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MISSOURI PUBLIC SERVICE COMMISSION

UTILITY SERVICES DIVISION

SURREBUTTAL TESTIMONY

OF

ROBERT E. SCHALLENBERG

UNION ELECTRIC COMPANY
D/B/A AMERENUE
CASE NO. ER-2007-0002

Jefferson City, Missouri
February 2007

**** Denotes Proprietary Information ****
****Denotes Highly Confidential Information****

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BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area.	))))	Case No. ER-2007-0002

AFFIDAVIT OF ROBERT E. SCHALLENBERG

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Robert E. Schallenberg, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Surrebuttal Testimony in question and answer form, consisting of 26 pages to be presented in the above case; that the answers in the foregoing Surrebuttal Testimony were given by him; that he has knowledge of the matters set forth in such answers; and that such matters are true and correct to the best of his knowledge and belief.

Robert E. Schallenberg

Robert E. Schallenberg

Subscribed and sworn to before me this 28th day of February, 2007.

Toni M Charlton

TONI M. CHARLTON, NOTARY SEAL, NOTARY PUBLIC, STATE OF MISSOURI

TONI M. CHARLTON
Notary Public - State of Missouri
My Commission Expires December 28, 2008
Cole County
Commission #04474301

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SURREBUTTAL TESTIMONY

OF

ROBERT E. SCHALLENBERG

UNION ELECTRIC COMPANY

d/b/a AMERENUE

CASE NO. ER-2007-0002

Q. Please state your name and business address.

A. Robert E. Schallenberg, 200 Madison Street, Jefferson City, Missouri, 65102.

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

A. I am the Director of the Utility Services Division of the Missouri Public Service Commission (MoPSC).

Q. Are you the same Robert E. Schallenberg who filed rebuttal testimony in this proceeding?

A. Yes, I am.

EXECUTIVE SUMMARY

Q. Can you provide a summary of your surrebuttal testimony?

A. Yes. My surrebuttal testimony addresses the rebuttal testimony of other witnesses concerning the EEInc. issue as well as provides Staff position on the issue in light of the filed rebuttal testimony. My analysis of that testimony is based on my review of the filed rebuttal testimony of AmerenUE witnesses Messrs. Michael L. Moehn, David A. Svanda and Robert C. Downs and Intervenor witness Michael L. Brosch.

This issue was created when AmerenUE sought to recover an increased level of fuel and purchase power costs with lost off-system sales caused by the elimination of the utilization of AmerenUE's share of the energy and capacity from the Joppa Plant owned by EEInc. to serve AmerenUE's retail customers. These increased fuel and purchase power costs result from AmerenUE's use of higher cost generation or purchased power to serve its Missouri retail customers than would be available to serve these customers from the AmerenUE share of the Joppa Plant. The AmerenUE share of the Joppa Plant is being sold instead to serve the wholesale market with AmerenUE recording the profit from these sales in accounts that AmerenUE does not use to reduce the cost of service that it proposes to be used to set the rates in this case. These profits are recorded as below-the-line profits in the sense that the AmerenUE intends for these profits not to be used to establish rates in this case. My surrebuttal testimony will address the misuse of the term below-the-line in the AmerenUE rebuttal testimony to create an impression that is not true. The lost off system sales are the result of not having the energy from the Joppa Plant available for off system sales during the times that the Joppa energy would not be needed to serve AmerenUE retail customers. The value of the increased costs and lost revenue will be quantified in the reconciliation of the differences between the Staff and AmerenUE positions regarding cost of service related to this issue.

AmerenUE is seeking to include these increased costs and lost revenues in the cost of service that will be used to determine the level of rates that AmerenUE will be authorized to charge its Missouri retail customers, thus creating a higher rate level than would result from the continued utilization of the Joppa energy on a cost basis. It is a regulatory requirement that only prudently incurred costs and prudent investment including an appropriate return on these investments is permitted to be covered in rates.

It is Staff's position that not only was AmerenUE imprudent in that AmerenUE failed to make every reasonable effort to prevent or minimize the increased costs and revenue loss related to this issue but AmerenUE was directly responsible for creating the situation that caused increased costs and revenue loss related to this issue.

ELECTRIC Energy, Inc. (EEINC.)

Q. Are you aware of any instances where AmerenUE has acknowledged that its rates in this case will only be based on prudently incurred costs?

A. Yes. AmerenUE informed its customers of this requirement in its January 2007 Amerenlines customer bill insert discussing this rate case, where it states: "Under Missouri regulation, AmerenUE can recover from its customers prudently incurred electric operations costs and prudently incurred investments, including an appropriate return on those investments."

Q. Has Ameren acknowledged at the Federal Energy Regulatory Commission (FERC) the jurisdiction of the Missouri Commission regarding this issue but AmerenUE has not noted this fact in the rebuttal testimony of Messrs. Moehn, Svanda or Downs?

A. Yes. Counsel for the Staff has advised me that the prudence criteria standard and the Commission retail ratemaking treatment jurisdiction for this issue was acknowledged in the Federal Energy Regulatory Commission (FERC) filings by Ameren and FERC orders in those proceedings. OPC filed a Protest in the FERC proceeding, Docket No. EC04-81, where Ameren, Dynegy, Illinois Power sought FERC authorization to merge. At pages 43 and 44 of Applicants' (Ameren, Dynegy, Illinois Power, et al.) May 25, 2004 Motion For Leave To Submit Answer And Answer, in FERC Docket No. EC04-81 Applicants told the FERC that the EEInc. issue is a Missouri Commission issue. In fact, Ameren stated that "[if] any entity should have the right to compel AmerenUE to purchase capacity or energy from EEInc. to serve native load, it should be the MoPSC, as part of a prudence review of AmerenUE's retail rates, or some similar proceeding":

> IV.A.2.c. The Missouri Office of the Public Counsel's Concerns About AmerenUE's Rights To Power From EEInc Facilities Are Erroneous And Should Be Addressed By The MoPSC, Not FERC.
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> In protest, MOPC raises certain concerns related to the proposed acquisition of a 20 percent ownership interest in EEInc by AER. . . . according to MOPC, Missouri ratepayers have historically supported the costs of the EEInc capacity and output, and should continue to have access to the 40 percent of output to which AmerenUE is entitled. [footnote omitted.] . . . .
>
> MOPC recently raised these same issues before the Missouri Public Service Commission ("MoPSC") in AmerenUE's Metro East proceeding, in which AmerenUE has requested MoPSC authority to transfer its Illinois-based assets to AmerenCIPS. In particular, MOPC has asked the MoPSC to require AmerenUE to extend its agreement to purchase energy from EEInc. [footnote omitted.] . . . This issue remains pending before the MoPSC and falls squarely within the area of primary jurisdiction of the MoPSC – retail utility rates. The Commission should not concern itself with these state retail rate issues – which are nonetheless false – and should instead require MOPC to continue to litigate its issues at the MoPSC.
>
> . . . If any entity should have the right to compel AmerenUE to purchase capacity or energy from EEInc to serve native load, it should be the MoPSC, as part of a prudence review of AmerenUE's retail rates, or some similar proceeding. The Commission should not allow itself to be dragged into theses issues by the MOPC.

Q. Is the Staff proposing that this Commission order AmerenUE to purchase capacity or energy from EEInc. to serve its Missouri customers?

A. No, although Mr. Svanda, at page 3, lines 8-14, and page 9, lines 5-10, seems close to suggesting that this is what Staff has proposed. Staff is not proposing that the Commission order AmerenUE to purchase capacity or energy from EEInc. to serve its Missouri retail customers. Staff would no more recommend that the Commission order

AmerenUE to purchase from a lower cost vendor should AmerenUE choose to imprudently act otherwise. Staff is proposing that the Commission not set rates for Missouri retail customers that reflect the higher cost or lost revenues resulting from AmerenUE's failure to use reasonable efforts available to it to avoid negative effects on AmerenUE's cost to serve its retail customers.

Counsel for the Staff has also advised me that on July 29, 2004 the FERC issued an Order Authorizing Disposition Of Jurisdictional Assets And Accepting Power Purchase Agreements Subject To Conditions in which it stated in relevant part OPC's EEInc. issues were a state commission matter:

> 66. . . . Regarding MOPC's request that Applicants commit that AmerenUE's current 40 percent entitlement to the output of the Joppa Facility be preserved, Applicants argue that this is a state retail ratemaking issue that will be addressed by the Missouri Commission.
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> . . . .
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> 67. . . . Regarding MOPC's request that Applicants commit that AmerenUE's current entitlement to the output of the Joppa Facility be preserved, we agree with Applicants that the issue is under the state's jurisdiction. The Missouri Commission has intervened in the proceeding but has not filed comments or a protest. . . .

Counsel for the Staff also informed me that OPC and MIEC filed Requests For Rehearing and Ameren, Dynegy and Illinois Power filed on September 7, 2004 Motion For Leave To Submit Answer And Answer To Requests For Rehearing wherein it stated at pages 3-4 that the Missouri Commission has primary jurisdiction:

> On July 29, 2004, the Commission issued its order approving, among other things, the sale of Illinova Generating's interest in EEInc to AER. In doing so, *the Commission expressly declined to condition its approval on the requests of MOPC and MIEC.* Rather, the Commission sided with Applicants, stating "we agree with Applicants that the issue is under the state's jurisdiction." [footnote omitted.]

> Applicants believe that the Commission properly decided this issue, and nothing stated by MOPC or MIEC in their requests for rehearing should persuade the Commission to change its position.
>
> Indeed, the requests for rehearing of MOPC and MIEC are little more than the rehashing of the same unfounded arguments raised in their respective protests. [footnote omitted.] In all four pleadings – the MOPC Protest, the MIEC Response, and both the MOPC and MIEC requests for rehearing – the core of MOPC's and MIEC's claims is their theory that, if Ameren UE fails to continue receiving 40 percent of the capacity and energy of EEInc's Joppa facility, Missouri ratepayers will somehow be harmed. Not only are these arguments just as speculative now as they were when the MOPC Protest and MIEC Response were filed, but they (continue to) fall squarely within the primary jurisdiction of the Missouri Public Service Commission ("MoPSC"). This, precisely, is what the Commission held in the July 29 Order. [footnote omitted.] No different outcome is warranted here.

Counsel for the Staff has advised me that the FERC's April 18, 2005 Order Denying Rehearing unequivocally pointed again to the Missouri Commission's jurisdiction:

> 10. . . . MOPC's request for clarification appears to be an attempt to undermine the Commission's clear articulation of the appropriate forum for MOPC's concerns: the Commission has no jurisdiction over AmerenUE's retail rates or the manner in which it procures capacity or energy to serve its native load, except to the extent wholesale competition could be harmed, which is not at issue here. Clearly, the July 29 Order did not preempt state authority over retail rates. No further clarification is required.

Finally, counsel for the Staff has informed me that on September 15, 2005, as amended on November 3, 2005, EEInc. filed an application with the FERC for market-based rate authority, with an accompanying tariff, in FERC Docket No. ER05-1482. The Missouri Commission and the Missouri Industrial Energy Consumers filed Notices Of Intervention and OPC filed a Motion To Intervene And Protest. FERC's December 8, 2005 Order Granting Market-Based Rate Authorization to EEInc looks to the Missouri Commission for resolution of issues relating to retail rates:

> 34. The Missouri Office's concerns essentially center on the argument that it already made full payment of AmerenUE's

> share of all capital costs on a front-loaded basis and no longer will have the right to receive power from the plant once its contract expires. In particular, the Missouri Office argues that "Missouri ratepayers' historic cost support of the EEInc power supply entitles them to the full value of the plant for its remaining life." This argument is not relevant to the decision of this Commission as to whether EEInc meets this Commission's standards for market-based rate authority and further is an issue that is better resolved at the state level. In addition, the Missouri Commission has intervened in this proceeding but has not filed comments or protested the application.

Q. Are Messrs. Moehn (Rebuttal Testimony, page 3, lines 2-4) and Svanda (Rebuttal Testimony, page 3, lines 3-5 and page 18, lines 4-5) correct in their assertions that the EEInc.'s Joppa unit has always been recognized to be a below the line investment by the Staff?

A. No. In fact, AmerenUE's share, 40%, of EEInc.'s Joppa unit has always been treated as an "above-the-line" investment. The term "below-the-line" is typically used to indicate that the item is not considered in the ratemaking process. This is not true for the costs related to AmerenUE's share, 40%, of EEInc.'s Joppa unit.

Q. AmerenUE witness Mr. David Svanda at page 9, line 10 of his Rebuttal Testimony, accuses the other parties, among other things, of making "an alarming distortion of the familiar concept of prudence." Do you have a response?

A. Yes. The Staff is approaching this matter as a retail ratemaking issue and whether the increased costs and lost revenues related to this issue should be used to establish the level of rates in this case. Staff is agreeing with the aforenoted FERC filings of Ameren and Orders of the FERC that this matter is a Missouri jurisdictional issue, and I am advised by Staff counsel that Staff's briefs' will also address in what capacity the Joppa Plant may be viewed as part of the AmerenUE system.

Staff is using the prudence standard to determine the proper ratemaking treatment for the monies related to this issue. The Staff' prudence review centers on the question as to whether AmerenUE used every reasonable effort to minimize its costs of doing business relative to matters that resulted in the increased fuel and purchase power costs and lost off-system sales involved in this issue. If the Commission finds that AmerenUE was not prudent in its actions relative to this issue, then the Commission should not include the increased costs and lost off-system sales impact of this issue in the cost of service used to the determine the level of rates Missouri ratepayers will be required to pay as a result of this case.

It is Staff's position that AmerenUE was imprudent in that it not only did make every reasonable effort to prevent or minimize the increased costs and revenue loss related to this issue but it was directly responsible for creating the situation that caused increased costs and revenue loss related to this issue.

Q. How does AmerenUE describe in its rebuttal testimony its view of the situation related to the opportunity for AmerenUE to purchase cost-based power through a power supply agreement from its share of the EEInc. Joppa Plant that would avoid the increased costs and revenue loss related to this issue?

A. Mr. Moehn states in his Rebuttal Testimony at page 7, lines 3-6: "AmerenUE did not choose to forgo any such opportunity because such opportunity did not exist after the expiration of the then current PSA on December 31, 2005. The Board of Directors of EEInc. made the decision to sell power from the Joppa Plant at market-based prices." Neither Ameren nor AmerenUE raised the matter to EEInc. regarding extension of the then current cost-based power supply agreement terms beyond December 31, 2005. (AmerenUE response to AG Data Request No. 25 and Deposition of Gary L. Rainwater, p. 97, line 11 through

p. 99, line 12.). It was the position of AmerenUE that it had the discretion to direct its investment in the EEInc. Joppa Plant to serve more profitable markets than service to its Missouri customers. AmerenUE maintains that the Joppa Plant is a below-the-line asset owned by shareholders and never was used in a way that put UE customers at risk for the cost of those assets. ** ____ ____ ____ ____________________ ** (AmerenUE response to OPC Data Request No. 2005).

Q. Does the Staff concur with AmerenUE's description of the situation?

A. No. The decision that created this issue was made by AmerenUE not EEInc. For the period 1953-2003, in the federal Form No. 1 Annual Reports, at page 102, EEInc. stated to FERC and its predecessor, the Federal Power Commission, that EEInc. is directly controlled by the Sponsoring Companies through their ownership of the voting securities of EEInc. It should be noted that EEInc. omitted this statement from its 2004 and 2005 Form No. 1 Annual Reports to FERC. AmerenUE has held a 40% control during this period. AmerenUE, by itself, held more than the necessary share of votes under the EEInc. Bylaws to continue to purchase power from EEInc after December 31, 2005. "Article II, Section 6. Voting." of the EEInc. Bylaws provides that "decisions to allocate the sale of generating capacity of EEInc. among the EEInc. stockholders in a manner other than in accordance with their percentages of ownership of EEInc. stock in the event of such capacity available for sale to parties other than the U.S. Enrichment Corporation" and "a material change in the business purpose or objectives of EEInc" constitute "corporate restructuring transactions" and "other major corporate actions." "Article II, Section 6. Voting." of the EEInc Bylaws also provides that when any holder of voting capital of EEInc., including such holder's affiliates, owns in excess of 50% of the voting capital stock of EEInc., "all corporate restructuring transactions and other major corporate actions shall be decided by the vote of the holders of 75% or more of the outstanding shares of the Corporation entitled to vote." This latter provision is applicable because AmerenUE and its affiliate Ameren Energy Resources Company, combined, own 80% of the voting capital stock of EEInc.[1] AmerenUE owned 40% of the voting capital stock of EEInc. and could use this leverage to achieve cost based rate terms for its allocated share of the generating capacity of EEInc. ** ____________________

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____ ** AmerenUE rebuttal testimony acknowledges that an exempt wholesale generator (EWG) with market based rate

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[1] AmerenUE owns 40% of the stock of EEInc and Ameren Energy Resources Company owns 40% of the stock of EEInc. as a result of the following FERC Dockets. On December 13, 2001 in FERC Docket No. EC02-34-000, AmerenCIPS and Ameren Energy Resources Company filed, pursuant to Federal Power Act (FPA) Section 203, for authorization for AmerenCIPS to transfer its 20% common stock interest in EEInc to Ameren Energy Resources Company. FERC issued its Order Authorizing Disposition Of Jurisdictional Facilities on February 25, 2002. In FERC Docket No. EC04-81-000, the Merger Application of Ameren, Dynegy, Inc., Illinova Corporation and Illinova Generating Company, the FERC issued on July 29, 2004 its Order Authorizing Disposition Of Jurisdictional Assets And Accepting Power Purchase Agreements Subject To Conditions. The FERC authorized Illinova Generating Company to transfer its 20% interest in EEInc. to Ameren Energy Resources Company. Prior to this merger with Ameren, Illinois Power Company had become a direct wholly owned subsidiary of Illinova.

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authority such as EEInc. is not precluded from selling power at cost based rates. (David A. Svanda, Rebuttal Testimony, p. 14, lines 21-22).

The fact that EEInc. can arrange to sell its power on different terms is shown by the fact that ** ____

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____________ ** (AmerenUE Response to OPC Data Request No. 2005).

Q. Does the Staff fundamentally view the EEInc. issue as a prudence question?

A. Yes. There is a difference of opinion between AmerenUE and the Staff regarding the relevance and the significance of the prudence element of AmerenUE's actions related to this issue versus the relevance and the significance of the legality of AmerenUE's actions. Over my approximate 30 years of regulatory experience, there appears to me to be a relationship between legality and prudence but the relationship is not absolute or constant. For example, not all actions found to be imprudent actions are also found to be illegal. It is not unusual that a utility action that is deemed to be imprudent is deemed to be legal, and a utility action that is deemed to be legal is not deemed to be prudent. "Legality" or "lawfulness" is an element of any prudence review considered when determining what was the reasonable course of action or whether the course of action taken was prudent. Certain prudent actions may be found to be illegal at a later date. Mr. Downs' rebuttal testimony appears to address the "legality" of AmerenUE's actions and seems to offer a legal opinion

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that any other options that have been suggested were illegal. Regarding the question of the lawfulness of AmerenUE's actions, that will be argued in the Staff's briefs. I am only challenging the prudence of the new EEInc. purchased power supply agreement related to AmerenUE's share of the capacity and energy from the Joppa Plant. Counsel for the Staff will address in Staff's briefs in what capacity the Joppa Plant may be viewed as part of the AmerenUE system.

AmerenUE attempts to address the prudence element of this issue in its rebuttal testimony by attempting at times to separate the prior Power Supply Agreement between EEInc. and the Sponsoring Companies of which AmerenUE is a Sponsoring Company from AmerenUE's stock ownership of EEInc. which makes AmerenUE a Sponsoring Company. At other times AmerenUE acknowledges the relationship between its stock ownership of EEInc. and the prior Power Supply Agreement.

Q. Do you agree with (1) Mr. Moehn equating at pages 15 to 16 of his Rebuttal Testimony the Power Supply Agreement between EEInc.and the Sponsoring Companies with any other purchased power agreement between electric utilities, (2) Mr. Moehn's comparison of the Power Supply Agreement with the purchased power agreements between UE and Arkansas Power & Light Company / Entergy Arkansas at pages 12-13 of his Rebuttal Testimony, or (3) Mr. Svanda's statement at page 10 of his Rebuttal Testimony that the Staff mischaracterizes commonplace aspects of cost plus contracts?

A. No. The EEInc. Power Supply Agreement with its owners, including AmerenUE, is more akin to an operating agreement between multiple owners of a generating unit than a separate, independent wholesale power supply agreement. The EEInc. Power Supply Agreement is related to ownership and not related to a separate, independent wholesale power supply transaction designed to meet an electric utility system's need for a set time period. The EEInc. Power Supply Agreement contained a contract term designed to match the term of the DOE contract and not EEInc. owner system needs. (Deposition of Mr. Gary L. Rainwater, p. 97, line 11 through p. 111, line 10 through line 14). AmerenUE acknowledges that the contract duration was an element of the contract that could be changed at any time. AmerenUE attempts to compare the EEInc. Power Supply Agreement to a power supply agreement with a non-affiliated power supplier. EEInc. is not a non-affiliated power supplier. AmerenUE has no control over a non-affiliated power supplier unlike the situation it is in with its percentage ownership share of the stock of EEInc.

The comparability Mr. Moehn tries to make in his rebuttal testimony using the purchased power agreements of UE and Arkansas Power & Light Company / Entergy Arkansas for comparison with the Power Supply Agreement of EEInc. and the Sponsoring Companies is more akin to the power supply agreement of the Department of Energy (DOE) and EEInc. than the Power Supply Agreement of the Sponsoring Companies and EEInc. because DOE has a defined load that will be supplied by EEInc. through Joppa Plant generation or energy provided by the Sponsoring Companies. UE has the defined load that will be served by supplier Arkansas Power & Light Company / Entergy Arkansas. The Sponsoring Companies have no long term defined firm load that was being served by the Power Supply Agreement with EEInc. The Sponsoring Companies committed to buy the power from the EEInc. Joppa Plant whenever DOE did not commit to the generation. The Sponsoring Companies' Power Supply Agreements with EEInc. were financial commitments by the Sponsoring Companies to make whatever proportionate payments were needed to pay EEInc. costs whether energy was generated or not. The Sponsoring Companies' Power

Supply Agreements were financial backstops to substitute for the low amount of equity invested in EEInc. by the Sponsoring Companies.

A key point of disagreement in this issue is the validity of the position that AmerenUE had no effective options available to effectuate an extension of its EEInc. Power Supply Agreement at cost based rates after the expiration of the then current Power Supply Agreement because the EEInc. Board of Directors made the decision to sell power from the Joppa Plant at rates higher than the prior cost based rates. The specification of what constitutes market-based rates can be different depending on the entities involved in a particular transaction. For example, ** ____

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________ ** (AmerenUE Response to OPC Data Request No. 2169). Thus, Kentucky Utilities' market based rate was lower than the rate offered by EEInc.

The issue of prudence is addressed by AmerenUE by solely asserting it had no control over a legal situation. Issues such as ratepayer support or prior ratepayer benefit are tangential to the prudence of AmerenUE actions related to AmerenUE access to the capacity and energy of the Joppa Plant. Staff not covering the assertions of ratepayer support or prior ratepayer benefit in greater detail does not indicate Staff support for AmerenUE's assertions, but merely indicate that these areas are not justification for AmerenUE to not make every reasonable effort to minimize its cost of operations. Staff asserts that AmerenUE had effective options available to obtain a continuation of then existing EEInc. Power Supply Agreement on cost based terms and avoid the increased costs and lost revenue impacts

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AmerenUE is now seeking to recover from its Missouri customers while retaining for itself the gains achieved by this scheme.

Q. How do you address Messrs. Moehn's and Svanda's contentions in their rebuttal testimonies that no ratepayers' dollars were put at risk respecting the AmerenUE investment in EEInc. relative to the Joppa Plant?

A. I would agree partially. No ratepayer dollars are put at risk until the matter comes before the Commission for a ratemaking determination. However, this point is not unique to AmerenUE investment in EEInc. relative to the Joppa Plant. This same contention applies equally to the building or acquisition of AmerenUE's other generators. This point does not distinguish AmerenUE investment in EEInc. relative to the Joppa Plant from AmerenUE's investment in its other generating stations.

Q. How do you respond to Mr. Moehn's testimony on page 7, lines 7-14 regarding AmerenUE's control of EEInc's operation and maintenance of Joppa Plant?

