YUNKER & ASSOCIATES

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RECEIVED
JAN 26 2004

January 26, 2004
VIA HAND DELIVERY

Thomas M. Dorman, Executive Director
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

Re: Case No. 2003-00266, Investigation into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.

Dear Mr. Dorman:

Enclosed please find the original copy of Midwest ISO's Response to Commission Staff's and of its Response to LG&E/KU's Data Requests, which together consist of: three bound volumes of text responses and paper-copy attachments; two copyrighted survey articles, of which only one copy each is provided to the Commission; and three CD-ROM discs, one of which is provided under seal with the original of a Petition for Confidentiality.

Because this filing is voluminous and we are using the after-hours filing box, we will bring additional copies of these materials to the Commission tomorrow. Thank you for your attention to this matter.

Sincerely,

Katherine K. Yunker

Enclosures

Drop Box

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Investigation into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.	Case No. 2003-00266

Responses of
Midwest Independent Transmission System Operator, Inc.
to the LG&E/KU Data Requests

Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") hereby responds to the data requests propounded by Louisville Gas and Electric Company and Kentucky Utilities Company (collectively, "LG&E/KU"). Midwest ISO's response consists of the following materials:

- two bound volumes of text responses and paper-copy attachments; and
- three CD-ROM discs, one of which is provided to the Commission under seal with the original of a petition for confidentiality.

One copy of the CD-ROM titled "Confidential Volume" has been provided to in-house counsel for LG&E/KU because confidential treatment is being sought in accordance with a confidentiality agreement by which Midwest ISO obtained information from LG&E/KU at an earlier stage in these proceedings.

Counsel for Midwest ISO, rather than a witness, are responsible for any objection interposed to a data request. In most instances, in a spirit of cooperation and without waiving the stated objection, a response has nonetheless been provided.

Respectfully submitted,

Katherine K. Yunker
Ben D. Allen
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James C. Holsclaw
MIDWEST INDEPENDENT TRANSMISSION
SYSTEM OPERATOR, INC.
701 City Center Drive
Carmel IN 46032
(317) 249-5769
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By: ______________________
ATTORNEYS FOR MIDWEST ISO

CERTIFICATE OF SERVICE

I hereby certify that on this the 26th day of January, 2004, a copy of the foregoing Response to LG&E/KU Data Requests was served by sending the materials of the Response as indicated via U.P.S. for overnight delivery to:

Michael S. Beer
Linda S. Portasik
LG&E Energy Corp.
220 West Main St.
P.O. Box 32030
Louisville, KY 40232-2030

Michael L. Kurtz
Boehm, Kurtz & Lowry
Suite 2110 CBLD Building
36 East Seventh Street
Cincinnati, OH 45202

Elizabeth E. Blackford
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1024 Capital Center Drive; Suite 200
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Kendrick R. Riggs
Ogden, Newell & Welch, PLLC
1700 Citizens Plaza
500 West Jefferson Street
Louisville, KY 40202

____
ATTORNEY FOR MIDWEST ISO

RECEIVED

JAN 2 6 2004

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Investigation into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.	Case No. 2003-00266

Responses of
Midwest Independent Transmission System Operator, Inc.
to the Commission Staff's Data Requests

Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") hereby responds to the data requests propounded in the Commission's Order dated January 12, 2004. Please note that the Commission Staff's Data Requests have two data requests numbered "2" and "3." The responses to the second data requests numbered "2" and "3," found on page three of the Staff's Data Requests, have been renumbered as Midwest ISO response numbers 15 and 16. Midwest ISO's response consists of the following materials:

- one bound volume of text responses and paper-copy attachments;
- two copyrighted survey articles, of which only one copy each is provided to the Commission; and
- three CD-ROM discs, one of which is provided under seal with the original of a Petition for Confidential Treatment.

Information responsive to Staff Data Request 8 is provided in electronic format. Due to the voluminous nature of these files, even after compression, the folder containing the non-confidential materials begins on the disc titled "Public Vol. I" and continues to the disc titled "Public Vol. II." (Two copies of these public CD-ROMs are provided to the Commission.) In addition, other information responsive to Staff Data Request is provided on the CD-ROM titled "Confidential Volume" or in response to other, more specific, requests for information by the Staff or LG&E/KU.

Counsel for Midwest ISO rather than a witness, are responsible for any objection interposed to a data request. In most instances, in a spirit of cooperation and without waiving the stated objection, a response has nonetheless been provided.

Respectfully submitted,

Katherine K. Yunker
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By: Katherine K. Yunker

ATTORNEYS FOR MIDWEST TRANSMISSION SYSTEM OPERATOR, INC.

CERTIFICATE OF SERVICE

I hereby certify that on this the 26th day of January, 2004, a copy of the foregoing Response to Commission Staff's Data Requests was served by sending the materials of the Response as indicated via U.P.S. for overnight delivery to:

Michael S. Beer
Linda S. Portasik
LG&E ENERGY CORP.
220 West Main St.
P.O. Box 32030
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Michael L. Kurtz
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January 27, 2004
VIA HAND DELIVERY

JAN 26 2004

Thomas M. Dorman, Executive Director
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

Re: Case No. 2003-00266, Investigation into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.

Dear Mr. Dorman:

Enclosed please find ten (10) copies of a Petition for Confidentiality and seven (7) copies of the bound volumes of the Responses to Commission Staff's Data Requests and to LG&E/KU's Data Requests, to be filed in the above-referenced proceeding on behalf of Midwest Independent Transmission System Operator, Inc. Also enclosed are an additional set of the CD-ROM discs containing the publicly-filed electronic documents provided as part of the Responses. Originals of the Responses and of the Petition for Confidentiality, together with other materials relating to the Responses, were submitted to the Commission last night by leaving them in the after-hours filing box.

Thank you for your assistance in this matter.

Sincerely,

Katherine K. Yunker

Katherine K. Yunker

Enclosures

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Investigation into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.	Case No. 2003-00266

PETITION FOR CONFIDENTIALITY

Pursuant to 807 KAR 5:001 § 7, Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") hereby petitions the Public Service Commission for an Order granting confidential treatment and protection from public disclosure certain information provided by the Midwest ISO in response to Data Requests 37 and 43 of Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") in the above-captioned proceeding. The Midwest ISO also petitions for confidential treatment of certain information provided in response to Data Request 8 of the Commission Staff. Specifically, the Midwest ISO requests confidential treatment of the electronic files contained on the CD-ROM disc titled "Confidential Volume." The information contained on this disc includes data derived from information provided to it by LG&E/KU under a confidentiality agreement. A copy of the "Confidential Volume" CD-ROM is hereby filed with the Commission under seal for the purposes of this petition.

In support of its request for confidential treatment, the Midwest ISO states as follows:

1. The information contained in the disc titled "Confidential Volume" is classified as confidential by the Kentucky Open Records Act, which excludes information of this type from the application of its disclosure mandates. KRS 61.878.

2. This information is (a) confidentially disclosed to the Commission or required by the Commission to be disclosed to it and (b) is generally recognized as confidential or proprietary. KRS 61.878(1)(c).

3. Open disclosure of this information would deny protection to information for which the Commission has previously granted confidential status. In addition, open disclosure would be contrary to the express confidentiality agreement between the Midwest ISO and LG&E/KU.

4. No public interest would be served by denying confidential treatment to these Data Request responses, and preservation of the confidential character of that information is claimed by LG&E/KU to be needed to prevent is competitors from gaining an unfair commercial advantage.

WHEREFORE, Midwest ISO requests an Order of the Commission granting confidential treatment to the material provided.

Respectfully submitted,

Katherine K. Yunker
Benjamin D. Allen
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BY: ______________________
ATTORNEYS FOR MIDWEST INDEPENDENT
TRANSMISSION SYSTEM OPERATOR, INC.

CERTIFICATE OF FILING AND SERVICE

I hereby certify that on this the 26th day of January, 2004, a copy of this Petition was served by sending it via U.P.S. for overnight delivery to:

Michael S. Beer
Linda S. Portasik
LG&E ENERGY CORP.
220 West Main St.
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Louisville, KY 40232-2030

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ATTORNEY FOR MIDWEST INDEPENDENT
TRANSMISSION SYSTEM OPERATOR, INC.

Attachment to LGE/KU #15(a)
Witness: Falk
Page 35

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COSTS OF SERVICE DISRUPTIONS TO ELECTRICITY CONSUMERS†

CHI-KEUNG WOO§ and ROGER L. PUPP‖,‡

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(Received 30 July 1991)

Abstract - After reviewing 16 recent studies, we (i) identify the general approaches used to estimate customer outage costs, (ii) ascertain the relative merits of each approach, and (iii) determine the extent to which existing studies can provide accurate and meaningful estimates. We present cost estimates on a common denominator, explain variations in the results, and suggest areas for future research.

1. INTRODUCTION

Electricity, unlike other forms of energy such as gas, oil or coal, cannot be economically stored, but rather must be provided on demand. Consequently, a major concern of all electric utilities is the level of reliability at which they can supply energy. Reliability is defined as the ability to deliver uninterrupted service on demand, to whatever degree required.¶ Common engineering service reliability criteria are one-day-in-ten-years loss-of-load-probability, expected unserved energy, and reserve margins. A discussion of each is presented in Refs. 1-4. An electric utility traditionally chooses a particular level of service reliability by using probabilistic and deterministic standards and judgements based on experience. For instance, a utility may design their generating system to maintain adequate generation reserve margin to provide an acceptable level of service reliability. Similarly, the design of a transmission and distribution (T&D) network may rely on redundancy to satisfy reliability standards determined by historical practice.[5-7] Customer preferences for service reliability are typically not considered in these types of planning decisions. As a result, the cost and level of service reliability supplied by a utility may differ from what customers want and for what they are willing to pay. If so, the reliability level provided is not economically efficient for either the utility or the customer.

Most electric utilities have also traditionally ignored customer reliability preferences in product development. For example, a retail customer class is typically offered a standard service whose price does not necessarily closely correspond with customer value of service reliability.[8] As a result, customers who are willing to pay for premium uninterruptible service or are willing to accept a bill discount for interruptible service have not been given the opportunity to choose between these two. This is in sharp contrast to the

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† This paper is a highly condensed version of several reports sponsored by Niagara Mohawk Power Corporation (NMPC) during 1987-1990. The paper also benefits from the research partially funded during 1985-1988 by Pacific Gas and Electric Company (PG&E) and Economic Models of Israel (EML). However, the paper does not reflect the views of CPHK, AG, NMPC, PG&E and EML. Many individuals have contributed to our past research on the subject. In particular, we thank A. Adriance, D. Aigner, R. Billinton, H.P. Chao, M. Doane, T. Flaim, R. Hartman, D. Keane, R. Mango, G. McClelland, M. Munasinghe, B. Neenan, W. Schulze, D. Spulber, and G. Wacker. Without implications, all errors are ours. After completing the paper, we became aware of a recently published survey by D.W. Caves, J.A. Herriges and R.J. Windle (Ref. 21). There are substantial differences between their paper and ours. The two papers are complementary and should be read together to obtain a complete view of the subject.

‡ Author to whom all correspondence should be addressed.

¶ Reliability is distinct from service quality in that the latter refers to the provision of electricity within acceptable frequency and voltage ranges.

airlines and long-distance telecommunications industries, which offer a full spectrum of differentiated services from which customers can select options that best match their needs.†

Due to both customer dissatisfaction with utility electricity service and the financial risks of major plant additions, some electric utilities have recently begun to explore alternative methods to plan and price electricity supply. The result of this exploration is an increasing popularity of economic reliability planning and efficient pricing principles. To wit, (i) a reliability improvement should be undertaken if its benefits exceed its costs,[2-5,8,9,13,17] and (ii) the cost of an improvement should be reflected in the rate design.[2,8,9,11,13,18] Customer outage costs are an essential input for implementing these two important principles. We provide three notable examples. The first is from generation planning and marginal cost pricing. The benefit of new generation capacity is a decrease in expected customer outage costs. The reliability improvement obtained with additional capacity is economically efficient if the benefits of increased reliability exceed the costs of installing new capacity. Setting efficient electricity rates requires the change in expected customer outage costs and the capacity costs to be included in the rate design. Under a flat rate design, for example, the efficient price is the sum of the expected marginal fuel cost and the expected marginal outage cost. Under the economic reliability planning principle, the expected marginal outage cost at the long run equilibrium equals the marginal capacity cost.[2,8,13]

Our second example is the design of interruptible and curtailable (I/C) service. Offering I/C service at reduced rates to customers who have relatively low outage costs helps to both defer capacity expansion and decrease emergency power pool purchases.[9-11,13,16] Our final example is a T&D planning project. Repairing an aging transmission line after each failure may be more cost-effective than replacing the line. Another option may be to install switches to isolate faults so that distribution related outages are reduced. The costs of the switches must be balanced against the benefits to determine whether the reliability improvement is economically efficient. Benefits comprise reduced outage costs and corresponding lower maintenance costs.[5,7]

While the principles of economic planning and efficient pricing are well established, a utility may be unable to apply the principles because customer outage costs in each of the utility's service regions are generally unavailable. By reviewing some recent contributions to the estimation of customer outage costs, we (i) identify the general approaches used, (ii) ascertain the relative merits of each approach, and (iii) determine the extent to which existing studies can provide accurate and meaningful estimates which are transferable across utilities. If the existing estimates of different utilities varied little, a utility that has no information on their customers' outage costs may substitute the outage costs of another utility. Conversely, highly diverse estimates may indicate either a lack of consensus among experts regarding the magnitude of outage costs or a recognition that outage costs vary highly with customer characteristics. If the latter is true, utilities would need to collect outage costs estimates for their customers rather than substituting estimates from another utility.

With these objectives in mind, the remainder of the paper is organized as follows. Because a variety of measures have been used in the literature, we define in Sec. 2 the concept of customer outage costs to eliminate any ambiguities that may arise in the subsequent discussion. In Sec. 3, we identify and evaluate the approaches commonly employed to estimate customer outage costs. In Sec. 4, we present the empirical results in 16 recent studies, a majority of which are based on outage cost survey data.‡ We conclude in Sec. 5 by recapitulating the major findings and suggesting some areas for future research.

2. DEFINITIONS

The value of service reliability represents the maximum amount a customer is willing to pay for the particular level and type of service provided. As such, it reflects the usefulness and/or necessity of electric service to the customer. Although electricity is familiar to most users, the market for its reliability is not well developed. For example, since 1977, Pacific Gas and Electric Company has been offering interruptible and curtailable service options to approximately 1,000 large customers with monthly demand over 1,000 kW. However, less than 10% of these customers subscribed to any of these options.[22] It is difficult to judge consumers' willingness to pay (WTP) for different reliability levels, because there exists a limited amount of data on customer reliability/price choices. Accordingly, the amount customers are willing to pay for service reliability is often approximated by its opportunity costs which equals the value of unsupplied electricity. Thus, customer value of service reliability becomes synonymous with customer outage costs.

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† Various form of reliability differentiation have been proposed in the literature including, (i) priority service in Refs. 9-10, (ii) simple interruptible service in Ref. 11, (iii) demand subscription service in Ref. 12, (iv) self-rationing in Ref. 13, and (v) proportional rationing in Refs. 14-15. However, their implementation is relatively limited as noted in Ref. 16.

‡ For surveys of earlier works, see Refs. 19 and 20. A review of North American studies prior to 1988 is provided in Ref. 21.

Customer outage costs can be collected either *ex post* (i.e. after the fact) or *ex ante* (i.e. before the fact).[23,24] *Ex post* measures represent the economic costs incurred by households or firms when a service disruption occurs with certainty. *Ex ante* measures equal the maximum amount a customer is willing to accept (pay) for an increase (decrease) in the likelihood that an outage will occur in the future. An *ex ante* value of reliability does not depend on the actual realization of an outage. It is sometimes inferred from household purchases of a backup generator or household participation in a load management program.

Outage costs are commensurate with a customer's dependence on electricity during an outage. Outage costs vary significantly depending on the particular attributes of the outage. Attributes known to influence costs include: timing (season and time-of-day), advance notice, frequency, duration and severity. With the exception of severity, the meaning of the remaining attributes is self-evident. Severity is the extent of service disruption characterized by the following: (i) Full Outage - A complete or total loss of service, typically resulting from a distribution-related cause (e.g. storms, car-pole accidents, or vandalism), or transmission failure, rotating blackouts or enforcement of an interruptible service contract as described in Ref. 6; and (ii) Partial Outage - A curtailment of service due to a utility's public appeal for voluntary load reduction, or participating in a load management program targeted to a particular end-use such as air conditioning or water heating.[25]

3. APPROACHES

Description

Using the preceding concepts and definitions, we describe three techniques commonly employed to estimate outage costs. These procedures are the (i) proxy, (ii) market-based and (iii) contingent valuation methods.

Proxy methods use secondary data to measure customer willingness to pay for service reliability. The following are examples of proxies: (i) Average electricity tariff[26,27] - This method is based on the assumption that customers purchase electricity if consumption benefits are greater than costs. As a result, the average electricity tariff measures what customers are willing to pay for the last kWh purchased. (ii) Cost of maintaining backup power[28] - This approach assumes that electricity users act rationally and insure themselves against the damages caused by power failures when it is economic for them to do so. For instance, a firm's acquisition of a backup generator will reflect the marginal value of unsupplied electricity. Outage costs are derived by assuming that a competitive risk-neutral firm maximizes expected profit. At the margin, they equate the expected marginal costs of self-generating a kWh of the unsupplied utility electricity to the expected avoided outage costs due to this self-generated kWh. (iii) Value of foregone leisure/wage rate[7] - This method views the principal cost of a power failure as a loss of leisure. (iv) Value of foregone production (GNP per kWh consumed) - The gross national product (GNP) measures the value of goods and services produced by an economy. Because electricity is an essential input to all economic activities, it is argued that the GNP would be greatly reduced in the absence of electricity. Thus, the ratio of GNP to total electricity consumption may be used as an approximation of the aggregate effect of an outage on an economy.

In contrast to proxy techniques, market-based methods use data from observed customer behavior to infer outage costs. These approaches include (i) consumer surplus methods used in Refs. 29-32 and (ii) analysis of customer choice of I/C rate options as in Ref. 22. The consumer surplus approach estimates outage costs by equating them to the compensating variation. The compensating variation equals the area under customers' compensated demand curves.[33-34] Early applications of this method relied on readily available monthly or yearly aggregate demand function data which were used to approximate either daily or hourly electricity consumption by customers.[29] Hourly and daily consumption was then used to estimate outage costs. In more recent work, outage cost estimates were obtained from consumer surplus losses calculated from a system of time-of-use demand equations.[31]

Also, the market-based approach uses data that utilities have collected from recently introduced I/C rate options for their large commercial and industrial users. These options, and others similar to them, offer a customer a price discount in return for a lower reliability of service.[†] In this approach, it is assumed that customers rationally choose an option which maximizes their expected net benefit of electricity consumption. Each option has both a particular rate discount and level of reliability. An econometric analysis of customer choices will provide a market determined value of service reliability. The data may be used to infer the monetary compensation required for each customer such that they are indifferent between the discount/reliability choice they actually made and alternative choices they could have made. These compensation differentials among the options measure customer WTP for alternative reliability levels. The

---

[†] For example, Pacific Gas and Electric Company rate E-20 for large light and power customers offers discounts for both the demand charge and the energy rate. Participation may result in service curtailment with varying degree of notice.[22]

procedures used to obtain such estimates are outlined in Refs. 25 and 35-38.

The contingent valuation method (CVM) is a third technique which may be used to collect outage costs. In the CVM approach, individuals are asked to reveal in a survey or experimental setting how much they value a hypothetical good which is not priced in the market. For instance, people have been asked "How much would you be willing to pay to clean-up this river?" A thorough description and assessment of this approach is contained in Ref. 39. CVM surveys have been widely used to estimate outage costs differentiated by outage attributes and customer characteristics. Empirical examples of the approach can be found in Ref. 35. Three contingent valuation techniques are discussed below.

The first technique is based on customer surveys of direct costs.[40-42] Customers are asked to identify the actions they would normally take to adjust to an outage. Next, they are asked to provide an estimate of the out-of-pocket and/or inconvenience costs of each action. The total outage cost is estimated as the sum of the individual costs. In the residential sector, the individual actions may include the use of candles for lighting; dining out or visiting friends; buying ice to preserve food; staying at a hotel or motel; or the use of a home generator, etc.[†] In the commercial and industrial sectors, specific costs comprise lost sales or production, spoilage, equipment repair and the expenses of making-up lost sales and production.

The second CVM technique asks customers in a survey to state the maximum amount of money they would be willing to pay (or accept) for an increment (or a decrement) in service reliability. The amount of money individuals are willing to pay (WTP) should approximately equal the amount of money that they are willing to accept (WTA) for a marginal change in service reliability. Willig[33] presents the theory from which this implication is drawn. It is possible that the WTP and the WTA may not by identical due to income effects. If these effects are negligible as assumed in this theory, the difference between WTP and WTA is slight. However, this hypothesis is contradicted by the empirical evidence presented in Refs. 37-38.

The last CVM technique we discuss is the analysis of customer preference data. In a survey, individuals are given a set of hypothetical mutually exclusive service alternatives. Each alternative depicts a different combination of service reliability and price. Individuals are then asked to rank the options by their order of preference or to choose the option that best meets their needs. Marginal rates of substitution and monetary values of willingness to pay can be inferred from these rankings.[25,37,38,40,43]

<u>Evaluation</u>

Here we evaluate the pros and cons of the three approaches. We summarize our findings in Table 1 which provides a synopsis of the relative merits of each method using the following criteria: (i) <u>Data requirement</u> Amount of data necessary for outage cost estimation, (ii) <u>Computational cost</u> Amount of research effort and time required for data analysis, (iii) <u>Verifiability</u> Extent to which the outage cost estimates are supported by observed customer behavior, and (iv) <u>Outage attributes and customer demographics</u> Extent to which the estimates reflect outage cost variations by these determining factors. In Table 1, the symbol + indicates that an approach scores well under a particular criterion while the symbol - indicates the opposite.

Table 1. Relative merits of outage cost estimation techniques.

Criterion	Proxy	Market-Based	Contingent Valuation
Data Requirement	+	-	+/-
Computation Cost	+	-	+/-
Verifiability	-	+/-	?
Outage Attributes	-	-	+
Customer Demographics	-	+	+

The major advantage of the proxy methods is that they are straightforward to apply and require minimal data. Thus, computational costs are relatively inexpensive. However, theoretical deficiencies and/or lack of detail may result in inaccurate outage cost estimates. This limits the usefulness of proxy outage cost estimates in a utility's planning and pricing activities, so that proxy methods score poorly under the remaining three categories. We argue why this is so by providing examples. First, the average electricity tariff proxy fails to quantify the total cost of a complete service disruption, because it only measures the value of the

† In most cases the resulting estimates should be interpreted as an upper bound of customers' willingness to pay. This is because certain actions during the outage provide an associated consumption benefit. For example, dining out in a fine restaurant during an outage has a consumption benefit due to the enjoyment consumers obtain by having someone else cook for them.

marginal kWh lost. If the marginal cost of backup power exceeds the marginal outage cost, a rational firm would not invest in backup power. This implies that the marginal cost of backup power overestimates the marginal outage cost.

Second, the wage proxy inaccurately measures outage costs because labor-leisure tradeoff theory assumes workers can vary their hours of work to equate their wage with the marginal value of their leisure time. This tradeoff may be infeasible due to the traditional 40-hour work week, union restriction on hours worked, or insufficient employment alternatives. It also effectively ignores the cost to nonwage earning family members. Another weakness of this approach is that it is valid only for electricity-dependent leisure activities.

Our third example is the GNP/kWh consumed proxy approach in which the underlying production technology for GNP is assumed to be a fixed coefficient. This assumption is not supported by empirical evidence presented in Ref. 44. Outage costs estimates from any of the three proxy methods can not be verified. In addition, none of these approaches is able to sufficiently estimate differences in outage costs due to outage attributes and customer demographics. In summary, we conclude that the proxy method has three deficiencies and only two advantages. On balance, the disadvantages may result in inaccurate outage cost estimates. This seriously limits their usefulness in a utility's planning and pricing activities.

Next, we discuss the advantages and disadvantages of using each of the two market-based methods (customer choice and consumer surplus) in estimating outage costs. The customer choice approach can generate valid, defensible and verifiable outage cost estimates, because it uses data on actual customer subscriptions to reliability differentiated rates. If data on customer demographics is also available, the effect of these variables on outage costs can be econometrically estimated if computational cost is not of high concern. On the other hand, sufficient data is generally not available to adequately estimate outage costs and the effect of outage attributes on outage costs, so it scores poorly on the data requirement and outage attribute criteria.† Thus, we conclude in Table 1 that this market-based method does not score well under the data requirement, computational cost and outage attribute criteria, but it scores well for the verifiability and demographic criteria.

The market-based consumer surplus approach suffers from a number of theoretical deficiencies making it difficult to verify outage cost estimates. First, considerable care must be taken to ensure that the correct demand curve is identified by which we mean that it corresponds to the period of the loss. In addition, using this approach to estimate outage costs for a momentary outage as in Ref. 31 is generally infeasible, because it requires the estimation of a demand equation for a time period less than a minute.‡

Second, Munasinghe[7] notes that the consumer surplus measure may be inappropriate because an unexpected service disruption is not the same as a reduction of planned consumption caused by a price increase. He argues that actual outage costs may be significantly larger due to the unplanned nature of the outage.¶ Finally, the consumer surplus approach requires an estimate of the price increase that would reduce the quantity demanded to zero. While this price increase is well defined for a linear demand equation,[32] most empirical demand equations are nonlinear. A finite price increase that would completely choke-off such demand may not exist. For example, the required price increase for the popular double-log demand equation is infinite, implying that the resulting consumer surplus loss due to the outage is also infinite.[34]

This approach performs poorly in evaluating the role of frequency and notice attributes on outage costs, because time-of-use data is collected for the purpose of determining how consumption varies with price. On the other hand, the effects of customer demographics and outage attributes such as duration and time-of-day on outage costs may be determined (if sufficient data on hourly loads and prices are available), but it requires extensive computational analysis.[45,46]

The last outage cost estimation approach we discuss is contingent valuation surveys. Depending on a utility's planning and pricing needs, the amount and detail of information collected on a survey can be

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† For example, PG&E's interruptible rate option offers a large rate discount with little difference in actual service reliability.[22] Thus, the data available from this rate option experiment would not be rich enough to predict what customers would choose when confronted with a menu of truly competing service options.

‡ On the other hand, momentary outage costs can be estimated using the CVM approach. The authors of Ref. 40 estimated residential outage costs ranging from $0.18 to $1.88 (1989$) per interruption.

¶ Ongoing research sponsored by NMPC and the Electric Power Research Institute (EPRI) attempts to address this issue using the hourly demand model.[46] Preliminary findings in this report support the hypothesis that actual outage costs due to an unexpected outage are higher than reductions in consumption due to price increases.

adjusted. A utility needing only a moderate amount of information may limit the length of a survey to a few pages and a couple of outage scenarios. Also, to limit computational costs, simple statistical techniques such as crude sample averages may be used to estimate outage costs from survey results. On the other hand, the utility may need much more detail. If so, the survey may contain a great number of demographic questions and collect much information on how outage attributes (such as duration, notice, etc.) affect outage costs. In addition, this more carefully designed survey may also be accompanied by a more thorough statistical analysis of the survey responses.[47-48] For example, survey data often contain up to 60% of zero cost responses, creating an estimation difficulty known as truncation bias. Statistical methods to correct for this bias are presented in Refs. 49-51, but it requires extra computational cost. For these reasons, Table 1 indicates that contingent valuation methods perform well under outage attributes and customer demographics criteria, but not as well under data requirement and computation cost criteria.

Verifiability of outage cost estimates obtained using CVM remains unknown, in particular because the results of CVM applications always show large disparities between reported WTP and WTA responses. In theory, there should be no empirical difference between these responses. However, typical reported WTP values ranges from one-fourth to one-third of reported WTA values. To date, researchers have been unable to definitively explain the persistence of this disparity. Various conjectures include both strategic response bias on the part of the respondent and cognitive dissonance. Coursey et al[52] designed a laboratory experiment to investigate if either of these conjectures can explain this disparity. In this experiment, individuals are given a drop of bitter tasting liquid, and asked both what they would be WTP and WTA to avoid and suffer the experience, respectively. A Vickrey auction mechanism is used to elicit the hypothesized values in the form of individual bids. The authors conclude the following: First, the observed divergences between WTP and WTA may be due to hypothetical bias resulting mainly from the lack of a market-like environment. This finding is consistent with results obtained from the analysis of survey data on customer subscription to hypothetical rate options. Choice sets that include unrealistic reliability levels such as a 1 five-second outage every 5 years vs 30 two-day outages every year tend to yield outage cost estimates that are unrealistically high.[43] More plausible estimates have been obtained when respondents have been confronted with a set of realistic service options as in Keane et al.[25]

Second, hypothetical bias is likely to yield outage costs responses above prices respondents would pay if the service were actually available in a market-like setting, because respondents are not required to purchase the product at the value they assign it. Third, WTP measures of value may correspond more closely to the true value than do WTA measures. Finally, extreme risk aversion in the form of a strong preference for the status-quo may also account for the disparity between WTA and WTP.† As shown in Refs. 37-38, this bias has important implications in estimating the value of service reliability, especially for those utilities interested in offering reliability-differentiated rates. The bias suggests that customers attach a strong premium to the current service level and are unwilling to select a non-firm service option unless the price discounts are sufficiently large to overcome the psychological barrier to participation. However, it is important to note that Cummings et al[39] document eight studies in which both CVM and actual market data were used to value the same commodity and each gave similar results. While outage cost estimates in the CVM approach are not directly verifiable at this time, this study indicates that these results are very reasonable.

4. SUMMARY OF PRIOR RESULTS

This section summarizes 16 recent studies on customer outage cost estimation. We choose these studies to (i) review the state-of-art approaches, (ii) demonstrate the differences in approaches and results by including some contributions not reviewed in prior survey articles,[19-21] and (iii) address the specific features of both the residential and nonresidential customer classes.‡ Due to dissimilar measurement concepts, and outage attributes and customer demographics in the databases used in various studies, the outage cost estimates are diverse. In our summary, we attempt to reconcile differences among estimates.

Residential Sector

Table 2 lists the features and the empirical results of eight residential studies; 3 and 5 studies use *ex*

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† See Ref. 53 for a discussion on the kinked value function which implies extreme risk aversion due to status-quo bias.

‡ We have not discussed Refs. 37-38 in our review because the primary emphasis of these two papers is on investigating consumer rationality. Also, the numerical results in these papers are identical to those in Refs. 36 and 40. We have also excluded Ref. 54 because the authors use an input-output table to analyze the aggregate outage cost for the Egyptian economy. Because their study focuses on the macroeconomic impact of a capacity shortage rather than microeconomic effects, it is beyond the scope of our paper.

Table 2. Estimates of the value of service reliability and outage costs in the residential sector in 1989 U.S. $.

Study/Country	Method/ Cost Type	Season/ Time-of-Day	Frequency	Duration (Hours)	Notice (Hours)	Dollars Per Interruption	Dollars Per Hour Unserved	Dollars Per kWh Unserved
						Bill Increase /k		
Doane, Hartman, and Woo (1988)/ California, USA	Customer Survey/ Ex Ante	Not Studied	2	1	0	45.02/g	11.25/h	16.11/i
						Bill Decrease /l		
			5	2	0	12.82	6.41	9.18
			5	4	0	45.02	6.43	4.61
			15	2	0	12.82	6.41	9.18
			15	4	0	16.18	4.04	5.79
						Bill Decrease /m		
Keane, MacDonald, and Woo (1988)/ California, USA	Customer Survey/ Ex Ante	Summer/ Afternoon	1	4	0	18.43	4.61	1.84
						Willingness-to-Pay /n		
Doane et al. (1990)/ New York, U.S.A.	Customer Survey/ Ex Post	Summer/ 8 a.m.	Not Studied	1	0	4.43	4.43	5.40
				4	0	6.4	1.6	1.89
				8	0	9.99	1.25	1.50
		Summer/ 2 p.m.	Not Studied	1	0	3.55	3.55	4.38
				4	0	4.88	1.22	1.48
				8	0	7.33	0.92	0.97
				1	1	3.55	3.55	4.38
				4	1	4.88	1.22	1.46
				1	4	3.55	3.56	4.38
				4	4	4.88	1.22	1.48
		Summer/ 6 p.m.	Not Studied	1	0	3.87	3.87	3.72
				4	0	5.35	1.34	1.28
		Winter/ 8 a.m.	Not Studied	1	0	6.71	6.71	7.14
				4	0	8.96	2.24	2.30
				8	0	13.38	1.67	1.73
		Winter/ 2 p.m.	Not Studied	1	0	6.11	6.11	6.57
				4	0	8.05	2.01	2.07
				8	0	12.06	1.51	1.38
		Winter/ 6 p.m.	Not Studied	1	0	7.30	7.30	6.08
				4	0	9.75	2.44	2.01
				1	1	7.13	7.13	5.94
				1	4	6.60	6.60	5.50
				4	1	9.50	2.38	1.96
				4	4	8.71	2.18	1.80

Notes:

a/ Based on the costs of the actions taken to mitigate the affect of an outage. Actions examined include the purchase and use of candles, an emergency lantern, and/or an emergency stove; purchase or rental of a small or large backup generator.

b/ N.A. = Not Available

c/ Based on the costs of the actions taken to mitigate the affect of an outage. Actions examined include using candles, flashlights, a propane gas stove or grill, a kerosene heater or wood stove, and/or a battery-operated radio; going out to eat, shop, visit friends; staying home and doing activities which do not require electricity; using a home generator.

d/ A partial outage resulting from a customer's voluntary response to the utility's public appeal 4 - 6 hours before a capacity shortage.

e/ The amount a customer is willing to pay for the service of a backup generator.

f/ Amount of annual bill increase that a customer is willing to pay to move from the current reliability level of two one-hour winter outage per year to a lower reliability level.

g/ The change in the annual bill divided by a change in frequency relative to the current reliability level.

h/ The change in the annual bill divided by a change in hours unserved relative to the current reliability level.

i/ The change in the annual bill divided by a change in kWh unserved relative to the current reliability level.

j/ Amount of annual bill decrease that a customer is willing to accept to move from the current reliability level of two one-hour winter outages per year to a lower reliability level.

k/ Amount of annual bill increase that a customer is willing to pay to move from the current reliability level of three 2-hour outages per year to a higher reliability level.

l/ The amount of annual bill decrease that a customer is willing to accept to move from the current reliability of three 2-hour outages per year to a lower reliability level.

m/ Amount of annual bill decrease that a customer is willing to accept to tolerate the loss of air-conditioning due to voluntary participation in a program.

n/ What is the most you would be willing to pay as a lump sum increase in your annual electricity bill to prevent this outage from occurring?

Table 2. Estimates of the value of service reliability and outage costs in the residential sector in 1989 U.S. $.

Study/Country	Method/ Cost Type	Season/ Time-of-Day	Frequency	Duration (Hours)	Notice (Hours)	Dollars Per Interruption	Dollars Per Hour Unserved	Dollars Per kWh Unserved
Munasinghe (1980)/ Cascavel, Brazil	Proxy-Wage Rate/ Ex Post	Not Studied/ Evening	Not Studied	1	0	3.06	3.06	1.73–2.66
Sanghvi (1983)/ Wisconsin, USA	Consumer Surplus/ Ex Post	Summer/ 12 noon	Not Studied	1	0	0.37	0.37	0.17
				2	0	0.75	0.37	0.18
				4	0	1.64	0.41	0.21
				12	0	19.27	1.60	0.77
		Summer/ 8 a.m.	Not Studied	1	0	0.37	0.37	0.23
				2	0	0.77	0.38	0.24
				4	0	1.84	0.46	0.28
				8	0	5.45	0.68	0.40
		Summer/ 4 p.m.	Not Studied	1	0	0.78	0.78	0.31
				2	0	2.05	1.03	0.32
				4	0	4.54	1.14	0.38
				8	0	7.27	0.90	0.37
Wacker, Wojczynski, and Billinton (1983)/ Canada	Customer Survey/ Ex Post	Winter/ Evening				Direct Costs /a		
			Monthly	1	0	1.46	1.46	N.A. /b
			Monthly	4	0	14.69	3.67	N.A.
			Weekly	4	0	22.72	5.68	N.A.
						Willingness-to-Pay		
			Monthly	4	0	6.55	1.64	N.A.
			Weekly	4	0	9.97	2.49	N.A.
			Daily	1	0	9.98	9.98	N.A.
						Willingness-to-Accept		
			Monthly	4	0	13.62	3.40	N.A.
Doane, Hartman, and Woo (1988)/ California, U.S.A.	Customer Survey/ Ex Post					Direct Costs /c		
		Winter/ Evening	Not Studied	1	0	12.15	12.15	16.19
				4	0	22.5	5.63	6.08
		Winter/ Morning	Not Studied	4	0	13.65	3.41	4.33
				12	0	45.82	3.82	4.67
		Summer/ Afternoon	Not Studied	1	0	4.14	4.14	5.51
				4	0	15.36	3.56	4.80
				12	0	42.97	3.58	4.29
				1	1	3.15	3.15	4.20
				5 /d	0	2.86	0.58	N.A.
		Any-Time	Not Studied	Momentary		1.88	N.A.	N.A.
						Willingness-to-Pay /e		
		Winter/ Evening	Not Studied	1	0	3.33	3.33	4.44
				4	0	5.40	1.36	1.46
		Winter/ Morning	Not Studied	4	0	3.38	0.85	1.07
				12	0	10.21	0.85	1.04
		Summer/ Afternoon	Not Studied	1	0	1.85	1.85	2.46
				4	0	4.07	1.02	1.28
				12	0	9.83	0.82	0.98
				1	1	1.11	1.11	1.47
		Any-Time	Not Studied	Momentary		0.18	N.A.	N.A.
Goett, McFadden, and Woo (1988)/ California, USA	Customer Survey/ Ex Ante	Winter/ Morning				Bill Increase /f		
			1	1	0	21.36 /g	21.36 /h	27.14 /i
						Bill Decrease /j		
			1	4	0	94.42	47.21	59.95
			2	4	0	N.A.	19.30	24.50
			4	1	0	21.36	21.36	27.14
			4	4	0	79.26	5.66	7.20

ante and *ex post* costs, respectively.† *Ex post* costs are approximated by using a wage rate proxy, consumer surplus and CVM. Munasinghe[55] uses a wage rate proxy and verifies its accuracy by comparing outage cost estimates obtained from it with the outage costs estimates acquired from a personal interview with 27 households. Sanghvi[31] adopts a consumer surplus approach in which a system of 24 hourly electricity demand equations is estimated using data from a time-of-use experiment. The area under the demand curve approximates the consumer surplus of electricity service. Doane et al,[40] Doane et al[47] and Wacker et al[56] estimate outage costs with household contingent valuation survey responses on both direct costs and WTP.

These authors employ different statistical techniques to estimates outage costs. Wacker et al[56] use descriptive statistics to summarize the survey results. A limited dependent variable regression model based on Heckman[51] is used by Doane et al[47] to quantify the effects of outage attributes and customer demographics on outage costs. These authors also correct for bias introduced by protest bids. A protest bid is a zero WTP answer from a respondent who is unwilling to pay for a reliability improvement for non-economic reasons. These reasons include the following: (i) "The utility should provide reliable service." (ii) "Even if I pay, the utility cannot eliminate outages anyway." In addition, these authors remove observations with a studentized residual over 3.5 from their analysis. Such observations are called outliers; they tend to be observations with huge reported outage costs. The outlier classification technique is explained in Belsley et al.[57]

Goett et al,[43] Keane et al[25] and Doane et al[36] use *ex ante* data obtained from contingent valuation surveys. Outage costs are inferred by analyzing the choices made by households among alternative reliability options each characterized by both a different bill discount and outage attributes such as expected frequency and duration.

Outage costs expressed as dollars per interruption are available for all studies in Table 2. In addition, outage costs for all non-momentary outages are stated in dollars per hour unserved. It would be ideal if all cost estimates could be normalized to dollars per kWh unserved to facilitate comparisons among results. However, less than half of the studies provide these normalized cost estimates, presumably due to the lack of data on energy unserved during an outage.

Obtaining dollar per kWh unserved by normalization of the cost per interruption is an important issue in presenting and using outage cost estimates. For instance, these estimates are used for system reliability planning. A unbiased estimate of dollar per kWh unserved equals the population estimate of the cost per interruption divided by the population estimate of the expected unserved energy per interruption.[58] To the extent that the cost per interruption is relatively stable for small changes in reliability, the economic benefit of a reliability improvement equals the product of the dollar per kWh unserved and the change in the population estimate of expected unserved energy.[3-5,7] Estimates of dollar per kWh unserved presented in Table 2 and later in Tables 3 and 4 are computed as above.‡

The per interruption cost estimates in Table 2 ranges from $0.18 to $94. After normalizing the per interruption costs by dividing by the duration of the outage, variations in the dollars per hour unserved estimates remain substantial. They range from $0.37 to $47 per hour unserved. Furthermore, normalizing dollars per interruption by kWh unserved indicates that cost differences cannot be adequately explained by energy unserved. For example, based on a survey of households' direct costs, Doane et al[40] finds the cost of a 4-hour outage is approximately $4 to $6 per kWh unserved, three to four times higher than WTP estimates obtained in the same survey. The *ex post* direct cost estimate for a 4-hour summer afternoon outage is approximately $4.8 per kWh unserved, three times the *ex ante* cost estimate of $1.84 per kWh unserved reported in Keane et al[25] for a partial load curtailment. Moreover, these estimates are substantially larger than the full outage cost estimate of $0.37 per kWh unserved in Sanghvi[31] for a summer afternoon outage of the

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† The estimates for countries outside the U.S. are first converted to U.S.$ using exchange rates published in the Statistical Abstract of the U.S. (1986). All estimates are then adjusted for inflation using the annual Consumer Price Index (CPI) available from the Monthly Labor Review (November 1990) published by the U.S. Bureau of Labor Statistics.

‡ For reliability pricing purposes, the cost per interruption is not meaningful since reliability differentiation requires information on the distribution of the individual per unit outage cost $y_i = c_i/e_i$; where c_i = estimate of cost per interruption for Customer i; and e_i = estimate of expected unserved energy per interruption for Customer i. Suppose the rate discount for a simple interruptible service is d ($/kwh). Customer i who is assumed to be risk neutral will select the interruptible service if his/her expected per unit cost of electricity consumption $[(1 - p)(z - d) + p(c_i - z - d)] < z$; where p = probability of service interruption; z = energy rate for firm service; and (z - d) = energy rate for interruptible service. If c_j is the per unit cost of the "marginal customer" who is indifferent between the two services, the participation rate in the interruptible service program is $F(c \le c_j)$ where F(c) is the cumulative distribution function of $c > 0$.[11] For a similar discussion on this point, see Ref. 21.

same duration. Below we discuss the factors that cause this diversity of results.

The consumer surplus approach adopted by Sanghvi[31] results in the lowest *ex post* cost estimates of $0.18 to $0.77 per kWh unserved which likely underestimate the *ex post* cost of an outage.† The *ex post* cost estimates derived from the WTP survey responses are the next lowest. Wacker et al[56] report that the average rate increase acceptable to a Canadian household to avoid a monthly 4-hour winter evening outage is approximately $6.6 per interruption, corroborating the WTP estimate of $5.4 in Doane et al.[40] The corresponding dollars per hour unserved estimates are between $1.36 to $1.64, which are approximately 50% of the Brazilian wage rate proxy in Ref. 7. It was found in Doane et al[40] that the *ex post* cost estimates derived from direct costs are $12 to $15 per interruption for a 4-hour morning outage. These estimates, however, are almost three times higher than the WTP estimates from the same surveys and two times those in Doane et al.[48] This difference is expected since the contingent valuation literature suggests that the compensation measurement of value typically exceeds the WTP value.[59]

Finally, *ex ante* measures of the value of service in Table 2 are generally higher than the *ex post* cost estimates. The estimates in Goett et al[43] are the highest. For example, the cost for a 1-hour winter morning outage is close to $21 per hour unserved. The authors of three studies[36,47,48] show that this outcome can be partially explained by status-quo bias. The *ex ante* value of a partial load curtailment is reported in Keane et al[25] to be $4.5 per hour unserved. After normalizing it by expected unserved energy, the estimate is $1.84 per kWh unserved.

Winter outages impose higher costs on households than summer outages. Early evening outages are most costly followed by afternoon and morning outages. While an increase in outage frequency or duration raises the cost per interruption, the effect on the cost per hour unserved is unclear.‡ Advance warning may reduce costs substantially, up to 40%. For example, the summer afternoon 1-hour direct cost estimate in Doane et al[36] reduces from $5.51 to $4.29 per interruption when advance notice is provided. Also, advance notice decreases the WTP estimate from $1.85 to $1.11 per interruption. On the other hand, Doane et al[47] find little effect of advance notice on outage costs.

Momentary outages impose some small costs on households ranging from $0.18 to $1.88 per interruption. As expected, the *ex ante* costs per hour unserved for total service disruption are generally higher than for partial load curtailment. Few residential studies have attempted to relate outage costs to customer demographics. However, a positive relationship between household income and outage costs is reported in Munasinghe.[55] Doane et al[40] and Doane et al,[47] using contingent valuation data, find that customer demographics account for substantial cost variations. For example, large users with electric appliances for space and water heating and cooking tend to have higher outage costs than small users who do not own these appliances. And, young urban dwellers who own electronic equipment as personal computers, VCR's and security alarm systems value service reliability more than other households not having these types of appliances. Not surprisingly, households in which either a home business is operated, or a family member has health problems, or there is a large family all have higher outage costs.

The results presented in Table 2 agree reasonably well with those presented in Table 2 of Ref. 19 and in Table 2 of Ref. 20.¶ After adjusting for inflation, the similarity becomes more apparent. Most of the *ex post* full outage cost estimates in Table 2 and in Refs. 19 and 20 range from $1 to $6 per kWh unserved. The exceptions are the winter evening 1-hour direct cost estimate of $16.2 per kWh unserved in Doane et al[40] and the (inflation adjusted) 2-minute WTP estimate of $12 per kWh in Table 2 of Ref. 19. The similarity among the WTP estimates is even more striking, clustering around $1 to $2 per kWh unserved for outages lasting more than one hour. Based on this comparison, we conclude an upper bound estimate for total service disruption would be $6 per kWh unserved. This estimate is higher than the estimate of $1.36 to $2.0 per kWh unserved (in 1989 prices) recommended in page 190 of Ref. 19.

<u>Industrial Sector</u>

Table 3 presents industrial outage cost estimates for six studies conducted in Israel, Canada and the United States. Two studies use *ex ante* data and four use *ex post* data. *Ex ante* costs in Bental et al[28] are

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† The theoretical premise of this approach is that the effect of an unexpected outage is the same as an instantaneous price increase that would completely "choke-off" demand. However, this price increase can only reduce <u>planned consumption</u> to zero but not necessarily the <u>actual demand</u> at the time of an unexpected outage.

‡ In Refs. 31 and 56, for example, the authors indicate that the cost per hour unserved increases with frequency or duration. However, this finding was not supported by Refs. 36, 40, 43 and 48.

¶ Because a majority of the residential studies cited in Fig. 2 of Ref. 21 are the same as those in our paper, we decided not to compare their summary with ours.

approximated by using the cost of owning and operating a backup generator. Also, these authors estimate the marginal cost of unserved energy by dividing the annual cost of owning and operating a 1 kw capacity backup generator by the expected yearly unserved energy. *Ex ante* outage costs in Gilmer et al[32] equal the loss in expected producer surplus caused by a change in service reliability. These authors show that the producer surplus lost due to an outage is the area under a linear electricity demand curve representing a firm's planned consumption at its expected unit cost of electricity. The total *ex ante* costs consist of the expected loss of profit and the cost of adjustment to the change in service reliability.

The four studies using *ex post* costs obtain them from contingent valuation surveys in which direct outage costs are reported. These studies primarily focus on the costs associated with full outages. The statistical techniques used to estimate direct outage costs vary among the studies. Descriptive statistics are used to examine the effects of causal factors on outage costs in Subramaniam et al.[60] Ordinary least squares regression is used by Fisher[61] to relate direct costs to customer characteristics and outage attributes. Woo et al[41] recognize that a sample truncation bias is caused by a large number of zero direct cost responses. They correct for this bias by using a two-step regression model to explain outage cost variations.

Doane et al[48] discovered that the distribution of the direct costs are log-normal with a few observations having very large values. As a result, they use a semi-log cost regression on a data sample that excludes outliers.† In addition to direct costs, Doane et al[48] measure industrial outage costs using data on WTP and WTA responses. However, they discovered that many firms exhibit strategic bias. Strategic bias occurs when WTP values are very small and close to zero while the WTA values are very large. The authors believe that this occurs because firms tend to relate WTP values to the best time an outage may occur such as when their plant is closed. On the other hand, firms associate WTA values to the worst time for an outage to occur such as when they are operating at full capacity. Due to this bias, the authors use direct costs in their outage cost analysis, because these costs are less likely to suffer from strategic bias.

The estimates of industrial outage costs are diverse, ranging from $324 to $1,334,055 per interruption. Even after adjusting for differences in outage duration, large variations still exist in cost per hour unserved estimates. For example, Subramanian et al[60] estimate outage costs ranging from $2,492 to $4,155 per hour unserved for a winter morning outage lasting one hour or more for firms without backup systems. Furthermore, large differences remain after adjusting outage costs by kWh unserved, so neither duration nor kWh unserved can adequately explain the differences in outage cost estimates among studies. For example, industrial *ex post* cost estimates in Fisher[61] range from approximately $8.3 to $26.7 per kWh unserved depending on the products produced and technology employed.

Bental et al[28] estimate *ex ante* outage cost by using backup generators as a proxy. They obtain lower estimates than Gilmer et al[32] who also use *ex ante* costs. The estimates range from $0.31 to $1.68 per kWh unserved depending on the expected number of unserved hours. This result is surprising because an industrial firm would install a backup generator only if it had a high value of service reliability. Thus, the cost of owning and operating a backup generator should reflect the high end of the range of industrial firms' *ex ante* outage costs.

Gilmer et al[28] report *ex ante* costs for an unspecified number of apparel manufacturing firms in the Tennessee Valley Authority service territory. Per interruption outage costs are over $1 million. After normalizing these costs by the amount of expected unserved energy, the per-unit outage costs are approximately $1.66 to $2.05 per kWh unserved. The highest outage cost estimates are those reported in the three contingent valuation studies. These estimates range from approximately $1,200 to $57,000 per interruption or $1,300 to $23,000 per hour unserved for outages lasting one hour or more. Fisher[61] presents normalized cost estimates ranging from $8.3 to $26.7 per kWh unserved. These estimates are substantially higher than the estimates of $1.7 to $7.3 per kWh unserved in Doane et al.[48]

The effects of outage attributes on industrial firms' outage costs are quite different from those for households. An increase in outage duration raises the industrial costs per interruption but at a decreasing rate. Perhaps after the first hour of an outage, additional costs become less significant (e.g. workers are sent home to reduce idle labor costs). Weekday outages occurring in the morning or the mid-afternoon are the most costly while weekend evening outages are the least costly. Seasonality does not appear to affect outage costs significantly. Estimates in Woo et al[41] indicate that outage costs per interruption decline when outages become more frequent. For a given number of unserved hours, industrial firms prefer fewer longer outages to a larger number of shorter outages. For example, the cost estimate for one 4-hour outage in Woo et al[41] is approximately 60% of the total costs of four 1-hour outages. Advance warning reduces outage costs sometimes

† An observation is classified as an outlier if its studentized residual is greater than 2.0 so that the likelihood of misclassification is less than 5%. This procedure is presented in Ref. 57.

Table 3. Estimates of the value of service reliability and outage costs in the industrial sector in 1989 U.S. $.

Study/Country	Method/ Cost Type	Season/ Time-of-Day	Frequency	Duration (Hours)	Notice (Hours)	Dollars Per Interruption	Dollars Per Hour Unserved	Dollars Per kWh Unserved
Bental and Ravid (1982)/Israel and USA	Proxy–Cost of Backup Generation/ Ex Ante	Not Studied	Not Studied	70 /a	0	N.A. /b	N.A.	0.31
				10 /c	0	N.A.	N.A.	1.68
Gilmer and Mack (1987)/ Tennessee, USA	Producer Surplus/ Ex Ante	Not Studied	0.1/year	4	0	1,334,055 /d	333,514	1.66 /e
			0.5/year	4	0	1,277,785	319,446	2.05
Subramaniam, Billington, Wacker (1985)/Canada	Cost Survey/ Ex Post	Winter/ Morning				Customers Without Standby System		
			Not Studied	1/60	0	324.3	19,468	N.A.
				1/3	0	2,061	6,182	N.A.
				1	0	4,155	4,155	N.A.
				4	0	9,965	2,492	N.A.
				8	0	25,097	3,137	N.A.
						Customers With Battery Standby System		
			Not Studied	1/60	0	5,259	315,571	N.A.
				1/3	0	11,436	34,307	N.A.
				1	0	17,904	17,904	N.A.
				4	0	38,727	9,682	N.A.
				8	0	57,189	7,148	N.A.
						Customers With Engine Standby System		
			Not Studied	1/60	0	10,874	652,468	N.A.
				1/3	0	14,015	42,045	N.A.
				1	0	22,821	22,821	N.A.
				4	0	39,060	9,764	N.A.
				8	0	56,752	7,094	N.A.
Fisher (1986)/ Massachusetts, USA	Cost Survey/ Ex Post	Summer/ Afternoon				Machinery		
			Not Studied	1/2	0	5,773	11,545	23.89
				1	0	11,380	11,380	22.74
				2	0	15,392	7,695	16.15
				4	0	20,503	5,126	18.83
						Electronic & Electrical Machinery		
			Not Studied	1/2	0	647	1,295	11.88
				1	0	1,375	1,375	9.12
				2	0	2,665	1,332	8.54
				4	0	4,814	1,203	8.33
						Measuring Analysis & Control Instruments		
			Not Studied	1/2	0	5,078	10,156	26.65
				1	0	9,478	9,478	19.11
				2	0	26,953	13,476	25.56
				4	0	37,460	9,364	17.96
						Other Manufacturing		
			Not Studied	1/2	0	9,077	18,155	19.40
				1	0	13,371	13,371	15.78
				2	0	22,565	11,282	15.20
				4	0	37,460	9,364	13.47
Woo and Gray (1987)/ California, USA	Cost Survey/ Ex Post	Summer/ Afternoon	1	1	1	14,450	14,450	57.91
			1	4	1	47,345	11,837	N.A.
			4	1	1	6,578	6,578	N.A.
			4	4	1	21,549	5,388	N.A.
			8	1	1	4,664	4,664	N.A.
			8	4	1	15,278	3,819	N.A.

Table 3. Estimates of the value of service reliability and outage costs in the industrial sector in 1989 U.S. $.

Study/Country	Method/ Cost Type	Season/ Time-of-Day	Frequency	Duration (Hours)	Notice (Hours)	Dollars Per Interruption	Dollars Per Hour Unserved	Dollars Per kWh Unserved
Doane et al. (1990)/ New York, U.S.A. /f	Cost Survey/ Ex Post	Summer/ 8 a.m.	Not Studied	8	0	49,392	6,174	4.41
		Summer/ 2 p.m.	Not Studied	1	0	10,460	10,460	7.29
				8	4	27,267	3,408	2.67
				8	24	17,255	2,157	1.69
		Winter/ 8 a.m.	Not Studied	8	0	62,064	7,758	5.57
		Winter/ 2 p.m.	Not Studied	4	0	20,064	5,016	3.79
				4	1	19,098	4,775	3.61
		Winter/ 6 p.m.	Not Studied	1	0	7,831	7,831	6.49

Notes:
a/ Estimated annual outage duration in Israel in 1980.
b/ N.A. = Not Available
c/ Estimated annual outage duration in the USA for 1980.
d/ Total costs per year for an unspecified number of small apparel manufacturing firms divided by the expected number of outages per year.
e/ Total costs per year divided by the expected unserved energy per year.
f/ Includes all large users with monthly billing demand over 1,000 kW.

Table 4 overleaf

Table 4. Estimates of the value of service reliability and outage costs in the commercial sector in 1989 U.S. $.

Study/Country	Method/ Cost Type	Season/ Time-of-Day	Frequency	Duration (Hours)	Notice (Hours)	Dollars Per Interruption	Dollars Per Hour Unserved	Dollars Per kWh Unserved
Billington, Wacker Subramaniam (1986)/ Canada	Cost Survey/ Ex Post	Winter/ Morning				Customers Without Standby System		
			Not Studied	1/60	0	79.1	4,714	N.A. /a
				1/3	0	334.5	1,002	N.A.
				1	0	828.3	828	N.A.
				4	0	3,036	759	N.A.
				8	0	8,161	1,020	N.A.
						Customers With Battery Standby System		
			Not Studied	1/60	0	18.95	1,050	N.A.
				1/3	0	218.1	654.3	N.A.
				1	0	696	696	N.A.
				4	0	2,941	736	N.A.
				8	0	8,030	1,003	N.A.
						Customers With Engine Standby System		
			Not Studied	1/60	0	2.3	122	N.A.
				1/3	0	853	2,559	N.A.
				1	0	2,189	2,189	N.A.
				4	0	5,862	1,466	N.A.
				8	0	14,309	1,789	N.A.
Fisher (1986)/ Massachusetts, USA	Cost Survey/ Ex Post	Summer/ Afternoon				Wholesale		
			Not Studied	1/2	0	2,112	4,225	8.95
				1	0	6,212	6,210	14.19
				2	0	12,578	6,290	16.30
				4	0	25,515	6,379	19.55
						Retail		
			Not Studied	1/2	0	293	585	15.35
				1	0	777	777	16.80
				2	0	1,216	608	13.11
				4	0	2,420	606	10.23
					0			
						Finance, Insurance & Real Estate		
			Not Studied	1/2	0	6,547	13,096	26.65
				1	0	9,299	9,299	15.92
				2	0	15,499	7,750	16.94
				4	0	27,816	6,954	20.13
						Services		
			Not Studied	1/2	0	9,077	18,155	8.69
				1	0	13,371	13,371	8.69
				2	0	22,565	11,282	9.20
				4	0	37,460	9,364	8.84
Woo and Train (1988)/ California, USA	Cost Survey/ Ex Post	Summer/ Afternoon	1	1	1	4,332	4,332	8.25
			1	4	1	14,118	3,529	N.A.
			4	1	1	2,885	2,885	N.A.
			4	4	1	9,400	2,349	N.A.
			8	1	1	2,495	2,495	N.A.
			8	4	1	8,130	2,032	N.A.

Note:
a/ N.A. = Not Available

substantially as discovered by Doane et al.[48] The cost for an 8-hour outage with 24-hour notice is $17,255 per interruption which equals 63% of the cost of an 8-hour outage with a 4-hour notice.

The more electricity-intensive the production process, the higher the cost per interruption. For instance, Doane et al[48] find that an outage is most damaging to firms with high load factors and greater dependence on such end uses as process heat and electronics. Prior outage experience tends to reduce outage costs as discovered by Fisher[61] and Subramaniam et al.[60] They indicate that large customers with backup systems tend to have higher costs per interruption. However, this finding is not supported by Woo et al[41] and Doane et al.[48,†]

The industrial outage cost estimates reported in Table 3 are generally higher than those reported in Table 3 of Ref. 19 and in Table 3 of Ref. 20. With the exception of the estimate of $58 in Woo et al,[41] the range for most of the cost estimates in Table 3 is $0.24 to $27 per kWh unserved for outages lasting one hour or more. However, Woo et al[41] admit that their estimate is too high partially due to the underestimation of the average industrial unserved energy. In summary, we note that the majority of the estimates in our Table 3 and Table 3 in both Refs. 19 and 20 are less than $10 per kWh unserved.

