Exhibit No.:
Issues: Resource Planning Analysis
Witness: Richard A. Voytas
Sponsoring Party: Union Electric
Type of Exhibit: Direct Testimony
Case No.: EO-2004-0108
Date Testimony Prepared: September 17, 2003

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. EO-2004-0108

DIRECT TESTIMONY

OF

RICHARD A. VOYTAS

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a AmerenUE

St. Louis, Missouri
September, 2003

** Denotes Highly Confidential Information **

NP

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the matter of the Application of Union Electric Company (d/b/a AmerenUE) for an order authorizing the sale, transfer and assignment of certain Assets, Real Estate, Leased Property, Easements and Contractual Agreements to Central Illinois Public Service Company (d/b/a AmerenCIPS) and, in connection therewith, certain other related transactions.	)	Case No. EO-2004-0108

AFFIDAVIT OF RICHARD A. VOYTAS

STATE OF MISSOURI)
) ss
CITY OF ST. LOUIS)

Richard A. Voytas, being first duly sworn on his oath, states:

1. My name is Richard A. Voytas. I work in St. Louis, Missouri and I am employed by Ameren as Manager, Corporate Analysis.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Union Electric Company d/b/a AmerenUE consisting of 9 pages and Schedules 1 through 5, all of which have been prepared in written form for introduction into evidence in the above-referenced docket.

3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct.

Richard A. Voytas
Richard A. Voytas

Subscribed and sworn to before me this 17th day of September 2003.

Valerie W. Whitehead
Notary Public

My commission expires:

VALERIE W. WHITEHEAD
Notary Public - Notary Seal
STATE OF MISSOURI
Jefferson County
My Commission Expires: Dec. 10, 2006

DIRECT TESTIMONY

OF

RICHARD A. VOYTAS

UNION ELECTRIC COMPANY

d/b/a AmerenUE

CASE NO. EO-2004-0108

Q. Please state your name and business address.

A. My name is Richard A. Voytas. My business address is 1901 Chouteau Avenue, St. Louis, Missouri 63103.

Q. By whom and in what capacity are you employed?

A. I am employed by Ameren Services Company as Manager of the Corporate Analysis section in the Corporate Planning Department.

Q. How long have you held your position, and what are your responsibilities?

A. The attached Schedule 1 summarizes my educational background, work experience and the duties of my position.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain why transferring electric transmission and distribution properties of Union Electric Company d/b/a AmerenUE in the Metro East Service Area in Illinois ("Metro East Service Area" or "Metro East") to Central Illinois Public Service Company d/b/a AmerenCIPS is the least cost alternative available to supply AmerenUE's long-term capacity and energy needs. I note that my testimony includes highly confidential information concerning AmerenUE's generation resource plan. The disclosure of this information could harm AmerenUE, its customers and shareholders by compromising the Company's ability to buy and sell electricity at wholesale at reasonable rates.

Q. Please explain further.

A. AmerenUE is proposing to restructure its operations in consideration of the following issues and benefits to AmerenUE and its retail customers.

1. The transfer of AmerenUE's Metro East service territory in Illinois to AmerenCIPS would include the transfer of 510 megawatts ("MW") of firm load. This transfer would provide AmerenUE's Missouri customers with low cost capacity and energy for many years. The transfer results in a 597 MW increase in existing AmerenUE capacity available to serve Missouri customers (**____________________**). This allows the current Missouri retail customers of AmerenUE to achieve greater benefits from an installed generating base currently valued at approximately $374/kW, rather than constructing additional gas-fired capacity at a current cost of at least $471/kW. A 510 MW peak demand reduction would defer the construction of 597 MW of new generation at a cost of $281 million. The avoided cost of $97/kW ($471/kW - $374/kW) for 597 MW, at a 13.22% carrying cost, results in a savings of $7.7 million per year in fixed costs.