A. AmerenUE does have a significant degree of degree control over EEInc. as previously noted in the majority of the EEInc. annual reports to its federal regulator. No other owner has a larger voting percentage. With its 40% of EEInc. stock, AmerenUE can vote on matters as to who will be EEInc.'s officers. In fact several EEInc. officers have Union Electric backgrounds. Mr. Naslund and Mr. Whiteley are EEInc. directors specifically representing AmerenUE. Mr. Naslund, an AmerenUE officer, advises EEInc. on operational matters. AmerenUE has a 40% vote on all matters brought to the EEInc. Board regarding matters such as power supply agreements.

Q. Does AmerenUE attempt to assert in the Rebuttal Testimony of Messrs. Moehn and Svanda that a different relationship exists regarding the Joppa plant, relative to the AmerenUE ownership of EEInc. stock, separate and apart of AmerenUE's ownership of other generating facilities?

A. Yes. A significant factor is AmerenUE labeling its EEInc. investment related to the Joppa unit as a "below the line" investment. However, at no time does AmerenUE claim that all relevant costs for AmerenUE's share of the Joppa Plant have been excluded from rates. In fact, AmerenUE's Missouri regulatory treatment of its ownership of EEInc. stock relative to the Joppa Plant has been similar if not better than the regulatory treatment afforded AmerenUE's ownership of its other generating facilities.

Q. How do you respond to Mr. Swanda's Rebuttal Testimony on page 16, line 18 through page 17, line 22?

A. AmerenUE has generation assets besides the Joppa Plant that have a cost structure that would be below the value that AmerenUE could receive for those assets' generation in the off-system market. This fact is seen in the significant levels of off-system sales enjoyed by AmerenUE. This fact does not justify the removal of any of these units from AmerenUE's cost of service to increase Ameren's overall profits at the expense of AmerenUE's Missouri retail customers paying higher rates. This situation is the classic affiliate abuse issue. A comparison of actions of AmerenUE on this matter to the actions of the non-affiliated Kentucky Utilities shows that the utility with the affiliation is the less active in pursuing its rights to seek the lower overall cost of service for its customers.

Kentucky Utilities actions provide the basis for the determination of prudent actions that should have been taken by AmerenUE. Given the present ownership of EEInc. shares, any two owners that vote together represent a majority. It is unusual in a prudence review to have an actual baseline of the actions that were reasonable under the facts and circumstances at the time, as is the case with the conduct of Kentucky Utilities.

Q. Do you agree with Mr. Moehn's rebuttal testimony on page 16, line 18 through page 17, line 22?

A. No. His conclusion is based on the premise that the owner of the generator would not use off-system sales, in this case, Atomic Energy Commission (AEC)/ Department of Energy (DOE) revenues, to determine its overall cost of service. This premise is flawed. AmerenUE would be entitled to 40% of the benefit of these sales as much as it is responsible for 40% of the costs.

The AmerenUE ratepayers paid rates that included all the costs of ownership of the Joppa Plant on similar terms as AmerenUE's other generating units. The inclusion of AmerenUE's stock in rate base would only require a reduction in the EEInc. demand charge to remove the return on equity component to avoid double recovery of costs.

I do agree with Mr. Moehn's Rebuttal Testimony on page 17, that there existed a relationship between the Sponsoring Companies' Power Supply Agreements and the EEInc. capital structure that made the Power Supply Agreements unique from typical non-affiliated power supply agreements. It was the nature of the commitments in the Sponsoring Companies' Power Supply Agreements and the EEInc. that reduced the amount of money that the Sponsoring Companies were required to invest in EEInc. Initially, AmerenUE invested approximately 5% equity in the EEInc. Joppa Plant project.

Q. Do you agree with Mr. Moehn's Rebuttal Testimony on page 19 that shareholders of EEInc. have always taken the investment risk?

A. Yes, but this fact is no different for the investment risk in AmerenUE's other generating units. In fact, the EEInc. power contracts mitigated this risk relative to AmerenUE's other generating units through the use of accelerated cost recovery mechanisms.

Q. Was there any actual distinction regarding AmerenUE's assumed risk relative to its investment in the EEInc. Joppa Plant compared to AmerenUE's other generating units?

A. No. The ratepayer relationship noted in the AmerenUE Rebuttal Testimony (e.g., responsibility for potential losses, prudent costs for capacity and energy, power supply agreement ratepayer obligations, potential losses on investment) relative to the EEInc. Joppa unit (i.e., EEInc. $1.7 million writeoff) apply equally to AmerenUE's other generating units. AmerenUE incurred a $100 million loss on its investment in Callaway and will absorb costs relative to its investment in Taum Sauk, both of these units are rate base generators.

The AmerenUE investment in EEInc. was not treated below-the-line as stated in AmerenUE's Rebuttal Testimony any differently than the interest and profit on investment in AmerenUE's other generating units is below-the-line. The interest and profit for the Joppa Plant was recorded in purchased power expense while the interest and profit for AmerenUE's other generating units is recorded in below-the-line accounts thus requiring rate base treatment to place these costs in AmerenUE's cost-of-service for ratemaking purposes. The Commission's actual cost of service formula in its orders does not use the above or below the line methodology. Above-the-line or below-the-line treatment in public utility regulation indicates whether an item has or has not been included in the rates charged to ratepayers. In the case of the AmerenUE costs related to AmerenUE's ownership in EEInc., Joppa Plant capacity and energy has been included in rates charged to Missouri retail customers including costs for depreciation or amortization, interest, and profit.

AmerenUE never made the representation before this case that it would not seek recovery from ratepayers from some catastrophic failure respecting the Joppa Plant. Such a hindsight assertion at this time is not appropriate for a prudence review nor is it relevant since ratepayers have paid rates sufficient to allow recovery of the AmerenUE investment in EEInc. This assertion is hypothetical since AmerenUE has never experienced any such loss relative to its investment in the EEInc. Joppa Plant. The new AmerenUE representation that it would not seek recovery from ratepayers from some catastrophic failure at the Joppa Plant is not a distinguishing factor respecting the Joppa Plant since this same situation can occur at other AmerenUE generating facilities (e.g., Taum Sauk). AmerenUE is providing no less assurance to this Commission regarding catastrophic, unfortunate and unforeseen events regarding its ownership in EEInc.'s Joppa Plant than it has relative to its other generating units on occasion.

The fact that an asset has been beneficial to consumers in the past does not make a decision to discontinue those benefits to consumers at a later date prudent. AmerenUE notes that it wants to sale the energy at market rates but AmerenUE makes no representation that it would make this decision if market rates were less than costs.

Q. How do you respond to Mr. Svanda's statements at page 10, lines 1-7 of his Rebuttal Testimony?

A. Mr. Svanda's statements regarding the fact that the Joppa Plant costs to produce power today is below the market price of the power applies to a majority of the AmerenUE generators not just the Joppa Plant. The fact that is ignored by Mr. Svanda's

Rebuttal Testimony is that cost based rates are typically higher than market based rates in the initial years of a coal baseload unit. Customers usually have to pay higher costs in the early years in order to begin to enjoy an overall benefit over the life of the unit. This principle is particularly true regarding the costs of EEInc.'s Joppa Plant because the recovery of those costs was based upon accelerated cost recovery methodologies resulting in the power costs being higher in the initial years with substantial benefits being realized after the expiration of the accelerated cost recovery methodologies.

Q. What were these accelerated cost recovery methodologies?

A. Initially the Power Supply Agreement provided for utility plant being amortized on a 25-year sinking fund basis with interest at rates corresponding to those of the First Mortgage Sinking Fund Bonds. This resulted in EEInc. reporting to FERC on page 112 of its 1980 Form No. 1 Annual Report: "The majority of the utility plant is fully amortized. The remaining utility plant is being amortized as prescribed by the Power Contract, on a sinking fund or straight line basis corresponding with either the retirement of related debt or the remaining life of the Power Contract." EEInc. would report in later Form No. 1 Annual Reports that certain utility plant additions were being depreciated as provided under the Modified Accelerated Cost Recovery System for both book and tax purposes. As a rule, the EEInc. investment is depreciated over a period less than the life of the plant. AmerenUE's other generating units have not been depreciated following such an aggressive approach in terms of seeking investment recovery over a period shorter than their useful lives.

Q. How could such accelerated cost recovery methods be found to be prudent at the time?

A. I can find no record that such methodologies were specifically examined. However, accelerated cost recovery methods can be prudent from a customer rate level perspective if one enjoys a significant period of time after the accelerated cost recovery scheme expires to realize net present value benefits greater than the extra costs paid during the accelerated cost recovery period. If one equates intergenerational equity as an element of prudence, then one would not find such an approach prudent. However, that question is moot at this stage since no one challenged the prudence of the Power Supply Agreement during the time of the accelerated cost recovery charges.

In prior rate cases, prudence reviews of the AmerenUE power supply costs were conducted under the representation that the AmerenUE would continue to use its share of the Joppa Plant capacity and energy as long as it was economic to do so and it was never represented that AmerenUE could choose to terminate use of this capacity and energy whenever the then current Power Supply Agreement concluded, and as a consequence there would be no future power supply agreement and therefore no retail ratemaking recognition of any future power supply agreement. Under these new conditions that the Joppa capacity and energy will not be used serve to AmerenUE's customers, it is possible that the Joppa Plant energy and capacity would not be economic given the significant fixed costs associated with the Power Supply Agreement.

Q. Does Mr. Moehn's Rebuttal Testimony on page 8, lines 12 through 17, prove that EEInc's power "was a good price and good value"?

A. No. Mr. Moehn's fifty (50) year average price does not show that in any given year EEInc.'s power cost relative to AmerenUE's alternative system average price "was a good price and good value." In the years 1954 through 1968 the price of the EEInc.

power was less than $4 per Mwh. A valid analysis to determine the value of the EEInc. capacity and energy over a specific period would need to determine comparable alternative costs for this time period. The fact that these prices are attractive from today's perspective or hindsight does not prove they were a good value at the time. During the period 1979 through 1995, these prices exceed $20 per Mwh with a high of $60 per Mwh. During the period 1969 through 1978, prices fluctuated between a low of $4 per MWH to a high of $16.50 per Mwh using Mr. Moehn's data. While it is likely that EEInc.'s power cost is cost effective in the later years, it just as likely that its price was not cost effective in the earlier years or in specific years. This fact would apply equally to most of AmerenUE's other generating units as well. This is especially true given the fact the AmerenUE never entered into these Power Supply Agreements as "pure" economic arms-length transactions. No definitive study could be attempted without defining the AmerenUE alternative to EEInc. in the 1954 through 2005 period. I have encountered some data issues that I will seek to resolve with AmerenUE before the hearing of this issue. I do not expect that resolution of these data issues would change Mr. Moehn's conclusions given his approach nor my disagreement with his methodology.

Q. Did AmerenUE ever represent that the Joppa Plant would be used to serve the Union Electric service territory over a period of time that would justify any such accelerated cost recovery approach?

A. Yes. Union Electric never indicated that the Joppa Plant capacity and energy would be used for any purpose other than serving its native load customers until after its merger with Central Illinois Public Service Company (CIPS) and restructuring as a subsidiary of a non-exempt public utility holding company. In fact, before its affiliation with the Ameren entities, Union Electric built and owned a transmission line to connect the Joppa Plant capacity and energy to its system, and represented its plans to continue to use and expand its use of the Joppa Plant capacity and energy to serve its native load customers after the then existing Power Supply Agreement's December 31, 2005 expiration date.

Beginning in the early 1950s with Union Electric's applications for Commission authority respecting EEInc. and continuing through the 1990's in Union Electric's electric supply resource plans, representations were made by Union Electric that indicated that the Joppa Plant would serve Union Electric customers over a period different than any existing EEInc. power supply agreement termination date. There was no representation by Union Electric/AmerenUE that it was only planning to use its share of Joppa Plant capacity and energy through the life of some existing contract, which was subject to change upon a vote of the EEInc. Board. Union Electric's building and owning a transmission line to connect its system to the Joppa Plant as well as a commitment to supply power to the Joppa Plant for station use and construction as well as supply backup to serve the DOE needs is more akin to the relationship existing between AmerenUE and its other generating units than a condition common in non-affiliated, wholesale power supply agreements.

Q. What documents does the Staff have that support your testimony that Union Electric/AmerenUE planned to continue use its share of the Joppa Plant after the expiration of the current Power Supply Agreement?

A. Attached to my Surrebuttal Testimony are three schedules. Schedule 1 attached to my Surrebuttal Testimony is a copy of the June 1995 "Energy Resource Plan" for Union Electric. Page number 1 of this document (Schedule 1-2) describes the Union Electric ownership of EEInc. in conjunction with Union Electric's other generating units. On page number 26 of the document (Schedule 1-27), a discussion of the Joppa Plant begins. A discussion of the Arkansas Power & Light Company (AP&L) purchased power agreement follows. It is interesting to note that the discussion regarding the purchased power agreement with AP&L mentions the contract termination date with the option to extend while the Joppa Plant discussion makes no mention of any contract termination date. On page number 30 of the document (Schedule 1-31), Union Electric mentions its opportunity to purchase additional energy from the Joppa Plant and extend the AP&L contract. On page number 31 of the document (Schedule 1-32), the additional Joppa Plant energy is listed as one of the "Possible Additional Resource Opportunities". On page number 33 of the document (Schedule 1-34), it is mentioned that the additional Joppa energy purchase passed the system level screening analysis as a future resource candidate. Page number 33 of the document also states that Table 4-3 shows the preferred all supply-side resource plan resulting from the quantitative screening analysis. Table 4-3 on page number 36 of the document (Schedule 1-37) shows 405 MW of Joppa Plant available from 1995-2014. Page number 46 of the document (Schedule 1-47) states that the sensitivity, scenario, and risk analyses show that the DSM-20 plan is preferred and Union Electric's preferred resource plan is shown in Table 6-7 and is based on the DSM-20 plan. Table 6-7 on page number 54 (Schedule 1-55) shows 405 MW of Joppa Plant available from 1995-2014. The planning period for this document goes through 2014 and at no time indicates any loss of Joppa Plant capacity and energy.

Schedule 2 attached to my Surrebuttal Testimony is a copy of Union Electric's October 1997 "Risk & Uncertainty Analysis Briefing" resource planning document. Page 3 of this document (Schedule 2-3) entitled "Optimized Expansion Plans For Various

Sensitivities" continues to show the use of Union Electric's share of the Joppa Plant through 2014 and shows the extra Joppa occurring as early as 2010, but more important to this issue is what the document does not show. The document does not show an entry in 2005 "Extend Joppa" as it shows an entry in 2002 "Extend AP&L," nor does the document analyze any risk scenario that Union Electric's share of the Joppa Plant would not be available. "Extend AP&L" is explained in a footnote as: "Extend The Present Purchase Contract With AP&L From 2002 to 2008."

Schedule 3 attached to my Surrebuttal Testimony are copies of AmerenUE's responses to certain Office of the Public Counsel's Data Requests in Case No. EC-2002-1. These responses show AmerenUE's 10 year forecast resource plans commencing for the years 1998, 1999, and 2000. **

NP

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Q. Does this conclude your surrebuttal testimony?

A. Yes.

NP

DOCUMENT 2

ENERGY RESOURCE PLAN

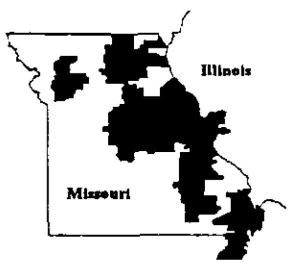
UNION ELECTRIC

RESOURCE PLANNING COMMITTEE

June 1995

COMPANY BACKGROUND

Union Electric Company (UE) is an independent, investor-owned utility headquartered in St. Louis, Missouri. UE currently supplies electric service to territories in Missouri and Illinois having an estimated population of 2,600,000 within an area of approximately 24,500 square miles. The population and electrical load is concentrated in the Metropolitan St. Louis Area.



Natural gas purchased from non-affiliated pipeline companies is distributed in 90 Missouri communities and the City of Alton, Illinois.

The Company employed 6,266 persons as of December 31, 1994. UE's highest gross instantaneous peak electrical load was 7,540 megawatts in the summer of 1993.

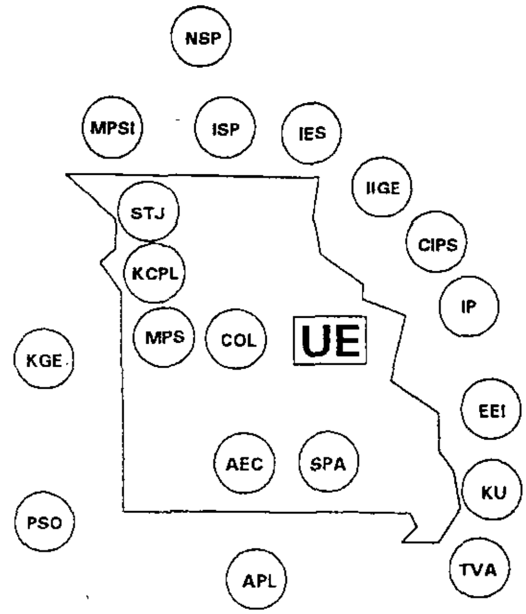
During 1994, 95.8% of total operating revenues was derived from the sale of electricity and 4.2% from the sale of natural gas. Approximately 89% of the Company's electric operating revenues was based on rates regulated by the Missouri Public Service Commission in 1994. The balance was regulated by the Illinois Commerce Commission (8%) and the Federal Energy Regulatory Commission (3%).

UE operates one nuclear-fueled and five fossil-fueled steam generating plants containing a total of 19 units with a net summer generating capacity of 6,758 megawatts. In addition, two hydroelectric plants, one pumped storage plant, nine combustion turbine units, and several small diesel units provide an additional net summer generating capacity of 1,067 megawatts. The Company's aggregate net summer generating capacity is 7,825 megawatts. In addition, UE owns 40% of Electric Energy Incorporated, providing 405 megawatts of capacity from the Joppa Plant which is located on the Ohio River, in Joppa, Illinois.

The Company is strategically located in the center of the United States and conducts interchange transactions directly with nineteen surrounding utilities. These numerous links give UE the flexibility to meet system requirements with the lowest cost power available. As of December 31, 1994, the Company owned approximately 3,315 circuit miles of electric transmission lines.

The following figure provides a pictorial representation of UE and the companies it can directly transact with.

UNION ELECTRIC COMPANY
TRADING PARTNERS



The Company faces issues common to the electric and gas utility industries which have emerged during the past several years. These include: changes in the structure of the industry as a result of amendments to federal laws regulating ownership of generating facilities and access to transmission systems; the potential for more intense competition; continually developing environmental laws, regulations, and issues; public concern about the siting of new facilities; magnetic fields emanating from power lines and other electric sources; proposals for demand-side management programs; and public concerns about the disposal of nuclear wastes and about global climate issues. The Company is monitoring these issues.

INTRODUCTION
SECTION 1

1.1 PURPOSE

The resource planning objective at Union Electric is to develop a plan that provides our customers high quality service at the lowest possible cost, consistent with paying a fair return to our investors and maintaining the welfare of our employees.

This Energy Resource Plan (ERP), which documents the process used to pursue this objective, is a snapshot of an ongoing planning process at UE. The plan continuously evolves as new information is received, economic conditions change, new technologies emerge, legislation changes, and the planning process itself improves.

The planning process focuses on identifying future system requirements and developing a flexible resource strategy to meet those requirements. This ERP provides the results of the planning process for the twenty-year planning horizon through 2014.

1.2 PLAN SUMMARY

This ERP updates the December 1993 ERP and addresses issues which will likely affect UE's future capacity and energy requirements. The load forecast used in the development of this ERP was prepared in October, 1994 and indicates that system resource requirements are not expected to exceed available resources before 2000.

The demand forecast, in conjunction with system reliability requirements, determines when additional resources — supply-side and demand-side management (DSM) — are required to meet customer demand. After the timing of future resource needs is determined, the preferred resource mix is developed.

Based on assumptions developed for this ERP, the preferred resource plan for the twenty-year planning horizon includes an economic combination of supply-side and demand-side resources as follows:

Additional Generation	**Capacity**
Sioux Operating Improvement	16 MW
Taum Sauk Runner Replacement	80 MW
Combustion Turbines	825 MW
Combined Cycle Units	180 MW
Venice Repowering	510 MW
Capacity Purchases 150 MW 1998-2004 50 MW 2000-2013	200 MW
Renewables	2 MW

Demand Reduction	**Capacity Equivalence**
Eliminate 25 Hz Losses	20 MW
DSM Programs (by June 2000)	133 MW
DSM Programs (by June 2014)	268 MW

This ERP relies on relatively small, short lead time resources to meet projected load growth. These qualities provide flexibility to meet the constantly changing external forces facing UE.

UE recognizes that purchases from independent power producers (IPPs) and competitive bidding programs may provide for a portion of these future resources. These options will be used to the extent they are economically justified when decisions are required.

Even though the plan calls for 1,515 megawatts of new dual fuel (gas and oil) generation, the Company's fuel mix changes only slightly over time. UE will remain heavily dependent on coal and nuclear generation.

This ERP does not require a substantial commitment for new supply-side resources over the next several years. UE has contracted for the purchase of 150 MW from Central Illinois Public Service Co. for the period June 1, 1998 through May 31, 2005.

The following programs will be initiated or continued over the next three years to provide more information for future decisions.

- Demand-Side Management (DSM) program development will continue in order to gain additional experience in implementing and marketing DSM strategies.
- Combustion turbine (CT) technology and siting will be reviewed and updated as conditions change, to minimize combustion turbine costs and construction lead time requirements.
- The Clean Air Act compliance study will be reviewed and updated as regulations are written and conditions change to yield the least-cost compliance strategy.
- All demand-side and supply-side resource options will be monitored for changes which could affect the preferred resource plan.
- Prior to proceeding with the Keokuk rewind project, the current preliminary estimates of project cost and efficiency gains will be reviewed and updated. In addition, the company will determine if there is a market for 25 Hz generation before a decision is made to proceed with project implementation.
- Engineering, design and procurement of the equipment necessary for the Taum Sauk runner replacement project will proceed.
- The wind analysis study that was initiated in 1995 will be continued to determine wind availability in the UE service area.
- The Meramec Unit 3 repowering study that was initiated in 1995 will be completed to determine the economics of repowering vs. rehabilitating the boiler.
- Studies will be initiated to evaluate the economics of potential upgrades at several coal-fired units and combustion turbines.

Demand-side options will be phased in over several years so they will be in place when needed. The Company is conducting pilot programs to help guide demand-side program selection and implementation. System-wide programs are scheduled to start in 1997 and gradually build toward a substantial demand reduction. The DSM program phase-in allows the Company to determine more accurately the expected demand reduction. Supply-side measures can be advanced if demand-side programs fail to meet expectations.

Varying degrees of uncertainty exist in the assumptions required to develop the preferred resource plan. Fuel prices, load growth, future legislation, econometric forecasts, new plant costs, and numerous other inputs cannot be predicted with certainty. Various risk analysis techniques, including sensitivity analysis, probabilistic decision trees, and scenario analysis were used to address these uncertainties.

In addition to the expected forecast scenario, the following alternative scenarios were created to investigate the effect of changing the assumptions.

- Low Forecast – Lower than expected peak and energy growth due to unfavorable economic conditions.
- Competition — Assumes a phased in competitive environment where industrial rates are deregulated in 1998, commercial rates in 2000, and retail rates in 2002.
- Environmental Regulation — Assumes a significant increase in environmental regulation beginning in 2000 and extending throughout the planning horizon.
- High Forecast – Higher than expected peak and energy growth due to favorable economic conditions.

This ERP identifies a resource plan that is robust across all of the scenarios. The scenarios do not affect the selection of DSM programs, however they do impact resource timing. The low forecast and environmental regulation scenarios delay the CT decision date. The high forecast scenario may advance the need for additional capacity. This scenario requires additional power purchases for several years and advances the required date for the first CT.

1.3 PLAN DEVELOPMENT

A Resource Planning Committee, chaired by the Manager - Resource Planning, is responsible for coordinating the information needed to prepare the ERP. This committee reviews the ERP prior to its submission to upper management for approval.

Members of this committee represent the following functions and departments:

- Corporate Planning
- Distribution Engineering
- Division Marketing
- Energy Supply
- Environmental Services
- Financial Planning and Investments
- Fossil Fuel
- General Counsel
- Mechanical Engineering
- Power Plant Maintenance and Engineering

Numerous functions supply information to develop the ERP and participate in its review. A brief description of responsibilities follows:

Fossil Fuel Supply

The Fossil Fuel and Energy Services Departments maintain up-to-date information on fossil fuel price and availability (coal, oil, natural gas and propane). These departments also maintain information on fuel transportation from origin to UE generating facilities. The departments forecast fossil fuel prices and availability.

