STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter of the Application of WABASH VALLEY POWER ASSOCIATION, INC. for authority to adjust and increase its rates and charges for electric service.	)))))	Case No. U-13951

DIRECT TESTIMONY

OF

KARI D. WETTER

On Behalf of Applicant
Wabash Valley Power Association, Inc.

Q1. PLEASE STATE YOUR FULL NAME AND BUSINESS ADDRESS.

A1. My name is Kari D. Wetter. My business address is Wabash Valley Power Association, Inc. (Wabash Valley), 722 North High School Road, Post Office Box 24700, Indianapolis, Indiana 46224.

Q2. WHAT IS YOUR POSITION WITH WABASH VALLEY?

A2. My current position is that of Manager of Planning and Risk Officer.

Q3. WHAT ARE YOUR JOB RESPONSIBILITIES?

A3. I am currently responsible for administering the resource planning and forecasting activities of Wabash Valley, as well as coordinating risk management activities. I oversee the planning and securing of power resources for Wabash Valley's native load.

Q4. PLEASE OUTLINE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A4. I received a Bachelor of Science degree in Mechanical Engineering from the University of Illinois in 1983. In 1991, I received a Masters in Business Administration from Indiana University, with a concentration in Finance. I am a licensed Professional Engineer in the state of Indiana. In 1983, I went to work for the Illinois Commerce Commission in the Economics and Rates Department. While there, my responsibilities included the development of marginal production costs, marginal cost of service studies, and the evaluation of generation capacity planning for electric and gas utilities in Illinois. I also provided expert testimony on these subjects in dockets before the Illinois Commerce Commission.

In 1986, I was employed by Wabash Valley as a Senior Planning Analyst. In 1992, I took the position of Planning Supervisor, in 1995, System Planning Principal, and

in 1998, the position of Manager of Planning and Finance. This year, I have taken the position of Manager of Planning and Risk Officer. I have been responsible for the projection of long-term power costs, corporate financial forecasts, power requirements forecasting, expansion planning, requests for power supply proposals, the evaluation of power supply bids, and developing sources of financing. My current responsibilities include resource planning and forecasting and the responsibility of overseeing risk management at Wabash Valley.

Q5. HAVE YOU EVER TESTIFIED BEFORE A REGULATORY AGENCY?

A5. I have testified before the Illinois Commerce Commission in electric and gas rate proceedings as an expert witness on behalf of the Illinois Commerce Commission. Issues included cost of service, electric generation planning, marginal production costs and fuel inventory. Since I have been with Wabash Valley, I have testified before the Indiana Utility Regulatory Commission (IURC) and have filed prefiled testimony (but did not testify) before the Michigan Public Service Commission on issues relating to resource planning, power costs, cost classification, and finance.

Q6. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A6. The purpose of my testimony is to present evidence and to sponsor exhibits that: (i) classify the Wabash Valley revenue requirements into demand and energy components for the High Load Factor (HLF) and Medium Load Factor (MLF) and seasonal rates; (ii) describe the pro forma adjustment to generation purchased power costs; (iii) describe the need and economic evaluation of new generation resources; and (iv) describe the Phase I Interim Rate surcharge.

Q7. ARE YOU SPONSORING ANY EXHIBITS IN THIS PROCEEDING?

A7. Yes, I am sponsoring:

Exhibit KDW-1, Cost Classification

Exhibit KDW-2, Summer Seasonal Classification

Exhibit KDW-3, Wabash Valley Expansion Plan Summary

Exhibit KDW-4, Integrated Resource Plan – Supply Alternatives

Exhibit KDW-5 Expansion Plan Alternatives – Peaking Power Resources, Vermillion Generating Station

Exhibit KDW-6, Response to WVPA's Request for Proposal (October 15, 2002)

Exhibit KDW-7, Expansion Plan Alternatives – Peaking power resources, Lawrence Peaking Station

Exhibit KDW-8, Comparison of Peaking Power Supply Alternatives, Lawrence Peaking Station

Exhibit KDW-9, Price Duration Curve – Forecast for 2006, into Cinergy

Exhibit KDW-10, Expansion Plan Alternatives – Base Load Power Resources -- Landfill Gas Generating Stations

Exhibit KDW-11, Requests for Proposal – Baseload Supply

Exhibit KDW-12, Annual Average Market Price

Exhibit KDW-13, Phase I Interim Rate Surcharge

CLASSIFICATION OF WABASH VALLEY REVENUE REQUIREMENTS

Q8. WERE THESE EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECTION AND SUPERVISION?

A8. Yes.

Q9. WHAT IS THE PROCEDURE YOU FOLLOWED TO CLASSIFY THE DEMAND AND ENERGY COMPONENTS OF THE REVENUE REQUIREMENTS?

A9. Two classification methods were used to assign the costs among power demand and energy. These classification methods support the four wholesale rate options.

Q10. BRIEFLY DESCRIBE THE TWO METHODS USED FOR COST CLASSIFICATION.

A10. The first classification method supports the HLF rate. Cost of power is classified between power demand and energy costs based on whether the cost is charged to Wabash Valley as a demand or energy charge. Other costs are classified between power and energy costs based on whether the cost is a fixed or variable cost. Fixed costs, such as those associated with depreciation, property taxes, and interest, are considered demand-related costs. Variable costs, such as fuel and production-related variable O&M, are considered energy related.

The second classification method supports the MLF rate. This classification was developed using a stratified methodology. This method uses a basic tool of power supply economics, the load duration curve, to assign purchased power and production costs between demand and energy classifications.

For the MLF classification method, the load duration curve is used to categorize power purchases and production costs among resources that serve base and peaking load requirements. All of the base load costs are considered energy-related; the costs associated with peaking load are considered demand related.

In the HLF and MLF classification methods, other costs, such as administrative and general costs, and other depreciation have been classified as either demand costs or energy costs based generally on whether they are considered fixed or variable with respect to energy sales.

Q11. WILL YOU PLEASE EXPLAIN EXHIBIT KDW-1, DEMAND AND ENERGY CLASSIFICATION METHOD?

A11. Yes. Exhibit KDW-1 illustrates the percentage classification of revenue requirements under the HLF and MLF methodology. These percentages are based on the pro forma revenue requirements for demand and energy, excluding substation-related costs.

Q12. WILL YOU PLEASE EXPLAIN THE HIGH LOAD FACTOR DEMAND AND ENERGY CLASSIFICATION METHOD IN EXHIBIT KDW-1?

A12. As I noted before, Production costs are classified as demand and energy-related based on the expected fixed and variable related operating costs. Production Fuel (line 1) is classified as energy. Line 2, Production O&M Taxes, and Labor, is classified as demand. The O&M is classified between demand and energy based on allocations provided by Cinergy with the Gibson 5 billings, as well as the expected fixed and variable costs related to the Vermillion, Twin Bridges, and Oak Ridge production facilities. Line 7, Cost of Power - Member, has all purchases classified to demand and energy based on the amounts billed as demand and energy. Line 5, Cost of Power - Members SDI, is classified as energy since they primarily purchase power on the spot market to meet their requirements. Line 78 Cost of Power - Non-Member, has all purchases classified to energy since the sales are all energy based. The associated non-member revenue (Line 18) has also been classified as energy. The majority of other revenue requirements are demand-related, with the exception of Administrative and General Expenses and Interest Income. The Administrative and General Expenses were classified as energy. Interest income (line 15) was allocated between demand and energy based on the estimated margin classified as demand plus depreciation. As a result, the interest income for the

HLF is classified primarily as demand due to the large level of demand related depreciation compared to the relatively small margin associated with the energy classification.

Q13. WILL YOU PLEASE EXPLAIN THE MEDIUM LOAD FACTOR DEMAND AND ENERGY CLASSIFICATION METHOD ON EXHIBIT KDW-1?

A13. The MLF classification is a stratified method, and the classification is different from the HLF classification for items relating to the production cost of power-related items. The power costs (both production and cost of power purchases) were classified based upon the economic loading of the production units and power purchases. The purchase and production resources were ordered or stratified by load factor. The resources that had load factors between 100% and 50% were considered to be base; the resources that had load factors between 50% and 0% were considered peaking. These costs were then classified into "Power Demand" and "Energy." The cost of power and production costs for the higher load factor power resources were classified 100% to energy; the cost of power and production costs for the lower load factor power resources were classified 100% to demand. Additionally, the depreciation and interest associated with the higher load factor resources were classified as energy as well.

The remaining costs were classified in the same manner as the HLF classification.

Q14. WILL YOU PLEASE EXPLAIN THE $17,361,000 SUMMER PEAKING COST USED FOR THE SEASONAL RATE CLASSIFICATION SUMMARIZED ON EXHIBIT KDW-2?