2. With the 510 MW demand on AmerenUE's system transferred to AmerenCIPS, regulated Missouri customers will enjoy (1) lower average production costs and (2) fewer wholesale energy purchases during periods of peak demand. For example, average variable production costs of AmerenUE plants, approximately **_____________,** are much lower than variable production costs of gas-fired capacity, at more than $61 per MWh, or of market purchases at about $33.72 per MWh. (The variable production cost of gas-fired capacity is based on a current natural gas price of $5.86/mmbtu. The $33.72 per MWh market price is

NP

based on an average of the next 12 months of Cinergy futures contracts, adjusted to around-the-clock usage and a 55% load factor.) Because the variable production costs of AmerenUE plants are lower than gas-fired capacity and market purchases of energy, AmerenUE believes the transfer will result in a least cost alternative for Missouri customers, relative to current and anticipated market cost expectations.

Production related fixed operations and maintenance ("O&M") expenses as well as administrative and general ("A&G") expenses that currently are allocated to AmerenUE's Illinois customers will be allocated to AmerenUE's Missouri customers after the transfer. However, the transfer is still expected to be the least cost alternative to meet AmerenUE's capacity and energy needs.

3. Since AmerenUE's customers in Missouri will receive the benefits of the increase in existing AmerenUE capacity from the Callaway Nuclear Power Plant ("Callaway"), it is appropriate that all future decommissioning charges be paid by these customers. The transfer will terminate the obligation of AmerenUE's Illinois customers to pay decommissioning charges related to Callaway. As explained in Mr. Kevin Redhage's testimony, existing assets in the nuclear decommissioning sub-account for Illinois will be reallocated to the Missouri and wholesale sub-accounts. As also explained in Mr. Redhage's testimony, no increase in the annual jurisdictional expense and amount currently contributed by Missouri ratepayers for decommissioning Callaway will be necessary.

Q. Will the Venice and Keokuk Plants remain with AmerenUE Missouri?

A. Yes.

Q. Does AmerenUE anticipate that it will execute interconnection agreements with AmerenCIPS for both plants?

A. Yes. AmerenUE anticipates it will execute such agreements as required to comply with Federal Energy Regulatory Commission ("FERC") regulations on this topic.

Q. You mentioned that production related fixed O&M expenses as well as A&G expenses that currently are allocated to AmerenUE's Illinois customers will be allocated to AmerenUE's Missouri customers after the transfer. Please explain.

A. Currently, AmerenUE's fixed generation production costs, such as O&M, and AmerenUE's generation related A&G costs are allocated to three customer bases: AmerenUE-Missouri, AmerenUE-Illinois, and AmerenUE-Wholesale accounts. After the transfer, those costs will still be the same, but they will be allocated to two customer bases: AmerenUE-Missouri and AmerenUE-Wholesale.

Q. What is the significance of this allocation?

A. For the transfer to be the least cost alternative, the costs associated with the reallocation of fixed generation production and A&G, minus the savings from the less expensive capacity, lower production expenses, and fewer energy purchases, need to be less costly than the other alternatives.

Q. What are the other alternatives to the transfer?

A. We have performed Asset Mix Optimization studies which have shown that building or purchasing combustion turbine generators ("CTGs") are the least cost generation alternative to supply AmerenUE's capacity and energy needs until around 2010.

Q. Was a comparison done for the two alternatives? If so, please explain.

A. Yes. An analysis was performed comparing the transfer of the Metro East Service Area to acquiring additional CTGs. The analysis compared total revenue requirements for both options for 25 years.

For the Metro East Service Area transfer revenue requirements analysis, the most current year-end rate base and revenue requirements (December 31, 2002) were used. The revenue requirements were normalized to more accurately reflect future expectations since AmerenUE experienced several extraordinary costs in 2002 (See Schedule 2 which is attached to my testimony). As discussed above, the majority of the AmerenUE-Illinois fixed generation costs will be allocated to AmerenUE-Missouri. After calculating the allocation, the AmerenUE-Missouri portion of the AmerenUE-Illinois rate base and revenue requirements were projected for 25 years (See Schedule 3 which is attached to my testimony). Next, the savings from the transfer were subtracted from the projected revenue requirements. Then, the present value ("PV") of the Metro East transfer was calculated based on the 25 years of revenue requirements (See Schedule 4 which is attached to my testimony).