<u>Commercial Sector</u>

Table 4 presents the empirical results of three contingent valuation surveys in which commercial firms were asked to provide estimates of their *ex post* direct costs incurred as a result of a full outage. Commercial outage costs are extremely diverse as is true for both residential and industrial outage costs. Below we consider some of the factors accounting for the divergence of results. Again, part of the differences in results are due to the various statistical techniques used by the authors. On the other hand, the diverse results cannot be completely attributed to differences in type of cost data collected, because all three studies estimate commercial firms' *ex post* outage costs with direct cost survey response data. On the other hand, we do know that part of the diverse results are due to the attributes of the outages presented in the surveys.

The effects of outage attributes on commercial outage costs resemble those for industrial companies. An increase in duration raises costs per interruption, but at a decreasing rate. Weekday outages occurring during normal business hours are the most damaging, followed by early evening and late evening outages. Summer outages impose slightly higher costs than winter outages. Costs per interruption decline when outages become more frequent. Advance warning does not reduce outage costs significantly. Commercial firms, like industrial firms, prefer fewer but longer outages to more but shorter outages. For example, Woo et al[42] report that the cost of one 4-hour outage is approximately $2,000 less than the sum of the costs of four 1-hour outages.

Large commercial firms employing many workers have a higher cost per interruption than smaller firms with few employees. Financial service companies and food outlets value service reliability more than retail companies and wholesale stores. Firms with no prior outage experience are more likely to report zero cost than firms with outage histories. However, when these inexperienced firms report some outage costs, their estimates are higher than those of the experienced firms. Billinton et al[62] and Fisher[61] suggest that large users with backup systems tend to have higher costs per interruption. This finding is not supported by Woo et al.[42]

The commercial outage cost estimates in Table 4 generally agree with the estimates reported in Table 4 of Ref. 19. They range from $2.3 to $27 per kWh unserved.[‡] It should be noted that most of the estimates are quite large because commercial firms tend to have relatively small usage. Thus, even though the costs per interruption are small, the normalized values are fairly large such as over $10 per kWh unserved.

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† While backup system ownership indicates a high *ex ante* value of service reliability, the *ex post* costs for firms with backup systems should be lower than firms without backup systems. For example, if the backup systems were sufficiently large, most of the negative effects of an outage on production could have been eliminated.

‡ The exceptions are the estimates for outages less than one hour and those reported by Ref. 63 in Table 2 of Ref. 19.

5. CONCLUSION

In this paper, we have reviewed the general approaches used to estimate customer outage costs and have summarized the empirical results in 16 recent studies. The following findings emerge from our review: (i) The value of service reliability represents the maximum amount a customer is willing to pay for the particular level and type of service provided. As such, it reflects the usefulness and/or necessity of service to the customer. (ii) Unlike other industries (e.g. airlines and telecommunications), the market for reliability in the provision of electricity service is not well established. As a result, there is a limited price history with respect to reliability from which to judge customers' willingness to pay. (iii) Absent a market for reliability, the amount customers are willing to pay for service reliability is often approximated by the opportunity cost of unsupplied electricity. Thus, customer value of service reliability becomes synonymous with customer outage costs. (iv) Outage costs can be evaluated either *ex post* (i.e. after the fact) or *ex ante* (i.e. before the fact). *Ex post* measures refer to the unavoidable costs a household or firm incur as the result of a power outage that occurs with certainty. *Ex ante* outage cost valuations represent the maximum amount a customer is willing to pay for a change in the likelihood of an outage. (v) Major factors known to affect customer outage costs are customer demographics and such outage attributes as frequency, duration, timing, advance warning and severity. Thus, a valid approach should generate outage cost estimates that are sensitive to such causal factors. (vi) A variety of approaches have been used to estimate outage costs. These approaches include simple proxies, market-based methods and contingent valuation surveys. The methods differ in terms of their data requirement, their theoretical rigor, and their ability to develop costs estimates distinguished by season, time-of-day, duration, and advance notice. (vii) An evaluation of the three common approaches indicates that absent good market data on customer choice of service reliability, one may use CVM to quantify outage costs. This recommendation is based on CVM's relative merits in data requirement, computational costs, verifiability of results and sensitivity to important causal factors such as outage attributes and customer demographics. However, the results based on CVM should be verified when suitable data on customer choice of I/C rate options become widely available. (viii) As shown in Tables 2-4, the empirical estimates of outage costs are diverse. This diversity can be explained by differences in the methods used, outage attributes considered, and customer characteristics. Therefore, considerable care must be taken when using outage cost estimates for the purpose of reliability planning and pricing.

Based on the above findings, we conclude that the recent research on estimating customer outage costs have made significant advances, especially in the areas of collecting and analyzing survey data. However, there is a number of important questions that remain unanswered. (i) What causes WTP and WTA values to differ substantially? Is it status-quo bias? (ii) How and when can survey results be validated by market data? (iii) Should we estimate costs for deterioration in other service attributes such as voltage? (iv) Should partial outage costs deserve more attention because they are important inputs to generation reliability planning? (v) Can outage cost data be used in an integrated framework for efficient pricing of and planning for reliability differentiated services? Ongoing and future research will hopefully provide answers to these questions which would result in a more efficient use of limited resources used in the production and distribution of electricity service.†

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† For example, Niagara Mohawk Power Corporation (NMPC) continues to investigate the effect of status-quo bias on customer participation in an I/C rate program. The Electric Power Research Institute and NMPC have jointly funded a study on the development of the integrated approach to reliability pricing using outage cost survey data and a demand model structure identified using real time pricing data. Initial results indicate that outage cost survey data can be used to parameterize the hourly electricity demand model for predicting customer response to alternative pricing schemes (e.g., priority service, proportional rationing and real time pricing). The response predictions are then used for evaluating the relative economic efficiency of the pricing schemes.

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CUSTOMER DEMAND FOR SERVICE RELIABILITY IN THE ELECTRIC POWER INDUSTRY: A SYNTHESIS OF THE OUTAGE COST LITERATURE[1]

Douglas W. Caves, Joseph A. Herriges and Robert J. Windle

I. INTRODUCTION

The electric power industry has, over the past 15 years, experienced increasing pressures to become more efficient, that is to provide greater value to its customers for the same resource utilization. These pressures have been accentuated by the possibility of deregulation in the United States, the 'privatization' of power in the United Kingdom, and the decreased confidence in and reliance upon nuclear power in parts of Europe. The industry's response to these pressures has given rise to the potential for major changes in the theory and practice of utility planning, operations and pricing. A common thread running through many of these changes is a recognition that the consumer's demand for service reliability plays a key role in designing prices and services. To cite two key examples, the efficiency properties of both real-time pricing and priority service pricing depend upon knowledge of the demand for service reliability.[2] The purpose of this paper is to review and synthesize recent North American research into the demand for service reliability and to draw conclusions of general interest to the utility industry.

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[2] Real-time pricing allows the price of electricity to change on any hourly basis to reflect utility cost conditions, while priority service varies customer reliability over time and for alternative levels of load. See Tabors, Schweppe and Caramanis (1989) and Caves and Kirsch (1989) for a review of real-time pricing and existing programs and Chao et al. (1988) and Chao and Wilson (1987a, b) for a description of priority service.

To date the demand for service reliability has been characterized almost exclusively in terms of 'outage costs', which refer to loss in value to the customer resulting from a sudden interruption of power.[3] In the case of industrial and commercial customers, these costs may take the form of lost sales, idle labor, or product and input spoilage. While residential outage costs may also include spoilage, the less tangible costs of inconvenience are likely to play a more dominant role. A review the outage cost literature is important at this time for two reasons. First, while there is a long history of research in this area, both in North America and elsewhere, there has been a significant increase in the number of outage cost studies in recent years, as well as changes in the methods being used to measure such costs.[4] Second, increased demands are being placed upon this literature for the purposes of system planning and rate design, by both theoreticians and utility analysts. The ability of the existing literature to fulfill these demands must be evaluated.

Three major conclusions are reached on the basis of the review.

1. Significant progress has been made in conceptualizing and measuring the demand for service reliability, providing valuable information for use in system planning. However, the current body of literature has not kept pace with the need for detailed and accurate information in the area of innovative rate design. Differences in the methodologies employed and in reporting procedures make it difficult to reconcile the highly disparate results regarding the cost of service interruptions.
2. Outage cost survey data provide the primary source of information on customer preferences for reliability. Because customers in developed countries have little experience with power interruptions, surveys may only provide information on customer attitudes and intentions towards hypothetical outages, and need not reflect how customers would behave in the event of an actual interruption. Outage cost estimates based upon customer behavior are needed in order to validate the available survey based estimates.
3. Finally, while outage cost studies have been somewhat successful in determining how preferences for service reliability are affected by

[3] Throughout this paper, the term outage cost is used to refer only to the direct costs incurred by the entity purchasing the power and experiencing the interruption. Indirect costs (i.e., the externalities) associated with power loss, such environmental hazards, are not considered. While some authors, such as Munasinghe and Sanghvi (1988) have noted that these indirect costs may be significant in the industrial and commercial sector, little quantitative information is available on these costs. In addition, the emphasis in this paper is on outage costs resulting from supply interruptions. Outage costs due to degradation in power quality, such as voltage and frequency reductions or spikes, are not discussed.

[4] Earlier surveys of the outage cost literature can be found in Anderson and Taylor (1986) and Sanghvi (1982a). Sanghvi (1982a), in particular, reviews numerous studies conducted outside of North America, including the United Kingdom, Brazil, Chile and Sweden. Other recent studies outside of North America include Costa Rica–Munasinghe (1980, 1988) and Egypt–Bernstein and Hegazy (1988).

the duration and timing of interruptions, the impact of warning, outage frequency, and partial outages have received relatively little attention.

The remainder of the paper is divided into five sections. Section II provides a brief review of the diverse uses of outage cost information in the electric power industry.[5] Section III then describes the methods currently used to measure the costs of power interruptions. Outage cost estimates, drawn primarily from North American work, are summarized in Section IV. This section includes not only a presentation of the typical or average outage cost, but also a review of the available information on the impact of outage characteristics (e.g., duration and frequency) and customer characteristics (e.g., outage experience and industrial classification) on outage costs. Section V briefly summarizes ongoing research based upon behavioral data and the potential for future research in this area. The paper is concluded in Section VI with a summary of the current state of knowledge regarding reliability preferences and suggested directions for future research.

II. BACKGROUND

The need for information on the value of electric service reliability, or conversely the cost of power interruptions, is apparent from even a cursory review of the literature. Early work by Telson (1975), for example, argued that traditional reliability levels in the electric power industry were not justified by the avoided customer outage costs.[6] Subsequent articles by Poland (1988), Munasinghe (1988), Munasinghe and Gellerson (1979) and Sanghvi (1983b, 1985, 1986) have refined and expanded upon the relationship between outage costs and system reliability. During the same period, the optimal price for electricity was being recast in terms of marginal operating and outage costs, rather than marginal operating and capacity costs. Early arguments along these lines were made by Balasko (1974) and Crew and Kleindorfer (1976). As stated by Chao (1983, p. 186), the '...optimal price [for electricity] can be expressed as a weighted average of marginal operating costs and marginal outage cost with the

[5] For additional discussion of role of outage costs in the electric power industry, see Munasinghe and Sanghvi (1988).

[6] US utilities have historically planned and built capacity to insure a loss of load probability (LOLP) of only one-day-in-ten-years. Poland (1988) describes the generation planning of one utility, Pacific Gas and Electric Co. As suggested by one referee, these high reliability levels are driven not only by economic considerations, but by the political costs of outages as well.

weights summing to unity'.[7] Marginal capacity costs are then used, in conjunction with marginal outage costs, to determine the optimal size and mix of capacity. Specifically, capacity changes are undertaken as long as the long-run marginal outage costs avoided by such changes exceed the marginal cost of capacity.[8]

The above principle is currently being implemented in the form of real-time pricing at several US utilities, but a recent series of articles has proposed an alternative implementation route in the form of priority service.[9] While utilities have traditionally offered electricity as a homogeneous product, priority service un-bundles the quality attributes of electricity and permits individual customers to purchase different mixes of those attributes. These quality attributes include, for example, power reliability and voltage level. By offering customers the choice of different 'qualities' of electricity at different prices, the value of electricity service may be increased for all customers. The design of priority service programs, and the assessment of the efficiency gains from their implementation, requires information on not only the typical reliability values in the service territory, but also on the entire distribution of these values. Marketing of priority service programs will likely require additional detail on the relationship between customer characteristics and the distribution of outage costs.

The need for information on the value of service reliability is not limited to theoretical research. While priority service has yet to be implemented on a comprehensive basis, a number of existing utility rate and service programs represent simple forms of priority service and require information on outage costs for design and evaluation. Prominent examples include interruptible/curtailable (I/C) service in the industrial and commercial sectors and direct load control (DLC) in the residential sector. Under I/C service, a firm agrees to temporarily reduce its consumption of electricity down to a prescribed level (i.e., its firm power level) when asked by the utility to do so. In return, the customer receives a reduced bill, typically in the form of a credit on demand (kW). Direct load control is a similar program, implemented primarily in the residential sector, in which

[7] Applications of this principle are not, as yet, widespread in North America. However, marginal operating and outage costs are used in the development of the real-time prices for industrial and commercial customers at Niagara Mohawk Power Corporation. See Munasinghe and Sanghvi (1988) for additional applications of outage costs.

[8] Long-run outage, or shortage, costs incorporate both the costs incurred by the consumer in the event of power interruptions (i.e., short-run outage costs) and the costs undertaken to cope with a change in the general level of service reliability, such as the cost of back-up generation. See Sanghvi (1983b).

[9] Chao *et al.* (1988), Chao and Wilson (1987a, b), Oren *et al.* (1986a, b), Oren, Smith and Wilson (1985) and Wilson (1989) provide theoretical details regarding priority service methods.

power is interrupted to specific appliances, such as water heaters and air conditioning units.[10]

III. ESTIMATING OUTAGE COSTS

In response to the larger role of outage costs in utility planning and operations, there has been a proliferation of outage cost studies in recent years. These studies can be categorized into four groups based on the underlying estimation technique: (1) proxy methods, (2) survey methods, (3) consumer surplus measures and (4) reliability demand models.

A. *Proxy Methods*

Early attempts to quantify outage costs relied primarily on proxies for the damages and inconvenience incurred by a customer during an interruption. In most instances, proponents characterized these proxies as lower or upper bounds on outage costs and not as exact outage cost measures. A partial listing of outage cost proxies appearing in the literature includes:

- *The cost of back-up generators.* Bental and Ravid (1982) argue that industrial customers purchase back-up generators until the expected marginal cost of additional back-up power ($/kWh) equals the expected marginal cost of an outage ($/kWh). Using assumptions regarding the average generator cost ($/kWh), depreciation rates, generator lifetime, fuel costs and interruption hours per year, the authors infer the expected marginal cost of back-up power, and hence marginal outage costs, for the US and Israel. The numerous assumptions that are required to convert generator costs to outage costs represents one of the limitations of this outage cost proxy. In addition, for customers that do not purchase any backup generation, this proxy provides only an upper bound on outage costs.
- *The ratio of output to electricity consumption.* A number of early studies, including Telson (1975), argue that output per kWh consumed provides an upper bound on the cost of electric power interruptions. As noted by Bental and Ravid (1982, pp. 249–50), this proxy assumes that there is no substitution between electricity and

[10] The use of both I/C and DLC programs has expanded substantially in the US over the past two decades. Between 1972 and 1986, the number of utilities with I/C programs has grown fivefold, with 71 per cent of large investor-owned utilities reporting I/C programs by 1986. Similarly, the use of DLC programs has grown to nearly 40 per cent during the same time period (Ebasco Business Consulting Company (1985, 1987)). See Caves, Herriges and Windle (1987b, c. 1988) for a review of I/C programs and Lawrence, Heberlein and Baumgartner (1984) for a review of DLC programs.

other factors of production. This proxy also ignores the costs of equipment and materials damaged during the course of an interruption and assumes that lost sales or production cannot be made up at a later date.

- *The price of electricity.* The price of electricity provides a lower bound on outage costs. It represents the cost of foregoing the last increment of consumption at any time, but provides no additional information.
- *The value of production in the home.* Gilmer and Mack (1983) treat households like firms, with electricity viewed as an input to the production of household services. Residential outage costs are then the market value of those services lost due to an interruption. There are two significant limitations to this approach. First, obtaining a complete listing of household services and their fair market values is difficult and involves many judgments regarding equivalent services. Second, the approach assumes that the services produced during an interruption cannot be readily transferred to another point in time or produced without electricity. For example, many aspects of food preparation and household upkeep can be produced with little or no electricity. Even if home food preparation is replaced by dinner at a restaurant, the outage cost is not the cost of the dinner, but rather the increase in costs over the home cooked meal and the associated increase or decrease in the meal's perceived value.
- *The wage rate.* A number of authors have argued that the outage cost to residential customers is primarily due to a loss of leisure.[11] If the marginal value of leisure is assumed to equal the wage rate, then residential outage costs should equal the prevailing wage rate. The obvious problem with this approach is that the connection between outages and the loss of leisure is quite tenuous.

The principal advantage of using proxies to estimate or bound outage costs is their simplicity. They can be calculated at only a small fraction of the costs required by either the survey methods described below or direct experimentation with reliability rate and service options. The major disadvantages of proxies are listed above. However, an additional limitation of most proxy approaches is that they do not differentiate outage costs by outage characteristics or provide information on the distribution of outage costs in the population. Instead, they at best reflect average outage cost conditions for the average customer. The influence of duration, frequency, timing, partial outages and warning time is unknown. Even the upper bounds typically apply only to average outage costs, and not to circumstances under which outage costs would be extraordinary.

[11] See, for example, Gilmer and Mack (1983), Yabroff (1981), and Munasinghe (1980).

B. Survey Methods

Surveys are currently the primary source of information on customer outage costs. There are a number of reasons for their popularity. First, unlike the proxy methods reviewed above, surveys can be used to determine how outage costs vary by the characteristics of the outage. Individuals can be asked to evaluate the impact of a variety of outage scenrios, varying the duration, frequency, or timing of the outage. Second, while proxy methods provide outage cost estimates (or bounds) for the average customer, surveys yield data on individual households and/or firms, thereby revealing the distribution of outage costs within a target population. Furthermore, detailed information on the survey respondents themselves can be used to characterize the distribution of outage costs.

There are a variety of approaches that have been used in outage cost surveys to extract information on the impact of power interruptions. The most commonly used techniques are:

- *Direct cost.* The direct (or self-stated) cost approach asks customers to assign a dollar value to the costs they would incur during an interruption. For example, in Pacific Gas and Electric's (PGandE) Residential Outage Cost Study, ten outage scenarios were described to each customer, with various outage durations and timings. For each outage type, customers were asked '...how much it would cost you to adjust to this power outage?' (Meta Systems *et al.* (1986)). In some studies, the survey respondents are asked to subdivide their outage costs into specific categories. This is particularly true in the industrial and commercial sectors, where there are natural divisions of outage costs (e.g., damage to plant and equipment, startup costs, lost production or sales, and labor costs). These categories serve two purposes. First, because customers may have little or no experience with power outages, they assist customers in evaluating interruption costs. Second, they provide the analyst with information on the sources of outage costs and may suggest ways of mitigating these costs. A variation on this approach, used in the residential sector by Billinton, Wacker and Wojczynski (1982), is to provide a list of coping strategies and their costs. The customers are then asked to indicate which strategies they would employ for various outage scenarios.
- *Contingent valuation.* As defined in Bishop, Heberlein and Kealy (1983, p. 619), the contingent valuation method (CVM) employs surveys and/or interviews '...to ask people about the values they would place on non-market commodities if markets did exist[12] ...That is, subjects are asked about their willingness to pay or compensation demanded, *contingent* on the creation of a market or

[12] In this application of CVM, the non-market commodity is service reliability.

other means of payment. All payments and receipts are purely hypothetical'. CVM questions are broadly classified into one of two approaches: willingness-to-pay (WTP) or willingness-to-accept (WTA). In the current context, the WTP approach is used to determine what consumers would be willing to pay either (a) to avoid a specific outage, or a series of outages, or (b) obtain an increased level of reliability. The willingness to accept (WTA) approach represents the counterpart to the WTP method. Customers are asked how much they would have to be compensated in order to either (a) accept a reduction in service reliability or (b) accept the current level of reliability in lieu of an increased reliability level.[13]

- *Contingent ranking method.* The contingent ranking (or choice) method (CRM) asks customers to rank or choose from a series of outage options.[14] Each option is accompanied by a rate increase or decrease. From the survey respondent's choices, willingness to pay and willingness to accept measures can be inferred using discrete choice models of customer preferences.

There are advantages and disadvantages to each of the survey approaches listed above. Industrial and commercial customers may be able to assess the direct costs associated with outages, particularly those outage scenarios for which they have experience. In these instances, further information can be gained about the composition of the outage costs and potential ways for mitigating them. However, in the residential sector, customers may find it difficult to place a dollar value on the inconveniences created by a power interruption. Many of the functions of a household do not have readily apparent values or counterparts.

Within the contingent valuation method, the choice between willingness to accept measures remains controversial. Historically, WTP and WTA measures have been found to yield widely diverging results, with consumers requiring a substantially higher compensation (WTA) for a reduction in quality than they are willing to pay (WTP) for an equivalent gain.[15] Recent work by Coursey, Hovis and Schulze (1987) indicates that

[13] The relationship between the WTP and WTA measures and Hicksian surplus measures depends upon the direction of reliability change being considered. Using notation similar to Carson and Mitchell (1989, p. 26), let $e(p, q, U)$ denote the minimum amount of income needed to maintain utility U, given price p and a service quality vector q. Let U_0, p_0, and q_0 denote the initial levels of the arguments of $e(\ )$. with U_1, p_1 and q_1 denoting alternative levels. If q_1 denotes a decreased level of service quality, the WTP measure corresponds to the Hicksian equivalence surplus, with $WTP = ES = e(p_0, q_0, U_1) - e(p_0, q_1, U_1)$. The WTA measure corresponds to the Hicksian compensating surplus $WTA = CS = e(p_0, q_0,$ $U_0) - e(p_0, q_1, U_0)$. With an increase in reliability, the WTA measure becomes an ES measure and WTP becomes a CS measure. See Carson and Mitchell (1989) and Brookshire *et al.* (1981) for additional details.

[14] We are adopting here the distinction and terminology suggested by Freeman (1986, p. 149).

[15] See Mitchell and Carson (1989, Ch. 2) and Cummings, Brookshire and Schulze (1986) for excellent discussions of this problem and experimental evidence supporting its existence.

the differences between WTP and WTA measures dissipate as consumers gain experience. Furthermore, the WTP measure changes little with experience, while the WTA measure declines towards the WTP value. This suggests that the WTP approach may yield the more accurate and stable measure of consumer outage costs. However, as noted by Mitchell and Carson (1989, p. 37), '...it is generally agreed that the correct measure for a decrease [in quantity or quality] is the Hicksian compensating surplus WTA measure'.

In addition to the individual limitations of the survey approaches listed above, there are significant problems with survey methods in general.[16] Three of these problems are of particular concern in the present context. First, because consumers have little experience with outages, they may have difficulty assessing the costs they might incur as a result of hypothetical outages, particularly outages outside of the range of their experience (e.g., frequency and/or long duration outages). An Israeli study, for example, found that industrial customers often overlooked simple procedures for coping with an interruption and therefore overstated their outage costs.[17] Cummings, Brookshire and Schultz (1986), while providing a generally optimistic assessment of CVM, note that the technique '...should not be applied to commodities with which people have little or no experience in making prior choices or which involve a high degree of uncertainty'.[18]

A second, but related, potential problem is that outage cost estimates from surveys depend significantly upon the presentation and wording of the questionnaire. Consider, for example, the problem of assessing the impact of duration on outage cost. If, at the beginning of an interruption, the customer has no information about an outage's duration he or she may incur many of the same costs for a 1 hour interruption as for a 12 hour interruption, not knowing which one to expect. On the other hand, if duration is known *a priori*, a customer may simply wait out a 1 hour interruption and incur only minor outage costs.[19] In Billinton, Wacker and Wojczynski (1982, p. 33), the analysts attempt to address this problem by asking households to '...assume that [they] did not know beforehand when failures would occur or how long they would last', even though the outage

[16] Schulze, d'Arge and Brookshire (1981) provide a systematic review of potential survey problems. In addition, Cummings, Brookshire and Schulze (1986) and Mitchell and Carson (1989) provide an extensive discussion of CVM as it has been applied to valuing environmental and other public goods. Many of the issues discussed, including the potential for strategic bias, are relevant to survey methods in general.

[17] Delson (1987).

[18] Cummings, Brookshire and Schulze (1986, p. 97). Similar views are expressed by Freeman (1986, p. 155).

[19] Billinton, Wacker and Wojczynski (1982, p. 118) found that knowledge of an outage's duration reduced outage costs by 21 per cent for large users and by almost 50 per cent for commercial and small industrial customers.

times and durations are specified in the outage descriptions. The interpretation of the resulting outage cost estimates depends on whether customers were successful in ignoring the information in the questions themselves. This second limitation of survey methods does not preclude its use in estimating outage costs. Rather, it points out the need for careful design and administration of survey instruments and caution in interpreting the results.

Finally, the survey method is limited because questionnaire responses provide information on customer attitudes and intentions, and not actual behavior. Survey responses provided by customers are not binding on the respondent. Studies have been conducted in the environmental literature to test empirically the differences between a customer's response to a hypothetical situation and a situation involving 'real money'. Studies by Bohm (1972) and Bishop and Heberlein (1979, 1986) have found significant differences and have led some researchers to conclude that '...the evidence for bias related to hypothetical payment is rather convincing'.[20] Other analysts remain unconvinced of the importance of this bias, questioning the research to date.[21]

C. *Consumer Surplus Measures*

The reliance on survey based outage costs is due, in part, to limitations on the data available. Utilities have only limited experience with rate and service options that vary the level of service reliability to individual consumers. Some authors have attempted to bypass this problem by using existing information on customer response to price changes to infer the value of reliability.[22] The price the consumer is willing to pay for electricity reveals information about the lost value when the electricity is unavailable due to a power interruption.

Figure 1 illustrates the consumer surplus approach. The vertical axis represents the price of electricity, while the horizontal axis represents the electricity demand by an individual consumer. The solid line indicates the demand for electricity at each price level. Now consider the impact of a partial outage (i.e., an outage during which the consumer is forced to shed a part, but not all, of his or her current electricity usage). A partial outage that forces a consumer to reduce usage from Q_1 to Q_2 is equivalent, from the consumer's point of view, to a price change from P_1 to P_2. Because the demand curve represents the marginal value of each additional unit of electricity consumed, the total value lost by moving from Q_1 to Q_2 is the

[20] Bishop and Heberlein (1986, p. 134).

[21] See, for example, Cummings, Brookshire and Schulze (1986, pp. 211-13). Recent research by Bishop, Heberlein, McCollum and Welsh (1988) suggests that the degree of hypothetical bias may depend upon the survey method used.

[22] Estimates of the price elasticity of electricity demand are readily available in the literature. See Caves, Herriges and Windle (1987a) for a recent review of this literature.

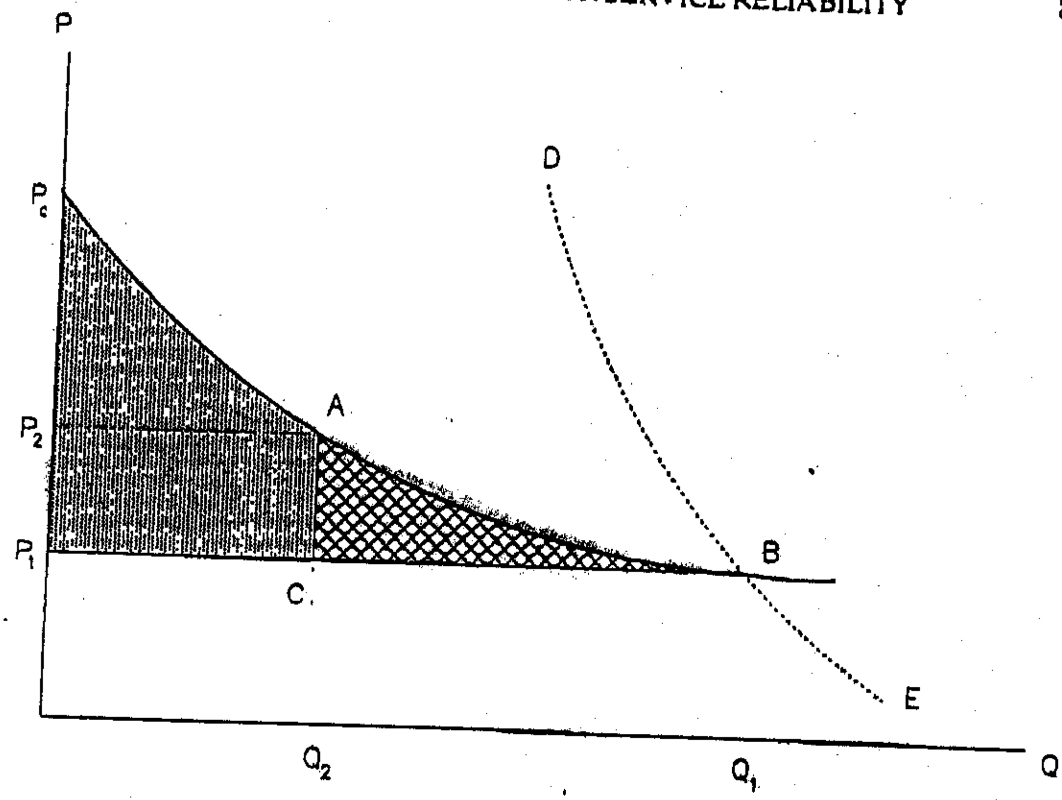


Fig. 1. The consumer surplus approach to outage cost estimation.

area ABQ_1Q_2. However, the household has saved CBQ_1Q_2 in electricity expenses. The difference (i.e., the cross-hatched area ABC), is the loss in consumer surplus from a partial outage reducing service from Q_1 to Q_2. Similarly, the lost consumer surplus from a complete power interruption would be equal to the area P_cBP_1, the shaded area plus the cross-hatched area in Figure 1.

There are two principal advantages to the consumer surplus approach. First, because the demand curves are, or at least should be, based on actual consumer behavior, they bypass the problem in the survey methods of relying only on consumer attitudes, intentions, and beliefs. Second, the consumer surplus approach can be used to infer the impact of a partial outage. This has not been addressed to any significant extent in the outage cost surveys to date and cannot be addressed using proxy methods without assuming away the problem.

Unfortunately, the consumer surplus approach is also plagued by three serious limitations related to the specification of the appropriate demand curve.[23] First, the demand curve drawn in Figure 1, and hence the implied outage cost estimates, depends crucially upon the advance warning

[23] The consumer surplus measure of welfare has a number of additional limitations that have been well documented elsewhere in the literature. See, for example Silverberg (1978) or Just, Heuth and Schmitz (1982). This paper focuses on those limitations that are of particular importance to applications in the outage cost literature.

customers have prior to price changes. The shorter the warning time the less the consumer will be able to adapt their consumption patterns and the steeper the demand curve will be. The dashed line (DE) reflects a shorter run demand curve than (*AB*). Using DE to infer outage costs will yield a much larger value than using demand curve *AB*. Because interruptions can occur with little or no warning, the demand curves used to infer outage costs should reflect price changes that occur with little or no warning. Unfortunately, currently available estimates of demand curves for electricity are based on price changes that are known well in advance.

Second, power interruptions typically last for only a few hours. Customers may be able to shift loads lost during an outage to immediately adjacent hours. Because there has been no experience until very recently with prices that affect only a few hours, the demand curves in the literature have necessarily been estimated using monthly or annual usage and price variables. The resulting aggregate price elasticities may understate the consumer's ability to respond to short term power interruptions and, hence, overstate outage costs.

Sanghvi (1983a) attempts to deal with this second problem by estimating price elasticities using hourly usage and price variables from the Wisconsin Time-of-Use (TOU) Pricing Experiment. But these data are still not adequate to uncover the required disaggregate elasticities. The best that can be achieved is the elasticities of hourly usage with respect to changes in the monthly peak price, which is far more aggregate than the required elasticity of hourly usage with respect to hourly price changes.[24] In addition, because consumers were informed about the TOU prices well in advance (i.e., prices were fixed at the beginning of each season), their usage patterns reflect long-, or at least intermediate-, run price elasticities and, therefore are likely to understate the cost of a power interruption. Recent applications of real time pricing may provide the necessary data base for estimating price elasticities for the very short run. Typically, consumers are provided less than 24 hours notice of each hour's price. Data from these experiments are only now becoming available.

The third problem with the consumer surplus approach occurs when the costs of a total outage are to be computed. Estimated price elasticities are most reliable around the mean value for the price of electricity in the data base. Extrapolating the demand curve back to the vertical axis, where usage is zero, is a risky undertaking at best. In many mathematical demand models the point of zero usage is not defined.

[24] The author's apparent ability to estimate price elasticities for each hour is due to the restrictive LES demand model employed and the relationships it imposes between price and income elasticities. See Caves, Christensen and Herriges (1987) for a delineation of the identified price and income elasticities when limited price variation exists.

D. Reliability Demand Models

The final approach considered in this section is the explicit inclusion of the quality of service in models of electricity demand. The principal limitation of this approach is that there are few instances where service reliability varies significantly. In particular, US reliability levels have historically been uniformly high throughout the country. Dias-Bandaranaike and Munasinghe (1983) is the only study that explicitly models the impact of quality of service on electricity demand. The authors draw on data from Costa Rica, where there are significant variations in reliability across the country. While the authors begin with a more complex quality specification, their empirical model ends up relying upon dummy variables for low and medium qualities of service. Inferring outage costs from these results is, therefore, difficult.

IV. OUTAGE COST ESTIMATES

The purpose of this section is to summarize some of the outage cost estimates that have been obtained in North American studies over the past 15 years. The review is not intended to be exhaustive, but, rather, to highlight the key findings to date and to illustrate problems that remain. The section begins by comparing outage cost estimates obtained for the average customer using the proxy, survey and consumer surplus methods described above.[25] Information on the influence of outage characteristics on outage cost are then summarized, including the impact of outage duration, frequency, timing, warning time, and partial outages. Finally, the section is closed with a discussion of the evidence available on the distribution of outage costs within each service classification.

A. A Comparison of Outage Cost Estimates

Direct comparisons of the outage cost estimates from different studies and for different customer classes is difficult and should be viewed with caution. Outage cost estimates differ not only in the underlying methodologies, but also in the reporting procedures used. It is important to distinguish these sources of variation from the more substantive variations in outage costs due to customer or outage characteristics.

In reviewing outage cost estimates below, two particular factors should be kept in mind. First, outage cost surveys typically ask respondents to indicate the total dollar cost of an interruption. In order to compare outage costs among customers, customer classes or studies, these costs per

[25] To date there are no outage cost estimates using reliability demand models.

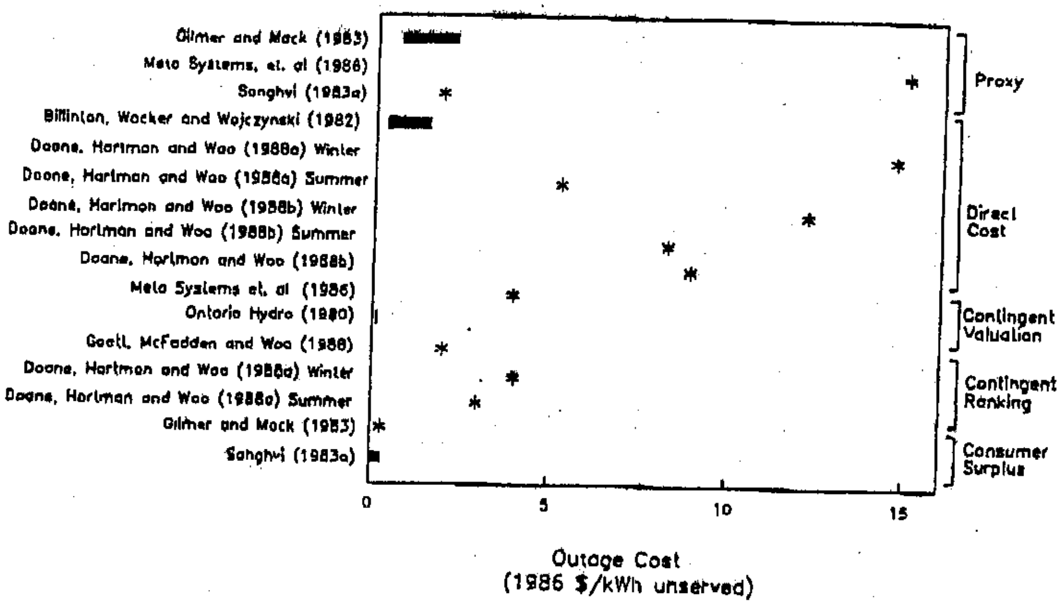


Fig. 2. Outage cost estimates for a one hour interruptions residential sector.

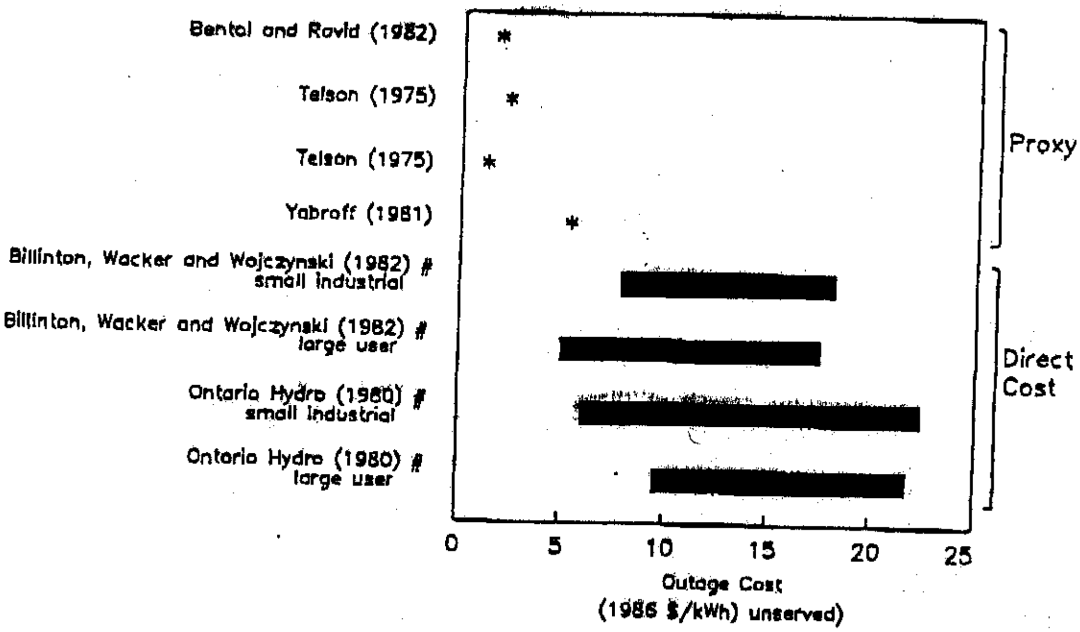


Fig. 3. Outage cost estimates for a one hour interruption industrial sector.

interruption must be converted to a common unit of measure. A natural choice of units is $/kWh unserved, which underlies much of the theoretical literature and which can be approximated by dividing the respondent's total outage cost estimate ($/interruption) by typical usage (kWh unserved/interruption) during the interruption period.[26] Unfortun-

[26] This approach assumes that historical usage during the interruption period provides a reasonable proxy for the customer's expectations concerning kWh unserved during the interruption.

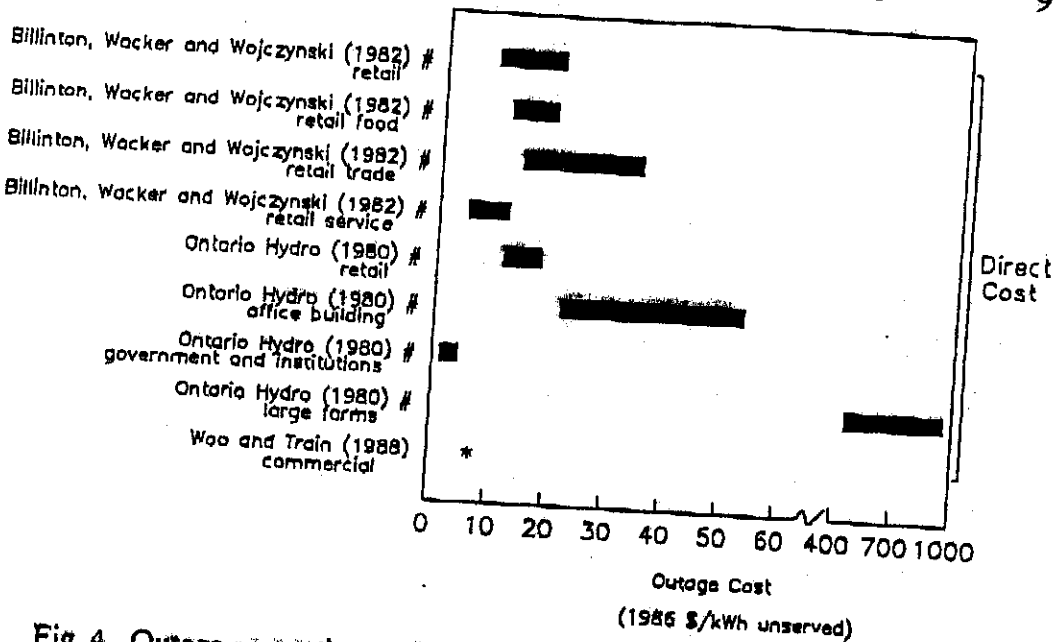


Fig. 4. Outage cost estimates for a one hour interruption commercial sector.

ately, most studies do not have available or do not use estimates of average kWh usage during the interruption period.[27] Instead, outage costs are frequently unitized in terms of $/(maximum kW) or $/(average kWh). Both of these units can be deceiving, depending upon the timing of the interruptions and the customer's usage pattern. Using maximum demand as the divisor will understate outage costs, since a customer's load during an interruption may not be near its peak level, while using average kWh as a divisor is likely to understate daytime outage costs.

Second, proxy and consumer surplus estimates of outage costs do not usually vary with the conditions of the outage (e.g., duration, frequency, warning time, and timing). Survey based outage costs, on the other hand, can vary significantly with the frequency, duration and timing of the interruption(s) described in the survey. Differences among outage cost estimates may be due more to the specific outages being considered than to the underlying methodology. Even comparisons among survey based outage costs are hampered because different outages are considered.

With these precautions in mind, average outage cost estimates for a 1 hour power interruption are depicted graphically in Figures 2, 3, and 4 for the residential, industrial, and commercial sectors, respectively.[28] Within

[27] Doane, Hartman and Woo (1988a) represents one of the few exceptions. However, even in this study, kWh unserved for each interruption scenario is estimated for the population as a whole and divided into the estimate of outage cost in $/interruption. It would be preferable to compute outage costs in $/(kWh-unserved) on a customer by customer basis and then average this value over the population.

[28] The corresponding numbers and the conversion methods are detailed in Caves, Herriges and Windle (1989).

each figure, the studies are organized according to the underlying methodology (i.e., proxy, consumer surplus, etc.) and then alphabetically within methodological groups. All outage cost estimates have been converted to $/kWh unserved. In those studies reporting outage costs in terms of $/interruption, $/(maximum kW) or $/(average kWh), a range of estimates is listed, reflecting differences in the assumed kWh unserved during an interruption.[29]

Figure 2 depicts residential outage costs from eight studies denominated in 1986 US dollars per kWh unserved. Substantial differences exist between methodologies and among studies using the same methodology, with outage cost estimates ranging from $0.02 to $14.61/kWh unserved. The consumer surplus measures, at the low end of this range, are likely to understate the true outage costs, since they are based on price elasticities in which customers have a month or more to adapt to price changes. The remaining estimates suggest that outage costs fall between the wide range of $0.09 to $14.61/kWh in the residential sector.

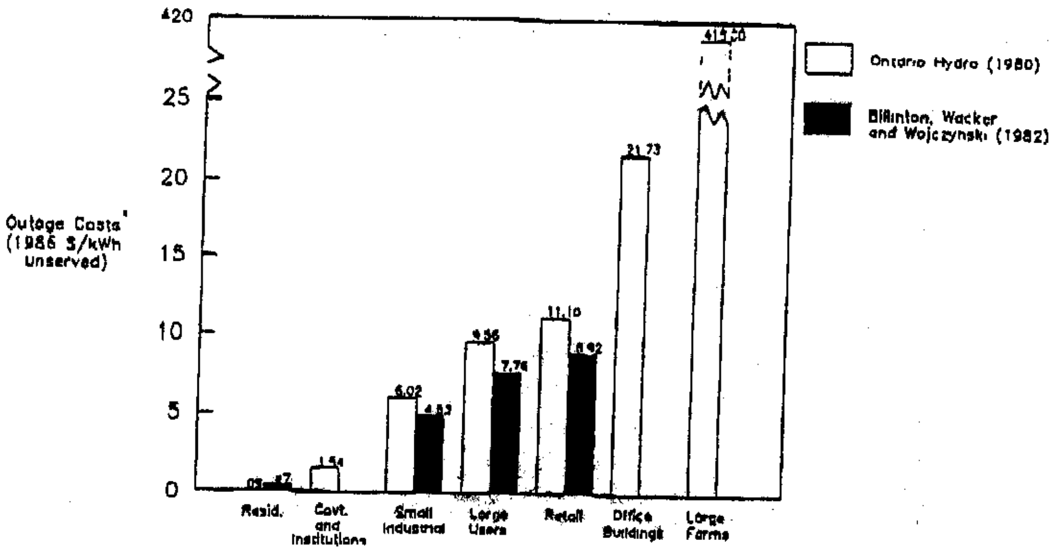
Industrial outage cost estimates are reported in Figure 3. The proxy estimates are generally lower than those reported by survey methods.[30] Telson's estimates, based upon ratios of output or wages to total usage, are likely to understate the true costs of an outage, since they do not reflect the sudden nature of power interruptions. Damaged equipment and materials, and their spillover effects on hours outside of the interruption itself (e.g., resulting in labor being sent home early, startup costs, etc.), are not captured by Telson's proxy method. Much of the uncertainty in the outage cost estimates, which range from $1.27 to $22.46/kWh, is due to the conversion of outage costs per interruption to $/kWh unserved. Yet even using only the lower estimates, industrial outage costs range widely, from $1.27 to $9.56/kWh unserved.

Finally, Figure 4 reports outage cost estimates for various commercial sectors of the economy. As with industrial outage cost estimates, much of the variability in Figure 4 lies in the conversion of outage costs to $/kWh unserved. Using a uniform assumption that demand is at 75 per cent of its annual peak during an interruption (i.e., the lower estimates in Figure 4), commercial outage costs range from $5.02/kWh in the retail service sector to $21.73/kWh for office buildings. The evidence points to significantly lower outage cost for government agencies and institutions.[31] Large farms,

[29] These cases are marked by a '#' in Figures 2, 3, and 4. The upper bound of these ranges assumes kWh unserved equals the annual average hourly kWh, while the lower bound uses 75 per cent of the annual peak demand.

[30] Bental and Ravid's (1982) estimate was converted to a 1 hour interruption per year from 10 hours of interruptions per year and assuming outage costs (in $/kWh unserved) are not a function of outage duration.

[31] This category in the Onatario Hydro study includes wide variety of agencies and institutions, but consists primarily of schools, utilities, hospital, public administration offices, court and police stations, and welfare organizations.



*For a one hour interruption

Fig. 5. Comparison of outage costs across customer classes.

at the other extreme, show outage costs over $418/kWh, a result that must be questioned, since it far exceeds the cost of backup power.

Figure 5 compares outage cost estimates across sectors for a 1 hour interruption, based upon results from Billinton, Wacker and Wojczynski (1982) and Ontario Hydro (1980).[32] These studies explicitly consider the variation in outage costs among customer classes, using the same or similar techniques for all sectors. The two studies yield similar conclusions. Residential outage costs are found to be at the low end of the spectrum, with costs less than one third of those estimated for industrial and commercial customers. Industrial outage costs are consistently smaller than those in the commercial sector, but the differences are not large. The Ontario Hydro study places government and institutional outage costs between those for the residential and industrial sectors, while office buildings and large farms have outage costs well excess of those for the commercial sector.

B. The Impact of Outage Characteristics

Power outages can be characterized along a number of dimensions, including duration, frequency, timing, warning time and interruption depth. Each of these characteristics potentially alters the outage costs incurred by a customer.

[32] For simplicity, only the lower estimates (i.e., assuming demand during the interruption is at 75 per cent of annual peak demand) are used in Figure 5.

1. Duration

Duration is one of the most extensively studied outage characteristics. Outage cost surveys typically ask respondents to evaluate a series of outages of different durations, ranging from 1 minute to 12 hours. Changes in customer self-stated costs or willingness to pay due to changes in outage duration can then be computed. The results regarding the impact of duration on outage costs are not yet conclusive, however, particularly in the residential sector.

As above, comparisons across outage cost studies are impeded by the differences in the methodologies and reporting procedures employed. In order to abstract from these differences the outage costs reported below are first converted to hourly figures (i.e., \$/interruption hour) and then normalized by the cost of a 1 hour interruption. Formally, normalized outage costs for an interrupton of duration h, denoted NOC(h), are defined as:

$$\mathrm{NOC}(h) = \mathrm{OC}(h)/[h \cdot \mathrm{OC}(1)] \tag{1}$$

where OC(h) denotes the total outage cost reported for an interruption with duration h hours. This normalization permits cross-study comparisons, abstracting from the level of outage costs and focusing on how outage cost vary with duration.

Normalized hourly outage cost estimates are illustrated in Figure 6 for studies in the residential sector. With the exception of Billinton, Wacker and Wojczynski (1982), hourly residential outage costs diminish with duration. This result is counter intuitive, as one would expect residential outage costs to increase as the thermal storage available in air conditioning, water heating, and space heating units are exhausted.[33]

One interpretation of the downward sloping lines in Figure 6 is that there are both fixed and variable costs associated with power interruptions in the residential sector. Specifically, OC(h) could be segmented as follows:

$$\mathrm{OC}(h) = \mathrm{FC} + \mathrm{TVC}(h) \tag{2}$$

where FC denotes the fixed costs associated with an interruption and TVC(h) denotes the total variable costs incurred during an interruption of duration h (with TVC(0) = 0). If we assume variable costs are proportional to duration then equation (2) becomes:

$$\mathrm{OC}(h) = \mathrm{FC} + \mathrm{VC} \cdot h \tag{3}$$

where VC denotes variable costs in \$/interruption hour. The normalized outage costs in equation (1), and in Figure 6, are then determined by:

$$\mathrm{NOC}(h) = [\mathrm{FC} + \mathrm{VC} \cdot h]/[(\mathrm{FC} + \mathrm{VC})\, h]$$

[33] This result also conflicts with the finding, reported below, that residential households generally prefer frequent short duration outages to infrequent long duration outages.

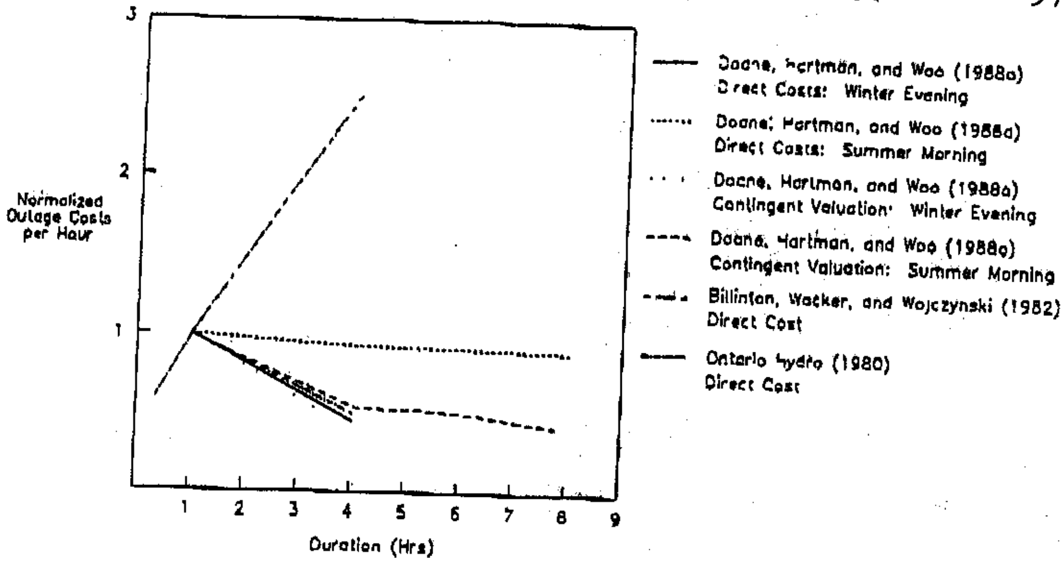


Fig. 6. The impact of duration on residential outage costs.

$$= W_V + W_F h^{-1}$$
$$= W_V + (1 - W_V)\, h^{-1} \tag{4}$$

where $W_V = VC/(FC+VC)$ denotes the percentage of outage costs that are variable during a 1 hour interruption and $W_F = 1 - W_V$ denotes the percentage of outage costs that are fixed during a 1 hour interruption. Using equation (4), non-linear ordinary least squares and the data underlying Figure 6, W_V is estimated to be 0.97 for the residential sector (with a standard error of 0.17), indicating that fixed costs are relatively small in the residential sector.[34] However, if the Billinton, Wacker and Wojczynski (1982) observations are excluded from this exercise, due to their large departure from the results of other studies, this result changes substantially, with $W_V = 0.49$ (with a standard error of 0.08). The conclusion reached regarding the importance of fixed outage costs in the residential sector depends substantially upon the weight given to the Billinton, Wacker and Wojczynski (1982) results.

The results in the industrial sector are more consistent, as illustrated in Figure 7. All of the studies indicate that firms experience high outage costs initially (in $/interruption hour). However, these average hourly costs diminish rapidly as duration increases, leveling off at about 50 per cent of the cost of a 1 hour interruption. Estimating the model in equation (4) using the data underlying Figure 7 yields estimates of $W_V = 0.73$, with a standard error of 0.03. Thus, with a 1 hour interruption, fixed costs constitute roughly 27 per cent of the total outage cost reported by industrial firms.

[34] The reported standard error should be viewed with considerable caution, as the observations drawn from the same data sets are unlikely to be uncorrolated.

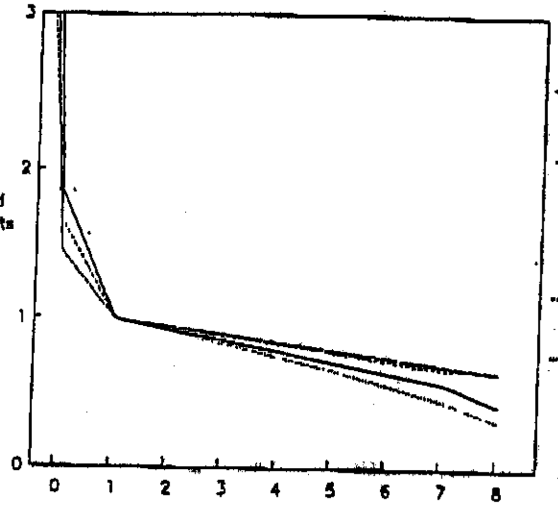


Fig. 7. The impact of duration on industrial outage cost.

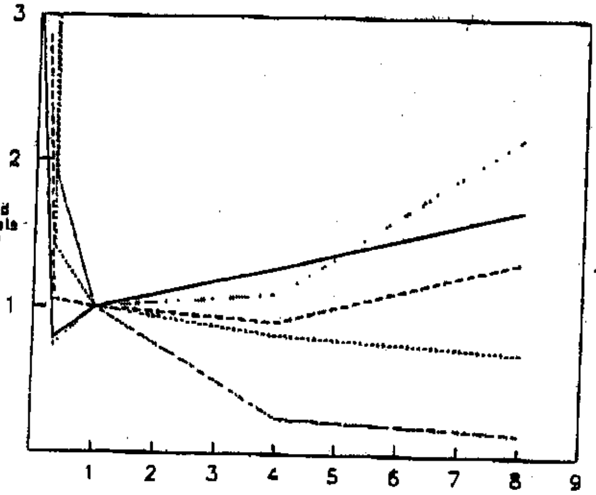


Fig. 8. The impact of duration on commercial outage costs.

Finally, Figure 8 depicts the impact of duration on outage cost for other sectors of the economy. Office buildings and farm customers exhibit duration results similar to those in the industrial sector, with high initial outage costs, diminishing as duration increases. Retail and government customers have U-shaped outage cost curves. This suggests that there is again a substantial fixed component to outage costs in these sectors, but also a variable component to outage costs that increases with duration.

2. *Frequency*

The relationship between outage costs and outage frequency has received less attention in the literature to date. The available results indicate that total outage costs are not proportional to outage frequency, but rather decline per interruption as frequency increases.[35] This pattern suggests that customers may be able to adapt to more frequent outages.

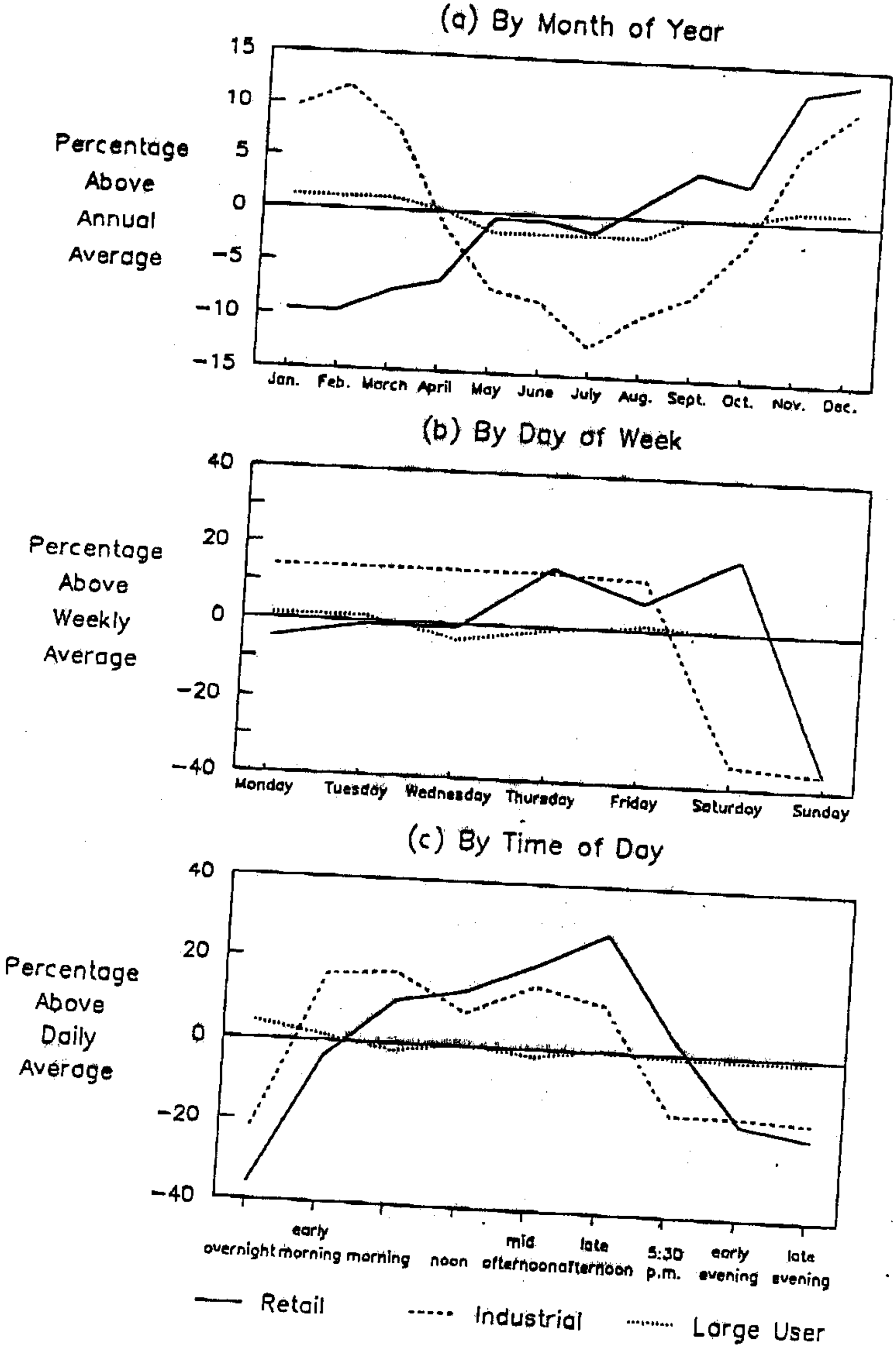
Many of the survey studies provide qualitative information on the impact of outage frequency on outage costs. For example, Billinton, Wacker and Wojczynski (1982, p. 32) ask residential customers to rank the undesirability of a 4 hour outage for frequencies of (1) once a year, (2) once a month, (3) once a week, and (4) once a day. Not surprisingly, frequent outages are less desirable than infrequent outages.