A14. The seasonal peaking cost represents the peaking resources that had energy usage only in the summer and not in the winter. Because Wabash Valley and the region in general is

summer peaking, there are certain peaking resources that, while available to meet load all year, generally are only utilized in the summer. The costs related to demand charges, Fixed O&M, depreciation, and interest related to these summer peaking resources have been identified and included in the $17,361,000 cost. Exhibit KDW-2 summarizes the costs that make up the $17,361,000.

Q15. PLEASE DESCRIBE THE PHASE II HIGH LOAD FACTOR CLASSIFICATION.

A15. The Phase II allocation is the same allocation method as the Phase I HLF classification. It has some changes in the Production O&M, Cost of Power - Members, and Interest Income due to the increase in Production-related and fixed costs and reductions in Purchased Power Costs for the addition of the new generation resources under the Phase II revenue requirements.

GENERATION AND PURCHASED POWER COST ADJUSTMENTS

Q16. CAN YOU PLEASE DESCRIBE THE PRO FORMA INCREASES RELATED TO PRODUCTION AND PURCHASED POWER COSTS?

A16. For the Phase I adjustments, the test year Cost of Power -- Member and Production related costs were adjusted for any known contract changes and new resources that are to occur during the twelve months following the end of the test year, as well as annualization of cost changes that occurred within the test year. These changes included contractual rate changes, as well as changes in contracted quantities. Major changes include the addition of new member load requirements, the inclusion of new owned generation expected to be in service, and changes in contracted power. Because there were numerous contract changes and additional member load requirements, the pro forma

costs for both production fuel and cost of power were estimated with the help of a production costing model.

A limited number of changes were made for the Phase II adjustments to reflect the end of a 100 MW peaking purchase and the addition of the 92 MW of generation assets of Lawrence Peaking Station, Jay County Landfill gas generation, and Liberty Landfill gas generation.

Q17. PLEASE DESCRIBE THE PRODUCTION COSTING MODEL USED TO ESTIMATE THE PHASE I PRODUCTION COSTS.

A17. The MIDAS Gold® model used by Wabash Valley was developed by M.S. Gerber and Associates, Inc. The model provides information on integrated resource planning issues, including interactions between demand and supply-side strategies. Wabash Valley uses the MIDAS Gold® model for all production cost modeling requirements. The model's flexibility allows for either high-level screening or considerable detail and accuracy. The MIDAS Gold® model has been used in electric utility proceedings before other regulatory commissions, including Indiana, Ohio, Illinois, Missouri, Maryland, Iowa, Pennsylvania, Washington, Arizona, Georgia, Florida, and Alabama. Wabash Valley has been a user of the M.S. Gerber's MIDAS production costing model since 1993 and has provided significant interaction with M.S. Gerber to develop and refine the model to meet Wabash Valley's specific modeling requirements.

Q18. WHAT WAS THE OVERALL RESULT OF THE CHANGES IN POWER RESOURCES AND ADDITIONAL MEMBER LOAD FOR PHASE I?

A18. Overall, the changes resulted in a $1,510,000 increase in Production Fuel, a $3,809,000 increase in Production O&M, and an increase of $18,976,000 in Member Related

Purchased Power. The majority of the increase in the cost of power for Members is due to a 10% increase in member sales and the associated purchases to support those.

Q19. WHAT NEW MEMBER LOAD REQUIREMENTS WERE ADDED?

A19. Wabash Valley added three new members in 2003. Corn Belt Energy Corporation and M.J.M. Electric Cooperative, Inc., were members as of January 1, 2003, and EnerStar Power Corp became a member effective March 1, 2003. Consequently, their load is included in only part of the May 2002 through April 2003 test year. As a result of the addition of these members, load requirements were increased by approximately 10% over the test year.

Q20. WHAT IS THE IMPACT OF THE INCLUSION OF NEW OWNED GENERATION?

Q20. In Phase I, Wabash Valley expects to have three new generation projects in service that are included in base rates for this filing. These projects, Vermillion (148 MW summer), Twin Bridges (3.2 MW), and Oak Ridge (3.2 MW), are being developed and acquired in order to meet Wabash Valley member load requirements as a result of both load growth and the replacement of expiring contracts. Since during the test year Wabash Valley had only one major owned generation resource, Gibson Unit 5, the impact of this additional owned generation is a decrease of purchased power costs that are offset by increases of production related costs including fuel, O&M, depreciation, interest and taxes.

Q21. WHAT ARE THE MAJOR CHANGES IN CONTRACTED POWER FOR PHASE I?

A21. The following major contracts are expiring after the test year:

100 MW Peaking purchase from Duke Power

100 MW Base purchase from Duke Power

75 MW Peaking purchase from Cinergy (PSI Energy)

The following major contracts are added or annualized:

100 MW of Base purchased from American Electric Power

50 MW Peaking purchase from American Electric Power

The Cinergy base purchase increases from 50 to 100 MW along with the associated amortizations related to Enron

22 MW purchase from Constellation

Additional network transmission services were purchased for the increased Member load

Additionally, some cost and rate changes are impacting the purchased power costs. These include additional MISO charges stemming from new tariffs and contractual changes in demand and energy charges.

All of these purchased power costs are expected to be reflected in Wabash Valley's PSCR filed annually with the Michigan Commission.

Q22. WHAT ARE THE MAJOR CHANGES IN PRODUCTION AND PURCHASED POWER COSTS FOR PHASE II?

A22. Because most of Wabash Valley's purchased power costs are tracked through the PSCR process, the changes for Phase II focus on the changes in the non-trackable production costs. The Production O&M was adjusted for the additional O&M of the Lawrence peaking station, the two additional landfill gas generating stations, and associated contractual increase in O&M. This is an increase of approximately 92 MW of generation capacity. The purchased power costs were decreased by the demand charge associated with a 100 MW peaking contract that will expire in 2005. No additional adjustments

were made to the Cost of Purchased Power or Production Fuel, since any changes will be tracked through the annual PSCR process. The production cost and purchased power changes for Phase II are an increase of $1,631,000 and decrease of $4,800,000, respectively.

NEW GENERATION NEED AND ECONOMIC EVALUATION

Q23. WHAT ARE THE NEW GENERATION CAPACITY ADDITIONS FOR PHASE I AND PHASE II?

A23. Wabash Valley has the following generation resources for Phase I:

Vermillion Generating Station	148 MW summer rating or 160 nominal rating
Twin Bridges	3.2 MW
Oak Ridge	3.2 MW

Wabash Valley has the following generation resources for Phase II:

Lawrence County	86 MW summer rating
Liberty	3.2 MW
Jay County	3.2 MW

Q24. WHAT ARE THE REASONS WABASH VALLEY IS ADDING THESE GENERATION RESOURCES?

A24. Wabash Valley has a need for these resources to meet member load requirements. All these investments are for additional capacity resources to meet Wabash Valley's expected member load requirements. These additional resources are consistent with the planning objectives approved by Wabash Valley's Board of Directors.

The following table illustrates Wabash Valley's expected member requirements and existing capacity resources, along with these new sources and further additional future needs.

					Additional Resource Needs	
	Member Requirements MW	Existing Resources MW	Phase I Additions MW	Phase II Additions MW	Base MW	Peaking / Seasonal MW
2004	1,533	1,228	154.4	92.4	0	50
2005	1,586	1,232	154.4	92.4	0	100
2006	1,641	1,281	154.4	92.4	0	100
2007	1,699	1,264	154.4	92.4	50	150
2008	1,759	1,124	154.4	92.4	100	300
2009	1,822	1,134	154.4	92.4	150	300
2010	1,885	1,045	154.4	92.4	250	350
2011	1,945	956	154.4	92.4	400	350
2012	2,008	902	154.4	92.4	500	350
2013	2,074	914	154.4	92.4	500	400
2014	2,142	877	154.4	92.4	550	450

Exhibit KDW-3 has a more detailed summary of Wabash Valley's current resource expansion plan.

Q25. HOW DID YOU DETERMINE THE TYPE OF GENERATION NECESSARY?

A25. Based on screening curves developed for Wabash Valley's Integrated Resource Plan submitted in Indiana (April 12, 2003) and attached in Exhibit KDW-4, the break-even point between the combined cycle units and peaking units fell between 20 and 25% capacity factor. Based on its annual load shape, Wabash Valley needs approximately 60 to 65% of its peak in base resources. Any needs above this level would be more economic to supply with peaking resources. Wabash Valley assumes that some of the summer reserves could be supplied by seasonal purchases of power; however, these can

often be nearly as expensive as the purchase of year-round peaking type capacity and is essentially a peaking type requirement.

