Period, Revised May 25, 2000. (Doc. 456)

No credible warning was available other than that of ICF Consulting up until weeks before California and WSCC prices exploded in June 2000.

YAG1204

Judah Rose
Managing Director
703-934-3342

JoAnne Grabowski
Staff Assistant
703-934-3787

Forward Price Forecasts

ICF CONSULTING

Published Articles:

•Rose, J.L. and C. Mann, "Unbundling the Electric Capacity Price in a Deregulated Commodity Market," Public Utilities Fortnightly, December 1995. The first article (and the only one before the first spikes) to predict prices in thousands of dollars per megawatt hour with explanation.

•Rose, J.L., "Last Summer's "Pure" Capacity Prices-A Harbinger of Things to Come", Public Utilities Fortnightly, December 1, 1997. A warning that the 1995 forecast was about to be imminently realized.

•Rose, J.L., "Analyst Sees Skyrocketing Peak Prices as Supply, Demand Approach a Balance", Power Markets Week, January 26 1998. Dramatic price increases were forecast in California and in other markets.

•Rose, J.L., "Missed Opportunity: What's Right and Wrong in the FERC Staff Report on the Midwest Price Spikes," Public Utilities Fortnightly, November 15, 1998. Forecasting a repeat of spikes while criticizing FERC's view that this was a one time approach.

•Rose, J.L. "Why the June Price Spike was not a Fluke," Electricity Journal, November 1998. Strenuously warning that 1998 was not a fluke.

•Rose, J.L. "Rose singles out desert southwest as most worrisome region". *Wall Street Journal Report July 25, 1999.*

•Rose, J.L. Personal communication to one of the leading U.S. energy companies, January 2000.

This unparalleled forecasting success is based on ICF Consulting's more than 25 years of experience in the power markets, which gives us a comprehensive understanding and approach to forward price forecasts and models.

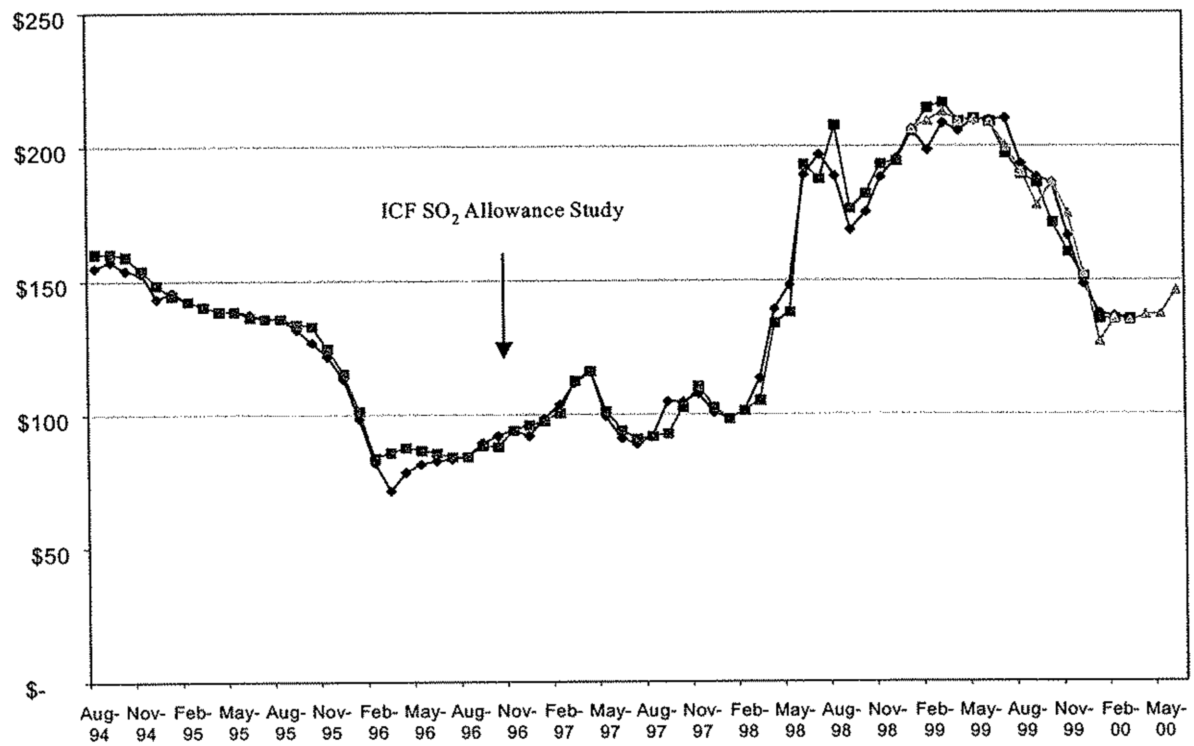
For more information about ICF Consulting's forecasting record and copies of published articles, please call or visit us at www.icfconsulting.com.

ATTACHMENT JLR-3
Case No. 2003-00252
July 21, 2003

Forward Price Forecasts

ICF CONSULTING

Accurate SO_2 Forecasts



ICF has also been very accurate in forecasting environmental allowances. In April 1996 when SO_2 allowance prices fell to $67/ton ICF forecast prices would rebound to $200/ton.

For more information about ICF Consulting's forecasting record and copies of published articles, please call or visit us at www.icfconsulting.com.

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ATTACHMENT JLR-4

ICF'S INTEGRATED PLANNING MODEL (IPM®)

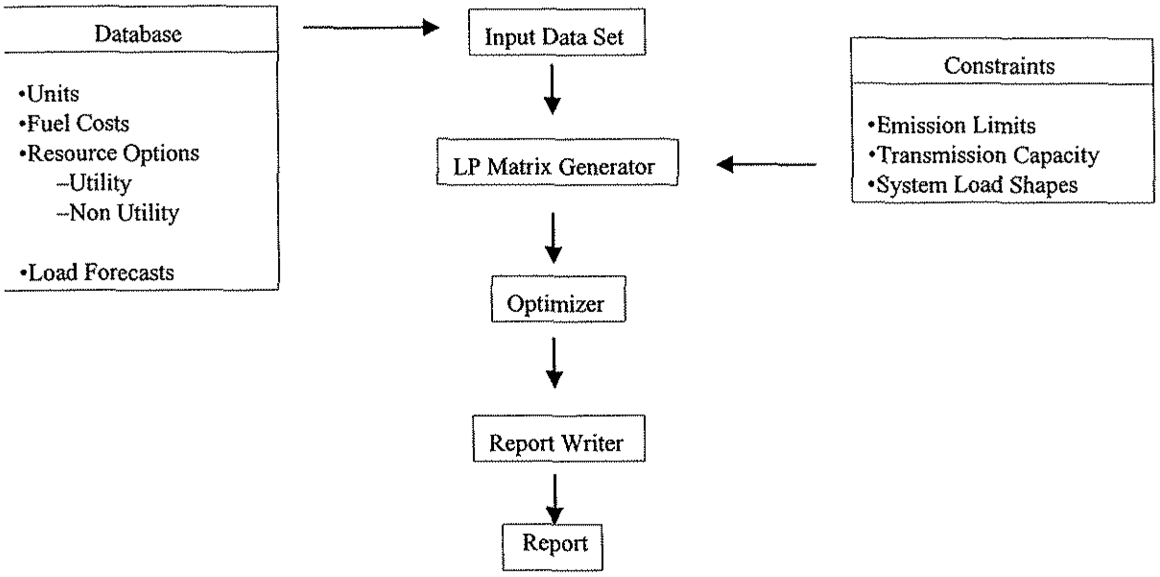
Modeling Overview

IPM® is an optimization mode that uses a linear programming formulation to forecast competitive wholesale power market prices and the dispatch of new or existing generating to meet overall electric demand (see Diagram 1). Investment options are selected by the model given the cost and performance characteristics of available options, forecasts or customer demand for electricity, and reliability criteria. System dispatch, determining the proper and most efficient use of the existing and new resources available to industry participants, is optimized given the resource mix, unit operating characteristics, and fuel and other costs. Unit and system operating constraints are included in the model's simulations. The model is dynamic; that is, it has the capability to use forecasts of future conditions, requirements, and option characteristics to make decisions for the present. This model replicates, as much as possible, the perspective of industry managers in reviewing important operational and investment options. Decisions are made on the basis of minimizing the net present value of capital plus operating costs over the full planning horizon in a manner which replicates competitive price determination.

