COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

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APR 2 2 2005
PUBLIC SERVICE COMMISSION

In the Matter of:

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| JOINT APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AND A SITE COMPATIBILITY CERTIFICATE FOR THE EXPANSION OF THE TRIMBLE COUNTY GENERATING STATEION | ) | Case No. 2004-00507 |

NOTICE OF FILING AND CERTIFICATION OF SERVICE

I hereby give notice that I have filed the original and ten true copies of the Direct Testimony of David Brown Kinloch with the Executive Director of the Kentucky Public Service Commission at 211 Sower Boulevard, Frankfort, Kentucky, 40601 this the 22nd day of April, 2005, and certify that this same day I have served the parties and all others shown on the service list by mailing a true copy, postage prepaid, to the following:

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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PUBLIC SERVICE
COMMISSION

CASE NO. 2004-00507

# TRIMBLE COUNTY 2 CERTIFICATE
# LOUISVILLE GAS AND ELECTRIC COMPANY
# KENTUCKY UTILITIES COMPANY

TESTIMONY OF

DAVID H. BROWN KINLOCH

On Behalf of

THE OFFICE OF THE ATTORNEY GENERAL
FOR THE COMMONWEALTH OF KENTUCKY

APRIL 2005

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COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

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In the Matter of:

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| JOINT APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY, AND A SITE COMPATIBILITY CERTIFICATE, FOR THE EXPANSION OF THE TRIMBLE COUNTY GENERATING STATION | ) CASE NO. 2004-00507 |

TESTIMONY OF DAVID H. BROWN KINLOCH

Q1: PLEASE STATE YOUR NAME AND ADDRESS.

A1: My name is David H. Brown Kinloch and my business address is Soft Energy Associates, 414 S. Wenzel Street, Louisville, KY 40204.

Q2: FOR WHOM HAVE YOU PREPARED TESTIMONY?

A2: I have prepared this testimony for the Office of the Attorney General for the Commonwealth of Kentucky.

Q3: PLEASE STATE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A3: I have received two master's degrees from Rensselaer Polytechnic Institute (RPI) in Troy, New York. I also received two undergraduate degrees from the same school. My master's degrees are a Master of Engineering in Mechanical Engineering and a Master of Science in Science, Technology and Values, received in 1979 and 1981 respectively. My undergraduate degrees are in Mechanical Engineering and Philosophy. Much of my master's work included preparing Electric Generation Planning studies for the Center for Technology Assessment at Rensselaer. From this work I published two technical papers with IEEE Power Generation Division, and was a contributing author on two others. I also did work on New York State's first Energy Masterplan, one of the first comprehensive long-term planning studies in the nation.

Q4: HAVE YOU PREVIOUSLY PRESENTED TESTIMONY BEFORE THIS COMMISSION?

A4: Yes, I testified in the following rate cases: Louisville Gas & Electric Co. Case No. 2003-00433, Case No. 2000-00080, Case No. 90-158, Case No. 10064, and Case No. 9824; Kentucky Utilities Co. Case No. 2003-00434, Kentucky Power Co. Case No. 91-066; Union Light Heat and Power Co. Case No. 92-346 and Case No. 91-370; Big Rivers Electric Corp. Case No. 9613 and Case No. 97-204; Delta Natural Gas Co. Case No. 97-066 and Case No. 2004-00067; Western Kentucky Gas Co. 95-010; East Kentucky Power Cooperative Case No. 94-336; Clark RECC Case No. 92-219; Jackson Purchase ECC Case No. 97-224; Meade County RECC Case No. 97-209; Green River EC Case No. 97-219, Henderson

Union ECC Case No. 97-220, Kenergy Corp. Case No. 2003-00165 and Licking Valley RECC Case No. 98-321. I also presented testimony in cases involving each of East Kentucky Power's Cooperatives in the pass-through of rate reductions associated with Case No. 94-336. I also testified in the Commission's reviews of LG&E's Trimble County power plant, Case No. 9934 and Case No. 9242, and the rate impact of the 25% disallowance of that project, Case No. 10320. In addition, I presented testimony in the Certificate of Convenience and Necessity cases for Kentucky Utilities, Case No. 91-115, LG&E and KU, Case No. 2002-00029, and East Kentucky Power, Case No. 92-112, Case No. 2000-056, Case No. 2000-079, Case No. 2001-053 and Case No. 2003-030. I have also testified in Fuel Adjustment Clause cases involving Louisville Gas and Electric, Case No. 96-524, and Kentucky Utilities, Case No. 96-523; and in Environmental Surcharge cases involving Kentucky Power, Case No. 96-489; Kentucky Utilities, Case No. 93-465; and Louisville Gas and Electric, Case No. 94-332. Other cases in which I presented testimony include the Kentucky Utilities' Coal Litigation Refund case, Case No. 93-113; the Big Rivers' sale of peaking capacity to Hoosier Energy case, Case No. 93-163; the Joint Application case with LG&E to establish Demand Side Management programs, Case No. 93-150; and the Louisville Gas and Electric and Kentucky Utilities merger case, Case No. 97-300, the LG&E Energy and PowerGen merger case, Case No. 2000-095; a Union Light, Heat and Power refund case, Case No. 2000-426: and the Union Light, Heat and Power generation acquisition case, Case No. 2003-0052.

Q5: WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS CASE?

A5: The Office of the Attorney General asked me to review the application of Louisville Gas and Electric Company and Kentucky Utilities Company (jointly the Companies) to build a 750 MW coal-fired Trimble County 2 unit, of which the joint applicants will own 75% of the capacity. The application calls for the unit to be built and on-line in 2010. The application includes a load forecast that purports to demonstrate the need for new capacity and an evaluation of baseload options submitted in support of the option presented in the application.

In my testimony I will examine: 1) whether the proposed schedule of adding new capacity by 2010 is appropriate; 2) if the Companies next capacity addition should be baseload capacity; and 3) whether Trimble County 2 is the best option to meet the Companies' capacity needs.

## SCHEDULE TO ADD NEW CAPACITY BY 2010

Q6: THE COMPANIES HAVE PROPOSED TO ADD NEW CAPACITY THAT WILL COME ON-LINE IN 2010. DO YOU BELIEVE THE COMPANIES NEED ADDITIONAL GENERATING CAPACITY BY 2010?

A6: No. On page 5 of his testimony, Mr. Sinclair acknowledges that the actual combined system peak has declined in the last two years. Even with weather normalization, the 2004 peak load declined, despite the fact that Mr. Sinclair had forecasted the peak to grow last year. Mr. Sinclair correctly states, "One year does not make a trend." My concern is not the single year of 2004, but that the 2004 peak load is the continuation of a trend of stagnant growth that the companies have experienced in recent years. Over the last 5 years, from 1999 to 2004, the combined weather normalized system peak load has only grown by 44 MW, from 6,318 MW in 1999 to 6,362 MW in 2004. In other words, over a period of the most recent 5 years, total system load growth has been less than 1% over the entire period, or about 0.14% per year over this period. For all practical purpose, the Companies have experienced no load growth for the last 5 years. While one year does not make a trend, five years of no growth is trend that should be of concern to both the Companies and the Commission, especially when a major new proposed plant's justification is based upon robust load growth.

Q7: HAVE THE COMPANIES INCLUDED THIS NO LOAD GROWTH TREND IN THEIR LOAD FORECASTS?

A7: This trend has been incorporated on a very limited basis. As growth targets have continued to be missed, despite the Companies' continued projection of robust growth of 2% per year by the load forecasts, the starting point when growth is forecast to resume has continued to be moved back during the no growth period. Exhibit DHBK-1 plots both the historic weather normalized peak loads, and the Companies last three load forecasts. This graph shows that as growth projections have failed to materialize, the Companies have simply shifted similar forecasts to a new starting point where growth is supposed to resume again.