Q26. HOW DO YOU PLAN TO MEET WABASH VALLEY'S SYSTEM REQUIREMENTS?

A26. Wabash Valley will meet these through a combination of: (a) existing generation and power contracts; (b) load management and distributed generation; and (c) supply resources, both owned by Wabash Valley and market purchases.

Q27. WHAT IS WABASH VALLEY'S GENERAL PROCESS FOR PLANNING FOR GENERATION RESOURCES?

A27. Generally, Wabash Valley has an ongoing planning process. Wabash Valley estimates expected power requirements to meet member load and compares the requirements to existing resources. When there is an additional resource need, Wabash Valley assesses the resources available to meet that need, analyzes the costs of the resources with an integrated corporate financial forecasting model, and makes a decision based on both economics and other risk criteria. Wabash Valley has overall planning goals of flexibility, diversity, and low cost. Any power purchase agreement over one year or an investment in a generation project is approved by the Wabash Valley Board of Directors, consisting of a representative from each member electric cooperative served by Wabash Valley.

VERMILLION GENERATING STATION ASSESSMENT

Q28. WHEN WAS THE DECISION MADE TO PURCHASE THE 25% OWNERSHIP IN THE VERMILLION GENERATING STATION?

A28. Wabash Valley's Board of Directors approved the purchase of the Vermillion Generating Station in June of 2003.

Q29. WHAT ALTERNATIVES WERE CONSIDERED WHEN WABASH VALLEY EVALUATED THE FINANCIAL COSTS OF THE VERMILLION GENERATING STATION UNITS?

A29. Wabash Valley considered a variety of alternatives when it evaluated the purchase of 25% of the Vermillion Generating Station. These included: (a) estimated cost of construction of new generation alternatives; (b) periodic formal and informal requests for proposals for power purchases; and (c) opinion of experts of the value of the Vermillion Generating Station units compared to expected wholesale market prices and other peaking resource alternatives.

Q30. PLEASE DESCRIBE THE COMPARISON TO THE ESTIMATED COST OF CONSTRUCTION OF NEW GENERATION ALTERNATIVES.

A30. Exhibit KDW-5 shows the peaking power resource expansion plan alternatives from Wabash Valley's Indiana Integrated Resource Plan submitted April 12, 2002, along with the proposed Vermillion Generating Station resources. Compared to generic peaking units evaluated for the IRP, the Vermillion units have a lower installed cost and a competitive total operating cost. In addition, these units are already built and operating, and as such, they have no construction cost risk.

It should be noted that this Exhibit shows the installed cost of Vermillion Generating Station units at $350 per kW. This is the cost of the units plus the $8 million contract termination fee, divided by the units' summer rated capacity. The summer rated

capacity was used in order to be consistent with the assumptions for generic combustion-turbine peaking units included in Wabash Valley's Integrated Resource Plan.

Q31. PLEASE DESCRIBE HOW THE VERMILLION GENERATING STATION UNITS COMPARED TO REQUESTS FOR PROPOSALS FOR POWER PURCHASES.

A31. In October 2002, Wabash Valley conducted a formal Request for Proposal (RFP) and received a number of bids for peaking capacity for terms between four and twenty years. Exhibit KDW-6, columns B through O, shows a summary of proposals received, with expected average energy cost calculated at a 10% load factor. These proposals are compared to the expected average energy cost of the Vermillion Generating Station, shown in column P. Note that Wabash Valley assumes an average natural gas price of $5.00 per million Btu (Henry Hub basis) in conducting this comparison.

The proposals described in Columns E and F were subsequently withdrawn by the offering company. Wabash Valley rejected the proposals described in Columns M, N, and O, as these companies could not meet Wabash Valley's credit requirements. Of the remaining proposals, only those described in Columns B and J have a lower expected average energy cost than the Vermillion Generating Station. Wabash Valley rejected the proposal described in Column B for two reasons: first, Wabash Valley already has contracts with the offering company for significant baseload and peaking resources and considers that additional reliance on this company may increase certain operational risks; and second, the offering company revised its offer by significantly reducing the proposed contract term.

The proposal described in Column J is part of Wabash Valley's negotiations to purchase 25% of the Vermillion Generating Station. Along with the purchase of capacity at the Vermillion Generating Station, Wabash Valley will also purchase 100 MW of peaking power supply from the offering company for 2006 through 2014.

Q32. GIVEN THE POTENTIAL ECONOMIC BENEFIT OF PURCHASING UNITS AT THE VERMILLION GENERATING STATION, DID WABASH VALLEY CONSIDER PURCHASING EVEN MORE CAPACITY FROM THAT FACILITY?

A32. Wabash Valley opted to limit its purchase to only 25% of the Vermillion Generating Station, since: (1) Wabash Valley does not need more capacity than the proposed purchase for 2004 and 2005; and (2) purchase of a larger percentage of the Station would adversely affect Wabash Valley's equity ratio.

Q33. WHAT EXPERTS HAVE YOU CONSULTED REGARDING THE VERMILLION GENERATING STATION UNITS?

A33. In May 2003, R. W. Beck completed an analysis of Wabash Valley's proposed purchase of 25% of the Vermillion Generating Station. R. W. Beck's analysis included a calculation of Wabash Valley's estimated power production cost for 2004 through 2023 with alternative scenarios that either included or excluded the Vermillion Generating Station resource. The R. W. Beck model evaluated probabilistic ranges of expected fuel prices, wholesale power market prices, and load. Results of this analysis indicate that purchasing the Vermillion Generating Station resource has a mean net present value of approximately $30 million. Furthermore, the analysis also indicates that the Vermillion Generating Station purchase appears to be robust, in that the total cost in scenarios that

include this resource is lower or approximately the same as in scenarios where this resource is excluded.

LAWRENCE PEAKING STATION ASSESSMENT

Q34. WHEN WAS THE DECISION MADE TO CONSTRUCT TWO LM6000 UNITS AT THE LAWRENCE PEAKING STATION?

A34. Wabash Valley's Board of Directors conditionally approved the purchase of the Lawrence Peaking Station units in September 2002 and confirmed the final decision in November 2002.

Q35. WHAT ALTERNATIVES WERE CONSIDERED WHEN WABASH VALLEY EVALUATED THE FINANCIAL COSTS OF THE LAWRENCE PEAKING STATION?

A35. Wabash Valley considered a variety of alternatives when it evaluated the Lawrence Peaking Station. These included: (a) estimated cost of construction of new generation alternatives; (b) periodic formal and informal requests for proposals for power purchases; (c) relevant market prices; and (d) opinion of experts of the value of the Lawrence Peaking Station alternative.

Q36. PLEASE DESCRIBE THE COMPARISON TO THE ESTIMATED COST OF CONSTRUCTION OF NEW GENERATION ALTERNATIVES.

A36. Exhibit KDW-7 shows the peaking power resource expansion plan alternatives from Wabash Valley's Integrated Resource Plan submitted in Indiana on April 12, 2002, along with the proposed LM6000s for the Lawrence Peaking Station resource. The Lawrence Peaking Station has the lowest installed cost and the lowest fuel cost. The Fixed O&M and Variable O&M costs are slightly higher than the other CT alternatives; however,

when all the costs are evaluated, the Lawrence Peaking Station has the lowest average total cost, at a 20% load factor. The Lawrence Peaking Station was evaluated at a higher capacity factor due to its lower heat rate. Additionally, the natural gas price reflects the prevailing prices during the fall of 2002, when the decision to invest in the Lawrence Peaking Station was made.

Q37. PLEASE DESCRIBE HOW THE LAWRENCE PEAKING STATION COMPARED TO REQUESTS FOR PROPOSALS FOR POWER PURCHASES.

A37. In the spring of 2001, Wabash Valley conducted a formal request for proposal and received a number of bids for peaking capacity for terms between one and fifteen years. Exhibit KDW-8, columns B through H, shows a summary of proposals received at a 20% load factor. In all cases, the Lawrence Peaking Station, on a levelized basis, is expected to be below the total monthly fixed capacity cost and have a better heat rate than the other bids. Additionally, the purchases for longer terms could have exposed Wabash Valley to the risk of substantial margin calls, as well as risks regarding the future creditworthiness of the bidders.

At the time Wabash Valley made the decision to purchase the LM6000s for the Lawrence County Peaking Station, Wabash Valley had spoken on an informal basis with power suppliers and had the opportunity to make a four-year purchase of unit peaking power (summer 2002). This is summarized in column J on Exhibit KDW-8. The all in price of this purchase is also higher than the levelized cost of the Lawrence Peaking Station at a 20% load factor.