For the CTG analysis, the 25 year capital and fixed costs were determined. Then, a "mark to market" analysis was done to determine the margin on potential energy sales to the market. The term "mark to market" means that the CTGs are assumed to run whenever market prices for electricity exceed the variable production costs of the CTGs. The margin on energy was subtracted from the capital and fixed costs to get the net CTG costs. Lastly, the PV was calculated on the 25 year net CTG costs (See Schedule 4).

Q. **What are the extraordinary costs that were included in the normalization of the 2002 AmerenUE Illinois rate base and revenue requirements?**

A. The extraordinary costs fall into two categories. The first is Production O&M Expenses included the cost of Callaway Refuel 12. Since the Callaway nuclear plant only refuels every 18 months, the Production O&M Expenses were adjusted to only include 2/3 (12 months) of the Callaway Refuel 12 expenses. The production expenses included $10 million for power purchased to serve customer load during the refueling and $35 million for other expenses in the refueling. Without this adjustment, the 25 year revenue requirements would inaccurately reflect the entire refueling cost in every year.

Next, the A&G Expenses included $65,201,317 one time costs related to the Voluntary Retirement Program ("VRP") and the Venice Plant shutdown. These expenses were removed.

Q. What are the savings in the Metro East transfer analysis that you mentioned?

A. First, there will be production cost savings from AmerenUE not having to produce energy to serve AmerenUE-Illinois customers. The amount of $35.6 million per year in savings comes from the "Fuel and Purchased Power for Load" line of the revenue requirement in Schedule 2.

Second, there will be savings from the lower average production costs that regulated Missouri customers will have access to after the transfer. They will experience lower production costs because the portion of low cost, base load AmerenUE generation that was dedicated to serve AmerenUE-Illinois customers will be available to serve AmerenUE-Missouri customers. Fuel production cost analyses for "before and after" the transfer show the savings to be $25 million per year (See Schedule 5 which is attached to this testimony).

Q. Are there additional savings that you did not attempt to quantify?

A. Yes. The impact of load growth and the ability to serve incremental load from the low-cost generation fleet that had been dedicated to AmerenUE-Illinois customers will result in additional savings to AmerenUE-Missouri customers. In addition, even though the analysis is focused on production costs savings, we anticipate that there will be savings related to transmission.

Q. What was the result of the comparison of the two alternatives?

A. For the 25 years of the analysis, the revenue requirements for the transfer option were $418 million compared to the CTG revenue requirements of $429 million. Over the life of the analysis, the transfer option costs less than the CTG option by $11 million.

On an annualized basis, the revenue requirements for the transfer option were $43 million compared to the CTG revenue requirements of $45.5 million. So, the transfer costs less by $2.5 million a year.

In summary, the analysis indicates that the transfer is the least cost option for AmerenUE's Missouri customers.

Q. After the transfer, what will be AmerenUE's year-by-year reserve margin?

A. With an increase of 597 MW available to serve Missouri load, AmerenUE's reserve margin, after the transfer, will be **_____** in 2004; **_____** in 2005; **_____** in 2006, and **_____** in 2007.

Q. What are the assumptions in regards to capacity additions at AmerenUE included in the reserve margin calculation stated above?

A. We assume that AmerenUE will purchase the Pinckneyville (316 MW) and Kinmundy (232 MW) peaking plants from Ameren Energy Generating Company ("AEG") by June 1, 2004. We also assume that approximately 330 MW of additional CTGs will be installed to replace the retired Venice steam plant by year-end 2005.

NP

Q. Do the capacity additions described in the preceding question address the terms and conditions of the Stipulation and Agreement ("Stipulation") in Case No. EC-2002-1?