Q8: DOES THE LOAD FORECAST FILED IN THIS CASE HAVE THE SAME PROBLEM OF FAILING TO REFLECT THE PRESENT NO GROWTH TREND?

A8: Yes. While Mr. Sinclair attempted to include this present trend by using the 2003 combined system peak as a starting point, the reality of this no growth trend has already caught up with this latest forecast. This forecast was completed in January 2004. It is likely that the Companies made a decision to pursue new baseload capacity at that time, based on this forecast. Since January 2004, the Companies have experienced yet another summer peak period with no growth, continuing the no growth trend. As a result, the load forecast that this case is based upon is already about 170 MW above the weather normalized joint system peak load experienced in 2004. Of more concern than the 170 MW over-projection is the fact that the no growth trend has continued while the Companies believe the trend has ended. In this case, the Companies have failed to provide evidence that the no growth trend is ending and a period of new growth has begun.

Q9: RECOGNIZING THIS 170 MW SHORTFALL IN THE COMPANIES' LOAD FORECAST, DO YOU BELIEVE THAT THE COMPANIES WILL NEED ADDITIONAL CAPACITY IN 2010?

A9: No. On page 6 of Mr. Malloy's Exhibit JPM-1, the Resource Assessment Report, Table 2, titled "Capacity Needs for Reserve Margin Range," is provided. This table projects the reserve margin range based on existing generating capacity and the load forecast. In Exhibit DHBK-2, I have the same Table 2, except I have inserted the actual weather normalized peak load experienced on the Companies' system in 2004, adjusted for interruptible and curtailable loads. From this experienced 2004 starting point, I have grown the peak loads for future years by the growth rates contained in Mr. Sinclair's Exhibit DSS-1.

The Commission should note that using the actual weather normalized peak load experienced in 2004, Exhibit DHBK-2 shows that the Company currently has a reserve margin of about 30%, well above target reserve margin range of 13% to 15%. Current generating capacity is over 1,000 MW greater than the mid-point of the target reserve margin range. Thus the Companies will have to experience significant growth simply to bring excess capacity back toward the reserve margin range.

Q10: ARE THERE ANY OTHER CHANGES THAT NEED TO BE MADE TO THIS RESERVE MARGIN PROJECTION TABLE?

A10: Yes. In response to the Commission's First Data Request, Question 2, Mr. Malloy states that the Companies are using a new reserve margin range, as a result of calculations done in preparing the Companies' 2005 Integrated Resource Plan. The Companies' new Reserve Margin Range is 12% - 14%. In Exhibit DHBK-3, I have added this new Reserve Margin Range to Table 2.

The result of using the experienced weather normalized 2004 peak load as a starting point and the Companies' new Reserve Margin Range, shows that there is no need for new capacity by the Companies until 2012, two years later than stated in the application. This change in when new capacity is needed is not a result of any errors in the Companies' application, but simply a result of updating the inputs provided by the Companies, applied to the same calculations. It should be noted that this revised calculation still assumes that the Companies' no growth trend of the last five years will end immediately, and growth will resume at the rates projected in Mr. Sinclair's testimony.

Q11: YOU HAVE SHOWN THAT NEW CAPACITY IS NOT NEEDED UNTIL AT LAST TWO YEARS LATER THAN THE COMPANIES PROPOSE. WHAT IS THE HARM OF LETTING THE COMPANIES PROCEED WITH THE SCHEDULE THEY HAVE PROPOSED, SO THAT THE NEW CAPACITY WILL BE AVAILABLE A FEW YEARS BEFORE IT IS ACTUALLY NEEDED?

A11: There are both financial costs and benefits associated with having excess capacity. When the excess capacity is peaking capacity, which is low cost to build, the extra cost to customers is not that much. This really becomes a concern when the excess capacity is expensive-to-build baseload units. The Trimble County 2 unit, proposed in this case, is a baseload unit.

While there are costs associated with excess baseload capacity, there are potential benefits that can offset at least part of these costs. Excess baseload capacity can reduce the runtimes of more expensive to operate peaking units. Excess baseload capacity not used to reduce on-system fuel costs can be sold off-system. The difference between these two uses of excess baseload capacity is that reductions in on-system fuel costs benefit ratepayers, while additional off-system revenues benefit shareholders instead.

To examine the cost to ratepayers of adding new baseload capacity before it is needed, the annual cost of the new capacity should be reduced by savings in fuel costs provided by the new capacity. Additional revenues that could be generated through off-system sales from this new capacity should not be included, since these sales do not benefit ratepayers.

I have made this calculation for Trimble County 2 being added two years early, in 2010 instead of 2012, in Exhibit DHBK-4. The fixed costs associated with Trimble County 2 for years 2010 and 2011 are the sum of Return on Capital, Depreciation, and Fixed O&M Costs. The savings associated with reduced variable costs are calculated by taking the variable costs from the Companies' Net Present Value analysis scenario with no baseload capacity added (Case 9) and subtracting the variable costs associated with the scenario of adding Trimble County 2 in 2010 (Case 1 or Case 5).

The net cost of adding Trimble County 2 before it is needed (annual fixed costs minus variable cost savings), is nearly $100 million in 2010 and over $72 million in 2011, for a total two year net cost of over $172 million. Since the extra cost to ratepayers of adding new baseload capacity before it is needed is so high, it is critical that the Commission refuse to allow the Companies to proceed with new capacity until it is clearly demonstrated that there is an immediate need for the capacity.

Q12: IF THE COMMISSION WERE TO ALLOW THE COMPANIES TO PROCEED WITH THE TRIMBLE COUNTY 2 PROJECT ON THE SCHEDULE PROPOSED BY THE COMPANIES, AND THE LOAD FAILED TO MATERIALIZE, WOULD RATEPAYERS BE HARMED IF CONSTRUCTION WAS SLOWED DOWN OR DELAYED UNTIL THE NEED DEVELOPED?

A12: Yes. The Commission need only look back to Trimble County 1 to see the implications of delaying construction of a major new power plant. If the Commission were to allow Construction Work In Progress (CWIP) for Trimble County 2, as it did for Trimble County 1 and has been proposed by the Companies for this new unit, ratepayers would pay a substantial cost during a construction delay. If the Companies are allowed to receive a return on a partially built plant, during a delay ratepayers would continue to pay extra in their rates and receive nothing in return. The exact extra cost to ratepayers during a delay would depend on the amount of CWIP in rates at the time of the delay, and the length of the delay. Trimble County 1 taught us the important lesson that construction of new expensive baseload capacity should not be allowed to proceed until the need for that new capacity is clearly demonstrated.

The extra cost to ratepayers is high if excess capacity is allowed to be built before it is needed, regardless of whether the capacity is completed before it is needed or whether construction starts and is delayed until the need develops.

NEED FOR NEW BASELOAD CAPACITY

Q13: THE COMPANIES HAVE CONCLUDED THAT THE NEXT ADDITION OF NEW GENERATING CAPACITY SHOULD BE BASELOAD CAPACITY. DO YOU AGREE WITH THIS CONCLUSION?

A13: Yes. In recent years, both of the companies have only added peaking generating units that are fired primarily with natural gas. The last coal-fired baseload unit that LG&E added was 15 years ago, and the last baseload unit added by KU was over 20 years ago. Since then, the two utilities combined have added 10 new peaking units with a combined summer capacity of 1,430 MW. Over 20% of the generating capacity owned by the Companies is now peaking capacity.

While peaking capacity is primarily used to meet reserve margin requirements and to meet peaks, a high penetration of peaking capacity can become a concern due to the high fuel costs associated with these units. Peaking units are relatively inexpensive to install, but have very high operating costs due mainly to high fuel costs. Today this is even more of a concern since natural gas fuel costs have doubled or tripled since the Companies' new peaking units were added.