Q38. PLEASE DESCRIBE HOW THE LAWRENCE PEAKING STATION COMPARED TO RELEVANT MARKET PRICES.

A38. Exhibit KDW-9 shows an estimated price duration curve for 2006 as a representative year. The information was based on long-run market price forecasts provided by R.W. Beck and the impact of forward market prices at the time the decision was made. The expected variable operating cost of the Lawrence Peaking Station was estimated at $39/MWh. Based on the price duration curve, the Lawrence Peaking Station project would be "in the money" around 30% of the time. The difference between the market price and the variable cost of the unit would be the contribution to fixed costs. For 20% of the hours (limited by NOx emissions), this contribution to fixed costs would be $56,000/MW-year or $4.67/kW-mo, well above the $3.37/kW-mo that was estimated for the Lawrence Peaking Station.

Q39. WHAT EXPERTS WERE CONSULTED REGARDING THE DECISION TO INVEST IN THE LAWRENCE PEAKING STATION?

A39. Wabash Valley contacted people at ACES Power Marketing and R.W. Beck. Those contacted had experience with costs of new CTs, and they indicated that the turbine cost for this Lawrence Peaking Station project was significantly below what they had experienced or reviewed. Additionally, a survey of relevant LM6000 machines posted for sale on the internet did not reveal any LM6000s available for below the price of this project. The project has also been reviewed and issued a Certificate of Need by the IURC.

LANDFILL GAS GENERATING STATION(S)

Q40. WHEN WERE THE DECISIONS MADE TO CONSTRUCT THE LANDFILL GAS GENERATING STATIONS?

A40. Wabash Valley's Board of Directors' decisions to approve the landfill gas generation have been made over the last three years. The approval of the Liberty site is expected during 2005 when negotiations are completed.

Q41. WHAT ALTERNATIVES WERE CONSIDERED WHEN WABASH VALLEY EVALUATED THE FINANCIAL COSTS OF THE WASTE MANAGEMENT LANDFILL GAS FUELED GENERATOR PROJECTS?

A41. Wabash Valley considered a variety of alternatives when it evaluated the landfill gas-fired reciprocating engine-generators. These included: (a) estimated cost of construction of other new generation alternatives; (b) periodic formal and informal requests for proposals for power purchases; and (c) relevant market prices.

Q42. PLEASE DESCRIBE THE COMPARISON TO THE ESTIMATED COST OF CONSTRUCTION OF NEW GENERATION ALTERNATIVES.

A42. Exhibit KDW-10 shows the baseload power resource expansion plan alternatives from Wabash Valley's Integrated Resource Plan filed in Indiana, along with the proposed landfill gas-fired engine-generators (with a additional contingency). The engine-generators have the lowest fuel cost and the lowest average total cost.

Q43. PLEASE DESCRIBE HOW THE LANDFILL GAS GENERATORS COMPARED TO PROPOSALS FOR POWER PURCHASES.

A43. In the spring of 2001, and again in the fall of 2002, Wabash Valley conducted formal requests for proposals and received a number of bids for baseload capacity between 2004 and 2006 for terms from one to twenty years. Exhibit KDW-11 shows a summary of proposals received, with average prices reflecting a 100% load factor. In all cases, the landfill gas-fired engine-generators are expected to have lower average production cost

(expressed as dollars per megawatt-hour) than the other baseload capacity alternatives. Additionally, purchases of baseload capacity for long contract terms may expose Wabash Valley to the risk of substantial margin calls, as well as risks regarding the future creditworthiness of the suppliers.

Q44. PLEASE DESCRIBE HOW THE LANDFILL GAS-FIRED ENGINE-GENERATORS COMPARED TO RELEVANT MARKET PRICES.

A44. Exhibit KDW-12 was prepared from the market price forecast information filed with Wabash Valley's Integrated Resource Plan in Indiana (April 12, 2002) and shows projected annual average market price for around-the-clock power. This projection was based on long-run market price forecasts provided by R.W. Beck and the impact of forward market prices at the time. In each year, the expected annual price for around-the-clock power is above the expected average cost of the landfill gas-fired generating units. As a result, power supplied from these units should be lower cost than purchasing equivalent supply from the wholesale market.

OTHER BENEFITS

Q45. ARE THERE ADDITIONAL BENEFITS OF THE NEW GENERATION RESOURCES FOR MEETING THE NEEDS OF WABASH VALLEY'S MEMBER SYSTEMS?

A45. In addition to providing a low-cost, long-term resource for Wabash Valley's members, all the generation projects provide a number of benefits that are difficult to quantify. Ownership of generation assets enhances Wabash Valley's ability to obtain credit from counterparties when making power purchases. Wabash Valley has developed its power resource plan on a portfolio approach with purchases of varying lengths, ownership vs.

purchase, and fuels. Prior to the addition of these generation resources, Wabash Valley had less than 15% of its capacity in owned resources. Owned capacity provides for greater future cost stability as compared to power purchases made on the market, and there are no requirements for posting collateral with a power supplier as a result of market fluctuations.

A second benefit is that the units will meet current and expected requirements for designated resource and available capacity requirements in the emerging regional transmission organizations.

A third benefit is that Wabash Valley will pool operations and maintenance of the peaking units, the two LM6000 units with Hoosier Energy's four LM6000s at the Lawrence Peaking Station, as well as the operations and maintenance of Wabash Valley's 25% ownership of the Vermillion Generating Station with Duke Energy's remaining 75% ownership. This pooling will mitigate the impact on Wabash Valley of a forced outage of a single unit at the site.

An additional benefit of this pooling arrangement is that Wabash Valley will achieve lower overall operating costs through shared facilities and economies of scale at the peaking sites.

An additional benefit of the LM6000 units at the Lawrence Peaking station is that the units have the ability to start within ten minutes and will meet current and expected requirements for operating reserve.

All of these new generation resources are small, and Wabash Valley has developed agreements for joint operations so that the impact of an outage of any single

unit will impact Wabash Valley less than 20 MW. These generation resources will help Wabash Valley maintain resource reliability in the future.

Q46. WHAT COSTS ARE INCLUDED IN THE INTERIM RATE SURCHARGE?

A46. The interim rate surcharge includes the costs associated with the generation assets that will be in-service by May of 2004. These are the major new projects that are included in Wabash Valley's Phase I revenue requirements. Exhibit KDW-13 shows the costs for the Gibson SCR, Vermillion Generating Station, and the Oak Ridge and Twin Bridges Landfill gas projects. This is a compilation of costs that are included in the Phase I pro forma revenue requirements for depreciation, O&M, interest, taxes, and insurance related to the new assets.

The total company costs associated with these projects are $10,787,000. The total company cost has been allocated to Michigan based on a 12 CP basis, since these costs are primarily fixed in nature. The 12 CP allocation results in $901,000 allocated to Michigan. Dividing by the Michigan Billing Units yields a surcharge of $0.98/kW-Mo.

The PSCR filed for 2004 on September 30, 2003, already incorporates the changes in fuel costs and power purchases associated with these new projects.

Q47. DOES THIS COMPLETE YOUR PREPARED DIRECT TESTIMONY?

A47. Yes, it does.

LAN_A\116488.2

DEMAND AND ENERGY CLASSIFICATION

Michigan Phase I and II

	EXPENSE	Phase I High Load Factor Demand %	Phase I High Load Factor Energy %	Phase I Meduim Load Factor Demand %	Phase I Meduim Load Factor Energy %	Phase II High Load Factor Demand %	Phase II High Load Factor Energy %
1	Production Fuel (majority PSCR Trackable)	0.00%	100.00%	2.84%	97.16%	0.00%	100.00%
2	Production O&M Taxes, Labor	100.00%	0.00%	35.79%	64.21%	100.00%	0.00%
3	Production O&M	80.05%	19.95%	8.29%	91.71%	77.42%	22.58%
4	EMS & Other Production	100.00%	0.00%	100.00%	0.00%	100.00%	0.00%
5	Cost Of Power - Members SDI	0.00%	100.00%	0.00%	100.00%	0.00%	100.00%
6	Cost Of Power - Enerstar Amortization	100.00%	0.00%	0.00%	100.00%	100.00%	0.00%
7	Cost Of Power - Members (PSCR Trackable)	33.26%	66.74%	26.54%	73.46%	31.63%	68.37%
8	Cost Of Power - Non- Members (PSCR Trackable)	0.00%	100.00%	0.00%	100.00%	0.00%	100.00%
9	Production Depreciation	100.00%	0.00%	30.54%	69.46%	100.00%	0.00%
10	Transmission	100.00%	0.00%	100.00%	0.00%	100.00%	0.00%
11	Administration and General	0.00%	100.00%	0.00%	100.00%	0.00%	100.00%
12	Depreciation and Amortization	100.00%	0.00%	100.00%	0.00%	100.00%	0.00%
13	Taxes	100.00%	0.00%	100.00%	0.00%	100.00%	0.00%
14	Interest	100.00%	0.00%	55.72%	44.28%	100.00%	0.00%
15	Interest Income	88.98%	11.02%	52.63%	47.37%	90.83%	9.17%
16	SDI Revenue	0.00%	100.00%	0.00%	100.00%	0.00%	100.00%
17	Other Revenues	100.00%	0.00%	100.00%	0.00%	100.00%	0.00%
18	Non-Member Revenues (PSCR Trackable)	0.00%	100.00%	0.00%	100.00%	0.00%	100.00%