A. Yes. The Stipulation requires that 700 MW of new regulated generating capacity, which does not include the replacement of the Venice power plant by new generation, nor the transfer of load to increase available generating capacity, but may include the purchase of generation plant from an Ameren affiliate at net book value, be completed by June 30, 2006. The Stipulation also requires that the replacement of the Venice power plant by new generating capacity, which does not include the transfer of load to increase available generating capacity, be completed by June 30, 2006. In addition, there are significant tax savings in the form of "bonus depreciation" (as allowed by a new federal law) to install the 330 MW of CTGs that replace the Venice steam plant by the end of 2005.

Q. How does Ameren intend to meet its capacity and energy needs beyond 2007?

A. AmerenUE will continue to follow least cost planning principles in its analyses of the type of generation and timing of generation needed to meets its capacity requirements beyond 2007. AmerenUE will work with the Staff of the Missouri Public Service Commission and Office of the Public Counsel via the semi-annual resource planning meetings to present its analyses of options to meet AmerenUE long-term resource requirements.

Q. Will the transfer benefit consumers?

A. Yes. The transfer results in a net benefit to AmerenUE's Missouri retail customers. Costs avoided by Missouri customers as a result of the transfer include the following: (1) a reduction of $2.5 million a year in revenue requirements compared to the best alternative – a CTG; (2) the ability to defer the construction of new generation to serve AmerenUE retail load with an estimated annual savings of $7.7 million per year; and (3) future reductions in energy costs. As mentioned above, the positive benefits are offset, in part, by the reallocation of fixed O&M costs, A&G costs, and decommissioning costs formerly allocated to Illinois ratepayers. However, as explained by Mr. Redhage, no increase is currently needed to fund Missouri's portion of the decommissioning fund. In summary, the transfer is the least cost available alternative to supply AmerenUE's long-term capacity and energy needs.

Q. Does this conclude your testimony?

A. Yes.

QUALIFICATIONS OF RICHARD A. VOYTAS

My name is Richard A. Voytas and my business address is 1901 Chouteau Avenue, St. Louis, MO 63103.

My educational background consists of a Bachelor of Science degree in Mechanical Engineering from the University of Missouri-Rolla in 1975 and a Masters In Business Administration from St. Louis University in 1979. I am a registered professional engineer in the state of Missouri.

I was employed full time by Union Electric beginning in May of 1975. Effective with the merger of Union Electric Company and Central Illinois Public Service Company into the Ameren Corporation, I assumed employment with Ameren Services. My work experience started at Union Electric as an Assistant Engineer in the Engineering and Construction function. I worked as an Assistant Engineer from 1975 to 1977. In 1977 I was promoted to Fuel Buyer in the Supply Services Function. In 1981 I transferred to the Engineering Department at Union Electric's Rush Island Plant. In 1982 I accepted a position in the coal marketing department at Cities Service Company in Tulsa, OK. In late 1982 I left Cities Service Company and returned to Union Electric as an Engineer in the Corporate Planning Department. From 1982 through 1992 I worked as an Engineer in the Corporate Planning Department, Engineer in the Quality Improvement Department and Engineer in the Rate Engineering Department. In 1993 I was promoted to Senior Engineer in the Corporate Planning Department. In 1995 I was promoted to Supervising Engineer in the Demand-Side Management section of Corporate Planning. In July 1998 the Resource Planning, Forecasting, Load Research and Demand-Side Management sections were combined into one section of Corporate Planning and I was named Supervisor of that section known as the Corporate Analysis department. Today, Corporate Analysis is divided into four subgroups, which are Resource Planning, Market Modeling, Load Analysis and Forecasting, and Load Research. In October 2001 I was promoted to my present position as Manager-Corporate Analysis.

My duties as Manager of Corporate Analysis include overseeing the preparation of the Ameren capacity position both on an annual and weekly basis, preparation of resource plans, development and evaluation of requests and proposals for capacity and energy for Ameren operating companies, preparation of the annual sales and peak demand forecasts, development of the Ameren forward view of electric energy market prices, and the collection, editing and analysis of monthly load research data.

I have submitted testimony concerning least cost planning and weather normalization of sales before the Missouri Public Service Commission, the Illinois Commerce Commission, and the Federal Energy Regulatory Commission.