Selection of fuels for each generating unit are based upon fuel prices and price escalation rates, availability constraints, usage constraints (*e.g.*, an oil or gas plant that is not coal-capable cannot burn coal), emissions characteristics, and environmental regulations. Options can include alternative strategies for meeting environmental constraints (*e.g.*, use of "clean" fuel vs. use of "dirty" fuel with pollution control and/or waste disposal equipment).

Diagram 1

IPM® Optimization Flow Chart



Model Inputs

Model inputs include demand, existing generating unit characteristics, new resource option characteristics, system operating constraints, fuel price forecasts, and the prices for and capacity available for economy and firm transmission between regions. These types of inputs are described briefly below.

- Demand: IPM® selects resource options to meet demand in future periods and to meet user-supplied reliability constraints -- usually specified in terms of a minimum planning reserve margin expressed in terms of percent reserve above the anticipated peak demand for electricity. Thus, the characterization of future demand is an important model input. The IPM® is structured to meet customer demands represented by seasonal load duration curves. A load duration curve, or LDC, is an ordering of customer loads by hour, from the highest load to the lowest load occurring over the full duration of the period captured by each of the different seasons modeled. Diagrams 2 and 3 illustrate an LDC and schematically (1) how this curve compares with a normal "seasonal" load curve, and (2) how the LDC is divided into distinct segments from peak segments (e.g., segments 1 and 2 in Diagram 3) to baseload segments (e.g., segments 8 and 9 in Diagram 3) for modeling purposes. Within IPM®, the definition of "season" is reflects such considerations as the definition NO_X summer season, seasonal fuel prices and run time. A season could be several months or a single month.

- Seasonal LDC's rather than annual LDC's are used to capture differences in the level and patterns of customer demands for electricity and to capture seasonal differences in resource availability or operating characteristics. For example, power exchanges between utility systems may be seasonal in nature. Further, because of maintenance scheduling for individual generating units, the capacity and utilization for these supply resources can also vary importantly between seasons.

Diagram 2

Hypothetical Summer Load Curve for one 24 Hour Period

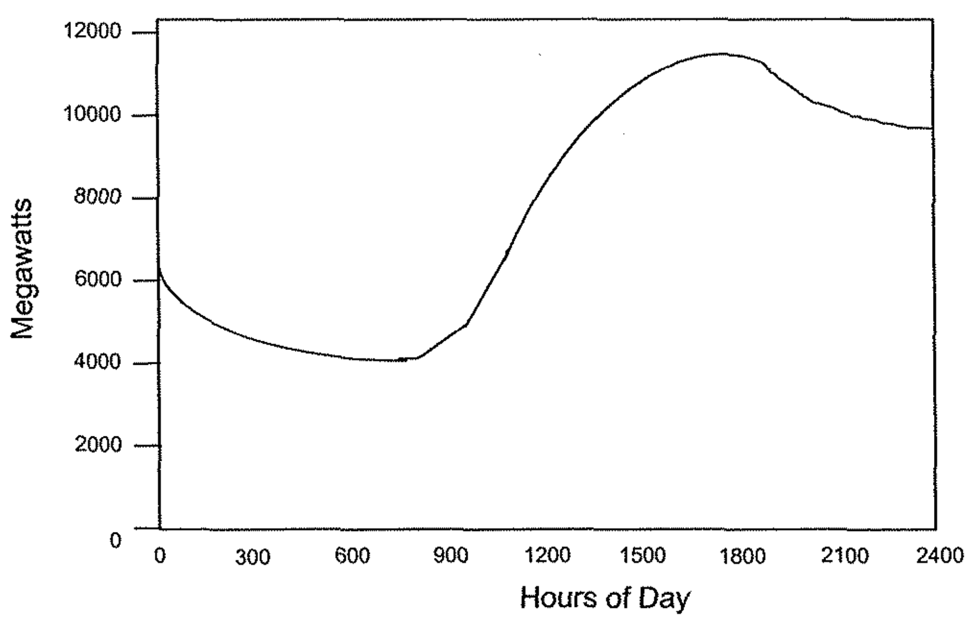
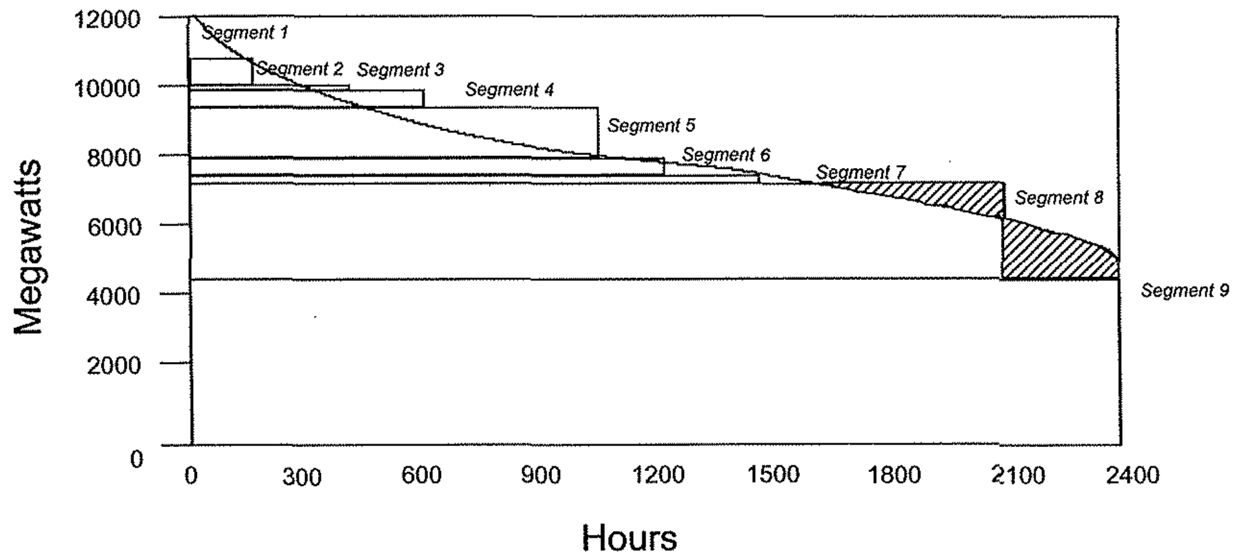


Diagram 3

Hypothetical Load Duration Curve



Within IPM®, LDC's are represented by a discrete number of horizontal segments, or strips, as illustrated previously in Diagram 3. The top segment generally contains less than one percent of the hours in the period (*i.e.*, "season"). The bottom segment includes 100% of the hours and has a load level equal to the minimum system load. The number of segments is flexible and is a user input. A greater number of segments provide a more detailed depiction of customer loads to the model's dispatch algorithm, but also increases the computational time of the model. Typically 7-12 segments provide an adequate representation for most applications.

