Exhibit No.:
Issue: Depreciation Expense Rates
Witness: L. W. Loos
Type of Exhibit: Direct Testimony
Sponsoring Party: The Empire District Electric Company
Case No.:

Date Testimony Prepared: October 31, 2000

Before the Public Service Commission
of the State of Missouri

Before the Public Service Commission of the State of Missouri

Case No.:

Direct Testimony of L. W. Loos

Contents

Qualifications

Q. Please state your name and business address.

A. L. W. Loos, 8400 Ward Parkway, Kansas City, Missouri 64114.

Q. What is your occupation?

A. I am a Vice President in the firm of Black & Veatch Corporation (Black & Veatch). I am currently assigned to the firm's Management Consulting Division, where I head that Division's Energy Services group.

Q. How long have you been associated with the firm of Black & Veatch?

A. I have been with the firm continuously since 1971.

Q. What is your educational background?

A. I am a graduate of the University of Missouri at Columbia, with a Bachelor of Science Degree in Mechanical Engineering and a Masters Degree in Business Administration.

Q. Are you registered as a Professional Engineer?

A. Yes, I am a registered Professional Engineer in the State of Missouri, as well as the states of Colorado, Indiana, Iowa, Kansas, Louisiana, Nebraska, New Mexico, and Utah.

Q. Do you belong to any professional societies?

A. Yes, I do. I am a member of the American Society of Mechanical Engineers, the National Society of Professional Engineers, and the Missouri Society of Professional Engineers. I am also a member of the Midwest Energy Association and the firm's representative to the American Gas Association and the American Public Gas Association.

Q. What is your professional experience?

A. I have been responsible for numerous engagements involving electric, gas, and other utility services. Clients served include both investor-owned and publicly owned utilities; customers of such utilities; and regulatory agencies. During the course of these engagements, I have been responsible for the preparation and presentation of studies involving valuation, depreciation, cost of service, allocation, rate design, financial feasibility, cost of capital, and other engineering, economic and management areas.

Q. Have you previously appeared as an expert witness?

A. Yes, I have. I have presented expert witness testimony before this Commission on several occasions. In addition, I have presented expert witness testimony before the Federal Energy Regulatory Commission as well as before regulatory bodies in the states of Colorado, Illinois, Indiana, Iowa, Kansas, Minnesota, New York, North Carolina, Pennsylvania, South Carolina, Texas, Utah, Wyoming, and Vermont. I have also presented expert witness testimony before District Courts in the states of Colorado, Iowa, Missouri, and Nebraska; and before Courts of Condemnation in the states of Iowa and Nebraska. I have also served as a special advisor to the Connecticut Department of Public Utility Control.

Q. Please describe something of the nature of the firm of Black & Veatch.

A. The firm of Black & Veatch has provided comprehensive engineering and management services to utility, industrial, and governmental clients since 1915. The firm specializes in engineering and construction connected with utility services, including primarily electric, gas, water, wastewater, telecommunications, and waste disposal. Service engagements consist principally of investigations and reports, design and construction, feasibility analyses, rate and financial reports, appraisals, reports on operations, and general consulting services. Present engagements include work throughout the United States and various foreign countries. Including personnel assigned to affiliated companies, we have a staff of about 9,000 people.

Q. For whom are you testifying in this proceeding?

A. I am testifying on behalf of The Empire District Electric Company (Empire or Company).

Q. What is the purpose of your direct testimony in this matter?

A. I sponsor the Company's proposed depreciation expense rates. In this regard, I present the results of the Black & Veatch report entitled "Analysis of Depreciation Accrual Rates," dated October 31, 2000. This study is based on plant balances as of December 31, 1999, with the exception of plant investment in State Line Unit 2, which is based on June 1, 2001.

Q. Have you previously investigated depreciation expense rates applicable to Empire?

A. Yes, I have. I completed studies based on plant data as of December 31, 1997, 1996, 1995, and 1992. The results of my current study are consistent with my findings in my earlier studies.

Q. Please outline your direct testimony.

A. I will (1) present my findings and conclusions and address depreciation expense rates in general; (2) present my proposed rates for the Company's unit and mass properties; (3) address the conversion of State Line Unit 2 to a combined cycle generating unit, and (4) address my proposed treatment of depreciation reserve surplus and deficiency.

Q. Do you sponsor any schedules with your direct testimony?

A. Yes, I do. I sponsor two schedules. These are:

- Schedule LWL-1 - a copy of the Black & Veatch Report on Analysis of Depreciation Accrual Rates prepared for The Empire District Electric Company dated October 31, 2000. This report was prepared under my direction and supervision.
- Schedule LWL-2 – A copy of the forecast of operation and maintenance expenditures (expenses and capital) at the Company's State Line generating station for the 20-year

period beginning June 1, 2000. This report was prepared by personnel assigned to Black & Veatch's Power Division in the course of their role as design engineer for the conversion of State Line Unit 2.

Conclusion

Q. What are your findings and conclusions?

A. Based on the results of my analysis, I find that the Company's existing depreciation expense rates are wholly inadequate. The Company's existing rates do not offer a reasonable probability that plant investment will be recovered through depreciation charges during the service life of the property. In light of the significant deficiency in depreciation expense rates at this time, I recommend the Commission adopt and the Company charge the depreciation rates set forth in Table 7-1, (Pages 7-3 and 7-4), Column [E] of Schedule LWL-1. Implementation of these rates will result in an increase in annual depreciation expense of about $6 million annually as shown in Column [F], Line 74 of this same table.

Depreciation Rates - General

Q. How do you define depreciation?

A. My definition is the same as that set forth in the FERC Uniform System of Accounts. This definition generally provides that depreciation is the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.

With regard to this definition, the reference to value is from an accounting perspective where value represents the investment (original cost) in electric plant. By properly charging depreciation, the investment in plant (initial cost less recovery through salvage and plus cost of removal) is distributed over the useful life of the assets being depreciated. This distribution is intended to equitably allocate total investment in plant to periods during which service is provided through the use and consumption of such facilities.

Q. When were the Company's depreciation rates last revised?

A. The current depreciation rates were approved by the Missouri Public Service Commission in 1994 in Case No. ER-94-174, based on plant investment as of December 31, 1992.

Q. What method do you use to develop your recommended rates?

A. I use the whole life method. Following the whole life method, the cost (investment) in plant is recovered uniformly over the life of the property.

Q. Are the procedures you follow the same for unit property and mass property?

A. No, they are not. Consistent with the whole life concept, for unit property (production plant), I develop a "history" of investment activity for each generating station. This "history" includes not only historical investment (additions) but also investment activity (interim additions, retirements, and balances) for each year that the unit is forecast to remain in service. With this information, I can reasonably calculate a whole life depreciation expense rate by dividing the sum of gross additions (investment to be recovered) by the sum of the annual depreciable balances (historical and forecast) over the life of property. I then adjust this accrual rate to reflect consideration of the recovery of investment through salvage and the additional "investment" required to remove plant from service. I consider net salvage (salvage less cost of removal) for both interim and final retirements.

Q. How are mass properties treated?

A. For transmission, distribution, and general plant (collectively, mass properties), I perform actuarial studies to determine the experienced mortality characteristics of property for each FERC account. Based upon the historical plant activity, a survivor stub curve is developed based on the percent of investment surviving by age. Using a least squares analysis technique, this experienced survivor stub curve is compared to general survivor curve types to identify the best fitting curves and service lives. I use the historical life developed by this method, results of prior studies, engineering judgement, and other considerations to determine a reasonable average service life and survivor curve applicable for each account. I calculate the depreciation expense rate by dividing one minus the forecast net salvage ratio by the average service life.

Unit Property

Q. Please describe your analysis of each of the Company's generating stations.

A. I apply the whole life procedure separately to each of the Company's generating stations. By separately analyzing each station, I recognize its unique nature. The annual accrual rate I develop will, if applied to annual plant balances over the entire life of the station from the year of commercial operation to the year of retirement, recover the Company's total investment in the station. The principal forecasts I rely on in the analysis include:

- The retirement date for each generating unit.
- The net salvage values at the retirement date.
- The forecast level of interim additions and retirements.
- Net salvage associated with interim additions and retirements.
- There will be no additional major plant additions, life extension costs, or equipment modifications.

Q. What service life have you estimated for each generating unit?

A. The Company's share of Iatan Unit No. 1 is jointly owned with and operated by the Kansas City Power & Light Company (KCPL). A life span of 35 years is estimated for this unit based on my understanding of the current depreciation practices of KCPL for this plant.

With respect to the Company's Asbury generating plant, I use a base line service life of 45 years. I believe this is a reasonable estimate given the age of the Riverton units, which the Company plans on retiring in 2008, and the age, size, and interim investment Empire has made at the Asbury Plant. For the Riverton combustion turbines, I use the service life based on the planned retirement of Unit 9 in 2008 and of Units 10 and 11 in 2017. For the Company's other combustion turbine based generating units, I use a base line service life of 35 years. For the Company's hydroelectric facility at Ozark Beach, I use a planned retirement date that corresponds to the expiration of the current license of this plant.

Q. Do you use a 45-year service life for both units at Asbury?

A. No, I do not. My treatment of Asbury reflects the fact that though the Company identifies two units at the plant, operationally, for depreciation expense and retirement planning purposes, there is only one.

Q. Please explain.

A. The Asbury Plant originally went into service in 1970. At that time, the plant consisted of a single boiler and a 191 MW steam/generator set (Unit 1). After the plant began commercial operations, Empire found that there was substantial capacity in the boiler which could not be utilized by the existing turbine/generator (Unit 1). In order to use this available capacity, the Company purchased a small, used (20 MW) turbine/generator set and added it to the plant in 1986. This small turbine/generator is referred to as Unit 2.

In the depreciation study which underlies the existing depreciation rates, Unit 1 is assumed to have a 45-year service life (2015 retirement), and Unit 2 is also assumed to have a 45-year service life (2031 retirement). I further understand that a portion of the boiler investment is allocated to "Unit 2."

This treatment is totally at odds with reality. Generally, boiler life tends to control plant life. When the boiler is retired, the entire plant will most likely be retired. The boiler is not divisible. It is a single integrated piece of equipment, which for most plants (including Asbury) is field erected and not transportable.

Even if the boiler does not control life, the Unit 1 turbine/generator will control the life of the boiler and the smaller (Unit 2) turbine/generator. Without the requirements of the large turbine/generator (Unit 1), the size of the boiler precludes its economic use solely to supply steam to the smaller turbine (Unit 2) alone.

Q. Could the Asbury Plant be reconfigured to allow Unit 2 to remain in service upon the retirement of Unit 1?

A. Certainly. However, that would involve an extremely large expenditure to permit, modify, and/or add to the plant in order to continue to operate the Unit 2 turbine/generator.

Consistent with my prior depreciation analyses, I tie the life of Unit 2 to Unit 1. By so doing and reflecting engineering reality, I recognize that following the whole life method it is inappropriate to recognize life in Unit 2 without recognizing the investment which would be required in order for Unit 2 to operate beyond the retirement of Unit 1. I have synchronized, consistent with the whole life concept, the investment to be recovered with the life "provided" by that investment. I use a service life for Unit 2 which corresponds to the level of investment I recover over that life.

Mass Property

Q. You touched earlier upon the approach you use to develop depreciation expense rates for mass property accounts. How do you distinguish mass property from unit property?

A. Mass property represents a collection of a relatively large number of homogeneous property units (i.e., poles, conductors, conduits, and meters) which are retired individually. Unit property, on the other hand, is characterized as a collection of interconnected, integrated, heterogeneous property elements; the individual components which have limited value outside their contribution to the whole. While individual components of the whole may be retired and/or replaced prior to final retirement, most components comprising the system will be retired with the balance of the whole. This retirement en masse is due to the fact that the benefit provided (engineering value) is a result of the inter-relationship of individual components with the whole.

Q. Does this difference affect how you develop depreciation rates?

A. Yes, it does. For unit property, my concern is that the life of the unit be synchronized with the total investment to be recovered. The total investment associated with a number of heterogeneous components. This requires that interim additions and retirements (those individual heterogeneous components) be incorporated in the development of depreciation expense rates since their cost must be recovered over the life of the facility, not over the life of the individual component. For mass property, interim additions and replacements are not a factor since the service life of individual components is not affected by the life of the system. The homogeneous nature of the property components allows depreciation rates to be developed based on the average service life of all units.

State Line Plant

Q. Please describe State Line Plant and the changes occurring there.

A. On December 31, 1999, the plant consisted of Unit 1, a 90 MW combustion turbine and Unit 2, a 152 MW combustion turbine. These were both simple cycle units. Though in service on December 31, 1999, work was underway to convert Unit 2 to combined cycle operation. On October 1, 2000, Unit 2 was removed from service in order to complete conversion of the unit. Unit 2 is scheduled to return to service on June 1, 2001. On June 1, 2001, the State Line Plant will have a total capacity of 590 MW. Unit 1, a 90 MW simple cycle combustion turbine, will operate as a peaking unit. Unit 2 combined cycle plant, with a capacity of 500 MW, will operate as a base load resource. The Company will retain 100 percent ownership of Unit 1. Unit 2 will be jointly owned by the Company (60 percent ownership share) and Western Resources (40 percent ownership share).[1] Common facilities, such as offices and maintenance buildings, will be owned 66 percent by the Company and 34 percent by Western Resources.

Q. With the conversion of State Line Unit 2 to combined cycle operation, does the Company's State Line Plant offer challenges in developing reasonable depreciation rates?

A. Not really, if we are consistent in our methodology. The challenge is that the plant is new and, therefore, retirement and other historical data are not available to use as a forecasting tool over the balance of the plant's life.

Q. Are there distinguishing features about the State Line Plant which separate it from the other plants?

1 Unless otherwise indicated, cost and capacity figures cited in this testimony are for the total unit (combined Empire and Western Resources share).

A. Yes, there are several. Foremost in connection with developing depreciation rates is the difference in expected interim capital requirements of the plant relative to other plants. This difference affects both units. This difference relates to different construction focus today relative to the date the Company's other plants went into service. This difference is discussed in Section 6 of Schedule LWL-1.

Q. Have there been substantial capital additions to the Company's other plants?

A. Yes, there have. However, these major capital items have not been of the magnitude or frequency contemplated for State Line Plant, nor can they be forecast as reliably as for State Line Plant.

Q. You indicate that capital requirements for State Line Plant are both substantial and can be reasonably forecast. Please explain.

A. Black & Veatch is responsible for the design and engineering in connection with the conversion of the State Line Unit 2 from simple cycle to combined cycle operation. In this regard, professionals assigned to our power generation group developed cost estimates for both Units 1 (simple cycle operation) and 2 (combined cycle operation). Schedule LWL-2 is a copy of the report prepared regarding the timing and level of costs necessary to operate the plants during the first 20 years of operation.

The expenditure levels are based on certain routine activities as specified in the report. These activities generally correspond to the number of equivalent starts that a unit undergoes in peaking operation or to the number of hours under load for combined cycle units operating in more of a base load manner. The activities are specified by the manufacturer and then costed based on input from the manufacturer as well as our experience. The following summarizes expenditure levels based on 2001 cost levels.

Level of Effort	Required Every Starts / Hours	Unit 1 $ million	Unit 2 $ million
Minor	400 / 8,000	0.5	1.8
Intermediate	800 / 24,000	2.3	12.0
Major	1,600 / 48,000	7.1	22.7

Based on this schedule, and based on forecast operating patterns, cost levels by year can be developed. This schedule is illustrated in Table 1 and Table 4 of Schedule LWL-2 based on 2001 cost levels assuming outages and major maintenance services are performed under long term contract with Siemens Westinghouse, the turbine/generator supplier. As can be seen in Schedule LWL-2 and in the above, minor activities occur generally every other year and their cost is relatively modest. Intermediate activities occur generally every 5 to 6 years with cost levels on the order of 5 times that of the minor effort. Major activities generally occur every 8 to 12 years with cost levels on the order of 12 times that of the minor level of effort.

Based on the frequency, timing, and magnitude of these forecast expenditures, I concluded that costs in excess of the minor level of effort should be capitalized for the purpose of developing depreciation expense rates.

Based on this schedule of interim capital additions and corresponding retirements and recognizing modest price level increases, along with allowance for salvage and cost of removal, I develop whole life depreciation rates for the State Line Plant. As shown in Table 7-1 of Schedule LWL-1, the base accrual rate I find for State Line Unit 1 is 4.79 percent and 4.93 percent for State Line Unit 2.

Depreciation Reserve

Q. How does depreciation reserve affect whole life depreciation rates?

A. As can be seen from examination of Schedule LWL-1, the base rates I develop differ in some instances substantially from the existing depreciation rates. This difference may result in a surplus or deficiency in the depreciation reserve relative to the level required by the whole life rate. Depreciation reserve surplus or deficiencies can arise for a variety of causes. Some causes are:

(1) Failure to include forecast levels of interim additions and retirements that correspond to levels which actually occur.

(2) Changes in average service lives occasioned by changes in technology, equipment, and other factors.

(3) Average service lives that do not correspond to actual experience due to inadequate historical retirement data or other considerations which lead to use of an average service life which differs from actual.

(4) Failure to include an allowance for net salvage at a level which corresponds to actual experience and forecast levels.

Q. Do you calculate a substantial reserve deficiency or surplus?

A. No, I do not consider the indicated deficiency or surplus particularly substantial. In total, I find a reserve deficiency of $23.0 million (see Schedule LWL-1, Table 7-1). When compared with $941 million in plant, this deficiency is less than 2.5 percent.

Further, while there are other differences, the entire aggregated deficiency can be attributed to the Asbury Plant. The deficiency attributed to the Asbury Plant is due in large part to the improper service life used in developing the existing depreciation expense rates for Unit 2.