An additional factor is the age of the Companies' baseload units. In recent years, some of the Companies' older and smaller coal-fired units have been retired due to equipment failure and the high cost of repairing the units to run efficiently and meet current environmental requirements. This trend is bound to continue as the Companies' units continue to age and wear.

Based on the concern about over-dependence on peaking units, the increased cost of operating peaking units, and the age of the Companies' existing baseload units, I would agree with the Applicants that it is appropriate to add baseload capacity as the next increment of generation.

SELECTION OF BEST BASELOAD OPTION

Q14: THE COMPANIES HAVE PROPOSED TO ADD A SUPER-CRITICAL COAL-FIRED UNIT AT THE TRIMBLE COUNTY SITE AS THEIR BEST BASELOAD OPTION. HOW DID THEY REACH THIS CONCLUSION?

A14: The Companies relied upon analysis done by Burns and McDonnell that determined that their best self-build option was to add a 750 MW super-critical coal-fired unit at the Trimble County site. A Request for Proposals was done to determine if there were any options that were lower costs than their selected self-build option. A number of competitively priced proposals were received. The next step was to refine the proposals that were competitive. In this refinement process, a few of the better options became uncompetitive. In the final analysis, the Companies compared three options, the Trimble County 2 unit, a jointly owned coal-fired plant with Marketer E, and a power purchase contract with three hydro plants to be built by Marketer F. To determine the best option or combination of options, the Companies employed a quantitative analysis that relied on a 30-year Net Present Value analysis. Nine scenarios were evaluated, including the option of simply continuing to add peaking units instead of a baseload unit.

This quantitative analysis shows that simply adding peaking units instead of a baseload option is significantly more expensive than any of the baseload options, being $480 million more expensive in Net Present Value Revenue Requirements. This is a quantitative verification of my previous conclusion that the next increment of capacity needed by the Companies is baseload.

Q15: WHAT OTHER CONCLUSIONS CAN BE DRAWN FROM THE NINE SCENARIOS RUN BY THE COMPANIES?

A15: When scenarios that contain the Marketer F option are compared to similar scenarios without Marketer F (Cases 3, 4, and 5 compared to Cases 1 and 2, and Case 8 compared to Cases 6 and 7), the addition of Marketer F significantly reduces the Net Present Value Revenue Requirements for both the addition of Trimble County 2 and for Marketer E. This analysis suggests that the Marketer F option is the lowest cost option.

Q16: IF MARKETER F SEEMS TO BE THE LOWEST COST OPTION, WHY DID THE COMPANIES PURSUE A CERTIFICATE OF CONVENIENCE AND NECESSITY FOR THE TRIMBLE COUNTY 2 UNIT INSTEAD?

A16: There are additional factors for consideration that are not addressed by the Net Present Value Revenue Requirements analysis. The Marketer F option has problems that prevented it from being pursued as the primary option for the

Companies. First, the Companies were looking for about 500 MW, but the Marketer F option could only provide under 200 MW at summer peak. In addition, Marketer F apparently had problems with the equipment supplier upon which its bid was based and now has had to pursue a different supplier. As such, the Companies are still waiting for new firm pricing from Marketer F. Therefore, while initial quantitative analysis suggests that Marketer F is the lowest cost option for the Companies, it is not possible to know this for sure until Marketer F gives firm pricing to the Companies, and the Companies analyze this new pricing.

Q17: WHAT OTHER CONCLUSIONS CAN BE DRAWN FROM THE COMPANIES' QUANTITATIVE ANALYSIS?

A17: When the two baseload coal options are compared, Trimble County 2 and Marketer E, under each scenario examined, with and without the inclusion of Marketer F, all Trimble County 2 scenarios have a lower Net Present Value Revenue Requirement than even the least cost Marketer E scenario (Case 8 which includes Marketer F). From these comparisons it can be concluded that Trimble County 2 is a lower cost option than Marketer E. Thus, Marketer E can be eliminated from consideration.

With the elimination of Marketer E, and the elimination of the very expensive all peaking unit option, analysis should be focused on the scenarios that contain Trimble County 2, Cases 1 though 5. The major difference between these scenarios is that Cases 1 and 2 have Trimble County 2 only, while Cases 3, 4, and 5 include Marketer F. As I previously mentioned, the inclusion of Marketer F significantly lowers the Net Present Value Revenue Requirements. The Companies correctly concluded that the lowest cost scenario is to add both Trimble County 2 and Marketer F, which is analyzed in Cases 3, 4, and 5.

Q18: IF CASES 3, 4, AND 5 EACH CONTAIN BOTH TRIMBLE COUNTY 2 AND MARKETER F, WHAT ARE THE DIFFERENCES IN THESE SCENARIOS?

A18: The primary difference between these scenarios is the timing of the addition of these two options. Case 3, which would add both options together in 2010, is more expensive than the other two scenarios and thus not the best option. From this it can be concluded that ratepayers only need one capacity addition at a time, and the question then becomes which option should be added first.

Case 4 would add Marketer F first with Trimble County a year later, while Case 5 would first add Trimble County 2, and then add Marketer F three years later. The cost of these two scenarios is virtually the same, a difference of only about $4 million in Net Present Value Revenue Requirements over a 30 year period, when transmission costs are included. This $4 million difference is insignificant when compared to the total Net Present Value Revenue Requirements of about $16,400 million for each scenario. Based on this $4 million difference over 30 years, the Companies have concluded that they should build Trimble County 2 before they purchase power from Marketer F.

Q19: DO YOU AGREE WITH THE COMPANIES' CONCLUSION THAT IT IS LESS EXPENSIVE TO BUILD TRIMBLE COUNTY BEFORE PURCHASING POWER FROM MARKETER F?

A19: Not necessarily. Marketer F is offering the Companies "Green Power," or renewable power with no associated emissions. Even though Green attributes are usually considered to have a value, the Companies, in response to the Attorney General's First Data Request, Item 13(b) state, "no economic value was included in the analysis" for Green Tags. The Companies said that they included no value to Marketer F's Green attributes because "The Companies currently do not have any renewable energy portfolio requirements and are not able to speculate on future requirements."

Q20: DO YOU AGREE THAT THE GREEN ATTRIBUTES OF MARKETER F'S POWER HAVE NO VALUE BECAUSE THE COMPANIES HAVE NO RENEWABLE ENERGY PORTFOLIO REQUIREMENTS?

A20: No. Whether the Companies currently or ever in the future have to comply with renewable energy portfolio requirements has no bearing on the value of the Marketer F option's Green attributes. Even if Kentucky and the federal government never adopts renewable energy portfolio requirements, because the Companies are in the ECAR region, Green Tags generated by new renewable energy projects anywhere in the ECAR regions can be sold to others within the ECAR regions that do have renewable energy portfolio requirements. Currently, Ohio, Illinois, and Michigan, all within ECAR, have adopted renewable energy portfolio requirements (requirements in Illinois and Michigan begin this year). Green Tags are tradable and can be separated from the actual power and be sold separately. In Marketer F's most recent offer to the Companies, it offered to include in the sale price not only the power but also the Green attributes, which can be separated and sold separately. If the Companies believe that Marketer F's Green Tags have no value, they might propose to Marketer F that it keep them and sell them separately, and thus might be able to lower the price for which it can sell power to the Companies.

Q21: WHAT IS THE VALUE OF THE GREEN TAGS ASSOCIATED WITH MARKETER F'S POWER?