Finally, the tradeoff between outage frequency and outage duration has been examined in a number of the outage cost studies. Both Billinton, Wacker and Wojczynski (1982) and Ontario Hydro (1980) ask customers to choose between frequent but short duration interruptions and infrequent but long duration interruptions. Between 70 per cent and 90 per cent of the industrial and large users interviewed were found to prefer infrequent long duration interruptions (e.g., one 4 hour interruption) to frequent short duration interruptions (e.g., four 1 hour interruptions). The reverse is true in the residential sector, with only about 25 per cent preferring the longer duration option. Commercial customers were more evenly divided. These results are substantiated in the residential sector by Doane, Hartman and Woo (1988b) and in commercial sector by Woo and Train (1988).

3. *Timing*

The relationship between outage costs and outage timing plays a critical role in the application of the outage cost literature to recent rate and service innovations. For example, real-time pricing programs require information on the hourly variations in marginal operating and marginal outage costs. Outage costs have, in fact, been found to vary with the timing of the power interruption. This has been addressed in two ways in the literature. First, survey questions have been used to directly assess the impact of timing on outage costs and, second, revealed outage costs for outages occurring at different times have been compared. Billinton, Wacker and Wojczynski (1982) utilize the first approach for the industrial and commercial sectors. Customers were asked to indicate the percentage increase in outage costs associated with a change in the month, day of week, and time of day during which an interruption occurred, as compared to a base case. Their results are depicted graphically in Figures 9(a) through 9(c). For example, Figure 9(a) depicts the variation in outage costs by month around the annual average outage cost estimate. Large industrial

[35] See Woo and Gray (1987) in the industrial sector, Woo and Train (1988) in the commercial sector and Doane, Hartman and Woo (1988b) and Goett, McFadden and Woo (1988) in the residential sector.



Source: Billington, Wacker and Wojczynski (1982)

Fig. 9. Variation in outage costs.

users exhibit little variability in estimated outage costs, while small industrial firms exhibit a definite seasonal pattern in outage costs, with substantially higher estimates during the winter season. The outage costs reported by the retail trade sector builds from January through December, possibly reflecting the importance of the Christmas season.

Figure 9(b) similarly depicts the variation in outage costs by day of the week. Again larger users exhibit little variability in outage costs. Small industrial firm's have substantially lower outage costs on Saturdays and Sundays, while retail outage costs are increased on Saturday and substantially lower on Sunday. Finally, Figure 9(c) depicts the variation in outage costs by time of day. Large users continue to have relatively stable outage costs, while small industrial and retail trade cost estimates vary substantially over the day.

The patterns in outage costs exhibited in Figures 9(a) through 9(c) again raise the concern that the observed variability in outage cost estimates reflects, to a large extent, variability in the kWh unserved by an interruption rather than variability in outage costs ($/kWh unserved) themselves. The stability of outage costs for large users is consistent with the generally high load factors found in that class. On the other hand, the daily outage cost patterns for retail and small industrial customers in Figure 9(c) are remarkably reminiscent of their load profiles. Similarly, it is not surprising that small industrial firms exhibit substantially lower outage costs on weekends when these firms are likely to have lower load requirements. The fundamental problem is again that observed patterns in outage costs per interruption provides little information on patterns associated with the variable of interest, outage costs in $/kWh unserved, unless variability in the kWh unserved is controlled for, both over time and across customers.

The second approach (i.e., comparing the revealed costs for different times of day and times of year) also finds that outage costs vary with timing. Goett, McFadden and Woo (1988) find winter and weekday outages are more costly in the residential sector, although these effects were not statistically significant. Meta Systems *et al.* (1986) and Doane, Hartman and Woo (1988a, b) both find residential outage costs are significantly higher during the evening hours. Woo and Gray (1987) find significantly higher outage costs for industrial customers during morning hours. Again, it is difficult to interpret these results in terms of the variation in outage costs measured by $/kWh unserved. While some of the studies do control for annual, seasonal, or monthly load levels, daily patterns of consumption or firm specific load factors are not controlled for.

4. *Warning Time*

The impact of warning time on outage costs has been studied to a lesser extent than either duration or timing. Early outage cost studies such as

Billinton, Wacker and Wojczynski (1982) and Ontario Hydro (1980) relied primarily on direct questions regarding the impact of advance notice. However, many of these questions were vaguely worded, providing qualitative, rather than quantitative, information. This point is illustrated by the following questions extracted from these two studies:

> If adequate advance warning of an impending interruption were given, do you think that your interruption costs would be reduced substantially?[36]

> If it were possible for your company to be given some *advance* warning of a short term electrical interruption, would your company be able to arrange things so that the cost of the interruption would be made less or not?[37]

Billinton, Wacker and Wojczynski (1982) do follow up their qualitative questions on warning time, asking respondents to indicate the percentage reduction in outage costs that can be achieved with 3 days advance notice. The authors found reported reductions of 60 per cent in the commercial sector, 68 per cent in the industrial sector, and 30 per cent for large users.[38] The impact of other warning times are not reported.

More recent outage cost studies have incorporated advance notice in the description of the outages to be evaluated by survey respondents. By comparing revealed costs of outages that differ only in warning time, the marginal effect of warning time can be measured. Studies using this approach have uniformly found advance notice to reduce outage costs, although the effect is not always statistically significant. In the residential sector Goett, McFadden and Woo (1988) use a single dummy variable to distinguish notice. While the authors find that advance notice significantly lowers outage costs, it is not possible to assess the impact of different amounts of notice. Meta Systems *et al.* (1986) and Doane, Hartman and Woo (1988a) reach similar conclusions using data from PGandE's 1986 residential outage cost survey. Woo and Gray (1987) find that a 1 per cent increase in advance warning reduces outage costs by 0.006 per cent in the industrial sector. In the commercial sector, Woo and Train (1988) estimate a 0.0012 per cent decline in outage costs with a 1 per cent increase in warning time.[39]

[36] Ontario Hydro (1978a, p. II–2).

[37] Billinton, Wacker and Wojczynski (1982, p. 152).

[38] These responses apply only to those customers indicating that any cost reductions were possible and, hence, overstate the average outage cost reductions due to 3 days advance notice.

[39] While these last two studies report that the impact of warning time is statistically significant, this significance is likely to be overstated. Outage cost estimates for different outage scenarios are pooled in the same regression, without controlling for correlations (i.e., similarities) in responses by the same customer for different outage scenarios.

5. Depth

The outage cost literature has focused on measuring the impact of total power interruptions, without investigating the impact of partial outages (i.e., the depth of the power interruption). In general, one would expect outage costs to increase with the depth of the outage, since customers would shed their least costly loads first.[40] The lack of partial outage cost information is a significant shortcoming of the literature, particularly in terms of its value in designing rates programs, such as priority service and curtailable rates, that envision partial load interruptions.[41]

C. The Distribution of Outage Costs

The design and marketing of utility rate programs often require information not only on the typical outage costs in the targeted population, but also the distribution of outage costs. This will determine the number and characteristics of program participants. For example, the objective of priority service is to provide a better match between customer demand for reliability and the cost of providing service. Designing a menu of rates to achieve the optimal match requires information on the distribution of outage costs in the target population.[42] In addition, the distribution of outage costs in the population may have important policy implications. Changes in the reliability level of the system may alter the welfare of one sector of the economy (e.g., low income households or urban communities) substantially more than other sectors (e.g., rural communities). The purpose of this subsection is to review the available information on the distribution of outage costs. The subsection is divided into two sections, with the first section providing an overview of the reported shape of outage cost distributions by customer class and the second section discussing attempts to characterize these distributions in terms of customer characteristics.

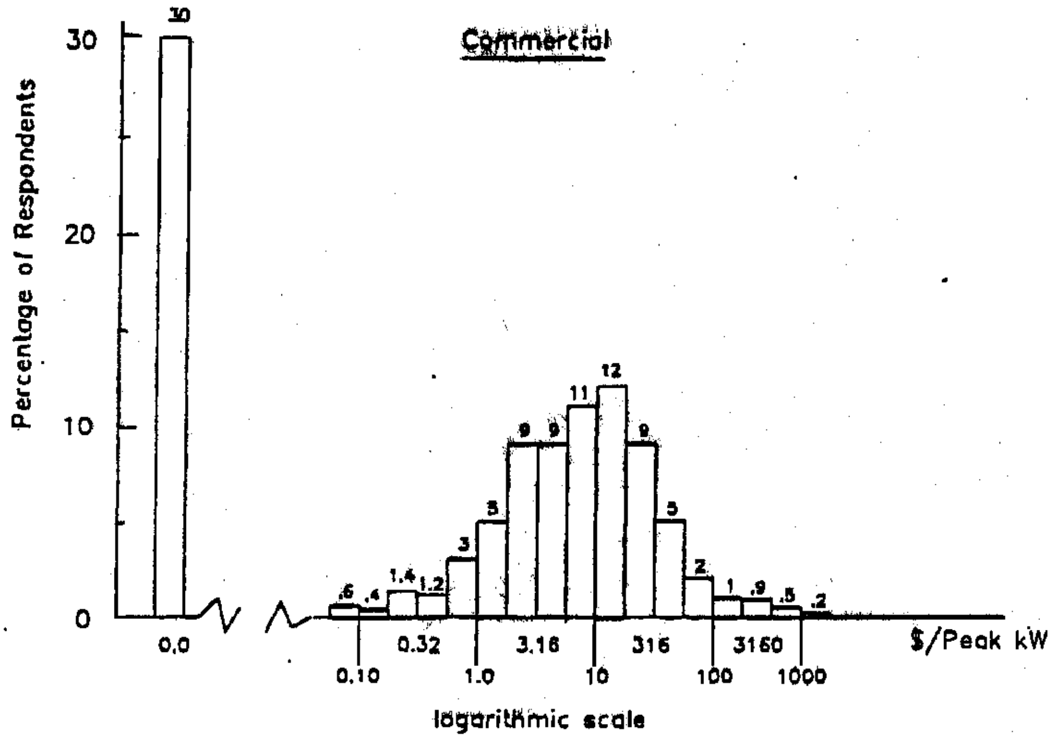
1. Unconditional Outage Cost Distributions

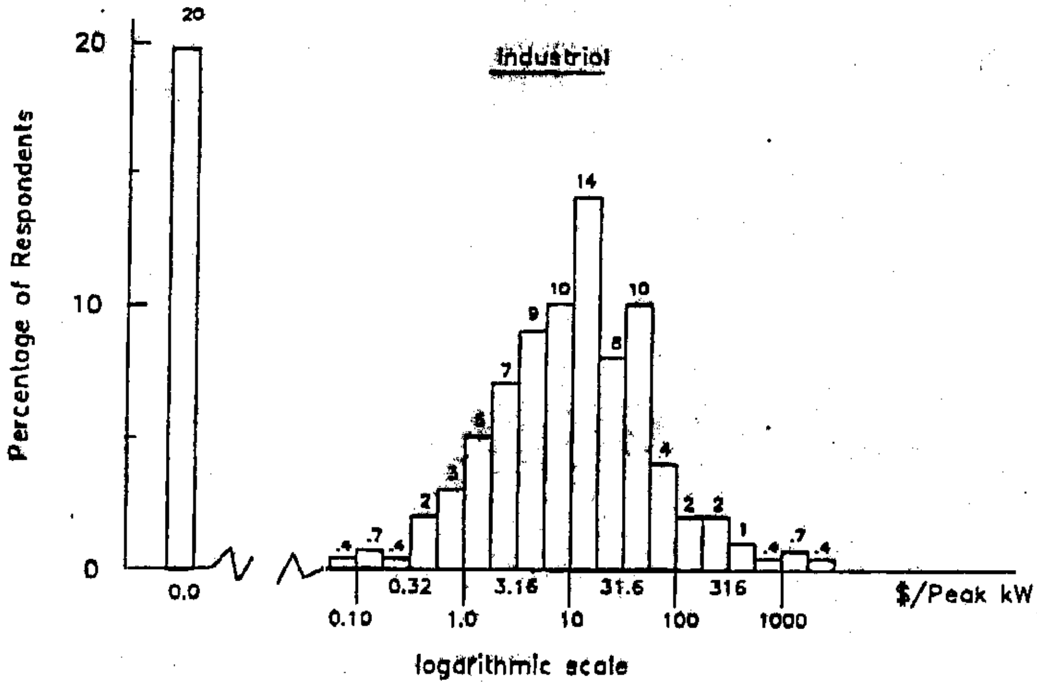
There are two basic sources of information on the distribution of outage costs within customer classes. First, many of the studies provide summaries of the reported outage costs in the form of frequency tables, graphs, or distribution quartiles. Figure 10 illustrates the distribution of reported outage costs, measured in \$/peak kW, reported by commercial

[40] There may be discontinuities in outage costs since it is difficult to partially turn off certain equipment.

[41] Alternative sources of information on the impact of outage depth and outage costs include (a) interruptible/curtailable rate programs and (b) real-time pricing programs. The information available from these sources is discussed in Caves, Herriges and Windle (1989).

[42] See, for example, Chao and Wilson (1987, p. 905).





Source: Billinton, Wacker and Wojczynski (1982, pp. 64 and 91)

Fig. 10. The distribution of one hour interruption costs.

and industrial firms in the Billinton, Wacker and Wjoczynski (1982) study. The pattern depicted in these figures is typical of most studies. The distribution of outage costs is found to be bimodal, with a large percentage of customers assigning zero costs to an outage and the remaining customers having costs distributed around a second peak.[43] The distribution of outage costs (\$/peak kW) appears to be symmetric (in logarithmic terms) for the positive portion of the distribution. One might approximate this pattern using the distribution $f(\mathrm{OC}^*)$, where

$$f(\mathrm{OC}^*) = \begin{cases} P_1 & \mathrm{OC}^* = 0 \\ (1-P_1)\,\phi_{ln}(\mathrm{OC}^*; \mu, \sigma) & \mathrm{OC}^* > 0 \end{cases} \tag{5}$$

where OC^* denotes outage costs in (\$/peak kW), P_1 denotes the probability of a zero outage cost, and $\phi_{ln}(\mathrm{OC}^*; \mu, \sigma)$ denotes the lognormal distribution with parameters μ and σ. Using the information underlying Figure 10, μ and σ can be approximated to be, respectively, 2 and 1.5 for the commercial sector and 2.4 and 1.7 for the industrial sector. Thus, the mean outage cost (\$/peak kW) would be \$16 and \$38 for the commercial and industrial sectors, respectively, with corresponding standard deviations of \$58 and \$190.[44] In this case, the industrial sector has both a higher average outage cost and greater variation in outage costs.

The dispersion of customer outage costs in Figure 10 would seem to bode well for programs, such as priority service, that depend upon customer variability for efficiency gains. However, the reported variation may be illusory. Much of the variation in outage costs may simply reflect differences in the amount of load being interrupted, in this case due to the unknown relationship between peak kW and kWh unserved. Firms will differ in the degree to which they are typically at or near their peak kW. Similarly, the outage cost variance reported above combines variation in outage costs (\$/kWh unserved) and variation in load (kWh unserved). Neither of these problems can be resolved without information on the load patterns and the variability of loads for the customer class used in the study.

This argument is made formally as follows. Let OC denote outage costs denominated in \$/kWh unserved and $R \equiv \mathrm{OC}/\mathrm{OC}^*$. OC, OC^*, and R have some distribution in the population. Since $\mathrm{OC} = \mathrm{OC}^*/R$, we can write that:[45]

$$E(\mathrm{OC}) \approx E(\mathrm{OC}^*)/E(R) - \mathrm{Cov}(\mathrm{OC}^*, R)/[E(R)]^2 + [E(\mathrm{OC}^*)\,\mathrm{Var}(R)]/[E(R)]^3 \tag{6}$$

and

[43] Similar results are reported in Woo and Train (1988), Woo and Gray (1987), and Meta Systems *et al.* (1986).

[44] These results correspond roughly with the numbers reported by Billinton, Wacker and Wojczynski (1982, pp. 64 and 91).

[45] See, Mood, Graybill and Boes (1974, p. 181).

$$\mathrm{Var}(\mathrm{OC}) = [\mathrm{Var}(\mathrm{OC}^*)/[E(\mathrm{OC}^*)]^2 + \mathrm{Var}(R)/[E(R)]^2 \\ - 2\,\mathrm{Cov}(\mathrm{OC}^*, R)/[E(\mathrm{OC}^*)\,E(R)]]\,[E(\mathrm{OC}^*)/E(R)]^2 \qquad (7)$$

While the results from Billinton, Wacker and Wojczynski (1982) can be used to provide estimates of $E(\mathrm{OC}^*)$ and $\mathrm{Var}(\mathrm{OC}^*)$, information is still needed on the variables $E(R)$, $\mathrm{Var}(R)$ and $\mathrm{Cov}(\mathrm{OC}^*, R)$ for the surveyed population.[46,47]

The second potential source of information on the distribution (i.e., variability) of outage costs within customer classes lies in the standard errors and other summary statistics provided by the analyses of variance and the regression analyses reported in the literature. For example, consider the Woo and Train (1988) study, which reports the results from estimating a two-stage model of commercial outage costs. Their assumptions regarding the distribution of outage costs are similar to those used in equation (5) above. The first stage models the probability that outage costs are positive (i.e., P_1 in equation (5)), while the second stage models the magnitude of outage costs given that outage costs are positive (i.e., ϕ in equation (5)).

A major difference between the model in Woo and Train (1988) and the model in equation (5) is that the former measures outage costs in (\$/interruption), while the latter focuses on (\$/peak kW).[48] However, the problems faced in trying to extract information on the variable of interest (i.e., the variation in population outage costs in \$/kWh unserved) are similar. In order to estimate the mean and variance of outage costs in terms of \$/kWh unserved, information is needed on the mean and variance of (kWh unserved/interruption) and the covariance of this variable with outage costs per interruption. This information is not available in Woo and Train (1988).

The distribution of direct outage cost estimates in the residential sector is similar in form to that found for commercial and industrial customers. A large percentage of households report that short power interruption have zero outage costs. The remaining customers have widely varying outage cost estimates. Unfortunately, these distributional results are again based upon outage costs in dollars per interruption. Thus, it is difficult to determine whether outage cost variations reflect differences in the amount of

[46] In general, it would be reasonable to assume that, ceteris paribus, $\mathrm{Cov}(\mathrm{OC}^*, R)$ would be positive, since a higher load factor increases the kWh unserved by an interruption and, hence, the outage costs in terms of \$/peak kW.

[47] One might approximate the distribution of R using information on the distribution of on-peak load factor (PLF), since $R = (\text{peak kW/kwh unserved}) = 1/(\mathrm{PLF}\cdot H)$, where H denotes the number of hours in the interruption. However, an estimate of $\mathrm{Cov}(\mathrm{OC}^*, \mathrm{PLF})$ or $\mathrm{Cov}(\mathrm{OC}^*, R)$ would still be required. Without this information, the mean and variance of the variable of interest cannot be determined.

[48] Woo and Train (1988) do condition on a number of customer size variables, including average electricity bill, number of employees, and the customer's classification as medium, large, or very large.

kWh unserved during an interruption or differences in outage costs per kWh unserved. A number of authors have cited variation in the former as evidence of customer heterogeneity. Doane, Hartman and Woo (1988b), for example, find residential outage costs to range from S0.44/month to $3.71/month for various monthly bill percentiles.[49] The authors conclude from this that there is a '...wide dispersion of outage costs in our sample. For example, households in the 90th monthly bill percentile have outage costs approximately ten times higher than those households in the 10th percentile, confirming our expectations regarding customer heterogeneity'.[50] However, this reported heterogeneity is due solely to variation in the size of customer bills in these percentiles. Normalizing these same numbers by average monthly bills in each percentile results in outage costs that are consistently 3.9 per cent of monthly bills for all percentiles.

2. *The Impact of Customer Characteristics*

An alternative approach to determining the distribution of outage costs is to measure the impact of customer characteristics on outage costs. The distribution of these characteristics in the population in turn implies a distribution for outage costs.[51] The purpose of this subsection is to review the available information on the relationship between outage costs and customer characteristics.

a. Residential Demographic Characteristics. There have been few attempts to characterize the distribution of residential outage costs as a function of customer characteristics. Wacker, Wojczynski and Billinton (1983, p. 3389) found that '...in no case was the amount of variance in cost estimates due to respondent characteristics a large part of the total variance of cost estimates'. Doane, Hartman and Woo (1988b) and Meta Systems *et al.* (1986), on the other hand, find a number of customer characteristics to significantly influence outage costs. The authors find outage cost to vary by customer location (geographically and rural versus urban), customer appliance holdings and when household members are at home. Outage experience is found to increase the proportion of customers reporting positive outage costs, but reduces the level of outage costs themselves.[52]

[49] Doane, Hartman and Woo (1988b, p. 132). These reported outage costs are for two additional 2-hour interruptions per year, measured from a base case of 3 interruptions per year with a duration of 2 hours per interruption.

[50] Doane. Hartman and Woo (1988, p. 131).

[51] This of course assumes outage costs are fully explained in terms of customer characteristics. However, even if this is not the case, the implied variance will provide a lower bound on the variance of outage costs in the population.

[52] As with Woo and Train (1988), the statistical significance of parameters reported in these studies are likely to be overstated because the models do not control for correlations among responses by the same customer to different outage scenarios.

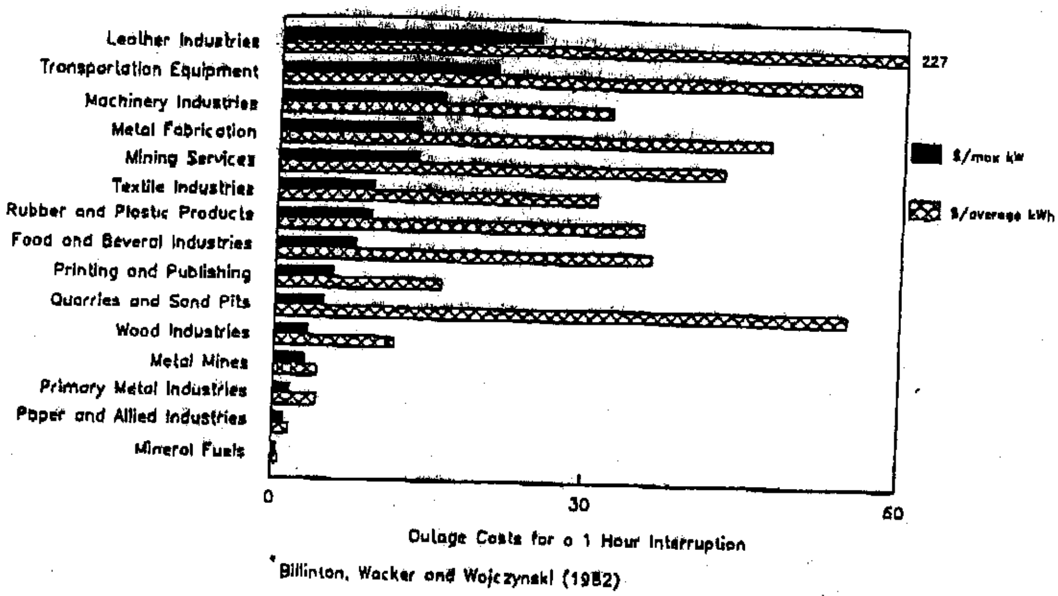


Fig. 11. Outage costs for mining and manufacturing categories.*

Again, however, it is difficult to determine from these studies whether their results indicate variations in the size of the interruption or in outage costs per kWh unserved. The variable modeled in both studies is outage costs per interruption. While customer bills are used in both studies to control for customer size, these variables will not capture variations in customer load patterns and perceived kWh unserved. For example, both studies typically find outage costs are lower when fewer household members are at home during the interruption. This result may simply reflect the fact that such households will also have less usage during the interruption (i.e., lower kWh unserved).

b. Industrial and Commercial Characteristics

(I) Industrial Classification. Virtually all of the industrial and commercial outage cost studies have attempted to measure the variation in outage costs by industrial classification. Billinton, Wacker and Wojczynski (1982, p. 209), for example, provide outage costs for major industrial categories (e.g., transportation equipment, food and beverage industries, etc.). Figure 11 illustrates the reported outage costs for 15 of these categories, using both $/max kW and $/average kWh as outage cost measures. One hour outage costs range from under $2.00/(average kWh) for Mineral Fuels and Paper and Allied Industries to over $60/(average kWh) for Leather Industries. Ontario Hydro (1977) reports similar results for 12 industry groups, with less variation in the outage costs among groups. The authors also graphically depict the range of outage cost estimates within each industry group. For example, the iron foundries in the Ontario Hydro sample have outage costs that fall in a very narrow band (from $0.30 to $0.90/kW for a 1 hour interruption) while the outage costs for iron and steel mills range from $0.10 to over $10.00/kW.

There are two limitations to the results in Ontario Hydro (1977) and Billinton, Wacker and Wojczynski (1982). First, industry specific outage cost estimates are typically based on few observations (i.e., less than 10) so that differences between industries may not be statistically significant. Second, much of the variation in outage costs by industrial category may reflect differences in load factors across groups. Ceteris paribus, low load factor industries will have lower outage cost in S/max kW becuase max kW overstates the actual kWh unserved in the event of an interruption. Figure 11 indicates how the measured outage costs change when calibrated in terms of S/average kWh instead of S/max kW. Not only do the magnitudes change, but also the relative ranking of industries changes.

On the commercial side, Billinton, Wacker and Wojczynski (1982) and Ontario Hydro (1979) both divide the retail sector into retail trade, retail food and retail services. However, the two studies reach somewhat different conclusions. Ontario Hydro (1979, p. 14) finds consistently lower outage costs for retail services and outage costs for retail food that increase dramatically with outage duration. Billinton, Wacker and Wojczynski (1982, p. 59), on the other hand, find similar outage cost patterns in all three retail sectors.

Woo and Train (1988) model direct cost estimates reported in PGandE's 1983 commercial outage cost survey. The authors find that food outlet stores are more likely to report positive outage costs than other retail concerns.[53] However, the impact of the retail sector on outage cost levels is not reported.

(2) Backup Generation and Self-Generation. One would expect that the impact of a power outage would be reduced for firms with standby systems. Subramaniam, Billinton and Wacker (1985) find this to be the case for industrial firms with battery operated standby systems. Outage costs for these customers are approximately 60 per cent lower for a 1 hour interruption when compared to customers with no standby equipment.[54] Outage costs are not reduced to zero for two reasons. First, standby equipment may be costly to operate. Second, standby equipment is not usually installed to maintain production. The primary reasons cited in Subramaniam, Billinton and Wacker (1985, p. 99) for standby equipment are (1) to minimize possible hazard to staff or the public and (2) to prevent damage to equipment, materials or finished products.

In the same study, engine driven standby systems are not found to reduce outage costs in the industrial sector. The authors attribute this result to the higher cost of operating engine driven standby equipment,

[53] The authors attribute this to the potential for food spoilage.
[54] The outage costs reductions are based upon S/(max kW) interruption costs and do not include the capital costs of stand-by systems.

compared with battery operated systems. However, both systems are found to reduce outage costs in the commercial sector, again by nearly 60 per cent.[55]

Woo and Gray (1987) find that industrial firms with self generating capabilities have lower outage costs. Self generation is found (1) to lower the probability that customers assign positive costs to an outage and (2) to reduce outage costs by approximately 40 per cent given outage costs are positive. Back-up power is found to increase the probability of a positive outage cost, but to reduce the level of outage costs by 0.03 per cent for each 1 per cent of back-up power capabilities. Woo and Train (1988) obtain similar results for back-up power used in the commercial sector.

(3) Outage Experience. Two studies have investigated the impact of outage experience on outage costs: Woo and Gray (1987) in the commercial sector and Woo and Train (1988) in the industrial sector. Both studies find that customers are more likely to assign positive costs to a power interruption if they have experience with interruptions. In the industrial sector, this experience also leads to higher self-stated outage cost levels. However, Woo and Train (1988) find that commercial firms with outage experience report outage costs that are nearly 30 per cent lower than those without experience.

c. Summary. There have been few attempts to date to characterize the distribution of outage costs as a function of customer characteristics. Furthermore, the studies which have modelled outage costs as a function of customer characteristics have typically relied upon $/interruption measures, instead of $/kWh unserved. This complicates attempts to relate outage cost levels and customer characteristics. Current evidence does not reveal whether outage costs in $/kWh unserved really depend upon customer characteristics or whether the apparent dependencies only reflect variations in the size of the customer or differences in load factor. While some authors have attempted to control for firm size in their analysis, the size variables are only proxies for the kWh unserved by an interruption. Billinton, Wacker and Wojczynski (1982) find commercial outage costs in $/interruption are significantly affected by firm characteristics, including commercial space, annual sales and number of employees. However, when these same data are normalized in terms of $/peak kW or $/kWh, '...the analysis do not indicate that there is a significant relationship between... [outage cost] estimates and the respondent characteristics'.[56] The above comments are not meant to imply that the variation is insignificant. However, additional research is still needed in order to determine the distribution of outage costs and its relationship to customer characteristics.

[55] Billinton, Wacker and Subramaniam (1986, p. 30).
[56] Billinton, Wacker and Wojczynski (1982, p. 80).

V. ALTERNATIVE SOURCES OF INFORMATION

Traditionally, utilities have marketed electricity as a homogeneous product. Changes in the electric power industry over the past two decades, however, have led to the introduction of numerous innovative rate and service options that unbundle the attributes of electric power, including reliability. A number of these programs provide a potential source of information on the demand for service reliability. In this subsection, two programs are reviewed in terms of their current and potential information on the demand for service reliability: (1) interruptible/curtailable (I/C) rates and (2) real-time pricing (RTP).

A. *Interruptible/Curtailable Service*

Interruptible/Curtailable (I/C) service is a form of priority service that has been in use in the electric power industry for over 35 years. Under I/C rates, the customer specifies a maximum level of demand known as the firm power level (FPL). The customer can utilize electricity service up to the FPL as if standard service applied. However, usage above the firm power level is subject to interruptions. In exchange for the lower reliability level for usage above the FPL, the firm receives a bill credit, typically in the form of a demand charge credit. I/C service is typically available on a voluntary basis in the commercial and industrial sectors. I/C service represents a simple form of priority service, with customers segmenting their loads into two reliability segments. Usage up to the FPL is serviced at the standard reliability level, while usage above the FPL (interruptible power) is serviced at a reduced reliability level determined, in part, by contractual limits on the frequency and duration of interruptions.[57]

Customer response to I/C programs can potentially provide information on the value firms place upon service reliability. This information is revealed in three decisions made by the firm. First, the customer must choose whether to participate in an I/C program. Assuming risk neutral behavior on the part of the firms, this will happen only if the total cost they expect to incur under the program is less than the credit they expect to receive. The second decision involves the selection of a firm power level. The choice of an FPL reveals the level of load at which the credit from putting one more kW at risk is offset by the expected costs of interrupting that kW. The third decision involves the firm's behavior at the time of an interruption. Most I/C rates allow customer to ignore an interruption request. The cost of non-compliance is typically a penalty imposed upon each kW used in excess of the FPL. Thus, the penalty for non-compliance

[57] See Caves, Herriges and Windle (1988) for a description of the different elements typically found in I/C programs and a review of ten existing programs.

places an upper bound on the outage costs for those firms that comply and a lower bound on outage costs for those firms that do not comply.

There have been few studies explicitly linking customer participation and response to I/C rates to the value of service reliability. This is, in part, due to the lack of information available on the reliability levels perceived by program participants. Many programs have contractual limits on the number of interruptions, but do not use these maximums. Thus, it is difficult to infer the customer's expectations regarding the extent of power interruptions. Without information on the expected kWh unserved by an I/C program, the outage costs ($/kWh unserved) cannot be inferred. In a recent study, Caves (1989) reports that, using data from ten I/C programs, utility credits per kWh unserved exceeded $23 for half of the programs on the basis of historical or contractual interruption patterns. This exceeds the outage costs ($/kWh unserved) typically reported in the industrial sector. Yet for these same programs, participation rates were consistently low, ranging from 2.8 per cent to 12.4 per cent.[58]

The primary lesson from the research to date using I/C programs is that reliable outage cost estimates will only be forthcoming from these programs when customers receive precise definitions of the reliability they can expect to experience under the program and analysts can obtain from participants and non-participants measures of their outage expectations. In addition, both participants and analysts must know the expected loads during these interruptions (i.e., kWh unserved).

B. *Real-Time Pricing*

Real-Time Pricing (RTP) refers to a class of rate structures in which the price of electricity changes frequently in order to reflect current information on system costs. The extreme form of RTP, 'spot pricing', allows the price of electricity to change instantaneously with no limitations on its level or variability over time. In practice, real-time pricing programs have abstracted from this extreme by providing customers with advance warning, limiting the number of hours in the year subject to sudden price changes, limiting the range of price changes, and or limiting the number of daily patterns RTP prices can follow.[59]

The relationship between real-time pricing and service reliability is less direct than for I/C programs. RTP does not alter the reliability with which customers receive power. However, customer response to rapidly

[58] While the low participation rates may indicate that customer outage costs are high, one must be careful in drawing this conclusion. A number of the I/C programs in the US were introduced as a means of reducing electricity prices in the industrial and commercial sectors and were targeted at specific firms. Other programs, however, such as the one at General Public Utilities, indicate a genuine interest in cost avoidance, using numerous interruptions and significant penalties for non-compliance.

[59] See Caves, Herriges and Windle (1988) for a review of recent RTP programs.

Drop By

REQUEST:

1. Refer to pages 2 through 5 of the Direct Testimony of James P. Torgeson concerning the history and growth of MISO.

   a. Provide the following information for each year since 1996.

      (1) MISO's capital and operating budgets, as approved by its board of directors, as well as any interim amendments made to those budgets.

      (2) The allocation of MISO's annual budgets to Day One and Day Two (energy markets) activities.

      (3) The total amount of the budget allocated to salaries and benefits and the number of employees included in the budget.

   b. Provide the following information for each of the past 3 years beginning in January 2001.

      (1) The salary for each officer at the level of vice president and above, and each director, and any bonus awarded.

      (2) The level of compensation paid to members of the MISO board of directors.

   c. Provide any salary or compensation study or analysis performed by or for MISO. If none exists, explain in detail how MISO establishes the compensation levels for its officers and directors.

OBJECTION:

The information sought in this Request is beyond the scope of the testimony of any of the witnesses on behalf of the Midwest ISO and of the issues designated by the Commission in its order initiating this proceeding. However, without waiving its objection, and in a spirit of cooperation, the Midwest ISO provides the following response.

Witness: Michael P. Holstein

RESPONSE:

a. The information requested does not exist for the time period specified. The earliest complete records containing this information date from the year 2000.

(1) Attached is a copy of the Midwest ISO's Capital and Operating Budgets, as approved by the Midwest ISO Board of Directors, for the years 2000 through 2004.

(2) Attached is an allocation of the Midwest ISO's Capital and Operating Budgets, as approved by the Midwest ISO Board of Directors, showing transmission costs recoverable under Schedule 10 for Day 1 as well as market costs recoverable under Schedules 16 and 17 for Day 2.

(3) Please refer to the document provided in response to Request 1(a)(1).

b. (1) Attached is a chart of the salaries of the Midwest ISO officers (at the level of vice president and above) as reported in the FERC Form 1 (Annual Report for Major Electric Utilities, Licensees and Others) for the years 2001 and 2002. As reported in the FERC Form 1, the amounts shown are cumulative of each officer's salary and bonus. Those cumulative amounts are not yet available for the year 2003, but will be reported on the FERC Form 1 to be filed on or before April 30, 2004. Elements of the compensation of the directors are provided in the next subpart of this Response.

(2) The level of compensation paid to members of the Midwest ISO Board of Directors is voted on by Midwest ISO members. Payments to the directors are as follows:

- $30,000 – Director Fee per annum paid quarterly;
- Chairman Fee of $10,000 and Vice Chairman Fee of $5,000 per annum paid quarterly;
- Committee Chairs - $3,000 per annum;

Witness: Michael P. Holstein

- Board Meetings and Committee Meetings - $1,000 per meeting;
- Meetings not coinciding with Board Meetings - $1,000 per meeting;
- Conference calls – not to exceed $500 per call; and
- Deferred Compensation per annum - $15,000 paid quarterly.

c. The Midwest ISO engages The Hay Consulting Group ("THCG") to annually assess the relevant market and establish salary ranges appropriate for the job requirements of each officer. The Midwest ISO has also engaged THCG to assess the relevant market for board of director compensation. The resultant work product is proprietary to THCG, and is provided to the Midwest ISO pursuant to an agreement by which its confidentiality must be maintained.

Witness: Michael P. Holstein

MISO
Capital and Operating Budgets - Approved by Board of Directors
Request No. 1 - Operating and Capital Expenditures Budgets

	Budget 2000	Budget 2001	Budget 2002	Budget 2003	Budget 2004
Customer Service and Informational	$0	$0	$87,792	$345,824	$168,322
Salaries and Benefits	8,559,476	18,751,006	24,707,443	40,496,371	49,494,146
Outside Services	2,826,196	4,724,525	6,665,164	20,155,753	44,438,195
Occupancy/Telecommunications	690,108	5,068,098	9,856,316	12,562,204	12,694,517
Insurance	260,000	299,171	3,518,106	2,356,592	5,006,952
Supplies and Other	3,165,791	2,944,542	4,482,435	15,071,889	17,187,193
Taxes	399,040	0	306,608	775,052	312,002
Total Operating Expenses w/o Interest and Depr/Amort	**$15,900,611**	**$31,787,342**	**$49,623,864**	**$91,763,685**	**$129,301,327**
Interest	1,395,459	15,125,536	10,113,920	19,999,410	21,410,963
Depreciation/Amortization	0	434,627	26,676,710	32,721,278	40,119,377
Total Operating Expenses	**$17,296,070**	**$47,347,505**	**$86,414,494**	**$144,484,373**	**$190,831,667**
Capital Budget	**$25,842,019**	**$65,242,171**	**$32,697,800**	**$61,497,460**	**$80,600,000**
Budgeted Headcount		201	210	323	465
Amendments:					
Capital:					
Data Replication			1,875,000		
Market Implementation			19,500,000		
Backup site				$7,500,000	
Data Exchange/Reimbursements				16,700,000	
Outreach, Time Extension				18,238,040	
Security Constrained Unit Commitment				3,544,500	
Total Capital Amendments			21,375,000	45,982,540	
Capital Budget after Amendments:			**$54,072,800**	**$107,480,000**	

Operating:
None

MISO
Capital and Operating Budgets - Approved by Board of Directors
Split between Day1 and Day2

($ in millions)	Budget 2002			Budget 2003			Budget 2004		
	Transmission[1]	Market[1]	Total	Transmission	Market	Total	Transmission	Market	Total
Salaries and Benefits	$24.3	$0.4	$24.7	$36.1	$4.4	$40.5	$32.0	$17.5	$49.5
Outside Services	$6.6	$0.1	$6.7	$18.8	$1.4	$20.2	$22.6	$21.9	$44.5
Occupancy/Telecommunications	$13.4		$13.4	$13.9	$1.0	$14.9	$11.7	$6.0	$17.7
Supplies and Other	$4.4	$0.5	$4.9	$11.4	$4.8	$16.2	$12.0	$5.6	$17.6
Total Operating Expenses w/o Interest and Depr/Amort	**$48.7**	**$0.9**	**$49.6**	**$80.2**	**$11.6**	**$91.8**	**$78.3**	**$51.0**	**$129.3**
Interest	$10.1	$0.0	$10.1	$12.8	$7.2	$20.0	$12.3	$9.1	$21.4
Depreciation/Amortization	$26.7	$0.0	$26.7	$32.5	$2.7	$32.7	$34.8	$5.3	$40.1
Total Operating Expenses	**$85.5**	**$0.9**	**$86.4**	**$125.5**	**$21.5**	**$144.5**	**$125.4**	**$65.3**	**$190.8**
Capital Budget	**$29.1**	**$25.0**	**$54.1**	**$20.2**	**$87.3**	**$107.5**	**$17.0**	**$63.6**	**$80.6**

[1] Transmission means costs recoverable under Schedule 10 (Day 1); Market means costs recoverable under Schedule 16/17 (Day 2)

Note: Cummulative market budget will not agree to FERC 60-day filing because the 60-day filing is updated with actuals.

For example, in 2003 $87.3 million was not spent on capital. $24.7 million was carried forward and is included in the $63.6 million.

Also, other costs included in the market budget (recoverable under Schedules 16/17) are not included in the midwest market initiative FERC filing. These expenditures include:

- Joint Operating Agreement
- Joint and Common Market
- Business Continuity Expenditures
- Price Transparency

Salary for each officer at the level of vice president and above

Reported on Form 1

		2001	2002
Jim Torgerson	President and CEO	464,160	879,152
Michael Holstein	Vice President and CFO	136,895	325,300
Michael Gahagan	Vice President, CIO & CSO	285,943	459,515
William Phillips	Vice President of Operations	274,832	428,878
Stephen Kozey	Vice President, General Counsel & Secretary	269,250	436,300
Alex DeBoissiere	Vice President & Chief Regulatory & Legislative Officer	-	144,902

REQUEST:

2. Refer to Exhibit RCH-1 of the Direct Testimony of Roger C. Harzy. Explain whether Mr. Harzy attributed the increase number of Transmission Load Relief procedures at level 4 ("TLR-4s") since MISO took over control of the Louisville Gas and Electric Company and Kentucky Utilities Company ("LG&E/KU") system to the fact that TLR-4 type reconfigurations and redispatch did not previously occur, or to the fact that such actions were not previously identified and reported as TLR-4s.

RESPONSE:

The most likely explanation for the increase of TLR Level 4s is that since the Midwest ISO has begun operations, it has been able to identify many instances not previously identified where – for a single contingency – a portion or all of the LGEE/Kentucky transmission system would be at risk of significant overloading, or instability.

In the event that LGEE had chosen not to redispatch under a TLR Level 4 for these constraints, the Midwest ISO then would have been forced to issue TLR Level 5 on the same constraints. This would have resulted in curtailment of firm point-to-point transmission service and a reduction in LGEE's generation to load impacts across the constraint.

Supporting this explanation, there were no significant changes to the transmission system in the Kentucky area or surrounding areas in the year immediately prior to the Midwest ISO becoming operational, or the years following, that would account for the substantial increase in the number of constraints identified and acted upon by the Midwest ISO, reflected in the exhibit.

Witness: Roger C. Harszy

REQUEST:

3. Refer to page 12 of the Direct Testimony of Jonathan Falk ("Falk Testimony") concerning the NERC Disturbance Analysis Working Group ("DAWG") reports used in his analysis of expected lost kilowatt-hours ("kWh").

    a. Explain how Mr. Falk determined that all DAWG reports since 1990 were the appropriate reports to review for his analysis.

    b. Explain in detail why all DAWG reports since 1990 are representative of lost kWh for LG&E/KU.

RESPONSE:

a. The 1990-2000 DAWG reports I used provide a sample which is both large enough to be reliable and contemporary enough to exclude conditions which do not resemble today's conditions. In any case, the distribution is fairly stable over time.

b. Since these outages represent a wide range of individual systems, I know of no reason why they should not be representative for LG&E/KU.

Witness: Jonathan Falk

4

REQUEST:

4. Refer to page 17 of the Falk Testimony concerning the possibility of LG&E/KU withdrawing from MISO.

   a. Explain whether MISO performs reliability coordinator function for non-MISO members. Is yes, describe the terms of such arrangements and provide any formal documentation of such terms, if it exists.

   b. Provide a cost estimate for MISO to assume reliability coordination functions for LG&E/KU assuming they are not members of MISO. Explain if this estimate is reasonable to compare to the $2.7 million identified in the Falk Testimony as the reliability benefits provided to LG&E/KU through membership in MISO. If a comparison is not reasonable, explain why.

RESPONSE:

a. The Midwest ISO performs reliability coordination services for MAPPCOR pursuant to a contract with MAPPCOR. The Midwest ISO does not currently perform reliability coordination services for other entities that are not members of the Midwest ISO.

b. No such analysis exists.

Witness: (a) Roger C. Harszy
(b) Jonathan Falk

REQUEST:

5. Refer to pages 3 through 5 of the Direct Testimony of Michael P. Holstein ("Holstein Testimony") concerning the merger of LG&E/KU.

   a. Identify the specific evidence which Mr. Holstein relies upon to conclude that the merger of LG&E/KU would not have occurred absent their commitment to join MISO.

   b. Explain whether Mr. Holstein has knowledge of whether the Federal Energy Regulatory Commission ("FERC") would have withheld its approval of the merger if LG&E/KU had committed to join a Regional Transmission Organization ("RTO") as opposed to committing to join MISO.

RESPONSE:

a. Among the criteria examined by the Federal Energy Regulatory Commission ("FERC") in reviewing a Federal Power Act Section 203 application is the effect a merger would have on competition. The LG&E/KU merger threatened to create unacceptably high concentrations of generation ownership in the region. But for the voluntary agreement of LG&E and KU to place their transmission assets under the control of an independent system operator, it is likely that the FERC would have denied merger approval due to adverse effects on competition. The specific evidence on which Mr. Holstein relies is the FERC's order approving the LG&E/KU order, which appears at *Louisville Gas and Electric Co.*, 82 FERC ¶ 61,208 (1998).

Moreover, in recent mergers, the FERC has consistently relied upon the applicants' commitments to participate in an independent system operator or RTO, including the Midwest ISO, as a condition of the merger. See the following:

- AEP secured federal and state approvals for the nation's largest utility merger based largely on a commitment to place all of its eastern and all of its southwestern transmission facilities under market-independent regional control by year-end 2001. See, *e.g., American Electric Power Co., et al.*, Opinion No. 442, 90 FERC ¶ 61,242, at 61,788

(2000), *aff'd sub nom., Wabash Valley Power Ass'n v. FERC,* 268 F.3d 1105 (D.C. Cir. 2001).

- In *Ameren Services Co.*, 101 FERC ¶ 61,202, at 61,842, ¶ 44 (2002), the Commission made clear that the commitment by Ameren and CILCO to participate in MISO was an action regarded by the Commission as "essential" in the Commission's approval of the Ameren-CILCO merger.

- The merger application that created Exelon was premised on ComEd's commitment to join an RTO, and the Commission relied on that commitment in allowing the merger. As the Commission correctly summarized matters (in a final order that is binding on each of the former Alliance Companies, including ComEd), ComEd is one of the "numerous Alliance Companies [that] as a result of merger conditions or commitments made in merger proceedings, are required to join an RTO." *Alliance Companies, et al.*, 97 FERC ¶ 61,327, 62,531 n. 35 (2001), *citing Commonwealth Edison Company, et al.,* 91 FERC ¶ 61,036 (2000). The Commission further relied on ComEd's commitment to participate in some RTO when it allowed ComEd to withdraw from the Midwest ISO. See *Illinois Power Co., et al.*, 94 FERC ¶ 61,069 (2001).

- FirstEnergy has also long been required to join an RTO as a condition to the merger that formed it. See *Alliance Companies, et al.*, 97 FERC 61,327 at 62,531 n. 35, citing *Ohio Edison Co., et al.*, 94 FERC ¶ 61,291.

- After Dynegy and Illinova expressly relied on Illinois Power's participation in the MISO to support their then-pending merger (see Joint Application in Docket No. EC99-99 at 6, 30, 36, and Appendix B), the Commission relied on Illinois Power's MISO participation in finding no adverse rate effects from the merger. *Illinova Corporation, et al.,* 89 FERC ¶ 61,163, 61,487-88 (1999). Also see the citation of this order in *Alliance Companies, et al.*, 97 FERC 61,327 at 62,531 n. 35. The Commission further relied on Illinois Power's commitment to participate in some RTO when it allowed Illinois Power to withdraw from the Midwest ISO. See *Illinois Power Co., et al.,* 94 FERC ¶ 61,069 (2001).

Witness: Michael P. Holstein

- In approving the proposed Columbia-NiSource merger, the Commission made clear that it was relying upon NIPSCo's commitment to join a Commission-approved RTO within one year of merger closing. *NiSource Inc. and Columbia Energy Group*, 92 FERC ¶ 61,068, 61,239-40 (2000).

b. Mr. Holstein has no specific knowledge with respect to this question, which involves "what-if" speculation. Mr. Holstein would note, however, that Independent System Operators ("ISOs") and RTOs are both independent entities that ensure open and non-discriminatory transmission access to promote competition. Thus, the form of organization would not likely have been material to the merger approval. In Order No. 2000, the Commission mandated that ISOs acquire the characteristics and functionality to become RTOs; therefore, the Midwest ISO, which began its existence as an ISO, matured into the nation's first RTO.

Witness: Michael P. Holstein

REQUEST:

6. Refer to pages 11 through 15 of the Holstein Testimony concerning the estimated benefits to LG&E/KU through 2010 of continued membership in MISO.

   a. Explain whether the starting year for the period "through 2010" is 2004. If yes, explain why 2004 was used rather than 2005 as was used in the Direct Testimony of Dr. Ronald R. McNamara ("McNamara Testimony").

   b. Provide the derivation of the Net Energy Market Benefits of $197.8 million shown on page 14.

   c. Provide the derivation of the $95 million in net present value of benefits shown on page 11, which are referenced to the McNamara Testimony.

RESPONSE:

a. The starting year for the period "through 2010" in Mr. Holstein's pre-filed testimony is 2004. This is an error. It should have been 2005. Included with this response are redlined copies of pages 12-14 and 16-17 of Mr. Holstein's testimony, which contain corrected values for these sections. See Attachment #6(a), pp. 1-5.

Please note that the corrections on the attached pages also require corrections to Table RRM_1-1 to Mr. McNamara's testimony. The corrections made to Table RRM_1-1 to Mr. McNamara's testimony are to the following items:

- Cost of MISO Membership category, line item "Total of Schedule 10, 16, 17 Charges;" and
- Cost of Stand Alone Operation category, line item "MISO Exit Fee."

The net impact of the corrections made to these two line items is to change the result for "Cumulative NPV Savings from MISO Membership" from $95,010,765 in Mr. McNamara's pre-filed testimony to $95,509,956 in the corrected version of Table RRM_1-1. The corrected version of Table RRM_1-1 is Attachment #6(a), p. 6.

Witness: Michael Holstein

b. The derivation of Net Energy Benefits is shown on the document attached hereto as Attachment #6(b). These values are based on the corrected values in Table RRM_1-1, and the corrections to the values in the table on page 16 of Mr. Holstein's revised testimony.

c. The derivation of the $95 million in net present value of benefits shown on page 11 of Mr. Holstein's testimony is summarized in Table RRM_1-1 of Mr. McNamara's testimony.

Witness: Michael Holstein

Midwest ISO's implementation of short-term energy markets in its region. Finally, if LG&E and KU remain in the Midwest ISO, LG&E and KU's retail customers will avoid paying the withdrawal fee that would be imposed under the Transmission Owners' Agreement if LG&E and KU withdraw from the Midwest ISO.

Q. What benefits will LG&E/KU retail customers receive during that period as a result of the companies' merger?

A. As described above, under the settlement agreement approved by the Commission on October 16, 2003, LG&E and KU's retail customers will receive an additional ~~$161,748,846~~$143,776,752 in billing credits as a direct result of the non-fuel savings created by the merger. That amount of billing credits will be paid through June 2008. The costs to achieve the merger savings have been fully amortized, so those billing credits and the lump sum payments made to certain customers will reflect the entire amount of additional merger non-fuel savings realized through June 2008, without offset. Additionally, LG&E and KU's retail customers may receive additional benefits for non-fuel merger savings realized after June 2008.

Q. What are the future benefits of improved reliability through 2010?

A. Based on Mr. Falk's mean value of the reduced probability of loss of load of $2.7 million annually, the reliability benefits through 2010 to LG&E and KU's retail customers as a result of the companies' continued participation in the Midwest ISO is ~~$18.9~~$16.2 million.

Q. What is the sum total of the estimated merger non-fuel savings and reliability benefits through 2010?

A. The sum total of those amounts is approximately ~~$181~~$160 million.

Q. What benefits will LG&E/KU retail customers realize as a result of the Midwest ISO's implementation of short-term energy markets in its region?

A. Dr. McNamara addresses benefits that LG&E and KU's retail customers will realize as a result of the Midwest ISO's short-term energy markets. Dr. McNamara's testimony quantifies certain economic benefits that can only be realized by LG&E and KU's retail customers if LG&E and KU continue to participate in the Midwest ISO. Dr. McNamara estimates that those benefits range between $11.3 million and $12.9 million annually. The net present value of the benefits quantified in Dr. McNamara's testimony is $95 million over the period 2005 through 2010. As Dr. McNamara points out, however, if LG&E and KU continue participating in the Midwest ISO, LG&E and KU's retail customers will realize other potentially significant benefits that cannot easily be quantified.

Q. Do the net benefits quantified in Dr. McNamara's testimony include the estimated merger benefits and reliability benefits quantified above as $181 million over the same period?

A. No, they do not.

Q. Do the net benefits quantified in Dr. McNamara's testimony include a projection of the withdrawal fee required under the Transmission Owners Agreement?

A. Yes.

Q. How much is the projected withdrawal fee?

A. If LG&E and KU decide to pursue a withdrawal, the amount of the withdrawal fee will depend on the effective date of the withdrawal. Under Article Five of the Transmission Owners Agreement, a withdrawing transmission owning member is responsible for all financial obligations incurred and payments applicable to time periods prior to the effective date of the withdrawal. Furthermore, under the Transmission Owners Agreement, a transmission owning member's withdrawal is not effective until December 31 of the calendar year following the calendar year in which notice of withdrawal is given. If LG&E and KU were to give the Midwest ISO a proper notice of withdrawal in calendar year 2003, the earliest they could withdraw is December 31, 2004, assuming all regulatory approvals were obtained in that time frame. Based on the Midwest ISO's current and projected obligations as of December 31, 2004, LG&E and KU's estimated withdrawal obligation as of December 31, 2004, would be ~~$38.2~~$38.3 million.

Q. Why is it not the case, as LG&E and KU contend, that they could withdraw from the Midwest ISO within 30 days of an order by this Commission directing them to do so?

A. The provision in Article Seven of the Transmission Owners' Agreement that LG&E and KU refer to was intended to apply only during the preoperational period — that is from the time those companies executed the Transmission Owners' Agreement until the Midwest ISO commenced operations. This was the

Id. at 62,151.

Q. How do the benefits you have described above compare to LG&E and KU's costs of Midwest ISO membership through 2010?

A. LG&E and KU will continue to pay the Schedule 10 charges described above. Additionally, when the Midwest ISO implements the energy markets, including the administration of Financial Transmission Rights, it will recover its costs for providing those services through two new rate schedules in the Midwest ISO OATT: Schedule 16 (Financial Transmission Rights Administrative Service Cost Recovery Adder) and Schedule 17 (Energy Market Support Administrative Service Cost Recovery Adder). As explained by Dr. McNamara, LG&E and KU's retail customers may also incur certain other costs as a result of participating in the Midwest ISO. The table below illustrates the magnitude of the benefits I have described above relative to the projected costs LG&E and KU will incur to participate in the Midwest ISO through 2010.

Benefits to LG&E and KU Retail Customers Through 2010:

Costs Through 2010	
~~Schedule 10 Costs~~	~~$50,000,000~~
Schedule 10 Costs	$43,900,000
~~Schedule 16 Costs~~	~~$9,000,000~~
Schedule 16 Costs	$8,600,000
~~Schedule 17 Costs~~	~~$29,000,000~~
Schedule 17 Costs	$27,600,000
~~Total Costs~~	~~$88,000,000~~
Total Costs	$80,100,000
Benefits Through 2010	
~~Net Energy Market Benefits~~	~~$197,800,000~~
Net Energy Market Benefits	190,400,000
~~Merger Surcredits~~	~~$161,700,000~~

Merger Surcredits	$143,800,000
~~Reliability Benefits *f*(loss of load)~~	~~$18,900,000~~
Reliability Benefits *f*(loss of load)	$16,200,000
~~Total Benefits (nominal $)~~	~~$378,400,000~~
Total Benefits (nominal $)	$350,400,000
~~Net Benefits (nominal $)~~	~~$290,400,000~~
Net Benefits (nominal $)	$270,300,000

The table above includes 100 percent of the projected costs to be charged to MWhs of Transmission Service associated with LG&E and KU load in 2004 through 2010 under Midwest ISO OATT Schedules 10, 16 and 17. As I explained above, Midwest ISO's Schedule 10 costs are not currently included in base retail rates. However, LG&E and KU recently announced that they will seek an increase in their retail rates. LG&E and KU's notices to the Commission of the forthcoming rate filings indicated that their application and testimony in support of the rate increases would be filed on December 29, 2003, the same day this testimony is due to be filed in this proceeding. Accordingly, I do not know whether LG&E and KU will seek to include their Schedule 10 costs in their historic test year or will propose some other mechanism by which retail customers would pay a portion of the Midwest ISO's Schedule 10, 16 and 17 costs. The table above is a representation of the effect of fully recovering these costs from retail customers.