Nuclear Fuel Supply

The Nuclear Licensing & Fuels Department maintains up-to-date information on uranium price and availability. This department also maintains information on uranium, conversion, enrichment, and fabrication services. The department forecasts uranium prices and availability.

Generation Capacity

The Mechanical Engineering (Engineering & Construction) and Power Plant Maintenance and Engineering (Power Plants) Departments develop and maintain information on long-term, supply-side resource options. Mechanical Engineering is responsible for new facilities and major modifications or major improvements to existing facilities. Power Plant Maintenance and Engineering is responsible for existing unit performance ratings, capacity ratings, and improvements.

The Mechanical Development group of the Mechanical Engineering Department evaluates emerging generation technologies, renewables, near commercial technologies, and existing commercial technologies. These evaluations consider technical feasibility, commercial viability, costs, performance, and environmental concerns. Technologies include those appropriate for new generation capacity additions as well as retrofit technologies.

The Power Plant Maintenance and Engineering Department monitors existing plants for achieving performance and emissions requirements.

Studies by both departments are conducted to evaluate potential enhancements and improvements to existing facilities. These studies may result in operating improvements and/or plant modifications.

Purchased Power

The Energy Services Department maintains and develops information on the long-term, purchased power market.

Transmission

The Transmission Planning Department maintains and develops information regarding long-term transmission resource options. The Transmission and Interconnections group evaluates the transmission system considering feasibility, economics, reliability, and performance. These studies aid in developing long range plans for the utilization and optimal expansion of the transmission system.

Environmental

The Environmental Services Department maintains and develops information on environmental standards. It also actively supports the environmental permitting and regulatory process.

Cogeneration; Renewables; Demand-Side Management

The Mechanical Engineering and Corporate Planning Functions develop information on these resource options.

Regulatory Issues

The General Counsel Function monitors legislation and regulatory proceedings to determine impacts on the resource plan or the planning process. This function also develops information on possible future regulatory issues.

Financial Data

The Controller's Function annually develops the ten-year budget. The budget information and financial parameters developed by the Financial Planning and Investments Department are used in the planning process.

Distribution

Distribution Engineering develops information on loss reduction in the distribution system.

Plan Development

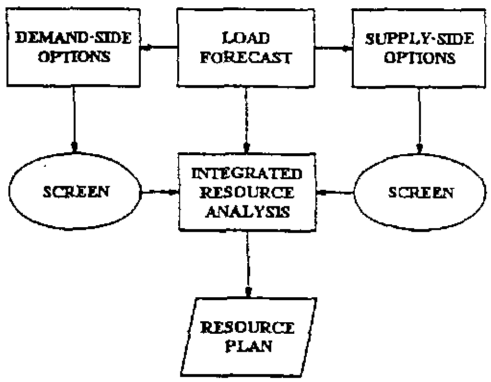
Corporate Planning is responsible for aggregating the data, modeling the UE system, analyzing resource options, and making recommendations to the Resource Planning Committee.

The plan development within Corporate Planning is divided between two groups:

- Demand-Side Planning — Forecast, DSM Screening, Non Utility Generators (NUGs), Cogeneration
- Corporate Analysis — Supply-Side Screening & Optimization, Integration, Risk Analysis, Reliability Analysis

The following figure portrays the process used to develop this ERP.

RESOURCE PLANNING PROCESS



1.4 PLANNING ENVIRONMENT

A number of regulatory and legislative requirements affect the Company's energy resource planning, and other developments will potentially affect the Company in the future.

Power Plant and Industrial Fuel Act of 1978

Substantial amendments to the Power Plant and Industrial Fuel Act of 1978 became effective in 1987. The basic result of these amendments was to remove restrictions on the use of natural gas and petroleum for the generation of electricity, except with respect to new power plants designed to operate as base load units.

Current regulations define base load units as power plants where the kilowatt-hour output exceeds the plant's design capacity multiplied by 3500 hours for any twelve calendar month period. The restrictions on new base load units are not onerous since oil and natural gas units must simply be capable of being converted to coal use in the future. Combined cycle units meet this requirement if they can be converted to burn gasified coal at a future date. Rules designed to implement the amendments to the Fuel Use Act became effective December 22, 1989.

Public Utility Regulatory Policies Act of 1978

The purpose of the Public Utility Regulatory Policies Act of 1978 (PURPA) was to encourage conservation of energy and efficient use of energy resources. PURPA encouraged production of electricity by cogeneration and small power production. This introduced a new form of competition for electric generation by:

- Requiring utilities to interconnect with qualifying facilities (QFs),
- Requiring utilities to buy power from qualifying facilities at the utility's avoided cost,
- Requiring utilities to provide qualifying facilities with supplemental, backup, maintenance, and interruptible power.

Purchasing power from qualifying facilities can reduce the amount of new generation required by a company. A Missouri statute enacted in 1986 requires electric suppliers to purchase the electrical output of municipally owned waste-to-energy facilities at the price they sell electricity to the municipality. However, contrary to a similar Illinois law, no tax credits are given to the utility for the difference, if any, between the rate and the utility's avoided cost.

UE currently purchases about 2.5 MW of waste-to-energy generation from facilities in Illinois and Missouri that use landfill gas.

Nuclear Waste Policy Act of 1982

Under the Nuclear Waste Policy Act of 1982, the U.S. Department of Energy (DOE) is responsible for the permanent storage and disposal of spent nuclear fuel. DOE currently charges one mill per nuclear kilowatt-hour generated and sold for future disposal of spent fuel. DOE is not expected to have its permanent storage facility for spent fuel available until at least 2010. UE has sufficient storage capacity at the Callaway Plant site until 2005, and has viable storage alternatives under consideration. Each alternative will likely require Nuclear Regulatory Commission approval, and may require other regulatory approvals. The National Association of Regulatory Utility Commissioners has been active in trying to facilitate an early resolution to the fuel storage issue. The delayed availability of DOE's disposal facility is not expected to adversely affect the continued operation of the Callaway Plant.

Energy Policy Act of 1992

While the Energy Policy Act of 1992 (EPAct) contains numerous electricity-related provisions, few of these provisions establish direct requirements for electric utilities. Most of EPAct sets policy for federal agencies — primarily the Department of Energy (DOE). However, some sections of EPAct will affect the electric utility industry:

- Promotion of Energy Efficiency
- Promotion of Renewable Energy Sources
- Provisions on Nuclear Licensing, Waste and Uranium Enrichment
- Increased Research on Environmental Issues
- Increased Competition in Electric Generation

Energy Efficiency

The EPAct promotes energy efficiency by setting equipment and appliance efficiencies, and requiring federal and state agencies to assess and revise standards for building codes. The net effect of these provisions on utilities will be to reduce the cost-effectiveness of some electric utility demand-side programs, as energy efficiency measures will be implemented without utility intervention. REEPS and COMMEND, the forecasting models used by Union Electric, now include the effects of EPAct standards for the residential and commercial classes.

Renewable Energy

The EPAct promotes renewable energy sources, like biomass and wind power, by requiring DOE research and development, and by creating a 1.5 ¢/kWh tax credit for electricity produced with wind and closed loop biomass resources installed between December 1, 1994 and July 1, 1999. The EPAct requires an inflation adjustment for this incentive, and the Internal Revenue Service announced on March 21, 1995 that the credit for 1995 will be 1.6 ¢/kWh.

This credit may encourage use of renewable resources by utility customers or utilities themselves, particularly where marginal energy costs are high.

Nuclear Power

The EPAct attempts to encourage the nuclear power option by streamlining the plant licensing process and moving toward a solution to long-term waste storage. EPAct also created the United States Enrichment Corporation to manage operation of the U.S. uranium enrichment plants.

Environmental Provisions

The EPAct requires the DOE to conduct research into environmental issues related to energy production and delivery, including EMF and coal. The most important provision is for global climate change research. DOE is required by EPAct to conduct global warming studies, assess alternative policies, and report its findings to Congress. DOE also must develop a greenhouse gas inventory and guidelines for voluntarily reporting data.

While carbon dioxide (CO_2) is a major focus of EPAct, it does not require CO_2 emission reductions. It does direct DOE to assess the feasibility and economic, energy, social, environmental, and competitive implications of reducing CO_2 emissions by 20 percent by 2005. See further discussions below under "Environmental Legislation and Regulation."

Competition in Electric Generation

Two EPAct provisions create greater competition for electric generation:

- The EPAct creates a new category of electric power supplier called an Exempt Wholesale Generator (EWG). EWGs, and their affiliates, are exempted by the EPAct from regulation under the Public Utility Holding Company Act.
- The EPAct grants the Federal Energy Regulatory Commission (FERC) expanded authority to order electric utilities to provide wholesale transmission access.

The magnitude of the effect of these provisions remains to be seen and could vary from region to region, based upon relative costs and transmission capacity. Union Electric has not seen any EWG development in its territory since the passage of EPAct.

Prior to EPAct, FERC had granted waivers to some regulations for "power marketers," entities included under the definition of electric utilities in the Federal Power Act. Power marketers do not need to own any generation facilities, which is a requirement for EWGs, but may request transmission service under Section 211 of the Federal Power Act. FERC may impose conditions relating to transmission access on utilities that form power marketing affiliates. Union Electric has seen considerable activity with marketers and brokers.

The development of rules and standards implementing EPAct is being closely monitored and results have been, and will continue to be, incorporated into the Company's resource planning process.

FERC Orders and Rulings

In October 1994, FERC issued a policy statement on pricing both firm and non-firm transmission services provided by public and transmitting utilities. This policy statement sets forth that transmission pricing must adhere to the Federal Power Act requirement that transmission rates be just and reasonable, and not unduly discriminatory or preferential. In addition, transmission pricing should follow five principles:

- Transmission Pricing Must Meet the Traditional Revenue Requirement - In the aggregate, rates must be designed so that a transmission owner meets, but does not exceed, its revenue requirement.
- Transmission Pricing Must Reflect Comparability - Transmission customers should receive access on the same or comparable basis, and under the same or comparable terms and conditions, as the transmitting utility uses for its system.
- Transmission Pricing Should Promote Economic Efficiency - Pricing should promote efficient expansion of transmission capacity, efficient location of new generation and load, efficient use of existing transmission facilities, and efficient dispatch of existing generating resources.
- Transmission Pricing Should Promote Fairness - Existing wholesale, retail, and transmission customers should not pay for the costs incurred to provide

wholesale wheeling services ordered under Section 211, and third-party customers should not subsidize existing customers.

- Transmission Pricing Should Be Practical - Pricing should be as easy to understand and administer as appropriate given the other pricing principles.

FERC distinguished between "conforming" and "non-conforming" pricing proposals. Non-conforming proposals are those which exceed traditional revenue requirements (the first principle listed above.) While FERC clearly indicated it prefers conforming proposals, it will accept non-conforming proposals that meet certain filing requirements and additional evaluation criteria.

At the same time it issued its new pricing policy, FERC also issued orders regarding two Regional Transmission Groups (RTG) and a notice of inquiry and request for comments regarding alternative power pooling institutions under the Federal Power Act. The RTG orders established criteria for approval of RTG organizations, requiring that all RTG members offer transmission services on a comparable basis to other members through a single RTG tariff or individual transmission tariffs. RTGs also must provide for the development of a single regional transmission plan. The alternative power pooling notice of inquiry stated FERC's belief that these pools have a great potential for addressing many barriers to transmission access and requested comments on the concept to allow FERC to better understand the merits of such arrangements. Comments on the proposal were received from many parties. As of this writing, FERC has not taken any additional action in this docket.

In March 1995 FERC issued a Notice of Proposed Rulemaking (NOPR) on open transmission access. The NOPR would impose two tariffs on all transmission providers, one for network service and one for point-to-point service. In addition, the NOPR establishes requirements for minimum ancillary services and procedures for obtaining services. Related dockets on real-time information networks (RIN) and stranded investment have been established. FERC is hosting a series of technical conferences and workshops to discuss components of the RIN, and interested parties are being given the opportunity to file initial and reply comments on this and other elements of the NOPR.

UE will continue to monitor and participate in FERC activities related to transmission access.

Other

In addition to the above, several other areas directly impact the planning environment, including:

- Resource Planning Legislation and Regulation
- Missouri Statewide Energy Planning and Global Warming Studies
- Illinois Legislation and Related Activities
- Environmental Legislation and Regulation

Resource Planning Legislation and Regulation

Both state jurisdictions in which Union Electric operates, Missouri and Illinois, have legislation and/or regulations which require resource planning. Illinois has established rules to implement amendments to the Illinois Public Utilities Act in the area of "Least-Cost Planning for Electric Utilities." The Missouri Public Service Commission has enacted rules for "Electric Utility Resource Planning".

In December 1988 the Illinois Commerce Commission adopted "Least-Cost Planning" rules, implementing Section 8-402 of the Illinois Public Utilities Act. UE filed resource plans under these rules in July 1989 and July 1992. These plans were accepted by the Illinois Commerce Commission with only minor modifications.

In May 1993 the Missouri Public Service Commission adopted "Electric Utility Resource Planning Rules". UE filed its first electric resource plan under these rules in December 1993. In early 1994 a series of workshops with interested parties was held to review the filing. These parties developed a "Joint Agreement" that established actions UE would take to provide supplemental information through additional filings or in future resource plans. In July 1994 the Commission issued an order accepting the Joint Agreement.

Missouri Statewide Energy Planning and Global Warming Studies

In 1991 the Missouri Department of Natural Resources (DNR), in conjunction with the Missouri Environmental Improvement and Energy Resources Authority, commissioned a statewide energy planning study. This study was to "provide recommendations to promote energy self-sufficiency as a means to enhance economic growth for the state of Missouri, while at the same time assuring environmental protection and sustained quality of life." Results of the study, issued in 1992, include a number of recommendations on energy use in the state. For electric utilities, emphasis is placed on using least-cost planning processes.

Partially in response to this study, Missouri Governor Mel Carnahan established a "Missouri Energy Futures Coalition" of key Missouri energy stakeholders in March 1994. The initial focus of the coalition is to perform "a thorough analysis of the Statewide Energy Study to identify long-term energy requirements and opportunities." The Coalition plans to issue a report to the General Assembly and governor in late 1995.

A report has also been developed by the Missouri Commission on Global Climate Change which recommends several policies related to demand-side management and least-cost planning.

Policy recommendations from the Energy Futures Coalition and Global Climate Change studies may generate additional legislative proposals in upcoming Missouri legislative sessions. It appears the goals of these policies and recommendations are already addressed through Union Electric's resource planning process.

Illinois Legislation and Related Activities

In April 1994 the Illinois Commerce Commission passed a resolution setting forth its intent to examine changes in the structure of the electric energy industry and the resulting implications for regulation of that industry. The Center for Regulatory Studies was selected to facilitate this examination. A task force of interested stakeholders formed the Regulatory Initiatives Task Force (RITF). Two working groups were established from this task force.

The Competition Group examined the existing legislative and regulatory framework for the Illinois electric utility industry, the change in the structure of that industry, and the implications of those changes for the various stakeholders. The Policy Group developed alternative scenarios for the future of the industry and potential legislative and regulatory responses to those scenarios. Over the remainder of 1994 and early 1995 the working groups met to develop and review sections of the RITF report, which was issued in final form in May 1995. It is anticipated this report will be used in additional policy review activities.

In the last Illinois legislative session several proposals were considered that deal with the structure of the Illinois electric utility industry and its regulation:

- Senate Joint Resolution 21 - This resolution establishes a special legislative committee to examine competition in the electric utility industry, with the support of a non-voting technical assistance group. The scope of the examination is roughly equivalent to the work of the RITF. SJR 21 requires the committee to consider the report of the RITF, and other industry studies and reports. It also requires that the proposed amendment to SB 1058 (see below) be used as a "key element for developing legislative proposals". The first meeting of the committee and the assistance group was held on June 15, 1995.
- Senate Bill 232 - This legislation allows any public utility to propose experiments in alternative regulation before the Illinois Commerce Commission. As of this writing, SB 232 is awaiting the Governor's signature.
- Amendment to Senate Bill 1058 - An amendment to SB 1058 was considered by the Senate Energy Committee in April 1995. This amendment, supported by Illinois Power Company, the Illinois Industrial Energy Consumers, and the Illinois Manufacturers' Association, includes provisions that would: (1) Allow utilities to lease generating plant to subsidiaries without ICC approval, in exchange for a freeze in certain retail rates; (2) Allow utilities to classify customers based upon their access to competitive services; (3) Require a phase-in of open retail transmission access; and (4) Provide for recovery of "stranded investment" over a specified time period. The Energy Committee passed Senate Bill 1058 to the Senate floor without this amendment. However, the proposal is referenced in SJR 21 (see above).

UE will participate in the work of the joint committee.

Environmental Legislation and Regulation

Several regulatory and legislative issues pertaining to the environment may affect the energy planning process. Air quality, water quality, solid waste, and hazardous waste regulations must be taken into account when planning facility modifications, improvements, and relocation's. These regulations can significantly affect project cost and scheduling. A combustion turbine at a new site may require as much as three to four years of lead time to perform adequate siting studies, complete environmental monitoring programs, and acquire the environmental permits before beginning onsite construction.

The appendix of *the Integrated Resource Analysis* (IRA) report provides a detailed discussion of environmental issues. The following is a summary of existing and potential environmental legislation.

Future supply-side resources included in this ERP are designed to meet or exceed New Source Performance Standards (NSPS). The estimated cost of future compliance with currently regulated emissions is included in the base resource cost estimates.

The Clean Air Act Amendments of 1990 (CAAA) require major Sulfur Dioxide (SO_2) and Nitrous Oxide (NO_x) emissions reductions from the UE system in steps. The first reductions began in 1995 and the second will start in 2000. The emission reduction requirements will increase beyond the year 2000 as load growth and new fossil-fired capacity require additional SO_2 allowances.

The CAAA established a market based approach for controlling SO_2 emissions. The estimated market value for SO_2 allowances is included in the Company's analysis of resource alternatives. The Company's estimate for the market value of allowances used in developing this ERP was $150/ton in 1995 nominal dollars, escalating to approximately $181/ton in 2000 nominal dollars. Escalation after 2000 is assumed to be 4% a year. The low and high estimates for allowances beginning in 2000 were $159/ton and $201/ton respectively. These values were also assumed to escalate at 2% and 6% a year respectively.

Information from the SO_2 allowance auction held by the EPA in March, 1995 and from recent activity in the allowance market indicates a 1995 allowance price on the order of $132/ton in 1995 nominal dollars, escalating at a rate slightly higher than the rate used in the Company's analysis. Based on these updated parameters, future prices should be within the bounds of the low and high estimates used in the analysis.

Considerable uncertainty remains in the environmental legislative and regulatory arenas. Key issues include:

- Global warming - which may lead to CO_2 emissions reductions,
- Air toxics - which could lead to additional particulate and flue gas controls,
- Ozone nonattainment - which could require accelerated NO_x controls on all fossil-fired units, and
- The operating permit program - which could reduce the Company's flexibility with regard to physical modification and fuel use.

Although future NO_x requirements are uncertain at this time, the estimates for pulverized coal plants include low NO_x burner systems which are expected to meet future requirements.

President Clinton's October 1993 Climate Action Plan sets a goal to reduce U.S. greenhouse emissions to 1990 levels by 2000. Unlike SO_2 and NO_x, CO_2 is a gas which cannot be economically reduced or removed and disposed of by existing technologies. However, this may not be the perception of current administration decision-makers and influential lobbyists.

"Some industry observers are convinced that the nation cannot meet Clinton's commitment without levying a tax on CO_2 emissions or imposing a tough and costly regulatory scheme. However, others in the industry, as well as some administration officials and environmentalists, believe it is possible to meet and possibly exceed the emission-reduction goal without imposing significant new costs on utilities and other U.S. businesses."[1]

UE is participating with the Department of Energy and the electric utility industry in the Climate Challenge Program, which is designed to develop voluntary, cost-effective limitations on greenhouse gas emissions.

Although the current effort to reduce greenhouse gas emissions is voluntary, international activities could lead to less flexible requirements. The first meeting of the "Conference of the Parties" that signed the 1992 "Framework Convention on Climate Change" was held in Berlin in late March and early April 1995. The Framework Convention required the Conference of the Parties to take up a number of matters at its first meeting, one of which was to determine if actions and

[1] Electrical World, September 1993, pg. 18.

measures specified to be taken by nations beyond the year 2000 were adequate to reduce emissions of greenhouse gases to levels considered necessary to protect against global warming. The initial goal specified by the Convention was that developed nations would institute actions and measures with the aim of reducing emissions of greenhouse gases to 1990 levels by 2000.

The Conference of the Parties agreed that negotiations should begin without delay and be conducted as a matter of urgency to strengthen the commitments of the developed nations with the stated aim to elaborate policies and measures, as well as to set quantified limitation and reduction objectives within specified time-frames, such as 2005, 2010, and 2020, with respect to greenhouse gas emissions.

Because the objectives and limitations may not apply to developing countries like China and India, concerns have been raised that U.S. industrial competitiveness could be severely hampered. The U.S. Senate will have to ratify any protocol or amendment, and opposition is already lining up against such actions.

1.5 Documentation

This ERP, which summarizes the preferred resource plan, and its development, is supported by three separate reports with associated appendices and references:

- *Load Forecast Data and Methodology* – Details and models used to determine the forecast.
- *Demand-Side Management Analysis* (DSMA) Report – Details and models used to develop and screen DSM programs.
- *Integrated Resource Analysis* (IRA) Report – Details and models used to identify the optimal supply-side plan and integrate with the demand-side options.

The balance of this document describes the planning process at UE. Section 2 summarizes the forecasting effort and results. Section 3 describes the demand-side planning process. Section 4 reviews the supply-side screening and optimization analysis. Section 5 delineates the integration process and results. Section 6 summarizes the scenario analysis, risk analysis, and preferred plan selection. Section 7 reviews the Company's Clean Air Act compliance strategy. Section 8 summarizes the preferred resource plan and describes the implementation plan associated with the results.

FUTURE REQUIREMENTS
SECTION 2

2.1 ENERGY AND DEMAND FORECAST

The 1995-2004 load forecast, prepared in the fall of 1994, provides the basis used to develop this ERP. The energy and demand forecasts do not include the effects of programs UE may institute in the areas of marketing, demand-side management, cogeneration, or new uses of electricity. These programs are discussed in other ERP sections.

The ten-year forecast of summer peak demand growth is 1.1% (80 MW/YR) and is lower than the 1.5% (100 MW/YR) experienced over the 1985-1993 period. The principal reasons for a lower forecast include air conditioning saturation on the UE system and air conditioning efficiency improvements.

The ten-year forecast of winter peak demand growth is 2.1% (130 MW/YR), consistent with historical growth. Winter peak demand growth is forecasted to continue, primarily due to residential heating growth and growth in electrically heated commercial developments.

The ten-year forecast of annual sales growth is 1.8% (659 GWh/YR), consistent with historical growth. The individual ten-year class forecasts are discussed below.

Residential

The residential sales forecast is 1.6% (191 GWh/YR), lower than the 2.3% (220 GWh/YR) experienced over the 1985-1993 period. The decrease mainly results from continued improvements in appliance efficiencies and the saturation of growth in major energy-using appliances.

Commercial

The commercial class continues to be the fastest growing class, forecasted to grow at 2.4% (315 GWh/YR), consistent with historical growth. The fastest growing sectors are forecasted to be the health and lodging sectors. The fastest growing electric end-uses are forecasted to be electric heating and electric water heating.

Industrial

The industrial sales forecast is 1.4% (126 GWh/YR), consistent with historical growth. Although employment in the industrial sector continues to decline, some growth is expected due to increased automation, electrotechnologies usage, new capacity additions, and environmental regulation compliance.

Wholesale

The wholesale sales forecast is 1.5% (27 GWh/YR), consistent with historical growth.

The following tables provide the annual sales and peak demand forecasts for the 1995-2004 period. The 1995-2004 Load Forecast represents UE's assessment of the most likely future growth pattern.