Existing Generating Resources: To improve the efficiency of the model's operation, individual generating units are sometimes aggregated into "plants" with similar cost and operating characteristics. For each aggregate plant, key characteristics specified in the model's input database can include:

- Plant capacities by year (summer and winter ratings)

- Heat rates

- Maintenance schedules (timing and duration)
- Forced outage rates
- Transmission and distribution loss characteristics
- Fuels used
- Fixed and variable O&M costs
- Emission limits and emission rates for SO_2, CO_2, NO_x, Mercury, Fly Ash or Scrubber Sludge.
- Capital and O&M costs and changes in plant operating characteristics associated with life extension, repowering, fuel conversion, retrofits, and other changes to existing generating units can be specified and included as potential new resource option investments.
- New Generating Resources: For new generating resource option investments, inputs include the cost and operating characteristics specified above for existing units. In addition, the user must specify the capital costs associated with each new unit option, capital charge rates, and lead times. Lead times are most frequently reflected in limitations on when and how much capacity of a particular technology can be considered by the model as fully commercial and available to meet demand or energy requirements.

Based primarily on these inputs and a user-supplied discount rate, IPM® calculates a levelized cost and potential contribution for meeting loads. Investment decisions are made by IPM© to minimize costs. Interregional bulk power purchases and sales (firm or economy) and power supply are considered simultaneously with other power supply options. The costs of these power resources and their supply characteristics are user inputs.

System Operating Constraints: Constraints are input to the model as a means of representing and accounting for specific operating conditions faced by a particular utility. Examples of these operating constraints include:

- Area protection constraints (e.g., load stability, etc.)
- Plant minimum operating constraints
- Reliability constraints (e.g., reserve margin,)
- System-specific regional generation requirements
- Emissions constraints: includes SO_2 credit purchases, sales, and banking; system-wide or plant-group constraints; and CO_2 constraints.

Fuel Price Forecasts. Forecasts of fuel prices for both utility and non-utility generating resources are important inputs for determining investment decisions as well as unit dispatch. Fuel prices typically are input to the IPM© on the basis of real (or constant dollar) costs.

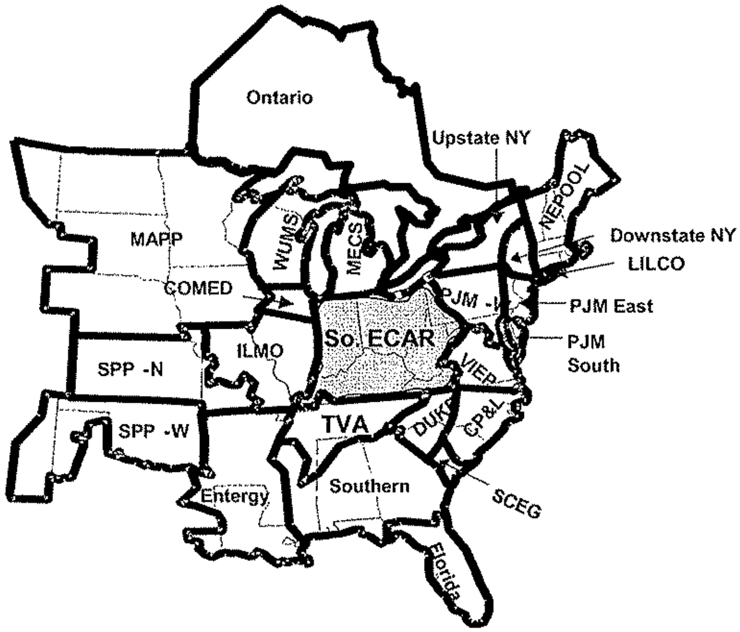
Model Outputs

Many detailed and summary reports can be generated by the IPM®. A useful feature of IPM® is that the entire model solution is stored, and additional detailed reports can be generated from the stored solution as the need arises. Among the standard reports are:

- Shadow prices on constraints (marginal energy costs and capacity prices)
- Summary of load and generation information
- Summary of demand-side program implementation rates and load impacts (peak demand and annual energy)
- Capacity requirements by plant
- Summary of generation by plant type
- Summary of fuel consumption
- Summary and detailed dispatch information by plant
- Summary and detailed emissions information by resource type

Summary and detailed cost information (capital costs, fixed O&M costs, variable O&M costs, fuel costs)

ATTACHMENT JLR-5
Regions Modeled



ATTACHMENT JLR-6
ICF Wholesale Power Modeling Regions – Eastern Interconnect

- ECAR (Southern ECAR and ECAR-MECS)
- SERC-TVA
- MAIN – ILMO
- MAIN – ComEd
- MAIN – WUMS
- Allegheny/Duquesne
- PJM West[1]
- PJM South
- PJM East
- Ontario
- MAPP
- SPP-South
- SPP-North
- Entergy
- VACAR – Duke
- VACAR – South Carolina
- VACAR - CP&L
- VACAR – VEPCo
- New York – Upstate
- New York – Downstate
- New York – LILCO
- New York – New York City
- NEPOOL
- SERC-Southern
- FRCC

[1] PJM West is used here to refer to an ICF modeling region, not the recently announced enlargement of PJM.

ATTACHMENT JLR-7
Base Case Firm[1] All-Hours Price Forecast -- Southern ECAR

Year	Base Case Firm All-Hours Price Forecast	
	2000$/MWh	Nominal$/MWh[2]
2003	[redacted]	[redacted]
2004	[redacted]	[redacted]
2005	[redacted]	[redacted]
2006	[redacted]	[redacted]
2007	[redacted]	[redacted]
2008	[redacted]	[redacted]
2009	[redacted]	[redacted]
2010	[redacted]	[redacted]
2011	[redacted]	[redacted]
2012	[redacted]	[redacted]
2013	[redacted]	[redacted]
2014	[redacted]	[redacted]
2015	[redacted]	[redacted]
2016	[redacted]	[redacted]
2017	[redacted]	[redacted]
2018	[redacted]	[redacted]
2019	[redacted]	[redacted]
2020	[redacted]	[redacted]
2021	[redacted]	[redacted]
2022	[redacted]	[redacted]
2023	[redacted]	[redacted]
2024	[redacted]	[redacted]
2025	[redacted]	[redacted]
Levelized[3] (2003-2025)	[redacted]	[redacted]

[1]Sum of energy price and pure capacity price at 100% capacity factor (unit contingent firm).
[2]Assumes 2.37 percent inflation between 2000 and 2001 and 2.5 percent thereafter.
[3]Using 11.2 percent real and 14 percent nominal discount rates.