Q. There appears to be substantial surplus or deficiency associated with State Line Units 1 and 2, respectively. Why are these amounts so great?

A. Since both units are relatively new and Unit 2 is being converted to combined cycle operation, one would expect that any reserve surplus or deficiency would be relatively minor. Based on my investigation, I conclude that the magnitude shown is attributable to the conversion of Unit 2 to combined cycle.

With respect to Unit 1, $3.7 million of common plant is reclassified from Unit 1 to Unit 2. This reclassification results in a substantial reserve surplus. In large part, the reserve deficiency attributable to Unit 2 is due to the replacement and upgrade of the hot gas path in March 2000. The result of upgrading the existing combustion turbine to increase its capacity involved the retirement of about $4 million of existing investment and replacing the facilities retired with equipment of about the same cost. An addition and retirement of this magnitude was not considered in developing the existing rate.

Q. What is your recommended treatment of the reserve surplus and deficiencies shown in Schedule LWL-1, Table 7-1?

A. I recommend that the surpluses and deficiencies be amortized and recovered prospectively through depreciation expense rates. The base depreciation rates I have previously discussed are shown in Column [B] of Table 7-1 of Schedule LWL-1. My recommended rates shown in Column [E] of that same schedule include an adjustment to amortize the indicated surplus or deficiency.

Q. Does this conclude your direct testimony in this matter?

A. Yes, it does.

Affidavit

State of Missouri)
) ss
County of Jackson)

On the 31st day of October, 2000, before me appeared L. W. Loos, to me personally known, who, being by me first duly sworn, states that he is Vice President of the Energy Services Group of the Management Consulting Division of Black & Veatch and acknowledged that he has read the above and foregoing document and believes that the statements therein are true and correct to the best of his information, knowledge and belief.

L W Loos
L. W. Loos

Subscribed and sworn to me this 31st day of October, 2000.

Linda K Mitchell
Notary Public

My Commission Expires

Notary Seal
STATE OF MISSOURI
Cass County
My Commission Expires June 26, 2002

Report on
Analysis of Depreciation
Accrual Rates

prepared for

EMPIRE

The Empire District
Electric Company

October 31, 2000

BLACK & VEATCH
Corporation

SCHEDULE LWL-1

BLACK & VEATCH

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Tel: (913) 458-2000

Black & Veatch Corporation

October 31, 2000

Mr. Robert Fancher
Vice President - Finance
The Empire District Electric Company
602 Joplin Street
Joplin, Missouri 64802

Dear Mr. Fancher:

Our enclosed report summarizes the results of our analysis of the depreciation accrual rates for the electric utility properties of The Empire District Electric Company (Company). Our studies are divided into two parts. The first part pertains to property currently in reserve. The second part relates to the State Line Unit 2 combined cycle generating unit currently under construction.

With regard to property currently in service, our studies are based on plant balances as of December 31, 1999. In this regard, our report updates previous studies we prepared for the Company in 1993 and a preliminary study we prepared in 1997. The results of our analyses demonstrate that the Company's existing depreciation expense rates applicable to property currently in service are inadequate. Existing rates do not offer a reasonable probability that investment will be recovered through depreciation charges during the service life of the property. Ultimately the appropriate level of depreciation expense rates is a management decision taking into consideration various factors. However, in light of the significant deficiency in depreciation expense rates at this time, we urge implementation of the rates set forth in Column F of Table 7-1 of this report. Implementation of these rates will result in an increase in depreciation expense of about $6.0 million annually.

With regard to the State Line Unit 2 combined cycle generating unit, this unit is currently under construction. It is scheduled for commercial operation on June 1, 2001. The development of an appropriate depreciation expense rate for this unit presents a number of challenges. Our studies pertaining to State Line Unit 2 are based on plant balances as of June 1, 2001. Based on our studies, we find that in order for Empire to have a reasonable probability of recovering its investment in the State Line Unit 2 generating facility, a depreciation expense rate of not less than 4.99 percent must be charged. We recommend the Company use this 4.99 percent rate for State Line Unit 2. This rate will produce an annual depreciation expense for Unit 2 of $7 million, based on the Company's 60 percent ownership share.

It has been a pleasure to be of assistance to The Empire District Electric Company in this matter. We will be available to discuss the results of this report at your convenience.

Very truly yours,

BLACK & VEATCH CORPORATION

L W Loos

L. W. Loos

jjt
Enclosure

Contents

List of Tables

Executive Summary

This report describes the analyses conducted and the results obtained for the electric utility property of The Empire District Electric Company with respect to its depreciation expense rates and accumulated provision for depreciation. This report is based on plant activity through December 31, 1999 with recognition given to known or planned changes since that date. The depreciation rates developed in this report are considered appropriate for use in the near future. We recommend these rates be reviewed at least every 3 to 5 years. Ultimately the appropriate level of depreciation expense rates is a management decision taking into consideration a wide range of plant specific, corporate and regional factors. However, in light of the significant deficiency in existing rates, we recommend implementation of the depreciation expense rates set forth in Column F of Table 7-1. Implementation of these rates will increase annual depreciation expense by about $6.0 million annually. Of this amount, approximately $2.3 million relates to Empire's portion of the investment in its State Line Unit 2 combined cycle plant.

Our analyses of depreciation expense rates is based on application of the whole life depreciation expense rate method. This method is premised on recovery of plant investment in generally equal amounts over the service life of plant facilities. In order to recognize changes which have occurred and are occurring with respect to changes in investment level and in the life characteristic of individual property units, adjustment is included in the development of the whole life rate to recognize reserve surplus and deficiency.

For mass property accounts (accounts other than production), we base whole life depreciation expense rates, in large part, on life characteristics developed using statistical analysis of plant additions, retirements, and balances. We include allowance for cost of removal and salvage based on historical experience adjusted to reflect consideration of past, present, and anticipated future factors which have a bearing on such costs.

For production property, we base whole life depreciation expense rates on best available estimates of the prospective retirement date of each generating unit operated by the Company. Consistent with the whole life concept and the prospective retirement date used, we include an allowance for interim additions and retirements of individual pieces of property. We also reflect consideration of salvage and cost of removal.

The scope of this report includes:

(1) a discussion of the practice of depreciation accounting (Section 2).

(2) the types of information examined in our analysis and the methods applied (Section 3).

(3) the results of the analyses conducted pertaining to production plant (Section 4).

(4) the results of analyses conducted of the Company's transmission, distribution, and general plant (Section 5).

(5) discussion regarding factors considered in our recommended depreciation rates for the Company's State Line generating station (Section 6).

(6) the results of our analysis of depreciation reserve (Section 7).

As stated previously, we recommend the Company change its depreciation expense rates. We recommend the Company implement the depreciation expense rates based on the analyses set forth in Sections 4.0 and 5.0 and that depreciation rates incorporate the implications of any indicated surplus or deficiency in the depreciation reserves for each account. This depreciation reserve analysis and adjusted accrual rates are summarized in Section 7.0.

Application of the depreciation rates set forth in Section 7.0 results in an increase in annual depreciation expense when applied to total Company depreciable plant as of December 31, 1999[1] of about $6 million. This increase is over the existing depreciation expense rates which were approved by the Missouri Public Service Commission in 1994 based on plant activity through December 31, 1992. The increase in depreciation expense is in large part attributable to several distinct factors. They are:

1. Recognition that both turbine/generator units at the Company's Asbury Plant will be retired concurrent with the retirement of the single steam generator at the plant.
2. Major additions of $5.1 million for a cooling tower and basin at the Asbury Plant in 1997 and $3.8 million to Account 312, Boiler Plant Equipment.
3. Additions of $1.6 million to Riverton combustion turbine units and $352,000 to Riverton steam units required as a result of flood damage in 1993.
4. Inclusion of State Line investment of combustion turbine Units 1 and 2, which were placed in service in 1995 and 1997, respectively, and the subsequent conversion of State Line Unit 2 from a simple cycle unit to a combined cycle operation.
5. Recognition of life characteristics specific to computer equipment included in Account 391, Office Furniture and Equipment.
6. Recognition of the planned retirement of the Riverton Plant Units 7, 8, and 9 in 2008.

1 With regard to State Line Unit 2, Empire's 60 percent interest in depreciable plant as of June 1, 2001 is used. June 1, 2001 is the date this unit is scheduled to return to service in combined cycle operation.

1.0 Introduction

This report presents the results of our analysis of the depreciation expense requirements for the electric utility property of The Empire District Electric Company (Company). The analysis is based on plant activity through December 31, 1999 (June 1, 2001 for State Line Unit 2). Implications of certain known and measurable changes that have occurred or are planned subsequent to December 31, 1999, are incorporated in the analysis.

We consider the rates developed and recommended in this report to be reasonable and appropriate for use prospectively. However, we do recommend that depreciation rates be reviewed every 3 to 5 years. We understand current depreciation rates were approved by the Missouri Public Service Commission in 1994 (Case No. ER-94-174) and are based on plant activity through December 31, 1992. Subsequent to the Commission's order, we prepared studies similar to those set forth in this report based on plant activity through December 31, 1995, 1996, and 1997. The results of those studies are generally in line with results presented in this report.

Currently, the Company accrues depreciation expense and maintains reserve balances by Federal Energy Regulatory Commission (FERC) account for its mass accounts. For production properties, depreciation expense is calculated separately for each generating facility by FERC account. In this report, annual depreciation expense rates are calculated by individual FERC account and for each generating facility.

In Section 2.0 of this report, we briefly discuss the practice of depreciation accounting. In Section 3.0 we discuss, in general, the type of information examined in the analysis and the methods applied to develop depreciation expense rates. The results of the analyses performed are discussed in Sections 4.0 through 7.0. These include a determination of whole life depreciation accrual rates for production, transmission, distribution and general plant, and an analysis of depreciation reserve. Whole life depreciation expense rates are developed for the purpose of this report consistent with our understanding of current Missouri Public Service Commission practice.

For some accounts, the depreciation accrual rates developed in this report are substantially less or greater than the rates currently used by the Company. These differences generally result from the occurrence of one or more of the following:

1. Additional information regarding plant history (retirement history) and changes in life characteristics indicated by such additional data.
2. Changes in life characteristics due to changes in equipment and/or manufacturing methods.

3. Changes in the anticipated retirement date of production plants and estimated cost of retirement (cost of removal/salvage).
4. Investment in electric utility generating property in excess of levels forecast in the development of existing rates.
5. Adjustment for amortization of depreciation reserve.

The two most significant changes relate to the prospective retirement of the Company's Asbury coal-fired steam generating station and the depreciation expense requirements associated with the Company's State Line generating station. Consistent with our recommendation in our December 1993 report and subsequent studies, we recognize the prospective retirement of the entire Asbury Plant will correspond to the estimated 45-year service life of the single steam generator located at the plant. We understand this controlling element of life has not been recognized heretofore in the development of depreciation expense rates charged by the Company.

With regard to the State Line Plant, the significant change in depreciation expense rates relates to (1) the investment incurred in converting the plant to combined cycle operation, and (2) to the substantially higher forecast interim capital additions required for the two units to achieve the forecast 35-year service life.

2.0 Depreciation Accounting

Depreciation is the loss in service value[2] not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes considered are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.[3]

Depreciation accounting provides a method whereby charges for the loss in service value are made against current income. By properly charging depreciation, the net investment in plant (gross plant investment less salvage plus cost of removal) is distributed over the useful life of the asset in such a way as to equitably allocate the investment to the period during which service is provided through the use and consumption of such facilities.

2.1 Annual Depreciation Expense

The annual depreciation expense represents the annual charge against income associated with the loss of service value of utility equipment. A number of different methods have been used by electric utilities to determine the level of depreciation expense to be charged against current income. Among the more common are:

1. A direct appropriation by management.
2. A percentage of revenues.
3. An amount equal to the original cost investment retired during the year.
4. A charge per unit of delivery (kWh, kW, etc.).
5. A percentage of the investment in depreciable property.

The Company's depreciation rates were last evaluated by the Commission in 1993. The current depreciation rates were approved by the Missouri Public Service in 1994 in Case No. ER-94-174. We conducted subsequent reviews of depreciation expense rates in 1996, 1997, and 1998. Annual depreciation expense is calculated by the Company based on application of straight-line depreciation rates to the respective plant investment account balances. In essence, the annual depreciation expense rate is a percentage figure which, when applied to the dollar balance of investment in plant, yields a depreciation expense level which is expected to amortize

2 For the purpose of this report, we use the term "loss in service value" in the accounting sense where value is equated to original cost.

3 This definition of depreciation is the same as set forth in the Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act. (18 CFR Part 101 Definitions.)

the Company's net investment over the whole life of the property in generally equal annual amounts.

2.2 Depreciation Reserve

Depreciation reserve is a balance sheet item that reflects accumulation of the activity related to annual depreciation expense and retirement accounting. Under the FERC Uniform System of Accounts, depreciation reserve is shown on the balance sheet as "Accumulated Provision for Depreciation."

The depreciation expense charged against income is credited to (accumulated in) depreciation reserve. Depreciation reserve is reduced by the original cost of investment, is increased by salvage realized, and is reduced by the cost of removal associated with property retired. The use of proper annual depreciation rates to amortize investment over its useful service life will result in accruals to the depreciation reserve which equal the total investment ultimately retired, adjusted for salvage and cost of removal.

3.0 Historical Information and Procedures

Our determination of a reasonable annual depreciation rate as a percentage of investment (cost) in depreciable property is largely dependent on analysis of Company records which show additions by year of installation (vintage year) and retirements by year of installation and by year of retirement. The property records of the Company are kept in accordance with the Uniform System of Accounts as prescribed by the FERC. The property records for production plant are maintained by individual generating station and show the cost of property installed and retired each year. The property records in all other property accounts (mass property accounts) show the aggregate investment activity for all property in that account (regardless of location). Salvage value and removal costs are reported by account.

The methods we use to estimate average service lives in this report include planned retirement dates of unit properties (production plant), actuarial analysis, review of service lives of similar types of properties, analysis of retirement history, and engineering judgment. The actuarial procedure we use to estimate mortality characteristics of group (mass) properties such as poles and meters is based primarily on the historical relationship of retirements to investment exposed to retirement. Actuarial analysis cannot be used for unit properties such as production plant because of the lack of homogeneity.

The procedure we use for production plant involves developing a history of investment activity for each generating station. For the Company's steam generating stations, we develop this history by account. This life history reflects gross additions, retirements, surviving property, and account balances. Based on the estimated life (current planned retirement date) for each generating unit, we forecast plant investment activity (interim additions, retirements, and balances) for each year that the unit is forecast to remain in service. We then calculate a whole life, straight line depreciation accrual rate by dividing the gross additions (original investment plus interim additions) by the sum of the annual depreciable balances over the life of the unit. Gross additions include both historical and forecast additions to plant over the forecast life of the plant. Annual depreciable balances are based on actual balances reported plus forecast balance based on forecast additions and retirements. We adjust this accrual rate to reflect consideration of salvage and cost of removal for both interim and final retirements.

For transmission, distribution, and general plant properties, we perform actuarial studies to determine the experienced mortality characteristics of property for each FERC account. Based upon the historical plant activity, a survivor curve that explains the percent of vintage additions surviving by age is developed for each account. Using a least squares analysis technique, this experienced survivor stub curve is compared to general survivor curve types to identify the best fitting curves and service lives. We use the historical average service life developed by this method, results of prior studies, engineering judgment, and other considerations to determine a reasonable average service life applicable for each account. We calculate the depreciation expense rate by dividing one minus the expected salvage ratio by the average service life.

We determine salvage (or cost of removal) ratios based on analysis of the most recent 30 year history of plant retirements, salvage and cost of removal values, engineering judgment, and experience.

4.0 Production Plant

In Table 4-1 we summarize the net salvage ratios and whole life depreciation accrual rates we recommend for production plant by FERC account numbers.[4] The whole life accrual rate is defined as the rate which, when applied to annual depreciable plant balances, will result in recovery of the original cost of gross additions (plus cost of removal and less salvage) over the entire life of the property. The depreciation accrual rates developed in this report are based on application of the whole life method. We include no adjustment in the base accrual rates to amortize any surplus or deficiency between the book accumulated provision for depreciation and the indicated depreciation reserve requirement. This adjustment is incorporated in our recommended rates as discussed in Section 7.0.

Summary data regarding the electric generating stations owned by the Company as of December 31, 1999 is presented in Table 4-2. This table summarizes the in-service date, projected retirement date, capacity rating, unit type, and fuel type for each unit. The retirement dates shown in Table 4-2 are based on the Company's current plans. No retirements are currently scheduled by the Company until the year 2008. We show in Table 4-2, data for the Company's State Line Unit 2 as a combustion turbine and as a to combined cycle unit.

Since our 1993 report, the Iatan Unit Train and Riverton Unit No. 6 were retired in 1995 and 1996, respectively. The Company's State Line combustion turbine Units 1 and 2 went into service in 1995 and 1997, respectively[5]. We also recognize a change in the projected retirement dates of Riverton Units 7, 8, and 9 from 2012 to 2008. The projected retirement dates for Riverton Units 10 and 11 remains at 2017.

We apply the whole life analysis procedure separately to each of the Company's generating stations. By separately analyzing each station, we recognize its unique nature. The annual accrual rate we develop will, if applied to annual plant balances over the entire life of the station from the year of commercial operation to the year of retirement, recover the Company's investment in the station. The principal forecasts we rely on in the analysis include:

- The retirement date for each generating unit.
- The net salvage values at such date.
- The level of interim additions and retirements.
- The net salvage values associated with interim retirements.