1995-2004 Sales Forecast

Year	Sales (GWh)	Annual Change
1994	32,100	
1995	32,991	2.8%
1996	33,735	2.3%
1997	34,455	2.1%
1998	35,068	1.8%
1999	35,643	1.6%
2000	36,276	1.8%
2001	36,876	1.7%
2002	37,544	1.8%
2003	38,297	2.0%
2004	38,926	1.6%
Compound Growth Rate (CPG) — 1995-2004		
		1.8%

1995-2004 Peak Demand Forecast

Year	Summer (MW)	Winter (MW)	Net Output (GWh)	Load Factor
1995	7,200	5,750	35,589	56.4%
1996	7,290	5,880	36,392	56.8%
1997	7,380	6,010	37,168	57.5%
1998	7,460	6,140	37,831	57.9%
1999	7,540	6,270	38,450	58.2%
2000	7,620	6,400	39,133	58.5%
2001	7,700	6,530	39,779	59.0%
2002	7,780	6,660	40,500	59.4%
2003	7,860	6,790	41,313	60.0%
2004	7,940	6,920	41,991	60.2%
Compound Growth Rate (CPG) — 1995-2004				
	1.1%	2.1%	1.9%	

The *1994 Load Forecast Data and Methodology* report provides additional details regarding the 1994 Load Forecast.

2.2 Reserve Requirements

System reserve capacity provides for such uncertainties as random unit outages, abnormal weather and unanticipated load growth. UE has developed an extensive transmission system that provides the capability to interchange power with most major utility systems in the Midwest. The interconnections allow the Company to plan for future resource needs on a regional basis and provide opportunities to make economic capacity and energy interchanges with other utilities.

UE is a member of both the Mid-America Interconnected Network (MAIN) and the Illinois-Missouri Power Pool. UE participates with the other MAIN companies to annually assess the adequacy of MAIN's generation system reliability.

The results of the 1994 assessment are contained in an August 10, 1994 report entitled, *MAIN Guide #6 Generation Reliability Study, 1994-2003*. This report indicates that MAIN has adequate reserves planned during the period analyzed. The assessment is based on calculations made using the Loss of Load Probability (LOLP) methodology. This methodology is also referred to as Loss of Load Expectation (LOLE) by some companies.

The adequacy criterion adopted by MAIN is generally used throughout the power industry and is an LOLP of 0.1 day per year (equivalent to 1 day in 10 years) or better.

MAIN's LOLP calculations consider both expected generator availability and emergency support available from other regions. Two levels of load forecast uncertainty are evaluated: (1) uncertainty due to weather only and (2) uncertainty due to all factors including weather.

The MAIN Engineering Committee reviews the work of the MAIN Guide No. 6 Working Group and recommends generation reserve goals for MAIN. The MAIN

Executive Committee recommends a minimum 18% to 22% reserve margin for planning future unit additions. UE uses a minimum 18% reserve margin for planning new resources. However, for near-term planning of approximately one year or less, uncertainties in variables such as load forecasts are reduced. As a result, a reduced reserve margin of 15% is considered adequate for a planning horizon of approximately one year.

The Company reviews its system reserve forecast before each peak season to determine if power purchases will be required to supplement existing resources to provide a minimum 15% short-term reserve margin.

The potential for purchasing power from other utilities is discussed in Section 4. The Company believes that economic, short lead time purchases will be available to allow it to maintain a minimum short-term reserve margin of 15% through at least 1999. Also, a purchase commitment should not be needed until a few months prior to power being required. The availability of interchange purchases allows the Company to plan for reliable power at the lowest reasonable cost to its customers.

The Company analyzes the interchange market and estimates when economic short-term interchange purchases will no longer be available. For purposes of this ERP, the Company plans to meet its minimum 18% reserve margin for planning future resources with owned resources or long-term resource commitments beginning in the year 2000.

DEMAND-SIDE RESOURCES SECTION 3

3.1 IDENTIFYING ENERGY EFFICIENCY MEASURES

Results from an earlier Barakat and Chamberlin, Inc. (BCI) study were used to identify energy efficiency measures for the commercial, industrial, and residential sectors.. The BCI work was originally done for the development of the December 1993 ERP.

In order to ensure that economic screening was manageable, measures were first subjected to a qualitative screen by considering several non-economic factors (e.g. technological maturity). Measures passing this qualitative screen were passed to the next level, the Measure Level Screening Analysis (MLSA).

3.2 MEASURE LEVEL SCREENING ANALYSIS

The Measure Level Screening Analysis (MLSA) is a per-unit life cycle analysis using annual avoided energy and capacity costs. "Per-unit" means the analysis considers only the impact of a single device or a single program participant. For example, room air conditioners are analyzed on a per-device basis, without developing assumptions concerning the average number of room air conditioners per customer, or the number of participating customers.

Avoided energy costs were calculated for six costing periods including summer on-peak, summer off-peak, winter on-peak, winter off-peak, transitional on-peak, and transitional off-peak, both with and without probable environmental costs. Avoided capacity costs were calculated based on levelized expected supply-side generation costs, including generation-related transmission costs and fixed operating and maintenance costs. These costs were then distributed across the three on-peak costing periods based on loss of load probabilities. Benefit-cost ratios were calculated based on annualized values. Two ratios were calculated, the utility test and the probable environmental test.

For the commercial sector, thirty-two building prototypes were developed based on the results of a commercial end use survey. Screening each measure for every building type resulted in over 1400 benefit to cost calculations for this sector alone.

Residential results covered all major electric end uses including air conditioning, heating, refrigeration, water heating and lighting. In order to evaluate building shell measures, three building prototypes were developed — single family, small multi-family, and large multi-family. Each building prototype had up to six HVAC system combinations. In total, the MLSA resulted in nearly 500 benefit to cost calculations for the residential sector.

Industrial measures were not analyzed through the MLSA because the diversity of industrial activities and the narrowness of process populations and measure applications in the Union Electric service territory prevent accurate generalizations. For example, previous industrial MLSAs found that motor downsizing was highly uneconomical; however, Union Electric's MotorMiser audits have uncovered several cost-effective opportunities to downsize motors. As such, generalization made within the complex industrial sector could prematurely exclude some cost-effective opportunities. Rather than exclude these opportunities, all applicable measures were passed directly to the program level analysis where they were incorporated into programs tailored to meet customers' specific energy and process efficiency needs.

3.3 DSM Program Development

The MLSA results were used to assemble potential demand-side programs. Results of pilot programs, either completed or on-going, were used extensively during this assembly. Pilot program results were used in order to incorporate actual field experience in the development of this ERP.

3.4 Program Level Screening Analysis

Program Level Screening Analysis (PLSA) was performed using the Electric Power Research Institute (EPRI) DSManager model. DSManager uses hourly system load profiles, system avoided energy cost, and program load impacts to calculate program benefits. The user provides annual cost assumptions for each program, including all costs incurred by either the utility or the participating customer. The model calculates five benefit-cost tests using California Standard Practice procedures. These include the Participant Test, the Utility Test, the Ratepayer Impact Test, the Total Resource Cost Test, and the Societal Test.

The Participant Test was used as an indicator of acceptable program design. The discount rate used to calculate benefits and costs reflected implicit discount rates observed in the marketplace. A 33% rate was assumed for commercial and industrial customers. Residential programs assumed a 20% rate. Programs were designed so that the Participant benefit-cost ratio was at least 1.0.

The expected discount rate for the Utility Test, Ratepayer Impact Test, Total Resource Cost Test, and Societal Test was 10.46%.

The PLSA used thirty-six day types to represent program load impacts and calculate program benefits. These day types for each month of the year were — Peak Weekday, Typical Weekday, and Typical Weekend. Typical load and avoided energy costs were determined for each hour of each day type. Avoided energy costs were developed using hourly data from the Company's Fall 1994 Forecast and Fuel Budget.

Annual avoided capacity costs were based on levelized avoided generation costs.

Additional information concerning the screening process is contained in the *Demand-Side Management Analysis* (DSMA) report. Information regarding capacity equivalence is contained in the *Integrated Resource Analysis* (IRA) report.

3.5 Potential Demand-Side Resources

A brief description of each program identified as a demand-side resource follows. All programs were assumed to start enlisting participants in 1997 and stop receiving new participants after 2006 (except to maintain a constant impact level through the end of the planning horizon).

Residential Audit & Financing – Water Heating and Lighting Measures

This program would target single-family residential customers with central electric heating and air conditioning or heat pump, and electric water heaters. The basic program would provide a comprehensive home energy audit to eligible customers for a price of $50. Those responding to the offer would receive a free package of measures including: a water heater blanket, pipe insulation, and one compact fluorescent bulb.

Residential Audit & Financing – Building Shell Measures

Residential customers receiving a comprehensive home energy audit would be eligible to participate in this program. Qualified specialists would perform blower door and duct blasting testing in order to identify the potential for infiltration reduction. At the customer's expense, improvements would be achieved by implementing several measures including: duct sealing, window caulking, weather stripping, and basement wall insulation.

Residential Audit & Financing – Central A/C and Heat Pump Shading – Incentives

Residential customers receiving a comprehensive home energy audit would be eligible to participate in this program. Where opportunities have been identified to cost-effectively shade air conditioner (A/C) units, Union Electric would provide limited incentives for landscaping used to shade the units.

Residential Setback Thermostats – Gas Heating Customers

This program would educate customers with central gas heating about the benefits of electronic setback thermostats. Participants would pay retail store prices for thermostats.

Residential Low Income – Water Heating and Lighting Measures

Residential customers with electric water heaters, who received free building shell measures, would be eligible to participate in this program. Qualified specialists would audit water heater systems and install packages of water heater measures, including water heater blankets and pipe insulation. Each customer would also receive one compact fluorescent bulb. Additionally, UE would assist the Community Action Agencies in conducting educational seminars on ways to reduce customers' energy costs.

Residential Low Income – Building Shell Measures

Low income residential customers in poorly weatherized multi-family dwellings with central electric heat would be targeted for this program. Qualified specialists would perform blower door and duct blasting testing to identify opportunities for infiltration reduction. Improvements would be achieved by implementing several measures including duct sealing, window caulking, and weather stripping. Energy service organizations would perform most of the marketing and administration of this program. Additionally, UE would assist the Community Action Agencies in conducting educational seminars on ways to reduce customers' energy costs.

Residential Low Income – Water Bed Measures

Residential customers with electrically heated water beds, who received free building shell measures, would be eligible to participate in this program. Qualified specialists would install foam mattress pads. Additionally, UE would assist the Community Action Agencies in conducting educational seminars on ways to reduce customers' energy costs.

Residential Appliance Cycling Program – Central A/C and Heat Pump Cycling

This program would target single-family residential customers with central air conditioning or heat pumps. Qualified contractors would install and service load management devices on outdoor cooling units. The normal operation of cooling units would be limited on the hottest days. Participants would receive limited summer bill credits and access to a free 24-hour emergency diagnostic service.

Residential Appliance Cycling Program – Water Heater Cycling

Residential customers with electric water heaters would be eligible to participate in this program. Similar incentives to the Central Air Conditioner and Heat Pump Cycling program would be offered.

Residential Appliance Removal Program – Refrigerator Removal

This program would remove old and inefficient refrigerators that operate on the UE system. PCBs would be removed from any oils and the metal and refrigerant would be recycled. UE would hire a contractor to provide turn-key services encompassing all program aspects. Such services would include: appointment scheduling, appliance removal, and proper recycling and reclaiming of environmentally hazardous materials.

Residential Appliance Removal Program – Freezer Removal

This program would remove old and inefficient freezers that operate on the UE system in the same fashion as the Refrigerator Removal program.

Residential New Construction – Building Shell Measures

This program would provide incentives to builders to encourage more efficient home construction. Reimbursement of qualified expenses would be provided to builders for the installation of several measures including duct sealing, window caulking, weather stripping, and basement wall insulation. Only builders installing high efficiency heating and cooling, water heating and specific environmental measures would be eligible.

Residential New Construction – Central A/C and Heat Pump Shading – Incentives

Builders that install high-efficiency end-use equipment would be eligible to participate in this program. Where opportunities are identified to cost-effectively shade A/C units, Union Electric would provide limited rebates for landscaping used to shade these units.

Commercial Audits – Level I: Walk Through Audit and Analysis

This program would provide a walk-through audit and follow-up energy analysis to large commercial customers. Energy services would consist of analyzing the customer's billing history, disaggregating consumption by end-use, and recommending energy efficiency improvements. Life cycle cost analysis would be provided for recommended measures. The audit would be provided at no cost to the customer.

Commercial Audits – Level II(a): Engineering Study With Lighting Emphasis

This program would provide follow-up service to customers participating in the Level I audit. Such services would provide a more focused analysis through computer modeling of electric loads, calibration to whole building metered data, and modeling of energy efficiency measures. Interactive effects would be considered by modeling the measures one at a time as well as bundled. Customers would initially split the audit cost with UE. If the customer chose to implement the recommendations, the audit cost would be refunded.

Commercial Audits – Level II(b): Comprehensive Building Modeling For All Major Systems (HVAC, Refrigeration, Lighting)

This program would provide follow-up service to customers participating in the Level I audit (and not participating in Level II(a) Lighting Emphasis). Such services would provide a more focused analysis through computer modeling of electric loads, calibration to whole building metered data, and modeling of energy efficiency measures. Interactive measure effects would be considered in order to optimize building efficiency. Customers would split the audit cost with UE. However, the audit cost would be refunded if the customer implements the audit recommendations.

Small Commercial Energy Services – Do It Yourself Audit

This program would provide small commercial establishments a survey to perform a simple audit. Customers would walk through their facility recording information on sources of energy use. When completed, the customer would return the audit to be scanned into a computer, where the audit responses would be matched with actual historical energy usage. A report would be returned to the customer. Included in this report would be a dissaggregation of past energy use by end-use and recommendations for improvement including simple payback analysis. The audit would be provided at no cost to the customer. A list of contractors and institutions providing installations and financing would be made available at no charge.

Small Commercial Energy Services – Walk Through Audit

This program would provide small commercial establishments the services of an expert auditor who would enter information on sources of energy use into a computer. When the analysis was complete, the customer would receive a dissaggregation of past energy use by end use and recommendations for improvement including simple payback analysis. The audit, analysis and recommendations would all be provided in one visit. The audit would be provided at a small fee to participating customers (well below the actual cost of the audit). A list of contractors and institutions providing installations and financing would be made available at no charge.

Commercial New Construction Design Assistance and Incentives (Financing or Reimbursement)

This program would provide design assistance to large commercial customers before they construct new facilities. In addition, the program would seek to identify institutions that provide low cost financing. Design assistance and low cost financing may not be enough to overcome barriers often associated with maximizing the efficiency of new construction. As such, the program may require reimbursement of the incremental cost of efficiency upgrades in order to be successful.

Thermal Storage – Off–Peak Cooling

This program would provide design assistance to customers considering installing thermal storage systems. In addition, a bill credit would be made to customers based on the avoided cost of on-peak demand. Because of the cost associated with these systems, customers would likely seek attractive financing. If the design assistance, bill credit, and financing were not enough to avoid lost opportunities in this market, reimbursement of the incremental cost of efficiency upgrades would be considered.

Customized Industrial Process Audits

This program would provide a free walk through audit and follow-up energy analysis to medium and large industrial customers. Energy services would consist of analyzing the customers' billing history, evaluating process, energy, and materials handling efficiencies, and recommending process/energy efficiency improvements. Simple payback analysis would be provided for recommended measures.

For customers with significant demand and/or energy reduction opportunities, Union Electric would offer to co-fund additional engineering analyses in order to encourage implementation. If measures are installed the customer would then be eligible to receive reimbursement for his audit costs.

Demand and Energy Control Informational Program

This program would provide free information and seminars to larger industrial customers. The program would mate actual metering data, local energy control successes, and trade allies in efforts to encourage the installation of demand and energy monitoring equipment at industrial sites. Trade allies would be relied on to deliver the program to the greatest extent possible.

Energy Efficient Motors – MotorMaster Software

This program would provide industrial customers with the *MotorMaster* software for evaluating options when purchasing or replacing three-phase motors. The software assists the user in choosing the most cost-effective and energy efficient option. The software would be provided free of charge.

Energy Efficient Motors – MotorMiser Audits

This program would provide qualified industrial customers with a free on-site evaluation of selected motor applications by a local motor expert/consultant. The purpose of the evaluations would be to identify cost effective opportunities for: upgrading to energy-efficient motors, installing adjustable speed drives, or improving drive train efficiencies.

Standby Generation/Curtailable Power Program

This program would supplement UE's power system during periods of stress. Customers that are willing to curtail load or use standby generation would receive a special rate discount. In return, UE would be allowed to curtail power as needed to maintain a firm power supply, deliver contractual power obligations to other utilities, and maintain the integrity of the interconnected system.

The following five DSM programs failed the Program Level Screening Analysis:

- Residential Audit & Financing - Central A/C and Heat Pump Shading - Incentives
- Residential Low Income - Water Heating and Lighting Measures
- Residential Appliance Cycling Program - Water Heater Cycling
- Residential New Construction - Central A/C and Heat Pump Shading - Incentives
- Commercial New Construction Design Assistance and Incentives (Financing or Reimbursement)

SUPPLY-SIDE RESOURCES
SECTION 4

4.1 EXISTING RESOURCES

The UE system relies on a diverse mix of generating technologies to supply electrical power. The vintage of the plants range from 1913 for the Keokuk Hydroelectric Plant to 1984 for the Callaway Nuclear Plant. Sufficient capital and maintenance work is planned for all units to provide for continued operation for an indefinite period.

Tables 4-1 and 4-2 list the existing units and summarize their capabilities.

Power plants are generally categorized by the type of load they serve; base, intermediate, or peaking.

Base Capacity

Base capacity for the UE system is provided by the Callaway, Keokuk, Labadie, Rush Island, and Sioux power plants. These plants represent 68% of the total system-owned capacity.

Callaway

The Callaway Plant, located in central Missouri, was placed in service in 1984. It consists of one pressurized water reactor nuclear power unit. The net capacity of the plant varies from 1,125 MW in the summer to 1,177 MW in the winter. Refueling of the unit occurs approximately every 18 months. The most recent refueling was completed in the spring of 1995.

Keokuk

The Keokuk Hydroelectric Plant, located on the Mississippi River in the vicinity of Keokuk, Iowa, was placed in service in 1913. The facility includes fifteen run-of-river hydroelectric generators that have a total net capacity of 119 MW, during expected summer river conditions. Eight of the fifteen units generate power at a frequency of 25 Hz. The 25 Hz power is currently sold to Iowa Electric Light & Power (IELP) or converted to 60 Hz and integrated into the UE System. The plant is not subject to license renewal requirements under the Federal Power Act.

Labadie

The Labadie Plant, located on the Missouri River in eastern Franklin County, Missouri, consists of four pulverized coal-fired units placed in service from 1970 to 1973. Each unit has a summer net rating of 559 MW, with a total plant rating of 2,236 MW. Coal for the plant is delivered by two rail lines.

These units were identified in the Clean Air Act Amendments of 1990 (CAAA) as Phase I affected units. Modifications have been implemented to achieve compliance with the Act and to allow the flexibility to burn low sulfur coal. All four units have been fitted with low NO_x burners.

Rush Island

The Rush Island Plant is composed of two pulverized coal-fired units, each with a summer net capacity of 581 MW. Rush Island Plant is located on the Mississippi River near Festus, Missouri. These units were placed in service in 1976 and 1977. Coal for the plant is delivered by rail.

Both units, although designated as Phase II units, have received Phase I permits as substitution units. Low NO_x burners have been installed on one of the units. Installation of low NO_x burners on the remaining unit is scheduled to be completed by the end of 1995.

Planned low sulfur coal modifications are scheduled to be completed in 1996.

Sioux

The two Sioux units use cyclone boilers and have a summer net capacity of 463 MW each. A restoration of net capacity to 471 MW is expected in 1997 as a result of improvements in plant equipment and operation. Sioux Plant is located on the Mississippi River in eastern St. Charles County, Missouri. The units were placed into service during 1966 and 1968. Coal is delivered to the plant by rail.

The Sioux units are also designated as Phase I affected units according to the CAAA. Modifications are currently being implemented to enhance the flexibility to burn low sulfur coal. These planned modifications are scheduled to be completed in 1997. As with all units, there are continuing investigations of compliance alternatives to optimize the operation of the plant. In addition, a long-range utilization planning study has identified modifications that are being incorporated in the budgeting and maintenance planning process.

UE began an experiment to burn used tires in the Sioux Plant in 1992. The results showed that a mixture of tires and coal could be economically burned in the boilers without adversely impacting compliance with environmental regulations. The Company is presently burning a mixture of chipped tires with the coal. When the project is fully implemented, the Sioux Plant is expected to burn a mixture composed of approximately 2% chipped tires and 98% coal. The plant is expected to burn approximately 2 million used tires each year. This is equivalent to 25,000 tons of coal.

Intermediate Capacity

The Meramec Plant and purchases of up to 405 MW from the Joppa Plant provide the Company's intermediate capacity requirements. These resources account for about 16% of the Company's capacity.

Meramec

The four-unit Meramec Plant is located in southern St. Louis County, Missouri on the Mississippi River. Two units, each with a net summer capacity of 131 MW, were placed in service in 1953 and 1954. The third unit has a summer net capacity of 280 MW and was placed in service in 1959. Unit 4, rated at 338 MW, was placed in service in 1961.

The primary fuel for all four units is coal, which is delivered by barge. Units 1 and 2 have the ability to achieve full rated capacity on either coal or natural gas. Up to 30% of Unit 3's output can be fueled by natural gas.

The units at the Meramec Plant, which are designated as Phase II units according to the CAAA, have received Phase I permits as substitution units.

Low NO_x burners are planned to be installed on Meramec Unit 4 in 1996, in conjunction with a planned major boiler rehabilitation. Meramec Unit 3 is a possible candidate for repowering and a final decision on low NO_x burner installation for this unit will not be made until an in-depth repowering study is completed. A site specific study is currently in progress, to identify costs for use in the further evaluations.

Implementation of projects identified in the Meramec long-range planning program continues.

Peaking Capacity

Peaking capacity is supplied by a variety of technologies that utilize oil, natural gas, hydroelectric, and pumped storage. Approximately 16% of the Company's total capacity is considered peaking capacity.

Combustion Turbine Generators

The Company's nine CTs have a total net summer capacity of 381 MW. The units were installed from 1967 through 1978. All of the units, except the Viaduct and Kirksville units, are fired with distillate fuel oil. The Viaduct and Kirksville units, with a combined net summer capacity of 38 MW, are fueled with natural gas.

Diesels

Approximately 5 MW of diesel engine capacity exists on the system.

Venice

The Venice Plant, located in Venice, Illinois, east of downtown St. Louis, is the oldest fossil-fueled plant on the UE system and is composed of eight boilers that supply steam to a header system for six generating units. The plant was originally built to fire coal and was placed in service from 1942 through 1950. In the mid-1970s, the first six boilers were converted to fire distillate fuel oil and natural gas. The remaining two boilers were converted to fire only distillate fuel oil. The six generating units have a combined net summer rating of 429 MW.

Osage

The Osage Hydroelectric Plant is located at Bagnell Dam on the Lake of the Ozarks, in central Missouri. The first six units were placed in service in 1931, and units 7 and 8 were placed in service in 1953. The eight hydroelectric generators result in a total plant capability of 212 MW. The Osage Plant is licensed until 2006 under the Federal Power Act, but the plant is expected to be available indefinitely.

Taum Sauk

Taum Sauk Plant is a pumped-storage facility located 90 miles southwest of St. Louis, Missouri. The plant has a net summer rating of 350 MW and includes two reversible pump-turbine units and upper and lower reservoirs. Both units were placed in service in 1963. The plant operates by pumping water from the lower reservoir to the upper reservoir during times of low system load and low energy cost. During peak demand periods the water is released from the upper reservoir for generation by the two water turbines.

Although the Federal Power Act license for the Taum Sauk Plant expires in 2010, it is assumed to be available indefinitely.

Power Plant Long Range Planning

Long range planning for existing power plants has been implemented by the Company.

Evaluations of the Venice, Meramec and Sioux units indicate that the overall condition of each plant is good. However, a number of major modifications and repairs are necessary to assure reliable generation in the future. Completed and planned projects include replacement of major boiler components, heat exchangers, controls, and others.

Interchange Purchases And Sales

Joppa

The Joppa Plant, located on the Ohio River in Joppa, Illinois, is owned by Electric Energy, Inc., which is jointly owned by four utilities. Union Electric owns 40% of Electric Energy, Inc. and is entitled to receive as much as 405 MW of capacity for a limited time each year. Union Electric can currently take 10% of the Joppa Plant available generation during a calendar year, and with a five year notice can increase its take to 40%.

Before August 1st of each year, Union Electric provides a schedule to Electric Energy, Inc. indicating the time periods and amounts of Joppa Plant's capacity that should be reserved for Union Electric during the following calendar year.