ATTACHMENT JLR-8
Historical Actual ECAR Peak Demand Growth – 10 Year Rolling Averages

Time Period	10 Year Rolling Average Peak Demand Growth (%)
1980 – 1990	2.3
1981 – 1991	2.4
1982 – 1992	2.8
1983 – 1993	2.0
1984 – 1994	2.8
1985 – 1995	3.4
1986 – 1996	2.7
1987 – 1997	2.6
1988 – 1998	1.7
1989 – 1999	2.8
1990 – 2000	1.5
1991 – 2001	2.1
Average	2.4

Source: NERC *Electricity Supply & Demand.*

ATTACHMENT JLR-8a
Historical ECAR Peak Demand Forecasts

Year of Forecast	Forecasted 10-Year Annual Average Growth Rate of Peak Demand (%)
1987	1.8
1988	1.6
1989	1.7
1990	1.6
1991	1.6
1992	1.5
1993	1.5
1994	1.4
1995	1.6
1996	1.9
1997	1.6
1998	1.7
1999	1.7
2000	1.7
2001	1.6
2002	1.9
15-Year Average	1.6

Source: NERC ES&D, 1987-2001

ATTACHMENT JLR-9
Base Case Implied[1] Heat Rate Forecast -- Southern ECAR

Year	Implied Heat Rate Forecast (Btu/kWh)
2003	[redacted]
2004	[redacted]
2005	[redacted]
2006	[redacted]
2007	[redacted]
2008	[redacted]
2009	[redacted]
2010	[redacted]
2011	[redacted]
2012	[redacted]
2013	[redacted]
2014	[redacted]
2015	[redacted]
2016	[redacted]
2017	[redacted]
2018	[redacted]
2019	[redacted]
2020	[redacted]
2021	[redacted]
2022	[redacted]
2023	[redacted]
2024	[redacted]
2025	[redacted]
Levelized[2] (2003-2025)	[redacted]

[1]Calculated by dividing firm all-hours price by delivered natural gas price.
[2]Using 11.2 percent real discount rate.

ATTACHMENT JLR-10
ICF Base Case Natural Gas Price Forecasts ($/MMBtu)

Year	Henry Hub		Southern ECAR[2]	
	Nominal$/MMBtu	2000$	Nominal$/MMBtu	2000$
Historical[3]				
1989 – 1999	2.00	2.23	N/A	N/A
2000	4.23	4.23	5.16	5.16
2001	4.07	3.97	4.16	4.06
2002	3.33	3.20	3.49	3.33
2003 YTD[1]	5.92	5.51	6.13	5.70
Forecast				
2003	[redacted]	[redacted]	[redacted]	[redacted]
2004	[redacted]	[redacted]	[redacted]	[redacted]
2005	[redacted]	[redacted]	[redacted]	[redacted]
2006	[redacted]	[redacted]	[redacted]	[redacted]
2007	[redacted]	[redacted]	[redacted]	[redacted]
2008	[redacted]	[redacted]	[redacted]	[redacted]
2009	[redacted]	[redacted]	[redacted]	[redacted]
2010	[redacted]	[redacted]	[redacted]	[redacted]
2011	[redacted]	[redacted]	[redacted]	[redacted]
2012	[redacted]	[redacted]	[redacted]	[redacted]
2013	[redacted]	[redacted]	[redacted]	[redacted]
2014	[redacted]	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]
Simple Average (2003-2025)	[redacted]	[redacted]	[redacted]	[redacted]

[1]Through May
[2]Cincinnati City Gate used for historical representation. Actual delivered price to Southern ECAR is higher than Cincinnati City Gate.
[3]Source: Natural Gas Week (1989-2002) and Gas Daily (2003) for Henry Hub and Bloomberg (2000-2003) for Cincinnati City Gate.

ATTACHMENT JLR-11
Southern ECAR Electric Energy Price-Related Assumptions

Parameter	**Treatment – Base Case**	
Delivered Natural Gas Price[1] (2000$/MMBtu) 2003 2006 2009 2012 2015 2025	[redacted]	
Crude Oil Prices – WTI Crude (2000$/Bbl) 2003 2006 2009 2012 2015 2025	[redacted]	
Representative Delivered Coal Prices[2,3] (Nominal$/MMBtu) 2003 2006 2009 2012 2015 2025	East Bend [redacted]	Miami Fort 6 [redacted]
Nuclear Capacity Factors (varies by plant) (%) 2003 2015 2025	[redacted]	
Nuclear Retirements	Current licenses are extended indefinitely; economic retirements possible.	

[1]Includes commodity price and basis differential; reflects annual average across all hours of the year; the actual realized price applicable to individual plants in the region will vary depending on the hours and seasons of dispatch.
[2]ICF models coal prices delivered to each coal power plant
[3]Provided by Cinergy.

ATTACHMENT JLR-11a
Southern ECAR Energy Price-Related Assumptions

Parameter	Treatment – Base Case				
New Power Plant Builds Heat Rate (Btu/kWh)[1] 2003 2006 2009 2012 2015 2025 Levelized[2] 2003-2025	CT [redacted]	LM6000 [redacted]	CC/Cogen [redacted]	Coal [redacted]	
Variable O&M (2000$/MWh)[3] Availability (%)	[redacted]	[redacted]	[redacted]	[redacted]	
Existing Power Plant Availability[4] (%) Coal Steam Oil/Gas Steam	Availability [redacted]				
Minimum Turndown[5] (%)	Coal Steam [redacted]		Oil/Gas Steam [redacted]		
Variable O&M (2000$/MWh)[6]	CC [redacted]	CT [redacted]	Oil/Gas Steam [redacted]	Unscrubbed Coal [redacted]	Scrubbed Coal [redacted]

[1]ISO, HHV, full load.
[2]Assumes 11.2 percent discount rate shown for expositional purpose.
[3]Values specified correspond to an 80 percent capacity factor for combined cycles (note, combined cycles with cycling option have higher VO&M as shown), a 5 percent capacity factor for combustion turbines and LM6000s, and an 80% capacity factor for coal plants.
[4]Availabilities are an approximate value representing all units within the region.
[5]Turndown applies to unit operation. It is the minimum level of generating capacity it needs to be operated.
[6]Inversely correlated with capacity factor and is an output of the model. *Values specified correspond to an 80 percent* capacity factor for combined cycles (note, combined cycles with cycling option have higher VO&M as shown), a 5 percent capacity factor for combustion turbines and LM6000s, and an 80% capacity factor for coal plants.

ATTACHMENT JLR-12
ECAR Demand and Capacity Price Related Assumptions

Parameter	Treatment – Base Case: Southern ECAR	Treatment – Base Case: Total ECAR
2001 Weather-Normalized Peak Demand (MW)[1] 2001 Net Internal Demand (MW)[2]	[redacted]	[redacted]
Annual Peak Growth (%) 2003-2005 2006-2010 2011-2020 2021-2025	[redacted]	[redacted]
2002 Weather-Normalized Net Energy for Load (GWh)[1]	[redacted]	[redacted]
Annual Energy Growth (%) 2003-2005 2006-2010 2011-2020 2021-2025	[redacted]	[redacted]
Planning or "Market Required" Reserve Margin (%) 2003 – 2009 2010 – 2019 2020 – 2022	[redacted]	[redacted]
Firm Builds (MW) As of May 1, 2003 2000 2001 2002 2003 2004 2005 Total	[redacted]	[redacted]

New Power Plant Characteristics	CC/ Cogen	CT	LM 6000	Coal
All-In Capital Cost Applicable to Summer Output (2000$/kW)[3] 2003 2006 2009 2012 2015 2025 Levelized[4] 2003-2025 Fixed O&M (2000$/kW/yr)	[redacted]5[6]	[redacted]	[redacted]	[redacted]