Summer Seasonal Resources

Classification -- Seasonal	Load Factor	Resource	kw	kWh (Purchased)	kWh (Delivered)	Demand rate $/kW-mo	demand $000
Generation Summer	0.2%	Vermillion 2	993,000	1,475,000	1,410,090	0.54	385
Generation Summer	0.8%	Vermillion 1	993,000	5,754,240	5,501,050	0.54	385
					Total Generation $000		**770**

Classification -- Seasonal	Load Factor	Resource	kw	kWh (Purchased)	kWh (Delivered)	Demand rate $/kW-mo	demand $000
Purchase Summer	0.0%	Cornbelt Diesels	108,000	-	-	5.11	92
Purchase Summer	0.0%	NIPS Peaking	1,320,000	-	-	33.00	3,624
Purchase Summer	2.6%	DETM Peaker 1	1,200,000	22,497,110	21,507,230	48.00	4,800
Purchase Summer	0.1%	Cinergy Peaking	600,000	291,250	276,110	55.20	2,760

Total Cost of Power Member $000		**11,276**
Vermillion O&M Taxes and Labor		515
Vermillion Depreciation		1,669
Vermillion Amortization		301
Vermillion Interest		2,830
Total Summer Seasonal Costs $000	**$**	**17,361**

WV Expansion Plan Summary
Summer Peak (Purchased MW)
2004 Budget

WVPA Planning Req'ts

	Original Peak	MJM Demand	Corn Belt Demand	EnerStar Demand	Total Member Demand	Losses	Total Peak	Rsv Req't	Total Req'ts	SDI Demand*
2003	1,171	29	109	17	1,327	57	1,366	116	1,482	100
2004	1,213	30	114	18	1,375	59	1,416	117	1,533	90
2005	1,256	30	119	19	1,424	62	1,467	119	1,586	90
2006	1,301	31	125	20	1,476	64	1,520	121	1,641	90
2007	1,348	31	131	20	1,530	67	1,577	122	1,699	90
2008	1,397	32	137	21	1,586	70	1,635	124	1,759	90
2009	1,449	32	143	22	1,645	72	1,696	126	1,822	90
2010	1,501	32	148	22	1,704	75	1,757	128	1,885	90
2011	1,551	33	154	23	1,761	78	1,816	129	1,945	90
2012	1,602	33	160	23	1,820	80	1,877	131	2,008	90
2013	1,656	34	167	24	1,881	83	1,940	133	2,074	90
2014	1,713	34	173	25	1,945	86	2,007	135	2,142	90

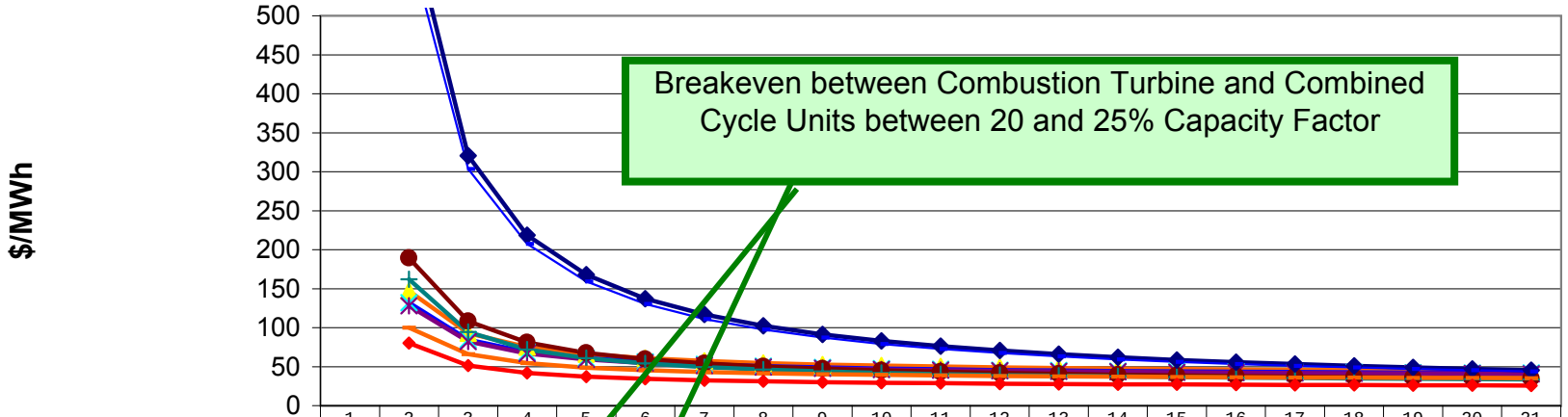
Uses Interim Forecast for Load (6-24-03)

WVPA Resources

	G5*	PSI Firm	CIPS	GM	IP&L & Constellation	Waste Mgmt*	Duke Firm	Global Base	HE	AEP Baseld	Cinergy Baseld	Mirant Baseld	Exelon Baseld	AEP Baseld	Dynergy 5X17	NIPS	Duke Pkng	Cinergy Pkng	Corn Belt Purch	AEP Pkng	Lawerence Peaking	Vermillion Station	Summer Option	DSM & Cust. Pbk	**Contracted Resources**
2003	156	70	65	25	24	9	100	-	232	-	50	-	-	-	-	110	200	50	45	150	-	-	50	65	**1,401**
2004	156	70	65	25	25	17	-	-	235	100	100	-	-	-	50	110	100	50	9	150	-	148	-	65	**1,475**
2005	156	70	65	25	26	20	-	-	249	50	100	50	50	-	-	110	-	50	9	150	86	148	-	65	**1,479**
2006	156	70	65	25	27	19	50	100	258	100	-	-	-	100	-	-	50	50	9	150	86	148	-	65	**1,528**
2007	156	70	65	25	-	19	-	100	268	-	-	-	-	200	-	-	100	50	9	150	86	148	-	65	**1,511**
2008	156	70	65	25	-	19	-	100	278	-	-	-	-	200	-	-	100	50	9	-	86	148	-	65	**1,371**
2009	156	70	65	25	-	19	-	100	288	-	-	-	-	200	-	-	100	50	9	-	86	148	-	65	**1,381**
2010	156	70	65	25	-	19	-	100	299	-	-	-	-	100	-	-	100	50	9	-	86	148	-	65	**1,292**
2011	156	70	65	25	-	19	-	100	310	-	-	-	-	-	-	-	100	50	9	-	86	148	-	65	**1,203**
2012	156	70	-	25	-	19	-	100	321	-	-	-	-	-	-	-	100	50	9	-	86	148	-	65	**1,149**
2013	156	70	-	25	-	19	-	100	333	-	-	-	-	-	-	-	100	50	9	-	86	148	-	65	**1,161**
2014	156	70	-	25	-	19	-	100	346	-	-	-	-	-	-	-	50	50	9	-	86	148	-	65	**1,124**

	Future Resource Needs	**Future Resources** Future Pkng	Future Base	Future Seas	**Total** Total Resources	% Rsvs	**Resource Mix** Baseloac	Peaking
2003	81	-	-	50	1,451	8%	50%	50%
2004	207	-	-	50	1,525	6%	56%	44%
2005	255	-	-	100	1,579	8%	59%	41%
2006	261	-	-	100	1,628	7%	64%	36%
2007	336	50	50	100	1,711	9%	60%	40%
2008	536	200	100	100	1,771	8%	62%	38%
2009	589	200	150	100	1,831	8%	63%	37%
2010	741	250	250	100	1,892	8%	62%	38%
2011	891	250	400	100	1,953	8%	63%	37%
2012	1,007	250	500	100	1,999	7%	63%	37%
2013	1,061	300	500	100	2,061	6%	62%	38%
2014	1,166	350	550	100	2,124	6%	63%	37%