A21: It is difficult to say with any certainty what Marketer F's Green Tags will be worth when the projects come on-line at least five years from now. Renewable energy portfolio requirements are new in the Midwest, as are the markets that trade these Green Tags. Also, in future years the requirements will increase, thus possibly increasing demand for the Green Tags faster than new renewable plants can come on-line. I am aware of projections for Green Tags associated with hydro that range from just a few mils to estimates of about 20 mils. Currently, Green Tags associated with hydro are being marketed to the retail market on the East Coast for 12 mils. Current hydro Green Tags in the Midwest are worth only a few mils, as regional portfolio standards are just now being implemented.

I have calculated the value of Marketer F's Green Tags in Exhibit DHBK-5. In this analysis, I have conservatively estimated the Green Tags to only be worth 3 mils during each year included in the Companies' analysis. In this analysis, the Green Tags would have a Net Present Value of about $27.5 million in Case 4 and almost $21 million in Case 5. The difference between the value of the Green Tags in these two cases is about $6.6 million.

I have also done the same calculation in Exhibit DHBK-6, but instead assumed a more realistic assumption of the Green Tags being worth 6 mils. In this scenario, the difference between the two cases is $13 million in Net Present Value terms.

Q22: IF THE COMPANIES HAD INCLUDED A VALUE FOR MARKETER F'S GREEN TAGS IN ITS ANALYSIS, WOULD IT HAVE IMPACTED THE RESULTS AND CONCLUSIONS?

A22: Yes. By including the value of Marketer F's Green Tags, the Companies' analysis would show that it is less expensive to add the Marketer F option to the Companies' system before Trimble County 2 is built. Even using the conservative 3 mil assumption, the $6.6 million advantage for Case 4 is larger than the $4.1 million advantage Case 5 had without inclusion of Green Tags.

Q23: WHETHER THE ADVANTAGE OF CASE 5 IS $4.1 MILLION OVER A THIRTY YEAR PERIOD WITHOUT GREEN TAGS, OR A $2.5 MILLION ADVANTAGE FOR CASE 4 WITH GREEN TAGS, THESE TWO SCENARIOS ARE VIRTUALLY THE SAME COST. ARE THERE OTHER

THINGS THAT SHOULD BE CONSIDERED THAT ARE NOT INCLUDED IN THE COMPANIES' ANALYSIS?

A23: Yes. The 800 pound Gorilla lurking just around the corner is reductions in Greenhouse Gas emissions. There is continuing national and international pressure to reduce Greenhouse Gas emissions, and the pressure is unlikely to abate. The industrial world, except for the United States and Australia, is now operating under the Kyoto Protocol, which calls for a reduction in carbon dioxide emissions to 7% below 1990 levels by 2010. Even if the United States never signs onto the Kyoto Protocol, most agree that the United States will do something to reduce Greenhouse Gas emissions; the questions are when and how much?

The Companies state that they will include an evaluation of this possibility in their 2005 Integrated Resource Plan, which will be released soon. The Companies state in their response to the Attorney General's Second Data Request, Item 15, that the 2005 IRP will include analysis of a carbon dioxide tax at \$10/ton, \$20/ton, and \$40/ton. I combined these tax levels with the carbon dioxide emissions associated with the nine cases the Companies examined in this case, which were provided in the Company's response to the Attorney General's First Data Request, Item 20(b). The calculation of the difference in Net Present Value between Cases 4 and 5 is contained in Exhibit DHBK-7. The difference ranges from over \$70 million with a \$10/ton tax to over \$280 million with a \$40/ton tax. These differences dwarf the differences of only a few million dollars between Cases 4 and 5 if no carbon dioxide tax is considered. In other words, if a carbon dioxide tax is implemented in the next 5 years, there is a significant savings associated with adding the power from Marketer F before Trimble County 2 is built.

It should be noted that if a carbon tax was imposed at even the lowest level contemplated by the Companies, $10 per ton of carbon dioxide, the value of Marketer F's power would be increased by over $11 million per year.

Q24: WHAT OTHER FACTORS SHOULD BE CONSIDERED THAT WERE NOT INCLUDED IN THE COMPANIES' ANALYSIS?

A24: There are a few of other factors the Commission should consider. For example, the Commission, when considering an application for a certificate to construct a baseload electric generating facility, may consider the policy of the General Assembly to foster and encourage use of Kentucky coal by electric utilities serving the Commonwealth. On this point, the Trimble County 2 unit will use a mix of eastern United States coal and western low-sulfur coal. Since Trimble County 2 may only partially use Kentucky coal, it appears that the General Assembly's policy would be difficult to apply in this case. The Commission though does though have an obligation to make sure that capacity options approved are least cost for customers. It is this clear mandate of low cost that the Commission should use to guide its decision.

There is another factor affecting costs that wasn't captured in the Companies' 30-year Net Present Value analysis. The two lowest cost options the Companies considered are Cases 4 and 5, which both call for adding Trimble

County 2 and Marketer F. Comparing Cases 4 and 5 provides only insight into the timing of adding both Trimble County 2 and Marketer F. Costs advantages associated with each of these options individually cannot be explored in these cases, except in the costs differences in the three years between 2010 and 2012, when these two cases differ. A very good example of this is the price advantage associated with the Marketer F offer in later years. After year 20 of the Marketer F offer, the price drops significantly for the next 10 years (or 15 years if an option for an additional 5 years of inexpensive power is exercised). The problem is that the Companies' 30-year analysis excludes most all of these lower cost years in the Marketer F offer. Because this will make little difference in comparing Cases 4 and 5, since both include Marketer F, this advantage of Marketer F over Trimble County 2 is ignored.

Q25: WHAT DIFFERENCE DOES THE LOWER COST ASSOCIATED WITH MARKETER F MAKE IF BOTH CASES 4 AND 5 CALL FOR PURCHASING POWER FROM MARKETER F, WHERE ONLY THE ORDER OF THE ACQUISITION OF THE OPTIONS DIFFERS?

A25: The concern about the difference between the timing of these options can be summed up in the filing of this case. While both Case 4 and 5 call for adding both Marketer F and Trimble County 2, this Certificate Case is for permission to pursue only Trimble County 2, even though the Marketer F option may be a lower cost. As soon as the Certificate for Trimble County 2 is issued, it is possible that the Companies' interest in the lower cost Marketer F option will wane. This is a real possibility if the Companies' load forecasts fail to materialize, as has happened with the Companies' load forecasts in their last two joint Integrated Resource Plans and the load forecast offered in this case. The Companies' opportunity to purchase low cost renewable energy, which could provide significant savings in the future, could be lost if the Companies become overbuilt with new coal-fired capacity and load fails to grow.

## RECOMMENDATIONS

Q26: BASED ON YOUR ANALYSIS OF THE COMPANIES' APPLICATION, WHAT ARE YOUR RECOMMENDATIONS?

A26: Currently, the Companies have over 1,000 MW of capacity in surplus of what is needed to meet reserve margin requirements. In addition, the Companies have been in a no growth trend for the last 5 years. Even if growth began again today at the Companies projected rate, new generating capacity would not be needed until 2012 to meet reserve margin needs. Clearly, the Companies have failed to demonstrate their assertion that new capacity will be needed by 2010 is true.

Ratepayers would pay a substantial extra cost if the Companies add new baseload capacity before it is needed. The Commission should reject the Companies application at this time. When the Applicants can demonstrate that load growth has begun again, they can resubmit this application.

Q27: WHAT WOULD BE NEEDED TO DEMONSTRATE THAT GROWTH HAS BEGUN AGAIN AND SHOW A NEED FOR NEW CAPACITY?

A27: Quoting from page 5 of Mr. Sinclair's testimony, "One year does not make a trend." If, for example, in the summer of 2005, the Companies experience a modest increase in peak load, it would be difficult to determine if this was simply a slight up and down variation, as has been seen during this no growth period, or the beginning of a new growth trend. Because of this, the Companies should have to demonstrate growth over a few years to demonstrate that the substantial surplus capacity available today will be used and new capacity will be needed.