Financing Costs for New Builds	CC/Cogen	CT	Coal
Debt to Equity Ratio (%) Nominal Debt Rate (%) Nominal After Tax Return on Equity (%) Income Taxes (%) Other[5] (%) General Inflation Rate (%) Levelized Real Capital Charge Rate (%)	[redacted]	[redacted]	[redacted]

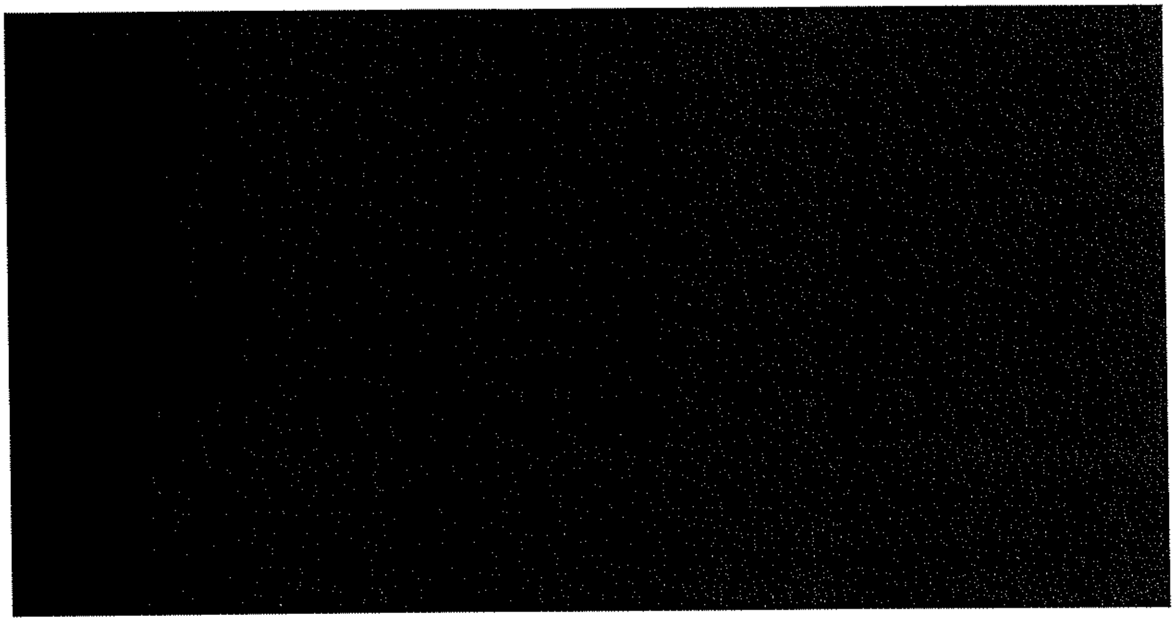
[1] NERC 2000 ES&D weather normalized forecast for 2002. ICF's SOECAR constitutes about 70% and 72% of NERC ECAR region's peak demand and net energy for load, respectively.
[2] Net internal demand is the equivalent of the peak load projection adjusted for interruptible load
[3] Adjusted for ambient conditions.
[4] Assumes an 11.2 percent real discount rate. Shown for exposition only
[5] Includes property taxes and insurance costs.
[6] For CC (Turndown)/CC (Cycling)/Cogeneration units.
Note: CC = Combined Cycle
CT = Simple Cycle Combustion Turbine

ATTACHMENT JLR-13
Base Case Non-Firm Builds[1] Forecast for Southern ECAR

Year	Natural Gas Combustion Turbines (MW)	Natural Gas Combined Cycles (MW)[2]	Coal-Fluidized Bed (CFB) (MW)	Total (MW)
2003	[redacted]	[redacted]	[redacted]	[redacted]
2004-2006	[redacted]	[redacted]	[redacted]	[redacted]
2007	[redacted]	[redacted]	[redacted]	[redacted]
2008-2009	[redacted]	[redacted]	-	[redacted]
2010-2012	[redacted]	[redacted]	-	[redacted]
2013-2015	[redacted]	[redacted]	-	[redacted]
2016-2025	[redacted]	[redacted]	-	[redacted]
Total	[redacted]	[redacted]	-	[redacted]

[1]Unplanned builds or non-firm resulting from the model are indicated excluding firmly planned builds which are not shown here. Unless specified as firm, the builds indicated are outputs of the model, which optimally selects the build mix to minimize system costs. The total amount of builds is based on the reserve margin criteria for the region.
[2]Includes cogeneration combined cycle units.

ATTACHMENT JLR-14
U.S. Power Plant Cancellations (MW)



ATTACHMENT JLR-15
Bloomberg as of May 29, 2003

Company	Is Issuer Security Sub-Investment Grade? (BB+ or lower from S&P, or Ba1 or lower from Moody's)	Has Debt Been Downgraded At Least Once Since 9/11/01? (by either S&P or Moody's)	Has Company Been Downgraded and/or is There at Least One Negative Outlook? (by either S&P or Moody's)	% Decrease in Stock Value from Its 52-Week High (Using the closing stock price on 5/29/03)
AES Corporation	yes	yes	yes	2%
AES Ironwood LLC	yes	yes	yes	2%
AES Red Oak LLC	yes	yes	yes	2%
Allegheny Energy Supply	yes	yes	yes	77%
Ameren Corporation	no	yes	yes	3%
American Electric Power Co., Inc.	no	yes	yes	38%
Aquila Inc.	yes	yes	yes	79%
BP America Inc.	no	no	yes	19%
Calpine Corp	yes	yes	yes	51%
Cinergy	no	no	yes	3%
Cleco Corp	no	yes	yes	27%
CMS Energy Corp	yes	yes	yes	58%
Constellation Energy	no	yes	yes	4%
Dominion	no	no	yes	6%
DPL Inc.	no	yes	yes	41%
DTE Energy	no	no	no	12%
Duke Energy Corp	no	yes	yes	46%
Dynegy Inc	yes	yes	yes	55%
Edison Mission Energy	yes	yes	yes	16%
El Paso Corp	yes	yes	yes	76%
Empire District Electric Co.	no	yes	yes	2%
Enron Corp	yes	yes	yes	na
Kinder Morgan Inc	no	no	yes	2%
Mirant	yes	yes	yes	68%
NiSource Inc.	no	yes	yes	20%
Northeast Utilities	no	yes	yes	22%
Northern Indiana Public Service Co.	no	yes	yes	0%
Northwestern Energy LLC	yes	yes	yes	86%
NRG Energy Inc.	yes	yes	yes	26%
PG&E Nat'l Energy Group, Inc.	yes	yes	yes	25%
Portland General Electric Company	no	no	yes	1%
Powergen	no	yes	yes	1%
PPL Corp	no	yes	yes	4%
Progress	no	yes	yes	12%
PSEG Power LLC	no	no	no	8%
Sempra Energy	no	yes	yes	3%
Sierra Pacific Power Co.	yes	yes	yes	38%
TXU Corp	yes	yes	yes	62%
Williams Co.	yes	yes	yes	40%
Xcel Energy	no	yes	yes	29%

[1] Aquila Inc. exited the wholesale market 9/02.
NiSource Inc. exited the wholesale market 2/19/03.
Portland General Electric Company exited the wholesale market 12/18/96.