Arkansas Power and Light (AP&L)

UE agreed to purchase unreserved capacity from AP&L as part of the agreement to buy portions of AP&L's service territory in southern Missouri. The contract specifies the purchase of capacity until March 2002 with an option to extend the purchase for six years. The purchase amount was increased to 160 MW beginning in 1995. Provisions exist to extend the contract beyond 2008.

Iowa Electric Light & Power Co. (IELP) and Central Illinois Public Service (CIPS)

As a result of the sale of the Company's Iowa and Northern Illinois service territories, which included both 60 Hz and 25 Hz loads, UE supplies 60 Hz power to the purchasing companies according to the following schedule:

Year	IELP	CIPS	Total
1995	100 MW	5 MW	105 MW
1996	80 MW		80 MW
1997	60 MW		60 MW

In addition, 54 MW of 25 Hz power is contracted to be sold to IELP on an interruptible basis so they may supply existing 25 Hz customers.

Associated Electric Cooperative (AEC)

UE and Associated Electric Cooperative have an existing interchange agreement. In exchange for use of available transmission capability on UE's system, Associated Electric Cooperative is expected to provide UE with 21-31 MW of capacity during the months of March through October. Similarly, UE is expected to provide 15 MW of capacity to Associated Electric Cooperative during the months of October through May in return for UE's use of Associated Electric Cooperative's transmission system. The capacity and energy that can be scheduled under this arrangement is limited and based on the peak demand and energy transmitted by the other party during the previous April through March period.

4.2 FUELS

The electricity generated by company-owned units is derived primarily from coal (65%) and nuclear (30%) with the remainder coming from hydroelectric, oil and natural gas.

The UE system depends on four coal-fired power plants to produce over 65% of the total energy. Currently, these plants consume about 11 million tons of coal annually. Small changes in the delivered price of coal significantly affect electricity production costs. Consequently, UE continually monitors transportation costs and various coal markets to assess changes and evaluate their impact on future conditions. Oil, natural gas, and nuclear fuel markets are also continually monitored and evaluated.

The Company's forecasts of fuel prices are based on many information sources, including published data, various forecasting organizations, and in-house fuel market knowledge. The forecasted prices of coal, oil, natural gas, and nuclear fuel used to develop this Energy Resource Plan were developed in the fourth quarter of 1994 and embody the best information available at that time. Further information on the forecasts and forecasted fuel prices is included in Section 4 of the *Integrated Resource Analysis* (IRA) report.

Existing Coal Contracts

Long-term contracts cover approximately 80% of the Company's 1996 coal requirements. No coal is under contract after 2001. Current contracts provide both low sulfur and high sulfur coal. Additional low sulfur coal will be required to meet the Company's long-range requirements and its compliance program under the CAAA.

4.3 System Improvements

Power Plant Improvements

Changes in unit efficiency occur over time for various reasons, such as the requirement to burn coal of a different quality than the coal for which the boiler was originally designed, new governmental regulations, etc. UE continually reviews its existing units to determine the economies of improving plant efficiency.

A wide array of projects are either planned, or are being evaluated, for maintaining and improving availability and efficiency. Large boiler components, heat exchangers, controls, etc., are systematically evaluated and replaced, or improved, if justified.

<u>Sioux Plant</u>

Each Sioux unit currently has a summer net capacity of 463 MW. An additional 8 MW (net) increase in the capacity rating for each of the two units is anticipated in 1997 due to further improvements in plant equipment and operation. By 1997 the rating of each of the units is expected to be 471 MW (net).

<u>Osage</u>

An increase in rated capability of the Osage Plant may be achievable by replacing the existing runners with new more efficient runners.

<u>Keokuk</u>

The overall economics of rewinding the existing 25 Hz generators at Keokuk will be dependent on the future needs of Iowa Electric Light & Power (IELP). UE has a contract to supply as much as 54 MW of IELP's 25 Hz requirements, on an interruptible basis, until the end of 1998. This contract can be extended beyond 1998 if both parties agree. If an agreement cannot be reached with IELP, this ERP shows that it would be beneficial to rewind the 25 Hz generators for 60 Hz service. Operation at 60 Hz would reduce system losses by as much as 19.5 MW at maximum loading conditions. If a 25 Hz customer is not available, savings in losses of about 103,000 MWh per year are estimated.

<u>Taum Sauk Plant</u>

The Taum Sauk Plant rating was increased to 350 MW (net) in the summer of 1991 to match the amount of system peak the plant is expected to carry. The rating is based on the amount of water expected to be discharged over a typical summer day to meet system load requirements. A 430 MW (net) rating may be achieved by increasing efficiency of the existing turbines by replacing the runners.

<u>Controls Replacements</u>

Modern control technology is being installed/planned at Meramec, Sioux, Labadie, and Rush Island. The new technology is expected to improve unit reliability, efficiency and safety as well as improve operator training and effectiveness.

Plant Auxiliary Power Reductions

Adjustable and two speed motors have been installed at Labadie, Meramec, Rush Island and Sioux to reduce station auxiliary power requirements. New energy saving static exciters have been installed at Sioux. More efficient lighting has been installed throughout Meramec Plant and other facilities.

Venice Plant Repowering

The Company participated with EPRI and Sargent & Lundy in a project to develop a workstation for utility repowering evaluations. As part of the project, a site specific study was performed for the Venice Plant. Although a generic workstation for this project is not available, the results for Venice Plant were available for use in the development of this ERP.

Meramec Plant Unit 3 Repowering Study

The Company is participating in a project with EPRI and Sargent & Lundy to identify site specific costs for repowering Meramec Plant Unit 3. This study is in progress and sufficient information was not available to include this option in the development of the ERP. The economics of this option will be analyzed when the data is received.

T&D System Improvements

Ongoing assessments of the age, condition, and efficiency level of UE's transmission and distribution facilities require daily decisions regarding implementation of cost-effective measures to ensure reliable service. These assessments would include the benefits of DSM and distributed generation targeted for specific T&D areas.

4.4 Probable Environmental Costs

For planning purposes, probable environmental costs are defined as the expected cost to the utility of complying with new or additional environmental laws, regulations, taxes or other requirements that utility decision makers judge may be imposed at some point within the planning horizon which would result in compliance costs that could have a significant impact on utility rates.

In order to develop resource plans, and test their robustness to more stringent environmental regulations than currently envisioned, three levels of mitigation more stringent than 1995 requirements were hypothesized. Fixed and variable costs to comply with regulations for those emissions that can be controlled were developed by Burns & McDonnell for use in the development of this ERP.

Estimates of CO_2 adders, ranging from \$1.45 to \$11.40 per ton of CO_2 (1995 dollars), were developed by the Company to serve as proxies for possible future regulations on greenhouse emissions. Every incremental dollar of adder per ton of CO_2 adds about \$0.48/MWh to the cost of a combined cycle unit operating on natural gas. About \$1/MWh would be added to the cost of operating a pulverized coal plant.

Subjective probabilities were assigned to each of the three mitigation levels.

The Burns & McDonnell estimates of costs to comply with regulations for those emissions that can be controlled are contained in a report entitled *Environmental Costs at Existing and Future Fossil Fuel Fired Units For Union Electric*. This report, and the IRA report, provide further details regarding the development and application of environmental control costs, and resultant probable environmental costs used in the development of this ERP.

4.5 FUTURE RESOURCES

The magnitude and timing of resource needs were established using the Company's 1994 peak demand and energy forecasts which indicate that the Company will require approximately 385 MW of new resources by the year 2000. Approximately 1,860 MW of new resources are required by the end of the 20 year study period.

Although capacity can be added to the system by improvements at existing units, new facilities will be required to satisfy future load growth. Power purchases, and a number of generation technologies, offer potential supply-side resource options for capacity additions. The options range from mature technologies, similar to existing units, to new technologies in various levels of development. In addition, the resources may be utility owned or purchased from another party.

Interchange Purchases

Future supply-side additions may be achieved through new generation resources or the purchase of power. In order to assess the availability and feasibility of employing purchased power in the development of this ERP, UE requested proposals from 65 parties for the supply of power. The parties included all the systems that have interchange agreements with UE as well as most of the systems that are one system removed. Based on the responses, there appears to be over 600 MW of purchased capacity available to UE near the end of the decade. Although some of the capacity may have already been committed to other purchasers, there should be sufficient capacity available to make economic short lead time purchases to meet system reserve requirements and to provide an alternative to building new generation capacity through at least the year 2000.

Future transactions in the generation market may be constrained by transmission line limits due to wheeling requirements that may be imposed on utilities in the future and actions resulting from the Federal Energy Regulatory Commission Notice of Proposed Rulemaking (NOPR) on transmission access and pricing. Thus, some purchase power sources may not be accessible when required in the future due to reasons other than generation unit outages.

The current analysis of the UE transmission system indicates that UE has adequate transmission capability to import several hundred megawatts of capacity from several directions. Based on current transmission system plans and the Company's anticipated capacity needs, UE does not foresee the need for additional transmission facilities to accommodate capacity purchases.

More specific studies will be undertaken when definitive resource opportunities are examined. Such studies will also take into account other transactions occurring on the interconnected system that affect UE's transmission system and may reduce the ability to transact with other systems.

Union Electric has contracted with Central Illinois Public Service Co. (CIPS) for the purchase of 150 MW of power from June 1998 to May 2005. This purchase was made recognizing that the power could be marketed or incorporated into the UE System.

UE also has the opportunity to purchase additional energy from the Joppa plant and to extend the existing contract for wholesale power with Arkansas Power and Light (AP&L).

Future Technologies

A qualitative screening review was performed to evaluate the future generation technologies and determine those that should be removed from further review at this time. Technologies considered significantly inferior in development potential, cost, performance, or applicability were eliminated from further quantitative evaluation.

The following is a summary of the potential technologies considered:

New Resources

- Conventional Pulverized Coal
- Super Critical Pulverized Coal
- Advanced Pulverized Coal
- Fluidized Bed Combustion
- Coal Gasification Combined Cycle
- Magnetohydrodynamics
- Simple Cycle Combustion Turbine
- Combined Cycle Combustion Turbine
- Compressed Air Energy Storage
- Fuel Cells
- Battery Energy Storage
- Super Conducting Magnetic Energy Storage
- Pumped Hydro
- Low-Head Hydro
- Wind Power
- Biomass
- Geothermal
- Solar
- Nuclear

The *Generation Technologies for Integrated Resource Planning* report provides a detailed discussion of each of these technologies, including ranges of costs, emissions and performance data.

In addition to the new technologies, descriptions of the following unit upgrade technologies are included in the report.

Existing Unit Potential Upgrades and Repowering

- Venice Repowering
- Taum Sauk Runner Replacement
- Osage Runner Replacement
- Inlet Air Cooling — Existing Combustion Turbines

The following additional resource opportunities, including power purchases, were considered as future resources in the development of this ERP. These resources are described in Section 3 of the IRA report and include:

Possible Additional Resource Opportunities

- Keokuk 25 Hz Generator Rewind
- Amorphous Transformers
- Iatan Jointly Owned Plant
- Alton Lock & Dam 26R
- Extension of the AP&L Purchase
- Additional Joppa Energy
- CIPS Peaking Capacity Purchase
- Intermediate Capacity Purchase #1
- Intermediate Capacity Purchase #2
- Base Capacity Purchase
- KLT - Iatan - Base Capacity Purchase

Cogeneration, IPPs, NUGs and QFs

The potential for development of cost effective non-utility generation in the UE service area appears to be limited. In general, UE rates are lower than the cost of non-utility generation options. Customers with steam loads that can justify the investment in cogeneration equipment have been cogenerating since the early 1960's. No new steam loads large enough to warrant cogeneration have been added to the UE service area.

There are 88 MW of non-utility generation, excluding emergency diesel backup generators, in the UE service area. Of the 88 MW, 14 MW have come on-line after PURPA became law in 1978. Included in the 14 MW are 6 MW of peak shaving diesel generators, 4 MW of either landfill gas or methane fueled generation, and 4 MW of peak shaving generation fueled by either coal or natural gas.

UE has either evaluated or reviewed several site specific studies on the feasibility of non-utility generation in the UE service area. UE's rates are lower than the costs of the alternatives considered in each study.

Even though none of the non-utility generation options reviewed are lower cost than the Company's current rates, generation fueled by certain types of waste resources may have economic potential by the end of this decade. The total capacity that may be available from generation fueled by these types of waste resources is in the 10 to 20 MW range.

Other than limited potential from non-utility generation fueled by waste resources, there does not appear to be significant potential for customer on-site generation in the future. The cost differential between UE rates and the cost of non-utility generation is projected to be greater than UE's avoided costs.

The mix of resources identified in the preferred resource plan is based on UE estimates of resource costs and the information available at this time. UE will continue to study these options as new information becomes available.

4.6 Screening Results

The potential supply-side resource options eliminated through the qualitative screening review include:

- Magnetohydrodynamics
- Super Conducting Magnetic Energy Storage
- New Pumped Hydro
- New Low-Head Hydro
- Advanced Battery Energy Storage
- Geothermal
- Nuclear - Advanced Light Water (Passive Safety)
- Solar - Thermal
- Nuclear - Advanced Liquid Metal Reactor
- Fuel Cells - Molten Carbonate

The remaining options were quantitatively screened at two levels, both with and without probable environmental costs. The first level involved a one-on-one comparison of costs over each resource option's operating range. Levelized annual costs for capital charges, fixed and variable O&M, fuel, emissions, and environmental costs were compared for each option at various capacity factors. Resources that produced the lowest cost for any of the ranges of capacity factor were considered for further review. Some options were only marginally higher in cost than the lowest cost options. To avoid excluding any attractive options, those within 20% of the lowest cost option were included in the second level screening review.

Although wind energy passed the first level of screening analysis, it will not be practical to commit to reliance on wind energy until its capacity equivalence and wind energy availability can be accurately evaluated. At present, there is insufficient wind energy resource data available for the UE service area to support operation in the 30% capacity factor range. Wind monitoring stations were installed in early 1995 and data will be collected for at least one year. A further assessment of wind energy and its potential contribution to the UE system will be made when this data is available.

Due to the environmental benefits of wind, this option is included in the renewable energy scenario, based on an assumed capacity factor of 30%.

The resource options that passed the first level of screening were then screened at the system level to determine which options would best satisfy UE system needs. The dominant options from the first level of screening, along with power purchases, were modeled with the Electric Power Research Institute (EPRI) developed Electric Generation Expansion Analysis System (EGEAS) optimization model.

The evaluations produced a group of resources that satisfied system needs at the lowest cost. The following resource options emerged from the system level screening analysis as future resource candidates:

- Combustion Turbines
- Combined Cycle
- Taum Sauk Runner Replacement
- Keokuk Generator Rewind
- Additional Joppa Energy Purchase
- Extension of AP&L Purchase 2002 -- 2007
- Venice Repowering
  Phase 1 - Units 5&6
  Phase 2 - Units 3&4
- CIPS Peaking Capacity Purchase - 1998-2004
- Intermediate Capacity Purchase #2 - 2000-2013

The following seven resource options failed the system level screening analysis:

- CAES
- Jointly Owned Iatan Unit
- Osage Runner Replacement
- Full Venice Repowering (all six units)
- Intermediate Capacity Purchase #1 — 1997-2013
- Base Capacity Purchase — 1998-2013
- KLT-Iatan Base Capacity Purchase

The details and results of the quantitative screening analysis are included in Section 5 of the IRA report.

Table 4-3 shows the preferred all supply-side resource plan resulting from the quantitative screening analysis. The results of the quantitative screening analysis were incorporated in the resource integration analysis described in Section 5.

Table 4-1

Generating Capability - Existing Units

1995 Unit Ratings

Station Unit	Type	Net Capability (MW) Summer	Net Capability (MW) Winter	Fuel Type	Transportation Method
Callaway	Nuclear	1125	1167	Uranium	Truck
Rush Island 1	Steam	581	583	Coal	Rail
Rush Island 2	Steam	581	583	Coal	Rail
Labadie 1	Steam	559	561	Coal	Rail
Labadie 2	Steam	559	561	Coal	Rail
Labadie 3	Steam	559	561	Coal	Rail
Labadie 4	Steam	559	561	Coal	Rail
Sioux 1	Steam	463	470	Coal	Rail
Sioux 2	Steam	463	470	Coal	Rail
Meramec 1	Steam	131	134	Coal/NG	Barge,RR/PL
Meramec 2	Steam	131	134	Coal/NG	Barge,RR/PL
Meramec 3	Steam	280	282	Coal/NG	Barge,RR/PL
Meramec 4	Steam	338	347	Coal	Barge,RR
Venice (6 Units)	Steam	429	439	NG/#2 Oil	Truck/PL
Total Steam Turbine		6758	6853		
Osage (8 Units)	Hydro	212	205	Water	
Keokuk (15 Units)	Hydro	119	122	Water	
Total Hydro		331	327		
Taum Sauk (2 Units)	PS	350	275	Water	
Total Pumped Storage		350	275		
Venice	CT	25	31	#2 Oil	Truck
Howard Bend	CT	43	48	#2 Oil	Truck
Meramec	CT	55	64	#2 Oil	Truck
Mexico	CT	55	64	#2 Oil	Truck
Moberly	CT	55	64	#2 Oil	Truck
Moreau	CT	55	64	#2 Oil	Truck
Fairgrounds	CT	55	64	#2 Oil	Truck
Kirksville	CT	13	15	Nat Gas	Pipeline
Viaduct	CT	25	31	Nat Gas	Pipeline
Total Combustion Turbine		381	445		
Canton (5 Units)	Diesel	4	4	#2 Oil	Truck
Portable	Diesel	1	1	#2 Oil	Truck
Total Diesel		5	5		
Total Company		7825	7905		
Joppa (1)	Steam	405	405	Coal	Rail,Barge
Grand Total		8230	8310		

(1) Amount of Joppa capacity scheduled according to the EEI/DOE contract. Union Electric's 40% share of the 6-unit Joppa Plant is 405 MW.

Table 4-2
1995 Capacity Mix
(Megawatts)

Station/Unit	Base	Intermediate	Peak	Total
Callaway	1125			1125
Rush Island 1	581			581
Rush Island 2	581			581
Labadie 1	559			559
Labadie 2	559			559
Labadie 3	559			559
Labadie 4	559			559
Sioux 1	463			463
Sioux 2	463			463
Keokuk (15 Units)	119			119
Meramec 1		131		131
Meramec 2		131		131
Meramec 3		280		280
Meramec 4		338		338
Venice (6 Units)			429	429
Osage (8 Units)			212	212
Taum Sauk (2 Units)			350	350
Venice			25	25
Howard Bend			43	43
Meramec			55	55
Mexico			55	55
Moberly			55	55
Moreau			55	55
Fairgrounds			55	55
Kirksville			13	13
Viaduct			25	25
Canton (5 Units)			4	4
Portable			1	1
Joppa		405 (1)		405
Total	5568	1285	1377	8230
Percent	67.7%	15.6%	16.7%	

(1) Amount of Joppa capacity scheduled according to the EEI/DOE contract. Union Electric's 40% share of the 6-unit Joppa Plant is 405 MW.

Table 4-3
All Supply-Side Resource Plan
1995 - 2014
Nominal Forecast

Year			MW Added Net
1995	Venice Restaffing		92
1996			
1997	Sioux Improvement		16
1998	CIPS Purchase[1]		
1999	Eliminate 25 Hz Losses[2]		20
2000	Taum Sauk Improvement	80 MW	282
	Power Purchase	50 MW	
	Renewables	2 MW	
	CTs - 2	150 MW	
2001	CT		75
2002	CT	75 MW	75
	Extend AP&L Purchase	—	
2003	CT		75
2004	CTs - 2		150
2005	CTs - 3	225 MW	75
	End CIPS Purchase	-150 MW	
2006	CT		75
2007	CT	75 MW	75
	Joppa Additional Energy	—	
2008	Venice 5 & 6 Repowering	248 MW	88
	End AP&L Purchase	-160 MW	
2009	Combined Cycle		180
2010			
2011	Venice 3 & 4 Repowering		262
2012			
2013	Combined Cycle		180
2014	End 50 MW Purchase		-50

Joppa	405 MW - 1995 - 2014
AP&L	160 MW - 1995 - 2007

Approximately 50 MW of unidentified purchases are assumed to be available after 2000 for future reliability, if required.

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1 CIPS Purchase Availability For UE System: 1998 - 80 MW, 1999 - 75 MW, 2000 Through May, 2005 - 150 MW

2 Keokuk Generator Rewind

RESOURCE INTEGRATION
SECTION 5

5.1 OVERVIEW

Integrated resource analysis identifies alternative strategies consisting of both demand-side and supply-side resources which meet future peak demand and energy requirements in a cost effective manner. This analysis develops the preferred resource strategy that provides reliable service at the lowest practicable cost, is equitable to customers, and provides flexibility to respond to changing conditions.

The Company used the EGEAS model to perform the integrated analysis. The analysis addressed the twenty-year planning period 1995-2014, with a 10 year extension period to account for end effects. All results are reported in terms of 1995 present value of revenue requirements (PVRR) over this 30 year period.

The EGEAS screening work discussed in Section 4 identified the supply-side options to be considered at integration. Likewise, the DSManager screening work discussed in Section 3 identified the demand-side programs to be considered at resource integration.

The demand-side screening effort identified 9 residential, 6 commercial and 5 industrial programs as potential resource options. These individual programs were combined into two integrated DSM programs — DSM-14 and DSM-20 — which are shown in Table 5-1.

The database underlying the integration analysis was developed using sources throughout the Company. The Company's "experts" in each area developed cost estimates, operational parameters, and subjective probabilities associated with their particular expertise. Thus, Financial Planning and Investments supplied cost of capital data, Energy Supply developed plant operating parameters, etc. The IRA report describes the data development responsibilities and data assumptions in greater detail.

5.2 ANALYSIS

The Company established three levels of environmental mitigation beyond 1995 requirements — Green, Greener and Greenest — for use in evaluating the potential impact of possible future regulations on resource plans. Optimal schedules of resources for the all supply-side and the two demand-side management strategies were developed for the three levels of mitigation.

The capacity equivalence and system load impact for the DSM measures included in the two demand-side management strategies were developed. The system adjusted demand, which is used for reserve calculations, was changed to account for the capacity equivalence of each strategy. System loads were adjusted for each of the DSM programs and the supply-side units were reoptimized using the EGEAS model.

A total of nine resource schedules for the following three strategies were developed.

All Supply-Side – This strategy does not include any DSM programs.

DSM-14 – This strategy includes the fourteen DSM programs which had a benefit/cost ratio greater than 1.0 for the total resource cost test performed without probable environmental costs.

DSM-20 – This strategy includes the twenty DSM programs which had a benefit/cost ratio of at least 0.95 for the total resource cost test performed with probable environmental costs. Participation levels and load impacts for the programs included in this strategy are higher than those used in the development of the DSM-14 strategy due to the addition of probable environmental costs in program development.

The nine resource schedules are shown on Table 5-2. In all cases, the optimal all supply-side schedules rely on a sequence of CTs, combined cycle units, and unit repowering to meet the expected load growth forecast.

The optimal schedules for the Green and Greener environmental cases require CTs beginning as early as 2000, followed by combined cycle units after 2006. The Greenest case advances combined cycle units to 2000. The early addition of combined cycle units in the Greenest case is due to capacity reductions on existing base load units to provide for the energy requirements of the additional environmental control equipment.

5.3 Sensitivity Analysis

The sensitivity of several parameters was evaluated for the all supply-side strategy to determine which assumptions had the largest impact on resource selection. These included forced outage rates of existing base load units, reduced economy coal purchases, construction and O&M costs, fuel costs, and SO_2 allowance costs.

It was determined *a priori* that risk analysis would be performed for the following factors, therefore they were not included in the sensitivity analysis.

- Environmental Cost
- Construction and O&M Cost (Renewable Technologies)
- Load Forecast

The following paragraphs describe the sensitivities. The base case conditions included expected values for all parameters including probable environmental costs.

Fuel Prices – Base case conditions assumed that Powder River Basin (PRB) coal would escalate annually at approximately 3% during the study period. This sensitivity assumed that PRB coal would escalate each year at approximately 1.5% (low) and 4.75% (high).

The base case conditions assumed that oil and natural gas prices would escalate at approximately 3.5% and 4.75% per year, respectively. This sensitivity assumed oil and natural gas price escalation rates would increase to approximately 4.5% and 6.0% (high) and decrease to approximately 1.0% and 2.0% (low), respectively.

Construction and O&M Costs – Capital and O&M cost estimates were varied based on the assumptions contained in the *Generation Technologies for Integrated Resource Planning* report. This resulted in costs being varied by as much as ± 15% from nominal values, depending on the technology, to arrive at high and low cost estimates.