AmerenUE

Illinois Generation Rate Base and Revenue Requirement

Adjusted Twelve Months Ending December 31, 2002

Rate Base		Generation Total AmerenUE	AmerenUE-IL Allocated to AmerenUE-MO
Production Plant		$5,480,084,533	$339,222,498
Allocation of General Plant		289,170,439	22,072,611
Total Plant		5,769,254,972	361,295,109
Depreciation Reserve - Production Plant		2,261,231,813	140,789,885
Depreciation Reserve - General Plant		82,329,592	6,284,284
Total Reserve		2,343,561,405	147,074,169
Net Plant		3,425,693,567	214,220,940
Unburned Nuclear Fuel in Reactor		60,729,909	5,619,997
Fuel (Fossil)		55,066,411	5,095,892
Materials and Supplies		65,170,078	6,030,894
Prepayments		4,597,634	394,342
Accumulated Deferred Income Taxes		(562,358,851)	(35,866,387)
			-
Total Rate Base		$3,048,898,748	$195,495,677
Fuel and Purchased Power For Load	(1)	$385,077,420	$35,635,388
Other Production Expenses	(1)	310,650,540	26,425,243
Fuel and Purchased Power For Interchange		127,712,586	0
Interchange Sales		(163,724,350)	0
Total Production Expenses		659,716,196	62,060,631
Administrative & General Expenses	(2)	137,197,167	10,472,370
Depreciation Expense - Production Plant		155,038,655	9,439,934
Depreciation Expense - General Plant		6,242,012	476,458
Taxes Other Than Income		67,665,534	4,512,539
Income Taxes		138,791,979	9,231,664
Return		287,419,685	18,618,915
Total Revenue Requirement		$1,452,071,228	$114,812,510

(1) The Production O&M Expenses included the cost of Callaway Refuel 12. Since the refuelings only occur every 18 months the above Production O&M Expenses were adjusted to only include 2/3 (12 months) of the Callaway Refuel 12 expenses.(Total $10 m Purchased Power and $35 m Other).

(2) The Administrative & General Expenses included $65,201,317 one time costs related the VRP and the Venice Plant shutdown. These expenses were removed.

AmerenUE
Missouri Generation Rate Base and Revenue Requirement
25 year projection

Year	1	2	3	4	5	6	7	8	9	10	11	12	13
Total Rate Base	$195,495,677	$185,579,286	$175,662,894	$165,746,503	$155,830,111	$145,913,720	$135,997,329	$126,080,937	$116,164,546	$106,248,154	$96,331,763	$86,415,372	$76,498,980
Fuel and Purchased Power	$35,635,388	$35,635,388	$35,635,388	$35,635,388	$35,635,388	$35,635,388	$35,635,388	$35,635,388	$35,635,388	$35,635,388	$35,635,388	$35,635,388	$35,635,388
Other Production Expenses	26,425,243	26,425,243	26,425,243	26,425,243	26,425,243	26,425,243	26,425,243	26,425,243	26,425,243	26,425,243	26,425,243	26,425,243	26,425,243
Fuel and Purchased Power For Interchange	-	-	-	-	-	-	-	-	-	-	-	-	-
Interchange Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Production Expenses	62,060,631	62,060,631	62,060,631	62,060,631	62,060,631	62,060,631	62,060,631	62,060,631	62,060,631	62,060,631	62,060,631	62,060,631	62,060,631
Administrative & General Expenses	10,472,370	10,472,370	10,472,370	10,472,370	10,472,370	10,472,370	10,472,370	10,472,370	10,472,370	10,472,370	10,472,370	10,472,370	10,472,370
Depreciation Expense - Production Plant	9,439,934	9,439,934	9,439,934	9,439,934	9,439,934	9,439,934	9,439,934	9,439,934	9,439,934	9,439,934	9,439,934	9,439,934	9,439,934
Depreciation Expense - General Plant	476,458	476,458	476,458	476,458	476,458	476,458	476,458	476,458	476,458	476,458	476,458	476,458	476,458
Taxes Other Than Income	4,512,539	4,512,539	4,512,539	4,512,539	4,512,539	4,512,539	4,512,539	4,512,539	4,512,539	4,512,539	4,512,539	4,512,539	4,512,539
Income Taxes	9,231,664	8,763,394	8,295,124	7,826,854	7,358,584	6,890,313	6,422,043	5,953,773	5,485,503	5,017,233	4,548,962	4,080,692	3,612,422
Return	18,618,915	17,674,482	16,730,050	15,785,617	14,841,185	13,896,753	12,952,320	12,007,888	11,063,456	10,119,023	9,174,591	8,230,159	7,285,726
Total Revenue Requirement	$114,812,510	$113,399,808	$111,987,105	$110,574,403	$109,161,700	$107,748,998	$106,336,295	$104,923,593	$103,510,890	$102,098,188	$100,685,485	$99,272,782	$97,860,080