This need to wait and demonstrate that a new long-term growth trend has begun must be balanced against the reality of a long lead-time associated with the construction of baseload capacity. Luckily, due to the 1,000 MW of excess capacity the Companies presently have, it is unlikely that new capacity will needed before 2012 at the earliest, thus providing some time before a decision to proceed is needed. Based on the construction schedule the Companies proposed in this case, it appears that the Companies have at least a two year window where growth can occur, to demonstrate a new growth trend, before construction needs to begin.

Q28: DO YOU HAVE ANY OTHER RECOMMENDATIONS?

A28: Yes. The other question that remains open is whether the Companies should proceed with the Marketer F purchase before building Trimble County 2. It is not possible to make this determination until Marketer F supplies the Companies with a firm price, which appears will not happen until this summer at the earliest.

The Marketer F option has the advantage of being smaller in size, and in a period of uncertainty about future load growth, the risk is smaller to ratepayers if load growth fails to materialize. It should be noted though that even if the Marketer F option is attractive, and the Joint Companies decide to pursue it before Trimble County 2, no new capacity can be justified, not from Marketer F or Trimble County 2, until 2012 at the earliest, based on information available today.

I have one other concern and related recommendation. The purchase arrangement that the Companies are pursuing with Marketer F would not capture one of the major values associated with this option. Ratepayers have received tremendous value from the low cost power provided by the Companies' hydro plants at Ohio Falls and Dix Dam. These plants are 75 to 80 years old and still producing low cost power, even lower cost than coal-fired plants. The problem with the purchase contemplated with Marketer F is that it is just for 30 years, with an option for an additional 5 years. After the 35 year period, when the plants are depreciated and producing extremely low cost power, the Companies will no longer be entitled to this low cost power.

Q29: HOW CAN RATEPAYERS BENEFIT FROM THIS LOW COST LONG-TERM POWER?

A29: The way to receive the long-term low costs offered by hydro plants is for the Companies to own them. It appears that the Companies were considering purchasing the plants outright from Marketer F, but are no longer considering this option. The problem with a Net Present Value analysis is that it gives little value to lower costs in the latter part of the 30 year analysis, and gives no value to the ability to produce low cost power after 30 years. We can thank employees of LG&E and KU in the early part of the twentieth century for the vision to invest in Dix Dam and Ohio Falls that continue to supply ratepayers with low cost power decades after the plants were fully depreciated. Ownership of the plants, as opposed to simply purchasing power from them, offers tremendous long-term benefits to ratepayers that simply are not captured in a 30-year Net Present Value analysis.

Q30: YOU MENTION THE LONG-TERM BENEFITS OF OWNERSHIP INSTEAD OF PURCHASE. AREN'T THERE ADDITIONAL RISKS ASSOCIATED WITH OWNERSHIP THAT AREN'T PRESENT WITH A SIMPLE POWER PURCHASE?

A30: While there is always some risk associated with asset ownership, the risk associated with Marketer F assets appears to be very low. The October 14, 2004, letter from Marketer F, submitted as part of Exhibit JPM-1, states that its new proposal is to use conventional hydro plants installed by Voith. Conventional hydro plants are among the more mature and risk-free generating plants available, relying on 100 year old technology that has been refined and improved over the last century. In addition, Voith is one of the most respected and experienced companies in the world involved in hydropower. Having a conventional hydro plant designed and installed by Voith involves very little risk. Properly written contracts can further protect against risk.

Therefore, I recommend that when the Companies negotiate with Marketer F with respect to final pricing, the option of outright ownership of these new renewable energy plants should be fully explored. Not only can these plants provide very low energy costs way into the future, they can provide long-term savings in environmental compliance costs, especially with respect to carbon dioxide limits. Not only can these plants can provide competitively priced power today, they can repeat the history of Dix Dam and the Ohio Falls plants and provide low cost energy to future generations.

Q31: DOES THIS CONCLUDE YOUR TESTIMONY?

A31: Yes it does.

I, David H. Brown Kinloch, certify that the statements contained in the foregoing testimony are true and correct to the best of my knowledge, information, and belief.

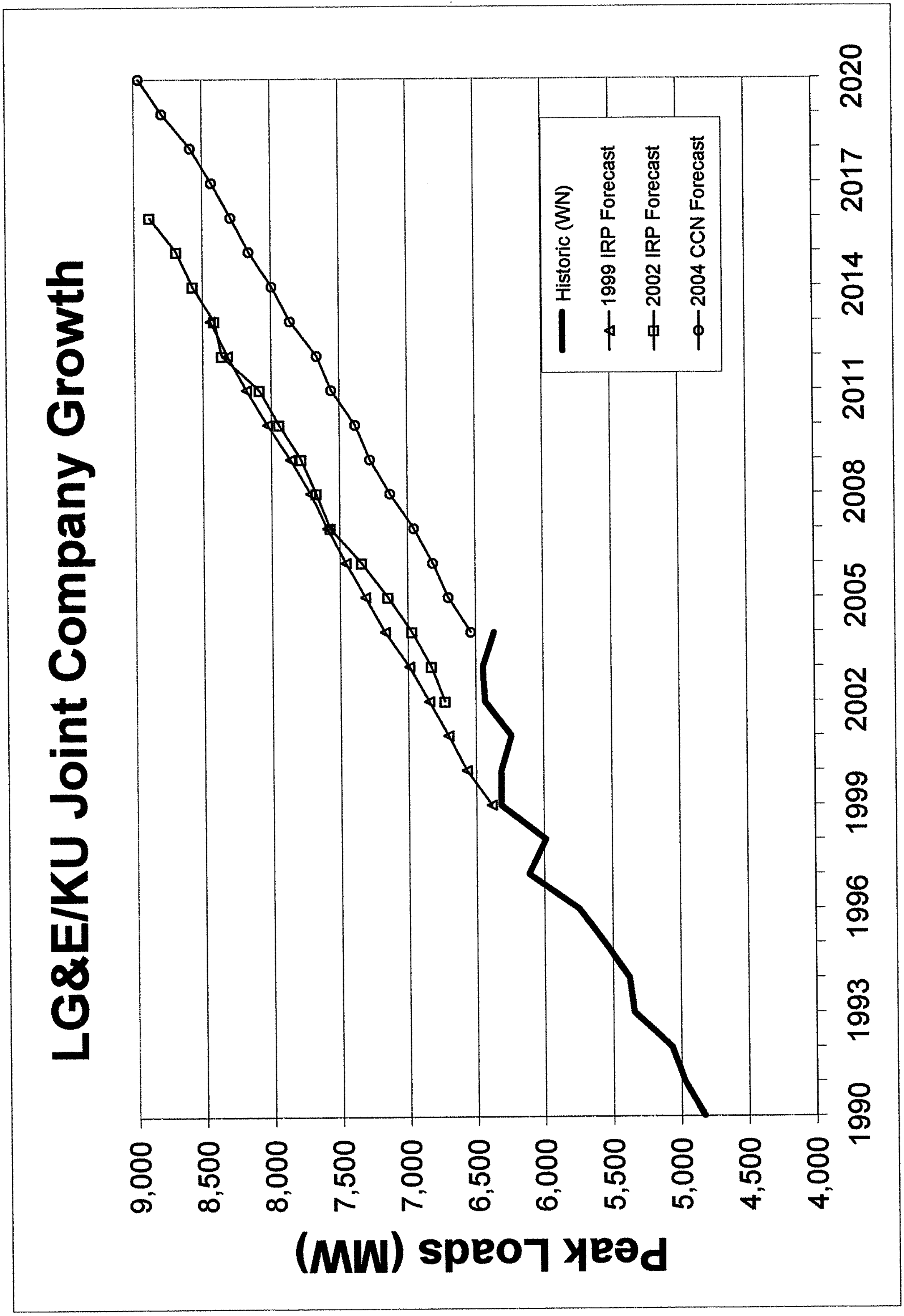
Dated this 18th day of April, 2005.