Chart V-2: Wabash Valley Power Association
Integrated Resource Plan - Supply Alternatives
Total Cost in $/MWh by Capacity Factor



	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
Capacity Factors ==>	0.0%	5.0%	10.0%	15.0%	20.0%	25.0%	30.0%	35.0%	40.0%	45.0%	50.0%	55.0%	60.0%	65.0%	70.0%	75.0%	80.0%	85.0%	90.0%	95.0%	100.0
80 MW CT		146.	93.1	75.1	66.1	60.8	57.2	54.6	52.7	51.2	50.0	49.0	48.2	47.5	46.9	46.4	46.0	45.6	45.2	44.9	44.6
115 MW CT		132.	84.5	68.6	60.7	56.0	52.8	50.5	48.8	47.5	46.5	45.6	44.9	44.3	43.7	43.3	42.9	42.5	42.2	42.0	41.7
170 MW CT		128.	82.2	66.8	59.2	54.6	51.5	49.3	47.7	46.4	45.4	44.6	43.9	43.3	42.8	42.3	42.0	41.6	41.3	41.1	40.8
260 MW CC		189.	108.	81.2	67.7	59.6	54.2	50.3	47.4	45.2	43.4	41.9	40.7	39.6	38.7	38.0	37.3	36.7	36.2	35.7	35.3
500 MW CC		162.	94.5	72.0	60.8	54.0	49.5	46.3	43.9	42.0	40.5	39.3	38.3	37.4	36.6	36.0	35.4	34.9	34.5	34.1	33.8
250 MW Coal		626.	320.	218.	167.	137.	116.	102.	91.4	82.9	76.2	70.6	66.0	62.1	58.7	55.8	53.2	51.0	49.0	47.2	45.6
500 MW Coal		592.	303.	207.	159.	130.	111.	97.5	87.2	79.2	72.8	67.5	63.2	59.5	56.3	53.5	51.1	49.0	47.1	45.4	43.9
Coal Gasification 1		99.8	65.8	54.5	48.8	45.4	43.1	41.5	40.3	39.4	38.6	38.0	37.5	37.0	36.7	36.3	36.1	35.8	35.6	35.4	35.2
Coal Gasification 2		80.1	51.5	42.0	37.3	34.4	32.5	31.2	30.1	29.3	28.7	28.2	27.8	27.4	27.1	26.8	26.6	26.4	26.2	26.0	25.9

Expansion Plan Alternatives – Peaking Power Resources --Vermillion Generating Station

Unit	Installed Cost ($/kW)	Fixed O&M Cost ($/kW-year)	Levelized Fixed Cost ($/kW-month)	Fuel Cost (3) ($/MWh)	Variable O&M Cost (4) ($/MWh)	Average Total Cost(5) ($/MWh)
80-MW CT(1)	442	4.43	**4.14**	36.74	2.57	**96.02**
115-MW CT(1)	393	3.69	**3.66**	34.45	2.57	**87.16**
170-MW CT(1)	385	3.08	**3.54**	33.21	3.08	**84.78**
Vermillion Co. CT (2)	**350**	**6.72**	**3.54**	**36.72**	**0.00**	**85.21**

(1) Cost data in 2001 dollars: WVPA 2001 Integrated Resource Plan Oct 30,2001(Revised April 12, 2002)
(2) Cost data in 2004 dollars. Vermillion Co. CT units installed cost is $350/kW based on summer capacity rating.
(3) Fuel estimated at $3/mmBTU, excluding unit start-up costs.
(4) All operating and maintenance costs for the Vermillion Co. CT units are included as fixed O&M cost.
(5) Average Total Cost based on a load factor of 10%

Levelized Fixed Charge

$$LFCR = r + A + P + d + [T / (1 - T) * (r - d - Dep) * ((r - b * L) / r)]$$

where

Cost of Capital	r		7.69%	
Property Tax rate	A		1.36%	
Property Insurance	P		0.25%	
Federal & state income	T		0.00%	
sinking fund Depreciati	d		0.93%	d = (r/(1+r)^n-1)
Life of unit	n		30	
Tax Depreciation	Dep	NA		(Only applicable if T>0)
Intrest rate on debt cap	b	NA		(Only applicable if T>0)
Debt Ratio	L	NA		(Only applicable if T>0)

LFCR = 10.23%

Responses to WVPA's Request for Peaking Proposal (October 15, 2002) **Responses to '**

COLUMN	B	C	D	E	F	G	H	I	J
Company	**Company 1**	**Company 2 (Station 1)**	**Company 2 (Station 2)**	**Company 3 (option 1) (Revised)**	**Company 3 (option 2)**	**Company 4**	**Company 5**	**Company 6**	**Company 7 (Revised)**
Type	Peaking Unit Contingent	Peaking Unit Contingent	Peaking Unit Contingent	Firm Peaking	Firm Peaking	Firm Peaking	Peaking Unit Contingent	Peaking Unit Contingent	Peaking Unit Contingent
Contract Start	06/01/2006	01/01/2006	01/01/2006	01/01/2006	1//1/2006	06/01/2006	06/01/2006	01/01/2006	06/01/2006
Term (yrs)	11	10	10	10	20	10	10	10	10
Amount (MW)	100	100	100	200	200	100	75	150	100
Pricing Detail									
Capacity ($/kW-month)	$4.20	$5.50	$5.50	$2.95	$4.20	$4.50	$3.92	$3.95	$2.95
Gas Index (if applicable)	Mich-Micon plus $0.062 plus 1.35% losses	TETCO M3 plus $0.05	Dominion South plus 2.28% plus $0.10	Henry Hub plus Appalachian basis	Henry Hub plus Appalachian basis	Henry Hub plus $0.50	Panhandle Eastern plus 4.09% plus $0.50	Dominion South plus 0.6% plus $0.14	Panhandle Eastern plus 4.53% plus $0.25
Heat Rate (if applicable)	10,900	9,000	9,000	12,500	11,000	11,000	12,200	11,000	12,500
Variable O&M ($/MWh)	$2.50	$2.00	$2.00	$0.00	$3.50	$3.00	$0.50	$1.25	$0.00
Startup ($/start)	$50/MW	$2,000	$2,000	$50/MW	$50/MW	$0	$2,200	$2,000	$50/MW
Escalation Components		Capacity, Var. O&M, Start-up Cost	Capacity, Var. O&M, Start-up Cost	Start-up Cost		Var. O&M	Capacity, Var. O&M, Start-up Cost	Var. O&M, Start-up Cost	Start-up Cost
Escalation Rate		Per Annual CPI	Per Annual CPI	1.00%		Per Annual CPI	Per Annual CPI	2.75%	1.5%, starting in 2004
First Year Energy ($/MWh)	$50.60	$61.29	$52.15	$43.64		$63.50	$69.41	$61.29	$69.22
Average Energy Cost ($/MWh)									
First Contract Year	**$108.14**	**$127.77**	**$127.49**	**$84.05**	**$104.67**	**$125.14**	**$123.06**	**$115.40**	**$109.68**
Last Contract Year	**$108.14**	**$148.19**	**$147.92**	**$84.34**	**$105.87**	**$125.92**	**$140.58**	**$115.98**	**$110.09**
Levelized (at 7.5%)	**$108.14**	**$136.29**	**$136.02**	**$84.18**	**$105.58**	**$125.47**	**$131.12**	**$115.64**	**$109.83**
Scheduling Flexibility	Day Ahead (by 10:00 a.m.)	Hour Ahead	Hour Ahead	Day Ahead	Day Ahead	Day Ahead (by 9:30 a.m.)	Day Ahead	Day Ahead (by 8:00 a.m.)	Day Ahead (by 9:15 a.m.)
Delivery Control Area	AEP - PJM West	AEP - PJM West	AEP - PJM West	MISO (Cinergy)	MISO (Cinergy)	AEP - PJM West	MISO	MISO	MISO (Cinergy)
Notes:	Min. 8 hours in Summer, 4 hours in other months.	Min. 4 hour run time Max. of 150 starts	Min. 4 hour run time Max. of 150 starts	Min. 16 hour run time	Min. 16 hour run time	Min. 6 hour run time Max. 1000 operating hours per year.	Capacity charge increases to $4.33/kW-mo. in 2008, then esc. at annual CPI.	Min. 4 hour run time	Schedule min. 25 MW for 11 hours.
	No more than 2,000 hours per year.	Heat rate adjusted for annual 0.5% degradation	Heat rate adjusted for annual 0.5% degradation						
	Peakers may also fire on oil if natural gas not available.						Capacity charge is $47/kW-year for 6/06 - 5/08, then $52/kW-year with 2.5% esc.		