Year	14	15	16	17	18	19	20	21	22	23	24	25
Total Rate Base	$66,582,589	$56,666,197	$46,749,806	$36,833,415	$26,917,023	$17,141,124	$17,141,124	$17,141,124	$17,141,124	$17,141,124	$17,141,124	$17,141,124
Fuel and Purchased Power	$35,635,388	$35,635,388	$35,635,388	$35,635,388	$35,635,388	$35,635,388	$35,635,388	$35,635,388	$35,635,388	$35,635,388	$35,635,388	$35,635,388
Other Production Expenses	26,425,243	26,425,243	26,425,243	26,425,243	26,425,243	26,425,243	26,425,243	26,425,243	26,425,243	26,425,243	26,425,243	26,425,243
Interchange Sales	0	0	0	0	0	0	0	0	0	0	0	0
Total Production Expenses	62,060,631	62,060,631	62,060,631	62,060,631	62,060,631	62,060,631	62,060,631	62,060,631	62,060,631	62,060,631	62,060,631	62,060,631
Administrative & General Expenses	10,472,370	10,472,370	10,472,370	10,472,370	10,472,370	10,472,370	10,472,370	10,472,370	10,472,370	10,472,370	10,472,370	10,472,370
Depreciation Expense - Production Plant	9,439,934	9,439,934	9,439,934	9,439,934	9,439,934	9,439,934	9,439,934	9,439,934	5,689,554	0	0	0
Depreciation Expense - General Plant	476,458	476,458	476,458	476,458	476,458	476,458	476,458	476,458	287,166	0	0	0
Taxes Other Than Income	4,512,539	4,512,539	4,512,539	4,512,539	4,512,539	4,512,539	4,512,539	4,512,539	4,512,539	4,512,539	4,512,539	4,512,539
Income Taxes	3,144,152	2,675,882	2,207,612	1,739,341	1,271,071	809,435	809,435	809,435	809,435	809,435	809,435	809,435
Return	6,341,294	5,396,861	4,452,429	3,507,997	2,563,564	1,632,512	1,632,512	1,632,512	1,632,512	1,632,512	1,632,512	1,632,512
Total Revenue Requirement	$96,447,377	$95,034,675	$93,621,972	$92,209,270	$90,796,567	$89,403,879	$89,403,879	$89,403,879	$85,464,208	$79,487,488	$79,487,488	$79,487,488

25 Year Analysis of Alternatives

Transfer UE-IL Service Territory

	Annuity	PV	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12
Revenue Requirements	(103.60)	(1007.3)	(114.8)	(113.4)	(112.0)	(110.6)	(109.2)	(107.7)	(106.3)	(104.9)	(103.5)	(102.1)	(100.7)	(99.3)
Annual Production Cost Savings	$35.6	345.8	35.6	35.6	35.6	35.6	35.6	35.6	35.6	35.6	35.6	35.6	35.6	35.6
Annual Variable Production Cost Savings	25.0	243.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
	(43.1)	(418.4)	(54.1)	(52.7)	(51.3)	(49.9)	(48.5)	(47.1)	(45.7)	(44.2)	(42.8)	(41.4)	(40.0)	(38.6)
Capital and Fixed Cost	$0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Margin on Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Cost	(43.1)	(418.4)	(54.1)	(52.7)	(51.3)	(49.9)	(48.5)	(47.1)	(45.7)	(44.2)	(42.8)	(41.4)	(40.0)	(38.6)