Economy Coal Purchase – Base case conditions assumed a varying level of economy coal purchase power availability during the study period. The level was held constant over the second ten-year period. This sensitivity assumed that economic coal purchase power would be reduced by 50% after 1999, and would be eliminated in 2005. Thus, this sensitivity resulted in replacing economic coal purchases with internal generation or oil and natural gas purchases starting in 2000.

Equivalent Forced Outage Rate — The base case conditions assumed forced outage rates consistent with the Company's ten-year fuel budget. This sensitivity assumed that existing coal and nuclear units would experience an increase in equivalent forced outage rate (EFOR) of 0.5 percentage points each year over the period 2005-2014 for a total increase of five percentage points by 2014.

SO_2 Allowance Costs — The allowance cost for SO_2 emissions included in base case conditions was $150 per ton of SO_2 in 1995 escalating at 4% per year thereafter. For this sensitivity, high and low escalation rates of 6% and 2% respectively were applied to the $150 per ton base condition value for 1995.

Results

The sensitivity analysis shows that three of the factors do not significantly change resource selection. The factors that are not critical for decision making include:

- Construction and O&M Costs
- Increased Forced Outage Rates (Existing base load units)
- SO_2 Allowance Costs

These factors were removed from the list of uncertainties to be considered in the risk analysis discussed in Section 6.

The remaining uncertain factors were examined from the standpoint of their impact on resource timing and selection as well as other issues. The following factors were found to have a significant impact on the selection or timing of resources and were selected for risk evaluation:

- Economy Coal Purchases
- Fuel Cost

Table 5-3 shows the results of the sensitivity analysis for resource selection and timing for the all supply-side side strategy. Although resource timing changes based on the sensitivities considered, CTs are selected to meet future requirements through at least 2004. This is also true for the Green and Greener environmental mitigation levels selected for analysis, as shown in Table 5-1.

Thus, based on the integration analysis, a resource plan calling for CTs in the early years of the planning period is robust for all but the Greenest level of environmental mitigation. This level is considered an extreme case and results in significant reductions in the output of existing units due to the addition of environmental controls.

A more detailed discussion of the sensitivity analysis is contained in Section 6 of the IRA report.

Table 5-1

Individual DSM Programs Included in DSM-14 and DSM-20 Integrated Programs

	DSM-14		DSM-20	
	Capacity Equivalence (MW)		Capacity Equivalence (MW)	
	2000	2014	2000	2014
Commercial Programs:				
Audits-Level I - Walk Through Audit	6.7	16.7	10.0	25.0
Audits-Level IIA - Engrg Study Lighting Emphasis	6.7	16.7	10.0	25.0
Audits-Level IIB - Comprehensive Bldg Modeling	13.1	32.8	19.7	49.2
Small Comm Do-it-Yourself Audit	1.7	4.2	2.5	6.3
Small Comm Walk-Thru Audit	3.2	8.1	4.8	12.1
Thermal Storage - Off-Peak Cooling			2.2	5.6
Industrial Programs				
Customized Process Audit Program	3.9	9.7	4.9	12.2
Demand & Energy Control Info Program	4.6	11.4	5.0	12.6
MotorMaster Software Subprogram	0.1	0.3	0.2	0.4
MotorMiser Audit Subprogram	1.5	3.7	2.3	5.7
Standby Generation/Curtailable Power Rate	40.4	40.4	44.4	44.4
Residential Programs				
Water Heater and Lighting Measures			0.3	0.6
Building Shell Measures			0.1	0.3
Setback Thermostats - Gas Heating Cust	0.5	1.0	0.6	1.2
Low Income Building Shell Measures	0.3	0.8	0.5	1.1
Low Income Water Bed Measures				0.1
Central Air Conditioner/Heat Pump Cycling			18.8	46.1
Refrigerator Removal	1.5	4.0	5.3	13.9
Freezer Removal			0.8	2.8
New Construction Building Shell Measures	0.4	2.0	0.6	3.1
Total	84.6	151.8	133.0	267.7

Table 5-2
Optimized Expansion Plans
Green, Greener and Greenest Levels of Environmental Control

	Level of Environmental Control								
	Green			Greener			Greenest		
Year	All Supply	DSM 14 152 MW	DSM 20 268 MW	All Supply	DSM 14 152 MW	DSM 20 268 MW	All Supply	DSM 14 152 MW	DSM 20 268 MW
1995									
1996									
1997	Sioux	Sioux	Sioux	Sioux	Sioux	Sioux	Sioux	Sioux	Sioux
1998	CIPS PP	CIPS PP	CIPS PP	CIPS PP	CIPS PP	CIPS PP	CIPS PP	CIPS PP	CIPS PP
1999	KGR	KGR	KGR	KGR	KGR	KGR	KGR	KGR	KGR
2000	TS 1 CT 50 MW PP	TS 50 MW PP	50 MW PP	TS 2 CT 50 MW PP	TS 1 CT 50 MW PP	TS 50 MW PP	TS 1 CT 2 CC 50 MW PP	TS 2 CC 50 MW PP	TS 1 CT 1 CC 50 MW PP
2001	1 CT	1 CT	TS	1 CT	1 CT	1 CT	1 CT	1 CT	1 CT
2002	Extend AP&L 2 CT	Extend AP&L 1 CT	Extend AP&L 1 CT	Extend AP&L 1 CT	Extend AP&L 1 CT	Extend AP&L 1 CT	Extend AP&L 1 CT	Extend AP&L 1 CT	Extend AP&L 1 CT
2003	1 CT	1 CT	1 CT	1 CT	1 CT	1 CT	1 CC	1 CT	1 CC
2004	1 CT	1 CT	1 CT	2 CT	1 CT	1 CT		1 CT	
2005	3 CT	3 CT	3 CT	3 CT	3 CT	3 CT	1 CT 1CC	1 CT 1CC	1 CC
2006	2 CT	2 CT	1 CT	1 CT	1 CT	1 CT	1 CC	1 CT	1 CC
2007	Extra Joppa 1 CT	Extra Joppa 1 CT	Extra Joppa 1 CT	1 CC	1 CC	1 CT		1 CT	
2008	Repower V5&6	Repower V5&6	Repower V5&6	Repower V5&6 Extra Joppa	Repower V5&6 Extra Joppa	Repower V5&6 Extra Joppa	Repower V5&6	Repower V5&6	Repower V5&6
2009	1 CT	1 CT	1 CT			1 CT	2 CT	1 CT	1 CC
2010	1CT	1CT	Repower V3&4	1 CC	1 CC	Repower V3&4	1 CT	Repower V3&4	
2011	Repower V3&4	Repower V3&4					1 CT		1 CC
2012			1 CT	Repower V3&4	Repower V3&4		1 CT	1 CT	
2013			1 CC			1 CC	Repower V3&4	1 CC	Repower V3&4
2014	2 CT	2 CT		1 CT	1 CT	1 CT			
CT (MW)	1200	1050	750	900	750	825	675	675	225
CC (MW)	0	0	160	360	360	180	900	720	1080
Repower (MW)	528	528	528	510	510	510	510	510	510
Upgrades (MW)	116	116	116	116	116	116	116	116	116
Total - Supply (MW)	1844	1694	1574	1886	1736	1631	2201	2021	1931
DSM (MW)	0	152	268	0	152	268	0	152	268
Total (MW) - 2014	1844	1846	1842	1886	1888	1899	2201	2173	2199

Sioux	Sioux 16 MW Improvement
CIPS PP	CIPS 150 MW Power Purchase
KGR	Keokuk Generator Rewind 20 MW Capacity Equivalence
50 MW PP	50 MW Intermediate Power Purchase
Repower V3&4	Repower Venice Units 3 & 4
Repower V5&6	Repower Venice Units 5 & 6
Extra Joppa	Increased Utilization Of Joppa Energy
Extend AP&L	Extend The Present Purchase Contract With AP&L As Provided For In The Contract
TS	Taum Sauk Runner Replacement - 80 MW
DSM	Demand-Side Management Capacity Equivalence

Table 5-3
Optimal All Supply-Side Expansion Plans - Sensitivities
Probable Environmental Costs — Included

	Case								
	Base	Sensitivity							
Year	Nominal Conditions	Increased F.O.R	Reduced Economy Purchases	High Const. and O&M Costs	Low Const. and O&M Costs	High Fuel Costs	Low Fuel Costs	High SO2 Costs	Low SO2 Costs
1995									
1996									
1997	Sioux	Sioux	Sioux	Sioux	Sioux	Sioux	Sioux	Sioux	Sioux
1998	CIPS PP	CIPS PP	CIPS PP	CIPS PP	CIPS PP	CIPS PP	CIPS PP	CIPS PP	CIPS PP
1999	KGR	KGR	KGR	KGR	KGR	KGR	KGR	KGR	KGR
2000	TS 2 CT 50 MW PP	TS 2 CT 50 MW PP	TS 2 CT 50 MW PP	TS 2 CT 50 MW PP	TS 2 CT 50 MW PP	TS 2 CT 50 MW PP	TS 2 CT 50 MW PP	TS 2 CT 50 MW PP	TS 2 CT 50 MW PP
2001	1 CT	1 CT	1 CT	1 CT	1 CT	1 CT	1 CT	1 CT	1 CT
2002	Extend AP&L 1 CT	Extend AP&L 1 CT	Extend AP&L 1 CT	Extend AP&L 1 CT	Extend AP&L 1 CT	Extend AP&L 1 CT	Extend AP&L 1 CT	Extend AP&L 1 CT	Extend AP&L 1 CT
2003	1 CT	1 CT	1 CT	1 CT	1 CT	1 CT	1 CT	1 CT	1 CT
2004	2 CT	2 CT	2 CT	2 CT	2 CT	2 CT	2 CT	2 CT	2 CT
2005	3 CT	3 CT	Extra Joppa Repower V 5&6	3 CT	3 CT	3 CT	Repower V 5&6	3 CT	3 CT
2006	1 CT	1 CT	1 CT	1 CT	1 CT	1 CT	1 CT	1 CT	1 CT
2007	1 CT Extra Joppa	1 CT Extra Joppa	1 CT	1 CT Extra Joppa	1 CT Extra Joppa	1 CT Extra Joppa	1 CT	1 CT Extra Joppa	1 CT Extra Joppa
2008	Repower V 5&6	Repower V 5&6	Repower V 3&4	Repower V 5&6	Repower V 5&6	Repower V 5&6	Repower V 3&4	Repower V 5&6	Repower V 5&6
2009	1 CC	1 CC	1 CT	1 CC	1 CC	1 CC	1 CT	1 CC	1 CC
2010			1 CT				1 CT Extra Joppa		
2011	Repower V 3&4	Repower V 3&4	1 CC	Repower V 3&4	Repower V 3&4	Repower V 3&4	2 CT	Repower V 3&4	Repower V 3&4
2012							1 CT		
2013	1 CC	1 CC	1 CC	1 CC	1 CC	1 CC	1 CT	1 CC	1 CC
2014			1 CT				2 CT		
CT (MW)	900	900	900	900	900	900	1275	900	900
CC (MW)	360	360	360	360	360	360	0	360	360
Repower (MW)	512	512	512	512	512	512	512	512	512
Upgrades (MW)	116	116	116	116	116	116	116	116	116
Total - Supply (MW)	1888	1888	1888	1888	1888	1888	1903	1888	1888
DSM (MW)	0	0	0	0	0	0	0	0	0
Total (MW) - 2014	1888	1888	1888	1888	1888	1888	1903	1888	1888

Sioux	Sioux 16 MW Improvement
CIPS PP	CIPS 150 MW Power Purchase
KGR	Keokuk Generator Rewind 20 MW Capacity Equivalence
50 MW PP	50 MW Intermediate Power Purchase
Repower V3&4	Repower Venice Units 3 & 4
Repower V5&6	Repower Venice Units 5 & 6
Extra Joppa	Increased Utilization Of Joppa Energy
Extend AP&L	Extend The Present Purchase Contract With AP&L As Provided For In The Contract
TS	Taum Sauk Runner Replacement - 80 MW
DSM	Demand-Side Management Capacity Equivalence

PLAN SELECTION
SECTION 6

6.1 SCENARIO DEVELOPMENT

For this ERP, a new scenario analysis methodology was developed by a team consisting of forecasting, DSM analysis, and supply-side analysis personnel. The first step consisted of interviewing senior management about what issues or trends they thought would impact the electric utility industry. The two theme areas that senior management believes will impact the industry are competition and the environment. Based on these results, the team decided to analyze a competition scenario and an environmental scenario, along with the usual base, high, and low forecast scenarios. Each scenario was generated using the 1995-2014 sales and peak demand forecasts developed in the fall of 1994 as a starting point. A brief summary of the five scenarios follows.

Base Forecast Scenario – The base forecast scenario represents the Company's assessment of the most likely growth pattern for the future. It assumes no exogenous shocks (e.g., recession, deregulation, etc.) to the system. The twenty-year forecasted peak demand growth under this scenario is 1.0%, or 82 MW, per year.

Low Forecast Scenario – This scenario is the lower band of a 75% confidence interval around the base forecast. This scenario is attributed to lower population growth and household formation, a smaller rise in labor force participation rates, lower labor productivity growth, more rapidly rising energy prices, slower foreign growth, and a slower increase in government purchases than the expected forecast. The result is higher inflation and lower real GNP growth due to reduced levels of industrial production and personal consumption. The twenty-year peak demand growth under this scenario is reduced to 0.4%, or 31 MW, per year.

Competition Scenario – This scenario assumes an aggressive deregulation schedule. Industrial rates are assumed to be deregulated in 1998, commercial rates in 2000, and residential rates in 2002. After deregulation, prices in each market class are assumed to achieve the market clearing price for that market class. The market clearing prices for each market class were determined by surveying experts within the Company. The twenty-year forecasted peak demand growth under this scenario is 1.0%, or 82 MW, per year, which is the same as the "Base Forecast Scenario".

Environmental Scenario – This scenario is based on extreme environmental regulations being imposed on the electric utility industry. It assumes Maximum Available Control Technology for new units and existing units. In addition it assumes a CO_2 tax of $11.40 per ton of CO_2 for all emissions in excess of 1990 levels. Environmental compliance is assumed to begin in 2000 and extend throughout the planning horizon. The twenty-year forecasted peak demand growth under this scenario is 0.7%, or 51 MW, per year.

High Forecast Scenario – This scenario is the higher band of a 75% confidence interval around the base forecast. The high forecast scenario is attributed to higher population growth, increased household formation, higher labor force participation rates, higher labor productivity growth, slower energy price growth, increased foreign economic growth and increased government purchases. Increased industrial production and personal consumption levels result in lower inflation and higher real GNP growth. The twenty-year peak demand growth under this scenario increases to 1.6%, or 132 MW, per year. A 15% planning margin was used to determine resource needs to avoid double counting forecast uncertainty. The 18% margin used in other scenarios accounts for forecast uncertainty due to weather and non-weather related factors.

These five scenarios set reasonable bounds on what might occur over the next twenty years. Other scenarios could be developed that would result in conditions outside the bounds. However, every conceivable future cannot be modeled in a timely manner. The five scenarios selected were judged to be inclusive of most realistic assumptions.

Optimal supply-side and integrated resource expansion plans were developed for each scenario.

6.2 Scenario Analysis

The various scenarios were modeled with the EGEAS program. An optimal expansion plan was developed for each scenario. The resource options for the expansion plans included the Taum Sauk runner replacement, Keokuk generator rewind, Venice Repowering, CTs, CC units, additional Joppa energy purchase, and the extension of the AP&L purchase. Wind generation was included as a candidate resource in the environmental scenario.

The low load growth and environmental scenarios result in lower demand and delay the need for additional capacity. The competition scenario does not change resource timing or selection. With the high growth scenario, the first resource need is advanced to 1996. Based on current information, there is adequate generation in the midwest to cover this need, through economical purchases until at least 1999 or 2000. The high growth scenario advances the need for the first CT to 1999 or 2000.

The DSM-20 strategy was preferred over the all supply-side strategy, based on the utility cost test, for all of the scenarios that were evaluated.

Table 6-1 shows the optimal integrated resource plan for each scenario. All scenarios include the Taum Sauk runner replacement project and the Keokuk generator rewind project in the expansion schedule. The Keokuk generator rewind option is always selected in the first year available, *i.e.*, 1999. The Taum Sauk runner replacement is also selected as the first addition to satisfy capacity needs. CTs are added as necessary until about 2005 or 2008, when the CIPS and AP&L purchases are tentatively scheduled to end. The low growth scenario does not include any CC units.

The scenario analysis produced results similar to the results of the sensitivity analysis described in Section 5. In general, the strategy of implementing unit improvements and installing CTs is robust across most scenarios through 2005. Only in the high growth scenario are intermediate load units added prior to 2005. Furthermore, all of the resource additions included in the strategy are relatively low cost and have short lead times.

The high growth scenario is considered an extreme event which could be met through power purchases until new CTs can be installed.

The optimum resource plan developed by EGEAS for each scenario was simulated using the MIDAS model. The results of that analysis are shown in Table 6-2. This table provides a comparison of the all supply-side strategy to the DSM-20 strategy based on three evaluation criteria: levelized average system rates, utility cost, and total resource cost. In general, the DSM-20 strategy is preferred for all of the evaluation criteria over all the futures considered. Slightly higher levelized average system rates are shown for the low and high forecast scenarios. These results indicate that the DSM-20 strategy is a robust strategy across the futures considered.

6.3 Risk Analysis

The results of the sensitivity analysis discussed in Section 5 indicate that UE is faced with two major resource decisions at the current time. The Company needs to decide what level of DSM to implement in 1997. In addition, it must decide whether to plan on installing peaking or intermediate resources in the early and mid 2000's. These decisions may be impacted by the following five uncertainties:

- Load Forecast
- Fuel Cost
- Future Availability of Economy Coal Energy for Purchase
- Future Environmental Costs
- Construction and Fixed O&M Cost for Wind Generation

The EPRI developed Multiobjective Integrated Decision Analysis System (MIDAS) model was used for the risk analysis. In order to limit the size of the decision tree being analyzed, it was decided to use two expansion strategies for the risk analysis, one consisting of all CTs and the second consisting of all CCs. This decision was based on a review of the results of the system integration analysis discussed in Section 5.

Figure 6-1 depicts the decision tree that was developed. The risk analysis results are contained in Table 6-3 and show that the outcomes, using expected values, are very close for the two DSM strategies. Also, both DSM strategies are preferred to the all supply-side strategy based on the Utility Cost Test and the Total Resource Cost Test. Further, the results support a decision to delay installation of intermediate resources to the late 2000's.

An expansion strategy of DSM and CTs plus power purchases appears to be the most economic choice through the early and mid 2000's.

An Expected Value of Perfect Information (EVPI) analysis was performed to determine the value of resolving the uncertainties considered in the decision tree. The results of the EVPI analysis are shown in Table 6-4. If the value of resolving the uncertainty is zero, then the preferred strategy remains preferred for all modeled values of the uncertainty. If the preferred strategy would change for one or more of the uncertainty values modeled, then the value of resolving the uncertainty is not zero.

As shown in Table 6-4, the expected savings that would result from having perfect information is very small on a percentage basis for the variables analyzed. The uncertainty in future environmental costs is the most significant, followed by uncertainty in availability of economy coal energy for purchases, and uncertainty in the load forecast.

The savings shown in Table 6-4 would be expected if perfect information were available. They do not reflect the savings, if any, from decreasing the uncertainty in these variables. In fact, the uncertainties may not be able to be resolved, even with additional research and investment. The data highlights where uncertainty would have a significant impact on expected outcomes.

Section 7 of the IRA report contains a more complete discussion of the risk analysis performed.

6.4 PLAN SELECTION

The sensitivity, scenario and risk analyses show that the DSM-20 plan is preferred. The DSM-20 plan is composed of a menu of cost effective DSM programs; Venice repowering; Sioux, Taum Sauk and Keokuk plant improvements; combustion turbines; combined cycle units; an extended AP&L contract; additional Joppa energy and economic power purchases. It includes 825 MW of combustion turbines, 180 MW of combined cycle capacity, 510 MW of Venice Repowering and 268 MW of equivalent DSM capacity.

Both the DSM-20 plan and the all supply-side plan provide for system reliability and flexibility. Tables 6-5 and 6-6 show the timing of resources for these plans. Both plans utilize combustion turbines in the early years, with the DSM-20 plan substituting demand-side resources for some of the early combustion turbine additions. Combustion turbines and demand-side resources can be added in increments to closely match forecasted load growth. Thus, from the perspective of reliability and flexibility, either plan would perform well. Likewise, neither plan should be difficult to finance due to the relatively small capital expenditures required for resource additions in any given year.

The DSM-20 plan provides for maximum annual energy savings of nearly 0.9 million MWh over the all supply-side plan. As such, it would likely perform better for futures with increased emphasis on the environment.

The levelized system rates test yielded results for the DSM-20 plan that were approximately equal to the all supply-side plan for the expected forecast scenario. Given no average rate impact and the fact that the DSM-20 plan contains programs directed at each of the three major retail rate classes, the Company does not believe that the DSM-20 plan should be rejected based on equity considerations.

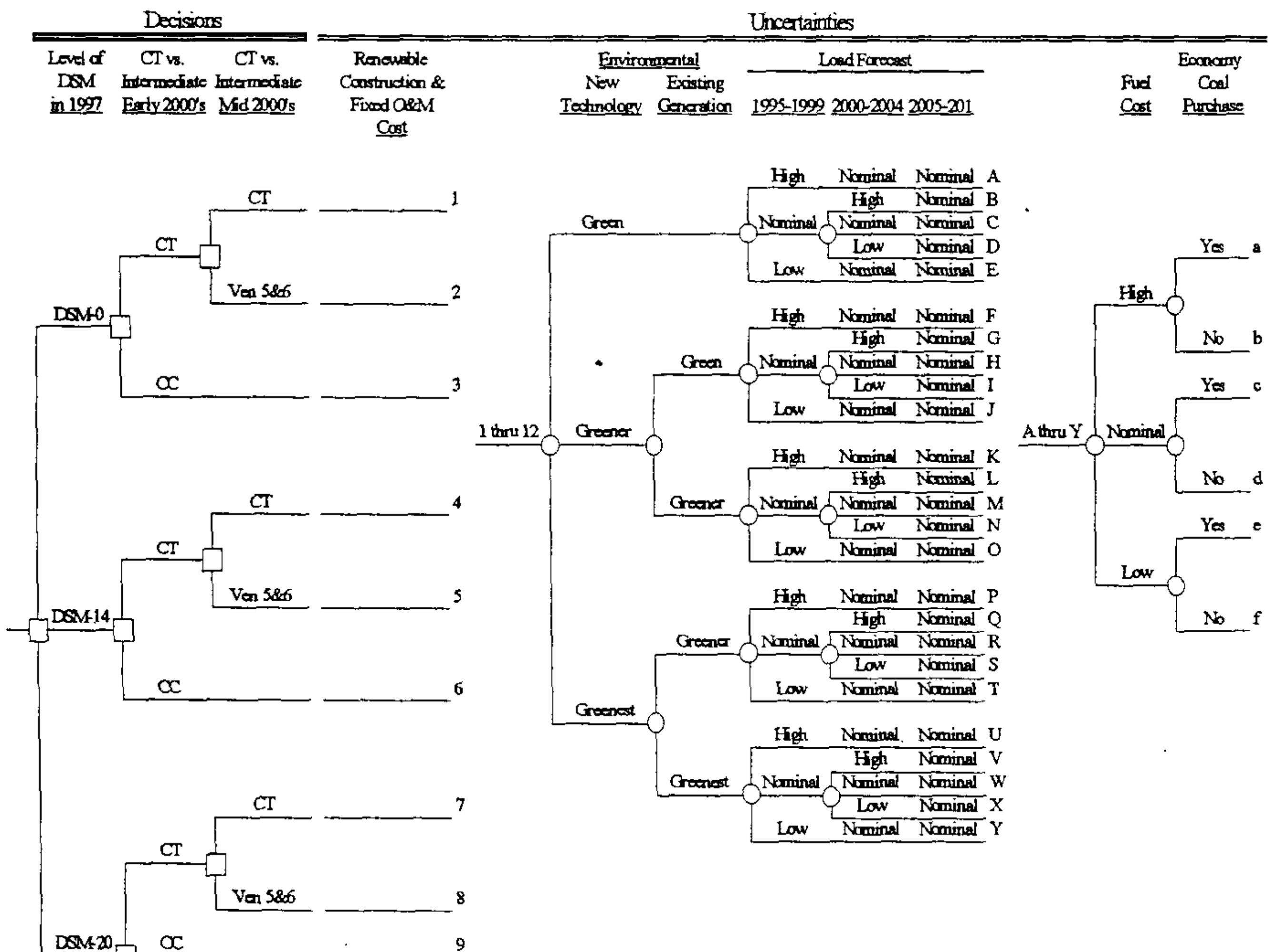
The DSM-20 plan provides the maximum insurance against actions in the environmental area.