ATTACHMENT JLR-16
Base Case ECAR Power Price Summary

Year	All Hours Electrical Energy Prices ($/MWh)		Annual Capacity Price ($/kW/yr)		Firm Power Price[1] ($/MWh)	
	2000$	Nominal$[2]	2000$	Nominal$[2]	2000$	Nominal$[2]
2003	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2006	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2007	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2009	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2012	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Levelized Price 2003-2025[3]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[1]Calculated as the all hour energy price plus the capacity price at 100% load factor (unit contingent firm).
[2]Utilizes a 2.37 percent inflation rate between 2000 and 2001, and 2.5 percent thereafter.
[3]Utilizes 11.2 percent real and 14 percent nominal discount rates.

ATTACHMENT JLR-17
Environmental-Related Assumptions – Base Case

Parameter	Treatment	
SO_2 Regulations	[redacted]	
NO_x Regulations	[redacted]	
CO_2 Regulations	[redacted]	
Mercury Regulations	[redacted]	
Allowance Prices (2000$/ton)	[redacted]	[redacted]

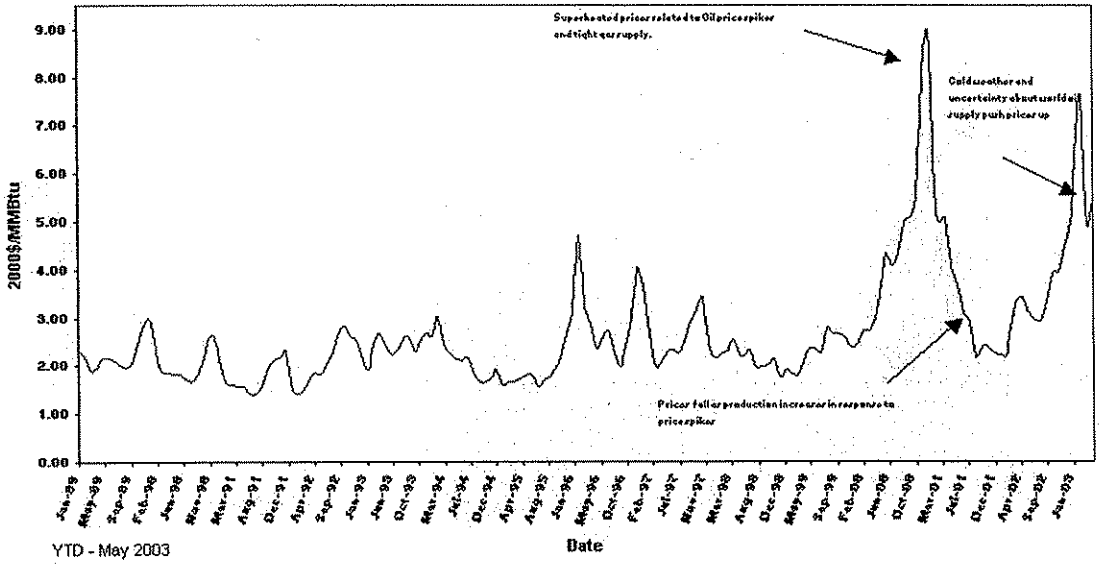
[1]SIP Call in 2003 for OTR regions, 2004 for all others including ECAR.

ATTACHMENT JLR-18
Market Structure and Modeling Approach

Parameter	Treatment – Base Case
Economic Regulation	[redacted]
Power Market Structure	[redacted]
Power Market Transaction Type	[redacted]
Fuel Market Transaction Type	[redacted]
Firm Power Plant Builds	[redacted]
New Non-Firm Builds	[redacted]
Price Volatility	[redacted]
Economic Retirements	[redacted]
Transmission Tariff Structure	[redacted]
New Transmission Lines	[redacted]
Environmental Regulations	[redacted]

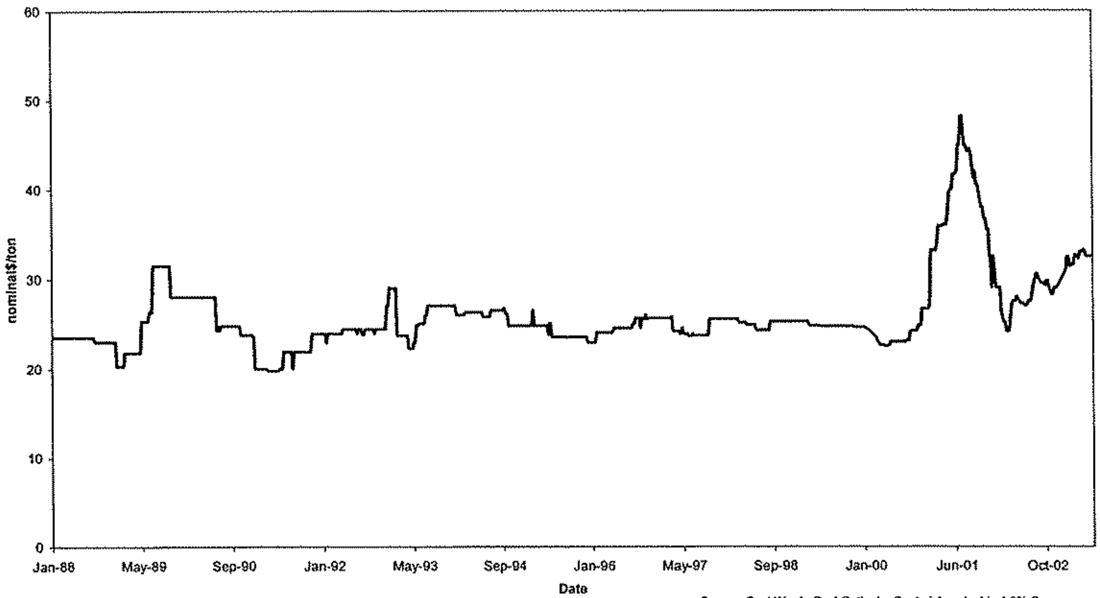
[redacted] is defined as a transaction lasting one year or less.

ATTACHMENT JLR-18a
Historical Natural Gas Prices at Henry Hub (January 1988 – May 2003) (Nominal $)