Q. **Do you believe the Commission should allow LG&E and KU to recover a portion of their Schedule 10, 16 and 17 costs from their retail customers?**

A. Yes. In fact, I believe it is appropriate for LG&E and KU to include in retail rates all of the costs of the Midwest ISO under Schedules 10, 16 and 17. As noted

New Total Benefit - Cost Calculation

Net Benefits to LGE / KU

	2004	2005	2006	2007	2008	2009	2010
Cost of MISO Membership							
System Operations & Transmission Costs							
MRMD Staffing, Training, Consulting		$400,000	$400,000	$400,000	$400,000	$400,000	$400,000
Miscellaneous Uplift Charges		$500,000	$500,000	$500,000	$500,000	$500,000	$500,000
Congestion Costs Not Covered by FTRs		$73	$73	$73	$73	$73	$73
Implementation and Administration Costs							
Total of Schedules 10, 16, 17 Charges		$13,023,172	$13,434,813	$13,725,538	$13,977,637	$13,526,898	$12,441,769
Ancillary Market Cost				$280,000	$280,000	$280,000	$280,000
Legal, Regulatory, & Transaction Costs							
Net Cost of Committee Participation, Contracts		$400,000	$400,000	$400,000	$400,000	$400,000	$400,000
Net FERC Attachement O Fees		$860,000	$860,000	$860,000	$860,000	$860,000	$860,000
Less: Transmission Revenues							
MISO Schedule 1, 7, 8 and 14 Revenues		($21,824,753)	($21,824,753)	($21,824,753)	($21,824,753)	($21,824,753)	($21,824,753)
Total Cost of MISO Membership		**-$6,641,508**	**-$6,229,867**	**-$5,659,142**	**-$5,407,043**	**-$5,857,782**	**-$6,942,911**
Cost of Stand Alone Operation							
MISO Exit Fee	**$ 38,300,000**						
System Operation Costs							
Additional Staffing		$300,000	$300,000	$300,000	$300,000	$300,000	$300,000
Systems Related Costs		$720,000	$720,000	$720,000	$720,000	$720,000	$720,000
Congestion Management Costs		$3,657,767	$3,657,767	$3,657,767	$3,657,767	$3,657,767	$3,657,767
Lost Revenues							
Lost FTR Revenue		$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000
Lost Margin on Wholesale Sales		$8,348,007	$8,348,007	$8,348,007	$8,348,007	$8,348,007	$8,348,007
Less: Transmission Revenues							
LGE/KU Sch 1, 7, 8 and 14 Revenue on Off-System Sales		($9,148,532)	($9,148,532)	($9,148,532)	($9,148,532)	($9,148,532)	($9,148,532)
Total Cost of Stand Alone Operations	**$38,300,000**	**$5,877,242**	**$5,877,242**	**$5,877,242**	**$5,877,242**	**$5,877,242**	**$5,877,242**
Net Cost Savings of MISO Membership	**$38,300,000**	**$12,518,750**	**$12,107,109**	**$11,536,384**	**$11,284,285**	**$11,735,024**	**$12,820,153**
Cumulative Net Savings of MISO Membership	**$38,300,000**	**$50,818,750**	**$62,925,859**	**$74,462,243**	**$85,746,528**	**$97,481,552**	**$110,301,705**
Net Present Value Savings from MISO Membership in 2004	**$38,300,000**	**$11,699,766**	**$10,574,818**	**$9,417,126**	**$8,608,727**	**$8,366,910**	**$8,542,609**
Cumulative NPV Savings from MISO Membership	**$38,300,000**	**$49,999,766**	**$60,574,584**	**$69,991,710**	**$78,600,437**	**$86,967,347**	**$95,509,956**

	2004	2005	2006	2007	2008	2009	2010	Sum		
Net Cost Savings of MISO Members	$38,300,000	$ 12,518,750	$ 12,107,109	$ 11,536,384	$ 11,284,285	$ 11,735,024	$ 12,820,153	$ 110,300,000		
ISO Cost Adders: 2005 - 2010								$ 80,100,000		
Net Energy Market Benefits								$ 190,400,000		
Merger Surcredits									Check:	
- LG&E		$ 18,045,255	$ 18,045,255	$ 18,045,255	$ 18,045,255			$ 72,181,020	$ 18,045,255	2004 LGE
- KU		$ 17,898,933	$ 17,898,933	$ 17,898,933	$ 17,898,933			$ 71,595,732	$ 17,898,933	2004 KU
								$ 143,776,752	$ 35,944,188	
									$ 17,972,094	(1/2 2004)
Reliability Benegits f(loss of load)		$ 2,700,000	$ 2,700,000	$ 2,700,000	$ 2,700,000	$ 2,700,000	$ 2,700,000	$ 16,200,000	$ 161,748,846	
							Total Nominal Benefits	$ 350,400,000	$ 159,976,752	
							Net Nominal Benefits	$ 270,300,000		

REQUEST:

7. Refer to lines 5-7 of page 3 of the McNamara Testimony. Explain what is meant by "physical re-dispatch procedures" to the extent that the term "physical" implies "non-physical" redispatch procedures.

RESPONSE:

(Assuming the question refers to lines 7-8 of page 3 of Mr. McNamara's Testimony:)

Without centralized security constrained economic dispatch based on locational marginal prices, the dispatcher has to use some mechanism other than price to re-dispatch the system in the event a constraint arises. The current methodology, and the one that is used in non-market areas, is to "cut" a schedule. In simple terms, the dispatcher does not allow the schedule to physically flow. There is virtually no means for the parties to the schedule to indicate their willingness to pay additional costs that might be incurred if that schedule were permitted to flow. Under LMP, the schedule is not cut, but rather the associated costs are reflected in the prices and the decision is left to the parties.

Witness: Ronald R. McNamara

REQUEST:

8. Refer to pages 4 through 6 of the McNamara Testimony concerning the estimated benefits of LG&E/KU's continued membership in MISO. Provide the calculations, supporting workpapers, etc. showing the derivation of all the savings amounts identified on these pages.

RESPONSE:

These documents are available in electronic format and are included in the folder named "Staff Item 8" on the CD-ROM named "Public Vol. I" accompanying this response. Those electronic documents for which confidential treatment has been requested are found in the folder named "Confidential Staff Item 8," located on a separate, confidential CD-ROM.

Witness: Ronald R. McNamara

9

REQUEST:

9. Refer line 14 of page 5 of the McNamara Testimony. Explain the term "volume." Does this mean an increase in actual energy produced and capable of being transferred or the dollars realized from the sales?

RESPONSE:

LG&E / KU's participation MISO centralized security constrained economic dispatch and the resulting regional wholesale spot market will increase both the energy produced and the dollars realized from sales when compared to LG&E / KU operation of transmission on a Stand Alone basis outside of the MISO market.

Witness: Paul Centolella

10

REQUEST:

10. Refer line 9 of page 6 of the McNamara Testimony. Explain what is meant by "likely improvement in investment decisions" as referred to in this sentence.

RESPONSE:

The likely improvement in investment decisions refers to the ability to inform investment decisions and operations based on transparent wholesale prices. As described in Section 5 of Exhibit RRM-1, transparent location-specific wholesale markets can improve investment decisions through a variety of mechanisms including:

- Enhancing the options for shifting some or all capital investment risks associated with developing new generating capacity from ratepayers to investors;
- Identifying where it may be cost-effective to build new generation or transmission capacity;
- Facilitating enhanced demand response so as to reduce the need for new investment in generation or transmission capacity;
- Fostering the development of energy products designed to better match consumer risk preferences and facilitating economic consumer investments that reflect the value and marginal cost of power;
- Providing benchmarks and incentives for improved operations and greater unit availability during peak price periods; and
- Improving the evaluation of the timing and capital intensity of investments made under uncertainty.

Witness: Ronald McNamara

REQUEST:

11. Refer lines 15-16 of page 14 of the McNamara Testimony. If there is economic value to a transaction, explain why the transacting entity does not request, and pay for, firm transmission service to avoid having service curtailed.

RESPONSE:

Providing the option to purchase firm service is an inefficient and imperfect substitute for recognizing the time- and location-specific economic value of transmission service. The physical rights model in which distinctions between firm and non-firm service, duration of transmission reservations, and the order in which reservations are received are substituted for prices as indicators of economic value reflects a static perspective on how transmission produces economic value that is at odds with the way in which power systems and electricity markets actually function. For example, a given power transfer may be highly valued by a pair of market participants for a few hours on a given day and not valued at all during any other hours. Since firm transmission service is not offered on an hourly basis, they would have to purchase at least daily firm service—potentially precluding others from buying firm service to meet their high value service requirements during different hours on that day. Having purchased daily firm service, their transaction could nonetheless be preempted by longer term reservations even where the service provided under the longer term reservation produced smaller economic benefits. And, if we extend the example by assuming that this pair of market participants bought long-term firm service, they would receive at most only a right to be curtailed on a pro rata basis under a TLR 4 or above with other transactions that had the same curtailment priority, but potentially a much lower economic value.

Witness: Paul Centolella

12

REQUEST:

12. Refer to lines 23-25 of page 20 of the McNamara Testimony. Explain what is meant by "point-to-point charges are essential to avoid cross-subsidizing transmission users seeking a 'free ride' on transmission investments made by others."

RESPONSE:

In the absence of applying MISO point-to-point transmission service charges to purchases made at the MISO boundary, external purchasers, such as LG&E and KU in the Stand Alone scenario, would become free riders taking power at the MISO boundary without contributing to the recovery of costs for the transmission service required to move that power from generators within MISO to the MISO border. Permitting free riders to purchase at the MISO border without paying for MISO point-to-point transmission service would unfairly penalize MISO members and tend to erode or prevent the development of efficient energy markets.

Witness: Ronald McNamara

REQUEST:

13. Refer to page 21 of the McNamara Testimony concerning KRS 278.214 and how MISO energy markets address the requirement contained therein. Affirm or deny that under the MISO tariffs LG&E/KU will be able to comply with the requirement to interrupt retail loads, only after interrupting all other customers whose interruption may eliminate the transmission emergency.

OBJECTION:

Midwest ISO cannot affirm or deny that one or both of two of its member transmission owners, LG&E and KU, will always or ever be able to comply with the requirement of KRS 278.214 in the face of unspecified hypothetical events in the future. Midwest ISO does not know of any situation that has yet arisen in which there would be any obligation or requirement on LG&E or KU under KRS 278.214; the referenced testimony states that real-time markets, such as the ones being proposed by Midwest ISO, avoid situations in which there are interruptions of service to end-use customers.

Midwest ISO is aware that there is litigation in the Franklin Circuit Court and the federal court for the Eastern District Court involving the Commission and others, including LG&E/KU, in which the meaning and interaction of KRS 278.214 with federal requirements are in dispute. Midwest ISO is not a party to those proceedings and has taken no position with respect to them.

Witness: (Not Applicable)

REQUEST:

14. Refet to Exhibit RRM1-1 to the McNamara Testimony. Does the analysis contained in the exhibit reflect the potential impacts of other MISO projects currently under consideration, such as, but not limited to:

    a. The costs of implementing, operating, and complying with MISO's resource adequacy proposal; and

    b. Potential subsidies for "Reliability Must Run" units that would not be economical to operate without subsidy, etc.

RESPONSE:

a. The analysis contained in the exhibit reflects the potential impacts of implementing, operating and complying with the Midwest ISO's interim resource adequacy proposal to the extent that the Midwest ISO's interim resource adequacy proposal reflects what is currently in place today and implemented by the applicable reliability authorities.

b. No Reliability Must Run units have been identified in or adjacent to the LG&E/KU load zone. The Midwest ISO has not proposed and does not expect that subsidies for Reliability Must Run units will be paid by entities outside the load zone in which any such units may be located. Thus, there were no relevant subsidies for Reliability Must Run units to include in the analysis.

Witness: Ronald McNamara

15

REQUEST:

2. Refer to page 14 of the Falk Testimony concerning surveys related to the value of lost load ("VOLL").

   a. Provide the applicable sections of the Caves, Herriges, and Windle and the Pupp and Woo surveys referenced by Mr. Falk which support the VOLL amounts discussed by Mr. Falk.

   b. The first sentence on line 7 states that there have been many studies of VOLL, although Mr. Falk only references the two studies cited in part (a) of this request. Identify all the other studies with which Mr. Falk is familiar and provide the VOLL estimates from each of these additional studies.

RESPONSE:

a. Copies of the two surveys are provided.

   (N.B. To respect copyrights in the Caves, Herriges, and Windle survey and the Woo and Pupp survey, <u>one</u> copy of each is being filed separately with the Commission. A copy of the surveys is also located at the offices of Midwest ISO's in-house and outside counsel, and may be reviewed there by arrangement with counsel.)

b. In addition to the two surveys specifically referenced in my testimony, studies relating to VOLL with which I am familiar, that are relevant, and for which I can provide specific identifying information are listed below. The specific estimates found in my testimony do not appear in these studies. Rather, I derived those estimates based upon my reading of the entire literature.

   (N.B. Given the volume of the materials and the fact that many are subject to a copyright held by a third party, copies of the identified studies are not provided with this response. Copies of these materials are located at the offices of Midwest ISO's in-house and outside counsel, and may be reviewed there by arrangement with counsel.)

Witness: Jonathan Falk

(1) Stoft, "Price Spikes and the Value of Lost Load," *Power System Economics*, January 31, 2001 (Draft), 128 pp.

(2) Eric Hirst and Stan Hadley, sponsored by U.S. Environmental Protection Agency, Energy Division, "Maintaining Generation Adequacy in a Restructuring U.S. Electricity Industry," October 1999, 53 pp.

(3) Mohan Munasinghe, "Optimal Planning, Supply Quality and Shortage Costs in Power Systems: Case of Costa Rica," *The Energy Journal*, vol. 9, 1988, pp. 43-75.

(4) *The Energy Journal*, vol. 9, 1988, Special Issue on Energy Reliability:

- William B. Poland, "The Importance of Including Uncertainties in Economic Generation Reliability Planning," pp. 19-32.
- Lucien Gouni and Phillipe Torrion, "Risk and Cost of Failure in the French Electricity System," pp. 33-37.
- Eric Woychik, "Regulatory View of Capacity Valuation in California," pp. 39-42.
- Andrew A. Goett, Daniel L. McFadden, and Chih-Keung Woo, "Estimating Household Value of Electrical Service Reliability with Market Research Data," pp. 105-20.
- Michael J. Doane, Raymand S. Hartman, and Chi-Keung Woo, "Household Preference for Interruptible Rate Options and the Revealed Value of Service Reliability," pp. 121-34.
- Michael J. Doane, Raymand S. Hartman, and Chi-Keung Woo, "Households' Perceived Value of Service Reliability: An Analysis of Contingent Valuation Data," pp. 135-49.
- Dennis M. Keane, S. Leslie MacDonald, and Chi-Keung Woo, "Estimating Residential Partial Outage Cost with Market Research Data," pp. 151-59.
- Chi-Keung Woo and Kenneth Train, "The Cost of Electric Power Interruptions to Commercial Firms," pp. 161-88.

(5) Arun P. Sanghvi, "Optimal electricity supply reliability using customer shortage costs," *Energy Economics*, vol. 5, no. 2, April 1983, pp. 129-36.

Witness: Jonathan Falk

(6) Douglas W. Caves, Joseph A. Herriges, and Robert J. Windle, "The Cost of Electric Power Interruptions in the Industrial Sector: Estimates Derived from Interruptible Service Programs," *Land Economics*, vol. 68, no. 1, February 1992, pp. 49-61

(7) Southern Australian Independent Industry Regulator, "Electricity Tariffs and Security of Supply," Information Paper No. 1, June 2000, 24 pp.

(8) Klaus Moeltner and David Layton, "A Censored Random Coefficients Model for Pooled Survey Data With Application to the Estimation of Power Outage Costs," 37 pp.

(9) Benjamin Bental and S. Abraham Ravid, "A simple method for evaluating the marginal cost of unsupplied electricity," *The Bell Journal of Economics*, vol. 13, no. 1, Spring 1982, pp. 249-53.

(10) Energy Information Administration, "Performance Issues for a Changing Electric Power Industry," January 1995, Appendix B (The Economics of Electric Power Reliability), pp. 45-47.

(11) Michael L. Telson, "The economics of alternative levels of reliability for electric power generation systems," *The Bell Journal of Economics*, vol. 6, no. 2 (1975), pp. 679-94.

Witness: Jonathan Falk

REQUEST:

3. Refer to pages 15 and 16 of the Falk Testimony concerning the aggregate value of increased reliability.

   a. Provide a detailed description of the "sample from the distribution of lost kilowatt-hours [used] to simulate kilowatt-hours lost in the outage."

   b. Provide the VOLL amount(s) used in Mr. Falk's analysis.

   c. Provide the loss amount for each percentile from 86 to 89 and from 91 to 95.

RESPONSE:

a. The distribution of lost kilowatt-hours was modeled as log-normal with parameters of $\mu = 12.73$ and $\sigma = 2.14$. Thus, to simulate lost kilowatt-hours, the rand() function of Excel was used to simulate a uniform 0-1 value, the normsinv() function of Excel was used to transform this value into a standard normal variate, and then Excel's exp() function was used to transform the standard normal times μ plus σ into a lognormally distributed variate.

b. VOLL was chosen as a uniformly distributed value between $4.00 and $8.00. Thus, it varied across iterations.

c.

86	$0
87	$17,993
88	$125,323
89	$278,882
91	$818,670
92	$1,285,268
93	$1,962,811
94	$2,996,527
95	$4,519,328

Witness: Jonathan Falk

Drop Box

20

REQUEST:

20. Please provide a list of the specific services that are provided or will be provided by MISO that create merger benefits for LG&E/KU retail customers.

OBJECTION:

The Midwest ISO objects to this request as it is premised on a misreading of the prepared Testimony filed on its behalf. The merger benefits are those savings that have been claimed by LG&E and KU as stemming from the merger of those two companies, and are to be shared with their Kentucky retail customers through the tariffed merger surcredit. The FERC's approval for that merger was based on continued LG&E and KU participation in the Midwest ISO; therefore, that participation was either a but-for condition or one of the sufficient conditions for effecting the LG&E-KU merger. No merger, no merger benefits. Although services are and will be provided to Midwest ISO members, it was membership participation, rather than the receipt of those services, that was the necessary or facilitating condition of the FERC's approval of the merger. Please refer to pp. 3-5 and 10-11 of the Testimony of Michael P. Holstein and pp. 8-11 of the Testimony of James P. Torgerson.

Witness: (Not Applicable)

REQUEST:

21. Please provide all data, work papers and any other supporting documents that were used by Mr. McNamara or by any persons that Mr. McNamara supervised in the preparation of the cost-benefit study for which Mr. McNamara provides testimony in this proceeding. Please provide all electronic files, such as Excel Spreadsheets, Access Databases, CSV files (i.e., text files) and files that are the product of any computer software programs that were used in the conduct of the study on which Mr. McNamara testifies.

OBJECTION:

The request for "all data, workpapers and any other supporting documents" and "all electronic files … that are the product of any computer software programs" calls for a massive amount of information, some of it ephemeral in nature and some of it not within the possession or control of the Midwest ISO. To provide a complete response would require, *inter alia*, turning over proprietary software and source code, intermediate data generated during model runs, and computer diagnostic and transactional information. Much of the material sought is irrelevant and would be unduly burdensome to produce (particularly given that it is of dubious usefulness to the requesting party). In addition, the request asks for (1) information protected from disclosure as attorney-client communications or work product; (2) data provided by LG&E/KU or which it has already received and reviewed pursuant to an agreed-upon procedure for confirming or verifying the accuracy of information about LG&E/KU; and (3) information which is confidential or proprietary to the Midwest ISO or a third party or for which open disclosure would give LG&E/KU or others an unfair competitive advantage.

Without waiver of its objection and in the spirit of cooperation, the Midwest ISO is providing a response to this request. In addition to documents and files provided in response to more specific requests, a large number of electronic files are provided on accompanying CD-ROMs. However, despite the volume of data it is providing, the Midwest ISO is <u>not</u> providing all responsive material. It is not providing information protected from disclosure, or data for which the burden of production is undue given the limited relevance or usefulness of the data or

Witness: Ronald McNamara

the competitive harm that might result from open disclosure. An example of such undue burden would be the production of the 30-second interval data from the MISO flowgate monitoring tool; where hourly interval data has been compiled, it is being provided.

RESPONSE:

See, generally, the files on the accompanying CD-ROMs "Public Vol. I" and "Public Vol. II." Electronic files responsive to this request for which confidential treatment is sought are contained on a "Confidential Volume" CD-ROM.

See also the attachments to the responses to Staff Data Requests 1 and 6, and LG&E/KU Data Requests 44 and 45.

Witness: Ronald McNamara

22

REQUEST:

22. Mr. McNamara (p. 4. *ll.* 17-19) states that continued membership after the implementation of centralized security constrained economic dispatch and the resulting day- ahead and real-time energy markets yields yearly ongoing net benefits of approximately $12 million per year. Mr. McNamara, (p5 *l.* 15) states that, compared to the stand-alone case, it is anticipated that LG&E/KU will realize approximately $8.3 million in additional benefits from being part of a large regional wholesale electricity market. Please account for the difference between the $8.3 million and $12 million.

RESPONSE:

On p. 4 at *ll.* 17 – 19, my testimony refers to the net annual benefit of continued membership in the MISO after implementation of centralized security constrained economic dispatch and the resulting energy markets. This figure of approximately $12 million per year in savings is reflected on the Net Cost Savings of MISO Membership line of Table RRM_1-1.

On p. 5 at *l.* 15, my testimony discusses the annual benefits of being part of a large regional wholesale electricity market associated with the opportunity for LG&E / KU to increase the volume of their off-system sales. The figure of approximately $8.3 million per year in annual benefits is reflected in the Lost Margin on Wholesale Sales line of Table RRM_1-1.

The differences between the $8.3 million and $12 million figures are shown in Table RRM_1-1.

Witness: Ronald McNamara

REQUEST:

23. Mr. McNamara (p. 14, *ll. 18-25)* describes how NERC TLR procedures can affect transactions. Will MISO use TLRs after the Day 2 startup? If so, will MISO base its TLR calls on actual power flows or on estimated distribution factors?

RESPONSE:

The Midwest ISO will use TLRs after Day 2 startup to curtail transactions that are "in" or "out" transactions, meaning that the transaction has a source outside of the Midwest ISO and a sink within the Midwest ISO, or conversely, a source within the Midwest ISO and a sink outside of the Midwest ISO. In these instances, the use of TLR will be based upon actual power flows.

Witness: Ronald McNamara

REQUEST:

24. Mr. McNamara (p. 16, *ll.* 1-20) discusses MISO's use of real-time information from multiple utilities.

    a. Will MISO be able to perform in real-time the analysis that Mr. McNamara describes in his testimony as "after the fact"?

    b. Please explain why the use of AEP is a reasonable example even though AEP is not (and does not intend to be) a MISO member.

    c. What is the status of negotiations with AEP on a coordination agreement with MISO?

RESPONSE:

a. Yes. For the management of real-time market mitigation of internal constraints, real-time data will be used to manage transmission facilities rather than predicted effects.

b. The AEP line is just an example. However, we will be monitoring and including contingencies from the Baker to Bradford line in our dispatch process.

c. The Midwest ISO and AEP have begun confidential discussions regarding the development of a coordination agreement.

Witness: Ronald McNamara

REQUEST:

25. Mr. McNamara states (p. 18, ll. 2) that "We do not anticipate continuing to have short-term TRM in the real-time market." How does the MISO propose to facilitate transmission capacity for Automatic Reserve Sharing within ECAR, which is currently included in the TRM?

RESPONSE:

It is my understanding that the Midwest ISO is planning to simulate generator contingencies as well as the response from reserve sharing groups to ensure that enough transmission capacity is available should a generator be lost. It is also my understanding that under centralized dispatch this analysis will be more dynamic than it is today.

Witness: Ronald McNamara

REQUEST:

26. Referring to Mr. McNamara's testimony (p.7, *ll.* 18-25). Does MISO need full participation of all MISO generation and load in the set of day ahead and real-time offers and bids in order to prrovide its members the benefit of coordinated economic unit commitment and dispatch?" If not, what level of participation is required?

RESPONSE:

No. To avoid the costs of uneconomic resource utilization, resources that could be on the margin, given their relative costs and the extent of uncertainty regarding load, generator operations, and transmission availability, can be expected to bid into the energy markets. The resulting level of participation will change with market conditions.

Witness: Ronald McNamara

REQUEST:

27. Mr. McNamara (p. 8) acknowledges that through and out rates will be eliminated. Will the proposed elimination of the through and out rates between MISO and PJM change the hurdle rates discussed on page 8? If so, by how much? If not, why not?

OBJECTION:

The Midwest ISO objects to this Request on the basis that it mischaracterizes Dr. McNamara's testimony. Without waiver of its objection, the Midwest ISO provides the following response.

RESPONSE:

No. For purposes of this analysis, the hurdle rate between MISO and PJM was set at $0.00 per MWH.

Witness: Ronald McNamara

2

REQUEST:

28. Mr. McNamara (p. 14, *ll.* 1-2) discusses the average unused available transmission capacity ("ATC") during the TLR calls. Does the 9.31% unused ATC include any "head room" related to a safety factor, for example, 95% of OSL, used in issuing TLRs?

OBJECTION:

The Midwest ISO objects to this Request on the basis that it mischaracterizes Dr. McNamara's testimony. Without waiver of its objection, the Midwest ISO provides the following response.

RESPONSE:

The average 9.31% of the (post-contingency) flowgate capacity described in my testimony is not related to the calculation of ATC between control areas.

The real-time energy market will enable MISO to match power flows to (post-contingency) flowgate limits, minimize the use of TLRs, and largely eliminate the need to maintain "head room" after any TLRs are implemented.

Witness: Ronald McNamara

2

REQUEST:

29. Referring to Mr. McNamara's Exhibit RRM-1 [p.2 *et seq*].

a. For what sample of hours were production costs and power flow modeling results calculated?

b. Were results calculated for a hypothetical peak hour only, for all 8,760 hours of 2004 or some other year, or for some other period(s)?

RESPONSE:

a. Results were calculated for an 8760-hour year using PROMOD IV, an hourly chronological production costing and power flow model. Given the amount of data in the model, output reports were not produced for all result values on an hourly basis. For some model outputs, the model accumulated hourly values and reported values on a monthly basis.

b. See the response to part (a) above.

Witness: Ronald McNamara

3

REQUEST:

30. Referring to Exhibit RRM-l, pp.6-7. Please provide an electronic file (e.g., Excel Spreadsheet) that has complete LMP results for all periods and both the LG&E/KU as MISO member case and the LG&E/KU as standalone system case.

RESPONSE:

The .BUS, .BS1, and .BS2 files in the folder "Staff Item 8" of the accompanying CD-ROM named "Public Vol. I" provide complete LMP results for all cases.

Witness: Ronald McNamara

3

REQUEST:

31. Referring to Mr. McNamara's Exhibit RRM-1, p.8.

    a. Please identify any facilities, other than FG 2195 and FG 2500, on which you made Transmission Reserve Margin (TRM) adjustments.

    b. For all facilities on which you made TRM adjustments, what capacities did you assume for the standalone alternative before and after the adjustments?

    c. What capacities did you assume for all such facilities on which you made TRM adjustments for the LGEE-within-MISO alternative?

RESPONSE:

a. There was a typographical error in Exhibit RRM-1: "FG 2195" should read "FG 2915." TRM adjustments were not made on flowgates other than FG 2915 and FG 2500.

b. During the modeling, we applied the higher of the TLR adjustment or the TRM adjustment. The specific capacities used for each facility considered for TRM adjustment are listed below.

1) LGE KU in MISO

FG 2915 - 26855 27042 1 10NEWTVL 138-11CLVRPR 138 ckt 1 Capacity 143 MW

FG 2500 - 26855 27042 1 10NEWTVL 138-11CLVRPR 138 ckt 1 Capacity 143 MW

2) Cost to Serve Control Area Load - LGE KU in MISO

FG 2915 - 26855 27042 1 10NEWTVL 138-11CLVRPR 138 ckt 1 Capacity 143 MW

FG 2500 - 26855 27042 1 10NEWTVL 138-11CLVRPR 138 ckt 1 Capacity 143 MW

3) Cost to Serve Control Area Load - LGE KU Stand Alone Effective Physical Limits

FG 2915 - 26855 27042 1 10NEWTVL 138-11CLVRPR 138 ckt 1 Capacity 130 MW

FG 2500 - 26855 27042 1 10NEWTVL 138-11CLVRPR 138 ckt 1 Capacity 130 MW

Witness: Ronald McNamara

4) Cost to Serve Control Area Load - LGE KU Stand Alone Financial Hurdle Rates

FG 2915 - 26855 27042 1 10NEWTVL 138-11CLVRPR 138 ckt 1 Capacity 143 MW

FG 2500 - 26855 27042 1 10NEWTVL 138-11CLVRPR 138 ckt 1 Capacity 143 MW

5) LGE KU Stand Alone Effective Physical Limits and Financial Hurdle Rates

FG 2915 - 26855 27042 1 10NEWTVL 138-11CLVRPR 138 ckt 1 Capacity 130 MW

FG 2500 - 26855 27042 1 10NEWTVL 138-11CLVRPR 138 ckt 1 Capacity 130 MW

6) Cost to Serve Control Area Load - LGE KU Stand Alone Effective Physical Limits and Financial Hurdle Rates

FG 2915 - 26855 27042 1 10NEWTVL 138-11CLVRPR 138 ckt 1 Capacity 130 MW

FG 2500 - 26855 27042 1 10NEWTVL 138-11CLVRPR 138 ckt 1 Capacity 130 MW

c. TRM adjustments were not made in the LGEE within MISO case. See also response part (b) above.

Witness: Ronald McNamara

3

REQUEST:

32. Referring to Mr. McNamara's Exhibit RRM-1, Table RRM 1-1. What was assumed with regard to LG&E/KU retail load paying Schedule 1, 7, 8, and 14 charges under the standalone system option?

RESPONSE:

The reference to "Schedule 1, 7, 8, and 14" in Table RRM_1-1 is to Schedules 1, 7, 8, and 14 in the Midwest ISO Open Access Transmission Tariff. LG&E/KU would pay charges under Schedules 1, 7, 8, and 14 when purchasing power within the Midwest ISO footprint and importing that power to serve LG&E/KU retail load.

Witness: Ronald McNamara

3

REQUEST:

33. Referring to Mr. McNamara's Exhibit RRM-l, Table RRM 1-3.

a. Please explain the basis or rationale for each of the figures with values above 0.10.

b. Please confirm that these figures are in units of $/MWh.

RESPONSE:

a.

Source to Sink or Component (with a value above 0.10)	**On-Peak**	**Off-Peak**	**Basis**
MISO to LGE & KU			
Base Non-Firm Hourly Service	$3.50000	$1.75000	MISO discounted Schedule 8, 14, 18, and 19 Non-firm Hourly Point-to-Point Transmission Service rates
Ancillary Service 1 (Scheduling, System Control, and Dispatch Service)	0.15137	*NA <0.10*	MISO Schedule 1 Transmission Service rates
Ancillary Service 2 (Reactive Supply and Voltage Control)	0.37347	0.17736	MISO Schedule 2 Transmission Service rates
Ancillary Service 3 (Regulation and Frequency Response Service)	0.11000	0.11000	MISO Schedule 3 Transmission Service rates based on exporting power from a Cinergy bus into LG&E / KU
Schedule 10 (ISO Cost Recovery)	0.15000	0.15000	MISO Schedule 10 Transmission Service rates
Total Tariff	4.41014	2.38454	Total of Applicable MISO Transmission Service Charges
Transaction Costs	3	3	Professional experience and judgment as to the transaction costs (including: search, contracting, scheduling, settlement, and dispute resolution costs) and the opportunity costs of being unable to identify and complete the most economic set of transactions in a timely manner that are incurred as a result of relying on bilateral transactions, expressed in $/MWH

Witness: Ronald McNamara

Source to Sink or Component (with a value above 0.10)	**On-Peak**	**Off-Peak**	**Basis**
Total Hurdle Rate	7.41014	5.38454	Sum of Total Tariff charges and Transaction Costs
LGE & KU to MISO or PJM			
Schedule 8 Non-Firm Point-to-Point Service	$2.4329	$1.1585	Pricing for Non-Firm Point-to-Point Transmission Service based on LGEE revenue requirements as reported to MISO
Schedule 2 (Reactive Supply and Voltage Control from Generation Sources)	0.3	0.15	Pricing for Schedule 2 Ancillary Service Charge from LG&E / KU Pro Forma Open Access Transmission Tariff of October 9, 1997 based on LGEE revenue requirements as reported to MISO
Schedule 3 (Regulation and Frequency Response)	0.199	*NA <0.10*	Pricing for Schedule 3 Ancillary Service Charge from LG&E / KU Pro Forma Open Access Transmission Tariff of October 9, 1997 based on LGEE revenue requirements as reported to MISO
Total Tariff	3.01520	1.48680	Sum of Applicable Transmission Service Charges
Transaction Costs	3	3	Professional experience and judgment as to the transaction costs (including: search, contracting, scheduling, settlement, and dispute resolution costs) and the opportunity costs of being unable to identify and complete the most economic set of transactions in a timely manner that are incurred as a result of relying on bilateral transactions, expressed in $/MWH
Total Hurdle Rate	6.01520	4.48680	Sum of Total Tariff charges and Transaction Costs
PJM to LGE & KU			
Discounted Non-firm Price	$0.67		Based on PJM Non-Firm Pricing and Discounting Policy, PJM Regional Transmission and Energy Scheduling Practices

Witness: Ronald McNamara

Source to Sink or Component (with a value above 0.10)	**On-Peak**	**Off-Peak**	**Basis**
Control Area Services	0.3042		Approved 2004 PJM Control Areas Services rate
Regulation & Frequency Response	0.4379		Approved 2004 PJM Regulation and Frequency Response rate
Total Tariff	1.4854		Sum of Applicable Transmission Service Charges
Transaction Costs	3		Professional experience and judgment as to the transaction costs (including: search, contracting, scheduling, settlement, and dispute resolution costs) and the opportunity costs of being unable to identify and complete the most economic set of transactions in a timely manner that are incurred as a result of relying on bilateral transactions, expressed in $/MWH
Total Hurdle Rate	4.48540		Sum of Total Tariff charges and Transaction Costs

b. Yes, the figures are in units of $/MWh.

Witness: Ronald McNamara

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REQUEST:

34. Referring to Mr. McNamara's Exhibit RRM-l, Table RRM 1-6.

a. Please explain how congestion costs can be negative and why the largest absolute congestion costs (7/20, hours 15 and 17) are negative.

b. In hours when congestion costs are negative, are prices at LG&E/KU's resource locations higher than prices at LG&E/KU's sink locations? If so, how can this occur?

c. Does the analysis implicitly assume that, in hours when congestion costs are negative, LG&E/KU is transporting power from high-cost locations to low-cost locations? And if it does not assume that, what does it assume?

RESPONSE:

a. Although it is possible to imagine a hypothetical FTR allocation in which the congestion revenues collected by an RTO might be insufficient to permit that RTO to pay out 100% of the value of allocated FTRs, the MISO allocation analyzed in Exhibit RRM-1 has been designed to avoid such a result.

b. When congestion costs are negative, the LMP prices at LG&E/KU resource locations would generally be higher than at LG&E/KU load locations (in the absence of possible counter effects due to the marginal loss component of the LMP). This can occur when substantial power flows through the LG&E/KU system cause internal congestion counter to the direction of LG&E/KU generation-to-load.

It should be noted that the level of LMP prices at LG&E/KU resource locations does not directly affect the cost of generation to serve LG&E/KU retail ratepayers for whom rates are set on a cost of service basis.

c. The analysis does not imply that, when congestion costs are negative, LG&E/KU is physically transporting energy from high-LMP locations to low-LMP locations. Physically, flow into and through the low-price load zone is physically serving that load, and LG&E/KU generation at the higher-price locations is replacing energy used to serve

Witness: Ronald McNamara

that load and flowing out to serve other loads outside of the LG&E/KU area. On a cost accounting basis, it appears that generation at high-LMP locations is being assigned to serve load at low-LMP locations, but the physical flows are in the opposite direction because of regional power transfers through the LG&E/KU area.

Witness: Ronald McNamara

REQUEST:

35. Referring to Mr. McNamara's Exhibit RRM-l, (p.11), does the figure assume that the FTR payouts to LG&E/KU in the Day 2 Market will equal 100% of their nominal value? If not, what was assumed?

OBJECTION:

The request is vague and ambiguous in failing to specify what is meant by "100% of their nominal value." Without waiver of its objection, the Midwest ISO provides the following response based on its understanding of the request.

RESPONSE:

Although it is possible to imagine a hypothetical FTR allocation in which the congestion revenues collected by an RTO might be insufficient to permit that RTO to pay out 100% of the value of allocated FTRs, the Midwest ISO allocation analyzed in Exhibit RRM-1 has been designed to avoid such a result.

Witness: Ronald McNamara

REQUEST:

36. Referring to Mr. McNamara's Exhibit RRM-1, and his discussion of the PROMOD IV model (Section 2.0, Quantification of Near Term Congestion Management and Net Margin On Off-system Sales Benefits).

    a. Please provide all of the supporting documents, work papers and data supporting these documents and work papers for the analysis conducted of the quantification of near-term congestion management and net margin on offsystem sales benefits.

    b. What is the objective function used in the PROMOD IV model employed by MISO?

    c. Do the "transmission interface limits" used by PROMOD IV change dynamically within PROMOD IV in response to changes in flows throughout a 24 hour period?

    d. Cases 2.7.3 and 2.7.4 imposed hurdle rates on certain LG&E/KU transactions because LG&E/KU was not a member of an RTO. Were similar hurdle rates applied to other non-RTO participant entities in the Eastern Interconnect? If so, what were these hurdle rates?

    e. Mr. McNamara (p. 2, Exhibit RRM-1) states that the PROMOD IV model calculates hourly production costs and location-specific market clearing prices.

        i. How is the Output from PROMOD IV analysis used to calculate the benefits of FTRs, given that MISO has proposed to apply FTRs to the day-ahead market?

        ii. Does this mean that, for the results of the PROMOD IV model to be used to calculate the benefits of FTRs, it must be assumed that hourly day-of-dispatch results from PROMOD IV are an accurate representation of day-ahead market outcomes?

RESPONSE:

a. Please see the Midwest ISO's response to LGE/KU Data Requests, Midwest ISO Request Numbers 21, 38(b) and 42.

Witness: Ronald McNamara

b. During its unit commitment process, PROMOD IV considers the start-up costs and variable operating costs of each generating unit to develop a unit commitment schedule. Once the unit commitment schedule is developed, PROMOD IV dispatches the power system in each hour to minimize total variable production costs. For generating units, these costs include fuel costs (applied to the heat rate profile of the unit), variable O&M costs, and emissions costs. Each unit's cost is scaled by a dynamic transmission loss factor that is calculated each hour during the dispatch, reflecting the unit's incremental effect on total system transmission losses. Additionally, economy transfers from one area to another area are priced to reflect the hurdle rate for that buyer/seller pair. Also included in the objective function is the hourly energy cost for dispatchable purchases and sales with areas outside the modeled footprint.

c. During its economic dispatch, PROMOD IV monitors a set of flowgates, each of which may be an individual transmission branch or a composite of interface limits. The limit for each PTDF constraint is constant from hour to hour. The post-contingency flow limit for each OTDF constraint is also constant from hour to hour.

d. Yes. In all cases, hurdle rates were applied when modeling exports of power from a specified area not a member of an RTO. The following hurdle rates were applied to other non-RTO entities in each of the scenarios analyzed:

Source	**Sink**	**Total Hurdle Rate ($/MWh)**	
		On-Peak	**Off-Peak**
SPP	All other directly interconnected areas	$6.4633	
Big Rivers Electric Cooperative	All directly interconnected areas	$6.80	$5.05
East Kentucky Power Cooperative	All directly interconnected areas	$7.24049	$5.49049
All other specified areas	All directly interconnected areas	$6.50	$4.50

e. PROMOD IV was used to calculate the congestion costs in hourly LMP prices that would not be covered by FTR allocations. The Midwest ISO has proposed to settle FTRs at

Real-time Prices until the Day Ahead market is introduced. Thus for the near term, no assumption is required regarding the relationship of hourly day-of-dispatch market results to day ahead market outcomes. Following full implementation of the Day Ahead market, FTRs may be settled at Day Ahead prices. There is no reason to believe, however, that future settlement of FTRs on the basis of the Day Ahead Market would materially and systematically disadvantage LGE/KU.

Witness: Ronald McNamara

REQUEST:

37. With respect to the PROMOD IV inputs:

a. Did constructing a set of appropriate data inputs for PROMOD IV require a detailed examination of the various federal submittals or did it make use of an aggregated database provided by a vendor? If a vendor database was used, who was the vendor?

b. In exhibit RRM-l, (p.2), it is stated that the PROMOD IV model captures operating details of 5,000 generating units in the entire Eastern Interconnect. How many generating units in the Eastern Interconnect were not included in PROMOD IV model? What criteria were used to exclude generators or generating units?

c. Is the PROMOD IV model NOX and S02 emission-constrained?

d. How were spinning and operating reserves modeled?

e. How is hydroelectric generation modeled?

f. How are scheduled maintenance outages on nuclear and fossil units modeled?

g. Please provide all input data for LG&E/KU generating units, load forecasts, and the characterization of its transmission system.

h. Please identify the RTO membership of all load and generating units in the model.

i. Was AEP assumed to be in or out of PJM for the 2004 simulation and the various cases modeled?

j. How does the model address generating capacity scarcity? Did the model identify any scarcity in 2004 and if so, what was the impact?

RESPONSE:

a. The data inputs for PROMOD IV were based on data for LG&E and KU provided by the Companies in response to data requests, Energy Information Administration survey data and NYMEX prices used in gas and oil price forecasts as described in Exhibit RRM-1, sections 2.3.1 through 2.3.3, and the Powerbase database of North American electric

Witness: Ronald McNamara

systems, provided by New Energy Associates, A Siemens Company. New Energy's Powerbase database, in turn, obtains much of its data from Platts / RDI's Basecase database, which is compiled from various public sources, including FERC forms, EIA surveys, CEMS data, and reports from NERC and the various ISOs.

b. The analysis is intended to represent all generating resources of 1 MW or more within the footprint that was modeled in detail. This footprint comprised the entire Eastern Interconnect, except for Florida, New York, New England, Quebec, and the Canadian Maritime provinces. The effects of generation in Florida, New York, New England, Quebec, and the Canadian Maritime provinces were represented by purchase and sale transactions into and out of these regions at representative region-specific price points.

c. In this analysis, the utilization of SO_2 emission allowances and NO_X emission credits were treated as dispatch costs rather than as constraints. Additionally, unit operating costs reflect the cost of operating SO_2 and NO_X emission control technologies.

d. Each generating resource is designated as providing either quick start or spinning reserve. Within MISO, specific operating reserve constraints were specified for individual control areas. Other regions had operating reserve constraints specified at the regional level. The actual constraint values are as follows:

	Operating Reserve % of Load	**Spinning Reserve as % of Operating Reserve**
AEP	4	62.5
ALWST	3.078	50.0
APS	4	50.0
AUEP	1.98	50.0
BREC	4	62.5
CGE	4	62.5
CIL	5.737	70.0
COED	2.383	50.0
DECO	4	62.5
DP&L	4	62.5
DPC	4.75	50.0
DQE	4	62.5
EEI	2.158	50.0
EKPC	4	62.5
FE	4	62.5

Witness: Ronald McNamara

	Operating Reserve % of Load	Spinning Reserve as % of Operating Reserve
GPUWST	4	50.0
GRE	5.05	50.0
HEC	4	62.5
HUC	4	50.0
ILPC	2.636	50.0
IP&L	4	62.5
LBWL	3	50.0
LG&E	4	62.5
MDU	3	50.0
MGE	2.724	50.0
MHSP	5.64	50.0
MIDAM	4.88	50.0
MPC	6.05	50.0
MPL	3	50.0
MPW	5.29	50.0
NIPS	4	62.5
NPPD	4.04	50.0
NSP	4.53	50.0
NWPS	4.5	50.0
ONTHY	4	50.0
OPPD	4.42	50.0
OTP	7.87	50.0
OVEC	4	62.5
PJME	4	50.0
PJMS	4	50.0
PPL	4	50.0
PSI	4	50.0
SASK	4	50.0
SERC	4	62.5
SIGE	4	62.5
SIPC	4.273	60.0
SMMP	3.82	50.0
SPP	4	50.0
SPRIL	3.052	50.0
STJO	4	50.0
WABDK	7.97	50.0
WABNI	7.97	50.0
WEP	4	50.0
WPL	2.264	50.0
WPPI	2.582	50.0
WPS	2.612	50.0
WPSC	2.612	50.0

e. Each hydroelectric generator is represented by a monthly energy and a minimum and maximum capacity. The minimum capacity of the generator is run as run-of-river generation, constant over all hours of the week, and the remaining energy is applied as a peak-shave reduction in load.

f. Nuclear unit refueling outages are specified in the data. Scheduled maintenance for other generating units is scheduled by PROMOD IV to minimize unreliability of the system. The maintenance requirement for each generator is specified as a number of weeks per year of planned maintenance.

g. The response is provided in the file named "LGEInputSummary_37g.REP" in the folder named "Confidential Item 37" on the "Confidential Volume" CD-ROM; confidential treatment is being sought for this file.

h. See the file named "UnitsByRTO_37h.xls" in the folder named "Item 37" on the accompanying CD-ROM named "Public Vol. II".

i. AEP was modeled as part of PJM in all cases.

j. New generating units scheduled to be placed in service in 2004 were included in the analysis. PROMOD IV checks for and addresses any generation scarcity. In the event of insufficient generation to serve the load at all locations, PROMOD IV allows the dispatch of emergency generation at any generator bus, priced at $1,000/MWh. In the event that this emergency generation is dispatched, it will show up in the output results as an Emergency Purchase, and its price will show up in the LMPs. No such emergency energy was observed in any of the scenarios.

Witness: Ronald McNamara

3

REQUEST:

38. With respect to PROMOD IV model outputs:

  a. Please provide all model outputs related to LG&E/KU units.

  b. Please provide the outputs from PROMOD IV modeling in all cases for LG&E/KU 0SS volumes and margins by hour or peak type (5x16, 2x16, 7x8) by month.

  c. Since only 2004 was modeled, were any sensitivities performed for changes in natural gas and coal prices. If so, please provide.

  d. Please provide all outputs on LMP prices, marginal losses and marginal congestion costs for all LSEs and all generating units modeled in the 2004 simulation cases examined.

RESPONSE:

a. Model outputs the .REP and .UNT files in the "Confidential Staff Item 8" folder. These are files for which confidential treatment is sought.

b. Hourly LG&E/KU hourly net sales volumes and revenues are presented in the file named "Hourly Exports_38b.xls," which is found in the folder named "Item 38," located on the CD-ROM entitled "Public Vol. II." Monthly sales margins were calculated by comparing the total hourly off-system sales revenues for a month to the change in total LGE/KU production costs between two cases — one reflecting full participation in the market including LGE/KU off-system sales and a second which calculated the cost to serve LGE/KU control area load. Monthly production cost components for these cases are presented in the file "Monthly Generation Costs _38b.xls," which is also in the "Item 38" folder. Additionally, please see the responses to LGE/KU Data Requests No. 21 and 42.

c. Given the limited time available, no sensitivity runs have been completed for changes in natural gas and coal prices.

Witness: Ronald McNamara

d. LMP, the congestion cost component of LMP, and the marginal loss cost component of LMP are presented in the .BUS, .BS1, .BS2, and .MIS files included in the "Item 8" folders contained on both CD-ROMS titled "Public Vol. I" and "Public Vol. II."

Witness: Ronald McNamara

3

REQUEST:

39. Refer to Exhibit RRM-l, Section 2.11.

a. If LG&E/KU is being inefficient by generating and selling less energy prior to the LMP market, what entities are also being inefficient by generating and selling too much energy? Please identify all volumes by source and hour.

b. Has the PROMOD IV model for 2004 been benchmarked against 2002 actuals? Is so, provide the results of that benchmarking. If not, why not?

RESPONSE:

a. The study presented in Exhibit RRM-1 was designed to quantify the economic benefits and costs for LGE/KU and its native load customers of operating LGE/KU transmission within the Midwest ISO versus transferring functional control back to LGE/KU to operate as a Stand Alone system. It was not designed to quantify inefficiencies that may be imposed on any other entities by virtue of LGE/KU operating its transmission system on a Stand Alone basis.

The hourly net sales volumes for individual entities are presented in the file "Hourly Sales_39a.xls" in the folder "Item 39" on the CD-ROM "Public Vol. II."

b. The results of the 2004 analysis were reviewed to ensure that regional reserve margins, flows on major flowgates, profitability of marginal generators, and regional committed capacity were reasonable. However, PROMOD IV results were not benchmarked against 2002 actuals in the sense of forcing modeled results to match actual values. Optimization models such as PROMOD IV represent market operations with a level of efficiency that tends not to be achieved in bilateral energy markets.

Witness: Ronald McNamara

4

The specific transmission service charges used in the Stand Alone LGE/KU Transmission Operations – Hurdle Rates and Stand Alone LGE/KU Transmission Operations – Combined Effective Physical Limit and Hurdle Rate Effects scenarios for transactions from MISO to LGE/KU, LGE/KU to MISO or PJM, and PJM to LGE/KU are presented in Exhibit RRM-1 at Table RRM_1-3. With the exception of the use of the Total Tariff Charges presented in Exhibit RRM-1 at Table RRM_1-3 for transactions from MISO to LGE/KU, LGE/KU to MISO or PJM, and PJM to LGE/KU in the Stand Alone LGE/KU Transmission Operations – Hurdle Rates and Stand Alone LGE/KU Transmission Operations – Combined Effective Physical Limit and Hurdle Rate Effects scenarios, the following transmission service charges were incorporated in the development of hurdle rates.

See: Exhibit RRM-1 at Table RRM_1-3. Transmission rates for other systems in the model are presented below:

Source	Sink	Total Transmission Service Charge ($/MWh)	
		On-Peak	Off-Peak
SPP	All other directly interconnected areas	$3.4633	
Big Rivers Electric Cooperative	All directly interconnected areas	$3.80	$2.05
East Kentucky Power Cooperative	All directly interconnected areas	$4.2049	$2.49049
All other specified areas	All directly interconnected areas	$3.50	$1.50

In this PROMOD IV analysis, the energy for average transmission losses was included in the load forecast for each entity. During the economic dispatch, PROMOD IV calculates the marginal impact of transmission losses due to the incremental dispatch of each generating unit. These dynamic loss penalty factors are applied as a scaling of the generator's dispatch cost. This loss penalty factor is used in the calculation of the bus LMP and in determining the loss component of LMP relative to the reference bus.

d. The transaction cost factor is a conservative estimate of transaction and opportunity costs based on professional experience and judgment. It is intended to account for the search, negotiation, contracting, scheduling, settlement, dispute resolution, and associated administrative costs that market participants incur entering into bilateral energy transactions and to recognize that there are opportunity costs associated with being unable to identify and complete all cost-effective transactions in a timely manner relying only on bilateral transactions.

Witness: Ronald McNamara

4

REQUEST:

41. Refer to Exhibit RRM- 1, Section 3 and table RRM_1-6. In calculating the congestion cost not covered by FTRs, it appears MISO only considered hours in which the load exceeds the FTRs held. Please verify whether the FTR holder could be exposed to cost in hours in which the load is less than the FTRs held?

RESPONSE:

Congestion costs will be incurred and FTR revenues received in all hours in which transmission is constrained. Given the basis on which FTRs would be allocated, such costs and revenues will generally offset one another. Thus, the analysis presented in Exhibit RRM-1 provides a reasonable basis for evaluating the extent to which congestion costs are likely to exceed FTR revenues.

Witness: Ronald McNamara

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REQUEST:

42. Refer to Table RRM_1-5. Please provide all of the supporting calculations and describe the source data for all elements of this table.

RESPONSE:

Net margins on off-system sales were calculated by comparing the total hourly sales revenues for each month to the change in total LGE/KU production costs between two cases, one reflecting full participation in the market including LGE/KU off-system sales and a second which calculated the cost to serve LGE/KU control area load.

The columns labeled "LGE/KU Total Generation Cost" reflect the sum of monthly fuel costs, variable O&M costs, emissions costs, fixed O&M and start-up costs for cases that estimate the total cost of LGE/KU generation to serve both control area loads and off-system sales. The columns labeled "LGE/KU Generation Costs in Cost to Serve Control Area Loads" reflect the sum of monthly LGE/KU generator fuel costs, variable O&M costs, emissions costs, fixed O&M and start-up costs for cases that estimate the cost to serve LGE/KU control area loads. Monthly values for the components of these calculations are presented in the file "Monthly Generation Costs _38b.xls" in the "Item 38" folder of the "Public Vol. II" CD-ROM.

The columns labeled "Off-System Sales Revenue at Generator LMP" reflect the monthly sum of hourly revenues for exports from the LGE/KU control area priced at generator LMPs. The figure for Modeled LGE/KU Stand Alone Off-System Sales (MWH) which appears in Line Number 1 of the section of the Table Titled "Scaling of Stand Alone Net Margin on Off-System Sales to 2002 actual Net Non-Requirements Sales for Resale" is the sum of hourly exports from the LGE/KU control area in the LGE/KU Stand Alone: Effective Physical Limits and Financial Hurdle Rates scenario. Hourly LGE/KU hourly net sales volumes and revenues are presented in the file "Hourly Exports_38b.xls" in the "Item 38" folder of the "Public Vol. II" CD-ROM.

The value for LGE/KU 2002 Non-requirements Sales (MWH) is based on the Companies' FERC Form 1 filings for 2002.

Witness: Ronald McNamara

REQUEST:

43. Refer to Exhibit RRM-l, Section 5 (P. 15).

a. Please provide financial analysis that supports MISO's assertion on p.l5 that creating a new energy market is the least-cost means to accomplish the activities enumerated.

b. Referencing the middle of p. 16. Please provide all supporting documents related to the claim that a 100 MW peak reduction could be achieved on LG&E / KU system as a result of "transparent spot markets."

RESPONSE:

a. The following activities can be accomplished only if there are transparent, location-specific spot prices:

- Benchmark utility fuel and operating costs against location-specific spot prices;
- Use location-specific prices to help identify where it may be cost-effective to build new generation or transmission capacity;
- Design for price responsive consumers variable pricing products which are based on efficient price signals that customers can trust to reflect the actual real-time and day-ahead marginal cost of power; and
- Foster the development of differentiated consumer energy products designed to better match customer risk preferences.

And, the only way to generate transparent location-specific spot prices is to create transparent, location-specific spot markets. Thus, the development of a new energy market is the only and least-cost means to accomplish these activities.

It may be possible to shift from ratepayers to investors some of the capital investment risks associated with the development of new generating capacity in the absence of a transparent spot market through contracting for power from new generators. However, the development of transparent regional spot markets is expected to improve the options available to the Kentucky Commission related to the development of new generating capacity. The development of MISO energy markets will increase market liquidity and expand the scope of the market into which new suppliers can economically sell power. As a result, the risk premium, minimum take provisions, and/or term of the contractual commitment required to elicit investment in merchant capacity will tend to decline. When one compares the costs, in some cases still being paid by ratepayers, for uneconomic generation completed or purchased under long-term contracts in the 1980s and early 1990s to the much smaller impact on consumers of the capacity bubble of the last few years, it is evident that improving market liquidity reduces the investment risks that must be absorbed by consumers. A quantitative comparison of the reduction in risk premiums for merchant generation from the development of a liquid, regional spot market to the costs of developing new markets was not undertaken for this study.

b. Electronic files of the following documents may be found in the folder "Item 43" on the CD-ROM "Public Vol. II":

- EEI, The Role of Demand Response in Electric Power Design. (October 2002).
- Christensen Associates. "Electricity Customer Price Responsiveness – Literature Review of Customer Demand Modeling and Price Elasticities." Paper. (September 29, 2000).
- Center for the Study of Energy Markets (CSEM). Dynamic Pricing, Advanced Metering and Demand Response in Electricity Markets. (October 2002).
- Neenan Associates, Lawrence Berkeley National Laboratory, Pacific Northwest Laboratory. How and Why Customers Respond to Electricity Price Variability: A Study of NYISO and NYSERDA 2002 PRL Program Performance. (January 2003).
- Neenan Associates. NYISO Price-Responsive Load Program Evaluation Final Report – Update. (February 2002).

Witness: Ronald McNamara

- Lawrence Berkeley National Laboratory. Customer Participation in Wholesale Markets: Summer 2001 Results, Lessons Learned and "Best Practices". (February 2002).

The following electronic files are included on the "Confidential Volume" CD-ROM, with other information for which confidential treatment is sought:

- a Word file of a study entitled "Evaluating the Potential Elasticity Effects of RTP and Day Ahead Price Responsive Load Programs and the Implications for the LGE and KU C/I Markets"
- an Excel file, entitled "DR Range Calculation.xls."

Witness: Ronald McNamara

REQUEST:

44. Mr. Holstein (P. 12, *ll.* 7-19) discusses estimates of the withdrawal fee that would be assessed LG&E/KU. Please provide all work papers that support your calculation of this $38.2 million withdrawal fee.

RESPONSE:

Please note that Mr. Holstein's testimony misstated the value of the estimated exit fee. The correct estimate is $38.3 million, as supported by the work papers entitled "KU Estimated Calculation of MISO Exit Obligation" attached hereto (pp. 1-14) as well as the workpapers entitled "Midwest ISO Financial Projections – Annual Income Statement – ($ in thousands, except Billing Rates)" attached hereto (pp. 15-27).

Witness: Michael P. Holstein

KU
Estimated Calculation of MISO Exit Obligation

	12/31/2004			12/31/2006			12/31/2008		
	Schedule 10	Schedule 16	Schedule 17	Schedule 10	Schedule 16	Schedule 17	Schedule 10	Schedule 16	Schedule 17
Total Liabilities	$ 202,084,121	$ 58,532,669	$ 159,708,712	$ 219,905,007	$ 50,604,914	$ 140,825,906	$ 205,788,815	$ 41,605,223	$ 108,435,178
Less: Unamortized GridAm Costs	$ 20,277,250	$ -	$ -	$ 15,642,450	$ -	$ -	$ 11,007,650	$ -	$ -
Interest Expense	$ 74,256,059	$ 15,211,898	$ 34,232,792	$ 54,567,175	$ 10,524,982	$ 22,398,840	$ 34,778,281	$ 6,321,811	$ 12,074,228
Operating Leases	$ 12,964,912	$ 495,791	$ 495,791	$ 10,049,649	$ 192,016	$ 192,016	$ 6,972,363	$ -	$ -
Total Obligations	$ 269,027,842	$ 74,240,358	$ 194,437,295	$ 268,879,381	$ 61,321,911	$ 163,416,762	$ 236,531,809	$ 47,927,034	$ 120,509,406
Less: Current Assets	$ 18,810,954	$ 2,685,647	$ 7,296,783	$ 57,336,814	$ 16,769,249	$ 46,362,042	$ 80,857,955	$ 27,997,114	$ 72,308,849
Net Obligation	$ 250,216,888	$ 71,554,711	$ 187,140,512	$ 211,542,567	$ 44,552,662	$ 117,054,719	$ 155,673,854	$ 19,929,920	$ 48,200,557
Billing Determinants									
Total Midwest ISO Projection	756,010,529	464,478,148	1,161,195,370						
Less: GridAm Projection	124,162,196	-	-						
Less: ITC	84,355,422								
Net Midwest ISO Projection	547,492,911	464,478,148	1,161,195,370						
KU Projection	31,387,087	17,271,478	43,178,696						
KU Portion of Total Billing Determinants	5.73%	3.72%	3.72%	5.73%	3.72%	3.72%	5.73%	3.72%	3.72%
Estimated Exit Obligation - By Schedule	$ 14,337,428	$ 2,661,835	$ 6,961,627	$ 12,121,389	$ 1,657,359	$ 4,354,436	$ 8,920,112	$ 741,393	$ 1,793,061
Total Estimated Exit Obligation (1)		**$23,960,890**			**$18,133,184**			**$11,454,566**	

Notes;
(1) Interest on senior unsecured notes over life of notes included as an obligation to be covered upon exiting the Midwest ISO.
(2) Operating lease obligations for life of leases included as an obligation to be covered upon exiting the Midwest ISO.
(3) Load ratio share assumed to be the same for all years.
(4) Schedule 10 billing determinants are demand-based.