WVPA's Request for Peaking Proposal (October 15, 2002)

COLUMN	K	L	M	N	O	P
Company	**Company 8**	**Company 9**	**Company 10**	**Company 11 (Offer 5)**	**Company 11 (Offer 6)**	**Vermillion Generating Station**
Type	Daily Peaking Call	Heat Rate Call Option	Peaking Unit Contingent	Firm Peaking (1x24 Must Take)	Firm Peaking (1x16 Must Take)	Ownership
Contract Start	01/01/2006	06/01/2006	01/01/2006	01/01/2006	01/01/2006	04/01/2004
Term (yrs)	4	11	10	10	10	30
Amount (MW)	50 or 100	200	225	200	200	148
Pricing Detail						
Capacity ($/kW-month)	$3.50	$5.67	$3.10	$4.14	$4.77	$3.50
Gas Index (if applicable)	Actual gas cost	TETCO M3 plus $0.15	Buyer supplies gas. Nearest hub is Columbia Gas (citygate), per ACES PM.	Henry Hub plus transmission	Henry Hub plus transmission	Panhandle Eastern plus 4.53% plus $0.25
Heat Rate (if applicable)	15,000	7,672	12,200	10,000	10,000	12,000
Variable O&M ($/MWh)	$3.00	$2.90	$1.25 plus LDC charges ($0.0536)	$0.00	$0.00	$6.25
Startup ($/start)	$0	$8,000	$2,000 per 75 MW block	$0	$0	$0
Escalation Components			Var. O&M, Start-up Cost			
Escalation Rate			2.50%			
First Year Energy ($/MWh)	$84.87	$48.09	$69.47	$54.50	$54.50	$61.92
Average Energy Cost ($/MWh)						
First Contract Year	**$132.82**	**$125.76**	**$111.93**	**$111.18**	**$119.85**	**$109.86**
Last Contract Year	**$132.82**	**$125.76**	**$112.67**	**$111.18**	**$119.85**	**$111.10**
Levelized (at 7.5%)	**$132.82**	**$125.76**	**$112.24**	**$111.18**	**$119.85**	**$110.18**
Scheduling Flexibility	Day Ahead (by 8:00 a.m.)	Day Ahead (by 10:00 a.m.)	Non-binding Day Ahead / Binding Hour Ahead	Day Ahead (by 8:00 a.m.)	Day Ahead (by 8:00 a.m.)	Owned
Delivery Control Area		AEP - PJM West	PJM West	MISO	MISO	MISO
Notes:		Min. 8 hour run time				
		No more than 285 calls per year.				

Expansion Plan Alternatives – Peaking Power Resources - Lawrence Peaking Station

Unit	Installed Cost ($/kW)	Fixed O&M Cost ($/kW-year)	Levelized Fixed Cost ($/kW-month)	Fuel Cost [3] ($/MWh)	Variable O&M Cost ($/MWh)	Average Total Cost[4] ($/MWh)
80-MW CT[1]	442	4.43	**4.14**	36.74	2.57	**67.67**
115-MW CT[1]	393	3.69	**3.66**	34.45	2.57	**62.09**
170-MW CT[1]	385	3.08	**3.54**	33.21	3.08	**60.54**
LM6000 CT [2]	**350**	**4.65**	**3.37**	**30.29**	**3.50**	**56.87**

[1] Cost data in 2001 dollars: WVPA 2001 Integrated Resource Plan Oct 30,2001(Revised April 12, 2002)
[2] Excluding IDC
[3] Fuel estimated at $3/mmBTU
[4] Average Total Cost load factor= 20%

Levelized Fixed Charge

LFCR = r + A + P +d+ [T / (1 - T) * (r - d - Dep) * ((r - b * L) / r)]

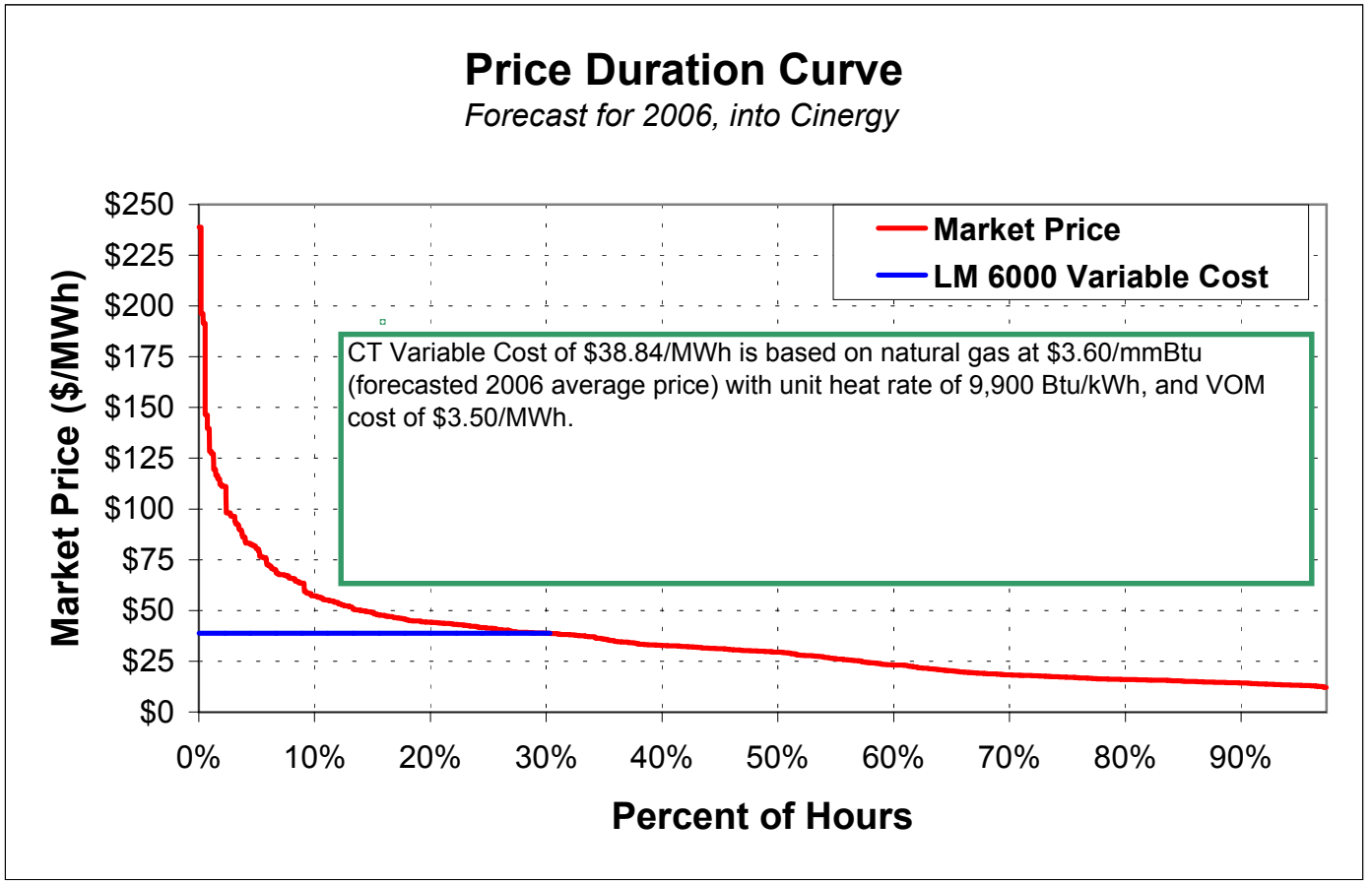
where

Cost of Capital	r		7.69%	
Property Tax rate	A		1.36%	
Property Insurance	P		0.25%	
Federal & state income	T		0.00%	
sinking fund Depreciatio	d		0.93%	d = (r/(1+r)^n-1)
Life of unit	n		30	
Tax Depreciation	Dep	NA		(Only applicable if T>0)
Intrest rate on debt capi	b	NA		(Only applicable if T>0)
Debt Ratio	L	NA		(Only applicable if T>0)