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4 For Other Production Plant, we recommend composite depreciation accrual rates for each plant (for each unit at State Line). We do not recommend separate rates for each account.

5 Subsequently, beginning in March 1999, the Company began converting the 152 MW simple cycle Unit No. 2 combustion turbine to combined cycle operation. This conversion includes removing Unit 2 from service beginning October 1, 2000 until June 1, 2001 when it will return to service as a combined cycle unit.

- There will be no major plant additions, life extension costs, or equipment modifications except as discussed in Section 6.0 with regard to the State Line Plant.

Table 4-1
Empire District Electric Company
Depreciation Rate Analysis - Unit Properties
Production Plant Summary
Recommended Depreciation Accrual Rates

Line No.	Account No.	Description	[A] Recommended Base Accrual Rate	[B] Recommended Net Salvage Final	[C] Recommended Net Salvage Interim
			%	%	%
		Asbury			
1	311	Struct. & Improv.	4.94	-10.00	-10.00
2	312	Boiler Plant Eq.	5.42	-5.00	-20.00
3	312	Unit Train	3.98	10.00	10.00
4	314	Turbogen. Units	3.64	0.00	-15.00
5	315	Acc. Elect. Equip.	2.84	5.00	-5.00
6	316	Misc. Pwr. Plt. Eq.	6.06	5.00	0.00
		Riverton			
7	311	Struct. & Improv.	4.19	-10.00	-10.00
8	312	Boiler Plant Eq.	3.77	-10.00	-25.00
9	314	Turbogen. Units	2.78	0.00	-15.00
10	315	Acc. Elect. Equip.	2.21	5.00	-5.00
11	316	Misc. Pwr. Plt. Eq.	4.94	5.00	0.00
		Iatan			
12	311	Struct. & Improv.	3.92	-10.00	-10.00
13	312	Boiler Plant Eq.	3.26	-5.00	-20.00
14	314	Turbogen. Units	3.09	0.00	-15.00
15	315	Acc. Elect. Equip.	2.94	5.00	-5.00
16	316	Misc. Pwr. Plt. Eq.	4.81	5.00	0.00
		Ozark Beach - Hydro			
17	331	Struct. & Improv.	3.50	-10.00	-5.00
18	332	Res., Dams & W. Ways	1.55	-10.00	-5.00
19	333	W Wheel, Tur. & Gen.	1.25	0.00	5.00
20	334	Acc. Elect. Equip.	3.21	5.00	0.00
21	335	Misc. Pwr. Plt. Eq.	4.53	5.00	0.00
		Other Production			
22	(1)	Riverton	4.09	5.00	-4.00
23	(1)	Energy Center	3.90	5.00	-4.00
24		State Line			
25	(1)	Unit No. 1	4.79	5.00	0.00
26	(2)	Unit No. 2 (Combined Cycle)	4.93	5.00	0.00

(1) Composite for Accounts 341 to 346.
(2) Composite for Accounts 310 to 353.

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Table 4-2

Empire District Electric Company
Summary of Production Plant Characteristics

Plant Name/Unit	In Service Date	Projected Retirement Date	Capacity	Unit Type	Fuel Type
			MW		
Riverton					
Unit 7	1950	2008	38.1	SC	Coal
8	1954	2008	53.2	SC	Coal
9	1964	2008	14.5	CT	Gas/Oil
10	1988	2017	16.5	CC	Gas/Oil
11	1988	2017	16.5	CT	Gas/Oil
Asbury					
Unit 1	1970	2014	191	SC	Coal
2	1986	2014	20	See Note (f)	
Iatan					
Unit 1	1980	2014	80(c)	SC	Coal
Ozark Beach					
Unit 1	1931	2022(a)	4	H	-
2	1931	2022(a)	4	H	-
3	1931	2022(a)	4	H	-
4	1931	2022(a)	4	H	-
Energy Center					
Unit 1	1978	2012(b)	90	CT	Oil
2	1981	2015(b)	90	CT	Oil
State Line					
Unit 1	1995	2029(b)	90	CT	Gas/Oil
2 CT(e)	1997	2031(b)	152	CT	Gas/Oil
2 CC	2001	2035(b)	300(d)	CC	Gas

SC = Steam Conventional   CT = Combustion Turbine – Simple Cycle

CC = Combined Cycle   H = Hydraulic

(a) The current operating license for the Ozark Beach Plant became effective March 1, 1992, for a term of 30 years.

(b) Based on estimated unit service life of 35 years.

(c) Company 12 percent share of jointly owned Iatan plant, 673.73 MW total capacity.

(d) Company 60 percent share of jointly owned State Line Unit 2 (Combined Cycle), 500 MW total capacity.

(e) Removed from service October 1, 2000. Will return to service June 1, 2001, as combined cycle plant jointly owned by Western Resources.

(f) Asbury "Unit 2" consists only of a turbine/generator unit, the structure housing it, and piping, electrical equipment, etc., to connect this turbine/generator unit to Unit 1. Empire added the turbine/generator in order to use available steam generating capability in the boiler that went into service in 1970. Though this turbine/generator set is referred to as Unit 2, it is not a separate unit as used in the conventional sense because, without the steam generating capacity in Unit 1, "Unit 2" cannot operate.

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The Company's share of Iatan Unit No. 1 is jointly owned with and operated by the Kansas City Power & Light Company (KCPL). A life span of 35 years is used for this unit based on our understanding of the current depreciation practices of KCPL for this plant. Values shown for the Iatan Plant in this report represent Empire's portion.

With respect to the Company's Asbury generating unit, we forecast a base line service life of 45 years. We believe this is a reasonable estimate given the age of the Riverton units and the age, size, and interim investment Empire has made at the Asbury Plant. The base line service life of the Company's combustion turbine and combined cycle units is 35 years. With respect to the Company's hydroelectric facility at Ozark Beach, we have used an estimated retirement date that corresponds to the expiration of the current license of this plant.

Table 4-1 sets forth the net salvage ratios used in this report for each plant and account. The production plant net salvage ratios are established separately for interim and final retirements. The net salvage ratios for interim retirements of production plant are based on consideration of the past 30-year history of net salvage actually experienced. The net salvage ratios we use in our analysis of interim retirements are conservatively estimated to be below the levels booked historically. In estimating net salvage/cost of removal allowances for production plant facilities, consideration is given to the relative cost associated with removal of asbestos and other materials which are considered hazardous. These materials were commonly used in power production facilities in the past.

The recommended composite base depreciation accrual rate for the Asbury Plant is in total 1.98 percent higher than the existing composite rate of 2.89 percent (see Table 7-1). The magnitude of this increase in depreciation expense rate is due, in large part, to recognition of the facilities in service and their dependency on other component parts. Asbury Unit No. 1 consists of one boiler and one turbine/generator set. "Unit 2" consists of only a turbine/generator set. Unit No. 2 is a small turbine/generator (previously used) that was added to Unit No. 1 in 1986 to better utilize available boiler capacity.

Prior to our study in 1993, we understand that the life of the second turbine/generator and a proportional share of Unit No. 1 boiler which powers this equipment was extended beyond the life of the single boiler.[6] This treatment fails to recognize that the life of "Unit 2" cannot be extended beyond the life of Unit No. 1 without the expenditure of extremely substantial sums. Consistent with our recommendation since 1993, the engineering reality of the plant's configuration, we retire all of Asbury Unit No. 1 and Unit No. 2 concurrent with the estimated retirement of the original turbine/generator and boiler (Unit No. 1). This treatment reflects the

6 We understand the depreciation rates approved by the Commission in 1994 follow this treatment (life of the second turbine/generator set extended beyond the life of the boiler).

fact that the existing boiler cannot be operated economically to power only the second, small turbine/generator. Further, when initially installed in 1986, this turbine/generator set had been previously used.

5.0 Transmission, Distribution, and General Plant

For transmission, distribution, and general plant accounts, we rely in large part on an actuarial method to estimate the average service lives. Average service lives used are based not only on this retirement history but also on the results of prior studies, engineering judgment, and other considerations.

Table 5-1 summarizes the average service lives and net salvage ratios used for the purpose of this report. We combine the estimated average service life with an allowance for net salvage to calculate a whole life depreciation accrual rate which is designed to recover the original cost investment over the expected life of the property. An underlying assumption of the whole life method is that for mass accounts, as property is retired and new property is installed, the average service life of the group does not change significantly. The whole life method is predicated on homogeneity of the property units included in the group. For property accounts that have significant retirement history, where vintage retirement history is available, and where life characteristics in the future are anticipated to be similar to the past, an actuarial analysis is used as the principal basis to estimate average service life.

In order to develop the annual accrual rates for the mass accounts using the whole life methodology, the expected average service life and the general survivor curve type that reasonably approximate the experienced survivor curve of the property account are determined. At our direction, Company personnel prepared detailed historical data for each account. This data includes additions, retirements, and adjustments by vintage and transaction year.

Upon receipt of this data, we verified its reasonableness and accuracy. In addition, we adjust certain data to eliminate negative vintage year plant balances. We analyze in detail the original cost additions by vintage year along with retirements and adjustments through the year 1999 to develop survivor curves based on the life (retirement) history of each plant account. "Stub survivor curves" are developed since development of a complete survivor curve is not possible until all property has been retired. Theoretically, a complete survivor curve can only be developed after a period of time equal to about twice the average service life and then only if the number of property units retired is sufficient to produce meaningful results. Since the average life of electricity utility property is normally expected to be in the range of 30 to 50 years, stub curves must be used.

The stub survivor curves developed from actual Company experience are compared with general survivor curves types as developed by the Iowa Engineering Experiment Station (collectively known as Iowa Curves). These curves represent a family of general retirement dispersion patterns of property. The comparison is accomplished through a statistical least squares procedure which identifies the best fitting average service life for each Iowa Curve type.

Table 5-1

Empire District Electric Company

Depreciation Rate Analysis - Mass Properties
Transmission, Distribution, and General Plant Summary
Recommended Depreciation Accrual Rates

			[A]	[B]	[C]
			Recommended		
Line No.	Account No.	Description	Average Service Life	Net Salvage Ratio	Base Accrual Rate
			Years	%	% (1-[B]/100)/[A]
1	**Transmission Plant**				
2	352	Structures & Improvements	50	(15)	2.30
3	353	Station Equipment	46	(20)	2.61
4	354	Towers and Fixtures	50	(25)	2.50
5	355	Poles and Fixtures	50	(30)	2.60
6	356	OH Conductors & Devices	50	(15)	2.30
7	**Distribution Plant**				
8	361	Structures & Improvements	50	(15)	2.30
9	362	Station Equipment	38	(10)	2.89
10	364	Poles, Towers, and Fixtures	41	(65)	4.02
11	365	OH Conductors & Devices	48	(20)	2.50
12	366	Underground Conduit	34	(5)	3.09
13	367	UG Conduct. and Devices	27	0	3.70
14	368	Line Transformers	40	(10)	2.75
15	369	Services	33	(25)	3.79
16	370	Meters	39	0	2.56
17	371	Install. on Cust. Premises	20	(10)	5.50
18	373	St. Lighting & Signal Systems	43	(20)	2.79
19	**General Plant**				
20	390	Structures & Improvements	25	(10)	4.40
21	391.1	Office Furniture and Equip.	20	0	5.00
22	391.2	Computer Equipment	5	10	18.00
23	392	Transportation Equipment	10	10	9.00
24	393	Stores Equipment	25	(5)	4.20
25	394	Tool, Shop and Garage Equip.	40	0	2.50
26	395	Laboratory Equipment	38	0	2.63
27	396	Power Operated Equipment	15	5	6.33
28	397	Communication Equipment	20	0	5.00
29	398	Miscellaneous Equipment	27	0	3.70

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The curve type selected and indicated service lives are determined primarily using a best-fit approach. For certain transmission plant accounts, our actuarial analysis indicated a service life far greater than considered reasonable. This result is common for mass property accounts that have little retirement history. In these cases, we use our knowledge of life history for similar property of other utilities and industry averages in estimating average service life and our judgment as to overall reasonable lives based on current conditions.

We develop recommended net salvage ratios for Transmission, Distribution, and General Plant accounts based on the average experienced net salvage ratios over the past 30 years, engineering judgment, and industry averages. The net salvage ratios we use represent levels we believe reasonably correspond to future retirements.

We calculate a base depreciation rate using the following equation:

$$\text{Depreciation Rate} = \frac{1 - \text{Salvage Ratio}}{\text{Estimated Average Life}}$$

As evident from the above, this equation consists of two elements. The first element reflects recovery of the initial investment. The second element reflects recovery of net salvage. The purpose of the net salvage element of the accrual rate is to credit salvage and recover cost of removal over the life of the property.

5.1 Transmission Plant

As of December 31, 1999, transmission plant facilities consisted of 17 transmission substations and about 1,330 pole miles of transmission circuits. Primary transmission voltages are 345 kV, 161 kV, 69 kV, and 34.5 kV. Generally, the causes for retirement of transmission plant have been obsolescence resulting from voltage upgrading, deterioration of wood poles and core wire oxidation of steel reinforced aluminum conductor. Based on a review of the results of actuarial analyses, along with consideration of the average age of retired properties and our engineering judgment, we use the average service lives shown in Table 5-1. The net salvage ratios are based on analysis of historical net salvage ratios and engineering judgment.

5.2 Distribution Plant

The Company's distribution plant consists of substations, overhead and underground lines, line transformers, services, meters, and lighting facilities. In Table 5-1, we show the average service lives and net salvage ratios we use for each plant account.

Much like the results of our analysis of transmission plant, relatively modest changes (relative to our prior reports) are recommended for the distribution plant accrual rates. Some minor changes are made to the net salvage ratios and the estimated average service lives.

5.3 General Plant

General plant consists of facilities and equipment which are used to support multiple functional plant and expense groups. We show in Table 5-1 the average service lives and net salvage ratios we use for each general plant account.

In order to recognize the different life characteristics of property included in Account 391, computer equipment was analyzed separately from office furniture and equipment. The Company provided historical plant activity for computer equipment. Computer equipment represents 36 percent of the plant balance for Account 391. We used actuarial analysis to study the average service life of the computer equipment, however, the results of the analyses indicated relatively high service life (15 years). This level is not representative of our experience in connection with contemporary computer equipment and software. Therefore, based on engineering judgment and experience with computer equipment, we find that an average service of life of 5 years and a 10 percent salvage ratio appropriate.

6.0 State Line Plant

In the prior sections of this report, we describe our development of depreciation expense rates associated with plant in service as of December 31, 1999. On that date, along with other production, transmission, distribution and general plant, the Company had its State Line simple cycle combustion turbine plant in service. On December 31, 1999, the plant consisted of Unit 1, a 90 MW combustion turbine and Unit 2, a 152 MW combustion turbine.

Though in service on December 31, 1999, work was underway to convert Unit 2 to combined cycle operation. On October 1, 2000, Unit 2 was removed from service in order to complete conversion of the unit. Unit 2 is scheduled to return to service on June 1, 2001. On June 1, 2001, the State Line Plant will have a total capacity of 590 MW. Unit 1, a 90 MW simple cycle combustion turbine, will operate as a peaking unit. Unit 2, with a capacity of 500 MW, will operate as a base load resource. The Company will retain 100 percent ownership of Unit 1. Unit 2 is jointly owned by the Company (60 percent ownership share) and Western Resources (40 percent ownership share).[7] Common facilities, such as offices and maintenance buildings, will be owned 66 percent by the Company and 34 percent by Western Resources.

Generally, a simple cycle combustion turbine like State Line Unit No. 1 is less efficient and is used primarily for peaking power generation. The gas turbine is operated alone, without the benefit of recovering any of the energy in the hot exhaust gases. The exhaust gases are sent directly to the atmosphere. Conversely, combined cycle units like State Line Unit No. 2 combine one or more gas turbines with one or more steam turbines to increase plant efficiency by utilizing a portion of the gas turbine exhaust gas to produce steam to power a steam turbine/generator set. The exhaust gas from the gas turbine is directed through a heat recovery steam generator (HRSG) that generates steam at one or more pressure levels. The steam is used to drive a steam turbine/generator to produce additional power beyond that produced by the combustion turbine driven generator(s). The extremely high efficiency of a combined cycle plant generally results in the plant being dispatched as base load resource. With the State Line Unit No. 2 combined cycle arrangement, the gas turbines cannot be "decoupled" from the operation of the steam turbine, allowing for steam turbine shutdown with continued gas turbine operation. As such, the plant is designed for base load operation.

State Line Unit 2 originally consisted of a Westinghouse 501F combustion turbine installed in 1997. In spring of 2000, the unit underwent a complete major overhaul to upgrade it from the original FC compressor design to the new FD compressor design. In October 2000, Unit 2 was removed from service to add a second Westinghouse 501F combustion turbine, two

7 Unless otherwise indicated, cost and capacity figures cited in this report are for the total unit (combined Empire and Western Resources share).

heat recovery steam generators, a steam turbine/generator, a cooling tower, and associated equipment to create a 2 X 1 (two combustion turbines, one steam turbine) F class combined cycle plant having a nominal capacity of 500 MW.

As with other production plants, there are three principal components leading to the development of a reasonable depreciation rate for the State Line Plant. These three components are:

1. Expected service life.
2. Capital additions (and retirements) required in order for the plant (unit) to realize expected service life.
3. Net salvage (gross salvage less cost of removal) associated with interim and final retirements.

In order to develop a reasonable and proper depreciation expense rate, these three components must be synchronized. For example, as the level of interim additions decrease, so does the expected life of the plant (unit). The need to tie interim additions and expected service life is especially critical for newer projects, such as State Line Unit 1 and Unit 2.