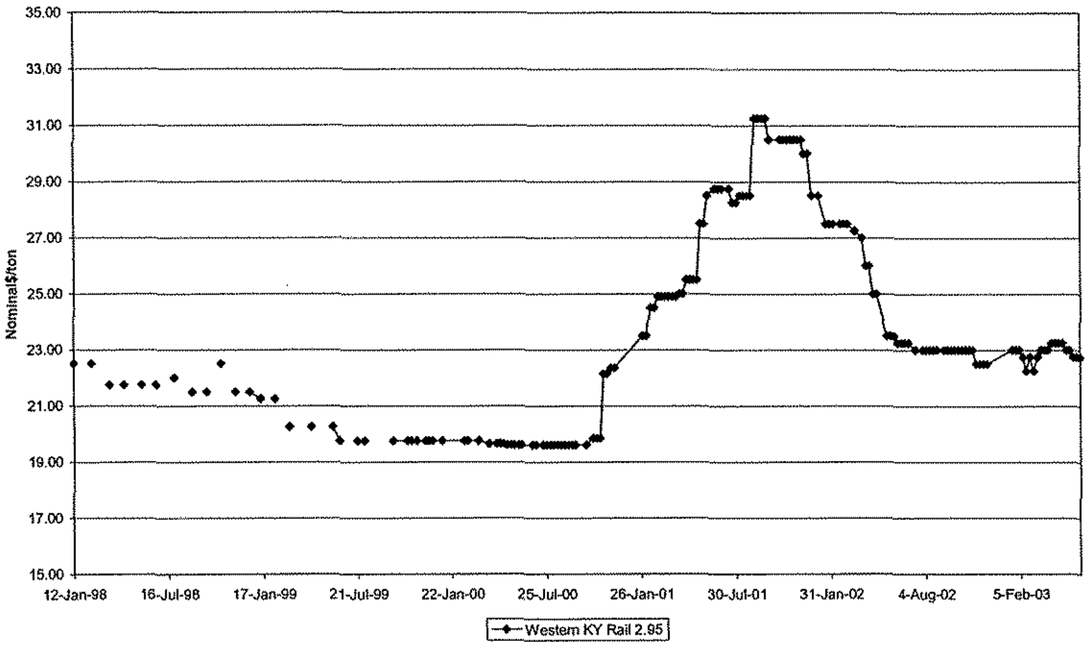
YTD - May 2003
Source: Natural Gas Week

ATTACHMENT JLR-18b
Historical Central Appalachia Coal Prices



Source: Coal Week; Coal Outlook; Central Appalachia 1.0% S

ATTACHMENT JLR-18c
Historical Illinois Basin Coal Prices



ATTACHMENT JLR-19
Henry Hub Natural Gas Price Forecasts Sensitivity Cases (2000$/MMBtu)

[redacted]

ATTACHMENT JLR-20
High and Low Natural Gas Price Sensitivity Firm[1] All-Hours Price Forecast -- Southern ECAR ($/MWh)

Year	High Natural Gas Case		Base Case		Low Natural Gas Case	
	2000$	Nominal$[2]	2000$	Nominal$[2]	2000$	Nominal$[2]
2003	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2004	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2005	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2006	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2007	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2008	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2009	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2010	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2011	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2012	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2013	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2014	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Levelized[3] (2003-2025)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[1]Sum of energy price and pure capacity price at 100% capacity factor (unit contingent firm)
[2]Assumes 2.37 percent inflation between 2000 and 2001 and 2.5 percent thereafter.
[3]Using 11.2 percent real and 14 percent nominal discount rates.

ATTACHMENT JLR-21
Summary of ECAR Firm Price[1] Forecast – Base and Sensitivity Cases

Case	All Hours Electrical Energy Prices ($/MWh)		Annual Capacity Price ($/kW/yr)		Firm Power Price[3] ($/MWh)	
	2000$	Nominal$[2]	2000$	Nominal$[2]	2000$	Nominal$[2]
Base	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
High Gas Prices	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Low Gas Prices	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
High Power Plant Supply	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

( ) Change from the Base Case. Differences may be due to rounding.
[1]Levelized averages shown; assumes 11.2 percent real and 14 percent nominal discount rates.
[2]Assumes 2.37 percent annual inflation rate between 2000 and 2001 and 2.5 percent thereafter.
[3]Calculated as the all hour energy price plus the capacity price at 100% load factor (unit contingent firm).

ATTACHMENT JLR-22
High Natural Gas Price Case ECAR Power Price Summary

Year	All Hours Electrical Energy Prices ($/MWh)		Annual Capacity Price ($/kW/yr)		Firm Power Price[1] ($/MWh)	
	2000$	Nominal$[2]	2000$	Nominal$[2]	2000$	Nominal$[2]
2003	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2006	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2007	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2009	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2012	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Levelized Price 2003-2025[3]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

( ) Change from the Base Case.
[1]Calculated as the all hour energy price plus the capacity price at 100% load factor (unit contingent firm).
[2]Utilizes a 2.5 percent inflation rate.
[3]Utilizes 11.2 percent real and 14 percent nominal discount rates.

ATTACHMENT JLR-23
Low Natural Gas Price Case ECAR Power Price Summary

Year	All Hours Electrical Energy Prices ($/MWh)		Annual Capacity Price ($/kW/yr)		Firm Power Price[1] ($/MWh)	
	2000$	Nominal$[2]	2000$	Nominal$[2]	2000$	Nominal$[2]
2003	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2006	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2007	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2009	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2012	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Levelized Price 2003-2025[3]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

( ) Change from the Base Case.
[1]Calculated as the all hour energy price plus the capacity price at 100% load factor (unit contingent firm).
[2]Utilizes a 2.5 percent inflation rate.
[3]Utilizes 11.2 percent real and 14 percent nominal discount rates.

ATTACHMENT JLR-24
High Power Supply Case ECAR Power Price Summary

Year	All Hours Electrical Energy Prices ($/MWh)		Annual Capacity Price ($/kW/yr)		Firm Power Price[1] ($/MWh)	
	2000$	Nominal$[2]	2000$	Nominal$[2]	2000$	Nominal$[2]
2003	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2006	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2007	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2009	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2012	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Levelized Price 2003-2025[3]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

( ) Change from the Base Case.
[1]Calculated as the all hour energy price plus the capacity price at 100% load factor (unit contingent firm).
[2]Utilizes a 2.5 percent inflation rate.
[3]Utilizes 11.2 percent real and 14 percent nominal discount rates.

ATTACHMENT JLR-25
2004-2010 Levelized SoECAR All-Hour[1] Firm Prices (Nominal$/MWh)

[redacted]

1 Assuming a 100% Capacity Factor

ATTACHMENT JLR-25a
2007-2031 Levelized SoECAR All-Hour[1] Firm Prices (Nominal$/MWh)

[redacted]

1 Assuming a 100% Capacity Factor

ATTACHMENT JLR-26 and JLR-26a
Case No. 2003-00252
July 21, 2003

ATTACHMENT JLR-26
Changes in Portfolio Value under Various Sensitivities (2007$/kW)

[redacted]

Book Value: $332/kW　　　　Base Case Value: $1,004/kW

ATTACHMENT JLR-26a
Portfolio Values under Various Sensitivities versus Book Value (2007$/kW)

[redacted]