David H. Brown Kinloch

Affirmed to and subscribed before me, this 18th day of April, 2005.

Notary Public

My Commission Expires: April 26, 2006


LG&E/KU Joint Company Growth
Peak Loads (MW)
9,000
8,500
8,000
7,500
7,000
6,500
6,000
5,500
5,000
4,500
4,000
1990
1993
1996
1999
2002
2005
2008
2011
2014
2017
2020
Historic (WN)
1999 IRP Forecast
2002 IRP Forecast
2004 CCN Forecast

# Table 2. Capacity Needs for Reserve Margin Range
## Revised December 2004
(All values in MW at Summer Peak)

| Component | | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 |
|---|---|---|---|---|---|---|---|---|---|---|
| Peak Load | | 6,462 | 6,624 | 6,736 | 6,878 | 7,050 | 7,198 | 7,306 | 7,474 | 7,578 |
| CSR/Interrupt | | -100 | -100 | -100 | -100 | -100 | -100 | -100 | -100 | -100 |
| Existing DSM | | -44 | -67 | -89 | -108 | -116 | -116 | -116 | -116 | -116 |
| 02 IRP DSM Program | | 0 | 0 | -1 | -1 | -2 | -2 | -2 | -2 | -2 |
| Net Load | | 6,318 | 6,456 | 6,547 | 6,668 | 6,831 | 6,979 | 7,087 | 7,255 | 7,360 |
| Existing Capability | | 7,615 | 7,608 | 7,609 | 7,596 | 7,582 | 7,547 | 7,549 | 7,550 | 7,555 |
| Purchases | | 593 | 605 | 574 | 572 | 572 | 571 | 570 | 569 | 568 |
| Total Supply | | 8,208 | 8,213 | 8,183 | 8,168 | 8,154 | 8,118 | 8,119 | 8,119 | 8,123 |
| 13% RM | MW Need Before DSM | -1,019 | -841 | -684 | -509 | -301 | -98 | 23 | 213 | 328 |
| | MW Need After DSM | -1,069 | -917 | -785 | -633 | -435 | -232 | -111 | 79 | 193 |
| 15% RM | MW Need Before DSM | -892 | -711 | -551 | -374 | -162 | 44 | 168 | 361 | 477 |
| | MW Need After DSM | -942 | -788 | -654 | -499 | -298 | -92 | 31 | 224 | 341 |
| Existing Reserve Margin, % | Before DSM | 29.0% | 25.9% | 23.3% | 20.5% | 17.3% | 14.4% | 12.7% | 10.1% | 8.6% |
| | After DSM | 29.9% | 27.2% | 25.0% | 22.5% | 19.4% | 16.3% | 14.6% | 11.9% | 10.4% |

Exhibit DHBK - 3

## Capacity Needs for Reserve Margin Range
## Revised by Attorney General
(All values in MW at Summer Peak)

| Component | | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 |
|---|---|---|---|---|---|---|---|---|---|---|
| Peak Load | | 6,462 | 6,624 | 6,736 | 6,878 | 7,050 | 7,198 | 7,306 | 7,474 | 7,578 |
| CSR/Interrupt | | -100 | -100 | -100 | -100 | -100 | -100 | -100 | -100 | -100 |
| Existing DSM | | -44 | -67 | -89 | -108 | -116 | -116 | -116 | -116 | -116 |
| 02 IRP DSM Program | | 0 | 0 | -1 | -1 | -2 | -2 | -2 | -2 | -2 |
| Net Load | | 6,318 | 6,456 | 6,547 | 6,668 | 6,831 | 6,979 | 7,087 | 7,255 | 7,360 |
| Existing Capability | | 7,615 | 7,608 | 7,609 | 7,596 | 7,582 | 7,547 | 7,549 | 7,550 | 7,555 |
| Purchases | | 593 | 605 | 574 | 572 | 572 | 571 | 570 | 569 | 568 |
| Total Supply | | 8,208 | 8,213 | 8,183 | 8,168 | 8,154 | 8,118 | 8,119 | 8,119 | 8,123 |
| 12% RM | MW Need Before DSM | -1,083 | -907 | -750 | -577 | -370 | -169 | -49 | 140 | 253 |
| | MW Need After DSM | -1,132 | -982 | -851 | -700 | -503 | -301 | -181 | 7 | 120 |
| 14% RM | MW Need Before DSM | -955 | -776 | -618 | -441 | -231 | -27 | 95 | 287 | 402 |
| | MW Need After DSM | -1,005 | -853 | -720 | -566 | -367 | -162 | -40 | 152 | 267 |
| Existing Reserve Margin, % | Before DSM | 29.0% | 25.9% | 23.3% | 20.5% | 17.3% | 14.4% | 12.7% | 10.1% | 8.6% |
| | After DSM | 29.9% | 27.2% | 25.0% | 22.5% | 19.4% | 16.3% | 14.6% | 11.9% | 10.4% |

# Cost of Building Trimble County 2 Before Needed

## Trimble County 2 Annual Fixed Cost

| | 2010 | 2011 |
|---|---|---|
| Capital Cost (Generation and Transmission) (1) | $882,353,000 | $855,617,704 |
| Return including Gross up for Taxes (2) | 10.94% | 10.94% |
| Annual Return on Capital | $96,529,418 | $93,604,577 |
| Depreciation | $26,735,296 | $25,925,216 |
| Fixed O&M Costs (3) | $7,300,000 | $7,300,000 |
| Annual Fixed Costs for Trimble County 2 | $130,564,714 | $126,829,793 |

## Variable Cost Savings with Trimble County 2

| | 2010 | 2011 |
|---|---|---|
| Case 9 - No New Baseload (4) | $805,754,000 | $857,693,000 |
| Case 1 or Case 5 - TC2 in 2010 (4) | $775,112,000 | $803,621,000 |
| Variable Cost Savings | $30,642,000 | $54,072,000 |

## Cost Associated with Building Trimble County 2 Before Needed

| | 2010 | 2011 |
|---|---|---|
| Fixed Costs | $130,564,714 | $126,829,793 |
| Variable Cost Savings | -$30,642,000 | -$54,072,000 |
| Annual Cost | $99,922,714 | $72,757,793 |
| **Total Cost** | | **$172,680,507** |

(1) Source: LG&E/KU Response to 1AG-22 Attachment Page 1 of 1
(2) Source: LG&E/KU Response to 1PSC-1a Attachment Page 19 of 22
(3) Source: Exhibit JPM-1 - Resource Assessment - Appendix D
(4) Source: LG&E/KU Response to 1PSC-1a Attachment Page 2 of 22