For the purpose of this report, we use a 35-year expected life for the State Line Plant. This 35-year life is at the upper limit of what we consider reasonable at this time. However, with sufficient interim additions, we believe with reasonable certainty, that physically, the unit will be capable of operating for a 35-year period.

We are somewhat less confident that the unit's economic life will extend for a 35-year period. Whereas physical life is in large part controlled by the level of investment made in a plant, economic life is, in large part, beyond the control of the owner/operator. Physical life is generally controlled by factors internal to the plant, whereas economic life is controlled by factors external to the plant.

Our economic concern is in two parts. First, the viability of Unit 2, especially as a base load resource, is in large part dependent upon the price of fuel (natural gas) relative to alternative fuels available for electric generation. For most of the past 20 years, the price and availability of natural gas for combined cycle electric generation was attractive relative to other fuels. The life cycle cost of combined cycle generation was competitive with and often substantially less than for coal-fired and nuclear steam generation. Combined cycle generation is even more attractive when the environmental risks associated with coal and nuclear are considered. With the recent increase and volatility in the wellhead cost of natural gas, the risk of an uneconomical fuel supply is heightened.

The second major risk pertains to obsolescence. With technological advances in distributed generation, the viability of central station generation may be threatened. The actual life achieved by the plant may be limited by obsolescence as well as fuel cost and availability.

For the purpose of this report, we do not reduce expected physical life (35 years) to reflect economic and/or obsolescence considerations.

In order to physically achieve a life span of 35 years as a base load unit (and Unit 1 as a peaking unit) will require the expenditure of extremely large sums. While the Company's experience has been that the need for capital additions and replacements are relatively modest for combustion turbines operating as peaking units, changes in equipment and construction practices do not reasonably allow one to extend historical experience to newer combustion turbines and other plant equipment.

Historically, "utility grade" generating resources have been constructed with reliability in mind. Redundant systems were often specified. Equipment was purchased with long-term serviceability and reliability in mind. Initial construction costs were not the primary concern so long as value was received and operating expenditures (including capital additions and replacements) were minimized. Historically, "utility grade" generation could be characterized by relatively high construction costs and relatively low capital additions and replacements.

Today, this concern is reversed. The primary and overriding focus is to minimize construction costs. As a result, equipment tolerances are closer, equipment is more closely engineered, less steel is used, and redundancies are eliminated. Economics of construction has replaced reliability as the primary focus. Plants built today have relatively lower initial cost. However, in order to realize front-end initial cost savings, higher operating and capital expenditures are required if a plant is to realize its service life potential.

Maintenance requirements, including interim capital additions and replacements, are in large part dependent upon how a plant is operated. The number of starts (and their severity) and the hours connected to load are the primary drivers of maintenance and normal interim capital additions and retirements.

Based on Table 5 of the "Operation and Maintenance Estimate for State Line Power Plant," developed by Black & Veatch in our role as plant engineer, the maintenance capital requirements (with a forecast of 3 percent annual cost level increase) of State Line Unit 1 and Unit 2 (combined cycle) that we include in our analyses are:

Year	Maintenance Capital Required at Unit 1	Maintenance Capital Required at Unit 2
	$	$
2005	7,372,100	11,941,600
2009	---	30,758,600
2012	2,436,900	---
2013	---	15,127,300
2017	---	38,964,000
2018	10,826,200	---
2020	---	18,604,700
2024	3,474,500	---
2025	---	49,358,500
2028	---	23,567,900
Total	**$24,109,700**	**$188,322,600**

In developing a depreciation expense rate which will recover investment over a plant's useful life, we must recover not only the initial investment over the facility's life, but interim investment incurred in order for the plant to realize that life. Assuming State Line Unit 2 (combined cycle) operates at a 70 percent capacity factor, over its 35-year expected life, interim additions required to keep the plant operating will total on the order of $188 million.[8] Interim retirements will closely match interim additions.[9] For Unit 1, these additions will total about $24 million.

With regard to salvage and cost of removal, interim additions, as developed in the foregoing, include allowance for net salvage for those individual projects. Thus, no additional net salvage needs to be considered. Final salvage used for the purpose of this report is set equal to 5 percent final retirements.

Based on the foregoing, we find the required base depreciation expense rate for State Line Unit 2 (combined cycle) is 4.93 percent, and State Line Unit 1 is 4.79 percent. Based on Empire's 60 percent interest in State Line Unit 2, the composite base rate for the State Line Plant amounts to 4.90 percent. We recommend Empire use these base rates for depreciating the State

8 This figure includes allowance only for major interim additions which can be forecast with reasonable certainty at this time. In addition to these major capital items, other smaller items will be incurred. For the purpose of this report, we include only those major items as capital additions and replacements. Minor items will be expensed. As experience with the plant and the accounting of expenditures is gained, additional allowances will likely be required.

9 For example, in 2020 hot gas path maintenance is forecast at a total cost of $21.1 million. Of this amount, for the purpose of developing depreciation rates $18.6 million is capitalized. The hot gas path maintenance required in 2020 will result in the retirement of $15.1 million capitalized in connection with hot gas path maintenance forecast for 2013.

Line Plant. These rates are based on recovery of the total investment over the service life corresponding to that investment. These base rates are not adjusted for the amortization of any depreciation reserve deficiency or surplus. An adjustment for amortization of reserve deficiency is discussed in Section 7.0.

7.0 Depreciation Reserve

We performed a detailed study of each FERC plant account and of each generating plant to determine the adequacy existing depreciation reserve levels. For unit properties such as production plant accounts, we calculate required reserves (as of December 31, 1999) based on the difference between (1) the plant balance as of December 31, 1999 plus forecast additions and final net salvage (investment to be recovered), and (2) the forecast depreciation accruals (reserves) over the remaining life of the plant. We forecast accruals based on the whole life base depreciation rates developed in this study (Sections 4 and 5) as adjusted for salvage and cost of removal associated with interim retirements.

For mass property accounts such as transmission, distribution and general plant accounts, we calculate reserves based on the difference between (1) the original cost of surviving properties and (2) the product of the annual base depreciation rate and the remaining life. We adjust the calculated theoretical reserve as necessary to reflect estimated salvage and removal costs.

In Table 7-1, we present a summary of the results of our reserve analysis and the indicated total accrual rates adjusted for the amortization of reserve surplus or deficiency. The total accrual rates (recommended) and the resultant increase or decrease in depreciation expense by account and by plant using the indicated rates are shown in Columns E and F, respectively. We show on Page 2 of Table 7-1 that our recommended depreciation expense rates applied to depreciable plant balances as of December 31, 1999 will increase annual depreciation expense by $6,028,225 over levels produced by existing rates. This $6.0 million increase is primarily due to increases in base rates applicable to Asbury Plant and to the implications of the relatively high level of interim additions forecast for the State Line Plant.

As shown in Table 7-1, our study shows that the total Company reserve deficiency of $23 million (Column D, Line 74) is within 5 percent of the $24 million reserve deficiency (Column D, Line 7) we find for the Asbury Plant. As discussed in Section 4.0, with respect to the Asbury Plant, we retire all facilities concurrent with the retirement of the original (Unit No. 1) turbine/generator and boiler. We follow this treatment because the existing boiler cannot be operated economically to power only the second, smaller turbine/generator as is assumed in the development of the existing deprecation rates. Other significant items that contribute to the overall increase in depreciation expense rates and to the overall reserve deficiency include:

1. A major addition of $5.1 million related to the cooling tower and basin at the Asbury Plant (Account 314) in 1997 and $3.8 million to Account 312 in 1998. We consider both costs major additions and reflect them as such in our analysis. Since these major additions were not considered in prior

depreciation studies, the whole life investment in the plant was understated by these amounts.

2. Costs attributable to flood damage in 1993 account for the addition of $1.6 million to Riverton combustion units and $352,000 to Riverton steam units. We consider these costs a major addition and do not reflect them in the interim addition ratio analysis.
3. The inclusion of the $176 million investment of State Line Units 1 and 2. Our analyses indicate a base accrual rate of 4.90 percent as compared with the existing rate of 3.37 percent. This difference in rates and the retirement of a portion of the existing Unit 2 combined turbine investment in connection with the conversion to combined cycle contribute to the indicated reserve deficiency.

Without adjustment, to the extent that calculated reserve is greater than or less than the book reserve, the Company will under or over recover, respectively, its depreciable plant investment. The purpose of the adjustment is to preclude the Company from recovering through depreciation accruals, amounts in excess or below its plant investment basis. This amortization also limits recovery from customers to the capital investment used to serve them during the period of service of each investment. Differences between the calculated theoretical reserve and the book reserve can be attributed primarily to changes in life characteristics and investment levels. These changing life characteristics and the degree to which these changes are recognized and reflected in the depreciation rates directly affect the book reserves.

With the similarity between the reserve deficiency associated with the Asbury Plant ($24,150,753) and the total Company ($22,981,978), existing reserves can be adjusted to eliminate nearly all of the deficiency. This can be accommodated by increasing reserves by the amount of the reserve deficiency shown in Column D of Table 7-1 for each account and each plant except for the Asbury Plant. In aggregate, reserves associated with mass property accounts would be reduced by $9,562,381 and reserves associated with production plants (except for Asbury) would be increased by $8,338,645. The difference, $1,168,775, would be used to increase the reserves applicable to the Asbury Plant. If these transfers are made, the amortization of reserve deficiency embodied in depreciation expense rates would be limited to a $22,981,978 deficiency in the Asbury reserve.

Table 7-1

Empire District Electric Company

Depreciation Rate Analysis - Indicated Rates
Reserve Analysis at 12/31/1999 (Note 3)
Page 1 of 2

			[A]	[B]	[C]	[D]	[E]	[F]
Line No.	Account No.	Description	Depreciable Plant	Base Accrual Rate	Existing Accrual Rate	Reserve (Surplus) or Deficiency	Total Accrual Rate	Increase (Decrease) Depreciation Expense
			$	%	%	$	%	$
		Asbury						
1	311	Struct. & Improv.	8,831,444	4.94	2.15	2,350,501	6.53	386,817
2	312	Boiler Plant Eq.	53,717,466	5.42	2.91	18,302,522	7.49	2,460,260
3	312	Unit Train	5,580,297	3.98	5.67	(124,378)	3.82	(103,235)
4	314	Turbogen. Units	19,559,979	3.64	2.60	2,869,992	4.60	391,200
5	315	Acc. Elect. Equip.	2,328,232	2.84	2.10	8,548	2.86	17,695
6	316	Misc. Pwr. Plt. Eq.	2,709,600	6.06	2.10	743,568	7.46	145,235
7		Total Asbury	92,727,018	4.87	2.89	24,150,753	6.45	3,297,970
		Riverton						
8	311	Struct. & Improv.	8,098,667	4.19	2.05	3,123,030	8.29	505,357
9	312	Boiler Plant Eq.	19,892,538	3.77	2.77	2,340,377	5.04	451,561
10	314	Turbogen. Units	6,469,874	2.78	1.79	(234,261)	2.38	38,172
11	315	Acc. Elect. Equip.	1,334,120	2.21	1.98	(356,173)	-0.73	(36,155)
12	316	Misc. Pwr. Plt. Eq.	1,405,029	4.94	2.02	510,469	8.64	93,013
13		Total Riverton	37,200,228	3.68	2.39	5,383,442	5.21	1,051,948
		Iatan						
14	311	Struct. & Improv.	3,789,814	3.92	3.35	557,092	4.83	56,089
15	312	Boiler Plant Eq.	28,143,993	3.26	4.19	(2,505,858)	2.68	(424,974)
17	314	Turbogen. Units	7,705,139	3.09	3.00	322,478	3.36	27,739
18	315	Acc. Elect. Equip.	3,494,267	2.94	3.18	30,545	3.00	(6,290)
19	316	Misc. Pwr. Plt. Eq.	702,319	4.81	2.94	148,429	5.96	21,210
20		Total Iatan	43,835,532	3.29	3.81	(1,447,315)	3.06	(326,226)
		Total Steam Production						
21	311	Struct. & Improv.	20,719,925	4.46	2.33	6,030,623	6.91	948,263
22	312	Boiler Plant Eq.	101,753,997	4.50	3.24	18,137,041	5.68	2,486,846
23	312	Unit Train	5,580,297	3.98	5.67	(124,378)	3.82	(103,235)
24	314	Turbogen. Units	33,734,992	3.35	2.54	2,958,208	3.89	457,110
25	315	Acc. Elect. Equip.	7,156,619	2.77	2.60	(317,080)	2.26	(24,750)
26	316	Misc. Pwr. Plt. Eq.	4,816,948	5.55	2.20	1,402,466	7.59	259,458
27		Total Steam Production	173,762,778	4.21	3.02	28,086,880	5.33	4,023,692
		Ozark Beach - Hydro						
28	331	Struct. & Improv.	498,456	3.50	1.98	263,617	5.26	16,349
29	332	Res., Dams & W. Ways	1,396,859	1.55	1.90	(50,611)	1.39	(7,124)
30	333	W Wheel, Tur. & Gen.	353,036	1.25	0.00	(147,011)	(0.52)	(1,836)
31	334	Acc. Elect. Equip.	737,339	3.21	1.78	123,656	3.87	15,410
32	335	Misc. Pwr. Plt. Eq.	244,207	4.53	2.10	106,701	5.89	9,255
33		Total Ozark Beach	3,229,897	2.42	1.69	296,352	2.68	32,055
		Other Production						
34	(1)	Riverton	11,774,979	4.09	3.41	773,175	4.50	128,347
35	(1)	Energy Center	34,770,564	3.90	3.43	1,377,800	4.18	260,779
36		State Line						
37	(1), (2)	Unit No. 1	35,716,024	4.79	3.38	(1,034,230)	4.70	471,452
38	(3), (4)	Unit No. 2	140,475,204	4.93	3.37	3,044,383	4.99	2,275,698
39		Total Other Production	222,736,771	4.70	3.38	4,161,127	4.79	3,136,276
40		Total Production Plant	399,729,446	4.47	3.21	32,544,359	5.01	7,192,024

(1) Composite for Accounts 341 to 346.
(2) State Line Unit No. 1 plant in service balance at 12/31/99 reflects transfer of common investment from SL 1 to SL 2.
(3) State Line Unit No. 2 combined cycle plant is based on plant in service at 6/1/01. Figures shown include only Empire share of SL Unit No. 2.
(4) Composite for Accounts 310-353.

SCHEDULE LWL-1

Table 7-1

Empire District Electric Company

Depreciation Rate Analysis - Indicated Rates

Reserve Analysis as of December 31, 1999 (Note 1)

Line No.	Account No.	Description	[A] Depreciable Plant	[B] Base Accrual Rate	[C] Existing Accrual Rate	[D] Reserve (Surplus) or Deficiency	[E] Total Accrual Rate	[F] Increase (Decrease) Depreciation Expense
			$	$	$	$	%	$
41	**Transmission Plant**							
42	352	Structures & Improvements	2,333,000	2.30	1.58	(600,985)	1.76	4,301
43	353	Station Equipment	59,405,382	2.61	2.57	(279,344)	2.59	14,734
44	354	Towers and Fixtures	777,079	2.50	1.56	(213,257)	1.51	(426)
45	355	Poles and Fixtures	21,264,202	2.60	2.71	(1,342,718)	2.43	(59,468)
46	356	Overhead Conductors and Devices	38,472,953	2.30	2.25	(1,004,228)	2.23	(6,679)
47		Total Transmission Plant	122,252,616	2.50	2.47	(3,440,531)	2.43	(47,538)
48	**Distribution Plant**							
49	361	Structures & Improvements	8,503,744	2.30	2.25	147,181	2.34	8,042
50	362	Station Equipment	47,342,791	2.89	3.00	(1,419,876)	2.79	(99,936)
51	364	Poles, Towers, and Fixtures	76,134,158	4.02	4.25	4,302,902	4.22	(25,402)
52	365	Overhead Conductors and Devices	83,780,468	2.50	2.87	(1,346,304)	2.46	(346,823)
53	366	Underground Conduit	11,852,108	3.09	3.96	(492,419)	2.93	(121,601)
54	367	UG Conduct. and Devices	25,434,746	3.70	4.19	(335,247)	3.64	(140,262)
55	368	Line Transformers	55,472,129	2.75	2.82	(741,062)	2.71	(63,817)
56	369	Services	35,129,098	3.79	4.19	(894,444)	3.68	(180,341)
57	370	Meters	12,650,100	2.56	2.63	(1,005,245)	2.28	(44,345)
58	371	Installation on Customer Premises	9,575,078	5.50	5.82	(474,738)	5.13	(65,985)
59	373	Street Lighting & Signal Systems	8,514,692	2.79	2.48	(1,707,146)	2.24	(20,749)
60		Total Distribution Plant	374,389,112	3.20	3.45	(3,966,397)	3.16	(1,101,220)
61	**General Plant**							
62	390	Structures & Improvements	9,162,404	4.40	4.68	1,345,838	5.42	67,577
63	391.1	Office Furniture and Equipment	4,633,354	5.00	4.67	(67,026)	4.90	10,629
64	391.2	Computer Equipment	2,611,643	18.00	4.67	0	18.00	348,113
65	392	Transportation Equipment	6,047,214	9.00	9.00	(2,279,067)	3.22	(349,378)
66	393	Stores Equipment	350,586	4.20	4.57	(28,488)	3.69	(3,094)
67	394	Tool, Shop and Garage Equipment	2,172,026	2.50	3.67	(787,082)	1.44	(48,507)
68	395	Laboratory Equipment	879,216	2.63	3.00	(185,677)	1.84	(10,172)
69	396	Power Operated Equipment	9,418,975	6.33	6.71	(221,477)	6.09	(58,905)
70	397	Communication Equipment	9,620,429	5.00	4.76	84,378	5.07	29,843
71	398	Miscellaneous Equipment	184,451	3.70	3.88	(16,852)	3.26	(1,148)
72		Total General Plant	45,080,298	5.23	5.34	(2,155,453)	4.54	(15,041)
73		Total Mass Property	541,722,026	3.30	3.41	(9,562,381)	3.20	(1,163,799)
74		Total Plant (1)	941,451,472	3.80	3.33	22,981,978	3.97	6,028,225

(1) All plant in service is shown at 12/31/99 with the exception of State Line Unit 2, which is shown at 6/1/01.