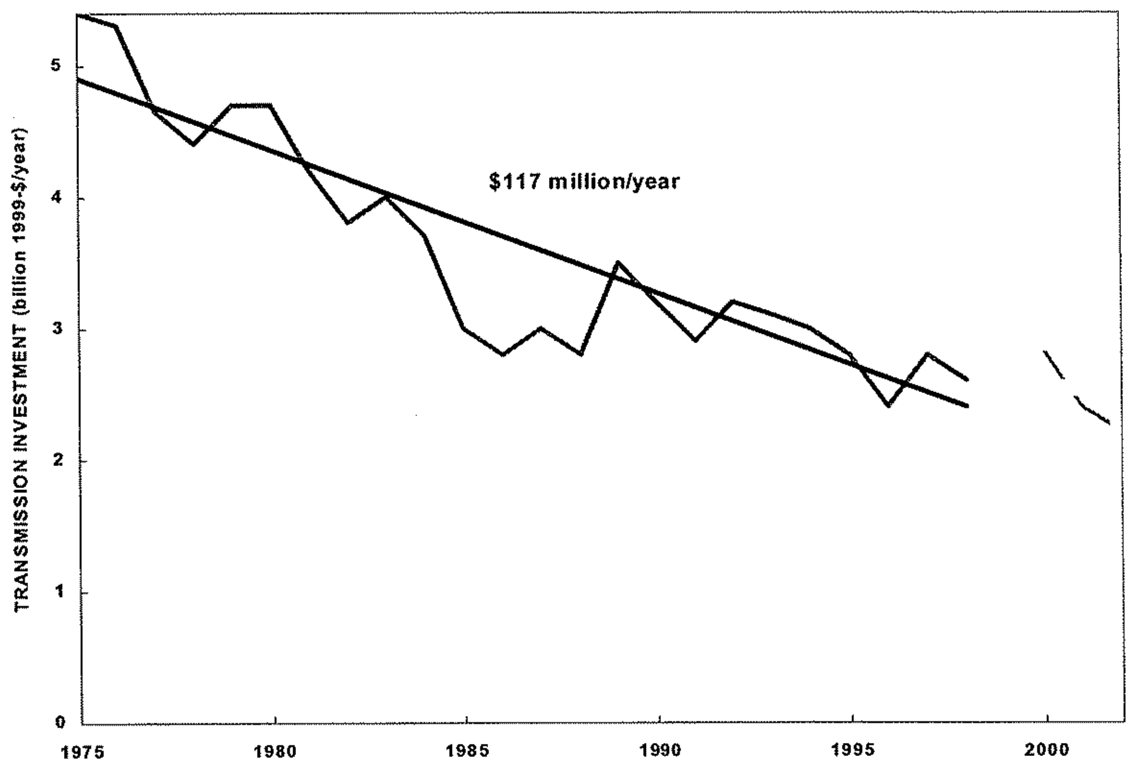
Book Value: $332/kW　　　　Base Case Value: $1,004/kW

ATTACHMENT JLR-27
ECAR[1] Wholesale Electricity Prices – For All Hours Supply (Around Clock Supply) ($/MWh)

Year	Price (Nominal$/MWh)
1996	17
1997	19
1998	34
1999	28
2000	26
2001	28
2002	22
2002 Jan – April	21
2003 Jan – April[2]	36
Average (1996 – 2003 April)	26

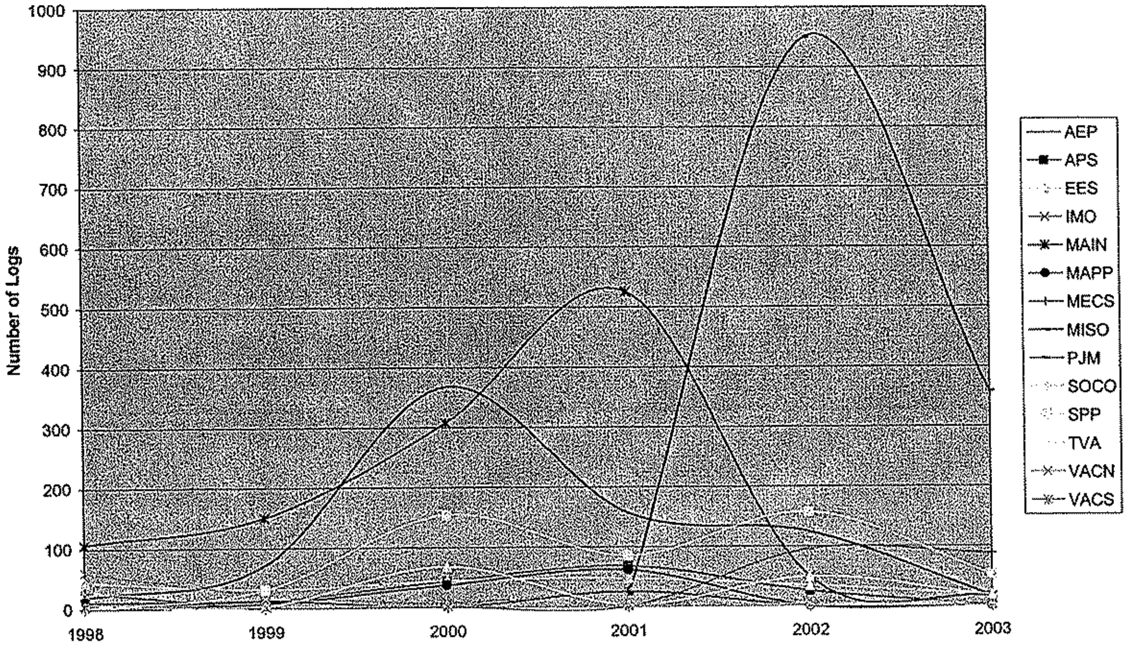
[1]The ECAR index has been replaced by Northern ECAR since May 3, 1999. The Northern ECAR index encompasses next day trades in Michigan, Ohio, and Northern Indiana.
[2]Through April 21
Source: Power Markets Week

ATTACHMENT JLR-28
Annual U.S. Transmission Investments from 1975 through 1999 and Projections for 2000, 2001, and 2002.



Source: Eric Hirst and Brendan Kirby, Transmission Planning for a Restructuring U.S. Electricity Industry, June 2001.

ATTACHMENT JLR-29
Total Logs by Security Coordinator (1998-2003 YTD)



Source: NERC - http://www.nerc.com/~filez/Logs/index.html
Dated through May 31, 2003

ATTACHMENT JLR-29a
2001 Summer Peak Demand by NERC Region

NERC Area	Peak Demand[1]	Share %	Total Number of 345 kV and Above Flowgates[2]	Share %	Total Number of 115 kV and Above Flowgates[2]	Share %
ECAR	100,235	19	157	34	268	23
MAIN	56,344	11	103	22	250	22
US Eastern Interconnect	523,492	100	459	100	1,148	100

Source:
[1]NERC ES&D 2002.
[2]NERC Book of Flowgates, 5/8/2002.

ATTACHMENT JLR-30
CSA Case ECAR Power Price Summary

Year	All Hours Electrical Energy Prices ($/MWh)		Annual Capacity Price ($/kW/yr)		Firm Power Price[1] ($/MWh)	
	2000$	Nominal$[2]	2000$	Nominal$[2]	2000$	Nominal$[2]
2003	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2006	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2007	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2009	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2012	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Levelized Price 2003-2025[3]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

( ) Change from the Base Case.
[1]Calculated as the all hour energy price plus the capacity price at 100% load factor (unit contingent firm).
[2]Utilizes a 2.5 percent inflation rate.
[3]Utilizes 11.2 percent real and 14 percent nominal discount rates.

ATTACHMENT JLR-31
Mercury MACT Case ECAR Power Price Summary

Year	All Hours Electrical Energy Prices ($/MWh)		Annual Capacity Price ($/kW/yr)		Firm Power Price[1] ($/MWh)	
	2000$	Nominal$[2]	2000$	Nominal$[2]	2000$	Nominal$[2]
2003	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2006	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2007	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2009	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2012	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Levelized Price 2003-2025[3]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

( ) Change from the Base Case.
[1]Calculated as the all hour energy price plus the capacity price at 100% load factor (unit contingent firm).
[2]Utilizes a 2.5 percent inflation rate.
[3]*Utilizes 11.2 percent real and 14 percent nominal discount rates.*

VERIFICATION

STATE OF VIRGINIA)
) **SS:**
COUNTY OF Fairfax)

The undersigned, Judah L. Rose, being duly sworn, deposes and says that he is Managing Director of ICF Consulting, that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Judah L. Rose

Judah L. Rose

Sworn to and subscribed in my presence on this 30th day of June 2003.

Dawn M. Cutotta

NOTARY PUBLIC