Attachment to LGE/KU #44
Witness: Holstein

LG&E
Estimated Calculation of MISO Exit Obligation

	12/31/2004			12/31/2006			12/31/2008		
	Schedule 10	Schedule 16	Schedule 17	Schedule 10	Schedule 16	Schedule 17	Schedule 10	Schedule 16	Schedule 17
Total Liabilities	$ 202,084,121	$ 58,532,669	$ 159,708,712	$ 219,905,007	$ 50,604,914	$ 140,825,906	$ 205,788,815	$ 41,605,223	$ 108,435,178
Less: Unamortized GridAm Costs	$ 20,277,250	$ -	$ -	$ 15,642,450	$ -	$ -	$ 11,007,650	$ -	$ -
Interest Expense	$ 74,256,059	$ 15,211,898	$ 34,232,792	$ 54,567,175	$ 10,524,982	$ 22,398,840	$ 34,778,281	$ 6,321,811	$ 12,074,228
Operating Leases	$ 12,964,912	$ 495,791	$ 495,791	$ 10,049,649	$ 192,016	$ 192,016	$ 6,972,363	$ -	$ -
Total Obligations	$ 269,027,842	$ 74,240,358	$ 194,437,295	$ 268,879,381	$ 61,321,911	$ 163,416,762	$ 236,531,809	$ 47,927,034	$ 120,509,406
Less: Current Assets	$ 18,810,954	$ 2,685,647	$ 7,296,783	$ 57,336,814	$ 16,769,249	$ 46,362,042	$ 80,857,955	$ 27,997,114	$ 72,308,849
Net Obligation	$ 250,216,888	$ 71,554,711	$ 187,140,512	$ 211,542,567	$ 44,552,662	$ 117,054,719	$ 155,673,854	$ 19,929,920	$ 48,200,557
Billing Determinants									
Total Midwest ISO Projection	756,010,529	464,478,148	1,161,195,370						
Less: GridAm Projection	124,162,196	-	-						
Less: ITC	84,355,422								
Net Midwest ISO Projection	547,492,911	464,478,148	1,161,195,370						
LG&E Projection	18,701,681	10,406,167	26,015,418						
LG&E Portion of Total Billing Determinants	3.42%	2.24%	2.24%	3.42%	2.24%	2.24%	3.42%	2.24%	2.24%
Estimated Exit Obligation - By Schedule	$ 8,557,418	$ 1,602,826	$ 4,191,947	$ 7,234,756	$ 997,980	$ 2,622,026	$ 5,324,046	$ 446,430	$ 1,079,692
Total Estimated Exit Obligation (1)		**$14,352,191**			**$10,854,761**			**$6,850,169**	

Notes;
(1) Interest on senior unsecured notes over life of notes included as an obligation to be covered upon exiting the Midwest ISO.
(2) Operating lease obligations for life of leases included as an obligation to be covered upon exiting the Midwest ISO.
(3) Load ratio share assumed to be the same for all years.
(4) Schedule 10 billing determinants are demand-based.

Exit Fee Workpaper

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Total Current Assets	$ 28,793,384	$ 70,587,509	$ 120,468,105	$ 159,653,681	$ 181,163,917	$ 193,669,001	$ 185,496,948	$ 174,593,786	$ 51,465,992	29,881,886
Schedule 10 Prepaids	$ 10,865,169	$ 10,865,169	$ 10,865,169	$ 10,865,169	$ 10,865,169	$ 10,865,169	$ 10,865,169	$ 10,865,169	$ 10,865,169	$ 10,865,169
Current Assets	$ 17,928,215	$ 59,722,340	$ 109,602,936	$ 148,788,512	$ 170,298,748	$ 182,803,832	$ 174,631,779	$ 163,728,617	$ 40,600,823	$ 19,016,717
Net Property & Equip.										
Schedule 10	$ 97,061,585	$ 83,711,621	$ 66,795,988	$ 50,089,199	$ 35,181,923	$ 30,296,085	$ 28,012,793	$ 26,331,154	$ 24,902,225	$ 23,829,406
Schedule 16	$ 32,821,066	$ 29,181,588	$ 24,106,281	$ 18,532,425	$ 14,074,531	$ 9,386,302	$ 9,248,594	$ 9,186,719	$ 9,124,844	$ 8,787,969
Schedule 17	$ 89,150,049	$ 78,893,012	$ 66,635,975	$ 50,435,904	$ 36,341,574	$ 21,978,071	$ 21,081,614	$ 20,685,156	$ 20,559,531	$ 19,808,906
TOTAL	$ 219,032,701	$ 191,786,221	$ 157,538,244	$ 119,057,528	$ 85,598,028	$ 61,660,458	$ 58,343,001	$ 56,203,029	$ 54,586,600	$ 52,426,281
Allocation Factor (Total NP&E)										
Schedule 10	44.32%	43.64%	42.40%	42.07%	41.10%	49.14%	48.02%	46.85%	45.62%	45.46%
Schedule 16	14.98%	15.22%	15.30%	15.57%	16.44%	15.22%	15.85%	16.35%	16.72%	16.76%
Schedule 17	40.70%	41.14%	42.30%	42.36%	42.46%	35.64%	36.13%	36.80%	37.66%	37.78%
	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Schedule 16 - LTD	$ 51,750,000	$ 57,500,000	$ 64,500,000	$ 63,214,286	$ 57,857,143	$ 48,500,000	$ 37,714,286	$ 25,500,000	$ 11,357,143	$ 2,678,571
Schedule 17 - LTD	$ 160,750,000	$ 148,750,000	$ 123,000,000	$ 110,000,000	$ 88,571,429	$ 71,142,857	$ 55,142,857	$ 40,571,428	$ 20,785,714	$ 12,499,999
LTD (Sch. 16 & 17)	$ 212,500,000	$ 206,250,000	$ 187,500,000	$ 173,214,286	$ 146,428,572	$ 119,642,857	$ 92,857,143	$ 66,071,428	$ 32,142,857	$ 15,178,570
Allocation of NP&E (Sch. 16 & 17)										
Schedule 16	26.91%	27.00%	26.57%	26.87%	27.92%	29.93%	30.49%	30.75%	30.74%	30.73%
Schedule 17	73.09%	73.00%	73.43%	73.13%	72.08%	70.07%	69.51%	69.25%	69.26%	69.27%
	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Allocation of LTD (Sch. 16 & 17)										
Schedule 16	$ 57,183,750	$ 55,687,500	$ 49,818,750	$ 46,542,679	$ 40,882,857	$ 35,809,107	$ 28,312,143	$ 20,316,964	$ 9,880,714	$ 4,664,375
Schedule 17	$ 155,316,250	$ 150,562,500	$ 137,681,250	$ 126,671,607	$ 105,545,714	$ 83,833,750	$ 64,545,000	$ 45,754,464	$ 22,262,143	$ 10,514,196
Liabilities & Net Assets										
Schedule 10	$ 202,084,121	$ 204,486,944	$ 219,905,007	$ 215,542,296	$ 205,788,815	$ 195,998,589	$ 186,168,211	$ 176,293,960	$ 73,514,624	$ 53,718,617
Schedule 16	$ 53,098,919	$ 58,314,063	$ 65,286,164	$ 63,969,964	$ 58,579,509	$ 49,185,965	$ 38,360,476	$ 26,102,727	$ 11,912,377	$ 8,791,119
Schedule 17	$ 165,142,462	$ 152,006,253	$ 126,144,656	$ 113,022,712	$ 91,460,892	$ 73,886,718	$ 57,727,617	$ 42,982,337	$ 23,006,653	$ 19,817,406
Total Liabilities - Sch. 16	$ 58,532,669	$ 56,501,563	$ 50,604,914	$ 47,298,357	$ 41,605,223	$ 36,495,072	$ 28,958,333	$ 20,919,691	$ 10,435,948	$ 10,776,923
Total Liabilities - Sch. 17	$ 159,708,712	$ 153,818,753	$ 140,825,906	$ 129,694,319	$ 108,435,178	$ 86,577,611	$ 67,129,760	$ 48,165,373	$ 24,483,082	$ 17,831,602

PRESENT VALUE - LEASES AND INTEREST AT 12/31/04 TOTAL					[redacted]				
CAPITAL LEASES	1%								
	2004	2005	2006	2007	2008	2009	2010	2011	2012
INTEREST									
H&P	1,282,590.29	1,246,907.38	1,207,993.23	1,165,555.24	1,119,274.28	1,068,802.38	1,013,760.06	953,733.39	888,271.06
First Fed	174.90	-	-	-	-	-	-	-	-
EMC	315,708.43	124,735.91	1,413.79	-	-	-	-	-	-
TOTAL	1,598,473.62	1,371,643.29	1,209,407.02	1,165,555.24	1,119,274.28	1,068,802.38	1,013,760.06	953,733.39	888,271.06
NPV (end of year)	**$11,928,091.39**	**$10,675,729.01**	**$9,573,079.28**	**$8,503,254.84**	**$7,469,013.10**	**$6,474,900.86**			
OPERATING LEASES									
	2004	2005	2006	2007	2008	2009	2010	2011	2012
Duke	-	-	-	-	-	-	-	-	-
Atapco 1 (LCC)	170,817.11	175,738.58	180,660.11	185,581.58	54,546.63	-	-	-	-
Atapco 2 (635)	204,067.46	382,260.90	391,710.54	401,160.18	136,344.96	-	-	-	-
Thomson (615)	213,780.00	89,075.00	-	-	-	-	-	-	-
IOS Capital	42,363.00	26,943.00	1,835.00	-	-	-	-	-	-
MAPP Center	1,339,636.80	1,339,636.80	1,339,636.80	1,436,584.20	1,436,584.20	1,436,584.20	1,436,584.20	1,436,584.20	1,436,584.20
Agiliti lease payments	(285,732.00)	(142,866.00)	-	-	-	-	-	-	-
MAPPCOR lease payments	(62,502.00)	-	-	-	-	-	-	-	-
TOTAL	1,622,430.37	1,870,788.28	1,913,842.45	2,023,325.96	1,627,475.79	1,436,584.20	1,436,584.20	1,436,584.20	1,436,584.20
NPV (end of year)	**$13,956,493.74**	**$12,225,270.40**	**$10,433,680.66**	**$8,514,691.50**	**$6,972,362.63**	**$5,605,502.06**			
DEBT INTEREST									
	2004	2005	2006	2007	2008	2009	2010	2011	2012
IDFA Note Interest	57,670.49	21,618.55	18,488.08	15,263.24	11,941.18	8,518.99	4,993.62	1,368.09	-
2012 Note Interest	8,750,000.00	8,750,000.00	8,750,000.00	8,750,000.00	8,750,000.00	8,750,000.00	8,750,000.00	8,750,000.00	2,916,666.67
2013 Note Interest	4,620,000.00	4,620,000.00	4,620,000.00	4,070,000.00	3,410,000.00	2,750,000.00	2,090,000.00	1,430,000.00	770,000.00
2014 Note Interest*	5,144,791.67	5,612,500.00	5,612,500.00	5,612,500.00	4,944,345.24	4,142,559.52	3,340,773.81	2,538,988.10	1,737,202.38
TOTAL	18,572,462.16	19,004,118.55	19,000,988.08	18,447,763.24	17,116,286.42	15,651,078.51	14,185,767.43	12,720,356.19	5,423,869.05
2014 Note Int - GridAm	954,873.33	1,041,680.00	1,041,680.00	1,041,680.00	917,670.48	768,859.05	620,047.62	471,236.19	322,424.76
TOTAL w/o GridAm	17,617,588.82	17,962,438.55	17,959,308.08	17,406,083.24	16,198,615.94	14,882,219.47	13,565,719.81	12,249,119.99	5,101,444.29
NPV TOTAL	**$117,940,994.59**	**$100,116,285.98**	**$82,116,460.76**	**$64,489,862.13**	**$48,018,474.34**	**$32,847,580.56**			
NPV TOTAL (w/o) GridAm	**$111,772,657.55**	**$94,927,945.58**	**$77,917,916.96**	**$61,291,012.88**	**$45,705,307.07**	**$31,280,140.68**			
GridAm	**$6,168,337.03**	**$5,188,340.41**	**$4,198,543.81**	**$3,198,849.25**	**$2,313,167.26**	**$1,567,439.89**			
*Assumes 4.49%, 10 year maturity, start 2/1/04									
GRAND TOTAL NPV	**$143,825,579.72**	**$123,017,285.40**	**$102,123,220.71**	**$81,507,808.47**	**$62,459,850.07**	**$44,927,983.48**			

PRESENT VALUE - LEASE										
CAPITAL LEASES										
	2013	2014	2015	2016	2017	2018	2019	2020	2021	TOTAL
INTEREST										
H&P	816,880.82	739,025.91	654,120.86	561,527.31	460,549.01	350,426.69	230,332.28	99,362.86	3,009.80	14,187,993.09
First Fed	-	-	-	-	-	-	-	-	-	333.21
EMC	-	-	-	-	-	-	-	-	-	549,333.54
TOTAL	816,880.82	739,025.91	654,120.86	561,527.31	460,549.01	350,426.69	230,332.28	99,362.86	3,009.80	14,737,659.84
NPV (end of year)										
OPERATING LEASES										
	2013	2014	2015	2016	2017	2018	2019	2020	2021	TOTAL
Duke	-	-	-	-	-	-	-	-	-	58,673.63
Atapco 1 (LCC)	-	-	-	-	-	-	-	-	-	809,176.75
Atapco 2 (635)	-	-	-	-	-	-	-	-	-	1,543,668.00
Thomson (615)	-	-	-	-	-	-	-	-	-	356,300.00
IOS Capital	-	-	-	-	-	-	-	-	-	94,678.25
MAPP Center	1,436,584.20	-	-	-	-	-	-	-	-	14,409,909.00
Agiliti lease payments	-	-	-	-	-	-	-	-	-	(500,031.00)
MAPPCOR lease payments	-	-	-	-	-	-	-	-	-	(93,753.00)
TOTAL	1,436,584.20	-	-	-	-	-	-	-	-	16,678,621.63
NPV (end of year)										
DEBT INTEREST										
	2013	2014	2015	2016	2017	2018	2019	2020	2021	TOTAL
IDFA Note Interest	-	-	-	-	-	-	-	-	-	139,862.24
2012 Note Interest	-	-	-	-	-	-	-	-	-	77,291,666.67
2013 Note Interest	110,000.00	-	-	-	-	-	-	-	-	28,490,000.00
2014 Note Interest*	935,416.67	66,815.48	-	-	-	-	-	-	-	39,688,392.86
TOTAL	1,045,416.67	66,815.48	-	-	-	-	-	-	-	145,609,921.76
2014 Note Int - GridAm	173,613.33	12,400.95	-	-	-	-	-	-	-	7,366,165.71
TOTAL w/o GridAm	871,803.33	54,414.52	-	-	-	-	-	-	-	138,243,756.05
NPV TOTAL										
NPV TOTAL (w/o) GridAm										
GridAm										
*Assumes 4.49%, 10 year maturity,										
GRAND TOTAL NPV										

PRESENT VALUE - LEASES AND INTEREST AT 12/31/04 SCHEDULE 10									
CAPITAL LEASES	1%								
	2004	2005	2006	2007	2008	2009	2010	2011	2012
INTEREST									
[redacted]									
First Fed	174.90	-	-	-	-	-	-	-	-
[redacted]									
TOTAL	799,324.26	685,821.65	604,703.51	582,777.62	559,637.14	534,401.19	506,880.03	476,866.70	444,135.53
NPV (begin '04)	**$5,964,045.69**	**$5,337,864.51**	**$4,786,539.64**	**$4,251,627.42**	**$3,734,506.55**	**$3,237,450.43**			
OPERATING LEASES									
	2004	2005	2006	2007	2008	2009	2010	2011	2012
Duke	-	-	-	-	-	-	-	-	-
[redacted]									
MAPP Center	1,339,636.80	1,339,636.80	1,339,636.80	1,436,584.20	1,436,584.20	1,436,584.20	1,436,584.20	1,436,584.20	1,436,584.20
Agiliti	(285,732.00)	(142,866.00)	-	-	-	-	-	-	-
MAPPCOR	(62,502.00)	-	-	-	-	-	-	-	-
TOTAL	1,306,916.58	1,533,779.54	1,626,739.62	1,729,955.08	1,532,029.99	1,436,584.20	1,436,584.20	1,436,584.20	1,436,584.20
NPV (end of year)	**$12,964,911.54**	**$11,560,781.12**	**$10,049,649.31**	**$8,420,190.72**	**$6,972,362.63**	**$5,605,502.06**			
DEBT INTEREST									
	2004	2005	2006	2007	2008	2009	2010	2011	2012
IDFA Note Interest	57,670.49	21,618.55	18,488.08	15,263.24	11,941.18	8,518.99	4,993.62	1,368.09	-
2012 Note Interest	8,750,000.00	8,750,000.00	8,750,000.00	8,750,000.00	8,750,000.00	8,750,000.00	8,750,000.00	8,750,000.00	2,916,666.67
2013 Note Interest	-	-	-	-	-	-	-	-	-
2014 Note Interest*	1,028,958.33	1,122,500.00	1,122,500.00	1,122,500.00	988,869.05	828,511.90	668,154.76	507,797.62	347,440.48
TOTAL	9,836,628.82	9,894,118.55	9,890,988.08	9,887,763.24	9,750,810.23	9,587,030.89	9,423,148.38	9,259,165.71	3,264,107.14
NPV (end of year)	**$68,292,013.44**	**$59,080,815.03**	**$49,780,635.10**	**$40,390,678.21**	**$31,043,774.76**	**$21,767,181.62**			
*Assumes 4.49%, 10 year maturity, start 1/1/04									
GRAND TOTAL NPV	**$87,220,970.68**	**$75,979,460.65**	**$64,616,824.05**	**$53,062,496.35**	**$41,750,643.95**	**$30,610,134.10**			

PRESENT VALUE - L

CAPITAL LEASES										
	2013	2014	2015	2016	2017	2018	2019	2020	2021	TOTAL
INTEREST										
[redacted]										
First Fed	-	-	-	-	-	-	-	-	-	333.21
[redacted]										
TOTAL	408,440.41	369,512.96	327,060.43	280,763.66	230,274.51	175,213.35	115,166.14	49,681.43	1,504.90	7,368,996.53
NPV (begin '04)										
OPERATING LEASES										
	2013	2014	2015	2016	2017	2018	2019	2020	2021	TOTAL
Duke	-	-	-	-	-	-	-	-	-	58,673.63
[redacted]										
MAPP Center	1,436,584.20	-	-	-	-	-	-	-	-	14,409,909.00
Agiliti	-	-	-	-	-	-	-	-	-	(500,031.00)
MAPPCOR	-	-	-	-	-	-	-	-	-	(93,753.00)
TOTAL	1,436,584.20	-	-	-	-	-	-	-	-	15,276,710.14
NPV (end of year)										
DEBT INTEREST										
	2013	2014	2015	2016	2017	2018	2019	2020	2021	TOTAL
IDFA Note Interest	-	-	-	-	-	-	-	-	-	139,862.24
2012 Note Interest	-	-	-	-	-	-	-	-	-	81,291,666.67
2013 Note Interest	-	-	-	-	-	-	-	-	-	-
2014 Note Interest*	187,083.33	13,363.10	-	-	-	-	-	-	-	7,937,678.57
TOTAL	187,083.33	13,363.10	-	-	-	-	-	-	-	89,369,207.48
NPV (end of year)										
*Assumes 4.49%, 10 year ma										
GRAND TOTAL NPV										

PRESENT VALUE - LEASES AND INTEREST AT 12/31/04 SCHEDULE 16								
CAPITAL LEASES	1%							
	2004	2005	2006	2007	2008	2009	2010	2011
INTEREST								
[redacted]								
First Fed	-	-	-	-	-	-	-	-
[redacted]								
TOTAL	399,574.68	342,910.82	302,351.76	291,388.81	279,818.57	267,200.60	253,440.02	238,433.35
NPV (end of year)	**$2,982,022.85**	**$2,668,932.25**	**$2,393,269.82**	**$2,125,813.71**	**$1,867,253.28**	**$1,618,725.21**		
OPERATING LEASES								
	2004	2005	2006	2007	2008	2009	2010	2011
Duke	-	-	-	-	-	-	-	-
[redacted]								
MAPP Center	-	-	-	-	-	-	-	-
Agiliti	-	-	-	-	-	-	-	-
MAPPCOR	-	-	-	-	-	-	-	-
TOTAL	157,756.89	168,504.37	143,551.41	146,685.44	47,722.90	-	-	-
NPV (end of year)	**$495,791.10**	**$332,244.64**	**$192,015.68**	**$47,250.39**	**$0.00**	**$0.00**		
DEBT INTEREST								
	2004	2005	2006	2007	2008	2009	2010	2011
IDFA Note Interest	-	-	-	-	-	-	-	-
2012 Note Interest	-	-	-	-	-	-	-	-
2013 Note Interest	1,243,242.00	1,247,400.00	1,227,534.00	1,093,609.00	952,072.00	823,075.00	637,241.00	439,725.00
2014 Note Interest*	850,614.34	931,046.40	916,218.62	926,563.58	848,155.36	761,774.94	625,829.03	479,685.94
TOTAL	2,093,856.34	2,178,446.40	2,143,752.62	2,020,172.58	1,800,227.36	1,584,849.94	1,263,070.03	919,410.94
NPV (end of year)	**$12,229,874.75**	**$10,173,727.10**	**$8,131,711.75**	**$6,192,856.28**	**$4,454,557.49**	**$2,914,253.12**		
*Assumes 4.49%, 10 year maturity, start 1/1/04								
GRAND TOTAL NPV	**$15,707,688.70**	**$13,174,903.99**	**$10,716,997.24**	**$8,365,920.38**	**$6,321,810.76**	**$4,532,978.34**		

PRESENT VALUE - L										
CAPITAL LEASES										
INTEREST	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
[redacted]										
First Fed	-	-	-	-	-	-	-	-	-	-
[redacted]										
TOTAL	222,067.77	204,220.21	184,756.48	163,530.22	140,381.83	115,137.25	87,606.67	57,583.07	24,840.72	752.45
NPV (end of year)										
OPERATING LEASES										
Duke	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
	-	-	-	-	-	-	-	-	-	-
[redacted]										
MAPP Center	-	-	-	-	-	-	-	-	-	-
Agiliti	-	-	-	-	-	-	-	-	-	-
MAPPCOR	-	-	-	-	-	-	-	-	-	-
TOTAL	-	-	-	-	-	-	-	-	-	-
NPV (end of year)										
DEBT INTEREST										
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
IDFA Note Interest	-	-	-	-	-	-	-	-	-	-
2012 Note Interest	-	-	-	-	-	-	-	-	-	-
2013 Note Interest	236,698.00	33,803.00	-	-	-	-	-	-	-	-
2014 Note Interest*	328,099.44	176,611.46	12,615.10	-	-	-	-	-	-	-
TOTAL	564,797.44	210,414.46	12,615.10	-	-	-	-	-	-	-
NPV (end of year)										
*Assumes 4.49%, 10 year ma										
GRAND TOTAL NPV										

PRESENT VALUE - L	
CAPITAL LEASES	
	TOTAL
INTEREST	
[redacted]	[redacted]
First Fed	-
[redacted]	[redacted]
TOTAL	3,684,331.66
NPV (end of year)	
OPERATING LEASES	
	TOTAL
Duke	-
[redacted]	[redacted]
MAPP Center	-
Agiliti	-
MAPPCOR	-
TOTAL	700,955.75
NPV (end of year)	
DEBT INTEREST	
	TOTAL
IDFA Note Interest	-
2012 Note Interest	-
2013 Note Interest	7,934,399.00
2014 Note Interest*	6,857,214.21
TOTAL	14,791,613.21
NPV (end of year)	
*Assumes 4.49%, 10 year ma	
GRAND TOTAL NPV	

PRESEN. VALUE - LEASES AND INTEREST AT 12/31/04 SCHEDULE 17

CAPITAL LEASES	1%								
	2004	2005	2006	2007	2008	2009	2010	2011	2012
INTEREST									
[redacted]									
First Fed	-	-	-	-	-	-	-	-	-
[redacted]									
TOTAL	399,574.68	342,910.82	302,351.76	291,388.81	279,818.57	267,200.60	253,440.02	238,433.35	222,067.77
NPV (end of year)	**$2,982,022.85**	**$2,668,932.25**	**$2,393,269.82**	**$2,125,813.71**	**$1,867,253.28**	**$1,618,725.21**			
OPERATING LEASES									
	2004	2005	2006	2007	2008	2009	2010	2011	2012
Duke	-	-	-	-	-	-	-	-	-
[redacted]									
MAPP Center	-	-	-	-	-	-	-	-	-
Agiliti	-	-	-	-	-	-	-	-	-
MAPPCOR	-	-	-	-	-	-	-	-	-
TOTAL	157,756.89	168,504.37	143,551.41	146,685.44	47,722.90	-	-	-	-
NPV (end of year)	**$495,791.10**	**$332,244.64**	**$192,015.68**	**$47,250.39**	**$0.00**	**$0.00**	-	-	-
DEBT INTEREST									
	2004	2005	2006	2007	2008	2009	2010	2011	2012
IDFA Note Interest	-	-	-	-	-	-	-	-	-
2012 Note Interest	-	-	-	-	-	-	-	-	-
2013 Note Interest	3,376,758.00	3,372,600.00	3,392,466.00	2,976,391.00	2,457,928.00	1,926,925.00	1,452,759.00	990,275.00	533,302.00
2014 Note Interest*	2,310,345.66	2,517,273.60	2,532,101.38	2,521,756.42	2,189,650.36	1,783,413.63	1,426,742.40	1,080,268.34	739,237.71
TOTAL	5,687,103.66	5,889,873.60	5,924,567.38	5,498,147.42	4,647,578.36	3,710,338.63	2,879,501.40	2,070,543.34	1,272,539.71
NPV (end of year)	**$31,250,769.36**	**$25,673,403.45**	**$20,005,570.11**	**$14,707,478.40**	**$10,206,974.82**	**$6,598,705.94**			
*Assumes 4.49%, 10 year maturity, start 1/1/04									
GRAND TOTAL NPV	**$34,728,583.31**	**$28,674,580.35**	**$22,590,855.61**	**$16,880,542.50**	**$12,074,228.10**	**$8,217,431.15**			

PRESEN1 VALUE - L										
CAPITAL LEASES										
INTEREST	2013	2014	2015	2016	2017	2018	2019	2020	2021	TOTAL
[redacted]										
First Fed	-	-	-	-	-	-	-	-	-	-
[redacted]										
TOTAL	204,220.21	184,756.48	163,530.22	140,381.83	115,137.25	87,606.67	57,583.07	24,840.72	752.45	3,684,331.66
NPV (end of year)										
OPERATING LEASES										
Duke	2013	2014	2015	2016	2017	2018	2019	2020	2021	TOTAL
	-	-	-	-	-	-	-	-	-	-
[redacted]										
MAPP Center	-	-	-	-	-	-	-	-	-	-
Agiliti	-	-	-	-	-	-	-	-	-	-
MAPPCOR	-	-	-	-	-	-	-	-	-	-
TOTAL	-	-	-	-	-	-	-	-	-	700,955.75
NPV (end of year)										
DEBT INTEREST										
	2013	2014	2015	2016	2017	2018	2019	2020	2021	TOTAL
IDFA Note Interest	-	-	-	-	-	-	-	-	-	-
2012 Note Interest	-	-	-	-	-	-	-	-	-	-
2013 Note Interest	76,197.00	-	-	-	-	-	-	-	-	20,555,601.00
2014 Note Interest*	398,108.54	28,436.32	-	-	-	-	-	-	-	17,527,334.36
TOTAL	474,305.54	28,436.32	-	-	-	-	-	-	-	38,082,935.36
NPV (end of year)										
*Assumes 4.49%, 10 year ma										
GRAND TOTAL NPV										

2013 Notes

	Beginning Principal	Mandatory Principal Repayment	Ending Principal	Interest Rate	Interest Payment
2003	$ 100,000,000.00	$ -	$ 100,000,000.00	4.62%	$ 3,850,000.00
2004	$ 100,000,000.00	$ -	$ 100,000,000.00	4.62%	$ 4,620,000.00
2005	$ 100,000,000.00	$ -	$ 100,000,000.00	4.62%	$ 4,620,000.00
2006	$ 100,000,000.00	$ -	$ 100,000,000.00	4.62%	$ 4,620,000.00
2007	$ 100,000,000.00	$ 14,285,714.29	$ 85,714,285.71	4.62%	$ 4,070,000.00
2008	$ 85,714,285.71	$ 14,285,714.29	$ 71,428,571.43	4.62%	$ 3,410,000.00
2009	$ 71,428,571.43	$ 14,285,714.29	$ 57,142,857.14	4.62%	$ 2,750,000.00
2010	$ 57,142,857.14	$ 14,285,714.29	$ 42,857,142.86	4.62%	$ 2,090,000.00
2011	$ 42,857,142.86	$ 14,285,714.29	$ 28,571,428.57	4.62%	$ 1,430,000.00
2012	$ 28,571,428.57	$ 14,285,714.29	$ 14,285,714.29	4.62%	$ 770,000.00
2013	$ 14,285,714.29	$ 14,285,714.29	$ -	4.62%	$ 110,000.00

2014 Notes

	Beginning Principal	Mandatory Principal Repayment	Ending Principal	Interest Rate	Interest Payment
2004	$ 125,000,000.00	$ -	$ 125,000,000.00	4.49%	$ 5,144,791.67
2005	$ 125,000,000.00	$ -	$ 125,000,000.00	4.49%	$ 5,612,500.00
2006	$ 125,000,000.00	$ -	$ 125,000,000.00	4.49%	$ 5,612,500.00
2007	$ 125,000,000.00	$ -	$ 125,000,000.00	4.49%	$ 5,612,500.00
2008	$ 125,000,000.00	$ 17,857,142.86	$ 107,142,857.14	4.49%	$ 4,944,345.24
2009	$ 107,142,857.14	$ 17,857,142.86	$ 89,285,714.29	4.49%	$ 4,142,559.52
2010	$ 89,285,714.29	$ 17,857,142.86	$ 71,428,571.43	4.49%	$ 3,340,773.81
2011	$ 71,428,571.43	$ 17,857,142.86	$ 53,571,428.57	4.49%	$ 2,538,988.10
2012	$ 53,571,428.57	$ 17,857,142.86	$ 35,714,285.71	4.49%	$ 1,737,202.38
2013	$ 35,714,285.71	$ 17,857,142.86	$ 17,857,142.86	4.49%	$ 935,416.67
2014	$ 17,857,142.86	$ 17,857,142.86	$ (0.00)	4.49%	$ 66,815.48
		$ 125,000,000.00			$ 39,688,392.86

Midwest ISC ıancial Projections
Annual Income Statement
($ in thousands, except Billing Rates)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Revenue										
ISO Cost Recovery Adder	$ 67,326	$ 105,671	$ 108,764	$ 111,900	$ 115,078	$ 121,104	$ 113,681	$ 113,287	$ 114,989	$ 111,792
FTR Cost Recovery Adder	$ -	$ 2,175	$ 23,011	$ 24,416	$ 25,173	$ 24,204	$ 24,455	$ 19,858	$ 19,553	$ 17,588
Energy Market Cost Recovery Adder	$ -	$ 7,021	$ 74,988	$ 78,074	$ 79,755	$ 78,174	$ 78,696	$ 65,734	$ 64,622	$ 56,477
Contract Revenue (MAPPCOR, SPP, AEP, Engr. Studies)	$ 8,790	$ 8,288	$ 8,537	$ 8,793	$ 9,057	$ 3,701	$ 3,812	$ 3,927	$ 4,044	$ 4,166
Interest on Cash Balance	$ 1,008	$ 669	$ 536	$ 1,221	$ 1,818	$ 2,194	$ 2,474	$ 2,507	$ 2,374	$ 1,367
Miscellaneous Revenue	$ 54	$ 56	$ 57	$ 59	$ 61	$ 63	$ 64	$ 66	$ 68	$ 70
TOTAL REVENUE	$ 77,178	$ 123,880	$ 215,894	$ 224,462	$ 230,941	$ 229,441	$ 223,182	$ 205,379	$ 205,651	$ 191,459
Operating Expenses										
Salaries and Benefits	$ 38,578	$ 49,494	$ 58,746	$ 62,625	$ 65,594	$ 63,221	$ 65,281	$ 67,404	$ 69,590	$ 71,841
Outside Services	$ 16,233	$ 39,638	$ 28,291	$ 29,140	$ 30,014	$ 30,914	$ 31,842	$ 32,797	$ 33,781	$ 34,794
Occupancy and Telecom	$ 10,724	$ 12,695	$ 13,075	$ 13,468	$ 13,872	$ 14,288	$ 14,716	$ 15,158	$ 15,613	$ 16,081
Supplies, Travel and Computer Maintenance	$ 4,772	$ 16,312	$ 17,612	$ 18,140	$ 18,685	$ 19,245	$ 19,822	$ 20,417	$ 21,030	$ 21,661
Other	$ 3,831	$ 6,362	$ 6,553	$ 6,749	$ 6,952	$ 7,160	$ 7,375	$ 7,596	$ 7,824	$ 8,059
TOTAL OPERATING EXPENSES	$ 74,138	$ 124,501	$ 124,277	$ 130,122	$ 135,116	$ 134,828	$ 139,037	$ 143,372	$ 147,837	$ 152,436
EBITDA	$ 3,039	$ (621)	$ 91,617	$ 94,340	$ 95,825	$ 94,612	$ 84,145	$ 62,006	$ 57,814	$ 39,023
Interest Expenses										
Interest on Long Term Debt	$ 12,989	$ 18,515	$ 18,983	$ 18,983	$ 18,377	$ 16,983	$ 15,521	$ 14,059	$ 12,597	$ 6,031
Interest on Short Term Debt	$ 60	$ 67	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Interest on Capital Leases	$ 1,768	$ 1,551	$ 1,322	$ 1,205	$ 1,161	$ 1,114	$ 1,062	$ 1,005	$ 942	$ 874
TOTAL INTEREST EXPENSES	$ 14,817	$ 20,133	$ 20,304	$ 20,188	$ 19,539	$ 18,096	$ 16,582	$ 15,063	$ 13,539	$ 6,905
Depreciation and Amortization										
Depreciation on Capital Assets	$ 21,547	$ 24,700	$ 51,246	$ 55,048	$ 56,781	$ 51,760	$ 42,238	$ 21,617	$ 20,440	$ 19,916
Amort. Capitalized ISO Start-Up Costs	$ 9,819	$ 9,819	$ 9,819	$ 9,819	$ 9,819	$ -	$ -	$ -	$ -	$ -
Amort. Capitalized FTR Start-Up Costs	$ -	$ 209	$ 2,503	$ 2,503	$ 2,503	$ 2,503	$ 2,503	$ 2,503	$ 2,295	$ -
Amort. Capitalized Energy Market Start-Up Costs	$ -	$ 686	$ 8,235	$ 8,235	$ 8,235	$ 8,235	$ 8,235	$ 8,235	$ 7,549	$ -
Amort. GridAm Regulatory Assets	$ 579	$ 2,317	$ 2,317	$ 2,317	$ 2,317	$ 2,317	$ 2,317	$ 2,317	$ 2,317	$ 2,317
Amort. DECo/Consumers Regulatory Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amort. Illinois Power Regulatory Asset	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amort. Deferred ISO Revenue - $25 Million Settlement	$ -	$ -	$ -	$ -	$ -	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000
Amort. Deferred Revenue - Rate CAP 2/08	$ -	$ -	$ -	$ -	$ -	$ 4,176	$ 4,556	$ 4,556	$ 4,556	$ 4,556
Amort. Reimbursable Market Participant Costs	$ -	$ 596	$ 2,386	$ 2,386	$ 2,386	$ 2,386	$ 2,386	$ 2,386	$ 1,789	$ -
Amort. of Deferred Revenue - Market Implementation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amort. Capitalized Bond Offering Costs	$ 181	$ 406	$ 425	$ 425	$ 425	$ 369	$ 328	$ 328	$ 328	$ 328
TOTAL DEPRECIATION AND AMORTIZATION	$ 32,126	$ 38,734	$ 76,933	$ 80,734	$ 82,467	$ 76,747	$ 67,563	$ 46,943	$ 44,274	$ 32,118
Increase Deferred Asset										
Deferred ISO Revenue - Due to Rate Cap or Settlement	$ 25,000	$ 4,167	$ 5,620	$ 6,582	$ 6,180	$ 231	$ -	$ -	$ -	$ -
FTR Start-Up Costs	$ 4,494	$ 12,717	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Energy Market Start-Up Costs	$ 14,409	$ 42,604	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Billing Determinates										
ISO Cost Recovery Adder MWhs - Demand Based (000)	631,633	740,353	755,160	770,263	785,669	801,382	817,410	833,758	850,433	867,442
ISO Cost Recovery Adder MWhs - Energy (000)	469,207	570,001	581,401	593,029	604,890	616,988	629,327	641,914	654,752	667,847
Unbundled (TRANSLInk) ISO CRA MWhs (000)	-	-	-	-	-	-	-	-	-	-
FTR Cost Recovery Adder - FTR MW Volume (000)	-	38,775	465,121	474,423	483,912	493,590	503,462	513,531	523,802	534,278
Energy Market CRA - MWh (Load plus Generation) (000)	-	96,937	1,162,803	1,186,059	1,209,780	1,233,975	1,258,655	1,283,828	1,309,505	1,335,695
Billing Rates										
Schedule 10 - Demand Based- $ per MWh	$ 0.0946	$ 0.1131	$ 0.1131	$ 0.1131	$ 0.1131	$ 0.1169	$ 0.1073	$ 0.1049	$ 0.1044	$ 0.0994
Schedule 10 - Energy- $ per MWh	$ 0.0155	$ 0.0367	$ 0.0367	$ 0.0367	$ 0.0367	$ 0.0380	$ 0.0349	$ 0.0341	$ 0.0339	$ 0.0323
Schedule 10 - Total- $ per MWh	$ 0.1102	$ 0.1498	$ 0.1498	$ 0.1498	$ 0.1498	$ 0.1549	$ 0.1422	$ 0.1389	$ 0.1383	$ 0.1317
Portion of Sch 10 - Demand Based	90%	80%	80%	80%	80%	80%	80%	80%	80%	80%
Portion of Sch 10 - Energy	10%	20%	20%	20%	20%	20%	20%	20%	20%	20%
Schedule 16 - $ per FTR MW Volume	$ -	$ 0.0561	$ 0.0495	$ 0.0515	$ 0.0520	$ 0.0490	$ 0.0486	$ 0.0387	$ 0.0373	$ 0.0329
Schedule 17 - $ per MWh (Load plus Generation)	$ -	$ 0.0724	$ 0.0645	$ 0.0658	$ 0.0659	$ 0.0634	$ 0.0625	$ 0.0512	$ 0.0493	$ 0.0423

Midwest I[illegible] Financial Model
Annual Cash Flow Statement
($ 000)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Operating Activities										
Net Income	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Depreciation	$ 21,547	$ 24,700	$ 51,246	$ 55,048	$ 56,781	$ 51,760	$ 42,238	$ 21,617	$ 20,440	$ 19,916
Amort. Capitalized Pre-Operating Expenses	$ 9,819	$ 10,714	$ 20,558	$ 20,558	$ 20,558	$ 10,739	$ 10,739	$ 10,739	$ 9,844	$ -
Amort. GridAm Regulatory Assets	$ (22,595)	$ 2,317	$ 2,317	$ 2,317	$ 2,317	$ 2,317	$ 2,317	$ 2,317	$ 2,317	$ 2,317
Amort. DECo/Consumers Regulatory Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amort. Illinois Power Regulatory Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amort. Reimbursable Market Participant Costs	$ (16,700)	$ 596	$ 2,386	$ 2,386	$ 2,386	$ 2,386	$ 2,386	$ 2,386	$ 1,789	$ -
Amort. Capitalized Bond Offering Costs	$ 181	$ 406	$ 425	$ 425	$ 425	$ 369	$ 328	$ 328	$ 328	$ 328
Amort. Deferred ISO Revenue - $25 Million Settlemen	$ -	$ -	$ -	$ -	$ -	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000
Amort. Deferred Revenue - Rate CAP (2/08)	$ -	$ -	$ -	$ -	$ -	$ 4,176	$ 4,556	$ 4,556	$ 4,556	$ 4,556
Amort. of Deferred Revenue - Market Implementation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(Increase) Decrease Deferred Regulatory Asset	$ (43,904)	$ (59,488)	$ (5,620)	$ (6,582)	$ (6,180)	$ (231)	$ -	$ -	$ -	$ 0
Increase (Decrease) in Operating Liabilities	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TOTAL OPERATING ACTIVITIES	$ (51,651)	$ (20,754)	$ 71,312	$ 74,152	$ 76,286	$ 76,516	$ 67,563	$ 46,943	$ 44,274	$ 32,118
Investing Activities										
Capital Expenditures - Transmission Services	$ (21,070)	$ (17,000)	$ (10,000)	$ (7,500)	$ (7,500)	$ (7,500)	$ (7,500)	$ (7,500)	$ (7,500)	$ (7,500)
Capital Expenditures - FTR Services	$ (20,714)	$ (7,891)	$ (4,000)	$ (3,300)	$ (3,300)	$ (3,300)	$ (3,300)	$ (3,300)	$ (3,300)	$ (3,300)
Capital Expenditures - Energy Market Services	$ (22,949)	$ (55,710)	$ (10,000)	$ (10,000)	$ (7,500)	$ (7,500)	$ (7,500)	$ (7,500)	$ (7,500)	$ (7,500)
TOTAL CAPITAL EXPENDITURES	$ (64,732)	$ (80,601)	$ (24,000)	$ (20,800)	$ (18,300)	$ (18,300)	$ (18,300)	$ (18,300)	$ (18,300)	$ (18,300)
Financing Activities										
Change in Capital Lease Obligation	$ (3,368)	$ (3,580)	$ (3,518)	$ (471)	$ (515)	$ (563)	$ (615)	$ (672)	$ (734)	$ (803)
Settlement Offset - Member Withdrawal	$ (250)	$ (1,000)	$ (2,000)	$ (3,000)	$ (4,000)	$ (4,000)	$ (4,000)	$ (4,000)	$ (4,000)	$ (4,000)
Change in Long Term Debt	$ 98,611	$ 122,723	$ -	$ -	$ (14,286)	$ (32,143)	$ (32,143)	$ (32,143)	$ (32,143)	$ (132,143)
TOTAL FINANCING ACTIVITIES	$ 94,992	$ 118,143	$ (5,518)	$ (3,471)	$ (18,801)	$ (36,706)	$ (36,758)	$ (36,815)	$ (36,877)	$ (136,945)
Cash at Start of Year	$ 22,531	$ 8,279	$ 17,928	$ 59,722	$ 109,603	$ 148,789	$ 170,299	$ 182,804	$ 174,632	$ 163,729
Change in Cash	$ (21,391)	$ 16,788	$ 41,794	$ 49,881	$ 39,186	$ 21,510	$ 12,505	$ (8,172)	$ (10,903)	$ (123,128)
Short Term Debt Issued (Redeemed)	$ 7,139	$ (7,139)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cash at End of Year	$ 8,279	$ 17,928	$ 59,722	$ 109,603	$ 148,789	$ 170,299	$ 182,804	$ 174,632	$ 163,729	$ 40,601

Attachment to LGE/KU #44
Witness: Holstein

Midwe SO Financial Model
Annual Balance Sheet
($ 000)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
ASSETS											
Current Assets											
Cash and Cash Equivalents	$ 22,531	$ 8,279	$ 17,928	$ 59,722	$ 109,603	$ 148,789	$ 170,299	$ 182,804	$ 174,632	$ 163,729	$ 40,601
Other Current Assets	$ 10,865	$ 10,865	$ 10,865	$ 10,865	$ 10,865	$ 10,865	$ 10,865	$ 10,865	$ 10,865	$ 10,865	$ 10,865
TOTAL CURRENT ASSETS	$ 33,397	$ 19,145	$ 28,793	$ 70,588	$ 120,468	$ 159,654	$ 181,164	$ 193,669	$ 185,497	$ 174,594	$ 51,466
Property and Equipment											
Net Property and Equipment - Transmission Service	$ 100,629	$ 101,427	$ 97,062	$ 83,712	$ 66,796	$ 50,089	$ 35,182	$ 30,296	$ 28,013	$ 26,331	$ 24,902
Net Property and Equipment - FTR Services	$ 5,620	$ 25,912	$ 32,821	$ 29,182	$ 24,106	$ 18,532	$ 14,075	$ 9,386	$ 9,249	$ 9,187	$ 9,125
Net Property and Equipment - Energy Market Services	$ 13,698	$ 35,792	$ 89,150	$ 78,893	$ 66,636	$ 50,436	$ 36,342	$ 21,978	$ 21,082	$ 20,685	$ 20,560
TOTAL NET PROPERTY AND EQUIPMENT	$ 119,946	$ 163,132	$ 219,033	$ 191,786	$ 157,538	$ 119,058	$ 85,598	$ 61,660	$ 58,343	$ 56,203	$ 54,587
Other Assets											
Net Capitalized Pre-Operating Costs - Transmission Service	$ 49,095	$ 39,276	$ 29,457	$ 19,638	$ 9,819	$ -	$ -	$ -	$ -	$ -	$ -
Net Capitalized Pre-Operating Costs - FTR Services	$ 312	$ 4,806	$ 17,315	$ 14,812	$ 12,308	$ 9,805	$ 7,301	$ 4,798	$ 2,295	$ -	$ -
Net Capitalized Pre-Operating Costs - Energy Market Services	$ 634	$ 15,043	$ 56,960	$ 48,725	$ 40,490	$ 32,255	$ 24,019	$ 15,784	$ 7,549	$ -	$ -
Net Reimbursable Market Participant Costs	$ -	$ 16,700	$ 16,104	$ 13,718	$ 11,332	$ 8,946	$ 6,561	$ 4,175	$ 1,789	$ -	$ -
Net Capitalized Bond Offering Costs	$ 530	$ 1,349	$ 3,219	$ 2,794	$ 2,369	$ 1,943	$ 1,574	$ 1,246	$ 919	$ 591	$ 263
Net Deferred Revenue - ISO CRA Settlement	$ -	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 20,000	$ 15,000	$ 10,000	$ 5,000	$ -
Net Deferred Revenue - Rate CAP (2/08)	$ -	$ -	$ -	$ -	$ -	$ -	$ 18,604	$ 14,048	$ 9,492	$ 4,936	$ 380
Net Capitalized GridAm Regulatory Asset	$ -	$ 22,595	$ 20,277	$ 17,960	$ 15,642	$ 13,325	$ 11,008	$ 8,690	$ 6,373	$ 4,055	$ 1,738
Net Capitalized DECo/Consumers Regulatory Asset	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Capitalized Illinois Power Regulatory Asset	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Deferred Revenue - Market Implementation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Deferred Revenue - Due to Rate Cap	$ -	$ -	$ 4,167	$ 9,787	$ 16,369	$ 22,550	$ -	$ -	$ -	$ -	$ -
TOTAL OTHER ASSETS	$ 50,570	$ 124,769	$ 172,499	$ 152,434	$ 133,329	$ 113,824	$ 89,067	$ 63,742	$ 38,416	$ 14,582	$ 2,381
TOTAL ASSETS	$ 203,913	$ 307,045	$ 420,326	$ 414,807	$ 411,336	$ 392,535	$ 355,829	$ 319,071	$ 282,256	$ 245,379	$ 108,434
LIABILITIES AND NET ASSETS											
Liabilities											
Current Liabilities	$ 10,791	$ 10,791	$ 10,791	$ 10,791	$ 10,791	$ 10,791	$ 10,791	$ 10,791	$ 10,791	$ 10,791	$ 10,791
Accrued Liabilities	$ 8,708	$ 8,708	$ 8,708	$ 8,708	$ 8,708	$ 8,708	$ 8,708	$ 8,708	$ 8,708	$ 8,708	$ 8,708
Capitalized Leases	$ 24,223	$ 20,854	$ 17,274	$ 13,756	$ 13,284	$ 12,769	$ 12,206	$ 11,591	$ 10,919	$ 10,185	$ 9,382
Short Term Debt	$ -	$ 7,139	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Long Term Debt	$ 100,389	$ 200,000	$ 325,000	$ 325,000	$ 325,000	$ 310,714	$ 278,571	$ 246,429	$ 214,286	$ 182,143	$ 50,000
Settlement Proceeds - Member Withdrawal	$ 59,802	$ 59,552	$ 58,552	$ 56,552	$ 53,552	$ 49,552	$ 45,552	$ 41,552	$ 37,552	$ 33,552	$ 29,552
TOTAL LIABILITIES	$ 203,913	$ 307,045	$ 420,326	$ 414,807	$ 411,336	$ 392,535	$ 355,829	$ 319,071	$ 282,256	$ 245,379	$ 108,434
Net Assets											
Retained Earnings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TOTAL NET ASSETS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TOTAL LIABILITIES AND NET ASSETS	$ 203,913	$ 307,045	$ 420,326	$ 414,807	$ 411,336	$ 392,535	$ 355,829	$ 319,071	$ 282,256	$ 245,379	$ 108,434

Attachment to LGE/KU #44
Witness: Holstein

ALL - Schedules 10, 16 & 17 - Annual Income Statement

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Revenue											
Schedule 10 Revenue - Demand Based	59,783,709	83,736,817	85,411,553	87,119,784	88,862,180	93,683,171	87,744,822	87,429,496	88,791,533	86,233,487	78,571,661
Schedule 10 Revenue - Energy Based	7,292,307	20,934,204	21,352,888	21,779,946	22,215,545	23,420,793	21,936,206	21,857,374	22,197,883	21,558,367	19,642,920
Schedule 10A	-	-	-	-	-	-	-	-	-	-	-
TRANSlink Revenue - Unbundled Service	-	-	-	-	-	-	-	-	-	-	-
Settlement Offset - Member Withdrawal	250,000	1,000,000	2,000,000	3,000,000	4,000,000	4,000,000	4,000,000	4,000,000	4,000,000	4,000,000	4,000,000
MAPP - Pass Through	5,596,960	5,000,004	5,150,004	5,304,504	5,463,639	-	-	-	-	-	-
Miscellaneous Revenue	3,192,636	3,288,415	3,387,068	3,488,680	3,593,340	3,701,140	3,812,174	3,926,540	4,044,336	4,165,666	4,290,636
Membership and Dues	54,000	55,620	57,289	59,007	60,777	62,601	64,479	66,413	68,406	70,456	72,571
Adj for Timing Difference between Actual and Model	-	-	-	-	-	-	-	-	-	-	-
Schedule 10 Related Revenue Total	76,169,611	114,015,060	117,358,601	120,751,921	124,195,481	124,867,704	117,557,681	117,279,823	119,102,158	116,027,958	106,577,809
Schedule 16	-	2,175,165	23,011,266	24,415,746	25,172,930	24,204,494	24,455,091	19,857,556	19,552,742	17,587,720	17,484,765
Schedule 16 Total	-	2,175,165	23,011,266	24,415,746	25,172,930	24,204,494	24,455,091	19,857,556	19,552,742	17,587,720	17,484,765
Schedule 17	-	7,021,106	74,987,812	78,073,564	79,754,710	78,174,264	78,695,664	65,734,037	64,621,528	56,477,027	56,946,520
Schedule 17 Total	-	7,021,106	74,987,812	78,073,564	79,754,710	78,174,264	78,695,664	65,734,037	64,621,528	56,477,027	56,946,520
Schedule 10	319,849	486,639	404,397	686,737	1,231,257	1,478,639	1,669,289	1,752,615	1,813,573	970,603	335,549
Schedule 16	204,227	88,385	77,079	318,578	434,966	471,499	479,568	394,690	264,586	155,936	8,847
Schedule 17	484,112	93,940	54,716	235,381	151,959	244,066	325,203	359,879	296,184	239,972	8,502
Interest on Cash Balance Total	1,008,188	668,964	536,193	1,240,696	1,818,182	2,194,204	2,474,061	2,507,183	2,374,344	1,366,514	352,899
TOTAL REVENUE	77,177,600	123,880,296	215,894,072	224,461,947	230,947,303	228,440,887	223,182,497	205,378,600	205,650,771	191,459,218	181,391,793
Operating Expenses											
Transmission	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts	-	-	-	-	-	-	-	-	-	-	-
Customer Service & Informational	134,525	126,805	130,609	134,527	138,563	142,720	147,002	151,412	155,954	160,633	165,452
Sales	70,900	-	-	-	-	-	-	-	-	-	-
Salaries and Benefits	34,366,864	31,968,336	35,126,292	37,445,604	39,220,716	41,068,632	42,300,684	43,569,708	44,876,796	46,223,100	47,609,796
Outside Services	13,589,708	17,811,242	18,345,579	18,895,947	19,462,825	20,046,710	20,648,111	21,267,554	21,905,581	22,562,748	23,239,631
Telecom	7,820,465	5,817,512	5,992,037	6,171,798	6,356,952	6,547,661	6,744,091	6,946,414	7,154,806	7,369,450	7,590,534
Operating Leases	1,368,242	1,469,956	1,514,055	1,559,476	1,606,261	1,654,448	1,704,082	1,755,204	1,807,860	1,862,096	1,917,959
Building Services	1,009,540	1,181,667	1,217,117	1,253,631	1,291,239	1,329,977	1,369,876	1,410,972	1,453,301	1,496,900	1,541,807
Insurance	2,040,530	3,234,576	3,331,613	3,431,562	3,534,509	3,640,544	3,749,760	3,862,253	3,978,120	4,097,464	4,220,388
Supplies and Other	3,081,977	11,073,963	10,709,112	11,030,385	11,361,297	11,702,136	12,053,200	12,414,796	12,787,240	13,170,857	13,565,983
Miscellaneous	346,506	579,387	596,769	614,672	633,112	652,105	671,668	691,818	712,573	733,950	755,969
Taxes	780,360	202,528	208,604	214,862	221,308	227,947	234,785	241,829	249,084	256,556	264,253
Direct Assignment to Market Operations	(1,594,897)	-	-	-	-	-	-	-	-	-	-
Indirect Allocation from Schedule 10	(8,380,414)	-	-	-	-	-	-	-	-	-	-
Indirect Allocation to Schedule 10	6,133,959	-	-	-	-	-	-	-	-	-	-
MAPP Activity Termination Adjustment	-	-	-	-	-	(5,463,639)	(5,463,639)	(5,463,639)	(5,463,639)	(5,463,639)	(5,463,639)
Schedule 10 Total	60,766,285	73,463,972	77,171,787	80,752,484	83,626,782	81,549,240	84,158,620	86,846,321	89,617,677	92,470,116	95,408,152
Transmission	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts	-	-	-	-	-	-	-	-	-	-	-
Customer Service & Informational	37,987	7,997	8,237	8,484	8,739	9,001	9,271	9,549	9,835	10,130	10,434
Sales	(31)	-	-	-	-	-	-	-	-	-	-
Salaries and Benefits	842,174	3,380,305	4,826,284	5,147,088	5,391,084	5,645,088	5,814,444	5,988,876	6,168,540	6,353,604	6,544,212
Outside Services	528,672	5,506,144	2,282,566	2,351,043	2,421,575	2,494,222	2,569,048	2,646,120	2,725,503	2,807,269	2,891,487
Telecom	87,362	91,514	94,259	97,087	100,000	103,000	106,090	109,273	112,551	115,927	119,405
Operating Leases	14,252	153,051	157,643	162,372	167,243	172,260	177,428	182,751	188,233	193,880	199,697
Building Services	4,000	123,243	126,940	130,748	134,671	138,711	142,872	147,159	151,573	156,121	160,804
Insurance	32,589	341,346	351,586	362,134	372,998	384,186	395,714	407,585	419,813	432,407	445,379
Supplies and Other	337,992	1,803,718	2,477,940	2,552,278	2,628,847	2,707,712	2,788,943	2,872,612	2,958,790	3,047,554	3,138,980
Miscellaneous	536	56,693	58,394	60,146	61,950	63,808	65,723	67,694	69,725	71,817	73,972
Taxes	20,597	21,088	21,721	22,372	23,043	23,735	24,447	25,180	25,936	26,714	27,515
Direct Assignment from Schedule 10	318,979	-	-	-	-	-	-	-	-	-	-
Indirect Allocation to Schedule 16	449,291	-	-	-	-	-	-	-	-	-	-
Schedule 16 Total	2,674,401	11,485,099	10,407,570	10,893,753	11,310,149	11,741,725	12,093,980	12,456,796	12,830,500	13,215,422	13,611,885
Transmission	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts	-	-	-	-	-	-	-	-	-	-	-
Customer Service & Informational	151,946	33,520	34,526	35,561	36,628	37,727	38,859	40,025	41,225	42,462	43,736
Sales	(124)	-	-	-	-	-	-	-	-	-	-
Salaries and Benefits	3,368,696	14,147,505	18,791,856	20,032,632	20,982,276	21,970,872	22,630,008	23,308,908	24,008,172	24,728,412	25,470,264
Outside Services	2,114,668	16,320,809	7,662,866	7,892,773	8,129,556	8,373,443	8,624,646	8,883,385	9,149,887	9,424,384	9,707,115
Telecom	349,450	2,699,672	2,780,662	2,864,082	2,950,004	3,038,505	3,129,660	3,223,550	3,320,256	3,419,864	3,522,460
Operating Leases	57,008	641,509	660,754	680,577	700,994	722,024	743,685	765,995	788,975	812,644	837,024
Building Services	16,000	516,393	531,885	547,841	564,277	581,205	598,641	616,600	635,098	654,151	673,776
Insurance	130,358	1,430,706	1,473,627	1,517,836	1,563,371	1,610,272	1,658,580	1,708,338	1,759,588	1,812,376	1,866,747
Supplies and Other	1,351,968	3,434,719	4,424,926	4,557,676	4,694,406	4,835,238	4,980,295	5,129,704	5,283,595	5,442,103	5,605,366
Miscellaneous	2,143	238,713	245,874	253,251	260,848	268,674	276,734	285,036	293,587	302,394	311,466
Taxes	82,388	88,386	91,036	93,769	96,582	99,479	102,464	105,538	108,704	111,965	115,324
Direct Assignment from Schedule 10	1,275,918	-	-	-	-	-	-	-	-	-	-
Indirect Allocation to Schedule 17	1,797,164	-	-	-	-	-	-	-	-	-	-
Schedule 17 Total	10,697,602	39,551,932	36,698,036	38,475,998	39,978,943	41,537,439	42,783,572	44,067,076	45,389,068	46,750,755	48,153,277
TOTAL OPERATING EXPENSES	74,138,268	124,501,003	124,277,394	130,122,214	135,115,873	134,828,404	139,037,171	143,372,197	147,837,264	152,436,294	157,173,294
EBITDA	3,039,332	(620,705)	91,616,679	94,339,732	95,825,430	94,612,263	84,145,325	62,006,402	57,813,508	39,022,924	24,188,499