SCHEDULE LWL-1

FINAL REPORT

Operation & Maintenance Estimate for State Line Power Plant

Western Resources

EMPIRE

Services You Count On

WESTERN RESOURCES, INC.

EMPIRE DISTRICT ELECTRIC COMPANY

August, 2000

B&V Project 98698.0010

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The Empire District Electric Company / Westar Generating

O&M Analysis

Purpose

The purpose of this report is to provide the partnership of Empire District Electric Co. and Westar Generating Inc. (hereby known as "The Partners") with an operational and maintenance (O&M) estimate for the State Line Power plant. This report will present a Black & Veatch derived estimate of the expected life cycle costs of operating and maintaining Empire's simple cycle 501D5 and the soon to be completed jointly owned 2X1 F class combined cycle generator.

Background

In 1992, the Federal Energy Regulatory Commission (FERC) passed the U.S. Energy Policy Act (EPAct). The EPAct mandated that electric utilities provide electric transmission services for third party transactions and established a new class of generators known as Exempt Wholesale Generators (EWG's). FERC Orders 888 and 889, issued in 1995, address open access transmission pricing and electronic reporting of transmission availability, respectively. FERC issued Order 2000 in December 1999. Order 2000 addresses the integrated transmission system and requires all transmission owners to make a filing this year regarding their participation in a large regional transmission organization to support more efficient transfer of wholesale electricity. The 1992 EPAct also spurred states to begin considering deregulation of the generation component of retail energy business. All of these factors combined to make great uncertainty in the industry, and reserve margins fell.

As the events of the 1990's transpired, the purchase power that Empire had traditionally relied upon became scarce and more expensive. After careful analysis Empire determined that adding a nominal 100 MW 501D5 (State Line 1) in 1995 and a nominal 150 MW 501F (State Line 2) in 1997 was a prudent course of action. Finally, during September 1998, Empire determined it appropriate to expand State Line 2 into a 2X1 F class combined cycle.

Description of facilities

The State Line plant is located on the Missouri side of the Kansas-Missouri state line just west of Joplin, MO. The plant currently consists of one Westinghouse 501D5 installed in 1995 and one Westinghouse 501F originally installed in 1997. The 501F is currently being expanded with another 501F, two heat recovery steam generators, a steam turbine, a cooling tower, and associated equipment to create a 2X1 F class combined cycle of a nominal 500 MW. The 501D5 (State Line 1) is 100% owned by Empire. The 2X1 F class combined cycle (State Line 2) will be the jointly owned unit. The unit will be owned 60% by Empire and 40% by WRI. There are also common facilities on the site such as offices and maintenance buildings that will be owned 66% by Empire and 34% by WRI. Fuel procurement for the plant is done off-site. Empire plant personnel will do the majority of purchasing, inventory management, contract services administration, and general oversight/operations.

State Line 1

State Line 1 went commercial in June of 1995. Since commercial operation the unit has had about 890 equivalent starts, 4,000 hours of operation, and has generated over 430,000 MWh's of energy. The unit last had a hot path inspection during the fall of 1998. The unit has the dual fuel capability of natural gas or oil. Operated primarily on natural gas, the unit emits 25 PPM_v of NO_x from its dry low NO_x combustion system. When operating on oil, the unit is permitted at 42 PPM_v with water injection. The plant endeavors to maintain a 3-day supply of oil on-site as emergency fuel.

State Line 2

State Line 2 went commercial in June of 1997. Since commercial operation the unit had 900 equivalent starts, 3,600 hours of operation, and has generated about 570,000 MWh's of energy. The unit underwent a complete major overhaul in the spring of 2000. During this major, the unit was upgraded from the original FC compressor design to the new FD compressor design. The unit was returned to a virtually new condition as a result of the major. As of approximately September 15, 2000 unit 2 will stop operation as a simple cycle and begin upgrade to a combined cycle. The combined cycle Unit 2 will be brought back on line with a commercial date of July 1, 2001

State Line Combined Cycle

State Line 2 will be combined with a new 501F to form the basis of a new 2X1 F combined cycle. The unit will be rated a nominal 500 MW. Both combustion turbines will be tuned to have NOx emissions of 25 PPM_v. These emissions will be reduced to a level of 4 PPM_v through the use of an SCR. The plant will utilize a cooling tower. The water make-up for the cooling tower will come from a series of deep wells. The plant will be equipped with duct firing designed to bring the unit back to ISO conditions on a 100 F day. The combustion turbines will be equipped with pulse inlet and evaporative coolers.

The 1998 Analysis

During 1998, Black & Veatch performed energy supply planning analysis for Empire to assist in the combined cycle decision. This analysis contained a study level O&M estimate for a 2X1 F Class combined cycle of \$0.53/kW-month (2001\$) fixed and \$2.50/MWh variable without property tax, insurance or SCR costs. This initial study level estimate is provided only as a point of reference within this report.

Methodology

The estimate presented in this report has been customized for the State Line units and incorporates the Partner's current operational plan. Black and Veatch has done many estimates of Operation and Maintenance expenses for power plants throughout the world. Black & Veatch typically develops O&M estimates for Combustion Turbine plants in two components – fixed and variable.

Fixed O&M estimates are designed to represent components such as labor, staff supplies and materials, rentals, routine plant maintenance, contract services, insurance, property tax, safety, and environmental fees. Fixed O&M costs vary among like power plants due to different philosophies concerning the use of contract labor, support from other power plants, and corporate support for administrative and accounting functions. The costs shown in this report are based on B&V experience.

Variable O&M is generally estimated to include major maintenance expenses on the combustion turbines, steam turbine, and heat recovery steam generators. Since the combustion turbine components are such a large component of overall O&M costs, Black & Veatch estimates them based on experience and checks them against long-term service agreement proposals provided by the manufacturer, Siemens Westinghouse Power Corporation (SWPC). This insures that labor and parts prices are current as of the date of this report. It is expected that the Partners will be conducting operational-type maintenance, but very little major maintenance activities other than contractor oversight.

Major combustion turbine maintenance is included in the variable O&M component. It is classified according to the following table:

Maintenance Cycle	Simple Cycle Operation	Combined Cycle Operation
Combustor Inspection	Every 400 equivalent starts	Every 8,000 operating hrs
Hot Gas Path Maintenance	Every 800 equivalent starts	Every 24,000 operating hrs
Major Overall Maintenance	Every 1600 equivalent starts	Every 48,000 operating hrs

Maintenance intervals are usually governed by starts for the simple cycle unit and by hours of operation for the combined cycle unit. Each step from combustor inspection (CI) to hot gas path (HG) to major maintenance (M) increases in complexity and expense. The scope of work for each maintenance activity for a 501F is shown in Appendix A.

Fixed O&M

The following guidelines and criteria govern this analysis:

- Staffing for both units combined consists of the following personnel:

  1 – Plant Manager

  1- Maintenance Manager

  1 – Operations Manager

  1 – Cost / Inventory Manager

  1 –Results Manager

  1 – Project Manager

  1- Administrative Assistant

  11 – Operators / technicians

  11 – Technicians / Operators

  29 – TOTAL PERSONNEL

  Black & Veatch believes that the staffing proposed for this plant is within a typical range which has been experienced within the industry. As a result, the anticipated plant staffing has been included as shown above in the estimate.

- The estimated average staff labor cost was estimated at $38 / manhour. It includes benefits and overhead charges but does not assume any bonuses. The labor rate used in this analysis is typical and may need to be adjusted based on labor situations unique to the Partners.
- Staff supplies and materials (e.g. office equipment, supplies, etc.) were estimated to average 10% of payroll.
- Rentals were included to cover costs for heavy mobile equipment required for specific maintenance activities.
- Routine maintenance costs were estimated based on B&V experience. They include costs for painting of buildings, maintenance of facilities, etc.
- Contact services includes costs for services not directly related to power production (i.e. HVAC, plumbing, snow removal, pest control, security, etc.)
- Insurance includes liability and property damage coverage, but does not include business interruption coverage.
- Property taxes are assumed to be approximately 0.5 % of total plant value.
- Environmental fee is for air emissions.

Variable O&M - State Line 1 (Simple Cycle)

The following guidelines and criteria govern this analysis:

- Annual capacity factor: 20 percent (1,752 hours per year).
- Unit's last major work was a hot path completed in late 1998.
- Primary fuel is natural gas.
- Annual equivalent starts = 150. (Note: A manufacturer-supplied algorithm which accounts for fired aborts, trips from load, and instantaneous load changes. For full definition, see Appendix B.)
- Combustion turbine major maintenance expense was calculated based on two different scenarios: 1) Empire personnel performs outages, or 2) a long-term service agreement is entered into with SWPC.
- Balance of plant operational and maintenance costs are estimated based on Black & Veatch experience. These include items such as pump and valve maintenance and repair, etc.

- Initial operational spares, combustion spares, and hot gas spares have not been included. This expense will be included in the capital cost.

Variable O&M - State Line 2 (Combined Cycle)

The following guidelines and criteria govern this analysis:

- Annual capacity factor: 70 percent (6,132 hours per year).
- Primary fuel is Natural gas.
- Commercial operation date = 7/1/01
- Combustion turbine major maintenance expense was calculated based on two different scenarios: 1) Empire personnel provides labor for outages, or 2) a long term service agreement is entered into with Siemens Westinghouse.
- Balance of plant operational and maintenance costs are estimated based on Black & Veatch experience. These include items such as chemicals for water treatment, water well maintenance, pump and valve maintenance and repair, etrc.
- SCR uses aqueous ammonia and reduces NOx from 25 to 4 ppm @ 15% O2 with 9 ppm ammonia slip. Aqueous ammonia cost = $109.50 / ton.
- Raw and demineralized water costs are included. Raw water cost = $0.35 / 1000 gallons. Demineralized water cost = $1.85 / 1000 gallons.

Financial Analysis

The following guidelines and criteria govern this analysis:

- Cycle life: 20 years
- Annual escalation rate = 3%
- Discount rate = 12%

Results

Due to the increasing complexity and costs of outages in a maintenance cycle, examining only the first year O&M costs understates the average yearly O&M costs that should be expected. When life cycle O&M costs are analyzed on a constant dollar basis, Black & Veatch estimates the average annual fixed costs to be $5,667,903 and the annual average variable costs to be $9,212,987 for a total of $14,880,890 (see Table 6). If inflation is taken into account, the levelized average annual cost totals approximately $16,128,000 per year (see Table 7). The values developed for this report are in the normal range of costs that Black & Veatch would expect to encounter on plants similar to State Line. It is Black & Veatch's opinion that these are representative of the eventual operation and maintenance expenditures for the State Line facility.

The Black & Veatch estimates for the combined cycle unit have been consistent through time. The following table shows the consistency when comparing the combined cycle portion of the new estimate to the 1998 study mentioned above:

	1998 Study	Current Study	Difference
Fixed O&M	$3,180,000	$3,299,163 [1]	+ 3.7%
Variable O&M	$7,655,000	$7,902,000 [2]	+ 3.2%
Total O&M	$10,835,000	$11,201,163	+ 3.2%

[1] This equals $5,667,903 less property taxes and insurance which were not included in 1998 and less additions for State Line 1 staff (2 personnel)
[2] This equals $8,168,500 less $266,500 for SCR maintenance which was not included in 1998 study.

TABLE 1

Table 1 (two pages) outlines the schedule of combustion turbine maintenance for both State Line units. The outages are driven by starts and hours supplied by the Partners. The starts provided by Empire were adjusted to reflect equivalent starts.

TABLE 2

Table 2 (five pages) outlines the projected Operation and Maintenance costs for both State Line units for the next 20 year period. Values shown are in **constant 2001 dollars**. The staff and others services outlined in the fixed O&M estimate have been combined for both the simple cycle and combined cycle units. Variable costs, however, due to the different operation and configurations of the two units, has been developed separately. This analysis has assumed that the Partners will utilize its own staff for completing outages and major maintenance operations of the combustion turbines.

TABLE 3

The analysis in developing Table 3 (five pages) is identical to Table 2 with the exception that inflation has been included in the expenditures. The inflation rate utilized was 3% per year.

TABLE 4

The analysis for the development of Table 4 (five pages) is identical to that for Table 2 with the exception that it assumes that a long-term service agreement with Siemens Westinghouse has been entered into for outages and major maintenance services.

TABLE 5

The analysis in developing Table 5 (five pages) is identical to Table 4 with the exception that inflation has been included in the expenditures. The inflation rate utilized was 3% per year.

TABLE 6

Table 6 shows the summary of the results on a **constant dollar basis** as presented in Tables 2 and 4, including the annual levelized amount of total O&M costs. This levelized amount was derived using the financial criteria described in the report

TABLE 7

Table 7 shows the summary of the results on an as spent dollar basis as presented in Tables 3 and 5, including the annual levelized amount of total O&M costs. This levelized amount was derived using the financial criteria described in the report

APPENDIX A

SCOPE OF WORK FOR MAJOR MAINTENANCE ACTIVITIES

501D5 or 501F

501D5 or 501F
Combustor Inspection

The following parts will be replaced:

- Combustor baskets
- Transitions
- Fuel nozzles and mini-manifolds
- Cross-flame tubes
- Combustion Transition Cylinders with V-band clamps
- Row #1 vane segments

INLET SECTION

Disassembly
- Remove access cover on inlet manifold.

Inspection
- Visually inspect compressor inlet for damage and oil leaks.
- Visually inspect the inlet guide vanes and row #1 compressor blades.
- Measure the row #1 compressor blade radial clearances.

Assembly
- Install the inlet manifold access cover.

COMBUSTOR SECTION

Disassembly
- Remove the combustor access manway covers.
- Remove the combustor components.
- Remove the row 1 vane segments.

Inspection
- Visually inspect the combustor components for damage.
- Perform visual inspection of the rotor cooling air pipes in place.
- Perform visual inspection of the row #1 turbine blades.

Assembly
- Install the replacement row 1 vane segments.
- Install and align replacement transitions per the applicable Service Bulletin and measure clearances.
- Measure and record transition outlet mouth clearances.
- Install replacement combustor baskets and check alignment to the transitions.
- Install replacement cross-flame tubes.
- Install replacement combustor transition cylinders and v-band clamps.
- Install replacement fuel nozzles and mini-manifolds.
- Install fuel nozzle piping.

EXHAUST SECTION

Inspection

- Perform visual inspection of the turbine exhaust including the strut shields.
- Visually inspect the row #4 turbine blades and measure the radial clearances.

501D5 or 501F
Hot Gas Path Inspection

The following parts will be replaced:

- Combustor baskets
- Transitions
- Fuel nozzles and mini-manifolds
- Cross-flame tubes
- Combustion Transition Cylinders with V-band clamps
- Row 1 & 2 vane segments
- Row 1 & 2 Turbine Blades

INLET SECTION

Disassembly
- Remove access cover on inlet manifold.

Inspection
- Visually inspect compressor inlet for damage and oil leaks.
- Visually inspect the inlet guide vanes and row #1 compressor blades.
- Measure the row #1 compressor blade radial clearances.

Assembly
- Install the inlet manifold access cover.

COMBUSTOR SECTION

Disassembly
- Remove the combustor components.

Inspection
- Visually inspect the combustor components for damage.
- Perform visual inspection of the rotor cooling air pipes in place.

Assembly
- Install and align replacement transitions per the applicable Service Bulletin and measure clearances.
- Measure and record transition outlet mouth clearances.
- Install replacement combustor baskets and check alignment to the transitions.
- Install replacement cross-flame tubes.
- Install replacement combustor transition cylinders and v-band clamps.
- Install replacement fuel nozzles and mini-manifolds.
- Install fuel nozzle piping.

TURBINE SECTION

Disassembly

- Remove the turbine cooling air piping and cylinder cover.
- Unbolt and remove the upper half rows 2, 3, and4 blade rings and interstage seals.
- Measure the turbine axial and radial clearances.
- Remove the lower half rows 2, 3, and 4 blade rings.
- Remove the row 1, 2, 3, & 4 vane segments.
- Remove the turbine blades.

Inspection
- Clean and NDE the turbine discs per the applicable Service Bulletin.
- Clean and inspect the row 1 & 2 turbine ring segments per the applicable Service Bulletin.
- Clean and inspect the row 3 & 4 turbine vane and ring segments per the applicable Service Bulletin.
- Clean and visually inspect the turbine cylinder and piping.

Assembly
- Install replacement row 1 & 2 vane segments.
- Assemble the row 2, 3, & 4 blade rings
- Install replacement turbine blades.
- Install the lower half blade rings and measure the axial and radial clearances.
- Install and bolt the upper interstage seals.
- Install and bolt the upper half blade rings.
- Align the blade rings to the rotor.
- Install and bolt the turbine cylinder cover and piping.

EXHAUST SECTION

Inspection
- Perform visual inspection of the turbine exhaust including the strut shields.