Exhibit DHBK - 5

# VALUE OF MARKETER F's GREEN TAGS
## ASSUMING A VALUE OF $3.00 PER MWH

| | NPV factor 7.14% | Marketer F (MWH) Case 4 | Green Tags $3.00/MWH | NPVRR | Marketer F (MWH) Case 5 | Green Tags $3.00/MWH | NPVRR | Marketer F (MWH) Difference | Green Tags $3.00/MWH | NPVRR |
|---|---|---|---|---|---|---|---|---|---|---|
| 2005 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2006 | 0.9286 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2007 | 0.862298 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2008 | 0.80073 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2009 | 0.743558 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2010 | 0.690468 | 1,140,000 | 3,420,000 | 2,361,400 | 0 | 0 | 0 | 1,140,000 | 3,420,000 | 2,361,400 |
| 2011 | 0.641168 | 1,140,000 | 3,420,000 | 2,192,796 | 0 | 0 | 0 | 1,140,000 | 3,420,000 | 2,192,796 |
| 2012 | 0.595389 | 1,140,000 | 3,420,000 | 2,036,230 | 0 | 0 | 0 | 1,140,000 | 3,420,000 | 2,036,230 |
| 2013 | 0.552878 | 1,140,000 | 3,420,000 | 1,890,843 | 1,140,000 | 3,420,000 | 1,890,843 | 0 | 0 | 0 |
| 2014 | 0.513403 | 1,140,000 | 3,420,000 | 1,755,837 | 1,140,000 | 3,420,000 | 1,755,837 | 0 | 0 | 0 |
| 2015 | 0.476746 | 1,140,000 | 3,420,000 | 1,630,470 | 1,140,000 | 3,420,000 | 1,630,470 | 0 | 0 | 0 |
| 2016 | 0.442706 | 1,140,000 | 3,420,000 | 1,514,055 | 1,140,000 | 3,420,000 | 1,514,055 | 0 | 0 | 0 |
| 2017 | 0.411097 | 1,140,000 | 3,420,000 | 1,405,951 | 1,140,000 | 3,420,000 | 1,405,951 | 0 | 0 | 0 |
| 2018 | 0.381745 | 1,140,000 | 3,420,000 | 1,305,566 | 1,140,000 | 3,420,000 | 1,305,566 | 0 | 0 | 0 |
| 2019 | 0.354488 | 1,140,000 | 3,420,000 | 1,212,349 | 1,140,000 | 3,420,000 | 1,212,349 | 0 | 0 | 0 |
| 2020 | 0.329178 | 1,140,000 | 3,420,000 | 1,125,787 | 1,140,000 | 3,420,000 | 1,125,787 | 0 | 0 | 0 |
| 2021 | 0.305674 | 1,140,000 | 3,420,000 | 1,045,406 | 1,140,000 | 3,420,000 | 1,045,406 | 0 | 0 | 0 |
| 2022 | 0.283849 | 1,140,000 | 3,420,000 | 970,764 | 1,140,000 | 3,420,000 | 970,764 | 0 | 0 | 0 |
| 2023 | 0.263582 | 1,140,000 | 3,420,000 | 901,451 | 1,140,000 | 3,420,000 | 901,451 | 0 | 0 | 0 |
| 2024 | 0.244763 | 1,140,000 | 3,420,000 | 837,088 | 1,140,000 | 3,420,000 | 837,088 | 0 | 0 | 0 |
| 2025 | 0.227286 | 1,140,000 | 3,420,000 | 777,320 | 1,140,000 | 3,420,000 | 777,320 | 0 | 0 | 0 |
| 2026 | 0.211058 | 1,140,000 | 3,420,000 | 721,819 | 1,140,000 | 3,420,000 | 721,819 | 0 | 0 | 0 |
| 2027 | 0.195989 | 1,140,000 | 3,420,000 | 670,281 | 1,140,000 | 3,420,000 | 670,281 | 0 | 0 | 0 |
| 2028 | 0.181995 | 1,140,000 | 3,420,000 | 622,423 | 1,140,000 | 3,420,000 | 622,423 | 0 | 0 | 0 |
| 2029 | 0.169001 | 1,140,000 | 3,420,000 | 577,982 | 1,140,000 | 3,420,000 | 577,982 | 0 | 0 | 0 |
| 2030 | 0.156934 | 1,140,000 | 3,420,000 | 536,714 | 1,140,000 | 3,420,000 | 536,714 | 0 | 0 | 0 |
| 2031 | 0.145729 | 1,140,000 | 3,420,000 | 498,393 | 1,140,000 | 3,420,000 | 498,393 | 0 | 0 | 0 |
| 2032 | 0.135324 | 1,140,000 | 3,420,000 | 462,808 | 1,140,000 | 3,420,000 | 462,808 | 0 | 0 | 0 |
| 2033 | 0.125662 | 1,140,000 | 3,420,000 | 429,763 | 1,140,000 | 3,420,000 | 429,763 | 0 | 0 | 0 |
| TOTAL | NPV | | | 27,483,497 | | | 20,893,071 | | | 6,590,426 |

Exhibit DHBK - 6

# VALUE OF MARKETER F's GREEN TAGS
# ASSUMING A VALUE OF $6.00 PER MWH

| | NPV factor 7.14% | Marketer F (MWH) Case 4 | Green Tags $6.00/MWH | NPVRR | Marketer F (MWH) Case 5 | Green Tags $6.00/MWH | NPVRR | Marketer F (MWH) Difference | Green Tags $6.00/MWH | NPVRR |
|---|---|---|---|---|---|---|---|---|---|---|
| 2005 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2006 | 0.9286 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2007 | 0.862298 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2008 | 0.80073 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2009 | 0.743558 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2010 | 0.690468 | 1,140,000 | 6,840,000 | 4,722,799 | 0 | 0 | 0 | 1,140,000 | 6,840,000 | 4,722,799 |
| 2011 | 0.641168 | 1,140,000 | 6,840,000 | 4,385,592 | 0 | 0 | 0 | 1,140,000 | 6,840,000 | 4,385,592 |
| 2012 | 0.595389 | 1,140,000 | 6,840,000 | 4,072,460 | 0 | 0 | 0 | 1,140,000 | 6,840,000 | 4,072,460 |
| 2013 | 0.552878 | 1,140,000 | 6,840,000 | 3,781,687 | 1,140,000 | 6,840,000 | 3,781,687 | 0 | 0 | 0 |
| 2014 | 0.513403 | 1,140,000 | 6,840,000 | 3,511,674 | 1,140,000 | 6,840,000 | 3,511,674 | 0 | 0 | 0 |
| 2015 | 0.476746 | 1,140,000 | 6,840,000 | 3,260,941 | 1,140,000 | 6,840,000 | 3,260,941 | 0 | 0 | 0 |
| 2016 | 0.442706 | 1,140,000 | 6,840,000 | 3,028,109 | 1,140,000 | 6,840,000 | 3,028,109 | 0 | 0 | 0 |
| 2017 | 0.411097 | 1,140,000 | 6,840,000 | 2,811,902 | 1,140,000 | 6,840,000 | 2,811,902 | 0 | 0 | 0 |
| 2018 | 0.381745 | 1,140,000 | 6,840,000 | 2,611,133 | 1,140,000 | 6,840,000 | 2,611,133 | 0 | 0 | 0 |
| 2019 | 0.354488 | 1,140,000 | 6,840,000 | 2,424,698 | 1,140,000 | 6,840,000 | 2,424,698 | 0 | 0 | 0 |
| 2020 | 0.329178 | 1,140,000 | 6,840,000 | 2,251,574 | 1,140,000 | 6,840,000 | 2,251,574 | 0 | 0 | 0 |
| 2021 | 0.305674 | 1,140,000 | 6,840,000 | 2,090,812 | 1,140,000 | 6,840,000 | 2,090,812 | 0 | 0 | 0 |
| 2022 | 0.283849 | 1,140,000 | 6,840,000 | 1,941,528 | 1,140,000 | 6,840,000 | 1,941,528 | 0 | 0 | 0 |
| 2023 | 0.263582 | 1,140,000 | 6,840,000 | 1,802,903 | 1,140,000 | 6,840,000 | 1,802,903 | 0 | 0 | 0 |
| 2024 | 0.244763 | 1,140,000 | 6,840,000 | 1,674,176 | 1,140,000 | 6,840,000 | 1,674,176 | 0 | 0 | 0 |
| 2025 | 0.227286 | 1,140,000 | 6,840,000 | 1,554,639 | 1,140,000 | 6,840,000 | 1,554,639 | 0 | 0 | 0 |
| 2026 | 0.211058 | 1,140,000 | 6,840,000 | 1,443,638 | 1,140,000 | 6,840,000 | 1,443,638 | 0 | 0 | 0 |
| 2027 | 0.195989 | 1,140,000 | 6,840,000 | 1,340,562 | 1,140,000 | 6,840,000 | 1,340,562 | 0 | 0 | 0 |
| 2028 | 0.181995 | 1,140,000 | 6,840,000 | 1,244,846 | 1,140,000 | 6,840,000 | 1,244,846 | 0 | 0 | 0 |
| 2029 | 0.169001 | 1,140,000 | 6,840,000 | 1,155,964 | 1,140,000 | 6,840,000 | 1,155,964 | 0 | 0 | 0 |
| 2030 | 0.156934 | 1,140,000 | 6,840,000 | 1,073,428 | 1,140,000 | 6,840,000 | 1,073,428 | 0 | 0 | 0 |
| 2031 | 0.145729 | 1,140,000 | 6,840,000 | 996,786 | 1,140,000 | 6,840,000 | 996,786 | 0 | 0 | 0 |
| 2032 | 0.135324 | 1,140,000 | 6,840,000 | 925,615 | 1,140,000 | 6,840,000 | 925,615 | 0 | 0 | 0 |
| 2033 | 0.125662 | 1,140,000 | 6,840,000 | 859,526 | 1,140,000 | 6,840,000 | 859,526 | 0 | 0 | 0 |
| TOTAL | NPV | | | 54,966,994 | | | 41,786,143 | | | 13,180,851 |