	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25
Revenue Requirements	(97.9)	(96.4)	(95.0)	(93.6)	(92.2)	(90.8)	(89.4)	(89.4)	(89.4)	(85.5)	(79.5)	(79.5)	(79.5)
Annual Production Cost Savings	35.6	35.6	35.6	35.6	35.6	35.6	35.6	35.6	35.6	35.6	35.6	35.6	35.6
Annual Variable Production Cost Savings	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
	(37.2)	(35.8)	(34.4)	(32.9)	(31.5)	(30.1)	(26.7)	(28.7)	(28.7)	(24.8)	(18.8)	(18.8)	(18.8)
Capital and Fixed Cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Margin on Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Cost	(37.2)	(35.8)	(34.4)	(32.9)	(31.5)	(30.1)	(28.7)	(28.7)	(28.7)	(24.8)	(18.8)	(18.8)	(18.8)

Purchase CTG

	Annuity	PV	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12
Revenue Requirements	$0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Annual Production Cost Savings	$0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Annual Variable Production Cost Savings	$0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capital and Fixed Cost	(46.61)	(441.7)	(63.5)	(60.8)	(58.2)	(55.8)	(53.5)	(51.3)	(49.2)	(47.1)	(45.0)	(43.0)	(40.9)	(38.8)
Margin on Energy	$1.3	12.3	0.1	0.3	0.6	1.2	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
	(45.5)	(429.4)	(63.4)	(60.5)	(57.6)	(54.6)	(51.7)	(49.6)	(47.5)	(45.4)	(43.3)	(41.3)	(39.2)	(37.1)
Total Cost	(45.5)	(429.4)	(63.4)	(60.5)	(57.6)	(54.6)	(51.7)	(49.6)	(47.5)	(45.4)	(43.3)	(41.3)	(39.2)	(37.1)

	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25
Revenue Requirements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Annual Production Cost Savings	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Annual Variable Production Cost Savings	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capital and Fixed Cost	(36.8)	(34.7)	(32.6)	(30.6)	(29.5)	(28.4)	(27.3)	(26.2)	(25.1)	(24.0)	(22.9)	(21.8)	(20.7)
Margin on Energy	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
	(35.1)	(33.0)	(30.9)	(28.9)	(27.8)	(26.7)	(25.6)	(24.5)	(23.4)	(22.3)	(21.2)	(20.1)	(19.0)
Total Cost	(35.1)	(33.0)	(30.9)	(28.9)	(27.8)	(26.7)	(25.6)	(24.5)	(23.4)	(22.3)	(21.2)	(20.1)	(19.0)

	Annuity	PV 1/1/03
transfer is less by (Transfer - CTG)	2.4	11.0

UE/ILL Transfer Results for Variable Production Cost Savings

	No Transfer	With UE-ILL Transfer	Difference Transfer - No Transfer	Savings
Net fuel & purchase $ including revenuses from SET *	$319,868,196	$263,762,959	-$56,105,237	
SET SO2 Adjustment #	-$4,002,450	-$6,056,600	-$2,054,150	
Adjusted $	$315,865,746	$257,706,359	-$58,159,387	
UE Net Output - MWH	39,251,164	35,135,817	-4,115,347	
Rate	$8.05	$7.33	$0.71	
Savings				$25,041,970

Savings = Rate Reduction x Remaining Net Output

*SET $ includes variable O&M only and needs adjustment for SO2 costs. SO2 costs estimated to be $.50/mwh
SET SO2 Adjustment = (UE SET MWH - GEN SET MWH) x $.50/MWH, where SO2 is valued at $.50/mwh