ALL - Schedules 10, 16 & 17 - Annual Income Statement

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Interest Expenses											
Interest on Long Term Debt	8,572,185	10,419,719	9,624,615	9,662,031	10,433,750	10,213,259	9,972,723	9,732,187	9,491,652	3,022,693	163,698
Interest on Short Term Debt	59,885	67,407	-	-	-	-	-	-	-	-	-
Interest on Capital Leases	1,322,839	1,037,157	915,060	848,568	817,814	784,187	747,442	707,290	663,416	615,475	563,088
Schedule 10 Total	9,954,909	11,524,289	10,539,675	10,510,619	11,251,564	10,997,446	10,720,165	10,439,478	10,155,068	3,638,168	726,786
Interest on Long Term Debt	1,457,706	2,116,993	2,360,813	2,819,785	2,781,000	2,536,309	2,216,473	1,724,137	1,203,652	1,043,830	158,349
Interest on Short Term Debt	-	-	-	-	-	-	-	-	-	-	270,676
Interest on Capital Leases	118,341	120,257	86,333	71,324	68,737	65,911	62,822	59,448	55,760	51,731	47,328
Schedule 16 Total	1,576,048	2,237,290	2,447,145	2,891,109	2,849,737	2,602,220	2,278,296	1,783,585	1,259,412	1,095,561	476,352
Interest on Long Term Debt	2,959,221	5,978,080	6,977,073	6,500,883	5,162,750	4,232,962	3,332,548	2,602,633	1,901,869	1,964,697	601,565
Interest on Short Term Debt	-	-	-	-	-	-	-	-	-	-	272,069
Interest on Capital Leases	326,550	393,594	320,430	285,295	274,949	263,643	251,290	237,791	223,040	206,922	189,310
Schedule 17 Total	3,285,771	6,371,674	7,297,503	6,785,078	5,437,699	4,496,605	3,583,837	2,840,424	2,124,909	2,171,619	1,062,954
TOTAL INTEREST EXPENSES	14,816,727	20,133,207	20,304,323	20,187,707	19,539,000	18,096,271	16,582,298	15,063,487	13,539,389	6,905,348	2,266,092
Depreciation and Amortization											
Depr. Capital Assets	20,272,054	21,365,697	23,349,961	24,415,633	24,206,789	22,407,276	12,385,838	9,783,292	9,181,639	8,928,929	8,572,819
Amort. Capitalized ISO Start-Up Costs	9,819,026	9,819,026	9,819,026	9,819,026	9,819,026	-	-	-	-	-	-
Amort. Ameren Interest Repayment	-	-	-	-	-	-	-	-	-	-	-
Amort. Illinois Power Interest Repayment	-	-	-	-	-	-	-	-	-	-	-
Amort. Grid Am - Regulatory Asset	579,350	2,317,400	2,317,400	2,317,400	2,317,400	2,317,400	2,317,400	2,317,400	2,317,400	2,317,400	1,738,050
Amort. DECo/Consumers - Regulatory Asset	-	-	-	-	-	-	-	-	-	-	-
Amort. Illinois Power - Regulatory Asset	-	-	-	-	-	-	-	-	-	-	-
Amort. Deferred Revenue - $25 Million Settlement	-	-	-	-	-	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	-
Amort. Deferred Revenue - Rate CAP 2/06	-	-	-	-	-	4,178,377	4,556,047	4,556,047	4,556,047	4,556,047	379,671
[redacted]											
Amort. Capitalized Bond Offering Costs (Original Issue)	97,656	97,656	97,656	97,656	97,656	41,408	-	-	-	-	-
Schedule 10 Total	30,768,086	33,580,354	35,573,443	36,732,612	36,548,771	34,000,280	24,347,186	21,744,839	21,142,986	20,800,276	10,778,440
Depr. Capital Assets	420,723	981,936	7,639,474	8,375,307	8,873,656	7,757,884	7,888,229	3,437,708	3,361,875	3,361,875	3,361,875
[redacted]											
Amort. Capitalized Bond Offering Costs (2003 Issue)	27,500	33,000	33,000	33,000	33,000	33,000	33,000	33,000	33,000	33,000	5,500
Amort. of Deferred Revenue - Market Implementation											
Amort. Capitalized FTR Start-Up Costs	-	208,613	2,503,355	2,503,355	2,503,355	2,503,355	2,503,355	2,503,355	2,294,742	-	-
Schedule 16 Total	448,223	1,256,168	10,214,588	10,949,462	11,449,911	10,325,049	10,582,399	6,013,663	5,727,417	3,433,676	3,403,176
Depr. Capital Assets	854,196	2,352,104	20,257,034	22,257,033	23,700,071	21,594,330	21,863,502	8,396,457	7,896,458	7,625,625	7,625,625
Amort. Reimbursable Market Participant Costs	-	596,429	2,385,714	2,385,714	2,385,714	2,385,714	2,385,714	2,385,714	1,789,286	-	-
[redacted]											
Amort. Capitalized Bond Offering Costs (2003 Issue)	55,633	67,000	67,000	67,000	67,000	67,000	67,000	67,000	67,000	67,000	11,167
Amort. of Deferred Revenue - Market Implementation											
Amort. Capitalized Energy Market Start-Up Costs	-	686,270	8,235,241	8,235,241	8,235,241	8,235,241	8,235,241	8,235,241	7,548,971	-	-
Schedule 17 Total	910,029	3,795,203	31,649,989	33,046,689	34,490,027	32,034,286	32,050,456	19,169,413	17,403,715	7,794,825	7,788,792
TOTAL DEPRECIATION AND AMORTIZATION	32,126,339	38,733,656	76,932,681	80,734,066	82,466,809	76,746,694	67,563,027	46,942,915	44,274,118	32,117,576	21,922,406
Total Depreciation and Interest	46,943,066	58,867,063	97,236,884	100,921,773	102,005,808	94,842,964	84,145,325	62,006,402	57,813,508	39,022,924	24,188,499
Increase Deferred Asset											
Deferred ISO Revenue - Due to Rate Cap or Settlement	25,000,000	4,166,910	5,620,205	6,582,040	6,180,378	230,701	-	-	-	-	-
FTR Start-Up Costs	4,494,444	12,716,998	-	-	-	-	-	-	-	-	-
Energy Market Start-Up Costs	14,409,290	42,603,860	-	-	-	-	-	-	-	-	-
Total Increase (Decrease) Deferred Asset	43,903,734	59,487,768	5,620,205	6,582,040	6,180,378	230,701	-	-	-	-	-
Net Income	-	-	-	-	-	-	-	-	-	-	-
Billing Determinates											
Schedule 10 MWhs - Demand Based	631,632,512	740,353,027	755,160,087	770,263,289	785,668,555	801,381,926	817,409,565	833,757,756	850,432,911	867,441,569	884,790,401
Schedule 10 MWhs - Energy	469,206,643	570,001,263	581,401,289	593,029,314	604,889,901	616,987,699	629,327,453	641,914,002	654,752,282	667,847,327	681,204,274
Unbundled (TRANSLink) Schedule 10 MWhs	-	-	-	-	-	-	-	-	-	-	-
Schedule 16 - FTR MW Volume	-	38,774,855	465,121,031	474,423,451	483,911,921	493,590,159	503,461,962	513,531,201	523,801,825	534,277,862	544,963,419
Schedule 17 - MWh (Load plus Generation)	-	96,937,138	1,162,602,577	1,186,058,629	1,209,779,801	1,233,975,397	1,258,654,905	1,283,828,003	1,309,504,563	1,335,694,655	1,362,408,548
Billing Rates											
Schedule 10 - Demand Based- $ per MWh	$ 0.0946	$ 0.1131	$ 0.1131	$ 0.1131	$ 0.1131	$ 0.1169	$ 0.1073	$ 0.1049	$ 0.1044	$ 0.0994	$ 0.0888
Schedule 10 - Energy- $ per MWh	$ 0.0155	$ 0.0367	$ 0.0367	$ 0.0367	$ 0.0367	$ 0.0380	$ 0.0349	$ 0.0341	$ 0.0339	$ 0.0323	$ 0.0288
Schedule 10 - Total- $ per MWh	$ 0.1102	$ 0.1498	$ 0.1498	$ 0.1498	$ 0.1498	$ 0.1549	$ 0.1422	$ 0.1389	$ 0.1383	$ 0.1317	$ 0.1176
Portion of Sch 10 - Demand Based	90%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%
Portion of Sch 10 - Energy	10%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
Schedule 16 - $ per FTR MW Volume	$ -	$ 0.0561	$ 0.0495	$ 0.0515	$ 0.0520	$ 0.0490	$ 0.0486	$ 0.0387	$ 0.0373	$ 0.0329	$ 0.0321
Schedule 17 - $ per MWh (Load plus Generation)	$ -	$ 0.0724	$ 0.0645	$ 0.0658	$ 0.0659	$ 0.0634	$ 0.0625	$ 0.0512	$ 0.0493	$ 0.0423	$ 0.0418

ALL - Schedules 10, 16 & 17 - Annual Cash Flow Statement

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Operating Activities											
Net Income	-	-	-	-	-	-	-	-	-	-	-
Depreciation of Capital Assets	20,272,054	21,365,697	23,349,961	24,415,633	24,206,789	22,407,276	12,385,838	9,783,292	9,181,639	8,928,929	8,572,819
[redacted]											
Amort. of Capitalized Bond Offering Costs (Original Issue	97,656	97,656	97,656	97,656	97,656	41,406	-	-	-	-	-
Amortization of Capitalized ISO Start-Up Costs	9,819,026	9,819,026	9,819,026	9,819,026	9,819,026	-	-	-	-	-	-
Amortization of Ameren Repayment Interest	-	-	-	-	-	-	-	-	-	-	-
Amortization of Illinois Power Repayment Interest	-	-	-	-	-	-	-	-	-	-	-
Amortization of Grid Am - Regulatory Asset	(22,594,650)	2,317,400	2,317,400	2,317,400	2,317,400	2,317,400	2,317,400	2,317,400	2,317,400	2,317,400	1,738,050
Amortization of DECo/Consumers - Regulatory Asset	-	-	-	-	-	-	-	-	-	-	-
Amortization of Illinois Power - Regulatory Asset	-	-	-	-	-	-	-	-	-	-	-
Amort. Deferred Revenue - $25 Million Settlement	-	-	-	-	-	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	-
Amort. Deferred Revenue - Rate CAP (2/08)	-	-	-	-	-	4,176,377	4,556,047	4,556,047	4,556,047	4,556,047	378,671
(Increase) Decrease Deferred Revenue	(25,000,000)	(4,166,910)	(5,620,205)	(6,582,040)	(6,180,378)	(230,701)	-	-	-	0	(0)
Increase (Decrease) in Operating Liabilities	-	-	-	-	-	-	-	-	-	-	-
Schedule 10 Total	(17,405,914)	29,513,444	30,051,737	30,155,575	30,348,393	33,799,657	24,347,186	21,744,639	21,142,986	20,890,276	10,778,440
Net Income	-	-	-	-	-	-	-	-	-	-	-
Depreciation of Capital Assets	420,723	981,936	7,639,474	8,375,307	8,873,856	7,757,894	7,988,229	3,437,708	3,361,875	3,361,876	3,361,875
Amort. of Capitalized Bond Offering Costs (2003 Issue)	27,500	33,000	33,000	33,000	33,000	33,000	33,000	33,000	33,000	33,000	5,500
[redacted]											
Amort. of Deferred Revenue - Market Implementation		-	-	-	-	-	-	-	-	-	-
Amortization of Capitalized FTR Start-Up Costs	-	208,613	2,503,355	2,503,365	2,503,355	2,503,355	2,503,355	2,503,355	2,294,742	-	-
(Increase) Decrease Deferred Regulatory Asset	(4,494,444)	(12,716,998)	-	-	-	-	-	-	-	-	-
Schedule 16 Total	(4,046,221)	(11,458,799)	10,213,629	10,949,462	11,449,011	10,332,049	10,662,884	6,011,863	5,727,417	3,432,875	3,405,375
Net Income	-	-	-	-	-	-	-	-	-	-	-
Depreciation of Capital Assets	854,196	2,352,104	20,257,034	22,257,033	23,700,071	21,594,330	21,863,502	8,396,457	7,896,458	7,625,625	7,625,625
Amort. Reimbursable Market Participant Costs	(16,700,000)	596,429	2,385,714	2,385,714	2,385,714	2,385,714	2,385,714	2,385,714	1,789,286	-	-
Amort. of Capitalized Bond Offering Costs (2003 Issue)	55,833	67,000	67,000	67,000	67,000	67,000	67,000	67,000	67,000	67,000	11,167
[redacted]											
Amort. of Deferred Revenue - Market Implementation		-	-	-	-	-	-	-	-	-	-
Amortization of Capitalized Energy Market Start-Up Cost	-	686,270	8,235,241	8,235,241	8,235,241	8,235,241	8,235,241	8,235,241	7,548,971	-	-
(Increase) Decrease Deferred Regulatory Asset	(14,409,290)	(42,603,860)	-	-	-	-	-	-	-	-	-
Schedule 17 Total	(30,199,261)	(38,800,557)	31,046,989	33,046,989	34,499,027	32,384,286	32,653,458	19,186,418	17,409,715	7,794,625	7,738,792
TOTAL OPERATING ACTIVITIES	(51,651,396)	(20,753,912)	71,312,355	74,152,025	76,296,430	76,515,992	67,663,027	46,942,915	44,279,118	32,117,576	21,922,406
Investing Activities											
Capital Expenditures	(21,070,050)	(17,000,400)	(9,999,996)	(7,500,000)	(7,500,000)	(7,500,000)	(7,500,000)	(7,500,000)	(7,500,000)	(7,500,000)	(7,500,000)
Schedule 10 Total	(21,070,050)	(17,000,400)	(9,999,996)	(7,500,000)	(7,500,000)	(7,500,000)	(7,500,000)	(7,500,000)	(7,500,000)	(7,500,000)	(7,500,000)
Capital Expenditures	(20,713,560)	(7,890,591)	(3,999,996)	(3,300,000)	(3,300,000)	(3,300,000)	(3,300,000)	(3,300,000)	(3,300,000)	(3,300,000)	(3,025,000)
Schedule 16 Total	(20,713,560)	(7,890,591)	(3,999,996)	(3,300,000)	(3,300,000)	(3,300,000)	(3,300,000)	(3,300,000)	(3,300,000)	(3,300,000)	(3,025,000)
Capital Expenditures	(22,948,620)	(55,709,749)	(9,999,996)	(9,999,996)	(7,500,000)	(7,500,000)	(7,500,000)	(7,500,000)	(7,500,000)	(7,500,000)	(6,875,000)
Schedule 17 Total	(22,948,620)	(55,709,749)	(9,999,996)	(9,999,996)	(7,500,000)	(7,500,000)	(7,500,000)	(7,500,000)	(7,500,000)	(7,500,000)	(6,875,000)
TOTAL INVESTING ACTIVITIES	(64,732,230)	(80,600,740)	(23,999,988)	(20,799,996)	(18,300,000)	(18,300,000)	(18,300,000)	(18,300,000)	(18,300,000)	(18,300,000)	(17,400,000)
Financing Activities											
Change in Capital Lease Obligation	(6,184,546)	(1,871,349)	(1,847,177)	(331,937)	(362,711)	(396,338)	(433,083)	(473,235)	(517,109)	(565,050)	(617,436)
Settlement Offset - Member Withdrawal (Incl Ameren Re|	(250,000)	(1,000,000)	(2,000,000)	(3,000,000)	(4,000,000)	(4,000,000)	(4,000,000)	(4,000,000)	(4,000,000)	(4,000,000)	(4,000,000)
Change in Long Term Debt	24,610,564	11,621,000	6,250,000	18,750,000	-	(5,357,143)	(5,357,143)	(5,357,143)	(5,357,143)	(98,214,286)	(15,178,571)
Schedule 10 Total	18,176,018	8,749,651	2,402,823	15,418,063	(4,362,711)	(9,753,481)	(9,790,226)	(9,830,377)	(9,874,251)	(102,779,336)	(19,796,006)
Change in Capital Lease Obligation	368,283	(548,589)	(534,855)	(27,899)	(30,486)	(33,312)	(36,401)	(39,775)	(43,463)	(47,492)	(51,896)
Change in Long Term Debt	24,420,000	18,372,000	5,750,000	7,000,000	(1,285,714)	(5,357,143)	(9,357,143)	(10,785,714)	(12,214,286)	(14,142,857)	(8,678,571)
Schedule 16 Total	24,788,283	17,823,411	5,215,145	6,972,101	(1,316,200)	(5,390,455)	(9,393,543)	(10,825,490)	(12,257,749)	(14,190,350)	(8,730,467)
Change in Capital Lease Obligation	2,447,891	(1,160,217)	(1,136,209)	(111,597)	(121,943)	(133,249)	(145,602)	(159,101)	(173,852)	(189,970)	(207,582)
Change in Long Term Debt	49,580,000	92,730,000	(12,000,000)	(25,750,000)	(13,000,000)	(21,428,571)	(17,428,571)	(16,000,000)	(14,571,429)	(19,785,714)	(8,285,715)
Schedule 17 Total	52,027,891	91,569,783	(13,136,209)	(25,861,597)	(13,121,943)	(21,561,820)	(17,574,174)	(16,159,101)	(14,745,280)	(19,975,684)	(8,493,297)
Grand Total	94,992,192	118,142,845	(5,518,242)	(3,471,433)	(18,800,854)	(36,705,756)	(36,757,943)	(36,814,968)	(36,877,280)	(136,945,369)	(37,019,771)
Short Term Funding											
Beginning Cash Position	22,531,456	8,279,388	17,928,215	59,722,340	109,602,936	148,788,512	170,298,748	182,803,832	174,631,779	163,728,617	40,600,823
Change in Cash	(21,391,434)	16,788,193	41,794,125	49,880,596	39,185,576	21,510,236	12,505,084	(8,172,054)	(10,903,162)	(123,127,793)	(32,497,365)
Cash Surplus (Deficit)	1,140,022	25,067,581	59,722,340	109,602,936	148,788,512	170,298,748	182,803,832	174,631,779	163,728,617	40,600,823	8,103,459
Short Term Debt Issue (Redeem)	7,139,366	(7,139,366)	-	-	-	-	-	-	-	-	10,913,258

ALL - Schedules 10, 16 & 17 - Annual Cash Flow Statement

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Ending Cash Position	8,279,388	17,928,215	59,722,340	109,602,936	148,788,512	170,298,748	182,803,832	174,631,779	163,728,617	40,600,823	19,016,717

ALL - Schedules 10, 16 & 17 - Annual Balance Sheet

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
ASSETS												
Current Assets:												
Cash and Cash Equivalents	13,160,580	-	14,123,329	36,577,892	74,651,531	93,137,212	109,683,388	116,740,348	121,154,610	124,923,345	35,534,285	19,016,717
Other Current Assets	10,865,169	10,865,169	10,865,169	10,865,169	10,865,169	10,865,169	10,865,169	10,865,169	10,865,169	10,865,169	10,865,169	10,865,169
Sch 10 Total	24,025,749	10,865,169	24,988,498	47,443,061	85,516,700	104,002,381	120,548,557	127,605,517	132,019,779	135,788,514	46,399,454	29,881,886
Cash and Cash Equivalents	3,647,606	3,876,110	2,350,131	13,776,909	28,400,472	35,232,282	36,873,876	34,742,717	26,629,090	16,798,758	2,741,084	-
Sch 16 Total	3,647,606	3,876,110	2,350,131	13,776,909	28,400,472	35,232,282	36,873,876	34,742,717	26,629,090	16,798,758	2,741,084	-
Cash and Cash Equivalents	5,623,268	4,403,278	1,454,755	9,365,539	6,550,934	20,419,018	23,741,484	31,320,768	26,848,079	22,006,514	2,325,455	-
Sch 17 Total	5,623,268	4,403,278	1,454,755	9,365,539	6,550,934	20,419,018	23,741,484	31,320,768	26,848,079	22,006,514	2,325,455	-
TOTAL CURRENT ASSETS	33,296,625	19,144,557	28,793,384	70,587,509	120,468,105	159,653,581	181,163,917	193,669,001	185,496,948	174,593,786	51,465,992	29,881,886
Property and Equipment:												
Schedule 10												
Property and Equipment	104,333,884	137,466,275	153,184,800	163,768,163	171,476,496	178,976,496	186,476,496	193,976,496	201,476,496	208,976,496	216,476,496	223,976,496
Acc. Depr. - Property and Equipment	(15,902,163)	(36,174,217)	(57,539,915)	(80,889,875)	(105,305,508)	(129,512,297)	(151,919,573)	(164,305,411)	(174,088,703)	(183,270,342)	(192,199,271)	(200,772,090)
Net Property and Equipment	88,431,721	101,292,058	95,644,885	82,878,288	66,170,988	49,464,199	34,556,923	29,671,085	27,387,793	25,706,154	24,277,225	23,204,406
Construction in Progress	12,197,166	134,825	1,416,700	833,333	625,000	625,000	625,000	625,000	625,000	625,000	625,000	625,000
Sch 10 - TOTAL NET PROP AND EQUIP	100,628,887	101,426,883	97,061,585	83,711,621	66,795,988	50,089,199	35,181,923	30,296,085	28,012,793	26,331,154	24,902,225	23,829,406
Schedule 16												
Property and Equipment	2,103,617	2,103,617	33,671,090	37,925,448	41,283,781	44,583,781	47,883,781	51,183,781	54,483,781	57,783,781	61,083,781	64,383,781
Acc. Depr. Property and Equipment	(35,060)	(455,784)	(1,437,719)	(9,077,193)	(17,452,500)	(26,326,356)	(34,084,251)	(42,072,480)	(45,510,188)	(48,872,063)	(52,233,938)	(55,595,813)
Net Property and Equipment	2,068,557	1,647,833	32,233,371	28,848,255	23,831,281	18,257,425	13,799,531	9,111,302	8,973,594	8,911,719	8,849,844	8,787,969
Construction in Progress	3,551,017	24,264,577	587,695	333,333	275,000	275,000	275,000	275,000	275,000	275,000	275,000	-
Sch 16 - TOTAL NET PROP AND EQUIP	5,619,574	25,912,411	32,821,066	29,181,588	24,106,281	18,532,425	14,074,531	9,386,302	9,248,594	9,186,719	9,124,844	8,787,969
Schedule 17												
Property and Equipment	4,270,980	4,270,980	89,871,165	101,594,196	111,594,192	119,302,525	126,802,525	134,302,525	141,802,525	149,302,525	156,802,525	164,302,525
Acc. Depr. Property and Equipment	(71,183)	(925,379)	(3,277,483)	(23,534,517)	(45,791,550)	(69,491,621)	(91,085,951)	(112,949,453)	(121,345,910)	(129,242,368)	(136,867,993)	(144,493,618)
Net Property and Equipment	4,199,797	3,345,601	86,593,681	78,059,679	65,802,642	49,810,904	35,716,574	21,353,071	20,456,614	20,060,156	19,934,531	19,808,906
Construction in Progress	9,496,184	32,446,804	2,556,368	833,333	833,333	625,000	625,000	625,000	625,000	625,000	625,000	-
Sch 17 - TOTAL NET PROP AND EQUIP	13,695,981	35,792,405	89,150,049	78,893,012	66,635,975	50,435,904	36,341,574	21,978,071	21,081,614	20,685,156	20,559,531	19,808,906
TOTAL NET PROPERTY & EQUIPMENT	119,946,442	163,131,696	219,032,701	191,786,221	157,538,244	118,057,528	85,598,028	61,660,458	58,343,001	56,203,029	54,586,600	52,424,281
Other Assets:												
Schedule 10												
Capitalized ISO Start-Up Costs	58,914,154	58,914,154	58,914,154	58,914,154	58,914,154	58,914,154	58,914,154	58,914,154	58,914,154	58,914,154	58,914,154	58,914,154
Accumulated Amortization	(9,819,026)	(19,638,051)	(29,457,077)	(39,276,103)	(49,095,128)	(58,914,154)	(58,914,154)	(58,914,154)	(58,914,154)	(58,914,154)	(58,914,154)	(58,914,154)
Net Capitalized ISO Start-Up Costs	49,095,128	39,276,103	29,457,077	19,638,051	9,819,026	-	-	-	-	-	-	-
[redacted]												
Capitalized Bond Offering Costs (Original Issue)	585,938	585,938	585,938	585,938	585,938	585,938	585,938	585,938	585,938	585,938	585,938	585,938
Accumulated Amortization	(56,250)	(153,906)	(251,563)	(349,219)	(446,875)	(544,532)	(585,938)	(585,938)	(585,938)	(585,938)	(585,938)	(585,938)
Net Capitalized Bond Offering Costs	529,688	432,032	334,375	236,719	139,063	41,406	-	-	-	-	-	-
Deferred Revenue - Settlement - ER02-111-000	-	25,000,000	25,000,000	25,000,000	25,000,000	25,000,000	25,000,000	25,000,000	25,000,000	25,000,000	25,000,000	25,000,000
Accumulated Recovery of Deferred Revenue	-	-	-	-	-	-	(5,000,000)	(10,000,000)	(15,000,000)	(20,000,000)	(25,000,000)	(25,000,000)
Net Deferred Revenue - Settlement - ER02-111-000	-	25,000,000	25,000,000	25,000,000	25,000,000	25,000,000	20,000,000	15,000,000	10,000,000	5,000,000	-	-
Deferred Revenue - Rate CAP (2/08)	-	-	-	-	-	-	22,780,236	22,780,236	22,780,236	22,780,236	22,780,236	22,780,236
Accumulated Recovery of Deferred Revenue	-	-	-	-	-	-	(4,176,377)	(8,732,424)	(13,288,471)	(17,844,518)	(22,400,565)	(22,780,236)
Net Deferred Revenue - Rate CAP (2/08)	-	-	-	-	-	-	18,603,859	14,047,812	9,491,765	4,935,718	379,671	-
Ameren Repayment - Interest Amortization	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Amortization	-	-	-	-	-	-	-	-	-	-	-	-
Net Capitalized Ameren Repayment - Interest Amortization	-	-	-	-	-	-	-	-	-	-	-	-
Illinois Power Repayment - Interest Amortization	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Amortization	-	-	-	-	-	-	-	-	-	-	-	-
Net Capitalized Illinois Power Repayment - Interest Amortiza	-	-	-	-	-	-	-	-	-	-	-	-
GridAm - Regulatory Asset	-	23,174,000	23,174,000	23,174,000	23,174,000	23,174,000	23,174,000	23,174,000	23,174,000	23,174,000	23,174,000	23,174,000
Accumulated Amortization	-	(579,350)	(2,896,750)	(5,214,150)	(7,531,550)	(9,848,950)	(12,166,350)	(14,483,750)	(16,801,150)	(19,118,550)	(21,435,950)	(23,174,000)
Net GridAm - Regulatory Asset	-	22,594,650	20,277,250	17,959,850	15,642,450	13,325,050	11,007,650	8,690,250	6,372,850	4,055,450	1,738,050	-
DECo/Consumers - Regulatory Asset	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Amortization	-	-	-	-	-	-	-	-	-	-	-	-
Net DECo/Consumers - Regulatory Asset	-	-	-	-	-	-	-	-	-	-	-	-
Illinois Power - Regulatory Asset	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Amortization	-	-	-	-	-	-	-	-	-	-	-	-
Net Illinois Power - Regulatory Asset	-	-	-	-	-	-	-	-	-	-	-	-
Defered Revenue Due to Rate Cap	-	-	4,166,910	9,787,116	16,369,156	22,549,534	-	-	-	-	-	-
Sch 10 - TOTAL OTHER ASSETS	49,624,816	87,302,784	80,034,038	73,332,261	67,582,320	61,450,716	50,058,334	38,096,987	26,135,640	14,174,293	2,212,946	7,325

2004 Budget Scenario #1 (without Ameren IP) Summary.xls - Annual Bal Sh

1/20/2004

ALL - Schedules 10, 16 & 17 - Annual Balance Sheet

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Schedule 16												
Capitalized FTR Start-Up Costs	312,042	4,806,486	17,523,484	17,523,484	17,523,484	17,523,484	17,523,484	17,523,484	17,523,484	17,523,484	17,523,484	17,523,484
Accumulated Amortization	-	-	(208,613)	(2,711,968)	(5,215,323)	(7,718,677)	(10,222,032)	(12,725,387)	(15,228,742)	(17,523,484)	(17,523,484)	(17,523,484)
Net Capitalized FTR Start-Up Costs	312,042	4,806,486	17,314,871	14,811,516	12,308,161	9,804,806	7,301,452	4,796,097	2,294,742	-	-	-
Deferred Revenue - Market Implementation	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Recovery of Deferred Revenue	-	-	-	-	-	-	-	-	-	-	-	-
Net Deferred Revenue - Market Implementation	-	-	-	-	-	-	-	-	-	-	-	-
Capitalized Bond Offering Costs (2003 Issue)	-	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000
Accumulated Amortization	-	(27,500)	(60,500)	(93,500)	(126,500)	(159,500)	(192,500)	(225,500)	(258,500)	(291,500)	(324,500)	(330,000)
Net Capitalized Bond Offering Costs	-	302,500	269,500	236,500	203,500	170,500	137,500	104,500	71,500	38,500	5,500	-
[redacted]												
Sch 16 - TOTAL OTHER ASSETS	312,042	5,108,986	17,327,721	15,353,566	12,779,417	10,205,656	7,631,102	5,056,947	2,482,792	119,250	45,450	3,150
Schedule 17												
Capitalized Energy Market Start-Up Costs	633,540	15,042,830	57,646,690	57,646,690	57,646,690	57,646,690	57,646,690	57,646,690	57,646,690	57,646,690	57,646,690	57,646,690
Accumulated Amortization	-	-	(686,270)	(8,921,512)	(17,156,753)	(25,391,995)	(33,627,236)	(41,862,477)	(50,097,719)	(57,646,690)	(57,646,690)	(57,646,690)
Net Capitalized Energy Market Start-Up Costs	633,540	15,042,830	56,960,420	48,725,179	40,489,937	32,254,696	24,019,454	15,784,213	7,548,971	-	-	-
Reimbursable Market Participant Costs	-	16,700,000	16,700,000	16,700,000	16,700,000	16,700,000	16,700,000	16,700,000	16,700,000	16,700,000	16,700,000	16,700,000
Accumulated Amortization	-	-	(596,429)	(2,982,143)	(5,367,857)	(7,753,571)	(10,139,286)	(12,525,000)	(14,910,714)	(16,700,000)	(16,700,000)	(16,700,000)
Net Reimbursable Market Participant Costs	-	16,700,000	16,103,571	13,717,857	11,332,143	8,946,429	6,560,714	4,175,000	1,789,286	-	-	-
Deferred Revenue - Market Implementation	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Recovery of Deferred Revenue	-	-	-	-	-	-	-	-	-	-	-	-
Net Deferred Revenue - Market Implementation	-	-	-	-	-	-	-	-	-	-	-	-
Capitalized Bond Offering Costs (2003 Issue)	-	670,000	670,000	670,000	670,000	670,000	670,000	670,000	670,000	670,000	670,000	670,000
Accumulated Amortization	-	(55,833)	(122,833)	(189,833)	(256,833)	(323,833)	(390,833)	(457,833)	(524,833)	(591,833)	(658,833)	(670,000)
Net Capitalized Bond Offering Costs	-	614,167	547,167	480,167	413,167	346,167	279,167	212,167	145,167	78,167	11,167	-
[redacted]												
Sch 17 - TOTAL OTHER ASSETS	633,540	32,356,997	74,537,658	68,247,702	52,857,767	42,192,291	31,077,562	20,567,879	9,797,924	290,667	121,667	6,600
TOTAL OTHER ASSETS	50,570,396	124,768,767	172,499,417	152,433,530	133,329,478	113,823,763	89,087,271	63,741,613	38,416,356	14,582,209	2,381,062	16,975
TOTAL ASSETS	203,913,465	307,045,023	420,325,502	414,807,260	411,336,827	392,534,972	355,829,216	319,071,273	282,256,304	245,379,024	108,433,654	82,327,141
LIABILITIES AND NET ASSETS												
Current Liabilities	10,790,931	10,790,931	10,790,931	10,790,931	10,790,931	10,790,931	10,790,931	10,790,931	10,790,931	10,790,931	10,790,931	10,790,931
Accrued Liabilities	8,708,182	8,708,182	8,708,182	8,708,182	8,708,182	8,708,182	8,708,182	8,708,182	8,708,182	8,708,182	8,708,182	8,708,182
Capitalized Leases	19,588,544	13,403,998	11,532,649	9,685,472	9,353,535	8,990,824	8,594,486	8,161,403	7,688,168	7,171,060	6,606,010	5,988,573
Short Term Debt	-	7,139,366	-	-	-	-	-	-	-	-	-	-
Long Term Debt	75,389,436	100,000,000	112,500,000	118,750,000	137,500,000	137,500,000	132,142,857	126,785,714	121,428,571	116,071,428	17,857,143	2,678,571
Settlement Proceeds - Member Withdrawal	59,802,359	59,552,359	58,552,359	56,552,359	53,552,359	49,552,359	45,552,359	41,552,359	37,552,359	33,552,359	29,552,359	25,552,359
Sch 10 - LIABILITIES AND NET ASSETS	174,279,452	199,594,836	202,084,121	204,496,944	219,905,007	215,542,295	205,788,815	195,998,589	186,168,211	176,293,960	73,514,624	53,718,617
Current Liabilities	-	-	-	-	-	-	-	-	-	-	-	-
Capitalized Leases	1,529,224	1,897,507	1,348,919	814,063	786,164	755,678	722,366	685,965	646,190	602,727	555,235	503,339
Short Term Debt	-	-	-	-	-	-	-	-	-	-	-	5,609,208
Long Term Debt	8,250,000	33,000,000	51,750,000	57,500,000	64,500,000	63,214,286	57,857,143	48,500,000	37,714,286	25,500,000	11,357,143	2,678,571
Sch 16 - LIABILITIES AND NET ASSETS	9,779,224	34,897,507	53,098,919	58,314,063	65,286,164	63,969,964	58,579,509	49,185,965	38,360,476	26,102,727	11,912,377	8,791,119
Current Liabilities	-	-	-	-	-	-	-	-	-	-	-	-
Capitalized Leases	3,104,766	5,552,679	4,392,462	3,256,253	3,144,656	3,022,712	2,889,464	2,743,861	2,584,760	2,410,908	2,220,939	2,013,357
Short Term Debt	-	-	-	-	-	-	-	-	-	-	-	5,304,050
Long Term Debt	16,750,000	67,000,000	160,750,000	148,750,000	123,000,000	110,000,000	88,571,429	71,142,857	55,142,857	40,571,428	20,785,714	12,499,999
Sch 17 - LIABILITIES AND NET ASSETS	19,854,766	72,552,679	165,142,462	152,006,253	126,144,656	113,022,712	91,460,892	73,886,718	57,727,617	42,982,337	23,006,653	19,817,406
TOTAL LIABILITIES AND NET ASSETS	203,913,465	307,045,023	420,325,502	414,807,260	411,335,827	392,534,972	355,829,216	319,071,273	282,256,304	245,379,024	108,433,654	82,327,141
Net Assets:												
Retained Earnings	-	-	-	-	-	-	-	-	-	-	-	-
Sch 10 - Net Assets	-	-	-	-	-	-	-	-	-	-	-	-
Retained Earnings	-	-	-	-	-	-	-	-	-	-	-	-
Sch 16 - Net Assets	-	-	-	-	-	-	-	-	-	-	-	-
Retained Earnings	-	-	-	-	-	-	-	-	-	-	-	-
Sch 17 - Net Assets	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL NET ASSETS	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL LIABILITIES AND NET ASSETS	203,913,465	307,045,023	420,325,502	414,807,260	411,335,827	392,534,972	355,829,216	319,071,273	282,256,304	245,379,024	108,433,654	82,327,141

MWHs - Ann Sum

	Incl in Sch 10 Rev Calc?	Peak Demand - MWHs 2000	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
IES - Alliant Energy - IES Industries (Joining TRANSLink)	Yes	14,780,328	14,816,275	15,112,601	15,414,853	15,723,150	16,037,613	16,358,365	16,685,532	17,019,243	17,359,628	17,706,820	18,060,957	18,422,176
IPC - Alliant Energy - Interstate Power Company (Joining TRANSLink	Yes	7,289,136	7,270,780	7,416,196	7,564,520	7,715,810	7,870,126	8,027,529	8,188,080	8,351,841	8,518,878	8,689,256	8,863,041	9,040,301
WPL - Alliant Energy - Wisconsin Power & Light (ATC - American Tra	Yes	17,724,480	18,523,992	18,894,471	19,272,361	19,657,808	20,050,964	20,451,983	20,861,023	21,278,244	21,703,808	22,137,885	22,580,642	23,032,255
CILCO - AmerenCILCO	Yes	8,623,320	8,660,045	8,833,246	9,009,911	9,190,109	9,373,911	9,561,389	9,752,617	9,947,669	10,146,623	10,349,555	10,556,546	10,767,677
CGE - Cinergy - Cincinnati Gas & Electric	Yes	35,104,152	35,706,626	36,420,758	37,149,174	37,892,157	38,650,000	39,423,000	40,211,460	41,015,689	41,836,003	42,672,723	43,526,178	44,396,701
Union - Cinergy - Union Light, Heat & Power	Yes	5,590,872	5,407,412	5,515,560	5,625,871	5,738,389	5,853,156	5,970,219	6,089,624	6,211,416	6,335,645	6,462,358	6,591,605	6,723,437
PSI - Cinergy - PSI Energy	Yes	39,970,224	41,593,650	42,425,523	43,274,033	44,139,514	45,022,304	45,922,750	46,841,205	47,778,029	48,733,590	49,708,262	50,702,427	51,716,476
Srpingfield - City Water, Light & Power - Springfield, Illinois	Yes	2,823,960	2,938,048	2,996,809	3,056,745	3,117,880	3,180,238	3,243,842	3,308,719	3,374,894	3,442,391	3,511,239	3,581,464	3,653,093
Dairyland - Dairyland Power Cooperative	No	6,254,001	6,506,663	6,636,796	6,769,532	6,904,922	7,043,021	7,183,881	7,327,559	7,474,110	7,623,592	7,776,064	7,931,585	8,090,217
Grt Rvr - Great River Energy	No	14,016,552	14,582,821	14,874,477	15,171,967	15,475,406	15,784,914	16,100,612	16,422,625	16,751,077	17,086,099	17,427,821	17,776,377	18,131,905
Edison Sault - Wisconsin Energy Corp - Edison Sault Electric Compai	Yes	1,092,792	1,106,006	1,128,127	1,150,689	1,173,703	1,197,177	1,221,120	1,245,543	1,270,454	1,295,863	1,321,780	1,348,216	1,375,180
Hoosier - Hoosier Energy REC	Yes	7,252,304	7,545,297	7,696,203	7,850,127	8,007,130	8,167,272	8,330,618	8,497,230	8,667,175	8,840,518	9,017,328	9,197,675	9,381,629
IMPA - Indiana Municipal Power Agency	Yes	3,638,256	3,785,242	3,860,946	3,938,165	4,016,929	4,097,267	4,179,213	4,262,797	4,348,053	4,435,014	4,523,714	4,614,188	4,706,472
IPL - Indianapolis Power and Light	Yes	20,783,976	21,159,533	21,582,723	22,014,378	22,454,665	22,903,759	23,361,834	23,829,071	24,305,652	24,791,765	25,287,600	25,793,352	26,309,219
ITC - International Transmission Company	Yes	76,751,304	81,079,798	82,701,394	84,355,422	86,042,530	87,763,381	89,518,648	91,309,021	93,135,202	94,997,906	96,897,864	98,835,821	100,812,537
KU - LG&E Energy - Kentucky Utilities	Yes	28,681,488	30,168,288	30,771,654	31,387,087	32,014,829	32,655,125	33,308,228	33,974,392	34,653,880	35,346,958	36,053,897	36,774,975	37,510,474
LGE - LG&E Energy - Louisville Gas and Electric	Yes	16,706,064	17,975,472	18,334,981	18,701,681	19,075,715	19,457,229	19,846,374	20,243,301	20,648,167	21,061,130	21,482,353	21,912,000	22,350,240
Lincoln - Lincoln Electric (Nebraska) System	Yes	4,440,024	4,619,401	4,711,789	4,806,025	4,902,145	5,000,188	5,100,192	5,202,196	5,306,240	5,412,364	5,520,612	5,631,024	5,743,644
Madison	Yes	4,423,104	4,664,591	4,757,882	4,853,040	4,950,101	5,049,103	5,150,085	5,253,087	5,358,148	5,465,311	5,574,618	5,686,110	5,799,832
MH - Manitoba (Canado) Hydro - Coordination Agreement	Yes	31,159,770	32,418,625	33,066,997	33,728,337	34,402,904	35,090,962	35,792,781	36,508,637	37,238,810	37,983,586	38,743,257	39,518,123	40,308,485
METC - Michigan Electric Transmission Company (Trans-Elect)	Yes	53,645,688	47,737,151	61,550,857	62,781,874	64,037,511	65,318,261	66,624,627	67,957,119	69,316,262	70,702,587	72,116,638	73,558,971	75,030,151
Mid-Am - Mid-American Energy Company	No	24,820,080	25,689,092	26,202,874	26,726,931	27,261,470	27,806,699	28,362,833	28,930,090	29,508,691	30,098,865	30,700,843	31,314,859	31,941,157
MP - Minnesota Power	Yes	11,761,440	12,236,602	12,481,334	12,730,961	12,985,580	13,245,292	13,510,198	13,780,402	14,056,010	14,337,130	14,623,872	14,916,350	15,214,677
MIPU - Aquila - Missouri Public Service Co	No	8,408,832	8,748,549	8,923,520	9,101,990	9,284,030	9,469,711	9,659,105	9,852,287	10,049,333	10,250,319	10,455,326	10,664,432	10,877,721
MDU - Montana-Dakota Utilities	Yes	2,859,960	2,975,502	3,035,012	3,095,713	3,157,627	3,220,779	3,285,195	3,350,899	3,417,917	3,486,275	3,556,001	3,627,121	3,699,663
NPPD - Nebraska Public Power District	No	13,982,520	14,547,414	14,838,362	15,135,129	15,437,832	15,746,589	16,061,520	16,382,751	16,710,406	17,044,614	17,385,506	17,733,216	18,087,881
NSP-MN - Northern States Power Company (Minnesota)	Yes	45,117,120	50,019,072	51,019,453	52,039,843	53,080,639	54,142,252	55,225,097	56,329,599	57,456,191	58,605,315	59,777,421	60,972,970	62,192,429
NSP-WI - Northern States Power Company (Wisconsin)	Yes	9,107,256	9,367,416	9,554,764	9,745,860	9,940,777	10,139,592	10,342,384	10,549,232	10,760,217	10,975,421	11,194,929	11,418,828	11,647,204
NW Wis - Northwestern Wisconsin Electric	Yes	225,672	242,793	247,648	252,601	257,653	262,807	268,063	273,424	278,892	284,470	290,160	295,963	301,882
OPPD - Omaha Public Power District	No	12,833,040	13,351,495	13,618,525	13,890,895	14,168,713	14,452,087	14,741,129	15,035,952	15,336,671	15,643,404	15,956,272	16,275,398	16,600,906
OtterTail Power Company	Yes	4,839,936	5,102,073	5,204,114	5,308,196	5,414,360	5,522,648	5,633,100	5,745,762	5,860,678	5,977,891	6,097,449	6,219,398	6,343,786
SIGECO - Southern Indiana Gas & Electric Company (Vectren Energ	Yes	8,037,168	8,271,914	8,437,353	8,606,100	8,778,222	8,953,786	9,132,862	9,315,519	9,501,830	9,691,866	9,885,703	10,083,417	10,285,086
S ILL Cp - Southern Illinois Power Cooperative	Yes	2,022,144	2,103,839	2,145,915	2,188,834	2,232,610	2,277,263	2,322,808	2,369,264	2,416,649	2,464,982	2,514,282	2,564,568	2,615,859
SMMP - Southern Minnesota Municipal Power Agency	No	3,662,568	3,810,536	3,886,746	3,964,481	4,043,771	4,124,646	4,207,139	4,291,282	4,377,108	4,464,650	4,553,943	4,645,022	4,737,922
S. Beloit - Alliant Energy - South Beloit Water, Gas & Electric (ATC)	Yes	332,472	296,722	302,657	308,710	314,884	321,182	327,605	334,157	340,840	347,657	354,610	361,703	368,937
St Jo - Aquila - St. Joseph Light & Power	No	2,794,008	2,906,886	2,965,024	3,024,324	3,084,811	3,146,507	3,209,437	3,273,626	3,339,098	3,405,880	3,473,998	3,543,478	3,614,347
	No	0	0	0	0	0	0	0	0	0	0	0	0	0
UPP	Yes	1,127,904	1,177,341	1,200,888	1,224,906	1,249,404	1,274,392	1,299,880	1,325,877	1,352,395	1,379,443	1,407,032	1,435,172	1,463,876
Wabash - Wabash Valley Electric Association	Yes	2,774,808	2,886,910	2,944,648	3,003,541	3,063,612	3,124,884	3,187,382	3,251,130	3,316,152	3,382,475	3,450,125	3,519,127	3,589,510
WERL - Aquila - WestPlains Energy	No	3,262,272	3,394,068	3,461,949	3,531,188	3,601,812	3,673,848	3,747,325	3,822,272	3,898,717	3,976,691	4,056,225	4,137,350	4,220,097
WPP-MAIN - Wisconsin Public Power - MAIN Region	Yes	4,353,953	4,529,853	4,620,450	4,712,859	4,807,116	4,903,258	5,001,323	5,101,350	5,203,377	5,307,444	5,413,593	5,521,865	5,632,302
WPP-MAPP - Wisconsin Public Power - MAPP Region	Yes	416,306	433,125	441,787	450,623	459,635	468,828	478,205	487,769	497,524	507,475	517,624	527,977	538,536
WPS - Wisconsin Public Service	Yes	15,662,040	14,395,807	14,683,723	14,977,397	15,276,945	15,582,484	15,894,134	16,212,017	16,536,257	16,866,982	17,204,322	17,548,408	17,899,376
WEPCO - Wisconsin Electric Power Company	Yes	42,062,232	43,147,248	44,010,193	44,890,397	45,788,205	46,703,969	47,638,049	48,590,810	49,562,626	50,553,878	51,564,956	52,596,255	53,648,180
Corn Belt	No	1,858,599	1,933,686	1,972,360	2,011,807	2,052,043	2,093,084	2,134,946	2,177,645	2,221,198	2,265,622	2,310,934	2,357,153	2,404,296
KACY - Brd of Pub Util - Kansas City	No	3,337,776	0	3,542,075	3,612,916	3,685,174	3,758,878	3,834,055	3,910,737	3,988,951	4,068,730	4,150,105	4,233,107	4,317,769
INDN - City P&L - Independence, MO	No	1,736,256	0	1,842,529	1,879,379	1,916,967	1,955,306	1,994,412	2,034,301	2,074,987	2,116,486	2,158,816	2,201,992	2,246,032
SPRM - City Util - Springfield, MO	No	4,283,400	0	4,545,578	4,636,490	4,729,220	4,823,804	4,920,280	5,018,686	5,119,060	5,221,441	5,325,870	5,432,387	5,541,035
EMDE - Empire District Electric Co.	No	7,149,768	0	7,587,391	7,739,139	7,893,922	8,051,800	8,212,836	8,377,093	8,544,635	8,715,527	8,889,838	9,067,635	9,248,987
KACP - Kansas City P&L Co	No	22,063,248	21,620,467	22,052,876	22,493,934	22,943,812	23,402,688	23,870,742	24,348,157	24,835,120	25,331,823	25,838,459	26,355,228	26,882,333
KAGE - Kansas Gas & Elect Co.	No	15,902,880	16,009,700	16,329,894	16,656,492	16,989,621	17,329,414	17,676,002	18,029,522	18,390,113	18,757,915	19,133,073	19,515,735	19,906,049
KAPL - Kansas Power & Light Co	No	16,986,432	0	18,026,138	18,386,660	18,754,393	19,129,481	19,512,071	19,902,312	20,300,359	20,706,366	21,120,493	21,542,903	21,973,761
MIDW - Midwest Energy	No	1,308,600	0	1,388,697	1,416,471	1,444,800	1,473,696	1,503,170	1,533,233	1,563,898	1,595,176	1,627,080	1,659,621	1,692,814
	No	0	0	0	0	0	0	0	0	0	0	0	0	0
SUNC - Sunflower Electric Power Corp	No	2,583,648	0	2,741,788	2,796,624	2,852,556	2,909,607	2,967,799	3,027,155	3,087,699	3,149,452	3,212,442	3,276,690	3,342,224
AREC - Arkansas Electric Coop Corp	No	15,354,984	0	16,294,832	16,620,728	16,953,143	17,292,206	17,638,050	17,990,811	18,350,627	18,717,640	19,091,993	19,473,832	19,863,309
CELC - Central Louisiana Electric Co	No	13,688,664	0	14,526,520	14,817,050	15,113,391	15,415,659	15,723,972	16,038,452	16,359,221	16,686,405	17,020,133	17,360,536	17,707,747
CLWL - City of Clarksville, Mississippi	No	329,232	0	349,384	356,371	363,499	370,769	378,184	385,748	393,463	401,332	409,359	417,546	425,897
LAFA - City of Lafayette, Louisiana	No	3,266,280	0	3,466,202	3,535,527	3,606,237	3,678,362	3,751,929	3,826,968	3,903,507	3,981,577	4,061,209	4,142,433	4,225,281
GRRD - Grand River Dam Authority	No	8,843,232	0	9,384,509	9,572,199	9,763,643	9,958,916	10,158,094	10,361,256	10,568,481	10,779,850	10,995,447	11,215,356	11,439,664
LEPA - Louisiana Energy & Power Auth	No	1,632,432	0	1,732,350	1,766,997	1,802,337	1,838,384	1,875,151	1,912,654	1,950,907	1,989,925	2,029,724	2,070,318	2,111,725
NTEC - Northeast Texas Electric Coop	No	4,458,288	0	4,731,171	4,825,794	4,922,310	5,020,756	5,121,172	5,223,595	5,328,067	5,434,628	5,543,321	5,654,187	5,767,271
OKGE - Oklahoma Gas & Electric Co	No	37,895,904	70,938,857	37,903,503	38,661,573	39,434,805	40,223,501	41,027,971	41,848,530	42,685,501	43,539,211	44,409,995	45,298,195	46,204,159
OMPA - Oklahoma Municipal Power Auth	No	3,663,672	0	3,887,918	3,965,676	4,044,990	4,125,890	4,208,408	4,292,576	4,378,427	4,465,996	4,555,316	4,646,422	4,739,350
YAZO - Pub Serv of Yazoo City	No	190,272	0	201,918	205,957	210,076	214,277	218,563	222,934	227,393	231,941	236,579	241,311	246,137
PSOK - Pub Serv Co of Oklahoma	No	25,524,048	25,116,578	25,618,909	26,131,288	26,653,913	27,186,992	27,730,732	28,285,346	28,851,053	29,428,074	30,016,636	30,616,968	31,229,308
SOEP - Southwestern Electric Power Co	No	31,953,456	31,237,214	31,861,959	32,499,198	33,149,182	33,812,165	34,488,409	35,178,177	35,881,740	36,599,375	37,331,363	38,077,990	38,839,550
SWPA - Southwestern Power Admin	No	4,983,552	0	5,288,585	5,394,357	5,502,244	5,612,289	5,724,535	5,839,025	5,955,806	6,074,922	6,196,421	6,320,349	6,446,756
SWPS - Southwestern Public Service Co	No	27,373,128	31,955,164	32,594,267	33,246,152	33,911,076	34,589,297	35,281,083	35,986,705	36,706,439	37,440,567	38,189,379	38,953,166	39,732,230
WEFA - Western Farmers Electric Coop	No	8,331,864	0	8,841,841	9,018,678	9,199,051	9,383,032	9,570,693	9,762,107	9,957,349	10,156,496	10,359,626	10,566,818	10,778,155
First Energy	Yes	95,985,864	97,402,860	22,375,908	101,337,936	103,364,694	105,431,988	107,540,628	109,691,440	111,885,269	114,122,975	116,405,434	118,733,543	121,108,214
NIPSCO	Yes	21,086,088	21,275,323	5,147,945	22,824,260	23,280,745	23,746,360	24,221,287	24,705,713	25,199,827	25,703,824	26,217,900	26,742,258	27,277,103
Ameren	Yes	73,806,336	22,209,186	0	0	0	0	0	0	0	0	0	0	0
Illinois Power	Yes	0	23,698,011	0	0	0	0	0	0	0	0	0	0	0
New Customer	No	0	0	0	0	0	0	0	0	0	0	0	0	0
New Customer	No	0	0	0	0	0	0	0	0	0	0	0	0	0

Peak Demand - MWHs

	Incl in Sch 10 Rev Calc?	2000	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
New Customer	No	0	0	0	0	0	0	0	0	0	0	0	0	0
New Customer	No	0	0	0	0	0	0	0	0	0	0	0	0	0
New Customer	No	0	0	0	0	0	0	0	0	0	0	0	0	0
New Customer	No	0	0	0	0	0	0	0	0	0	0	0	0	0
New Customer	No	0	0	0	0	0	0	0	0	0	0	0	0	0
New Customer	No	0	0	0	0	0	0	0	0	0	0	0	0	0
New Customer	No	0	0	0	0	0	0	0	0	0	0	0	0	0
Point-to-Point	Yes	0	0	36,000,000	36,720,000	37,454,400	38,203,488	38,967,558	39,746,909	40,541,847	41,352,684	42,179,738	43,023,332	43,883,799
TOTAL		1,076,793,429	1,001,297,015	1,003,753,977	1,119,916,921	1,142,315,259	1,165,161,565	1,188,464,796	1,212,234,092	1,236,478,774	1,261,208,349	1,286,432,516	1,312,161,166	1,338,404,390
TOTAL Included in Sch 10	Yes	722,059,941	708,947,827	631,632,512	740,353,027	755,160,087	770,263,289	785,668,555	801,381,926	817,409,565	833,757,756	850,432,911	867,441,569	884,790,401

	Incl in Sch 10 Rev Calc?	Energy MWHs 2000	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
IES - Alliant Energy - IES Industries (Joining TRANSLink)	Yes	11,283,994	12,133,873	12,376,551	12,624,082	12,876,563	13,134,094	13,396,776	13,664,712	13,938,006	14,216,766	14,501,102	14,791,124	15,086,946
IPC - Alliant Energy - Interstate Power Company (Joining TRANSLink	Yes	5,633,511	5,896,612	6,014,544	6,134,835	6,257,532	6,382,682	6,510,336	6,640,543	6,773,354	6,908,821	7,046,997	7,187,937	7,331,696
WPL - Alliant Energy - Wisconsin Power & Light (ATC - American Tra	Yes	12,928,394	14,443,231	14,732,095	15,026,737	15,327,272	15,633,817	15,946,494	16,265,424	16,590,732	16,922,547	17,260,998	17,606,218	17,958,342
CILCO - AmerenCILCO	Yes	7,652,412	9,576,678	9,768,212	9,963,576	10,162,847	10,366,104	10,573,426	10,784,895	11,000,593	11,220,605	11,445,017	11,673,917	11,907,395
CGE - Cinergy - Cincinnati Gas & Electric	Yes	25,605,351	26,913,460	27,451,730	28,000,764	28,560,780	29,131,995	29,714,635	30,308,928	30,915,106	31,533,408	32,164,077	32,807,358	33,463,505
Union - Cinergy - Union Light, Heat & Power	Yes	4,012,529	3,887,251	3,964,996	4,044,296	4,125,181	4,207,685	4,291,839	4,377,676	4,465,229	4,554,534	4,645,624	4,738,537	4,833,308
PSI - Cinergy - PSI Energy	Yes	23,516,125	42,589,433	43,441,222	44,310,046	45,196,247	46,100,172	47,022,175	47,962,619	48,921,871	49,900,309	50,898,315	51,916,281	52,954,607
Srpingfield - City Water, Light & Power - Springfield, Illinois	Yes	1,904,701	1,981,651	2,021,284	2,061,710	2,102,944	2,145,003	2,187,903	2,231,661	2,276,294	2,321,820	2,368,256	2,415,621	2,463,934
Dairyland - Dairyland Power Cooperative	No	0	0	0	0	0	0	0	0	0	0	0	0	0
Grt Rvr - Great River Energy	No	0	0	0	0	0	0	0	0	0	0	0	0	0
Edison Sault - Wisconsin Energy Corp - Edison Sault Electric Compar	Yes	863,739	889,424	907,212	925,356	943,864	962,741	981,996	1,001,636	1,021,668	1,042,102	1,062,944	1,084,203	1,105,887
Hoosier - Hoosier Energy REC	Yes	4,826,020	5,020,991	5,121,411	5,223,839	5,328,316	5,434,882	5,543,580	5,654,452	5,767,541	5,882,891	6,000,549	6,120,560	6,242,971
IMPA - Indiana Municipal Power Agency	Yes	2,658,795	2,766,210	2,821,535	2,877,965	2,935,525	2,994,235	3,054,120	3,115,202	3,177,506	3,241,056	3,305,877	3,371,995	3,439,435
IPL - Indianapolis Power and Light	Yes	14,958,378	17,329,930	17,676,528	18,030,059	18,390,660	18,758,473	19,133,643	19,516,315	19,906,642	20,304,775	20,710,870	21,125,087	21,547,589
ITC - International Transmission Company	Yes	56,269,889	58,543,193	59,714,056	60,908,337	62,126,504	63,369,034	64,636,415	65,929,143	67,247,726	68,592,681	69,964,534	71,363,825	72,791,102
KU - LG&E Energy - Kentucky Utilities	Yes	20,054,942	20,751,007	21,166,027	21,589,348	22,021,135	22,461,557	22,910,788	23,369,004	23,836,384	24,313,112	24,799,374	25,295,362	25,801,269
LGE - LG&E Energy - Louisville Gas and Electric	Yes	11,146,262	12,502,604	12,752,656	13,007,709	13,267,863	13,533,221	13,803,885	14,079,963	14,361,562	14,648,793	14,941,769	15,240,605	15,545,417
Lincoln - Lincoln Electric (Nebraska) System	Yes	3,082,935	3,207,486	3,271,635	3,337,068	3,403,809	3,471,886	3,541,323	3,612,150	3,684,393	3,758,081	3,833,242	3,909,907	3,988,105
Madison	Yes	3,154,841	3,330,326	3,396,932	3,464,871	3,534,168	3,604,851	3,676,948	3,750,487	3,825,497	3,902,007	3,980,047	4,059,648	4,140,841
MH - Manitoba (Canado) Hydro - Coordination Agreement	Yes	24,323,673	25,306,349	25,812,476	26,328,726	26,855,300	27,392,406	27,940,255	28,499,060	29,069,041	29,650,422	30,243,430	30,848,299	31,465,265
METC - Michigan Electric Transmission Company (Trans-Elect)	Yes	38,737,818	27,351,679	41,108,882	41,931,060	42,769,681	43,625,075	44,497,576	45,387,528	46,295,278	47,221,184	48,165,608	49,128,920	50,111,498
Mid-Am - Mid-American Energy Company	No	0	0	0	0	0	0	0	0	0	0	0	0	0
MP - Minnesota Power	Yes	10,647,549	11,077,710	11,299,264	11,525,249	11,755,754	11,990,870	12,230,687	12,475,301	12,724,807	12,979,303	13,238,889	13,503,667	13,773,740
MIPU - Aquila - Missouri Public Service Co	No	5,421,657	5,640,692	5,753,506	5,868,576	5,985,947	6,105,666	6,227,780	6,352,335	6,479,382	6,608,970	6,741,149	6,875,972	7,013,491
MDU - Montana - Dakota Utilities	Yes	2,122,577	2,208,329	2,252,496	2,297,546	2,343,497	2,390,366	2,438,174	2,486,937	2,536,676	2,587,410	2,639,158	2,691,941	2,745,780
NPPD - Nebraska Public Power District	No	0	0	0	0	0	0	0	0	0	0	0	0	0
NSP-MN - Northern States Power Company (Minnesota)	Yes	33,909,003	34,039,361	34,720,148	35,414,551	36,122,842	36,845,299	37,582,205	38,333,849	39,100,526	39,882,537	40,680,187	41,493,791	42,323,667
NSP-WI - Northern States Power Company (Wisconsin)	Yes	6,762,601	6,960,183	7,099,387	7,241,374	7,386,202	7,533,926	7,684,604	7,838,297	7,995,062	8,154,964	8,318,063	8,484,424	8,654,113
NW Wis - Northwestern Wisconsin Electric	Yes	169,789	177,922	181,480	185,110	188,812	192,588	196,440	200,369	204,376	208,464	212,633	216,886	221,223
OPPD - Omaha Public Power District	No	0	0	0	0	0	0	0	0	0	0	0	0	0
OtterTail Power Company	Yes	4,164,658	6,184,186	6,307,869	6,434,027	6,562,707	6,693,961	6,827,841	6,964,397	7,103,685	7,245,759	7,390,674	7,538,488	7,689,257
SIGECO - Southern Indiana Gas & Electric Company (Vectren Energy	Yes	6,221,320	9,611,509	9,803,739	9,999,814	10,199,810	10,403,806	10,611,883	10,824,120	11,040,603	11,261,415	11,486,643	11,716,376	11,950,703
S ILL Cp - Southern Illinois Power Cooperative	Yes	1,391,653	1,447,876	1,476,833	1,506,370	1,536,497	1,567,227	1,598,572	1,630,543	1,663,154	1,696,417	1,730,346	1,764,952	1,800,252
SMMP - Southern Minnesota Municipal Power Agency	No	0	0	0	0	0	0	0	0	0	0	0	0	0
S. Beloit - Alliant Energy - South Beloit Water, Gas & Electric (ATC)	Yes	208,637	208,471	212,640	216,893	221,231	225,655	230,168	234,772	239,467	244,257	249,142	254,125	259,207
St. Jo - Aquila - St. Joseph Light & Power	No	1,780,249	1,852,171	1,889,214	1,926,999	1,965,539	2,004,850	2,044,947	2,085,845	2,127,562	2,170,114	2,213,516	2,257,786	2,302,942
	No	0	0	0	0	0	0	0	0	0	0	0	0	0
UPP	Yes	948,445	968,750	988,125	1,007,888	1,028,045	1,048,606	1,069,578	1,090,970	1,112,789	1,135,045	1,157,746	1,180,901	1,204,519
Wabash - Wabash Valley Electric Association	Yes	1,855,283	1,930,236	1,968,841	2,008,218	2,048,382	2,089,350	2,131,137	2,173,760	2,217,235	2,261,580	2,306,811	2,352,947	2,400,006
WEPL - Aquila - WestPlains Energy	No	2,587,550	2,692,087	2,745,929	2,800,847	2,856,864	2,914,002	2,972,282	3,031,727	3,092,362	3,154,209	3,217,293	3,281,639	3,347,272
WPP-MAIN - Wisconsin Public Power - MAIN Region	Yes	3,362,572	3,498,420	3,568,388	3,639,756	3,712,551	3,786,802	3,862,538	3,939,789	4,018,585	4,098,957	4,180,936	4,264,554	4,349,845
WPP-MAPP - Wisconsin Public Power - MAPP Region	Yes	292,074	303,874	309,951	316,150	322,473	328,923	335,501	342,211	349,055	356,037	363,157	370,420	377,829
WPS - Wisconsin Public Service	Yes	12,598,071	13,527,478	13,798,027	14,073,988	14,355,468	14,642,577	14,935,428	15,234,137	15,538,820	15,849,596	16,166,588	16,489,920	16,819,718
WEPCO - Wisconsin Electric Power Company	Yes	30,643,400	32,750,781	33,405,797	34,073,913	34,755,391	35,450,499	36,159,509	36,882,699	37,620,353	38,372,760	39,140,215	39,923,020	40,721,480
Corn Belt	No	0	0	0	0	0	0	0	0	0	0	0	0	0
KACY - Brd of Pub Util - Kansas City	No	0	0	0	0	0	0	0	0	0	0	0	0	0
INDN - City P&L - Independence, MO	No	0	0	0	0	0	0	0	0	0	0	0	0	0
SPRM - City Util - Springfield, MO	No	0	0	0	0	0	0	0	0	0	0	0	0	0
EMDE - Empire District Electric Co.	No	0	0	0	0	0	0	0	0	0	0	0	0	0
KACP - Kansas City P&L Co	No	0	18,504,946	18,875,045	19,252,546	19,637,597	20,030,349	20,430,956	20,839,575	21,256,366	21,681,494	22,115,124	22,557,426	23,008,575
KAGE - Kansas Gas & Elect Co.	No	0	13,217,674	13,482,028	13,751,668	14,026,701	14,307,236	14,593,380	14,885,248	15,182,953	15,486,612	15,796,344	16,112,271	16,434,516
KAPL - Kansas Power & Light Co	No	0	0	0	0	0	0	0	0	0	0	0	0	0
MIDW - Midwest Energy	No	0	0	0	0	0	0	0	0	0	0	0	0	0
	No	0	0	0	0	0	0	0	0	0	0	0	0	0
SUNC - Sunflower Electric Power Corp	No	0	0	0	0	0	0	0	0	0	0	0	0	0
AREC - Arkansas Electric Coop Corp	No	0	0	0	0	0	0	0	0	0	0	0	0	0
CELC - Central Louisiana Electric Co	No	0	0	0	0	0	0	0	0	0	0	0	0	0
CLWL - City of Clarksville, Mississippi	No	0	0	0	0	0	0	0	0	0	0	0	0	0
LAFA - City of Lafayette, Louisiana	No	0	0	0	0	0	0	0	0	0	0	0	0	0
GRRD - Grand River Dam Authority	No	0	0	0	0	0	0	0	0	0	0	0	0	0
LEPA - Louisiana Energy & Power Auth	No	0	0	0	0	0	0	0	0	0	0	0	0	0
NTEC - Northeast Texas Electric Coop	No	0	0	0	0	0	0	0	0	0	0	0	0	0
OKGE - Oklahoma Gas & Electric Co	No	0	27,278,581	27,824,153	28,380,636	28,948,249	29,527,214	30,117,758	30,720,113	31,334,515	31,961,205	32,600,430	33,252,438	33,917,487
OMPA - Oklahoma Municipal Power Auth	No	0	0	0	0	0	0	0	0	0	0	0	0	0
YAZO - Pub Serv of Yazoo City	No	0	0	0	0	0	0	0	0	0	0	0	0	0
PSOK - Pub Serv Co of Oklahoma	No	0	18,697,786	19,071,742	19,453,177	19,842,240	20,239,085	20,643,867	21,056,744	21,477,879	21,907,437	22,345,585	22,792,497	23,248,347
SOEP - Southwestern Electric Power Co	No	0	26,310,918	26,837,137	27,373,879	27,921,357	28,479,784	29,049,380	29,630,367	30,222,975	30,827,434	31,443,983	32,072,863	32,714,320
SWPA - Southwestern Power Admin	No	0	0	0	0	0	0	0	0	0	0	0	0	0
SWPS - Southwestern Public Service Co	No	0	27,234,383	27,779,070	28,334,652	28,901,345	29,479,371	30,068,959	30,670,338	31,283,745	31,909,420	32,547,608	33,198,560	33,862,532
WEFA - Western Farmers Electric Coop	No	0	0	0	0	0	0	0	0	0	0	0	0	0
First Energy	Yes	0	98,267,527	24,185,300	102,237,535	104,282,286	106,367,932	108,495,290	110,665,196	112,878,500	115,136,070	117,438,792	119,787,567	122,183,319
NIPSCO	Yes	0	17,332,275	4,108,373	18,032,498	18,393,148	18,761,011	19,136,232	19,518,956	19,909,335	20,307,522	20,713,672	21,127,946	21,550,505
Ameren	Yes	0	27,222,218	0	0	0	0	0	0	0	0	0	0	0
Illinois Power	Yes	0	17,525,562	0	0	0	0	0	0	0	0	0	0	0
New Customer	No	0	0	0	0	0	0	0	0	0	0	0	0	0
New Customer	No	0	0	0	0	0	0	0	0	0	0	0	0	0

	Incl in Sch 10 Rev Calc?	2000	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
New Customer	No	0	0	0	0	0	0	0	0	0	0	0	0	0
New Customer	No	0	0	0	0	0	0	0	0	0	0	0	0	0
New Customer	No	0	0	0	0	0	0	0	0	0	0	0	0	0
New Customer	No	0	0	0	0	0	0	0	0	0	0	0	0	0
New Customer	No	0	0	0	0	0	0	0	0	0	0	0	0	0
New Customer	No	0	0	0	0	0	0	0	0	0	0	0	0	0
New Customer	No	0	0	0	0	0	0	0	0	0	0	0	0	0
Point-to-Point	Yes	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL		397,701,397	721,093,292	613,464,466	717,144,243	731,487,128	746,116,870	761,039,208	776,259,992	791,785,192	807,620,896	823,773,314	840,248,780	857,053,755
TOTAL Included in Sch 10	Yes	387,911,941	579,664,053	469,206,643	570,001,263	581,401,289	593,029,314	604,889,901	616,987,699	629,327,453	641,914,002	654,752,282	667,847,327	681,204,274

REQUEST:

45. Mr. Holstein (p. 14, *l. 14)* in the table presents estimates of the Schedules 10, 16, and 17 charges for LG&E/KU for the period 2004 to 2010. Please provide all work papers that support your calculation of these charges.