501D5 or 501F
Major C.T. Inspection

The following parts will be replaced:

- Combustor baskets
- Transitions
- Fuel nozzles and mini-manifolds
- Cross-flame tubes
- Combustion Transition Cylinders with V-band clamps
- Rows 1, 2, 3, & 4 vane segments
- Rows 1, 2, 3, & 4 Turbine Blades
- Compressor diaphragms (all rows)
- Inlet Guide Vanes
- Journal Bearings (if required)
- Thrust Bearing (if required)
- Air and Oil Seals (if required)

INLET SECTION

Disassembly
- Remove upper half inlet manifold and inlet casing.
- Measure the inlet end journal bearing clearances and remove the bearing.
- Measure thrust bearing axial clearance and disassemble bearing.
- Measure air and oil seal clearances and remove seals.

Inspection
- Clean and visually inspect inlet manifold, inlet casing, and inlet guide vanes.
- Perform ultrasonic inspection of journal bearing babbitt.
- Perform ultrasonic inspection of thrust bearing babbitt.
- Perform visual and dimensional inspection of the oil and air seals.

Assembly
- Install air and oil seals and measure clearances.
- Install journal bearing and measure clearances.
- Assemble thrust bearing and measure clearance.
- Install and bolt upper half inlet casing and inlet manifold.

COMPRESSOR SECTION

Disassembly

- Remove upper half compressor covers.
- Measure compressor axial and radial clearances.
- Remove compressor diaphragms.

Inspection

- Clean and visually inspect compressor cylinders.

Assembly

- Install replacement compressor diaphragms.
- Measure compressor axial and radial clearances.
- Install and bolt compressor cylinder covers.

COMBUSTOR SECTION

Disassembly

- Remove the combustor components.
- Remove Compressor Combustor cover.

Inspection

- Visually inspect the combustor components for damage.
- Visually inspect the rotor cooling air pipes.

Assembly

- Install the rotor cooling air pipes.
- Install and align replacement transitions per the applicable Service Bulletin and measure clearances.
- Measure and record transition outlet mouth clearances.
- Install replacement combustor baskets and check alignment to the transitions.
- Install replacement cross-flame tubes.
- Install replacement combustor transition cylinders and v-band clamps.
- Install replacement fuel nozzles and mini-manifolds.
- Install fuel nozzle piping.

TORQUE TUBE SEAL HOUSING

Disassembly

- Remove the upper half torque tube seal housing.
- Measure the torque tube seal clearances.
- Remove the torque tube seals.

Inspection

- Clean and visually inspect the torque tube seals.
- Visually inspect the static seal segments.
- Clean and visually inspect the torque tube seal housing.

Assembly

- Install the torque tube seals and measure clearances.
- Install and bolt the upper half torque tube seal housing.

TURBINE SECTION

Disassembly
- Remove the turbine cooling air piping and cylinder cover.
- Unbolt and remove the upper half blade rings and interstage seals.
- Measure the turbine axial and radial clearances.
- Remove the lower half rows 2, 3, and 4 blade rings.
- Remove the row 1, 2, 3, & 4 vane segments.

Inspection
- Clean and inspect the turbine ring segments per the applicable Service Bulletin.
- Clean and visually inspect the turbine cylinder and piping.

Assembly
- Install replacement row 1, 2, 3, & 4 turbine vane segments.
- Assemble and install the lower half rows 2, 3, and 4 blade rings and measure the axial and radial clearances.
- Install and bolt the upper half interstage seals and blade rings
- Align the blade rings to the rotor.
- Install and bolt the turbine cylinder cover and piping.

EXHAUST SECTION

Disassembly
- Remove the exhaust cylinder cover.
- Measure the exhaust end journal bearing clearances and remove the bearing.
- Measure the air and oil seal clearances and remove the seals.

Inspection

- Clean and visually inspect the exhaust cylinder including the struts and strut shields.
- Perform ultrasonic inspection of journal bearing babbitt.
- Perform visual and dimensional inspection of the oil and air seals.

Assembly

- Install air and oil seals and measure clearances.
- Install the journal bearing and measure the clearances.
- Install and bolt the exhaust cylinder cover.

ROTOR

Disassembly

- Unbolt turbine/generator coupling and measure alignment.
- Rig and remove the rotor.
- Remove the turbine blades.

Inspection

- Clean and inspect the turbine discs per the applicable Service Bulletin.
- Clean and inspect the compressor blades in place per the applicable Service Bulletin.
- Clean and dimensionally inspect the bearing journals and thrust collar.
- Clean and inspect the coupling.

Assembly

- Install replacement rows 1, 2, 3, & 4 turbine blades.
- Rig and install rotor.
- Measure coupling alignment and bolt coupling.

APPENDIX B

How to Calculate the Equivalent Number of Starts (ES)

Because the effects of cyclic thermal stress caused by some starts, trip, and load changes are cumulative, they are combined into one parameter: equivalent starts.

1. **To calculate the Equivalent Number of Starts (ES), count only Successful Starts, Fired Aborts, Trips from Load, and Instantaneous Load Changes.**

   - **Successful Start** occurs when a unit reaches synchronization. Successful starts are further classified, depending on the total time to accelerate and reach base load:

     Normal start occurs if a unit reaches base load in 20 minutes or longer.

     Intermediate start occurs whenever a unit reaches base load in less than 20 minutes, but more than 10 minutes.

     Fast start occurs whenever a unit reaches base load in 10 minutes or less.

   - **Fired Abort** - Occurs if the unit enters the ignition sequence, but shuts down before reaching base load.

     An **unfired abort** occurs if the unit shuts down before ignition. Unfired aborts are to be disregarded in calculating equivalent starts.

   - **Trip From Load*** - Occurs after the unit reaches base load. This is an abrupt shutdown that does not follow the normal shutdown sequence.

   - **Instantaneous Load Change*** - Occurs when a unit abruptly increases or decreases load at a rate greater than the specified ramp rate (in response to a change in grid demand, a control system impetus, etc.).

     * Include the trips from load and instantaneous load changes that have occurred ONLY since the last hot path inspection.
     * For any trips or instantaneous load changes that have occurred during operation above base load, consult Westinghouse for additional guidelines and recommendations.

For Definitions of Fuel, Trip, & Load Change Factors, refer to Figure 4-1, page 17.

2. Calculate the Equivalent Number of Starts (ES).

- **Use Equation 3 for <u>single-fuel</u> operation:**

Equation 3

ES_f = Total number of (Successful Starts x Start Factor) +
Total number of fired aborts +
Total number of (Trips from Load x Trip Factor) +
Total number of (Instantaneous Load Changes x Load Change Factor)

Apply this value to the ES column that corresponds to the fuel used, on the inspection interval table recommended for your unit.

- **Use Equation 4 for <u>multiple-fuel</u> operation:**

Equation 4

ES_T = Total number of (Successful Starts x Start Factor x Fuel Factor)+
Total number of (Fired aborts x Fuel Factor) +
Total number of (Trips from Load x Trip Factor x Fuel Factor) +
Total number of (Instantaneous Load Changes x Load Change Factor x Fuel Factor)

Apply this value to the ES column labeled "Natural Gas/Propane," on the inspection interval table recommended for your unit.

3. You have completed calculation of ES.

Return to INSTRUCTIONS, on page 3, and continue to Step 6.

Figure B-1. Fuel Factors, Trip Factors, and Load Change Factors

Use these factors in Equations 3 or 4, on page 16, to calculate ES.

Start Factors

Total Time to Accelerate and Reach Base Load	Start Factor
Normal Start (20 minutes or longer)	1.0
Intermediate Start (less than 20 minutes, but more than 10 minutes)	10.0
Fast Start (10 minutes or less)	20.0

Fuel Factors

Fuel Used	Fuel Factor
Natural Gas	1.0
Distillate Oil	1.3
Crude / Residual (starting on Natural Gas, Distillate Oil)	1.8

Trip Factors

Percentage of Base Load at Time of Trip*	Trip Factor
Greater Than Base Load	Consult Westinghouse
76 - 100%	20.0
51 - 75%	14.0
26 - 50%	7.0
Up to 25%	4.0

* Should be counted as a full load trip if the trip occurs on a combined cycle unit that is operating on external control (IGVs modulated at reduced load to maintain exhaust temperature at upper limit).

Load Change Factors

Percentage of Base Load at Time of Instantaneous Load Change	Load Change Factor
Greater Than Base Load	Consult Westinghouse
76 - 100%	6.0
51 - 75%	4.0
26 - 50%	2.0
Up to 25%	1.0

END OF BULLETIN

TABLE 1

EMPIRE DISTRICT ELECTRIC
STATE LINE POWER STATION
SCHEDULE OF COMBUSTION TURBINE MAINTENANCE

State Line 1 - Simple Cycle [1]	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Annual No. of Starts	75	150	150	150	150	150	150	150	150	150
Cumulative No. of Starts	1,050	1,200	1,350	1,500	1,650	1,800	1,950	2,100	2,250	2,400
Type of Inspection or Maintenance Required		CI		CI	M			CI		CI

State Line - Combined Cycle [2]	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Annual Operating Hours	3,066	6,132	6,132	6,132	6,132	6,132	6,132	6,132	6,132	6,132
Cumulative Operating Hours	3,066	9,198	15,330	21,462	27,594	33,726	39,858	45,990	52,122	58,254
Type of Inspection or Maintenance Required		CI		CI	HG	CI		CI	M	CI

Combustor Inspection	CI
Hot Gas Path Maintenance	HG
Major Overall Maintenance	M

Notes:

[1] It is assumed that maintenance schedule is governed by starts for simple cycle operation (e.g., 400 equivalent starts occurs before 8000 hours of operation).

[2] It is assumed that maintenance schedule is governed by operating hours for combined cycle operation (e.g., 8000 hours of operation occurs sooner than 400 equivalent starts).

TABLE 1

EMPIRE DISTRICT ELECTRIC
STATE LINE POWER STATION
SCHEDULE OF COMBUSTION TURBINE MAINTENANCE

State Line 1 - Simple Cycle [1]	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Annual No. of Starts	150	150	150	150	150	150	150	150	150	150
Cumulative No. of Starts	2,550	2,700	2,850	3,000	3,150	3,300	3,450	3,600	3,750	3,900
Type of Inspection or Maintenance Required		HG		CI		CI		M		CI

State Line - Combined Cycle [2]	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Annual Operating Hours	6,132	6,132	6,132	6,132	6,132	6,132	6,132	6,132	6,132	6,132
Cumulative Operating Hours	64,386	70,518	76,650	82,782	88,914	95,046	101,178	107,310	113,442	119,574
Type of Inspection or Maintenance Required	CI		HG		CI	CI	M	CI	CI	HG

Combustor Inspection	CI
Hot Gas Path Maintenance	HG
Major Overall Maintenance	M

TABLE 2

STATE LINE POWER STATION (2001-2011)

Fixed O&M Costs - State Line 1-2	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Staffing	$1,212,683	$2,425,367	$2,425,367	$2,425,367	$2,425,367	$2,425,367	$2,425,367	$2,425,367	$2,425,367	$2,425,367	$2,425,367
Supplies and Materials	$121,268	$242,537	$242,537	$242,537	$242,537	$242,537	$242,537	$242,537	$242,537	$242,537	$242,537
Rentals	$82,500	$165,000	$165,000	$165,000	$165,000	$165,000	$165,000	$165,000	$165,000	$165,000	$165,000
Contracted Services	$107,500	$215,000	$215,000	$215,000	$215,000	$215,000	$215,000	$215,000	$215,000	$215,000	$215,000
Routine Maintenance	$247,500	$495,000	$495,000	$495,000	$495,000	$495,000	$495,000	$495,000	$495,000	$495,000	$495,000
Safety	$15,000	$30,000	$30,000	$30,000	$30,000	$30,000	$30,000	$30,000	$30,000	$30,000	$30,000
Employee Training	$30,000	$60,000	$60,000	$60,000	$60,000	$60,000	$60,000	$60,000	$60,000	$60,000	$60,000
Environmental Fees	$17,500	$35,000	$35,000	$35,000	$35,000	$35,000	$35,000	$35,000	$35,000	$35,000	$35,000
Insurance	$250,000	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000
Property Taxes	$750,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000
	$2,833,952	$5,667,903	$5,667,903	$5,667,903	$5,667,903	$5,667,903	$5,667,903	$5,667,903	$5,667,903	$5,667,903	$5,667,903
Variable O&M Costs - State Line 1											
Combustion Turbine Maintenance	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
- Labor (CI)		$40,100		$40,100				$40,100		$40,100	
- Labor (HG)											
- Labor (M)					$255,000						
- Materials (CI)		$574,900		$574,900				$574,900		$574,900	
- Materials (HG)											
- Materials (M)					$5,126,700						
- Management Fee											
BOP Maintenance	$140,800	$140,800	$140,800	$140,800	$140,800	$140,800	$140,800	$140,800	$140,800	$140,800	$140,800
	$140,800	$755,800	$140,800	$755,800	$5,522,500	$140,800	$140,800	$755,800	$140,800	$755,800	$140,800
Variable O&M Costs - State Line 2											
Combustion Turbine Maintenance	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
- Initial Spares	$0										
- Labor (CI)		$98,600		$98,600		$98,600		$98,600		$98,600	$98,600
- Labor (HG)					$268,200						
- Labor (M)									$556,100		
- Materials (CI)		$2,373,600		$2,373,600		$2,373,600		$2,373,600		$2,373,600	$2,373,600
- Materials (HG)					$6,791,600						
- Materials (M)									$23,642,000		
- Management Fee	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
HRSG and SCR Maintenance	$658,000	$1,316,000	$1,316,000	$1,316,000	$1,316,000	$1,316,000	$1,316,000	$1,316,000	$1,316,000	$1,316,000	$1,316,000
Steam Turbine Maintenance											
- Labor / Materials (Minor)		$355,500		$355,500		$355,500		$355,500		$355,500	$355,500
- Labor / Materials (Intermediate)					$1,111,000						
- Labor / Materials (Major)									$4,444,000		
Generator Inspections	$75,000	$150,000	$150,000	$150,000	$150,000	$150,000	$150,000	$150,000	$150,000	$150,000	$150,000
BOP Maintenance	$295,350	$590,700	$590,700	$590,700	$590,700	$590,700	$590,700	$590,700	$590,700	$590,700	$590,700
Water Consumption	$233,500	$467,000	$467,000	$467,000	$467,000	$467,000	$467,000	$467,000	$467,000	$467,000	$467,000
	$1,261,850	$5,351,400	$2,523,700	$5,351,400	$10,694,500	$5,351,400	$2,523,700	$5,351,400	$31,165,800	$5,351,400	$5,351,400

Note: All estimates are based on assumptions set forth on pages 4-6 and assume that CT part lifes meet OEM projections.

TABLE 2

STATE LINE POWER STATION (2012-2020)

Fixed O&M Costs - State Line 1-2	2012	2013	2014	2015	2016	2017	2018	2019	2020	TOTAL
Staffing	$2,425,367	$2,425,367	$2,425,367	$2,425,367	$2,425,367	$2,425,367	$2,425,367	$2,425,367	$2,425,367	$47,294,650
Supplies and Materials	$242,537	$242,537	$242,537	$242,537	$242,537	$242,537	$242,537	$242,537	$242,537	$4,729,465
Rentals	$165,000	$165,000	$165,000	$165,000	$165,000	$165,000	$165,000	$165,000	$165,000	$3,217,500
Contracted Services	$215,000	$215,000	$215,000	$215,000	$215,000	$215,000	$215,000	$215,000	$215,000	$4,192,500
Routine Maintenance	$495,000	$495,000	$495,000	$495,000	$495,000	$495,000	$495,000	$495,000	$495,000	$9,652,500
Safety	$30,000	$30,000	$30,000	$30,000	$30,000	$30,000	$30,000	$30,000	$30,000	$585,000
Employee Training	$60,000	$60,000	$60,000	$60,000	$60,000	$60,000	$60,000	$60,000	$60,000	$1,170,000
Environmental Fees	$35,000	$35,000	$35,000	$35,000	$35,000	$35,000	$35,000	$35,000	$35,000	$682,500
Insurance	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000	$9,750,000
Property Taxes	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$29,250,000
	$5,667,903	$5,667,903	$5,667,903	$5,667,903	$5,667,903	$5,667,903	$5,667,903	$5,667,903	$5,667,903	$110,524,115

Variable O&M Costs - State Line 1	2012	2013	2014	2015	2016	2017	2018	2019	2020	TOTAL
Combustion Turbine Maintenance										
- Labor (CI)			$40,100		$40,100				$40,100	$280,700
- Labor (HG)	$99,500									$99,500
- Labor (M)							$255,000			$510,000
- Materials (CI)			$574,900		$574,900				$574,900	$4,024,300
- Materials (HG)	$2,383,600									$2,383,600
- Materials (M)							$5,126,700			$10,253,400
- Management Fee										$0
BOP Maintenance	$140,800	$140,800	$140,800	$140,800	$140,800	$140,800	$140,800	$140,800	$140,800	$2,816,000
	$2,623,900	$140,800	$755,800	$140,800	$755,800	$140,800	$5,522,500	$140,800	$755,800	$20,367,500

Variable O&M Costs - State Line 2	2012	2013	2014	2015	2016	2017	2018	2019	2020	TOTAL
Combustion Turbine Maintenance										
- Initial Spares										$0
- Labor (CI)				$98,600	$98,600		$98,600	$98,600		$986,000
- Labor (HG)		$268,200							$268,200	$804,600
- Labor (M)						$556,100				$1,112,200
- Materials (CI)				$2,373,600	$2,373,600		$2,373,600	$2,373,600		$23,736,000
- Materials (HG)		$6,791,600							$6,791,600	$20,374,800
- Materials (M)						$23,642,000				$47,284,000
- Management Fee	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
HRSG and SCR Maintenance	$1,316,000	$1,316,000	$1,316,000	$1,316,000	$1,316,000	$1,316,000	$1,316,000	$1,316,000	$1,316,000	$25,662,000
Steam Turbine Maintenance										
- Labor / Materials (Minor)				$355,500	$355,500		$355,500	$355,500		$3,555,000
- Labor / Materials (Intermediate)		$1,111,000							$1,111,000	$3,333,000
- Labor / Materials (Major)						$4,444,000				$8,888,000
Generator Inspections	$150,000	$150,000	$150,000	$150,000	$150,000	$150,000	$150,000	$150,000	$150,000	$2,925,000
BOP Maintenance	$590,700	$590,700	$590,700	$590,700	$590,700	$590,700	$590,700	$590,700	$590,700	$11,518,650
Water Consumption	$467,000	$467,000	$467,000	$467,000	$467,000	$467,000	$467,000	$467,000	$467,000	$9,106,500
	$2,523,700	$10,694,500	$2,523,700	$5,351,400	$5,351,400	$31,165,800	$5,351,400	$5,351,400	$10,694,500	$159,285,750

Note: All estimates are based on assumptions set forth on pages 4-6 and assume that CT part lifes meet OEM projections.