The Company's preferred resource plan is shown in Table 6-7 and is based on the DSM-20 plan. The DSM-20 plan was developed for the Greener environmental mitigation level discussed in Section 5. The Greener mitigation level represents most likely conditions, based on the probabilities developed for this ERP, except for the installation of environmental controls on existing units. The level of environmental controls on existing units included in the Greener mitigation level has only a 15% probability of occurrence based on Company estimates. The level of environmental controls for existing units, included in the Green mitigation level, has a 80% probability of occurrence and is the most likely level.

The DSM-20 plan, shown in Table 6-5, includes a 48 MW reduction in existing system capability and a 3 MW reduction in the EEInc. purchase beginning in the year 2000. However, based on most likely conditions, these reductions would not be required. Therefore, the capacity and reserve values shown in Table 6-5, have been adjusted to eliminate the 51 MW reduction for the preferred resource plan shown in Table 6-7. This additional capacity may allow the Company to delay the first CT and the Taum Sauk runner upgrade projects by one year.

Figure 6-1

Risk Analysis Decision Tree



Probability Distributions of Uncertain Factors

	High	Nominal	Low
Forecasted Peak Growth Rate	1.8%	1.0%	0.0%
Probability	15%	70%	15%
Environmental	Green	Greener	Greenest
Prob - New Tech	10%	80%	10%
Prob - Existing Gen	80%	15%	5%
Fuel Cost	–	–	–
Probability	25%	40%	35%
Economy Coal Purch	Yes	No	–
Probability	90%	10%	–
Renewable Construction & Fixed O&M Cost	+25%	0%	-25%
Probability	25%	50%	25%

1800 Endpoints

Table 6-1

Optimal Integrated Resource Plans for Each Scenario (Probable Environmental Costs — Included) DSM-20 Plan

	Scenario				
Year	Nominal	Low Growth	High Growth	Environmental	Competition
1995					
1996					
1997	Sioux	Sioux	Sioux	Sioux	Sioux
1998	CIPS PP		CIPS PP	CIPS PP	CIPS PP
1999	KGR	KGR	KGR 4 CT	KGR	KGR
2000	TS 50 MW PP		50 MW PP	TS 50 MW PP	TS 50 MW PP
2001	1 CT		TS 1 CT		1 CT
2002	Extend AP&L 1 CT		Extend AP&L 1 CT	Extend AP&L	Extend AP&L 1 CT
2003	1 CT	TS	Repower V 5&6	1 CT	1 CT
2004	1 CT			1 CT	1 CT
2005	3 CT		Repower V 3&4	Repower V 5&6	3 CT
2006			1 CC		
2007	2 CT	1 CT	1 CT	1 CT	2 CT
2008	Repower V 5&6 Extra Joppa	Extra Joppa	2 CC	Repower V 3&4	Repower V 5&6 Extra Joppa
2009	1 CT	1 CT	1 CC		1 CT
2010	1 CT		1 CT Extra Joppa	1 CC	1 CT
2011	Repower V 3&4	1 CT	1 CC		Repower V 3&4
2012			1 CC	1 CC	
2013	1 CT	1 CT	1 CT		1 CT
2014	1 CT		1 CC		1 CT
CT (MW)	975	300	675	225	975
CC (MW)	0	0	1260	360	0
Repower (MW)	512	0	512	510	512
Upgrades (MW)	116	116	116	116	116
Total - Supply (MW)	1603	416	2563	1211	1603
DSM (MW)	268	268	268	268	268
Total (MW) - 2014	1871	684	2831	1479	1871

Sioux	Sioux 16 MW Improvement
CIPS PP	CIPS 150 MW Power Purchase
KGR	Keokuk Generator Rewind 20 MW Capacity Equivalence
50 MW PP	50 MW Intermediate Power Purchase
Repower V3&4	Repower Venice Units 3 & 4
Repower V5&6	Repower Venice Units 5 & 6
Extra Joppa	Increased Utilization Of Joppa Energy
Extend AP&L	Extend The Present Purchase Contract With AP&L As Provided For In The Contract
TS	Taum Sauk Runner Replacement - 80 MW
DSM	Demand-Side Management Capacity Equivalence

Table 6-2

Scenario Analysis
Strategy Comparison

Levelized Average System Rates (¢/kWh)

Strategy	Scenario				
	Base	Low	High	Environmental	Competition
All Supply	0.001	0	0	0.001	0.014
DSM-20	0	0.026	0.029	0	0

Utility Cost ($ in Millions)

Strategy	Scenario				
	Base	Low	High	Environmental	Competition
All Supply	303.72	179.69	214.58	392.41	303.72
DSM-20	0	0	0	0	0

Total Resource Cost ($ in Millions)

Strategy	Scenario				
	Base	Low	High	Environmental	Competition
All Supply	212.89	108.84	102.04	301.59	212.89
DSM-20	0	0	0	0	0

* The results shown for each scenario are the differences between the strategy cost and the low cost strategy expressed in either present value of revenue requirements or levelized rates over the period, 1995-2024.

Table 6-3

Risk Analysis
Expected Values for Strategies Evaluated

Strategy	Levelized Average System Rate Levelized ¢/kWh	Utility Cost 30 Yr PVR $ in Millions	Total Resource Cost 30 Yr PVR $ in Millions
DSM20; All CT Expansion; Ven 5&6 Repower 2008	7.458	26,040.05 *	26,125.82 *
DSM20; All CT Expansion; Ven 5&6 Repower 2005	7.458	26,040.37	26,126.14
DSM14; All CT Expansion; Ven 5&6 Repower 2008	7.456 *	26,042.25	26,126.45
DSM14; All CT Expansion; Ven 5&6 Repower 2005	7.457	26,046.95	26,131.14
DSM20; All CC Expansion; Ven 5&6 Repower 2008	7.471	26,085.52	26,171.29
DSM14; All CC Expansion; Ven 5&6 Repower 2008	7.471	26,094.04	26,178.24
DSM20; All CC Expansion; Ven 5&6 Repower 2008 Renewables in 2000	7.478	26,110.16	26,195.94
No DSM; All CT Expansion; Ven 5&6 Repower 2008	7.464	26,363.71	26,363.71
No DSM; All CT Expansion; Ven 5&6 Repower 2005	7.464	26,364.30	26,364.30
No DSM; All CC Expansion; Ven 5&6 Repower 2008	7.483	26,430.01	26,430.01

* Lowest Value

Table 6-4

EVPI Results

Evaluation Criteria: Levelized Average System Rates Expected Value: 7.456 ¢/kWh

Uncertainty	EVPI ¢/kWh
Load Forecast	0.000
Fuel Cost	0.001
Future Availability of Economy Coal Energy for Purchase	0.001
Future Environmental Costs	0.002
Capital and Fixed O&M Cost for Renewables	0.000

Evaluation Criteria: Utility Cost Expected Value: $26,040.05 Mil

Uncertainty	EVPI $ Millions
Load Forecast	1.58
Fuel Cost	0.92
Future Availability of Economy Coal Energy for Purchase	2.87
Future Environmental Costs	5.35
Capital and Fixed O&M Cost for Renewables	0.00

Evaluation Criteria: Total Resource Cost Expected Value: $26,125.82 Mil

Uncertainty	EVPI $ Millions
Load Forecast	2.60
Fuel Cost	0.92
Future Availability of Economy Coal Energy for Purchase	2.87
Future Environmental Costs	5.73
Capital and Fixed O&M Cost for Renewables	0.00

Table 6-5

DSM-20 Resource Plan
Greener Environmental Mitigation Level - Controls On New and Existing Units

		RESOURCE ADDITION (REDUCTION)									
		UE CAPACITY			PUR	UE CAPACITY	EEINC PURCHASE	PURCHASE (SALE)	ADJUSTED CAPACITY	ADJUSTED DEMAND	RESRVE
YEAR	UNIT	DSM MW	SUP MW	Total MW	MW	MW	MW	MW	MW	MW	%
1995	Venice Restaffing		92	92		7,825	405	155	8,385	7,143	17.4
1996				0		7,825	405	155	8,385	7,199	16.5
1997	DSM, SX Improvement	44	16	60		7,885	405	155	8,445	7,268	16.2
1998	DSM, CIPS Purchase	22		22	150	7,907	405	240	8,552	7,288	17.3
1999	DSM, Keokuk Generator Rewind	22	20	42		7,949	405	235	8,589	7,367	16.6
2000	DSM, Taum Sauk Runners	45	80	125		8,026	402	362	8,790	7,447	18.0
	Renewables				2						
	50 MW Purchase				50						
2001	DSM, CT	23	75	98		8,124	402	362	8,888	7,527	18.1
2002	DSM, CT	23	75	98		8,222	402	362	8,986	7,606	18.1
	Extend AP&L Purchase				—						
2003	DSM, CT	22	75	97		8,319	402	362	9,083	7,686	18.2
2004	DSM, CT	23	75	98		8,417	402	362	9,181	7,765	18.2
2005	DSM, CT-3	22	225	247		8,664	402	212	9,278	7,845	18.3
	End CIPS Purchase				(150)						
2006	DSM, CT	22	75	97		8,761	402	212	9,375	7,925	18.3
2007	CT		75	75		8,836	402	212	9,450	8,004	18.1
2008	Repower Venice Units 5&6		248	88		9,084	402	52	9,538	8,084	18.0
	End AP&L Purchase				(160)						
	Additional Joppa Energy				—						
2009	CT		75	75		9,159	402	52	9,613	8,163	17.8
2010	Repower Venice Units 3&4		262	262		9,421	402	52	9,875	8,243	19.8
2011				0		9,421	402	52	9,875	8,322	18.7
2012				0		9,421	402	52	9,875	8,402	17.5
2013	CC		180	180		9,601	402	52	10,055	8,481	18.6
2014	CT		75	75		9,676	402	2	10,080	8,561	17.7
	End 50 MW Purchase				(50)						

Table 6-6

All Supply-Side Resource Plan
Greener Environmental Mitigation Level - Controls On New and Existing Units

		RESOURCE ADDITION (REDUCTION)									
		UE CAPACITY			PUR	UE	EEINC	PURCHASE	ADJUSTED	ADJUSTED	
		DSM	SUP	Total		CAPACITY	PURCHASE	(SALE)	CAPACITY	DEMAND	RESRVE
YEAR	UNIT	MW	MW	MW	MW	MW	MW	MW	MW	MW	%
1995	Venice Restaffing		92	92		7,825	405	155	8,385	7,143	17.4
1996				0		7,825	405	155	8,385	7,199	16.5
1997	SX Improvement		16	16		7,841	405	155	8,401	7,268	15.6
1998	CIPS Purchase			0	150	7,841	405	240	8,486	7,288	16.4
1999	Keokuk Generator Rewind		20	20		7,861	405	235	8,501	7,367	15.4
2000	Taum Sauk Runners		80	230		8,043	402	362	8,807	7,447	18.3
	CT-2		150								
	Renewables				2						
	50 MW Purchase				50						
2001	CT		75	75		8,118	402	362	8,882	7,527	18.0
2002	CT		75	75		8,193	402	362	8,957	7,606	17.8
	Extend AP&L Purchase				—						
2003	CT		75	75		8,268	402	362	9,032	7,686	17.5
2004	CT-2		150	150		8,418	402	362	9,182	7,765	18.2
2005	CT-3		225	225		8,643	402	212	9,257	7,845	18.0
	End CIPS Purchase				(150)						
2006	CT		75	75		8,718	402	212	9,332	7,925	17.7
2007	CC		180	180		8,898	402	212	9,512	8,004	18.8
2008	Repower Venice Units 5&6		248	248		9,146	402	52	9,600	8,084	18.7
	End AP&L Purchase				(160)						
	Additional Joppa Energy				—						
2009				0		9,146	402	52	9,600	8,163	17.6
2010	CC		180	180		9,326	402	52	9,780	8,243	18.6
2011				0		9,326	402	52	9,780	8,322	17.5
2012	Repower Venice Units 3&4		262	262		9,588	402	52	10,042	8,402	19.5
2013				0		9,588	402	52	10,042	8,481	18.4
2014	CT		75	75		9,663	402	2	10,067	8,561	17.6
	End 50 MW Purchase				(50)						

Table 6-7

Preferred Resource Plan
Greener Environmental Mitigation Level - Controls On New Units

YEAR	UNIT	RESOURCE ADDITION (REDUCTION) UE CAPACITY DSM MW	SUP MW	Total MW	PUR MW	UE CAPACITY MW	EEINC PURCHASE MW	PURCHASE (SALE) MW	ADJUSTED CAPACITY MW	ADJUSTED DEMAND MW	RESRVE %
1995	Venice Restaffing		92	92		7,825	405	155	8,385	7,143	17.4
1996				0		7,825	405	155	8,385	7,199	16.5
1997	DSM, SX Improvement	44	16	60		7,885	405	155	8,445	7,268	16.2
1998	DSM, CIPS Purchase	22		22	150	7,907	405	240	8,552	7,288	17.3
1999	DSM, Keokuk Generator Rewind	22	20	42		7,949	405	235	8,589	7,367	16.6
2000	DSM, Taum Sauk Runners	45	80	125		8,074	405	362	8,841	7,447	18.7
	Renewables				2						
	50 MW Purchase				50						
2001	DSM, CT	23	75	98		8,172	405	362	8,939	7,527	18.8
2002	DSM, CT	23	75	98		8,270	405	362	9,037	7,606	18.8
	Extend AP&L Purchase				—						
2003	DSM, CT	22	75	97		8,367	405	362	9,134	7,686	18.8
2004	DSM, CT	23	75	98		8,465	405	362	9,232	7,765	18.9
2005	DSM, CT-3	22	225	247		8,712	405	212	9,329	7,845	18.9
	End CIPS Purchase				(150)						
2006	DSM, CT	22	75	97		8,809	405	212	9,426	7,925	18.9
2007	CT		75	75		8,884	405	212	9,501	8,004	18.7
2008	Repower Venice Units 5&6		248	88		9,132	405	52	9,589	8,084	18.6
	End AP&L Purchase				(160)						-
	Additional Joppa Energy				—						
2009	CT		75	75		9,207	405	52	9,664	8,163	18.4
2010	Repower Venice Units 3&4		262	262		9,469	405	52	9,926	8,243	20.4
2011				0		9,469	405	52	9,926	8,322	19.3
2012				0		9,469	405	52	9,926	8,402	18.1
2013	CC		180	180		9,649	405	52	10,106	8,481	19.2
2014	CT		75	75		9,724	405	2	10,131	8,561	18.3
	End 50 MW Purchase				(50)						

Clean Air Act Compliance Review
Section 7

7.1 Sulfur Dioxide – SO_2

In February, 1992, the Company completed its first comprehensive review of alternative strategies for complying with the Clean Air Act Amendments of 1990. That review recommended that the Company initially switch to low sulfur fuel. This provides the flexibility to install scrubbers or other control technologies in the future, if warranted. Four key uncertainties which could impact the compliance strategy were identified. They include:

- Scrubber cost
- Fuel price differential between Illinois and PRB coal
- SO_2 emission credit value
- Derate level, if any, from operating units on PRB coal

The review outlined the magnitude of change to the first three uncertain variables which would be necessary before the recommended strategy would change. The fourth uncertainty — derate level from operating units on PRB coal — provided an advantage to the scrub strategies in the 1992 review. A 400 MW system derate was assumed based on initial coal test burn results — 50 MW per unit for the eight units at Labadie, Rush Island, and Sioux when operating on 100% PRB coal. Any reduction in the derate level when operating on 100% PRB coal from that used in the review would increase the savings identified for the fuel switch strategy.

The 1992 review also recommended that the assumptions used in the analysis be reexamined periodically to identify any significant changes which would require a new review to determine whether the Company's preferred compliance strategy should be changed. The Company reviewed the planning assumptions included in the February 1992 review for both the July 1992 and December 1993 ERPs and for the development of this ERP.

The unit deratings assumed in the initial study amounted to approximately 400 MW when operating on 100% PRB coal. Work performed since that time and current operation, maintenance, and construction budgets reflect plans for plant investments and major projects that address the unit deratings. While the long-term impacts of PRB coal on unit capability, availability and efficiency are not known at this time, scheduled plant modifications and operating strategies are expected to eliminate the deratings while maximizing use of PRB coal.

Estimates for scrubber retrofits at the Company's existing facilities have not changed from those used in the 1992 study, other than for inflation.

The initial study assumed a fuel premium for PRB coal over Illinois coal of approximately 10¢/MMBtu in the year 2000. The expected fuel price differential is now projected to be lower than this value. It also assumed a value for Phase II SO_2 credits of approximately \$625/ton in the year 1995 (1993 dollar's) escalating at 5¾% per year. The estimate used for developing this ERP was \$150/ton in 1995, escalating at 4% per year. As discussed in Section 1, information from the SO_2 allowance auction held by the EPA in March, 1995 and from recent activity in the allowance market indicates a 1995 allowance price on the order of \$132/ton in 1995 nominal dollars, escalating at a rate slightly higher than the rate used in the development of this ERP.

Current assumptions all favor the Company's original fuel switch strategy. Union Electric will continue to monitor the SO_2 allowance market.

7.2 NITROGEN OXIDES – NO_X

The Environmental Protection Agency (EPA) published final rules on NO_x emissions in the March 22, 1994 Federal Register (Vol. 57, No. 228). As a result of these rules, the Company revised its NO_x compliance strategy. This revised strategy is documented in a July 1994 report entitled *NO_x Compliance Strategy*.

The July 1994 report recommends a strategy which involves averaging system units for NO_x compliance. Averaging will allow the company to minimize cost by only requiring controls on those units where it is most cost effective. Specifically, the study recommends:

- Installation of low NO_x burners at Labadie, Rush Island and Meramec 3 and 4.
- Substituting the two Rush Island units, and four Meramec units in 1995 and 1996. Investigate continued substitution at these units in 1997, 1998 and 1999 when Phase II NO_x limits are established.
- Avoiding expensive options at Sioux and Meramec 1&2 by utilizing more cost effective options at other units.
- Avoiding additional controls at Venice, existing combustion turbines and diesels.

The U. S. Court of Appeals for the District of Columbia vacated Section 407 of the EPA NO_x rules on November 29, 1994. The major reason for vacating the EPA rule was the definition of low NO_x burners. Although a change in definition may raise the NO_x requirements for Phase II units from the values that might have been determined using the original definition, the overall impact on the Company's July, 1992 strategy is not believed to be significant — other than to change the initial compliance date. An agreement was reached on a direct final EPA rule on March 28, 1995. This direct final rule establishes a compliance date of January 1, 1996 for Phase I units and defines low NO_x burner technology as "burners only."

Further changes in rules and additional regulations could require modifications to the recommended plan. Maintaining options and flexibility are important characteristics of the Company's preferred NO_x strategy as the key uncertainties are resolved over the next several years. The flexible strategy outlined above is designed to address potential regulatory changes in a least cost manner.

7.3 TITLE III – AIR TOXICS

Air toxic regulations are still in the formative stages and are addressed in detail in the IRA report and its appendices. The Company considered potential impacts of possible future regulations on existing and future generation requirements in the development of this ERP. The Company will follow developments in this area closely to further address potential impacts on existing and future generation.

PLAN SELECTION AND IMPLEMENTATION SECTION 8

8.1 PLAN SUMMARY

The Company's preferred resource plan (see Table 6-7) involves low cost, incremental capacity additions that can be adapted to changing conditions. Demand-side and supply-side options have been selected so as to minimize future revenue requirements. The Company has contracted for the purchase of 150 MW from Central Illinois Public Service Co. for the period 1998 to 2004 and the Sioux capacity restoration is currently planned for 1997. DSM implementation is planned to commence in 1997 and continue to grow into the early 2000's. The actions should allow the Company to delay the need for supply-side additions until 2001. The Keokuk generator rewind project depends on future 25 Hz generation requirements. The IELP contract expires on December 31, 1998. Prior to that date the company will determine if there is a market for 25 Hz generation and whether these generators should be rewound.

Additional peaking resources, including a 80 MW improvement at Taum Sauk, several new CTs, and additional DSM are required during the period 2003 to 2014. Repowering of Venice Units 5&6 is planned in 2008. Venice Units 3&4 are planned to be repowered in 2010. One combined cycle unit is planned for 2013. A decision to proceed with CTs, at an existing site, is expected to require two years lead time. Thus, under expected conditions, a decision would not be required until 1999 for the first CT installation. Repowering Venice Units 5&6 requires a decision by 2004, based upon a lead time of four years for that project.

The Company investigated each plan's potential impact on the environment using scenario and risk analysis. Since the preferred plan described in Section 6 relies on cost effective DSM programs and relatively low environmental impact resources — oil and/or natural gas-fired CTs and combined cycle units — it is also preferred when environmental impacts are considered. Thus, this plan is robust across most of the planning assumptions used in this study.

The financing requirements for resources included in the preferred resource plan should not have a significant impact on the Company. This assumes that reasonable rate treatment for both supply-side and demand-side resources will be provided.

Construction expenditures for the new resources included in the plan are expected to average approximately $120 million per year over the planning period with no one year exceeding $250 million. This relatively smooth pattern of expenditures is due to the phased installation of demand-side programs, the relatively short construction time for the supply-side facilities and the magnitude of the capital investment required for 75 MW combustion turbines and 180 MW combined cycle units.

Table 8-1 compares the preferred resource plan with the plan that would be preferred if probable environmental costs were not considered. This table shows that the need for the first combustion turbine is advanced one year by the preferred resource plan. Although the timing of unit additions differs between the two plans, they both include the same resource additions over the twenty year planning horizon — except for one additional combustion turbine in the preferred resource plan.

If the units in the preferred resource plan were all acquired with the controls necessary to meet the increased environmental mitigation requirements assumed in the development of the plan, the additional equipment costs would result in a 30 year 1995 PVRR of $61.5 million over the equipment costs for a plan based on existing environmental requirements. The 30 year PVRR includes the 20 years of the planning horizon and the additional 10 years used to account for end effects. This is the expected amount that would be required to provide for the uncertainties of future environmental regulation. It only accounts for added control equipment expenditures.

The likelihood of changes in environmental regulations will be assessed prior to each future unit commitment. The $61.5 million PVRR calculated in this plan as the cost to insure against an uncertain environmental future, assumes that all future unit purchases will be made without additional information.

The preferred resource plan is somewhat insensitive to assumptions on probable environmental costs due to its reliance on combustion turbines and combined cycle units operating on natural gas. If the Company needed base type capacity at this time, instead of peaking and intermediate capacity, probable environmental costs would have had a greater impact on resource selection.

The average system rates (as calculated by MIDAS) for the preferred resource plan increase at approximately 63% of the inflation rate used in the analysis. This value increases to about 67% of the inflation rate when probable environmental costs are considered. Thus, in real terms, electric rates are expected to decrease over the planning horizon. This moderate growth in nominal average system rates should not have an adverse impact on utility customers.

8.2 Implementation Responsibilities

The following departments are responsible for performing the detailed work of planning, scheduling, and implementing projects associated with acquiring resources once they are included in an ERP.

Resource Planning – Design and analyze demand-side programs, forecast customer energy and peak demand requirements, plan future resource additions.

Transmission Planning – Plan and schedule major transmission, subtransmission and major substation facilities.

E&C Electrical Engineering – Schedule, design, and procure transmission and substation facilities.

E&C Mechanical Engineering – Plan, schedule, design, and procure new generation facilities and improvements and modifications to existing generation facilities.

E&C Construction & Services – Manage outside construction labor and provide drafting and clerical support services.

Power Plant Maintenance and Engineering – Plan and schedule improvements and modifications to existing facilities. These projects are generally smaller in scope than projects carried out by the Mechanical Engineering Department.

Fossil Fuel – Procure fossil fuels, other than natural gas, for Company facilities.

Nuclear Licensing & Fuels – Procure Callaway Plant nuclear fuel.

Environmental Services – Conduct environmental impact studies and obtain permits for continued operation of existing facilities as well as new facilities.

Energy Services – Evaluate and acquire long-term purchased power. Procure Natural gas for Company facilities.

Division Marketing – Perform market research, program design, schedule, and implement demand-side management programs.