RESPONSE:

The work papers for the estimates of Schedules 10, 16 and 17 charges applicable to LG&E/KU are attached hereto. See also the workpapers provided as attachments (pp. 15-27) to the response to Data Request No. 44.

Witness: Michael P. Holstein

RE: Kentucky Utilities

	2004 (1)	2005	2006	2007	2008	2009	2010
Schedule 10							
Schedule 10 MWhs - Demand	31,387,087	32,014,829	32,655,125	33,308,228	33,974,392	34,653,880	35,346,958
Schedule 10 MWhs - Energy	21,589,348	22,021,135	22,461,557	22,910,788	23,369,004	23,836,384	24,313,112
Schedule 10 - Demand $s/MWh	$ 0.1131	$ 0.1131	$ 0.1131	$ 0.1131	$ 0.1169	$ 0.1073	$ 0.1049
Schedule 10 - Energy $s/MWh	$ 0.0367	$ 0.0367	$ 0.0367	$ 0.0367	$ 0.0380	$ 0.0349	$ 0.0341
Schedule 10 Charge	**$ 4,342,209**	**$ 4,429,053**	**$ 4,517,634**	**$ 4,607,987**	**$ 4,859,629**	**$ 4,550,251**	**$ 4,536,973**
Schedule 16							
Schedule 16 - FTR MW Volume	1,551,425	17,616,908	17,969,246	18,328,630	18,695,203	19,069,107	19,450,490
Schedule 16 - $/FTR MW Volume	$ 0.0561	$ 0.0495	$ 0.0515	$ 0.0520	$ 0.0490	$ 0.0486	$ 0.0387
Schedule 16 Charge	**$ 87,035**	**$ 872,037**	**$ 925,416**	**$ 953,089**	**$ 916,065**	**$ 926,759**	**$ 752,734**
Schedule 17							
Schedule 17 - MWh (Load + Gen)	3,878,562	44,042,270	44,923,114	45,821,576	46,738,008	47,672,768	48,626,224
Schedule 17 - $s/MWh (Load + Gen)	$ 0.0724	$ 0.0645	$ 0.0658	$ 0.0659	$ 0.0634	$ 0.0625	$ 0.0512
Schedule 17 Charge	**$ 280,808**	**$ 2,840,726**	**$ 2,955,941**	**$ 3,019,642**	**$ 2,963,190**	**$ 2,979,548**	**$ 2,489,663**
Total Charges	**$ 4,710,051**	**$ 8,141,816**	**$ 8,398,991**	**$ 8,580,717**	**$ 8,738,883**	**$ 8,456,558**	**$ 7,779,370**

NOTE:
(1) ... Schedule 16 & 17 Billing Determinants, for 2004, are based on December 2004 only (Demand - MWhs = 2,583,804 & Energy - MWhs = 1,939,281)

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RE: LG&E

	2004 (1)	2005	2006	2007	2008	2009	2010
Schedule 10							
Schedule 10 MWhs - Demand	18,701,681	19,075,715	19,457,229	19,846,374	20,243,301	20,648,167	21,061,130
Schedule 10 MWhs - Energy	13,007,709	13,267,863	13,533,221	13,803,885	14,079,963	14,361,562	14,648,793
Schedule 10 - Demand $s/MWh	$ 0.1131	$ 0.1131	$ 0.1131	$ 0.1131	$ 0.1169	$ 0.1073	$ 0.1049
Schedule 10 - Energy $s/MWh	$ 0.0367	$ 0.0367	$ 0.0367	$ 0.0367	$ 0.0380	$ 0.0349	$ 0.0341
Schedule 10 Charge	**$ 2,592,543**	**$ 2,644,394**	**$ 2,697,282**	**$ 2,751,227**	**$ 2,901,480**	**$ 2,716,767**	**$ 2,708,836**
Schedule 16							
Schedule 16 - FTR MW Volume	811,606	10,614,290	10,826,577	11,043,108	11,263,970	11,489,250	11,719,034
Schedule 16 - $/FTR MW Volume	$ 0.0561	$ 0.0495	$ 0.0515	$ 0.0520	$ 0.0490	$ 0.0486	$ 0.0387
Schedule 16 Charge	**$ 45,531**	**$ 525,407**	**$ 557,569**	**$ 574,242**	**$ 551,935**	**$ 558,378**	**$ 453,527**
Schedule 17							
Schedule 17 - MWh (Load + Gen)	2,029,014	26,535,726	27,066,442	27,607,770	28,159,926	28,723,124	29,297,586
Schedule 17 - $s/MWh (Load + Gen)	$ 0.0724	$ 0.0645	$ 0.0658	$ 0.0659	$ 0.0634	$ 0.0625	$ 0.0512
Schedule 17 Charge	**$ 146,901**	**$ 1,711,554**	**$ 1,780,972**	**$ 1,819,352**	**$ 1,785,339**	**$ 1,795,195**	**$ 1,500,036**
Total Charges	**$ 2,784,975**	**$ 4,881,356**	**$ 5,035,822**	**$ 5,144,821**	**$ 5,238,754**	**$ 5,070,340**	**$ 4,662,399**

NOTE:
(1) ... Schedule 16 & 17 Billing Determinants, for 2004, are based on December 2004 only (Demand - MWhs = 2,583,804 & Energy - MWhs = 1,939,281)

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Summary of ISO Charges: 2005 - 2010

	KU	LGE	KU/LGE
Schedule 10 Charge	$ 27,501,526	$ 16,419,987	$ 43,921,513
Schedule 16 Charge	$ 5,346,099	$ 3,221,056	$ 8,567,156
Schedule 17 Charge	$ 17,248,710	$ 10,392,449	$ 27,641,159
Total Charges	$ 54,806,386	$ 32,818,467	$ 80,129,827

REQUEST:

46. Mr. Holstein (p. 15 *ll.* 13-25) states: "I believe it is appropriate for all Schedule 10 costs to date to be capitalized and recovered through retail rates for the same reasons I believe prospective costs should be included in retail rates." Does Mr. Holstein mean to suggest that future charges that LG&E/KU pays to MISO for capital and operating costs through Schedule 10, 16 and 17 charges should be capitalized and recovered in LG&E's and KU's rates to retail customers?

RESPONSE:

Mr. Holstein's testimony, as qualified by the statement "... to date..." in the referenced sentence, refers to all charges paid to the Midwest ISO but not yet included in retail rates.

Witness: Michael P. Holstein

REQUEST:

47. Mr. Holstein (p. 15) talks about "the federal requirement to join an RTO as a means of mitigating market power." What "federal requirement" is the witness referring to?

RESPONSE:

Mr. Holstein was referring to the requirements of Order Nos. 888 and 2000, respectively, as issued by the FERC pursuant to the Federal Power Act. Order No. 888 was designed to mitigate the market power of vertically integrated utilities over generation by requiring them to adopt Open Access Transmission Tariffs and to take transmission services pursuant to that tariff on the same basis as third parties. In Order No. 2000, the Commission found that vertically integrated utilities continued to use their control over transmission to frustrate competition and ordered the establishment of Regional Transmission Organizations as a remedy under Section 206 of the FPA. All public utilities that own, operate or control interstate transmission facilities (except those already participating in an approved regional transmission entity) were required to file by October 15, 2000, "either a proposal to participate in an RTO or an alternative filing describing efforts and plans to participate in an RTO." Order No. 2000, FERC Stats. & Regs. [Reg. Preambles, 2000] ¶ 31,089 at 31,226 (2000). Transmission owners that were members of an ISO were given until January 15, 2001, to make a filing that would address "the extent to which that entity conforms to the minimum characteristics and functions of an RTO, any plans to make it conform, and any obstacles to full conformance with [the FERC's] final Rule." *Id.* at 31,227.

Witness: Michael P. Holstein

4

REQUEST:

48. How much has the increase in the MISO footprint over the past 2 years decreased LG&E/KU costs under Schedule 10?

RESPONSE:

The Midwest ISO has not performed the requested analysis. As such, it does not have the requested information.

Witness: Michael P. Holstein

Drop By

1

REQUEST:

1. Mr. Harszy (p. 5, *ll.* 15-18) states: "The State Estimator is a highly sophisticated computer model that uses real time measurements from the System Control and Data Acquisition System ("SCADA") supplied by member control areas to provide a periodic calculation of the current condition of the entire system.

    a. Does MISO acquire SCADA information from <u>only</u> MISO member systems?

    b. If so, what SCADA information is obtained and how frequently is it supplied?

    c. If the answer to (a) is No, what non-MISO entities supply SCADA information?

    d. Is there a reciprocal agreement between MISO and the entities listed in (c) regarding an exchange of information as inputs to State Estimators?

RESPONSE:

a. No.

b. The table below, taken from the Midwest ISO "ICCP Data Exchange Specification" indicates the type and frequency of data supplied. The entire document can be viewed at:

    http://www.midwestmarket.org//Attachments/MIG%20Vol7_ICCP_Data_Exchange_Specification_v3.2.pdf

Witness: Roger C. Harszy

Point Name	Object Type	Point Type STATE/ DISCRETE/ ANALOG	Period [illegible] (secs)	Report Style ALL/ RBE
Suppliers' ACEs and/or pseudo-ACEs (CAs, IPPs, other) Refer to the glossary for the definition of a pseudo-ACE.	Indication Point	ANALOG	10	
Control area actual net interchanges (MW)	Indication Point	ANALOG	10	
Dynamic schedules (MW) and/or pseudo ties	Indication Point	ANALOG	10	
Frequency from each control area (Hz)	Indication Point	ANALOG	10	
Supplier's (CAs, IPPs, other) actual spinning reserve (MW)	Indication Point	ANALOG	60	
Supplier's (CAs, IPPs, other) actual supplemental reserve (MW)	Indication Point	ANALOG	60	
Control area and LSE load (MW)	Indication Point	ANALOG	60	

c. The Midwest ISO receives data from MAPP, MAIN, PJM, SPP, ECAR, and IMO (Ontario).

d. Under NERC Policy 9, reliability coordinators are obligated to exchange information with each other about their regions. To effect this exchange of information, the entities must execute the NERC Confidentiality Agreement found in Appendix 4B of the NERC Operating Manual. Copies of these documents can be found in the NERC Operating Manual, on the NERC website: http://www.nerc.com/~oc/opermanl.html

Witness: Roger C. Harszy

REQUEST:

2. Mr. Harszy (p.6, *ll.* 17-18) states: "At the time of the August 14 blackout, the Midwest ISO's State Estimator had not yet been fully deployed by mapping into the system all of the 230 kV transmission facilities in and around the Midwest ISO footprint." In addition to the State Estimator not having been "fully deployed" on August 14, were there any other reasons in addition to those identified in the Joint Task Force Interim Report on the August 14, 2003 blackout[1] why the State Estimator did not provide MISO with contingency analysis during the afternoon of August 14, 2003?

RESPONSE:

No.

[1] U.S. Canada Power System Outage Task Force, Interim Report: Causes of the August 14th Blackout in the United States and Canada, November 2003.

Witness: Roger C. Harszy

3

REQUEST:

3. Mr. Harszy (p. 8. *ll.* 3-12), in referring to the charts that accompany his testimony (i.e., Chart 1, Exhibit RCH-1), concludes that the increase between 2001 and 2003 in the number of hours that an LGEE flowgate was in TLR due to a contingency external to Kentucky was due to an increase in reliability after the MISO became Reliability Coordinator. Did MISO make any attempt to weather normalize the comparison between years 2001 and 2002 in the charts accompanying the witness's testimony?

RESPONSE:

No. The concept of weather normalization is not meaningful in this context because there can be significant variations in local weather conditions across the Eastern Interconnection. The congestion experienced in any one spot on the grid may be related to any number of factors, including unplanned outages, fuel shortages, changes to system topology, or other variables that are not weather related.

Witness: Roger C. Harszy

REQUEST:

4. Does MISO provide Reliability Authority services to non-MISO control areas in the MidAmerica Power Pool (MAPP)?

   a. If so, what does MISO charge non-MISO member control areas in MAPP for provision of Reliability Authority services?

   b. If so, is there such a control area in MAPP comparably sized with respect to LG&E/KU, and what does MISO charge that control area for Reliability Authority services?

RESPONSE:

No. The Midwest ISO provides Reliability Authority services to MAPPCOR for the entire group of non-MISO MAPP members.

a. The Midwest ISO charges MAPPCOR for services provided; the charges are for recovery of costs only with no return on investment component.

b. The charges to MAPPCOR are not calculated on a control area basis.

Witness: Roger C. Harszy

5

REQUEST:

5. Mr. Harszy (p. 11 *l.* 13 to p. 12 *l.* 17) discusses the MISO's regional planning process.

   a. Does MISO's coordinated planning process require entities interested in any benefits associated with regional planning to become members of MISO?

   b. Does MISO have plans to coordinate its regional transmission expansion planning with other non-MISO member entities (e.g., TVA, PJM, and SPP)? If so, briefly describe these plans and name the entities involved.

   c. Does MISO have plans to coordinate its regional transmission expansion planning with such entities as East Kentucky Power Cooperative ("EKPC") or Big Rivers Electric Cooperative ("BREC")?

RESPONSE:

a. The planning process is open for public comment. Non-member entities may benefit incidentally from the process, for example, through a more robust transmission system within the Midwest ISO footprint. However, without a prior commitment for funding, the Midwest ISO does not undertake transmission expansions to relieve congestion for, or to otherwise benefit systems of, entities that are not Midwest ISO members.

b. Expansion Plans are developed based on ongoing facilities studies associated with continuing transmission customer requests for both interconnection and delivery service. Plans identified to meet these transmission customer needs are included with plans identified to meet the ongoing needs of existing Midwest ISO customers, including the load growth of network and native load customers. The Midwest ISO includes in planning studies representatives from all adjacent systems that may be impacted by customer requests. This provides a means of coordinating development of expansion plans with adjacent systems. In addition, the Midwest ISO seeks planning model reviews and updates from adjacent systems to ensure the best possible model representations of those systems in our planning studies. The Midwest ISO also publishes its expansion plan so that interconnected systems are aware of the planning studies and the identified expansion projects in the Midwest ISO region.

Under the recently filed, but not yet approved, Joint Operating Agreement between the Midwest ISO and PJM, additional planning coordination will take place under the terms and conditions set forth in Article IX. The following link will provide access to that document:
http://www.midwestiso.org/admin/ferc/files/123103_Joint_Filing_PJMMISO_of_JOA.pdf

The Midwest ISO has contacted TVA and SPP to discuss similar arrangements that would include coordinated planning provisions. No agreements have been signed with TVA or SPP at this time.

c. See the response to 5(b). The Midwest ISO has coordinated planning studies of generator interconnections with EKPC and with BREC. The Midwest ISO also bases its studies on planning models of those systems developed by those systems through the ECAR reliability region. As the Midwest ISO completes planning coordination agreements with PJM, it will seek to address coordinated planning with other adjacent entities on a similar basis, as one part of a more comprehensive arrangement with each of the Midwest ISO's interconnected neighbors. In the case of EKPC and BREC, no formal coordination agreement exists at this time to coordinate transmission expansion.

Witness: Roger C. Harszy

6

REQUEST:

6. Mr. Harszy (p. 12 *ll.* 3-8) discusses the MISO's ability to monitor and analyze "chronic" power flow constraints.

   a. Does Mr. Harszy, by his statements here, mean to imply that, if LG&E/KU were not in the MISO market footprint, security constraints arising from power flows on the Blue Lick-Bullitt County 161 kV line or the Ghent 345/138 kV transformer would be ignored by MISO?

   b. If LG&E/KU were required by an order from the Commission to exit MISO, would it be possible for LG&E/KU and MISO to enter into a market-to-non-market operating agreement similar to that currently being negotiated between PJM and MISO?

RESPONSE:

a. The Midwest ISO would not be able to proactively manage flows via AFC calculations and coordination over a wide area, by limiting additional reservations when there is not adequate additional room on the constraint, or by curtailing transactions when needed to the extent it can now with these facilities in the Midwest ISO. The Midwest ISO would also not be able to manage the flow with security constrained dispatch as it will be able to when the Midwest ISO begins is market operations. Thus, while Midwest ISO would not ignore congestion on these flowgates, the tools available to respond to the problem would be less efficient and reliable. This was the case before the Midwest ISO assumed this duty in 2001, and is the reason that LGE experiences direct financial benefits through Midwest ISO congestion management.

b. The PJM-MISO Joint Operating Agreement ("JOA") was negotiated pursuant to the FERC Order allowing AEP to become a member of PJM. *See* 100 FERC ¶ 61,137 (July 31, 2002). Should the FERC issue an order allowing LGE/KU to

Witness: Roger C. Harszy
James P. Torgerson

operate as a stand-alone transmission operator, with a similar condition that a JOA be negotiated, the Midwest ISO would comply with that order as well.

Witness: Roger C. Harszy
James P. Torgerson

7

REQUEST:

7. Mr. Falk (p. 17 *ll.* 15-18) states that if LG&E/KU were to operate as a standalone system at a higher level of system security than before MISO took over as Reliability Authority, such operation would "perforce include more costs which have not been included in their testimony." Has Mr. Falk performed any analysis of the costs of this higher level of system security? If so, please provide a copy of this analysis.

RESPONSE:

I have not performed such an analysis.

Witness: Jonathan Falk

8

REQUEST:

8. Mr. Falk asserts (p. 2, *ll.* 17-21) that "the pre-Midwest ISO LG&E/KU system was, on some occasions, being run in a state in which the probabilities of outage were higher than design criteria dictate. With enough incidents in these conditions, it is a probabilistic certainty that additional incidents of lost load will occur. The fact that LG&E and KU experienced no outages in this period was a matter of luck."

   a. Given the "probabilistic certainty," how many days or years would Mr. Falk expect the LG&E/KU system to operate on a standalone system before "additional incidents of lost load will occur"?

   b. Please define what Mr. Falk means "luck" as he has used that word in describing LG&E/KU's experience. Does Mr. Falk believe that "luck" is something that happens randomly, or that tends to repeat itself?

RESPONSE:

a. Assuming that the standalone system operated as the previous system did, an outage would be expected about once every 8 years.

b. I define luck in what I believe to be the normal sense: random events with favorable *ex post* results. Under this definition, luck occurs randomly. Luck also repeats, albeit randomly.

Witness: Jonathan Falk

9

REQUEST:

9. Mr. Falk has presented two figures, one at the top of p. 11 and one at the top of p. 12. Please explain the relationship between these two figures.

RESPONSE:

The second figure can be derived from the first by using the segment of the distribution for values of p less than or equal to 0.91% and rescaling so that the cumulative distribution integrates to one.

Witness: Jonathan Falk

10

REQUEST:

10. Please provide all data and work papers that support or are in any way related to Mr. Falk's calculation of the value(s) of probability p used to develop the table on page 16. Please provide all data and work papers that support or are in any way related to his calculation of the aggregate value of increased reliability (as discussed throughout pp. 10-18, including all work papers and data supporting his calculations of the following:

    a. the probability of an outage from an undeclared TLR,

    b. the kilowatt-hours lost in a typical outage, and

    c. the value of lost load from lost kilowatt-hours.

RESPONSE:

These documents are available in a usable electronic format and are included in the folder named "Item 10" on the CD-ROM named "Public Vol. I" accompanying this response, or are provided in response to another request.

a. See the Excel file entitled "10(a) Exhibit A (Monte Carlo).xls."

b. See the Excel file entitled "10(b) Historical Outages.xls."

c. See the response to PSC Staff Request 15 (the second Request No. 2).

In addition to the files listed in (a) and (b), the "Item 10" folder contains Excel Files entitled "LGEE TLR Levels (1999 to 2003).xls" and "LGEE TLRs (09-01-03 to 10-31-01).xls" and a database file entitled "LGEE TLRs.mdb"

Witness: Jonathan Falk

11

REQUEST:

11. Mr. Falk states (p. 13, *ll.* 7-8) that the August 14, 2003 "outage was really one-in-a-hundred year occurrence..." Please provide the evidence that the August 14 event was a one-in-a-hundred year occurrence.

RESPONSE:

I have no opinion as to the frequency of such outages, beyond the fact that it was the largest outage to date and we have had substantial electricity systems for around 100 years.

Witness: Jonathan Falk

12

REQUEST:

12. Please provide copies of the following documents cited in Mr. Falk's resume (MISO Exhibit JF-1):

    a. Guest Editorial regarding the Electric Blackout of August, 2003, *Electricity Journal,* November 2003, pp. 83-84.

    b. "Electricity Regulation: The Mess We're In, How We Got There, And The Road Out," presented at a Foundation for American Communications Seminar, Washington, DC, January 27, 2003.

    c. "A Contrarian View of Enron," Marsh, Inc. Power Group Conference, Palm Harbor, FL, February 20, 2002.

    d. "Competitive Markets for Power 2001: An Electrical Odyssey," presented at the US annual meeting. Key Largo, Florida, June 13, 2001.

    e. "Electricity Restructuring: The (Pretty) Good, The (Pretty) Bad, and the (Extremely) Ugly," Marsh, Inc. Power Group Conference, Palm Harbor, Florida, February 14, 2001.

RESPONSE:

Items b-e were oral, rather than written, presentations. Outlines and notes, if any, for the accompanying Power Point presentations are provided in response along with a print-out of any "slide" in which substantive content was presented in graphic rather than text form. In-house and outside counsel for the Midwest ISO have electronic copies of the Power Point files for these presentations, which can be provided on request and suitable arrangements therefor.

a. A copy of the Guest Editorial is attachment #12(a).

b. Documents are provided in attachment #12(b).

c. Documents are provided in attachment #12(c).

d. Documents are provided in attachment #12(d).

e. Documents are provided in attachment #12(e).

Witness: Jonathan Falk

Why Policy (Good and Bad) Follows Headlines

Electricity systems are hard to run. They were hard to run when the system was composed entirely of regulated entities and they remain difficult to run today. The difficulties stem largely from the laws of physics and the ability of customers to consume electricity at their whim, neither of which has changed at all since we first began producing electricity commercially. The collapse of the grid in the Northeast on Aug. 14 exemplifies a simple proposition: "When difficult tasks are taken on, sometimes there are failures."

There are normal human impulses to read far more into the events of Aug. 14 than this simple lesson. Like some other normal human impulses, however, they have no logical basis.[1] The fallacy is well understood: *Post hoc, ergo propter hoc.* Since the collapse followed Event A, Event A is probably in some way partially to blame for the collapse. The problem with this natural human propensity is that it is not only illogical, it is open-ended. Only human imagination and powers of persuasion limit the set of events which can be dubbed Event A. Among the most prominent "Event A's" mentioned:

(1) Deregulation in general
(2) Fragmentation of authority to run the grid
(3) Lack of transmission investment
(4) Excessive consumption of power by end users
(5) Insufficient generation located close to end users
(6) Failure to drill for oil in Arctic National Wildlife Refuge
(7) The fact that I was on a business trip in Buffalo, NY, which mysteriously never blacked out.[2] (OK ... that's just my wife's explanation since she was stranded in New York City.)

The search for exactly what happened is under way, and it would be foolish to make any definitive pronouncements. But like most other non-deliberate systemic failures, the cause will almost certainly be some combination of two factors: (1) flaws in the protocols for the way the system should be run; and (2) flaws in the execution of those protocols.

To many, this result, if true, is unsatisfactory. Big problems are supposed to require big solutions. And electricity systems have captured more than their share of controversy in the spasmodic transition to deregulated generation and perhaps, ultimately, transmission markets in the U.S. and abroad. Thus, all those with a hobbyhorse find the blackout a convenient episode to ride it. In addition, if there is a single political imperative it is to be seen doing something when one's constituents are worried about something. The possibilities for foolish legislation emanating from Aug. 14 are limitless, all in the name of protecting the voting public.

In particular, dispelling the notion that deregulation had anything to do with the blackout seems particularly urgent, only because the deregulatory momentum has clearly stalled, and there is no

Jonathan Falk *is a Vice President at National Economic Research Associates (NERA), based in its New York office, and a frequent contributor to* The Electricity Journal. *In NERA's energy practice he has worked on a variety of issues involving the modeling of investment and industry structure. In particular, he is the current developer of the NERA Electric Market Model, which estimates clearing prices in heretofore regulated markets. As of this writing, his wife was no longer mad at him for dodging the blackout with his well-timed visit to Buffalo.*

  1040-6190/$–see front matter doi:/10.1016/j.tej.2003.09.005

reason to burden it with further baggage which it does not own.

Economist and *New York Times* columnist Paul Krugman, in an op-ed piece on Sept. 2, wrote:

> So what does this say about electricity deregulation? There is a theoretical case for a deregulated electricity market. But making such a market work ... requires a robust transmission system, yet the recent blackout made it clear that we have now created a system in which nobody has clear responsibility for the transmission network.

What he does not say is that there was *never* clear responsibility for the transmission network under either regulation or deregulation, where by the "network" we mean the aggregate of interconnected systems which make up the Eastern Interconnection. If anything, the initiatives from the Federal Energy Regulatory Commission have been devoted to forcing on an unwilling set of independent regulated entities more cooperation and centralization than they were willing to engage in freely. A more interesting question might be: How did we make a *regulated* system work? The basic answer is: The same way we make the deregulated system work, by specifying the amount of electricity flowing over every link between individual control areas every hour and making it the internal responsibility of each control area to run its system to hold the power flowing to those values. As far as I am aware, none of those protocols has changed in any significant way. Again, those protocols may contain some subtle flaw. (The flaw must be subtle or it would have shown up sometime in the last 25 years.) But the process by which the electric system is kept stable has not changed in any significant fashion, so it is highly unlikely that deregulatory changes, which largely revolve around the scheduling of power transactions and *not* the moment-to-moment operation of the system, have anything to do with this particular incident.

Indeed, there is at least one bit of evidence that one of the allegations tossed at deregulated systems did not materialize. Most electrical generating stations require electricity to start up. Thus, after a blackout, the units which do not require electricity to start, like most hydro units, must be used to jump start the system—the so-called "black start" capability. Black start capability is contracted for in advance by the electric grids. Since black start capability is so infrequently used, there is an opportunity for shady behavior—promising to help with black start, collecting fees for that promise, but then failing to maintain facilities to be able to perform. As far as I have been able to gather, black start proceeded flawlessly—the sellers of black start capability lived up to their obligations.

In sum, unless people unrealistically expect perfection, failures are not necessarily an indication of a serious problem. Picture a complicated gymnastic formation with 30 acrobats carefully balanced in some impressive display. Owing to their superior skill and training, most of the time you can knock one of them out of the formation and the rest can adjust to keep the formation aloft, particularly if they have a little warning. But once in a while someone will make the wrong move, causing a wobble which another acrobat reacts to in the wrong way—the chain reaction continues and eventually they all come tumbling to the floor. That doesn't make them bad acrobats and it doesn't mean that we necessarily need new acrobat licensing tests. If it happened *every* time, or even *most* of the time, we might be entitled to be a little more censorious.

But because we do not keep count of the blackouts that didn't happen, we naturally focus on the ones that do. If we are to reap the benefit of complex systems, we must occasionally accept their failure. There is no human creation which is faultless, since there is always a way to spend more money and improve it. We don't do so, not because we like failure, but because we have more pressing issues to spend the money on. The Northeast blackout was costly; whether or not we should avoid another one depends on how often they tend to arise, what it would take to avoid them, and how much we dislike unreliability. When we have diagnosed the cause, we will be in better shape to assess whether or not it's worth doing anything to protect against future similar occurrences.■

Endnotes:

1. The discovery of illogicality of normal human impulses in response to rare events was honored with the 2002 Nobel Prize in Economics to Daniel Kahneman.

2. See http://cms.firehouse.com/content/article/article.jsp?sectionId=46&id=17386.

Attachment to LGE/KU #12(a)
Witness: Falk
Page 2

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Electricity Regulation: The Mess We're In, How We Got There, And the Road Out

FACS Seminar
Washington, DC
January 27, 2003

MMC Marsh & McLennan Companies

How Markets Work℠

1 **Electricity Regulation: The Mess We're In, How We Got There, And the Road Out**

2 **We're In A Mess**

3 **How We Got There**

Recognition that regulation didn't work particularly well
- Nuclear disallowances
- Large price differences between neighboring utilities
- Politics, politics, politics

Siren Call of Competition: Trucking, Airlines, Pipelines, Telecommunications

Changes in the structure of optimal provision: the Combined Cycle Combustion Turbine

4 **What Was Wrong with Our Deregulatory Vision?**

5 **A Way Out**

- Allow the FERC Standardized Market Design paradigm to work. This does not mean not to criticize parts of the plan... only that jurisdictional challenges should be quashed.
- Provide certainty to generators. Nothing will be built until people know how they will be paid. Remove as much discretion as possible from the procedure to determine prices
- Focus on wholesale competition. Retail competition can be delayed ... possibly forever. This should also allay fears of state regulators.
- Streamline approval processes for new generation in supply-constrained areas
- Make someone bear the costs.. It doesn't have to be the end-user, but it ought to be an arms-length deal, e.g. New Jersey
- Pray for cool weather and lots of rain

6 **Houston, We Have A Problem: A Contrarian View of Enron**

7 **What Was Enron, Anyway?**
- A Pipeline Company
- An Energy Trading Company
- A Bunch of "Rocket Scientists"
- A Dot.Com
- A Hedge Fund
- A House of Cards
- Whatever You Wanted It To Be

8 **What Do You Get When You Cross Don Corleone with an Enron Financial Statement?**

An Offer You Can't Understand

9 **The Possible Culprits**

1. Enron Management in their Role As Managers on Behalf of Enron Stockholders
2. Enron Managers in their Role As Managers on Behalf of Enron Managers
3. Arthur Andersen, LLP
4. Vinson and Elkins, LLP
5. Moody's and Standard & Poor's
6. Investment Analysts
7. The Investors Who Relied On The Investment Analysts or Enron Management or Andersen

10 **My View, Part 1**

On the collapse:
- Enron was a company which refused to tell analysts, and even their own shareholders, what they did for a living

- Amazingly, analysts recommended the stock anyway, and, slightly less amazingly, investors bought the stock anyway.
- Whatever happened to *caveat emptor?*
- I've studied most of what's been published about their collapse, and I still have no idea of anything they did wrong, other than certain technical rules involving outside capital

11 My View, Part 1

On the collapse:

- Enron was a company which refused to tell analysts, and even their own shareholders, what they did for a living
- Amazingly, analysts recommended the stock anyway, and, slightly less amazingly, investors bought the stock anyway.
- Whatever happened to *caveat emptor?*
- I've studied most of what's been published about their collapse, and I still have no idea of anything they did wrong, other than certain technical rules involving outside capital

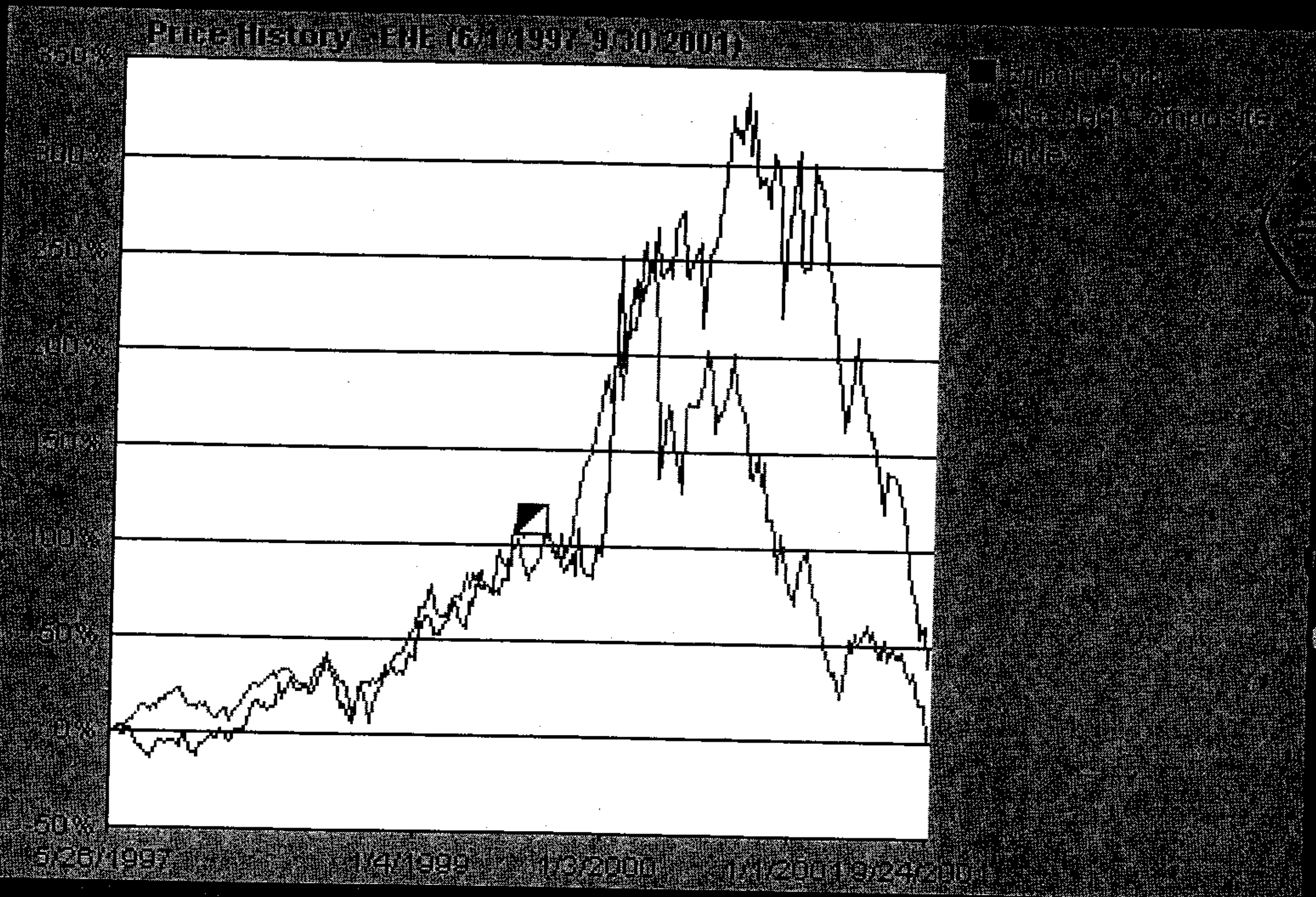
12 My View, Part 2

On Enron's effects in California

- Trivial as far as the "smoking gun" memos go
- FERC agrees with me
- The California ISO agrees with me
- Probably, on net, favorable
- A pure example of politics trumping fact

The real scandal: early access to the rules which were skewed to their benefit. A common problem

My View, Part 1



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February 21, 2002

Houston, We Have A Problem: A Contrarian View of Enron

MMC Marsh & McLennan Companies

How Markets Work

1 Houston, We Have A Problem:
A Contrarian View of Enron
February 21, 2002

2 What Was Enron, Anyway?
- A Pipeline Company
- An Energy Trading Company
- A Bunch of "Rocket Scientists"
- A Dot.Com
- A Hedge Fund
- A House of Cards
- Whatever You Wanted It To Be

3 Enron and Schadenfreude
"I knew it was too good to be true."
"Arrogant right-wing hogs."
"Growth through Government bribery."
"They named a ballpark, for God's sake."
"No one deserves to make that much money."
"Houston? Houston? That's so over."
"Markets are rigged. Traders are scum."
"The Internet mania is a hoax. Where's the value?"
"Bandwidth trading?"
"The seventh largest company in America. Capitalism is in trouble."

4 Enron Stumbles: A Tale In Eight Anagrams
- Sunbelt Sermon
- Loner Bent Sums
- Enron Stumbles
- Enron Stumbles
- Enron Stumbles
- Enron Stumbles
- Enron Stumbles
- Enron Stumbles

5 What Do You Get When You Cross Don Corleone with an Enron Financial Statement?

6 Let's Get The Territory Straight
✓Enron was never an $85 stock, for the same reason that Yahoo was never a $245 stock.

7 The Possible Culprits
1. Enron Management in their Role As Managers on Behalf of Enron Stockholders
2. Enron Managers in their Role As Managers on Behalf of Enron Managers
3. Arthur Andersen, LLP
4. Vinson and Elkins, LLP
5. Moody's and Standard & Poor's
6. Investment Analysts
7. The Investors Who Relied On The Investment Analysts or Enron Management or Andersen

8 A Jaundiced View of The Game
The goal of a manager is to maximize shareholder value.
Shareholders willingly cede some value to give management proper incentives
Accounting firms produce "accounting reports"
Law firms produce "fairness opinions"

Ratings firms produce "ratings"

Analysts produce "recommendations"

Investors rely on all or none of the above, as is their wont. When the fecal matter contacts the mechanical air circulatory device, they sue and get 10 percent (or less) of their losses back, with another 4 percent going to their attorneys. This money mostly comes from insurance companies, but in extraordinary circumstances, some comes from the game players themselves, Meaning....

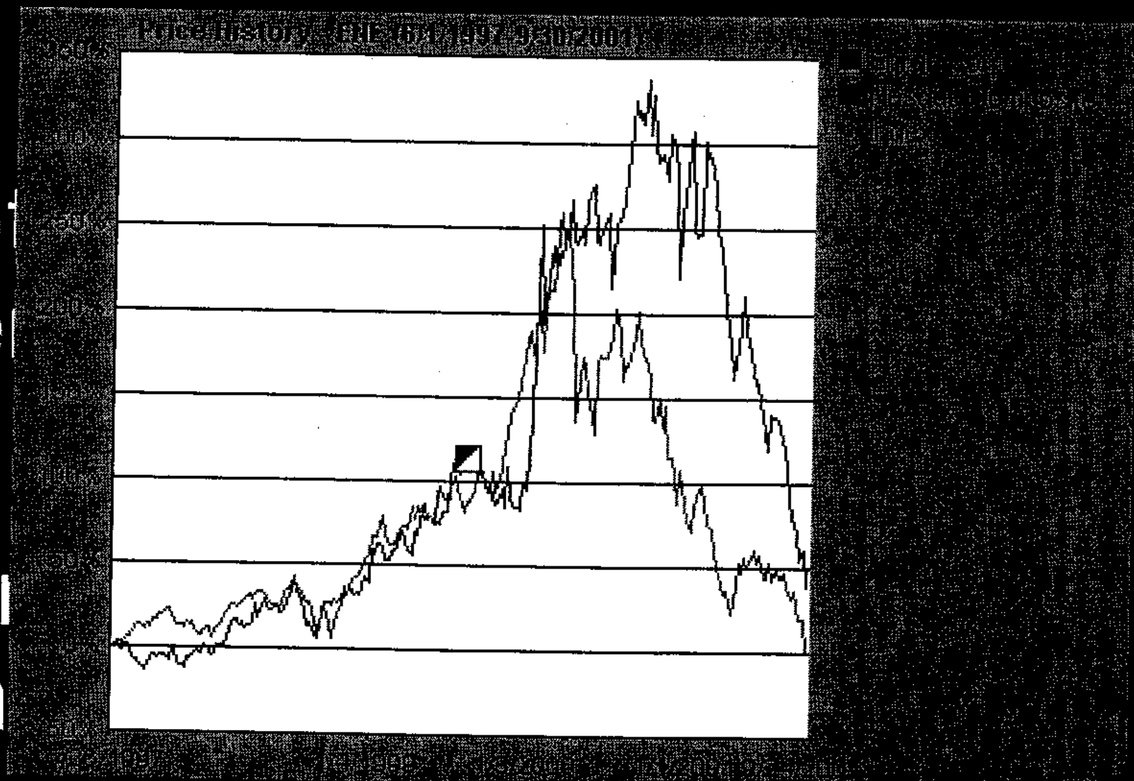
9

10 Enron's Collapse and Energy Markets

- Initial Impression: Business As Usual
- Who Supplies Liquidity?
  - Other Traders
  - Ratepayers
  - Generation Company Investors
  - Insurance Companies
- Was Enron the Cheapest Source of Liquidity?
- What Is The Elasticity Of Supply?

Let's Get The Territory Straight

- ✓Enron was never an $85 stock, for the same reason that Yahoo was never a $245 stock.
- ✓Enron migh[t] which is whe[n] resigned
- ✓So half the [r] The question rest?



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Competitive Markets for Power 2001: An Electrical Odyssey

June 13, 2001 Key Largo, FL

NATIONAL ECONOMIC RESEARCH ASSOCIATES
1166 AVENUE OF THE AMERICAS, NEW YORK, NEW YORK 10036
TELEPHONE: *212.345.3000* FACSIMILE: *212.345.4650*

n/e/r/a
Consulting Economists

1 Competitive Markets for Power 2001: An Electrical Odyssey

2 "Everything is going extremely well."

3 What The Heck Were They Thinking?

4 What **We** Were Thinking About

5 "There are some extremely odd things about this."

6 You Can See Why There Was A Problem

7 This Doesn't Look Quite Right, Either

8 Things Don't Always Go Smoothly

9 It's Both the Heat **and** the Humidity

10 "Thank you for an enjoyable game."

11 How much market power was there?

- Almost surely no explicit conspiracy
- Unilateral bidding is (probably) legal
- Proper measurement of opportunity costs is the big unknown
  - **Other markets**
  - **Credit risk**
  - **Generating Component Risk**
- Nobody knows

12 The Result.....

13 "Are you sure you're making the right decision? I think we should stop."

14 What will the regulators do?

- STOP!!!! It was all a big mistake!!!
- Temporary controls
- Permanent controls
- Big question: who really got the money?

15 "I know that you...were planning to disconnect me, and I'm afraid that's something I cannot allow to happen."

16

17 Demand response: the low-hanging fruit

- Substantial elasticity if we try
- Not everyone has to be measured (though it would be better if they were)
- What **really** makes electricity different?

18 "I'm sorry for the delay."

19 Can Restructured Electric Markets Build Enough Capacity?

- Just like any other industry
- Ask 'em in Texas
- Do we need capacity markets, or are energy-only markets enough?

20 Will any new capacity be nuclear?

- Bush initiative
  - **Life extension**
  - **Decommissioning funding flexibility**
  - **Quicker licensing of new designs**
- Kyoto and NOx

- The Magic Number:

21 "This conversation can serve no purpose anymore. Goodbye."

22

Notes to Slide #1

This is a comparison of electricity regimes in terms of clearing market structure only. It does not consider many other attributes of restructuring: stranded costs, vertical structure, retail competition, etc. Also, there is no discussion herein of the long-term financial markets….Except to the extent that they are just like the day ahead markets…. Nonetheless, I will later on give some off-the-cuff remarks on a topic which many of you may find timely…..

Notes to Slide #3

Before I can discuss this question, I first want to discuss why we ever thought electricity should be a competitive industry in the first place…

Notes to Slide #4

•Discuss each and discuss their importance

Notes to Slide #6

Or a search on the term power exchange

Notes to Slide #7

Clearly, these web searches are no good, so you have to go to an expert…. Oh, yeah, that's me.

A power exchange is a market which insures that supply = demands instantaneously at all points in time.

It is important to see that there are, to my knowledge, no other markets in the world that work this way. All others recognize (and adjust for temporary imbalances) this won't work in an electricity market

Will any new capacity be nuclear?

- Bush initiative
  - **Life extension**
  - **Decommissioning funding flexibility**
  - **Quicker licensing of new designs**
- Kyoto and NOx
- The Magic Number: 

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Consulting Economists

Competitive Markets for Power: The (Pretty) Good, The (Pretty) Bad and the (Extremely) Ugly

February 15, 2001 Tampa, FL

NATIONAL ECONOMIC RESEARCH ASSOCIATES

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n/e/r/a

Consulting Economists

1 Competitive Markets for Power:
The (Pretty) Good, The (Pretty) Bad and the (Extremely) Ugly

2 What The Heck Were They Thinking?

3 What **We** Were Thinking About

4 Why Now?

5 Why Now?

6 Why Now?

7 So What Is a Power Exchange, Anyway?

8 You Can See Why There Was A Problem

9 This Doesn't Look Quite Right, Either

10 Everybody In the Pool
(You Have No Choice)

11

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26 Whew! That's Complicated. Can't We Make It Simpler?

27 Differences in The UK Market

- Day-Ahead Bidding Only
  - **Poor real-time signals**
- No Zones
  - **No (market based) locational signals**
- "Extra" costs spread over all participants
  - **Inefficient ancillary services and congestion management**
- Synthetic Capacity market
- Regulatory Meddling
  - **Confiscatory second-guessing**
  - **Distrust of the pool concept**

28 OK. That doesn't work too well. Can we make it even more complicated?

29 Differences in The California Market

- Separation of power markets from operational reality
  - Intentional inefficiency in the role of dispatchers in resolving congestion
- Sequential ancillary service markets
- Multiple Clearing Markets (Scheduling Coordinators)
- Few routinely scheduled contracts
- No Capacity Market

30 Things Don't Always Go Smoothly

31

32 It's Both the Heat **and** the Humidity

33 The Result.....

34 Transmission: The Next Big Thing

35

Notes to Slide #1

This is a comparison of electricity regimes in terms of clearing market structure only. It does not consider many other attributes of restructuring: stranded costs, vertical structure, retail competition, etc. Also, there is no discussion herein of the long-term financial markets….Except to the extent that they are just like the day ahead markets…. Nonetheless, I will later on give some off-the-cuff remarks on a topic which many of you may find timely…..

Notes to Slide #2

Before I can discuss this question, I first want to discuss why we ever thought electricity should be a competitive industry in the first place…

Notes to Slide #3

•Discuss each and discuss their importance

Notes to Slide #4

•Marginal cost less than average cost is the economist's way of saying what was most important about these markets to politicians– they could give rate cuts

Notes to Slide #5

•We had noticed this in the nuclear age, but couldn't do much about it because of two things: scale and practicality. Both improved…

Notes to Slide #7

People keep talking about electric markets… This is the best picture of a market I could find. But power markets aren't like this…. What are they like? Well, start with a web search. www.powerexchange.com

Notes to Slide #8

Or a search on the term power exchange

Notes to Slide #9

Clearly, these web searches are no good, so you have to go to an expert…. Oh, yeah, that's me.

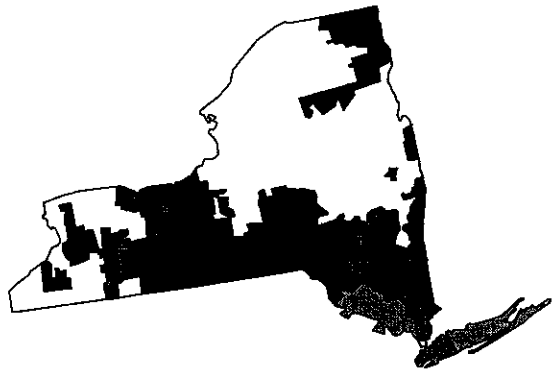
A power exchange is a market which insures that supply = demands instantaneously at all points in time.

It is important to see that there are, to my knowledge, no other markets in the world that work this way. All others recognize (and adjust for temporary imbalances) this won't work in an electricity market

Notes to Slide #10

Describe pool… Now let's see how one of the better of these works….

A (Pretty) Good Market: NY



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NYPP and NYISO

- The New York Power Pool (NYPP) was established with a signed agreement dated July 21, 1966 by the seven largest investor-owned utilities in New York State. The New York Power Authority (NYPA) agreed to participate in 1967.
- In 1997, the NYPP member systems filed a proposal with FERC, which dissolved the New York Power Pool and replaced it with the New York Independent System Operator.
- The NYISO was formed as a not-for-profit organization in 1998
- The NYISO market began operation November 18, 1999

n/e/r/a
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NYISO Markets

- All Load Serving Entities (LSEs) must purchase from the installed capacity market
- Two settlement energy market
  - Day-ahead market and real-time imbalance market
- Bids submitted simultaneously for energy and all ancillary services unit is capable of providing
  - Dispatch process decides how each unit will be used
  - Owners are not required to offer all of a unit's capacity to the market
- Day-ahead nodal prices and schedules are firm financial commitment
- One energy price set on 5-minute basis at each node
  - These are averaged to hour to compute imbalance energy price

n/e/r/a
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NYISO Markets

- **Installed Capacity Market**. Load Serving Entities (LSEs) are required to make their own contract arrangements with Generator Reserves for installed capacity to cover their load every year. If an LSE is unable to contract for sufficient capacity, the NYISO will hold a special auction for bidders to submit capacity bids.
- **Energy and Bilateral Market**. Provides a mechanism for market participants to buy and sell energy and to bid various kinds of bilateral transactions. Participants may be subject to congestion charges.

n/e/r/a
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NYISO Markets

- **Ancillary Services.** Six ancillary services are provided: scheduling, system control and dispatch; voltage support; regulation and frequency response; energy balance; black start; and operating reserve service. Transmission customers and suppliers are permitted to self-supply regulation and frequency response and operating reserve.
- **Transmission Congestion Contracts.** Transmission Congestion Contracts (TCCs) provide a way for market participants to pay a fixed charge for transmission service ahead of time, thereby minimizing their exposure to transmission congestion. TCCs may be bought or sold through direct sales or auction.