TABLE 3

STATE LINE POWER STATION (2001-2011)

Fixed O&M Costs - State Line 1-2	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Staffing	$1,212,683	$2,498,128	$2,573,071	$2,650,264	$2,729,772	$2,811,665	$2,896,015	$2,982,895	$3,072,382	$3,164,553	$3,259,490
Supplies and Materials	$121,268	$249,813	$257,307	$265,026	$272,977	$281,166	$289,601	$298,290	$307,238	$316,455	$325,949
Rentals	$82,500	$169,950	$175,049	$180,300	$185,709	$191,280	$197,019	$202,929	$209,017	$215,288	$221,746
Contracted Services	$107,500	$221,450	$228,094	$234,936	$241,984	$249,244	$256,721	$264,423	$272,356	$280,526	$288,942
Routine Maintenance	$247,500	$509,850	$525,146	$540,900	$557,127	$573,841	$591,056	$608,788	$627,051	$645,863	$665,239
Safety	$15,000	$30,900	$31,827	$32,782	$33,765	$34,778	$35,822	$36,896	$38,003	$39,143	$40,317
Employee Training	$30,000	$61,800	$63,654	$65,564	$67,531	$69,556	$71,643	$73,792	$76,006	$78,286	$80,635
Environmental Fees	$17,500	$36,050	$37,132	$38,245	$39,393	$40,575	$41,792	$43,046	$44,337	$45,667	$47,037
Insurance	$250,000	$515,000	$530,450	$546,364	$562,754	$579,637	$597,026	$614,937	$633,385	$652,387	$671,958
Property Taxes	$750,000	$1,545,000	$1,591,350	$1,639,091	$1,688,263	$1,738,911	$1,791,078	$1,844,811	$1,900,155	$1,957,160	$2,015,875
	$2,833,952	$5,837,940	$6,013,079	$6,193,471	$6,379,275	$6,570,653	$6,767,773	$6,970,806	$7,179,930	$7,395,328	$7,617,188

Variable O&M Costs - State Line 1	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Combustion Turbine Maintenance											
- Labor (CI)		$41,303		$43,818				$49,318		$52,321	
- Labor (HG)											
- Labor (M)					$287,005						
- Materials (CI)		$592,147		$628,209				$707,054		$750,114	
- Materials (HG)											
- Materials (M)					$5,770,146						
- Management Fee											
BOP Maintenance	$140,800	$145,024	$149,375	$153,856	$158,472	$163,226	$168,123	$173,166	$178,361	$183,712	$189,223
	$140,800	$778,474	$149,375	$825,883	$6,215,622	$163,226	$168,123	$929,539	$178,361	$986,148	$189,223

Variable O&M Costs - State Line 2	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Combustion Turbine Maintenance											
- Initial Spares	$0										
- Labor (CI)		$101,558		$107,743		$114,304		$121,266		$128,651	$132,510
- Labor (HG)					$301,861						
- Labor (M)									$704,451		
- Materials (CI)		$2,444,808		$2,593,697		$2,751,653		$2,919,229		$3,097,010	$3,189,920
- Materials (HG)					$7,644,006						
- Materials (M)									$29,948,978		
- Management Fee	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
HRSG and SCR Maintenance	$658,000	$1,355,480	$1,396,144	$1,438,029	$1,481,170	$1,525,605	$1,571,373	$1,618,514	$1,667,069	$1,717,082	$1,768,594
Steam Turbine Maintenance											
- Labor / Materials (Minor)		$366,165		$388,464		$412,122		$437,220		$463,847	$477,762
- Labor / Materials (Intermediate)					$1,250,440						
- Labor / Materials (Major)									$5,629,526		
Generator Inspections	$75,000	$154,500	$159,135	$163,909	$168,826	$173,891	$179,108	$184,481	$190,016	$195,716	$201,587
BOP Maintenance	$295,350	$608,421	$626,674	$645,474	$664,838	$684,783	$705,327	$726,486	$748,281	$770,730	$793,851
Water Consumption	$233,500	$481,010	$495,440	$510,304	$525,613	$541,381	$557,622	$574,351	$591,582	$609,329	$627,609
	$1,261,850	$5,511,942	$2,677,393	$5,847,619	$12,036,754	$6,203,739	$3,013,430	$6,581,547	$39,479,903	$6,982,363	$7,191,834

Note: All estimates are based on assumptions set forth on pages 4-6 and assume that CT part lifes meet OEM projections.

TABLE 3

STATE LINE POWER STATION (2012-2 STATE LINE POWER STATION (2016-2020)

Fixed O&M Costs - State Line 1-2	2012	2013	2014	2015	2016	2017	2018	2019	2020	TOTAL
Staffing	$3,357,275	$3,457,993	$3,561,733	$3,668,585	$3,778,642	$3,892,002	$4,008,762	$4,129,024	$4,252,895	$63,957,827
Supplies and Materials	$335,727	$345,799	$356,173	$366,858	$377,864	$389,200	$400,876	$412,902	$425,290	$6,395,783
Rentals	$228,399	$235,251	$242,308	$249,577	$257,065	$264,777	$272,720	$280,901	$289,328	$4,351,112
Contracted Services	$297,610	$306,539	$315,735	$325,207	$334,963	$345,012	$355,362	$366,023	$377,004	$5,669,631
Routine Maintenance	$685,196	$705,752	$726,924	$748,732	$771,194	$794,330	$818,160	$842,704	$867,985	$13,053,335
Safety	$41,527	$42,773	$44,056	$45,378	$46,739	$48,141	$49,585	$51,073	$52,605	$791,111
Employee Training	$83,054	$85,546	$88,112	$90,755	$93,478	$96,282	$99,171	$102,146	$105,210	$1,582,222
Environmental Fees	$48,448	$49,902	$51,399	$52,941	$54,529	$56,165	$57,850	$59,585	$61,373	$922,963
Insurance	$692,117	$712,880	$734,267	$756,295	$778,984	$802,353	$826,424	$851,217	$876,753	$13,185,187
Property Taxes	$2,076,351	$2,138,641	$2,202,801	$2,268,885	$2,336,951	$2,407,060	$2,479,271	$2,553,650	$2,630,259	$39,555,562
	$7,845,704	$8,081,075	$8,323,507	$8,573,212	$8,830,409	$9,095,321	$9,368,181	$9,649,226	$9,938,703	$149,464,733

Variable O&M Costs - State Line 1	2012	2013	2014	2015	2016	2017	2018	2019	2020	TOTAL
Combustion Turbine Maintenance										
- Labor (CI)			$58,888		$62,474				$70,316	$378,439
- Labor (HG)	$137,731									$137,731
- Labor (M)							$421,476			$708,481
- Materials (CI)			$844,260		$895,675				$1,008,091	$5,425,550
- Materials (HG)	$3,299,460									$3,299,460
- Materials (M)							$8,473,654			$14,243,800
- Management Fee										$0
BOP Maintenance	$194,900	$200,747	$206,770	$212,973	$219,362	$225,943	$232,721	$239,703	$246,894	$3,783,349
	$3,632,091	$200,747	$1,109,918	$212,973	$1,177,512	$225,943	$9,127,851	$239,703	$1,325,300	$27,976,810

Variable O&M Costs - State Line 2	2012	2013	2014	2015	2016	2017	2018	2019	2020	TOTAL
Combustion Turbine Maintenance										
- Initial Spares										$0
- Labor (CI)				$149,141	$153,616		$162,971	$167,860		$1,339,619
- Labor (HG)		$382,389							$470,290	$1,154,541
- Labor (M)						$892,377				$1,596,828
- Materials (CI)				$3,590,283	$3,697,991		$3,923,199	$4,040,895		$32,248,685
- Materials (HG)		$9,683,198							$11,909,112	$29,236,315
- Materials (M)						$37,938,470				$67,887,448
- Management Fee	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
HRSG and SCR Maintenance	$1,821,652	$1,876,301	$1,932,590	$1,990,568	$2,050,285	$2,111,794	$2,175,147	$2,240,402	$2,307,614	$34,703,413
Steam Turbine Maintenance										
- Labor / Materials (Minor)				$537,726	$553,857		$587,587	$605,215		$4,829,966
- Labor / Materials (Intermediate)		$1,584,020							$1,948,145	$4,782,606
- Labor / Materials (Major)						$7,131,315				$12,760,842
Generator Inspections	$207,635	$213,864	$220,280	$226,888	$233,695	$240,706	$247,927	$255,365	$263,026	$3,955,556
BOP Maintenance	$817,667	$842,197	$867,463	$893,487	$920,291	$947,900	$976,337	$1,005,627	$1,035,796	$15,576,980
Water Consumption	$646,437	$665,830	$685,805	$706,379	$727,571	$749,398	$771,880	$795,036	$818,887	$12,314,965
	$3,493,391	$15,247,800	$3,706,139	$8,094,473	$8,337,307	$50,011,960	$8,845,049	$9,110,400	$18,752,870	$222,387,763

Note: All estimates are based on assumptions set forth on pages 4-6 and assume that CT part lifes meet OEM projections.

TABLE 4

STATE LINE POWER STATION (2001-2011)

Fixed O&M Costs - State Line 1-2	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Staffing	$1,212,683	$2,425,367	$2,425,367	$2,425,367	$2,425,367	$2,425,367	$2,425,367	$2,425,367	$2,425,367	$2,425,367	$2,425,367
Supplies and Materials	$121,268	$242,537	$242,537	$242,537	$242,537	$242,537	$242,537	$242,537	$242,537	$242,537	$242,537
Rentals	$82,500	$165,000	$165,000	$165,000	$165,000	$165,000	$165,000	$165,000	$165,000	$165,000	$165,000
Contracted Services	$107,500	$215,000	$215,000	$215,000	$215,000	$215,000	$215,000	$215,000	$215,000	$215,000	$215,000
Routine Maintenance	$247,500	$495,000	$495,000	$495,000	$495,000	$495,000	$495,000	$495,000	$495,000	$495,000	$495,000
Safety	$15,000	$30,000	$30,000	$30,000	$30,000	$30,000	$30,000	$30,000	$30,000	$30,000	$30,000
Employee Training	$30,000	$60,000	$60,000	$60,000	$60,000	$60,000	$60,000	$60,000	$60,000	$60,000	$60,000
Environmental Fees	$17,500	$35,000	$35,000	$35,000	$35,000	$35,000	$35,000	$35,000	$35,000	$35,000	$35,000
Insurance	$250,000	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000
Property Taxes	$750,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000
	$2,833,952	$5,667,903	$5,667,903	$5,667,903	$5,667,903	$5,667,903	$5,667,903	$5,667,903	$5,667,903	$5,667,903	$5,667,903

Variable O&M Costs - State Line 1	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Combustion Turbine Maintenance											
- Labor (CI)		$141,184		$141,184				$141,184		$141,184	
- Labor (HG)											
- Labor (M)					$852,032						
- Materials (CI)		$395,610		$395,610				$395,610		$395,610	
- Materials (HG)											
- Materials (M)					$6,234,773						
- Management Fee	$60,000	$60,000	$60,000	$60,000	$60,000	$60,000	$60,000	$60,000	$60,000	$60,000	$60,000
BOP Maintenance	$140,800	$140,800	$140,800	$140,800	$140,800	$140,800	$140,800	$140,800	$140,800	$140,800	$140,800
	$200,800	$737,594	$200,800	$737,594	$7,287,605	$200,800	$200,800	$737,594	$200,800	$737,594	$200,800

Variable O&M Costs - State Line 2	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Combustion Turbine Maintenance											
- Initial Spares	$0										
- Labor (CI)		$302,176		$302,176		$302,176		$302,176		$302,176	$302,176
- Labor (HG)					$648,176						
- Labor (M)									$2,443,436		
- Materials (CI)		$1,118,700		$1,118,700		$1,118,700		$1,118,700		$1,118,700	$1,118,700
- Materials (HG)					$10,271,700						
- Materials (M)									$15,814,540		
- Management Fee	$60,000	$120,000	$120,000	$120,000	$120,000	$120,000	$120,000	$120,000	$120,000	$120,000	$120,000
HRSG and SCR Maintenance	$658,000	$1,316,000	$1,316,000	$1,316,000	$1,316,000	$1,316,000	$1,316,000	$1,316,000	$1,316,000	$1,316,000	$1,316,000
Steam Turbine Maintenance											
- Labor / Materials (Minor)		$355,500		$355,500		$355,500		$355,500		$355,500	$355,500
- Labor / Materials (Intermediate)					$1,111,000						
- Labor / Materials (Major)									$4,444,000		
Generator Inspections	$75,000	$150,000	$150,000	$150,000	$150,000	$150,000	$150,000	$150,000	$150,000	$150,000	$150,000
BOP Maintenance	$295,350	$590,700	$590,700	$590,700	$590,700	$590,700	$590,700	$590,700	$590,700	$590,700	$590,700
Water Consumption	$233,500	$467,000	$467,000	$467,000	$467,000	$467,000	$467,000	$467,000	$467,000	$467,000	$467,000
	$1,321,850	$4,420,076	$2,643,700	$4,420,076	$14,674,576	$4,420,076	$2,643,700	$4,420,076	$25,345,676	$4,420,076	$4,420,076

Note: All estimates are based on assumptions set forth on pages 4-6 and assume that CT part lifes meet OEM projections.

TABLE 4 STATE LINE POWER STATION (2012-2020)

Fixed O&M Costs - State Line 1-2	2012	2013	2014	2015	2016	2017	2018	2019	2020	TOTAL
Staffing	$2,425,367	$2,425,367	$2,425,367	$2,425,367	$2,425,367	$2,425,367	$2,425,367	$2,425,367	$2,425,367	$47,294,650
Supplies and Materials	$242,537	$242,537	$242,537	$242,537	$242,537	$242,537	$242,537	$242,537	$242,537	$4,729,465
Rentals	$165,000	$165,000	$165,000	$165,000	$165,000	$165,000	$165,000	$165,000	$165,000	$3,217,500
Contracted Services	$215,000	$215,000	$215,000	$215,000	$215,000	$215,000	$215,000	$215,000	$215,000	$4,192,500
Routine Maintenance	$495,000	$495,000	$495,000	$495,000	$495,000	$495,000	$495,000	$495,000	$495,000	$9,652,500
Safety	$30,000	$30,000	$30,000	$30,000	$30,000	$30,000	$30,000	$30,000	$30,000	$585,000
Employee Training	$60,000	$60,000	$60,000	$60,000	$60,000	$60,000	$60,000	$60,000	$60,000	$1,170,000
Environmental Fees	$35,000	$35,000	$35,000	$35,000	$35,000	$35,000	$35,000	$35,000	$35,000	$682,500
Insurance	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000	$9,750,000
Property Taxes	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$29,250,000
	$5,667,903	$5,667,903	$5,667,903	$5,667,903	$5,667,903	$5,667,903	$5,667,903	$5,667,903	$5,667,903	$110,524,115

Variable O&M Costs - State Line 1	2012	2013	2014	2015	2016	2017	2018	2019	2020	TOTAL
Combustion Turbine Maintenance										
- Labor (CI)			$141,184		$141,184				$141,184	$988,288
- Labor (HG)	$296,320									$296,320
- Labor (M)							$852,032			$1,704,064
- Materials (CI)			$395,610		$395,610				$395,610	$2,769,270
- Materials (HG)	$2,000,963									$2,000,963
- Materials (M)							$6,234,773			$12,469,546
- Management Fee	$60,000	$60,000	$60,000	$60,000	$60,000	$60,000	$60,000	$60,000	$60,000	$1,200,000
BOP Maintenance	$140,800	$140,800	$140,800	$140,800	$140,800	$140,800	$140,800	$140,800	$140,800	$2,816,000
	$2,498,083	$200,800	$737,594	$200,800	$737,594	$200,800	$7,287,605	$200,800	$737,594	$24,244,451

Variable O&M Costs - State Line 2	2012	2013	2014	2015	2016	2017	2018	2019	2020	TOTAL
Combustion Turbine Maintenance										
- Initial Spares										$0
- Labor (CI)				$302,176	$302,176		$302,176	$302,176		$3,021,760
- Labor (HG)		$648,176							$648,176	$1,944,528
- Labor (M)						$2,443,436				$4,886,872
- Materials (CI)				$1,118,700	$1,118,700		$1,118,700	$1,118,700		$11,187,000
- Materials (HG)		$10,271,700							$10,271,700	$30,815,100
- Materials (M)						$15,814,540				$31,629,080
- Management Fee	$120,000	$120,000	$120,000	$120,000	$120,000	$120,000	$120,000	$120,000	$120,000	$2,340,000
HRSG and SCR Maintenance	$1,316,000	$1,316,000	$1,316,000	$1,316,000	$1,316,000	$1,316,000	$1,316,000	$1,316,000	$1,316,000	$25,662,000
Steam Turbine Maintenance										
- Labor / Materials (Minor)				$355,500	$355,500		$355,500	$355,500		$3,555,000
- Labor / Materials (Intermediate)		$1,111,000							$1,111,000	$3,333,000
- Labor / Materials (Major)						$4,444,000				$8,888,000
Generator Inspections	$150,000	$150,000	$150,000	$150,000	$150,000	$150,000	$150,000	$150,000	$150,000	$2,925,000
BOP Maintenance	$590,700	$590,700	$590,700	$590,700	$590,700	$590,700	$590,700	$590,700	$590,700	$11,518,650
Water Consumption	$467,000	$467,000	$467,000	$467,000	$467,000	$467,000	$467,000	$467,000	$467,000	$9,106,500
	$2,643,700	$14,674,576	$2,643,700	$4,420,076	$4,420,076	$25,345,676	$4,420,076	$4,420,076	$14,674,576	$150,812,490

Note: All estimates are based on assumptions set forth on pages 4-6 and assume that CT part lifes meet OEM projections.