Distribution Engineering – Implement loss reductions on the distribution system if cost justified.

The responsible departments are charged with reviewing the parameters used in the development of the ERP for their specific areas and notifying Corporate Planning if any parameter changes would warrant an early plan review.

8.3 Demand-Side Implementation

Over the past few years, UE has made considerable progress in building the capability to evaluate demand-side resources. The Company has implemented several pilot programs in addition to conducting market and end use research.

This ERP has identified several new, potentially cost-effective, opportunities. These opportunities will be carefully evaluated by using pilot programs to test their effectiveness. Critical uncertainties include customer response, load impacts, and costs to manage and verify demand-side resources. UE expects the pilot phase of demand-side resource development to extend at least through the end of 1996.

Programs will be expanded to larger scales over time as they are determined to be cost-effective and the mechanisms necessary for effective implementation, management and evaluation are in place. For planning purposes, the Company has assumed that full-scale implementation of cost-effective programs will occur in 1997. Actual full-scale implementation of individual programs could occur before or after this date depending on the progress of capability building and the need for additional resources.

The following is a discussion of the major activities UE has recently completed, or is currently undertaking, to build its capability to implement cost-effective demand-side resources.

Pilot Programs

"Cold Cash"

This program offered residential customers a free removal and recycling service for old, inefficient refrigerators and freezers. In addition, a $50 savings bond was provided as an added incentive. Program evaluation suggests that the savings bond is unnecessary and that free riders need to be minimized if the program is to be cost-effective. The program design used in this ERP reflects the experience gained by the Company through "Cold Cash." The pilot results were used in the screening analysis of the Residential Refrigerator and Freezer Removal programs.

In Concert With The Environment®

The goal of *In Concert* is to provide cost-effective demand-side management through education. The program uses an energy survey to educate high school students and their families about household energy usage. In addition to teaching the importance of efficiency and environmental awareness, the program provides customers with a bill disaggregation and customized recommendations for a variety of energy efficiency measures. The program has reached thousands of students across numerous school districts over the past three years. Process evaluation and impact evaluation are currently underway. The pilot is testing the assumptions used in the screening of the Residential Water Heater and Lighting Measures, Building Shell Measures, and Setback Thermostats - Gas Heating Customers programs.

"No Sweat" Residential Energy Management Program

During the summers of 1993-94, residential customers received bill credits in return for allowing UE to cycle their air conditioners during peak times. Additional participation is being solicited in 1995; the final year of the pilot. Program evaluation will include a detailed analysis of load impacts, free riders, and reasons for participation. Preliminary data suggests that customers have not experienced significant discomfort during cycling periods and continuous financial incentives may not be required for prolonged participation, which could help the program become cost-effective. The pilot is testing the assumptions used in the screening of the Residential Central Air Conditioner/Heat Pump Cycling program.

"Green Key"

Through this pilot program, UE will investigate the cost-effectiveness of providing builder reimbursement to encourage the installation of specified energy efficiency measures in the residential new construction market. The reimbursement will be equal to the incremental cost of the specified energy efficiency measures for electrically heated homes. These measures include higher levels of ceiling insulation, low emissivity windows, basement wall insulation, programmable thermostats (single-family only), duct sealing, and building sealing to reduce air infiltration. The program will involve up to 500 units in the UE Missouri territory, with 100 units being targeted for low income housing. The pilot is scheduled to begin upon Missouri Public Service Commission approval of tariffs. The pilot will test the assumptions used in the screening of the Residential New Construction Building Shell Measures program.

Energy Savings Partnership Program

This pilot program was implemented in August 1993. The program is intended to reduce the energy and/or demand requirements of existing commercial buildings and to provide insight into the energy use and technical service needs of the customer. The program design calls for the Company to provide a variety of technical and administrative services to encourage commercial customers to implement electric efficiency measures. Examples include lighting retrofits, more efficient HVAC equipment and energy management systems. In addition, the Company may provide loans to customers who qualify for such services. Several audits are currently under way. The pilot is testing the assumptions used in the screening of the Commercial Audits programs — Level I - Walk Through Audit, Level IIA - Engineering Study Lighting Emphasis, and Level IIB - Comprehensive Building Modeling.

"MotorMiser" Information Campaign

Begun in mid-1993, this program encourages industrial customers to install high efficiency motors when they replace failed or existing motors. The program uses informational brochures and software to assist the customer with motor purchases. Interested customers will be given assistance in analyzing the economics and application of high efficiency motors and drives.

Preliminary information suggests that the program has successfully influenced customers to avoid making motor purchase decisions solely on initial cost. The program also offers a free on-site efficiency evaluation of selected motor applications for those customers having qualified demand/energy reduction opportunities. The pilot is testing the assumptions used in the screening of the Industrial MotorMaster Software and MotorMiser Audit programs.

Customized Industrial Process Audits

This pilot program began in the summer of 1993. Its purpose is to encourage industrial customers to make process-oriented efficiency and demand control improvements. Industrial customers are being offered the opportunity to have their production processes evaluated by a nationally recognized expert in their specific industrial field. Recommendations have included: replacing existing electric motors with high efficiency motors or adjustable speed drives, improving compressed air and refrigeration systems, installing heat recovery systems, insulating energy intensive processes, and deploying energy-saving technologies. Recommendations on how to best use existing curtailable and off-peak power rates are also provided. The pilot is testing the assumptions used in the screening of the Industrial Customized Process Audit program.

Demand and Energy Control Information Program

This pilot program was kicked off with an informational seminar in February of 1995. The purpose of the program is to encourage industries to install demand and energy monitoring equipment at their plants. The program supplies each participant with: their load profile, strategies and reasons for monitoring their electric usage, local energy control successes, and an opportunity to view currently commercially available equipment. Trade allies would be relied on to deliver the program to the greatest extent possible.

The pilot is testing the assumptions used in the screening of the Industrial Demand & Energy Control Information program.

"Rider G" Curtailable Power Pilot Project

This pilot program was fielded in Union Electric's Missouri service territories in September of 1994. The purpose of the program is to encourage larger customers to curtail demand during periods of system stress. The pilot provides a performance-based bill credit to participants who curtail demand during requested periods. The pilot is available to customers with curtailable loads as low as 1,000 kW and allows some compliance flexibility.

This pilot will test the assumptions used in the screening of the Standby Generation/Curtailable Power Rate program.

Small Commercial Walk Through Audit

This program would provide small commercial establishments an expert auditor who would enter information on sources of energy use into a computer. When the analysis was complete, the customer would receive a dissaggregation of past energy use by end use and recommendations for improvement, including simple payback analysis. The audit recommendations would be expected to primarily address lighting measures. The audit would be provided at a small fee to participating customers (well below the actual cost of the audit). A list of contractors and institutions providing installations and financing would be made available at no charge. A pilot is scheduled to begin during 1995. This pilot will test the

The Company will consider competitively bidding future supply-side resources prior to making a unit commitment.

The preferred resource plan is shown in Table 6-7.

Table 8-1

Comparison
Preferred Resource Plan
and
DSM-20 Plan W/O Probable Environmental Costs

Year	Preferred Resource Plan DSM 20	Plan Without Probable Environmental Costs DSM 20
1995		
1996		
1997	Sioux Improvement	Sioux Improvement
1998	CIPS PP	CIPS PP
1999	KGR	KGR
2000	Taum Sauk 50 MW PP	50 MW PP
2001	1 CT	Taum Sauk
2002	Extend AP&L 1 CT	Extend AP&L 1 CT
2003	1 CT	1 CT
2004	1 CT	1 CT
2005	3 CT	3 CT
2006	1 CT	1 CT
2007	1 CT	1 CT Extra Joppa
2008	Repower V5&6 Extra Joppa	Repower Ven 5&6
2009	1 CT	1 CT
2010	Repower Ven 3&4	Repower Ven 3&4
2011		
2012		1 CT
2013	1 CC	1 CC
2014	1 CT	
CT (MW)	825	750
CC (MW)	180	180
Repower (MW)	510	528
Upgrades (MW)	116	116
Total - Supply (MW)	1631	1574
DSM (MW)	268	268
Total (MW)	1899	1842
Environmental Cost Premium 20 Yr + 10 Yr Ext PVRR (Million)	$61.5	Base

Sioux	Sioux 16 MW Improvement
CIPS PP	CIPS 150 MW Power Purchase
KGR	Keokuk Generator Rewind - 20 MW Capacity Equivalence
50 MW PP	50 MW Intermediate Power Purchase
Repower V3&4	Repower Venice Units 3 & 4
Repower V5&6	Repower Venice Units 5 & 6
Extra Joppa	Increased Utilization Of Joppa Energy
Extend AP&L	Extend The Present Purchase Contract With AP&L As Provided For In The Contract
TS	Taum Sauk Runner Replacement - 80 MW
DSM	Demand-Side Management Capacity Equivalence

RISK & UNCERTAINTY ANALYSIS BRIEFING

UNION ELECTRIC

ue

RESOURCE PLANNING

October 1997

Summary of Sensitivity Analysis

Sensitivity analysis was performed to determine the critical uncertain factors that may impact resource planning decisions. Each of the factors investigated were varied individually while all other parameters were held constant. Optimal expansion plans were developed for each of the following uncertain factors:

- Increased Forced Outage Rates of Existing Base Load Units
- Reduced Economy Coal Purchases
- High and Low Construction and O&M Costs and Escalation Rates
- High and Low Fuel Costs
- High and Low SO_2 Allowance Costs
- No Probable Environmental Costs

The evaluation indicates that the expansion plan is relatively insensitive to all uncertain factors, except for probable environmental costs. If no probable environmental costs are included, the least cost plan involves the addition of combustion turbines instead of combined cycle units in 2002. Since the selection of the type of unit to be built in 2002 is a near term decision, it was included in the risk analysis.

The results also showed that the expansion plan is relatively insensitive to fuel prices. However, since fuel costs are a large component of the total cost, it was also included in the risk analysis.

Optimized Expansion Plans For Various Sensitivities
(Probable Environmental Costs Included)

	Base	Sensitivity								
Year	Nominal Conditions	Increased F.O.R	Reduced Economy Purchases	High Const. and O&M Costs	Low Const. and O&M Costs	High Fuel Costs	Low Fuel Costs	High SO2 Costs	Low SO2 Costs	WOPEC Costs
1997	Sx IMP-16 MW PP-140 MW	Sx IMP-16 MW PP-140 MW	Sx IMP-16 MW PP-140 MW	Sx IMP-16 MW PP-140 MW	Sx IMP-16 MW PP-140 MW	Sx IMP-16 MW PP-140 MW	Sx IMP-16 MW PP-140 MW	Sx IMP-16 MW PP-140 MW	Sx IMP-16 MW PP-140 MW	Sx IMP-16 MW PP-140 MW
1998	PP-80 MW CIPS PP-150 MW	PP-80 MW CIPS PP-150 MW	PP-80 MW CIPS PP-150 MW	PP-80 MW CIPS PP-150 MW	PP-80 MW CIPS PP-150 MW	PP-80 MW CIPS PP-150 MW	PP-80 MW CIPS PP-150 MW	PP-80 MW CIPS PP-150 MW	PP-80 MW CIPS PP-150 MW	PP-80 MW CIPS PP-150 MW
1999	2-KGR-7 MW TS IMP-80 MW PP-80 MW	2-KGR-7 MW TS IMP-80 MW PP-80 MW	2-KGR-7 MW TS IMP-80 MW PP-80 MW	2-KGR-7 MW TS IMP-80 MW PP-80 MW	2-KGR-7 MW TS IMP-80 MW PP-80 MW	2-KGR-7 MW TS IMP-80 MW PP-80 MW	2-KGR-7 MW TS IMP-80 MW PP-80 MW	2-KGR-7 MW TS IMP-80 MW PP-80 MW	2-KGR-7 MW TS IMP-80 MW PP-80 MW	2-KGR-7 MW TS IMP-80 MW PP-80 MW
2000	PP-100	PP-100	PP-100	PP-100	PP-100	PP-100	PP-100	PP-100	PP-100	PP-100
2001	PP-190 MW	PP-190 MW	PP-190 MW	PP-190 MW	PP-190 MW	PP-190 MW	PP-190 MW	PP-190 MW	PP-190 MW	PP-190 MW
2002	Extend AP&L 6-KGR-8 MW 2 CC-300 MW	Extend AP&L 6-KGR-8 MW 2 CC-300 MW	Extend AP&L 6-KGR-8 MW 2 CC-300 MW	Extend AP&L 6-KGR-8 MW 2 CC-300 MW	Extend AP&L 6-KGR-8 MW 2 CC-300 MW	Extend AP&L 6-KGR-8 MW 2 CC-300 MW	Extend AP&L 6-KGR-8 MW 2 CC-300 MW	Extend AP&L 6-KGR-8 MW 2 CC-300 MW	Extend AP&L 6-KGR-8 MW 2 CC-300 MW	Extend AP&L 6-KGR-8 MW 4 CT-520 MW
2003										1 CT-130 MW
2004	1 CT-130 MW	1 CT-130 MW	1 CT-130 MW	1 CT-130 MW	1 CT-130 MW	1 CT-130 MW	1 CT-130 MW	1 CT-130 MW	1 CT-130 MW	
2005	1 CC- 300 MW	1 CC- 300 MW	1 CC- 300 MW	1 CC- 300 MW	1 CC- 300 MW	1 CC- 300 MW	1 CC- 300 MW	1 CC- 300 MW	1 CC- 300 MW	1 CC- 300 MW
2006										1 CT-130 MW
2007	1 CC- 300 MW	1 CC- 300 MW	1 CC- 300 MW	1 CT-130 MW	1 CC- 300 MW	1 CC- 300 MW	1 CC- 300 MW	1 CC- 300 MW	1 CT-130 MW	
2008				1 CC -300 MW					1 CC- 300 MW	1 CC- 300 MW
2009	1 CC -300 MW	1 CC -300 MW	1 CC -300 MW		1 CC -300 MW	1 CC -300 MW	1 CC -300 MW	1 CC -300 MW		1 CT-130 MW
2010			Extra Joppa	1 CC -300 MW					1 CT-130 MW	1 CT-130 MW Extra Joppa
2011						Extra Joppa			1 CT-130 MW	
2012	1 CT-130 MW	1 CT-130 MW	1 CC-300 MW		1 CT-130 MW	1 CT-130 MW	1 CC- 300 MW	1 CT-130 MW		1 CT-130 MW
2013	1 CT-130 MW	1 CT-130 MW		1 CT-130 MW	1 CT-130 MW	1 CT-130 MW		1 CT-130 MW	1 CT-130 MW	1 CT-130 MW
2014	Extra Joppa	Extra Joppa			Extra Joppa			Extra Joppa	Extra Joppa 1 CT-130 MW	
2015	1 CT-130 MW	1 CT-130 MW	1 CT-130 MW	1 CT-130 MW	1 CT-130 MW	1 CT-130 MW	1 CT-130 MW	1 CT-130 MW		1 CT-130 MW
CT (MW)	520	520	260	520	520	520	260	520	780	1430
CC (MW)	1500	1500	1800	1500	1500	1500	1800	1500	1200	600
Upgrades (MW)	111	111	111	111	111	111	111	111	111	111
Total - Supply (MW)	2131	2131	2171	2131	2131	2131	2171	2131	2091	2141
DSM (MW)	0	0	0	0	0	0	0	0	0	0
Total (MW) - 2014	2131	2131	2171	2131	2131	2131	2171	2131	2091	2141

SX IMP	Sioux 16 MW Improvement
PP	One Year Power Purchase
2 KGR	2 Keokuk Generator Rewinds 6.8 MW Capacity Equivalence
6 KGR	6 Keokuk Generator Rewinds 8.3 MW Capacity Equivalence
CIPS PP	150 MW Purchase from CIPS 1998-2005
Extend AP&L	Extend The Present Purchase Contract With AP&L From 2002 to 2008
CC	Combined Cycle-300 MW
CT	CombustionTurbine-130 MW
TS IMP	Taum Sauk Runner Replacement - 80 MW
DSM	Demand-Side Management Capacity Equivalence
Extra Joppa	Increased Utilization Of Joppa Energy

Summary of the Risk Analysis

Based on the results of the sensitivity analysis performed with EGEAS, environmental regulations appears to be the key uncertainty which can impact the preferred resource plan. By its very nature, load forecast uncertainty could have the effect of significantly changing the timing of the preferred resource plan. In addition, due to the selection of gas fueled technologies as the primary resource options in the post 2000 period, fuel cost was included as an additional uncertainty to consider.

The major resource decisions faced by the Company appear to be whether to include DSM in the resource plan and what supply-side resources to select in the early and late 2000's time period, combustion turbines (CT) or combined cycle (CC) units.

An analysis was performed for an expansion with and without the set of DSM programs which had been determined to be cost effective. For each of these DSM alternatives, five supply-side expansion strategies were considered, an all CT expansion, an all CC expansion, a mixture of both CT and CC units, an expansion of CC units in the early 2000's followed by CT units in the late 2000's, and finally an expansion of CT units in the early 2000's followed by CC units in the late 2000's. These ten strategies were all evaluated under the uncertainty of environmental regulations, load forecast and fuel cost.

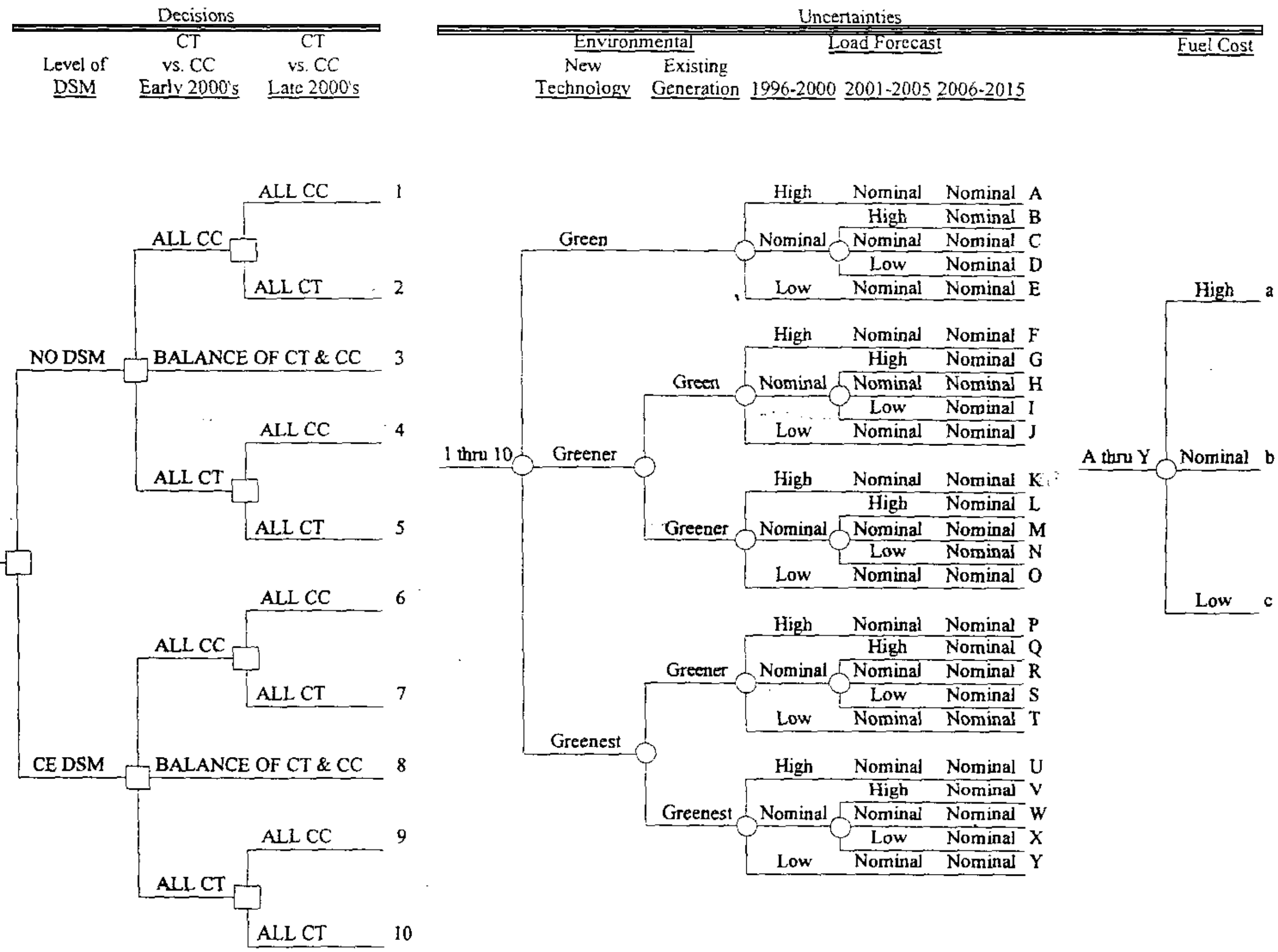
On the basis of expected values, the analysis indicates that the expansion plans which included DSM and CC units are preferred when PVRR was used as the evaluation criteria. When levelized rates was used, the expansion plans without DSM and with CC units are preferred. DSM programs offer a reduction in PVRR of approximately $80-$100 million but at a rate premium of 0.004-0.007 cents/kWh.

In addition to these expected value results, risk profiles, histograms, calculations of means and standard deviations were prepared for the various decisions described above. All of these methods are ways to describe the riskiness of the various decisions. An examination of all these results support the expected value results. The riskiest strategy is one which does not include DSM and relies on CT units exclusively during the early 2000's or over the entire planning period. Including DSM improves the economics somewhat, but it is still riskier than other resource strategies.

The following pages contain the supporting tables and figures for the discussion contained in the preceeding paragraphs.

Figure X-X

Risk Analysis Decision Tree



Probability Distributions of Uncertain Factors

	High	Nominal	Low
Forecasted Peak Growth Rate	1.8%	1.0%	0.0%
Probability	15%	70%	15%
Environmental	Green	Greener	Greenest
Prob - New Tech	10%	80%	10%
Prob - Existing Gen	80%	15%	5%
Fuel Cost	--	--	--
Probability	25%	50%	25%

750 Endpoints

Expected Value Results

Strategy	Levelized System Rate (Levelized ¢/kWh)	Utility Cost (30 Yr PVRR - $ in Millions)	Total Resource Cost (30 Yr PVRR - $ in Millions)
W No DSM Programs			
All CC Expansion	6.975	26,081.56	26,081.56
All CC thru 2008; All CT after 2008	6.973	26,073.05	26,073.05
Balanced- Alternating CT and CC additions	6.973	26,071.70	26,071.70
All CT thru 2007; All CC after 2007	6.987	26,124.64	26,124.64
All CT Expansion	7.015	26,232.01	26,232.01
W 10 DSM Programs			
All CC Expansion	6.980	25,983.10	25,996.66
All CC thru 2008; All CT after 2008	6.980	25,984.85	25,998.41
Balanced- Alternating CT and CC additions	6.979	25,977.75	25,991.31
All CT thru 2007; All CC after 2007	6.991	26,024.02	26,037.58
All CT Expansion	7.019	26,127.40	26,140.97
DIFFERENCE FROM LOWEST COST PLAN:			
W No DSM Programs			
All CC Expansion	0.002	103.81	90.25
All CC thru 2008; All CT after 2008	0	95.30	81.74
Balanced- Alternating CT and CC additions	0	93.95	80.39
All CT thru 2007; All CC after 2007	0.014	146.89	133.33
All CT Expansion	0.042	254.26	240.70
W 10 DSM Programs			
All CC Expansion	0.007	5.35	5.35
All CC thru 2008; All CT after 2008	0.007	7.10	7.10
Balanced- Alternating CT and CC additions	0.006	0	0
All CT thru 2007; All CC after 2007	0.018	46.27	46.27
All CT Expansion	0.046	149.65	149.66

Expected Value of Perfect Information (EVPI)

Evaluation Criteria: Levelized Average System Rates — Expected Value: 6.973 ¢/kWh

Uncertainty	EVPI ¢/kWh
Future Environmental Costs	0.003
Load Forecast	0.003
Fuel Cost	0.000

Evaluation Criteria: Utility Cost — Expected Value: $25,977.75 Mil

Uncertainty	EVPI $ Millions
Future Environmental Costs	10.22
Load Forecast	8.14
Fuel Cost	0.18

Evaluation Criteria: Total Resource Cost — Expected Value: $25,991.31 Mil

Uncertainty	EVPI $ Millions
Future Environmental Costs	10.22
Load Forecast	8.14
Fuel Cost	0.18