LFCR = 10.23%

Comparison of Peaking Power Supply Alternatives
Lawrence Peaking Station

A	B	C	D	E	F	G	H	I	J
Vintage	Apr-01	Apr-01	Apr-01	Apr-01	Apr-01	Apr-01	Apr-01	Aug-02	Aug-02
Company	**Company 1**	**Company 2 (Product 1)**	**Company 3 (Product 2)**	**Company 4 (Proposal 3)**	**Company 5**	**Company 6 (Proposal "A")**	**Company 6 (Proposal "D")**	**LM 6000**	**Company 7**
Type	Peaking Unit Contingent	Peaking Unit Contingent	Peaking Unit Contingent	Peaking Unit Contingent	Peaking System Firm	Peaking Unit Contingent	Peaking Unit Contingent	Peaking Unit Contingent	Peaking Unit Contingent
Contract Start	01/01/2004	06/01/2004	06/01/2004	01/01/2004	06/01/2004	01/01/2004	01/01/2004	06/01/2004	06/01/2005
Term (yrs)	12	5	10	15	1	5	5	Life of Unit	4
Amount (MW)	Up to 127	50 up to 250	50 up to 250	150	50	Up to 140	Up to 140	86	100
Pricing Detail									
Capacity ($/kW-month)	$5.00	$5.75	$5.60	$4.00	$4.45	$5.42	$5.42	$3.37	$3.75
Energy ($/MWh)	$41.39	$40.48	$40.48	$39.10	$40.40	$55.00	$44.90	$38.15	$39.46
Gas Index (if applicable)	Chicago LDC plus $0.25	Henry Hub plus $0.45	Henry Hub plus $0.45	Henry Hub	Dominion South Point		Michcon plus $0.20	Plus $0.27 for Firm Trans	Chicago Citygate plus 0.07
Heat Rate (if applicable)	11,750	10,880	10,880	10,900	11,000		12,000	9,900	11,500
Variable O&M ($/MWh)	$3.20	$2.94	$2.94		$3.00		$3.50	$3.50	$3.00
Startup ($/start)	$1,500	$2,000	$2,000	$9,650	$2,000				
Average Energy Cost ($/MWh) at 20% Load Factor	$77.52	$79.86	$78.83	$70.54	$73.39	$92.10	$82.00	$58.63	$65.14
Interruptible Hours per Year	-	-	-	-	-	-	-	-	-
Scheduling Flexibility	Day Ahead	Day Ahead	Day Ahead	Intra-day, depending on fuel availability	Day Ahead	Day Ahead, min. 8 hrs	Day Ahead, min. 8 hrs	10 Min Start	Intra day changes
Delivery Control Area	Cinergy	AEP	AEP	AEP	Cinergy	Seller's choice of AEP, NIPSCo, or Cinergy	Seller's choice of AEP, NIPSCo, or Cinergy	Hoosier/ Midwest ISO	Cinergy
Notes:	Max. 900 operating hours per year.	Max. 1500 operating hours per year.	Max. 1500 operating hours per year.	Capacity rate esc. at CPI.	Max. 1500 operating hours per year.			2 units - 43 MW each	2 units - 50 MW each
	VOM escalates at 3% per year	VOM escalates at PPI w/ 3% per year cap.	VOM escalates at PPI w/ 3% per year cap.				Var. O&M esc. 3% per year.	Owned Operating Cost	
		70 free unit starts per year	70 free unit starts per year					Fixed Capacity rate is levelized over 30 year life of unit	


Price Duration Curve
Forecast for 2006, into Cinergy
Market Price
LM 6000 Variable Cost
CT Variable Cost of $38.84/MWh is based on natural gas at $3.60/mmBtu (forecasted 2006 average price) with unit heat rate of 9,900 Btu/kWh, and VOM cost of $3.50/MWh.
Market Price ($/MWh)
$250
$225
$200
$175
$150
$125
$100
$75
$50
$25
$0
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
Percent of Hours

Expansion Plan Alternatives – Baseload Power Resources -- Landfill Gas Genarating Stations

Unit	Installed Cost ($/kW)	Fixed O&M Cost ($/kW-year)	Fuel Cost (3) ($/MWh)	Variable O&M Cost ($/MWh)	Average Total Cost(4) ($/MWh)
260-MW CC(1)	646	8.62	24.79	2.42	**33.36**
500-MW CC(1)	539	7.18	24.75	2.31	**34.68**
250-MW Coal(1)	1590	43.91	12.05	3.08	**37.69**
500-MW Coal(1)	1590	28.73	12.05	3.08	**35.96**
Landfill Gas Engin-Generators (2)	**1156**	**0.00**	**5.00**	**10.00**	**29.58**

(1) Cost data in 2001 dollars: WVPA 2001 Integrated Resource Plan Oct 30,2001(Revised April 12, 2002)
(2) Excluding IDC
(3) Combined Cycle unit fuel estimated at $3.50/mmBTU
(4) Average Total Cost load factor= 100%

Levelized Fixed Charge - 20 Years

LFCR = r + A + P +d+ [T / (1 - T) * (r - d - Dep) * ((r - b * L) / r)]

where

Cost of Capital	r		7.00%		
Property Tax rate	A		1.36%		
Property Insurance	P		0.25%		
Federal & state income tax rate	T		0.00%		
sinking fund Depreciation rate	d		2.44%	d =	(r/(1+r)^n-1)
Life of unit	n		20		
Tax Depreciation	Dep	NA		(Only applicable if T>0)	
Intrest rate on debt capital	b	NA		(Only applicable if T>0)	
Debt Ratio	L	NA		(Only applicable if T>0)	

LFCR = 11.05%

Levelized Fixed Charge - 30 Years

LFCR = r + A + P +d+ [T / (1 - T) * (r - d - Dep) * ((r - b * L) / r)]

where

Cost of Capital	r		7.00%		
Property Tax rate	A		1.36%		
Property Insurance	P		0.25%		
Federal & state income tax rate	T		0.00%		
sinking fund Depreciation rate	d		1.06%	d =	(r/(1+r)^n-1)
Life of unit	n		30		
Tax Depreciation	Dep	NA		(Only applicable if T>0)	
Intrest rate on debt capital	b	NA		(Only applicable if T>0)	
Debt Ratio	L	NA		(Only applicable if T>0)	

LFCR = 9.67%

Wabash Valley Power Association
Requests for Proposal - Baseload Power Supply
Summary of RFP Responses

	March 2001	October 2002
Number of Responses	17	22
Proposed Start of Supply	2004	2006
Proposed Contract Term	2 to 20 Years	5 to 20 Years
Indicative Average Prices ($/MWh)		
High	$47.0	$42.4
Low	$33.2	$31.1
Median	$35.0	$34.9

Annual Average Market Price ($/MWh)

Year	($/MWh)
2003	$32.66
2004	$32.18
2005	$46.97
2006	$47.65
2007	$49.20
2008	$51.31
2009	$52.33
2010	$54.64
2011	$56.60
2012	$58.64
2013	$60.18
2014	$61.74
2015	$63.34
2016	$64.97
2017	$66.67
2018	$68.41
2019	$70.18
2020	$72.01

Michigan Phase I Interim Rate Surcharge
Costs for Surcharge

	Investment		Depreciation	Depreciation and Amort	0&M		Interest		Taxes		Insurance	Total Interim Cost
	$000		Rate	$000	$000		$000		$000		$000	$000
Gibson SCR	33,000		2.6%	858	167	(4)	2,286	(5)	-	(2)	50	3,361
Vermillion	44,400		3.8%	1,669	814		2,830		155		360	5,828
Amort	8,000		3.8%	301			-		-		-	301
Oak Ridge	3,500		5.9%	205	252		236		34		20	747
Twin Bridges	3,075	(1)	5.9%	180	252		98		-	(3)	20	550
Total Interim	$ 91,975			$ 3,213	$ 1,485		$ 5,450		$ 189		$ 450	$ 10,787

(1) 4 Twin Bridges Units. 3 were installed and in service prior to test year.
(2) Pollution contol equipment had tax abatement
(3) Tax abatement at Twin Bridges Site
(4) WV 25% share of $392,000 SCR O&M plus A&G loadings Included in Gibson 5 Total O&M
(5) Interest Including CTC interest and interest income.

Michigan Phase I Interim Rate Surcharge
Wabash Valley Power Association, Inc.

Line	(1) Item	(2) Units	(3) Total	(4) Illinois & Indiana	(5) Michigan	(6) Industrial 1	(7) EDR - 4
(1)	Coin. Demand (CD)(b)	kW-month	11,926,124 [(a)]	10,476,753	996,502	421,962	30,907
(2)		%	100%	87.85%	8.36%	3.54%	0.26%
(3)							
(4)	Costs for Interim Rate	$000	$ 10,787	9,476	901	382	28
(5)							
(6)	Michigan Billing Units	kW-month			922,292		
(7)							
(8)	**Interim Rate Adder**	**$/kW-month**			**0.977**		

Note
a Demand excludes SDI Steel mill - New power resources will not be utilized by the steel mill per pass through contract
b Source Exhibit DJH-5 Page 2 of 5