TABLE 5

STATE LINE POWER STATION (2001-2011)

Fixed O&M Costs - State Line 1-2	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Staffing	$1,212,683	$2,498,128	$2,573,071	$2,650,264	$2,729,772	$2,811,665	$2,896,015	$2,982,895	$3,072,382	$3,164,553	$3,259,490
Supplies and Materials	$121,268	$249,813	$257,307	$265,026	$272,977	$281,166	$289,601	$298,290	$307,238	$316,455	$325,949
Rentals	$82,500	$169,950	$175,049	$180,300	$185,709	$191,280	$197,019	$202,929	$209,017	$215,288	$221,746
Contracted Services	$107,500	$221,450	$228,094	$234,936	$241,984	$249,244	$256,721	$264,423	$272,356	$280,526	$288,942
Routine Maintenance	$247,500	$509,850	$525,146	$540,900	$557,127	$573,841	$591,056	$608,788	$627,051	$645,863	$665,239
Safety	$15,000	$30,900	$31,827	$32,782	$33,765	$34,778	$35,822	$36,896	$38,003	$39,143	$40,317
Employee Training	$30,000	$61,800	$63,654	$65,564	$67,531	$69,556	$71,643	$73,792	$76,006	$78,286	$80,635
Environmental Fees	$17,500	$36,050	$37,132	$38,245	$39,393	$40,575	$41,792	$43,046	$44,337	$45,667	$47,037
Insurance	$250,000	$515,000	$530,450	$546,364	$562,754	$579,637	$597,026	$614,937	$633,385	$652,387	$671,958
Property Taxes	$750,000	$1,545,000	$1,591,350	$1,639,091	$1,688,263	$1,738,911	$1,791,078	$1,844,811	$1,900,155	$1,957,160	$2,015,875
	$2,833,952	$5,837,940	$6,013,079	$6,193,471	$6,379,275	$6,570,653	$6,767,773	$6,970,806	$7,179,930	$7,395,328	$7,617,188

Variable O&M Costs - State Line 1	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Combustion Turbine Maintenance											
- Labor (CI)		$145,420		$154,276				$173,639		$184,213	
- Labor (HG)											
- Labor (M)					$958,970						
- Materials (CI)		$407,478		$432,294				$486,550		$516,181	
- Materials (HG)											
- Materials (M)					$7,017,292						
- Management Fee	$60,000	$61,800	$63,654	$65,564	$67,531	$69,556	$71,643	$73,792	$76,006	$78,286	$80,635
BOP Maintenance	$140,800	$145,024	$149,375	$153,856	$158,472	$163,226	$168,123	$173,166	$178,361	$183,712	$189,223
	$200,800	$759,722	$213,029	$805,989	$8,202,264	$232,782	$239,766	$907,148	$254,367	$962,393	$269,858

Variable O&M Costs - State Line 2	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Combustion Turbine Maintenance											
- Initial Spares	$0										
- Labor (CI)		$311,241		$330,196		$350,305		$371,638		$394,271	$406,099
- Labor (HG)					$729,528						
- Labor (M)									$3,095,272		
- Materials (CI)		$1,152,261		$1,222,434		$1,296,880		$1,375,860		$1,459,650	$1,503,439
- Materials (HG)					$11,560,889						
- Materials (M)									$20,033,386		
- Management Fee	$60,000	$123,600	$127,308	$131,127	$135,061	$139,113	$143,286	$147,585	$152,012	$156,573	$161,270
HRSG and SCR Maintenance	$658,000	$1,355,480	$1,396,144	$1,438,029	$1,481,170	$1,525,605	$1,571,373	$1,618,514	$1,667,069	$1,717,082	$1,768,594
Steam Turbine Maintenance											
- Labor / Materials (Minor)		$366,165		$388,464		$412,122		$437,220		$463,847	$477,762
- Labor / Materials (Intermediate)					$1,250,440						
- Labor / Materials (Major)									$5,629,526		
Generator Inspections	$75,000	$154,500	$159,135	$163,909	$168,826	$173,891	$179,108	$184,481	$190,016	$195,716	$201,587
BOP Maintenance	$295,350	$608,421	$626,674	$645,474	$664,838	$684,783	$705,327	$726,486	$748,281	$770,730	$793,851
Water Consumption	$233,500	$481,010	$495,440	$510,304	$525,613	$541,381	$557,622	$574,351	$591,582	$609,329	$627,609
	$1,321,850	$4,552,678	$2,804,701	$4,829,936	$16,516,365	$5,124,080	$3,156,716	$5,436,136	$32,107,144	$5,767,197	$5,940,213

Note: All estimates are based on assumptions set forth on pages 4-6 and assume that CT part lifes meet OEM projections.

TABLE 5

STATE LINE POWER STATION (2012-2020)

Fixed O&M Costs - State Line 1-2	2012	2013	2014	2015	2016	2017	2018	2019	2020	TOTAL
Staffing	$3,357,275	$3,457,993	$3,561,733	$3,668,585	$3,778,642	$3,892,002	$4,008,762	$4,129,024	$4,252,895	$63,957,827
Supplies and Materials	$335,727	$345,799	$356,173	$366,858	$377,864	$389,200	$400,876	$412,902	$425,290	$6,395,783
Rentals	$228,399	$235,251	$242,308	$249,577	$257,065	$264,777	$272,720	$280,901	$289,328	$4,351,112
Contracted Services	$297,610	$306,539	$315,735	$325,207	$334,963	$345,012	$355,362	$366,023	$377,004	$5,669,631
Routine Maintenance	$685,196	$705,752	$726,924	$748,732	$771,194	$794,330	$818,160	$842,704	$867,985	$13,053,335
Safety	$41,527	$42,773	$44,056	$45,378	$46,739	$48,141	$49,585	$51,073	$52,605	$791,111
Employee Training	$83,054	$85,546	$88,112	$90,755	$93,478	$96,282	$99,171	$102,146	$105,210	$1,582,222
Environmental Fees	$48,448	$49,902	$51,399	$52,941	$54,529	$56,165	$57,850	$59,585	$61,373	$922,963
Insurance	$692,117	$712,880	$734,267	$756,295	$778,984	$802,353	$826,424	$851,217	$876,753	$13,185,187
Property Taxes	$2,076,351	$2,138,641	$2,202,801	$2,268,885	$2,336,951	$2,407,060	$2,479,271	$2,553,650	$2,630,259	$39,555,562
	$7,845,704	$8,081,075	$8,323,507	$8,573,212	$8,830,409	$9,095,321	$9,368,181	$9,649,226	$9,938,703	$149,464,733

Variable O&M Costs - State Line 1	2012	2013	2014	2015	2016	2017	2018	2019	2020	TOTAL
Combustion Turbine Maintenance										
- Labor (CI)			$207,333		$219,960				$247,567	$1,332,407
- Labor (HG)	$410,176									$410,176
- Labor (M)							$1,408,279			$2,367,249
- Materials (CI)			$580,967		$616,347				$693,705	$3,733,522
- Materials (HG)	$2,769,801									$2,769,801
- Materials (M)							$10,305,130			$17,322,422
- Management Fee	$83,054	$85,546	$88,112	$90,755	$93,478	$96,282	$99,171	$102,146	$105,210	$1,612,222
BOP Maintenance	$194,900	$200,747	$206,770	$212,973	$219,362	$225,943	$232,721	$239,703	$246,894	$3,783,349
	$3,457,931	$286,293	$1,083,182	$303,728	$1,149,147	$322,225	$12,045,301	$341,849	$1,293,376	$33,331,148

Variable O&M Costs - State Line 2	2012	2013	2014	2015	2016	2017	2018	2019	2020	TOTAL
Combustion Turbine Maintenance										
- Initial Spares										$0
- Labor (CI)				$457,068	$470,780		$499,451	$514,434		$4,105,485
- Labor (HG)		$924,144							$1,136,581	$2,790,252
- Labor (M)						$3,920,997				$7,016,269
- Materials (CI)				$1,692,134	$1,742,898		$1,849,041	$1,904,512		$15,199,108
- Materials (HG)		$14,644,988							$18,011,488	$44,217,365
- Materials (M)						$25,377,694				$45,411,080
- Management Fee	$166,108	$171,091	$176,224	$181,511	$186,956	$192,565	$198,342	$204,292	$210,421	$3,164,445
HRSG and SCR Maintenance	$1,821,652	$1,876,301	$1,932,590	$1,990,568	$2,050,285	$2,111,794	$2,175,147	$2,240,402	$2,307,614	$34,703,413
Steam Turbine Maintenance										
- Labor / Materials (Minor)				$537,726	$553,857		$587,587	$605,215		$4,829,966
- Labor / Materials (Intermediate)		$1,584,020							$1,948,145	$4,782,606
- Labor / Materials (Major)						$7,131,315				$12,760,842
Generator Inspections	$207,635	$213,864	$220,280	$226,888	$233,695	$240,706	$247,927	$255,365	$263,026	$3,955,556
BOP Maintenance	$817,667	$842,197	$867,463	$893,487	$920,291	$947,900	$976,337	$1,005,627	$1,035,796	$15,576,980
Water Consumption	$646,437	$665,830	$685,805	$706,379	$727,571	$749,398	$771,880	$795,036	$818,887	$12,314,965
	$3,659,499	$20,922,436	$3,882,363	$6,685,762	$6,886,334	$40,672,369	$7,305,712	$7,524,884	$25,731,958	$210,828,332

Note: All estimates are based on assumptions set forth on pages 4-6 and assume that CT part lifes meet OEM projections.

TABLE 6
SUMMARY OF O&M COSTS (2001$)

	OUTAGES DONE IN-HOUSE				OUTAGES DONE WITH SERVICE AGREEMENT			
	Fixed O&M Both Units	Var O&M Unit 1	Var O&M Unit CC	TOTAL O&M	Fixed O&M Both Units	Var O&M Unit 1	Var O&M Unit CC	TOTAL O&M
2001	$2,833,952	$140,800	$1,261,850	$4,236,602	$2,833,952	$200,800	$1,321,850	$4,356,602
2002	$5,667,903	$755,800	$5,351,400	$11,775,103	$5,667,903	$737,594	$4,420,076	$10,825,573
2003	$5,667,903	$140,800	$2,523,700	$8,332,403	$5,667,903	$200,800	$2,643,700	$8,512,403
2004	$5,667,903	$755,800	$5,351,400	$11,775,103	$5,667,903	$737,594	$4,420,076	$10,825,573
2005	$5,667,903	$5,522,500	$10,694,500	$21,884,903	$5,667,903	$7,287,605	$14,674,576	$27,630,084
2006	$5,667,903	$140,800	$5,351,400	$11,160,103	$5,667,903	$200,800	$4,420,076	$10,288,779
2007	$5,667,903	$140,800	$2,523,700	$8,332,403	$5,667,903	$200,800	$2,643,700	$8,512,403
2008	$5,667,903	$755,800	$5,351,400	$11,775,103	$5,667,903	$737,594	$4,420,076	$10,825,573
2009	$5,667,903	$140,800	$31,165,800	$36,974,503	$5,667,903	$200,800	$25,345,676	$31,214,379
2010	$5,667,903	$755,800	$5,351,400	$11,775,103	$5,667,903	$737,594	$4,420,076	$10,825,573
2011	$5,667,903	$140,800	$5,351,400	$11,160,103	$5,667,903	$200,800	$4,420,076	$10,288,779
2012	$5,667,903	$2,623,900	$2,523,700	$10,815,503	$5,667,903	$2,498,083	$2,643,700	$10,809,686
2013	$5,667,903	$140,800	$10,694,500	$16,503,203	$5,667,903	$200,800	$14,674,576	$20,543,279
2014	$5,667,903	$755,800	$2,523,700	$8,947,403	$5,667,903	$737,594	$2,643,700	$9,049,197
2015	$5,667,903	$140,800	$5,351,400	$11,160,103	$5,667,903	$200,800	$4,420,076	$10,288,779
2016	$5,667,903	$755,800	$5,351,400	$11,775,103	$5,667,903	$737,594	$4,420,076	$10,825,573
2017	$5,667,903	$140,800	$31,165,800	$36,974,503	$5,667,903	$200,800	$25,345,676	$31,214,379
2018	$5,667,903	$5,522,500	$5,351,400	$16,541,803	$5,667,903	$7,287,605	$4,420,076	$17,375,584
2019	$5,667,903	$140,800	$5,351,400	$11,160,103	$5,667,903	$200,800	$4,420,076	$10,288,779
2020	$5,667,903	$755,800	$10,694,500	$17,118,203	$5,667,903	$737,594	$14,674,576	$21,080,073
TOTAL	$110,524,115	$20,367,500	$159,285,750	$290,177,365	$110,524,115	$24,244,451	$150,812,490	$285,581,056
AVG/YR	$5,667,903	$1,044,487	$8,168,500	$14,880,891	$5,667,903	$1,243,305	$7,733,974	$14,645,182
		LEVELIZED AMOUNT @12% =		**$12,915,161**		LEVELIZED AMOUNT @12% =		**$12,777,016**

TABLE 7
SUMMARY OF O&M COSTS (Nominal $)

	OUTAGES DONE IN-HOUSE				OUTAGES DONE WITH SERVICE AGREEMENT			
	Fixed O&M Both Units	Var O&M Unit 1	Var O&M Unit CC	TOTAL O&M	Fixed O&M Both Units	Var O&M Unit 1	Var O&M Unit CC	TOTAL O&M
2001	$2,833,952	$140,800	$1,261,850	$4,236,602	$2,833,952	$200,800	$1,321,850	$4,356,602
2002	$5,837,940	$778,474	$5,511,942	$12,128,356	$5,837,940	$759,722	$4,552,678	$11,150,341
2003	$6,013,079	$149,375	$2,677,393	$8,839,847	$6,013,079	$213,029	$2,804,701	$9,030,809
2004	$6,193,471	$825,883	$5,847,619	$12,866,973	$6,193,471	$805,989	$4,829,936	$11,829,396
2005	$6,379,275	$6,215,622	$12,036,754	$24,631,652	$6,379,275	$8,202,264	$16,516,365	$31,097,903
2006	$6,570,653	$163,226	$6,203,739	$12,937,618	$6,570,653	$232,782	$5,124,080	$11,927,515
2007	$6,767,773	$168,123	$3,013,430	$9,949,325	$6,767,773	$239,766	$3,156,716	$10,164,255
2008	$6,970,806	$929,539	$6,581,547	$14,481,892	$6,970,806	$907,148	$5,436,136	$13,314,090
2009	$7,179,930	$178,361	$39,479,903	$46,838,195	$7,179,930	$254,367	$32,107,144	$39,541,442
2010	$7,395,328	$986,148	$6,982,363	$15,363,839	$7,395,328	$962,393	$5,767,197	$14,124,918
2011	$7,617,188	$189,223	$7,191,834	$14,998,246	$7,617,188	$269,858	$5,940,213	$13,827,259
2012	$7,845,704	$3,632,091	$3,493,391	$14,971,186	$7,845,704	$3,457,931	$3,659,499	$14,963,134
2013	$8,081,075	$200,747	$15,247,800	$23,529,622	$8,081,075	$286,293	$20,922,436	$29,289,804
2014	$8,323,507	$1,109,918	$3,706,139	$13,139,563	$8,323,507	$1,083,182	$3,882,363	$13,289,051
2015	$8,573,212	$212,973	$8,094,473	$16,880,658	$8,573,212	$303,728	$6,685,762	$15,562,702
2016	$8,830,409	$1,177,512	$8,337,307	$18,345,227	$8,830,409	$1,149,147	$6,886,334	$16,865,891
2017	$9,095,321	$225,943	$50,011,960	$59,333,224	$9,095,321	$322,225	$40,672,369	$50,089,916
2018	$9,368,181	$9,127,851	$8,845,049	$27,341,080	$9,368,181	$12,045,301	$7,305,712	$28,719,193
2019	$9,649,226	$239,703	$9,110,400	$18,999,329	$9,649,226	$341,849	$7,524,884	$17,515,958
2020	$9,938,703	$1,325,300	$18,752,870	$30,016,873	$9,938,703	$1,293,376	$25,731,958	$36,964,036
TOTAL	$149,464,733	$27,976,810	$222,387,763	$399,829,307	$149,464,733	$33,331,148	$210,828,332	$393,624,214
AVG/YR	$7,664,858	$1,434,708	$11,404,501	$20,504,067	$7,664,858	$1,709,290	$10,811,709	$20,185,857
			LEVELIZED AMOUNT @12% =	**$16,127,710**			LEVELIZED AMOUNT @12% =	**$15,922,550**