Exhibit DHBK - 7

# IMPACT OF MARKETER F ON $CO_2$ COMPLIANCE COSTS
## EFFECT IS DELAYING MARKETER F FOR THREE YEARS

| | NPV factor 7.14% | $CO_2$ Emissions Case 4 | $CO_2$ Emissions Case 5 | $CO_2$ Costs Difference | $CO_2$ Costs $10/ton | NPVRR | CO2 Cost $20/ton | NPVRR | CO2 Cost $40/ton | NPVRR |
|---|---|---|---|---|---|---|---|---|---|---|
| 2005 | 1 | 35,032,482 | 35,032,482 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2006 | 0.9286 | 35,736,785 | 35,736,785 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2007 | 0.862298 | 36,605,357 | 36,605,357 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2008 | 0.80073 | 37,255,183 | 37,255,183 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2009 | 0.743558 | 37,870,834 | 37,870,834 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2010 | 0.690468 | 37,646,526 | 38,621,996 | 975,470 | 9,754,700 | 6,735,306 | 19,509,400 | 13,470,611 | 39,018,800 | 26,941,223 |
| 2011 | 0.641168 | 38,452,059 | 39,432,215 | 980,156 | 9,801,560 | 6,284,450 | 19,603,120 | 12,568,900 | 39,206,240 | 25,137,800 |
| 2012 | 0.595389 | 38,975,113 | 40,031,702 | 1,056,589 | 10,565,890 | 6,290,814 | 21,131,780 | 12,581,628 | 42,263,560 | 25,163,256 |
| 2013 | 0.552878 | 39,682,695 | 40,697,612 | 1,014,917 | 10,149,170 | 5,611,254 | 20,298,340 | 11,222,509 | 40,596,680 | 22,445,018 |
| 2014 | 0.513403 | 40,325,749 | 41,347,817 | 1,022,068 | 10,220,680 | 5,247,324 | 20,441,360 | 10,494,649 | 40,882,720 | 20,989,297 |
| 2015 | 0.476746 | 41,129,700 | 42,053,317 | 923,617 | 9,236,170 | 4,403,304 | 18,472,340 | 8,806,609 | 36,944,680 | 17,613,218 |
| 2016 | 0.442706 | 41,680,148 | 42,687,865 | 1,007,717 | 10,077,170 | 4,461,224 | 20,154,340 | 8,922,449 | 40,308,680 | 17,844,897 |
| 2017 | 0.411097 | 42,189,796 | 43,153,336 | 963,540 | 9,635,400 | 3,961,083 | 19,270,800 | 7,922,165 | 38,541,600 | 15,844,330 |
| 2018 | 0.381745 | 43,206,521 | 44,175,113 | 968,592 | 9,685,920 | 3,697,547 | 19,371,840 | 7,395,094 | 38,743,680 | 14,790,188 |
| 2019 | 0.354488 | 43,589,524 | 44,449,716 | 860,192 | 8,601,920 | 3,049,277 | 17,203,840 | 6,098,554 | 34,407,680 | 12,197,109 |
| 2020 | 0.329178 | 44,492,990 | 45,389,800 | 896,810 | 8,968,100 | 2,952,097 | 17,936,200 | 5,904,194 | 35,872,400 | 11,808,388 |
| 2021 | 0.305674 | 44,879,803 | 45,685,101 | 805,298 | 8,052,980 | 2,461,589 | 16,105,960 | 4,923,177 | 32,211,920 | 9,846,355 |
| 2022 | 0.283849 | 45,469,814 | 46,251,523 | 781,709 | 7,817,090 | 2,218,874 | 15,634,180 | 4,437,748 | 31,268,360 | 8,875,496 |
| 2023 | 0.263582 | 45,959,085 | 46,720,946 | 761,861 | 7,618,610 | 2,008,131 | 15,237,220 | 4,016,261 | 30,474,440 | 8,032,523 |
| 2024 | 0.244763 | 46,799,583 | 47,558,663 | 759,080 | 7,590,800 | 1,857,943 | 15,181,600 | 3,715,887 | 30,363,200 | 7,431,773 |
| 2025 | 0.227286 | 47,048,402 | 47,772,629 | 724,227 | 7,242,270 | 1,646,070 | 14,484,540 | 3,292,140 | 28,969,080 | 6,584,280 |
| 2026 | 0.211058 | 47,533,044 | 48,244,508 | 711,464 | 7,114,640 | 1,501,603 | 14,229,280 | 3,003,206 | 28,458,560 | 6,006,413 |
| 2027 | 0.195989 | 48,251,180 | 48,956,634 | 705,454 | 7,054,540 | 1,382,610 | 14,109,080 | 2,765,220 | 28,218,160 | 5,530,439 |
| 2028 | 0.181995 | 48,280,814 | 48,890,824 | 610,010 | 6,100,100 | 1,110,188 | 12,200,200 | 2,220,376 | 24,400,400 | 4,440,753 |
| 2029 | 0.169001 | 48,307,250 | 48,931,116 | 623,866 | 6,238,660 | 1,054,337 | 12,477,320 | 2,108,675 | 24,954,640 | 4,217,350 |
| 2030 | 0.156934 | 48,476,241 | 48,992,126 | 515,885 | 5,158,850 | 809,599 | 10,317,700 | 1,619,198 | 20,635,400 | 3,238,395 |
| 2031 | 0.145729 | 48,878,515 | 49,346,431 | 467,916 | 4,679,160 | 681,889 | 9,358,320 | 1,363,778 | 18,716,640 | 2,727,555 |
| 2032 | 0.135324 | 49,374,316 | 49,734,620 | 360,304 | 3,603,040 | 487,577 | 7,206,080 | 975,154 | 14,412,160 | 1,950,309 |
| 2033 | 0.125662 | 48,694,844 | 49,020,238 | 325,394 | 3,253,940 | 408,896 | 6,507,880 | 817,791 | 13,015,760 | 1,635,583 |
| TOTAL | NPV | | | | | 70,322,987 | | 140,645,974 | | 281,291,948 |