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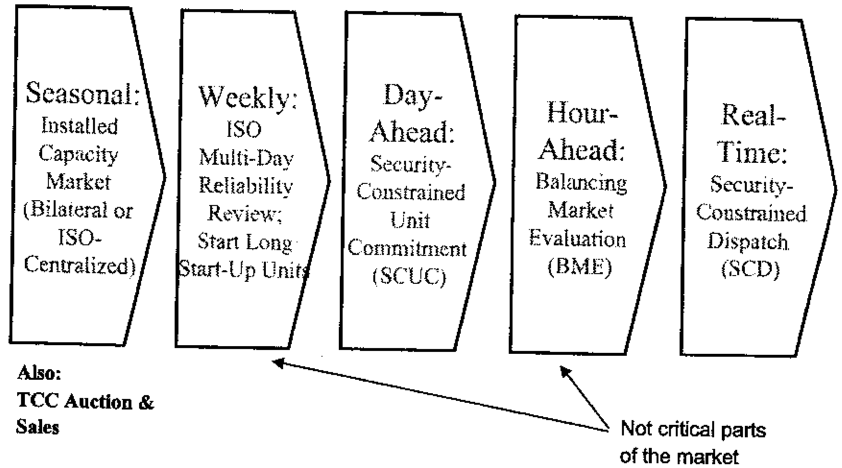
Timeline: NYISO Markets



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Day-Ahead Market

- Supply-side and demand-side bidding.
- Bids must be in by 5am on the day prior to the dispatch day.
- Multi-part bidding by generators: start-up, minimum load, and fuel costs
  - **bid curve for each hour (6 price/quantity pairs)**
  - **Single price/quantity pair for each reserve service**
- Generators also submit other technical info to the ISO.
  - **Minimum uptime, high operating limit, low operating limit, ramp rate**
- Generators also submit minimum hourly revenue requirements
  - **If the sum of these values for day is greater than market revenues anticipated from a unit's bids, it is not dispatched**
  - **If a generating unit's offer is greater than market price at its bus, then unit is not committed or dispatched**

n/e/r/a
Consulting Economists

Day-Ahead Market

- Generators are scheduled based on energy bids
- Multi-step day-ahead process to determine day-ahead energy and ancillary services schedules.
- LSEs submit load forecasts to ISO.
- No restriction on who can bid into the market.
- Bilateral schedules must be submitted to ISO. Schedules include incremental and decremental bids.

n/e/r/a
Consulting Economists

Day-Ahead Market (SCUC)

- 1st pass—Least cost optimization of energy and A/ S costs over day to meet load quantities bid into day-ahead market
- 2nd pass—Least cost optimization of energy and A/ S costs to add capacity to meet ISO's load forecast in 12 zones within state and 4 zones outside state
- 3rd pass—Local reliability pass dispatches units to meet system security requirements
  - **These costs are tracked and charged to locational loads**
  - **Passes 1 to 3 only determine what units will operate at minimum load**
- 4th pass—Given set of units on, what is least-cost way to satisfy bid load
- 5th pass—Fix anomalies
- These schedules and corresponding prices (LBMPs) are firm financial commitments
  - **Generators receive a nodal price, LSEs pay a zonal price.**

n/e/r/a
Consulting Economists

Hour-Ahead (BME)

- Hour ahead can change bids on uncommitted part of plant up or down
- Bids must be submitted 90 minutes before the dispatch hour.
- Bids and bilateral schedules from the day-ahead commitment may be revised, or new ones submitted.
- Generators may only revise downward their bid price for energy already committed day-ahead.
- No multi-part bidding for generators.
- LSEs cannot re-bid

n/e/r/a
Consulting Economists

Real-Time Market

- BME gives advisory energy schedule and prices for the coming hour, which have no financial commitment
- Hour-ahead bids are rolled over into real-time market
  - **Given an estimate of state of system, Security Constrained Dispatch (SCD) software is run; this sets single price for entire 5-minute interval**
  - **SCD yields prices (LBMPs), including congestion costs and marginal losses at every 5 minutes during the dispatch hour.**
  - **It honors generator constraints: generator ramp rates, current transmission constraints**
  - **It honors system constraints: scheduled interchanges with other ISOs, regulation margin requirements, etc**
- Penalties for deviations from 5-minute dispatch instructions
  - **Overgeneration—power sold for free**
  - **Undergeneration—buy back from market**
  - **Non-responsive regulation units**

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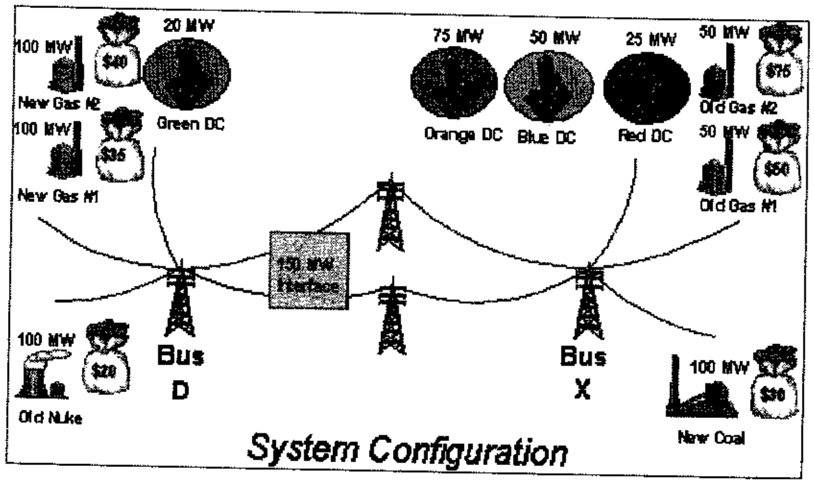
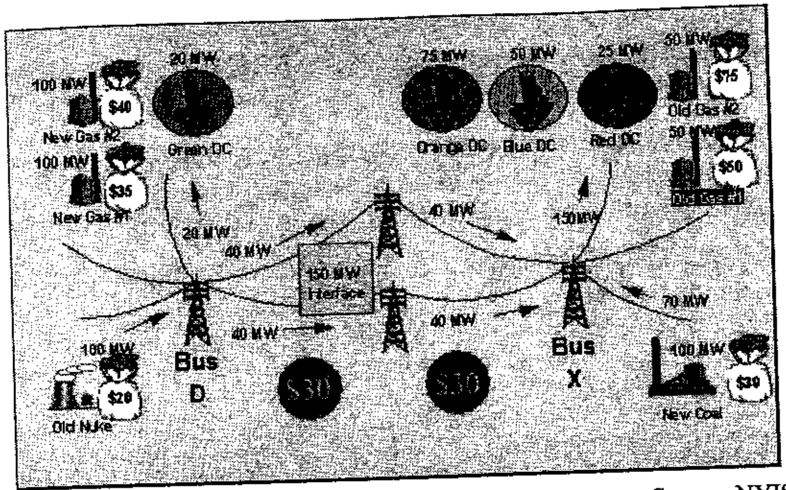
LBMP



Source: NYISO

n/e/r/a
Consulting Economists

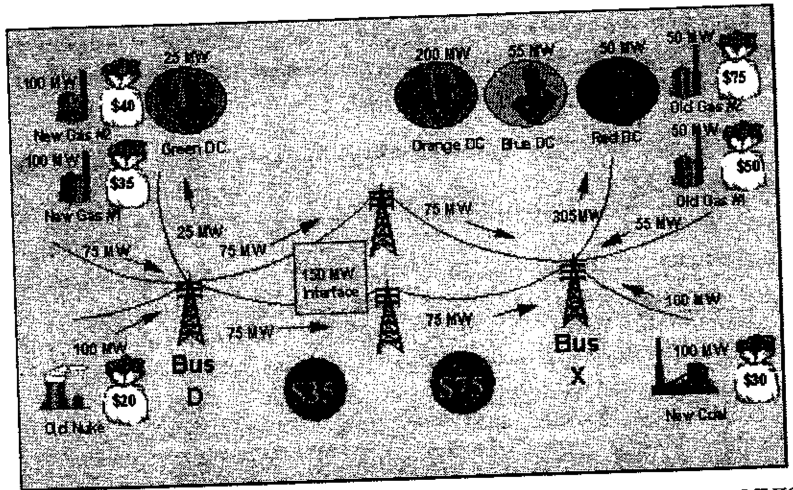
LBMP – Low Load



Source: NYISO

n/e/r/a
Consulting Economists

LBMP – High Load



Source: NYISO

n/e/r/a
Consulting Economists

NYISO Capacity Market

- All load serving entities (LSEs) must procure sufficient installed capacity to meet reserve margin requirements
  - **118% of current peak demand**
- Summer and Winter (6-month) capability periods
- There is a 6-month and 1-month ICAP auction, but LSEs can purchase bilaterally
- Locational ICAP requirements
  - **5000 MW of ICAP must be in New York City**
  - **ICAP requirement for Long Island**
  - **Price cap on ICAP at $52. 50/ kw per capability period**
- Some external sources can be used in ICAP market
- ICAP units obligated to be available to supply energy

n/e/r/a
Consulting Economists

13

REQUEST:

13. Mr. Falk (p. 5, *ll.* 2-17) discusses the relationship between a security system violation and a loss of load. Then (p.8 *ll.* 7-15) he explains why he focused on Level 4 TLR calls.

a. Please provide the evidence that Mr. Falk relied upon to assert the Level 4 TLRs examined involved security system violations or that the system was "already being run in unsafe conditions."

b. When a Level 4 TLR is called, is a security system violation always involved?

c. When a Level 4 TLR is called, does it require load shedding?

d. Please provide the evidence that Mr. Falk relied upon to make the assumption that his examination was limited to "circumstances with the highest probability of lost load." In other words, what evidence does Mr. Falk rely upon to assume that Level 4 TLRs are the contingencies for which the probability of lost load is the highest?

RESPONSE:

a. Section B.5.1 of NERC Appendix 9C1 defines a Level 4 event as one in which either:

- "One or more Transmission Facilities are above their OPERATING SECURITY LIMIT, or
- Such operation is imminent and it is expected that facilities will exceed their security limit unless corrective action is taken."

In an undeclared Level 4 event, it is therefore reasonable to assume that a security limit is violated, since the corrective action is not taken.

b. By definition, a security system violation exists or is imminent.

c. No.

d. In the data I examined in the LG&E/KU footprint, there are no incidents above Level 4. Level 4 is more serious than any of the levels below it.

Witness: Jonathan Falk

1

REQUEST:

14. Mr. Falk (p. 12, *ll.* 10-16) discusses his examination of the NERC Disturbance Analysis Working Group ("DAWG") reports on major disturbances since 1990.

a. For the period of 1990-2003, how many transmission related outages (excluding those attributable to weather) occurred on LG&E/KU's system?

b. Over the period 2002-2003 how many transmission related outages (excluding weather related) occurred on systems under MISO's operational control or within the MISO footprint?

c. Please provide the evidence that Mr. Falk relied upon to assume that the 2.6 million kWh that he states represents the "average number of kilowatt-hours lost in a disturbance," a number that is based on his examination of the DAWG reports on disturbances, could reasonably be used to represent the average number of kilowatt-hours lost in a disturbance effecting the LG&E/KU system.

RESPONSE:

a. None for the period 1990-2000. The relevant DAWG reports on major disturbances have not been published for years after 2000; the observed kilowatt-hour losses I used for my analysis were from the years 1990 through 2000.

b. DAWG reports on major disturbances are not available for the period 2002-2003. and I do not know of an alternative source of comparable data.

c. The data derive from a wide variety of outages on a wide variety of systems. Absent some clear reason to the contrary, it is reasonable that unexpected outages on the LG&E/KU electric system should resemble unexpected outages on other electric systems.

Witness: Jonathan Falk

1

REQUEST:

15. Please provide all empirical studies that Mr. Falk relied upon to assume that the distribution of outage costs derived from his Monte Carlo simulation is representative or characteristic of the distribution of outage costs associated with outages in the LG&E/KU service territory or outages within neighboring control areas that would impact LG&E/KU's service territory and its retail customers.

RESPONSE:

The data derives from a wide variety of outages on a wide variety of systems. Absent some clear reason to the contrary, it is reasonable that unexpected outages on the LG&E/KU electric system should resemble unexpected outages on other electric systems.

Witness: Jonathan Falk

1

REQUEST:

16. Please provide an estimate of the difference between the probability of a power outage with LG&E/KU operating as a standalone system and the probability of a power outage with LG&E/KU as a member of MISO. What would this difference in probabilities be if MISO continued to provide Reliability Authority and security services to LG&E/KU operating as a standalone system?

RESPONSE:

The difference, if any, in probability would depend on how LG&E/KU as a standalone system implemented security procedures and how effective communications across systems turned out to be. Since LG&E/KU has not described its procedures as a standalone system, there is no way to make such an estimate, unless they revert to the security systems they used before the Midwest ISO assumed the role of security coordinator. The current testimony details an estimate of that difference in that case.

Witness: Jonathan Falk

1

REQUEST:

17. Mr. Torgerson (p. 7 *ll.* 3-7) suggests through the quote from the MISO Open Access Transmission Tariff ("OATT") that non-MISO facilities are integrated with MISO facilities, and therefore all customers using the grid share in the costs.

    a. Does MISO currently provide services designed to "ensure the reliability of the bulk power system" to any non-MISO entities, for example, entities within MAPP?

    b. If the answer to (a) is yes, will MISO continue to provide such services after startup of the MISO Day 2 market?

    c. Does Mr. Torgerson believe it is possible for MISO to provide identical reliability services to LG&E/KU were the Companies to withdraw from MISO? If not, please explain why not.

OBJECTION:

Mr. Torgerson's testimony does not suggest or reference any quote from the Midwest ISO's Open Access Transmission Tariff. Mr. Torgerson's testimony references an excerpt from an order of the Federal Energy Regulatory Commission in *Midwest Independent Transmission System Operator, Inc.*, 98 FERC ¶ 61,141 at 61,412 (February 13, 2002).

RESPONSE:

a. No. The Midwest ISO does not currently provide services to non-MISO entities within MAPP. The Midwest ISO provides certain services to MAPPCOR pursuant to a contract between MAPPCOR and the Midwest ISO.

b. To the extent that the referenced contract between the Midwest ISO and MAPPCOR continues beyond the startup of the Midwest ISO Day 2 market, the Midwest ISO will continue to provide these services.

c. Any services provided to LG&E/KU, if they were to withdraw from the Midwest ISO, would be provided pursuant to a contract mutually acceptable by both parties

Witness: James P. Torgerson

and consistent with the Agreement of Transmission Facilities Owners to Organize the Midwest Independent Transmission System Operator, Inc., a Delaware Non-Stock Corporation.

Witness: James P. Torgerson

1

REQUEST:

18. Mr. Torgerson (p. 8 *ll.* 17-27), in response to the Question "Is the Midwest ISO creating the benefits that were envisioned by its founding members, this Commission, the FERC and other state commissions?" answers "Absolutely." With regard to ensuring the reliability of the bulk power system, please reconcile that answer with what could be a reasonable expectation of the Commission with regard to MISO's ensuring system reliability, namely that there be no widespread power outages, such as the August 14th blackout.

OBJECTION:

The Midwest ISO objects to this Data Request on the grounds that (1) it is beyond the scope of the direct testimony of the witness, and (2) it misstates the testimony of the witness.

Mr. Torgerson testified that one of the benefits of membership was "enhanced" reliability. The quoted word "ensure" contained in this request appears to be taken from the quoted portion of the Kentucky PUC order appearing at p. 8 of Mr. Torgerson's testimony. The words are those of the Commission, not the witness.

Further, this data request misstates not only the testimony of the witness, but the Commission's own order as well. This Data Request conveniently omits the words immediately preceding the word "ensure." The actual phrase used by the Commission was "helps to ensure" and further did not indicate that this task was solely that of the Midwest ISO. The quoted word in context referred to LG&E and KU's participation in "organizations such as the East Central Area Reliability Council and the Midwest Independent Transmission System Operator ("Midwest ISO") which help to ensure the reliability of the bulk power system . . .." As originally written, this phrase appears to correctly state the relationship of various entities working together to improve regional reliability.

Witness: James P. Torgerson

Without waiving its objection, and in the spirit of cooperation, the Midwest ISO provides the following response.

RESPONSE:

The Midwest ISO does not guarantee or "ensure" uninterrupted service. Among the reasons that it cannot make this assurance is that the Midwest ISO must depend on control areas (and others) to adequately perform their obligations, including those found in NERC Policy 2. Thus, the reliability of the bulk power system will depend on how well each control area cooperates with the authorized reliability coordinator in the region, and meets all of its operating obligations as set forth in the NERC Operating Manual. The fact that the August 14th blackout did not affect Kentucky customers illustrates the successful cooperation of utilities, regulatory agencies and RTOs.

With regard to the Midwest ISO's role in maintaining reliability, in concert with the control area operator, the testimony of Roger Harszy explains in detail the tools and systems by which the Midwest ISO "enhances" reliability in the region, to a level of dependability and efficiency not obtainable by a stand-alone transmission operator.

Finally, to assist the Commission's understanding of the measures taken in response to the blackout of August 14th, attached to this response is the Comprehensive Reliability Enhancement Plan now being implemented by the Midwest ISO.

Witness: James P. Torgerson

MISO

Midwest Independent Transmission
System Operator, Inc.

Comprehensive Reliability Enhancement Plan

Version 1.0

November 19, 2003

Version Change History

11/19/03	Issue of Version 1.0

Table of Contents

Introduction

The Midwest ISO has made a commitment to meet not only minimum requirements of a Reliability Coordinator, as put forth in NERC Policy and the Transmission Owner Agreement, but to meet the expectations of the membership, the industry, and the public. To this end, work is underway to enhance existing tools and processes within MISO, develop new programs, acquire new tools, and investigate & evaluate capabilities that may be possible in the future.

The Midwest ISO is committed to being the industry leader in reliability, facilities, tools, and training. The enhancements listed in this document lay the groundwork for helping the Midwest ISO achieve this goal.

This document is to serve as a mechanism for capturing and explaining the items that are being implemented to further MISO's commitment. It is to be considered a living reference document, and will be revised and added to as the need arises.

State Estimator/Contingency Analysis

The Midwest ISO's ESCA State Estimator/Contingency Analysis is being enhanced to perform more quickly and reliably and to provide more meaningful information to the reliability coordinators. These enhancements include:

4th Quarter 2003

- Provide basic training to all Carmel reliability coordination staff on basic functionality of ESCA State Estimator/ Contingency Analysis
- ESCA SE/CA to become fully utilized by reliability coordination staff
- Define process for determining status of ESCA SE/CA (Alarming):
  - When state estimator is not working
  - Process for determining SE/CA is running properly
- Define process for addressing failure of SE/CA:
  - Who is notified when state estimator is not working
  - Process for feedback to operators when SE is being fixed
  - Process for turning SE back over to RC
- Define process for emergency "patching" of model
- Define process for implementing emergency changes of model
- Determine:
  - What points are needed
  - What points are available
- Implement missing points

1st Quarter 2004

- Provide advanced training to all Carmel reliability coordination staff on ESCA SE/CA
- Provide basic training to all St. Paul reliability coordination staff on basic functionality of ESCA SE/CA
  - St. Paul reliability coordination staff will begin using the ESCA SE/CA in addition to the existing SIEMENS SE/CA located in St. Paul
- Investigate feasibility of additional specific Contingency Violation summary screens
- TO's to supply metering accuracy for SE measurement weights 345kV and above for refined solutions

2nd Quarter 2004

- Provide advanced training to all St. Paul reliability coordination staff on ESCA SE/CA
  - St. Paul reliability coordination staff will continue using the ESCA SE/CA in tandem with the SIEMENS SE/CA located in St. Paul
- Implement Contingency Violation summary screens specified per 1st Qtr investigation
- TO's to supply metering accuracy for SE measurement weights 100kV and above for refined solutions

Ongoing

SEE STATE ESTIMATOR/CONTINGENCY ANALYSIS CRITERIA

Power Supply Monitoring Tool

The MISO Power Supply Monitoring Tool (PSMT) monitors several key measurements, which indicate the health and performance of each control area in the MISO footprint. The PSMT is being enhanced to provide more information and functionality to the reliability coordinators. These enhancements include:

4th Quarter 2003

- Identify additional points and values to be received from member companies
  - MISO management to contact member companies to obtain all additional data
- Install additional data points into the tool
- Configure tool to alert the operator for the following:
  - Individual Control Area's Instantaneous ACE is +/- 2-times its respective L(10) value (i.e., yellow)
  - Individual Control Area's 10-min avg. ACE exceeds its respective L(10) value for 3, 6, 9, & 12 consecutive 10 min periods (i.e., 3-white, 6-yellow, 9-orange, 12-red)
  - Individual Control Area's frequency is +/- .03hz from 60.00hz (yellow), and +/- .05hz from 60.00hz (red)
  - MISO's total ACE $\geq$ MISO's L_{10}
  - Difference between lowest CA frequency and highest CA frequency is greater than .03hz – indicating possible islanding or separation

1st Quarter 2004

- Confirm all data points/real-time values with the Control Areas
- Provide ability to calculate required reserves on a Control Area basis
- Configure tool to alert the operator when actual reserves do not meet required reserves on a Control Area basis
- Investigate ability to move this tool to the ESCA or other environment. Include pros and cons of such a move
- Investigate adding user-specified trending functionality for any/all data points in the Power Supply Monitoring Tool:
  - User to be able to choose between the following timescales:
    - Past hour
    - Past 12 hours
    - Past 24 hours
  - User to be able to specify multiple points

2nd Quarter 2004

- Implement trending functionality specified per 1st Qtr investigation

Status & Analog Alarms

The MISO reliability coordinators receive thousands of alarms each day. The alarming tools used to display these alarms will be enhanced to allow for more effective monitoring of system conditions by the reliability coordinators. These enhancements include:

4th Quarter 2003

- Enhance audible alarming
- Alarming for:
  - Analog flows vs. limits
  - Analog voltages vs. limits
  - Status
  - Equipment 100kV and above

1st Quarter 2004

- Investigate additional alarming functionality, including:
  - Linking of alarms and one-line diagrams
  - Provide summary screen differentiating planned vs. forced outages
  - Improved alarm names/descriptions
  - Topology processor – indicates in real-time what facilities have tripped (transformers, circuits, etc., instead of individual breaker status alarms)

2nd Quarter 2004

- Implement additional functionality specified per 1st Qtr investigation

REFERENCE MISO ALARMING PHILOSOPHY DOCUMENT

Overview Displays of MISO Transmission System

Dynamic overview displays are being developed for the entire MISO reliability coordination area. These displays will allow the reliability coordinators to view the entire MISO region at once.

4th Quarter 2003

- Complete the mapping of real-time analogs and voltages for entire MISO area to overview displays
- Provide complete visual indications of overloaded facilities, forced outages, high voltage, low voltage
- Complete the linking of overview displays and individual station one-line diagrams

1st Quarter 2004

- Investigate feasibility of adding the following functionality:
  - In the event that all data is lost, the last known good scan of data can be called up and placed on the displays with a visual indication that it is last known good data
  - Toggle to state-estimator values rather than measured values

2nd Quarter 2004

- Implement additional functionality specified per 1st Qtr investigation
- Develop and implement procedures for reviewing, updating, and maintaining display

REFERENCE TO OVERVIEW DISPLAY PLAN

One line station diagrams for entire MISO transmission system

Dynamic one-line station diagrams are being developed for the entire MISO reliability coordination area. These diagrams will allow the reliability coordinators to view real time data and conditions at each of the stations within the MISO region.

4th Quarter 2003

- Complete the mapping of real-time analogs, breaker statuses, and voltages for all stations in the MISO model
- Provide ability to toggle between state-estimator values and measured values

1st Quarter 2004

- Investigate feasibility of adding the following functionality:
  - In the event that all data is lost, the last known good scan of data can be called up and placed on the displays with a visual indication that it is last known good data

2nd Quarter 2004

- Implement additional functionality specified per 1st Qtr investigation
- Develop and implement procedures for reviewing, updating, and maintaining diagrams

REFERENCE ONE LINE DIAGRAM PLAN

Video Projection System (VPS) upgrade–

In order to view the dynamic diagrams – as well as other tools currently existing or being developed – additional video projection screens will be installed in the MISO Control Center. The video projection system provides the ability for a large amount of real-time, dynamic, visual information to be displayed in a meaningful way and viewed by several people in the control center simultaneously.

4th Quarter 2003

- Install Phase 1 of expansion (18 screens)

1st Quarter 2004

- Final testing
- Final documentation
- Final acceptance

REFERENCE VPS EXPANSION PLAN

Voice Communication

Purchase and install a new turret-style phone system by summer of 2004 to enhance the existing phone communication system used by real-time operations personnel.

4th Quarter 2003

- Complete the specifications document for the phone system
- Contact vendors to solicit bids
- Review bids and select vendor
- Sign contract with selected vendor

1st Quarter 2004

- Purchase and install phone system and verify proper operation

Delta Voltage Tool

This tool will be populated with ICCP bus voltage measurements for all busses 230kV and above in and around the MISO Reliability Area. The tool will provide the Reliability Coordinator with a tool independent from the SE/CA with which to monitor 1.) Significant changes in voltage levels, and 2.) Unacceptable voltage levels across the system.

4th Quarter 2003

- Finalize all requirements for tool – including:
  - Tool will be populated with ICCP bus voltage measurements for all busses 230kV and above in the MISO Reliability Area
  - Tool will indicate the control area associated with each ICCP bus voltage measurement
  - Tool will alert the operator by sorting to the top of display any voltage measurement that reaches a percent of nominal that is either above or below acceptable levels for that particular voltage.
  - Tool will alert the operator by sorting to the top of display any voltage measurement that changes between scans by a threshold amount
  - When a point is sorted to the top, an indication will be given of what the previous value was for that point prior to moving into an alarm state
  - Determine the best application to use for this tool – Microsoft Excel or ESCA. (Data currently resides in SCADAMOM)

1st Quarter 2004

- Build Tool
- Implement specified functionality
- Once tool is checked out functioning properly, investigate feasibility of adding additional functionality, including:
  - Add all (or select) bus voltages 100kV and above to the tool
  - Add sorting capability to tool allowing all voltages that are in alarm in tool to be sorted by several different criteria:
    - Magnitude of change
    - Time of alarm

2nd Quarter 2004

- Implement additional functionality specified per 1st Qtr investigation

Delta-Flow Tool

The Reliability Coordinators' ability to monitor changes in energy flows across the transmission system will be enhanced by adding all transmission lines 230kV and above in and around the MISO Reliability Area into the existing Flowgate Monitoring Tool (FMT)– OR - into a separate tool working on same principle as the FMT. This tool will assist the Reliability Coordinators in knowing not only when facilities trip, but what facilities are impacted significantly by a trip.

4th Quarter 2003

- Finalize all requirements for tool – including:
  - Tool will be populated with the equipment names and mapped ICCP MW measurements for ALL available lines and transformers 230kV and above in MISO and first-tier areas
  - Tool will alert the operator by sorting to the top of display any equipment whose MW flow changes between scans by a threshold amount
  - When a piece of equipment is sorted to the top, an indication will be given of what the previous (pre-alarm) value was for that equipment prior to moving into an alarm state
  - Determine the best application to use for this tool – Microsoft Excel or ESCA. (Data currently resides in SCADAMOM)

1st Quarter 2004

- Build Tool
- Implement specified functionality
- Once tool is checked out functioning properly, investigate feasibility of adding additional functionality, including:
  - Add all equipment 100kV and above to the tool
  - Add sorting capability to tool allowing all transmission facilities that are in alarm in tool to be sorted by several different criteria:
    - Magnitude of change
    - Time of alarm

2nd Quarter 2004

- Implement additional functionality specified per 1st Qtr investigation.

Flowgate Monitoring Tool

The Flowgate Monitoring Tool (FMT) allows the reliability coordinators to monitor real time flows across key facilities via ICCP data from the Control Areas and to project post-contingent flows as well. The Flowgate Monitoring Tool will be enhanced as follows:

4th Quarter 2003

- MISO Operations Department to specify additional functionality being requested:
  - Additional logging capabilities
  - Automatic updating of Line Outage Distribution Factors (LODFs) to reflect real-time condition of transmission system
- MISO IT Department to begin implementing additional requested functionality
- MISO Operations Department to begin conducting review with all members of MISO Reliability Area to determine if additional facilities from their respective areas need to be added to the FMT for monitoring
- MISO Operations Department to begin conducting review with all members of MISO Reliability Area to determine that correct limits are being used in FMT for those elements already in the FMT.

1st Quarter 2004

- MISO IT Department to complete implementation of additional logging capabilities requested by Operations
- MISO IT Department and EMS Group to complete implementation of phase 1 automatic (hourly) updating of Line Outage Distribution Factors (LODFs) to reflect real-time condition of transmission system
- MISO Operations Department to complete review with all members of MISO Reliability Area to determine if additional facilities should be added to FMT, and provide list of these facilities to IT Department
- MISO IT Department to begin adding facilities to the FMT as specified by Operations Department/Control Areas
- MISO Operations Department to begin verifying flows/data points with Control Areas for all facilities listed in FMT
- MISO Operations Department to complete review with all members of MISO Reliability Area to determine that correct limits are being used in FMT for those elements already in the FMT.
- MISO IT Department to complete adding facilities to FMT as specified by Ops/CA's
- MISO Ops to complete verifying flows/data points with CA's for all facilities listed in FMT

2nd Quarter 2004

- MISO IT Department and EMS Group to complete implementation of phase 2 automatic (multiple times per hour) updating of Line Outage Distribution Factors (LODFs) to better reflect real-time condition of transmission system

Messaging System (OICL) Enhancements

The MISO Messaging System is the primary means of electronic communication between the Carmel Reliability Coordinators and those Control Areas within the Carmel Reliability Zone. Further enhancements are required to maximize the use of this important tool.

4th Quarter 2003

- Determine requirements for implementing the following requested functionality:
  - OICL to automatically notify transmission owners of all TLRs that are currently being issued on the grid
    - This notification should take the same form as is currently used to notify MISO Management of TLR level changes via their pagers
  - OICL (or other tool) to post all TLR curtailments to OASIS (Not intended to replace notification of CA's within MISO Reliability Area via Messaging System.)
  - OICL to be re-configured to allow for streamlined process of attaching and sending TLR Curtailment lists to all members.
  - OICL to automatically notify transmission owners of all transmission outages that are forced and voltage problems that are below emergency limits.
  - OICL to automatically notify TOs of their flowgates that exceed normal continuous limits on a real-time basis.
  - OICL to be re-configured to allow for streamlines process of sending out Time Error Corrections and Energy Emergency Alert (EEA) information
- Investigate pros/cons of using MISO Day 2 messaging system or other messaging system application vs. OICL

1st Quarter 2004

- Begin implementation of requested functionality – either through the OICL or other means as agreed upon by MISO Reliability Coordination

2nd Quarter 2004

- Complete implementation of requested functionality – either through the OICL or other means as agreed upon by MISO Reliability Coordination

Generator Tracking Tool – Ensuring PMAX is not exceeded

The Reliability Coordinator needs to be aware of any generator(s) whose megawatt-hour output is exceeding their interconnection study limits.

4th Quarter 2003

- Determine requirements for implementing the following requested functionality through the MISO Generation Monitoring Tool or other means:
  - MISO RC to be capable of monitoring and receiving visual indication any time a generator's megawatt-hour output is exceeding its interconnection study limits.
- Determine which generators have study limits and will be monitored

1st Quarter 2004

- Complete implementation of requested functionality as specified in 4th Qtr determination

ICCP Data Quality Indicating Tool

It is critical to know the quality of all data links and ICCP data that is received by MISO. Currently, the Flowgate Monitoring Tool and Power Supply Monitoring Tool do not have the capability of flagging or indicating when data may be suspect.

4th Quarter 2003

- Determine requirements for implementing the following requested functionality into the Flowgate Monitoring Tool:
    - Provide visual indication/alert whenever ICCP data or datalinks are lost, frozen, or lagging.
    - Provide for logging/recording
- Consider the following when developing solution:
    - Move FMT and PSMT into the ESCA environment so that the ESCA data-quality functionality can be utilized
    - IT Department is currently working on a standard ESCA display that indicates the health of ICCP data/data links. (This effort should move forward regardless of its impact on this subject tool)
    - Provide for logging/recording

1st Quarter 2004

- Begin implementation of requested functionality

2nd Quarter 2004

- Complete implementation of requested functionality

Backup Tool Designation/Development

A contingency plan is needed to cover the loss or unavailability of each critical reliability coordination tool at the primary control center. The backup tool/process may not be a 100% replacement, but will meet basic functionality.

4th Quarter 2003

- Determine and specify which reliability coordination tools/processes are critical – and will require backup/redundancy

1st Quarter 2004

- Determine backup tool/process for each specified reliability coordination tool/process used by MISO
- Where no backup tool exists, develop a backup tool or contingency plan to cover

2nd Quarter 2004

- Document the backup tool/process for each primary reliability coordination tool/process – including instructions/procedures as necessary
- Implement backup tools/processes that did not previously exist to cover all contingencies

MISO and PJM Joint Operating Agreement (JOA) quick hits

MISO and PJM have recommended that several processes listed MISO/PJM JOA be implemented immediately to enhance reliability. These processes relate to:

Data Exchange

4th Quarter 2003

- Determine requirements for implementing all of the phase 1 data exchange items in Article IV

1st Quarter 2004

- Implement all of the phase 1 data exchange items in Article IV
- Document the implementation agreement

ATC/AFC coordination

4th Quarter 2003

- Determine requirements for implementing all of the items in Article V

1st Quarter 2004

- Implement all of the items in Article V
- Document the implementation agreement

Outage Coordination

4th Quarter 2003

- Determine portions of Article VII to be implemented
- Determine requirements for implementing agreed upon portions of Article VII

1st Quarter 2004

- Implement agreed upon portions of Article VII
- Document the implementation agreement

Joint Operation and Emergency Procedures

4th Quarter 2003

- Determine portions of Article VIII to be implemented
- Determine requirements for implementing agreed upon portions of Article VIII

1st Quarter 2004

- Implement agreed upon portions of Article VIII
- Document the implementation agreement

Reliability Coordination Working Group (RCWG)

This group will consist of Operator/Shift Supervisor-level personnel from MISO and member companies. The group will provide prompt action on items as they arise and also provide support on refining MISO processes, procedures, and tools. RCWG will report to Reliability Subcommittee (RS).

The RCWG will be set up to:

- Review Tools, procedures, and processes
- Verify flows and limits
- Implement "quick hits"
- Review comprehensive reliability enhancement plan
- Review any NERC ORS/ RCWG/ Policy 9 changes
- Review any changes in the Functional Model

4th Quarter 2003

- Collect contact information for representatives for each CA and TO in the MISO Reliability Area
- Setup first meeting/conference call of the RCWG by Nov. 15th, 2003
- Assign action items to the group for completion by Dec. 31, 2003
- Work in concert with RCWG and TOCWG to implement Comprehensive Reliability Plan

1st Quarter 2004

- Ongoing

Revision of Reliability Coordination Manual

MISO process manuals must be kept current and up-to-date in order to provide concise information and clear direction to MISO Reliability Coordinators and other parties who deal with them. The following items will be addressed:

- Strengthen Emergency Procedures and Emergency Response
- Strengthen procedures for responding to specific alarms/conditions
- Develop process to ensure regular review and updating of this document

4th Quarter 2003

- Update and post updated version of the MISO Reliability Coordination Process Manual by December 15, 2003
    - Include – as appropriate – language and procedures to address all relevant recommendations put forth in the following documents:
        - NERC Near-Term Actions
        - ISO/RTO Council Recommendations
        - MISO/PJM JOA Quick Hit items
        - DOE Recommendations
        - MISO Reliability Plan
- Strengthen Emergency Procedures and Emergency Response
- Strengthen procedures for responding to specific alarms/conditions
- Develop process to ensure regular review and updating of this document
    - Include criteria for declaring an emergency and steps that occur as a part of the declaration.
- During interim, issue Directives as necessary to Reliability Coordinators covering any changes or updates to MISO Emergency/Normal Operating Procedures.
- Revise ACE portion of Manual regarding consecutive 10-minute periods for which a Control Area operates its ACE outside its L_{10}., and the actions the coordinator will take in response.

1st Quarter 2004

- Develop process for regular review and updating of the MISO Reliability Coordination Process Manual
- Create an email distribution list to send notification to stakeholders when revisions have been made
- Develop and implement process for input by RCWG concerning content and language included in the MISO Reliability Coordination Process Manual
- Develop process to train Reliability Coordinators and Control Areas/Transmission Operators (to the extent that Control Areas and/or Transmission Operators are impacted) on changes made to the Manual
- Develop process to notify Control Areas/Transmission Operators of MISO Reliability Coordination Directives that impact them

Restoration Planning

The MISO Power System Restoration Group (PSRG) will be leading the effort regarding restoration planning.

4th Quarter 2003

- Develop documentation outlining the scope of the sub-regional restoration group
- Hold initial planning meeting for the Southern Indiana/S.E.Ohio sub-regional working group
- Review and revise the MISO Restoration Philosophy documentation
- Prepare outline of Technical white paper to support possible tariff for BSS
- Finalize contract with contractor to assist in the development of a MISO restoration Plan

1st Quarter 2004

- Contractor start work
- PSR meeting to discuss draft of Technical paper outline and other items
- Northern Indiana/Ohio sub region initial meeting
- Illinois/Missouri sub-region initial meeting
- Review previously developed Tariff language.
- PSR training Seminar

2nd Quarter 2004

- PSR meeting to review progress on technical paper
- Prepare outline of MISO restoration Plan
- Finalize regional approach to restoration of the Southern Indiana/S.E.Ohio sub-regional

Collection of Underfrequency/Undervoltage Schemes

MISO will require its Control Areas to provide information on any underfrequency/undervoltage schemes that are present on their system along with explanations of the intended effects of these schemes on the transmission system.

4th Quarter 2003

- MISO will require each of the Control Areas within the MISO Reliability Area to provide information on any underfrequency/undervoltage schemes that are present on their system along with explanations of the intended effects of these schemes on the transmission system.

1st Quarter 2004

- MISO will compile this information for use by its real-time operations staff.

Attachment to LGE/KU #18
Witness: Torgerson Page 23

Collection of Backup Plans

MISO will require each Control Area and Transmission Operator in the MISO Reliability Area to provide a copy of their emergency backup plans.

4th Quarter 2003

- MISO will require that each Control Area and Transmission Operator in the MISO Reliability Area provide MISO with a copy of their respective emergency backup plans.

1st Quarter 2004

- MISO will compile this information for use by its real-time operations staff.

Development of Load Shedding Programs

The MISO will work with the Control Areas to develop load shedding programs that can be implemented within 5 to 10 minutes.

4th Quarter 2003

- MISO will develop a plan for compiling individual Control Area load shedding information/capabilities into Load Shedding Programs for use across the entire MISO Reliability Area
- MISO to begin collecting information from Control Areas:
  - Written documentation showing Control Area Operator authority to shed load
  - Written documentation indicating how much load can be shed within 5-10 minutes for transmission emergencies

1st Quarter 2004

- MISO works with Control Areas to begin the process of developing Load Shedding Programs across entire MISO Reliability Area.
  - Goal is for MISO to know on daily basis how much load shed is available to be shed in 5-10 minutes for transmission emergencies

2nd Quarter 2004

- MISO completes development of Load Shedding Programs
- MISO puts procedures in place for monitoring and implementation of Load Shedding Programs.

Exchange of Forced Outage Information

The SDX – as currently configured – is not an acceptable tool for use in a real-time environment. MISO needs to develop a system to exchange forced outage information with neighboring entities in near real-time. This may be accomplished through agreements with neighboring entities and/or procedures and/or new applications.

4th Quarter 2003

- MISO to investigate possible ways to accomplish this capability, including:
  - Agreements with neighboring entities
  - Processes and procedures
  - New software applications

1st Quarter 2004

- MISO to determine method(s) which will be used to accomplish this task
- MISO will pursue these methods with all related parties (neighboring entities, NERC, other)
- MISO will work on development of any necessary software applications, agreements, or processes

2nd Quarter 2004

- MISO completes all necessary agreements, applications, or processes
- MISO implements new procedure(s) with all neighboring entities

Review of Ratings

MISO will make a thorough review of the ratings it uses in the Flowgate Monitoring Tool, the SE/CA,, AFC calculations, and off-line models to ensure they are all consistent. There should be one set of ratings that are being used in all applications.

4th Quarter 2003

- MISO to define process for performing review and addressing conflicting ratings with members

1st Quarter 2004

- MISO to begin process of performing review and addressing conflicting ratings

2nd Quarter 2004

- MISO to complete the review and matching up of ratings

Comprehensive Flowgate List

MISO to maintain a comprehensive list of flowgates that defines the owner of the flowgate, the limiting element of the flowgate, and who is responsible for TLR on the flowgate, and AFC calculation. A list already exists, but will be reviewed and updated/augmented as necessary.

4th Quarter 2003

- MISO to define process for performing review

1st Quarter 2004

- MISO to begin review process between St. Paul and Carmel, and with Control Areas, Transmission Owners, and neighboring Reliability Coordinators
- Revise and augment list as necessary

2nd Quarter 2004

- MISO to begin complete review process with Control Areas, Transmission Owners, and neighboring areas
- MISO to implement ongoing process to ensure that list is reviewed and adjusted regularly

Comprehensive Daily Voltage/Reactive Management Process

While Control Areas in the Midwest ISO Reliability Area have their own daily voltage/reactive management plan, Midwest ISO will work with the Control Areas on implementing a comprehensive daily voltage/reactive management process for the entire MISO Reliability Area. While not yet fully developed, the Process will likely include the following:Will provide a more inclusive process for ensuring all possible VAR supplies are verified, available, and applied early in the day.

- While Control Areas continue to have primary responsibility for assuring adequate dynamic reactive supply reserves. MISO will, as the Reliability Coordinator, exercise its authority to call on available dynamic VAR resources or to shed load, if the Control Area does not meet its obligation
- Midwest ISO will monitor to assure that bulk electric transmission facilities remain above 95% of nominal or will direct corrective action to return voltages to above 95%, or to a higher level if the Control Area operates to a more stringent standard.
- The Control Area Operators within the MISO Reliability Area are required to report low voltage violations on transmission facilities to the MISO Reliability Coordinator immediately.
- Midwest ISO will adopt a policy of requiring generators to report any time generating units are not operating under AVR
- While Control Areas coordinate voltage schedules now, Midwest ISO will coordinate the differences among Midwest ISO Control Areas and across Reliability Coordination boundaries
- MISO to pursue near real-time VSAT program running during the day
- Outage reporting by MISO members to include the status of capacitor banks/reactors that are connected to the transmission system.

4th Quarter 2003

- Begin development of the Process with stakeholders

1st Quarter 2004

- Begin implementation of the process with stakeholders
- Begin development of tools/functionality associated with Plan

2nd Quarter 2004

- Complete implementation of tools/functionality associated with Plan
- Complete implementation of the Process with stakeholders

Reliability Charter

- Details to be determined

Staffing/ HR

The Midwest ISO will increase staffing levels in key areas to enhance reliability. MISO Human Resources will help to ensure that these additional positions will be filled with highly qualified personnel. The staffing goals are as follows:

- Implement Shift Supervisor position to provide 24x7 direction over all real-time operations
- Provide additional Reliability Coordinators in Carmel and St. Paul for additional monitoring, training, and visitation to Control Areas
- Increase Ops Engineer staffing in Carmel and St. Paul for greater voltage stability and analysis capabilities

4th Quarter 2003

- Operations to provide Human Resources with criteria for qualified applicants
- Human Resources to begin recruitment of qualified personnel
- Begin interviews of qualified applicants
- Begin hiring of qualified personnel to fill positions

1st Quarter 2004

- Continue interviewing and hiring of qualified personnel to fill positions
- Review number of qualified applicants and, if necessary, expand recruiting methods

2nd Quarter 2004

- Begin full implementation of Shift Supervisor position

Training

A robust ongoing training program is vital to maintaining a highly skilled, knowledgeable workforce. MISO's commitment is to become one of the best providers of training and training resources in the industry. Listed below are some possible aspects of the training plan that is being developed.

- Training to include cross-training between Carmel RCs, St. Paul RCs, and MISO Control Areas
- Develop Levels/Training Validations for Reliability Coordinators
- Investigate use of consultants to get take the MISO training program to the next level. Goal – to become the best in business
- Investigate ways to make active use of the simulator by the end of 2004
- Regularly train operators for emergency conditions using dispatcher-training simulator

4th Quarter 2003

- Acquire services of consultant services to assist in developing training plan that includes:
- Complete detailed training plan by November 30, 2003. Detailed plan to include:
    - Steps to be taken for more structured on-the-job training
    - Recommended requirements and schedule for initial and on-going training for Reliability Coordinators and control area operators
    - Recommendations for knowledge assessments following completion of training
    - More detailed timeline
    - Suggested number of personnel required to accomplish various steps
    - Cross-training in support of reliability
    - Recommended course content
- Train operators on State Estimator, Contingency Analysis
- Review emergency procedures with Reliability Coordinators

1st Quarter 2004

- Begin implementation of Training Plan

Timeline

4th Quarter 2003

State Estimator

- Provide basic training to all Carmel reliability coordination staff on basic functionality of ESCA State Estimator/ Contingency Analysis
- ESCA SE/CA to become fully utilized by reliability coordination staff
- Define process for determining status of ESCA SE/CA (Alarming):
  - When state estimator is not working
  - Process for determining SE/CA is running properly
- Define process for addressing failure of SE/CA:
  - Who is notified when state estimator is not working
  - Process for feedback to operators when SE is being fixed
  - Process for turning SE back over to RC
- Define process for emergency "patching" of model
- Define process for implementing emergency changes of model
- Determine:
  - What points are needed
  - What points are available

Implement missing pointsPower Supply Monitoring Tool

- Identify additional points and values to be received from member companies
  - MISO management to contact member companies to obtain all additional data
- Install additional data points into the tool
- Configure tool to alert the operator for the following:
  - Individual Control Area's Instantaneous ACE is +/- 2-times its respective L(10) value (i.e., yellow)
  - Individual Control Area's 10-min avg. ACE exceeds its respective L(10) value for 3, 6, 9, & 12 consecutive 10 min periods (i.e., 3-white, 6-yellow, 9-orange, 12-red)
  - Individual Control Area's frequency is +/- .03hz from 60.00hz (yellow), and +/- .05hz from 60.00hz (red)
  - MISO's total ACE $\geq$ MISO's L_{10}
- Difference between lowest CA frequency and highest CA frequency is greater than .03hz – indicating possible islanding or separation

Status and Analog Alarms

- Enhance audible alarming
- Alarming for:
  - Analog flows vs. limits
  - Analog voltages vs. limits
  - Status
- Equipment 100kV and above

Overview Displays

- Complete the mapping of real-time analogs and voltages for entire MISO area to overview displays
- Provide complete visual indications of overloaded facilities, forced outages, high voltage, low voltage
- Complete the linking of overview displays and individual station one-line diagrams

One-line Station Diagrams

- Complete the mapping of real-time analogs, breaker statuses, and voltages for all stations in the MISO model
- Provide ability to toggle between state-estimator values and measured values

Video Projection System Expansion

- Install Phase 1 of expansion (18 screens)

Voice Communication

- Complete the specifications document for the phone system
- Contact vendors to solicit bids
- Review bids and select vendor
- Sign contract with selected vendor

Delta Voltage Tool

- Finalize all requirements for tool – including:
  - Tool will be populated with ICCP bus voltage measurements for all busses 230kV and above in the MISO Reliability Area
  - Tool will indicate the control area associated with each ICCP bus voltage measurement
  - Tool will alert the operator by sorting to the top of display any voltage measurement that reaches a percent of nominal that is either above or below acceptable levels for that particular voltage.
  - Tool will alert the operator by sorting to the top of display any voltage measurement that changes between scans by a threshold amount
  - When a point is sorted to the top, an indication will be given of what the previous value was for that point prior to moving into an alarm state
- Determine the best application to use for this tool – Microsoft Excel or ESCA. (Data currently resides in SCADAMOM)

Flowgate Monitoring Tool

- MISO Operations Department to specify additional functionality being requested:
  - Additional logging capabilities
  - Automatic updating of Line Outage Distribution Factors (LODFs) to reflect real-time condition of transmission system
- MISO IT Department to begin implementing additional requested functionality
- MISO Operations Department to begin conducting review with all members of MISO Reliability Area to determine if additional facilities from their respective areas need to be added to the FMT for monitoring
- MISO Operations Department to begin conducting review with all members of MISO Reliability Area to determine that correct limits are being used in FMT for those elements already in the FMT.

Messaging System (OICL) Enhancements

- Determine requirements for implementing the following requested functionality:
  - OICL to automatically notify transmission owners of all TLRs that are currently being issued on the grid
    - This notification should take the same form as is currently used to notify MISO Management of TLR level changes via their pagers
  - OICL (or other tool) to post all TLR curtailments to OASIS (Not intended to replace notification of CA's within MISO Reliability Area via Messaging System.)
  - OICL to be re-configured to allow for streamlined process of attaching and sending TLR Curtailment lists to all members.
  - OICL to automatically notify transmission owners of all transmission outages that are forced and voltage problems that are below emergency limits.
  - OICL to automatically notify TOs of their flowgates that exceed normal continuous limits on a real-time basis.
  - OICL to be re-configured to allow for streamlines process of sending out Time Error Corrections and Energy Emergency Alert (EEA) information
- Investigate pros/cons of using MISO Day 2 messaging system or other messaging system application vs. OICL

ICCP Data Quality Indicating Tool

- Determine requirements for implementing the following requested functionality into the Flowgate Monitoring Tool:
  - Provide visual indication/alert whenever ICCP data or datalinks are lost, frozen, or lagging.
  - Provide for logging/recording
- Consider the following when developing solution:

- Move FMT and PSMT into the ESCA environment so that the ESCA data-quality functionality can be utilized
- IT Department is currently working on a standard ESCA display that indicates the health of ICCP data/data links. (This effort should move forward regardless of its impact on this subject tool)

- Provide for logging/recording

Backup Tool Designation/Development

- Determine and specify which reliability coordination tools/processes are critical – and will require backup/redundancy

MISO and PJM Joint Operating Agreement (JOA) quick hits

- Determine items to be implemented and requirements

Attachment to LGE/KU #18
Witness: Torgerson Page 35

RCWG

- Collect contact information for representatives for each CA and TO in the MISO Reliability Area
- Setup first meeting/conference call of the RCWG by Nov. 15th, 2003
- Assign action items to the group for completion by Dec. 31, 2003
- Work in concert with RCWG and TOCWG to implement Comprehensive Reliability Plan

Revision of Reliability Coordination Manual

- Update and post updated version of the MISO Reliability Coordination Process Manual by December 15, 2003
  - Include – as appropriate – language and procedures to address all relevant recommendations put forth in the following documents:
    - NERC Near-Term Actions
    - ISO/RTO Council Recommendations
    - MISO/PJM JOA Quick Hit items
    - DOE Recommendations
    - MISO Reliability Plan
- Strengthen Emergency Procedures and Emergency Response
- Strengthen procedures for responding to specific alarms/conditions
- Develop process to ensure regular review and updating of this document
  - Include criteria for declaring an emergency and steps that occur as a part of the declaration.
- During interim, issue Directives as necessary to Reliability Coordinators covering any changes or updates to MISO Emergency/Normal Operating Procedures.
- Revise ACE portion of Manual regarding consecutive 10-minute periods for which a Control Area operates its ACE outside its L_{10}., and the actions the coordinator will take in response.

Restoration Planning

- Develop documentation outlining the scope of the sub-regional restoration group
- Hold initial planning meeting for the Southern Indiana/S.E.Ohio sub-regional working group
- Review and revise the MISO Restoration Philosophy documentation
- Prepare outline of Technical white paper to support possible tariff for BSS
- Finalize contract with contractor to assist in the development of a MISO restoration Plan

Collection of Underfrequency/Undervoltage Schemes

- MISO will require each of the Control Areas within the MISO Reliability Area to provide information on any underfrequency/undervoltage schemes that are present on their system along with explanations of the intended effects of these schemes on the transmission system.

Collection of Backup Plans

- MISO will require that each Control Area and Transmission Operator in the MISO Reliability Area of the MISO Transmission Operators and Control Areas provide MISO with a copy of their respective emergency backup plans.

Development of Load Shedding Programs

- MISO will develop a plan for compiling individual Control Area load shedding information/capabilities into Load Shedding Programs for use across the entire MISO Reliability Area

- MISO to begin collecting information from Control Areas:
  - Written documentation showing Control Area Operator authority to shed load
- Written documentation indicating how much load can be shed within 5-10 minutes for transmission emergencies

Exchange of Forced Outage Information

- MISO to investigate possible ways to accomplish this capability, including:
  - Agreements with neighboring entities
  - Processes and procedures
- New software applications

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Review of Ratings

- MISO to define process for performing review and addressing conflicting ratings with members

Comprehensive Flowgate List

- MISO to define process for performing review

Comprehensive Daily Voltage/Reactive Management Process

- Begin development of the Process with stakeholders

Staffing

- Operations to provide Human Resources with criteria for qualified applicants
- Human Resources to begin recruitment of qualified personnel
- Begin interviews of qualified applicants
- Begin hiring of qualified personnel to fill positions

Training

- Acquire services of consultant services to assist in developing training plan that includes:
- Complete detailed training plan by November 30, 2003. Detailed plan to include:
  - Steps to be taken for more structured on-the-job training
  - Recommended requirements and schedule for initial and on-going training for Reliability Coordinators and control area operators
  - Recommendations for knowledge assessments following completion of training
  - More detailed timeline
  - Suggested number of personnel required to accomplish various steps
  - Cross-training in support of reliability
  - Recommended course content
- Train operators on State Estimator, Contingency Analysis
- Review emergency procedures with Reliability Coordinators

1st Quarter 2004

State Estimator/Contingency Analysis

- Provide advanced training to all Carmel reliability coordination staff on ESCA SE/CA
- Provide basic training to all St. Paul reliability coordination staff on basic functionality of ESCA SE/CA
  - St. Paul reliability coordination staff will begin using the ESCA SE/CA in addition to the existing SIEMENS SE/CA located in St. Paul
- Investigate feasibility of additional specific Contingency Violation summary screens
- TO's to supply metering accuracy for SE measurement weights 345kV and above for refined solutions

Power Supply Monitoring Tool

- Confirm all data points/real-time values with the Control Areas
- Provide ability to calculate required reserves on a Control Area basis
- Configure tool to alert the operator when actual reserves do not meet required reserves on a Control Area basis
- Investigate ability to move this tool to the ESCA or other environment. Include pros and cons of such a move
- Investigate adding user-specified trending functionality for any/all data points in the Power Supply Monitoring Tool:
  - User to be able to choose between the following timescales:
    - Past hour
    - Past 12 hours
    - Past 24 hours
- User to be able to specify multiple points

Alarms

- Investigate additional alarming functionality, including:
  - Linking of alarms and one-line diagrams
  - Provide summary screen differentiating planned vs. forced outages
  - Improved alarm names/descriptions
- Topology processor – indicates in real-time what facilities have tripped (transformers, circuits, etc., instead of individual breaker status alarms)

Overview Displays

- Investigate feasibility of adding the following functionality:
  - In the event that all data is lost, the last known good scan of data can be called up and placed on the displays with a visual indication that it is last known good data
- Toggle to state-estimator values rather than measured values

One-line Station Diagrams

- Investigate feasibility of adding the following functionality:
- In the event that all data is lost, the last known good scan of data can be called up and placed on the displays with a visual indication that it is last known good data

Video Projection System (VPS) Upgrade

- Final testing
- Final documentation
- Final acceptance

Voice Communication

- Purchase and install phone system and verify proper operation

Delta Voltage Tool

- Build Tool
- Implement specified functionality

- Once tool is checked out functioning properly, investigate feasibility of adding additional functionality, including:
  - Add all (or select) bus voltages 100kV and above to the tool
  - Add sorting capability to tool allowing all voltages that are in alarm in tool to be sorted by several different criteria:
    - Magnitude of change
- Time of alarm

Delta Flow Tool

- Build Tool
- Implement specified functionality
- Once tool is checked out functioning properly, investigate feasibility of adding additional functionality, including:
  - Add all equipment 100kV and above to the tool
  - Add sorting capability to tool allowing all transmission facilities that are in alarm in tool to be sorted by several different criteria:
    - Magnitude of change
- Time of alarm

Flowgate Monitoring Tool

- MISO IT Department to complete implementation of additional logging capabilities requested by Operations
- MISO IT Department and EMS Group to complete implementation of phase 1 automatic (hourly) updating of Line Outage Distribution Factors (LODFs) to reflect real-time condition of transmission system
- MISO Operations Department to complete review with all members of MISO Reliability Area to determine if additional facilities should be added to FMT, and provide list of these facilities to IT Department
- MISO IT Department to begin adding facilities to the FMT as specified by Operations Department/Control Areas
- MISO Operations Department to begin verifying flows/data points with Control Areas for all facilities listed in FMT
- MISO Operations Department to complete review with all members of MISO Reliability Area to determine that correct limits are being used in FMT for those elements already in the FMT.
- MISO IT Department to complete adding facilities to FMT as specified by Ops/CA's
- MISO Ops to complete verifying flows/data points with CA's for all facilities listed in FMT

Messaging System

- Begin implementation of requested functionality – either through the OICL or other means as agreed upon by MISO Reliability Coordination

Generator Tracking Tool (Ensuring PMAX is not exceeded)

- Complete implementation of requested functionality as specified in 4th Qtr determination

Data Quality Indicating Tool

- Begin implementation of requested functionality

Backup Tools

- Determine backup tool/process for each specified reliability coordination tool/process used by MISO
- Where no backup tool exists, develop a backup tool or contingency plan to cover

MISO and PJM Joint Operating Agreement (JOA) quick hits

- Implement specified items
- Document the implementation agreement

Revision of Reliability Coordination Process Manual

- Develop process for regular review and updating of the MISO Reliability Coordination Process Manual

- Create an email distribution list to send notification to stakeholders when revisions have been made
- Develop and implement process for input by RCWG concerning content and language included in the MISO Reliability Coordination Process Manual
- Develop process to train Reliability Coordinators and Control Areas/Transmission Operators (to the extent that Control Areas and/or Transmission Operators are impacted) on changes made to the Manual
- Develop process to notify Control Areas/Transmission Operators of MISO Reliability Coordination Directives that impact them

Restoration Planning
- Contractor start work
- PSR meeting to discuss draft of Technical paper outline and other items
- Northern Indiana/Ohio sub region initial meeting
- Illinois/Missouri sub-region initial meeting
- Review previously developed Tariff language.
- PSR training Seminar

Collection of Underfrequency/Undervoltage Schemes
- MISO will compile this information for use by its real-time operations staff.

Collection of Transmission Owner and Control Area Backup Plans
- MISO will compile this information for use by its real-time operations staff.

Development of Load Shedding Programs
- MISO works with Control Areas to begin the process of developing Load Shedding Programs across entire MISO Reliability Area.
  - Goal is for MISO to know on daily basis how much load shed is available to be shed in 5-10 minutes for transmission emergencies

Exchange of Forced Outage Information
- MISO to determine method(s) which will be used to accomplish this task
- MISO will pursue these methods with all related parties (neighboring entities, NERC, other)
- MISO will work on development of any necessary software applications, agreements, or processes

Review of Ratings
- MISO to begin process of performing review and addressing conflicting ratings

Comprehensive Flowgate List
- MISO to begin review process between St. Paul and Carmel, and with Control Areas, Transmission Owners, and neighboring Reliability Coordinators
- Revise and augment list as necessary

Staffing/HR
- Continue interviewing and hiring of qualified personnel to fill positions
- Review number of qualified applicants and, if necessary, expand recruiting methods

Training
- Begin implementation of Training Plan

2nd Quarter 2004

State Estimator/Contingency Analysis

- Provide advanced training to all St. Paul reliability coordination staff on ESCA SE/CA
  - St. Paul reliability coordination staff will continue using the ESCA SE/CA in tandem with the SIEMENS SE/CA located in St. Paul
- Implement Contingency Violation summary screens specified per 1st Qtr investigation
- TO's to supply metering accuracy for SE measurement weights 100kV and above for refined solutions

Power Supply Monitoring Tool

- Implement trending functionality specified per 1st Qtr investigation

Alarms

- Implement additional functionality specified per 1st Qtr investigation

Overview Displays

- Implement additional functionality specified per 1st Qtr investigation
- Develop and implement procedures for reviewing, updating, and maintaining display

One-line Station Diagrams

- Implement additional functionality specified per 1st Qtr investigation
- Develop and implement procedures for reviewing, updating, and maintaining diagrams

Delta Voltage Tool

- Implement additional functionality specified per 1st Qtr investigation.

Delta Flow Tool

- Implement additional functionality specified per 1st Qtr investigation.

Flowgate Monitoring Tool

- MISO IT Department and EMS Group to complete implementation of phase 2 automatic (multiple times per hour) updating of Line Outage Distribution Factors (LODFs) to better reflect real-time condition of transmission system

Messaging System (OICL) Enhancements

- Complete implementation of requested functionality – either through the OICL or other means as agreed upon by MISO Reliability Coordination

Data Quality Indicating Tool

- Complete implementation of requested functionality

Backup Tools

- Document the backup tool/process for each primary reliability coordination tool/process – including instructions/procedures as necessary
- Implement backup tools/processes that did not previously exist to cover all contingencies

Restoration Planning

- PSR meeting to review progress on technical paper
- Prepare outline of MISO restoration Plan
- Finalize regional approach to restoration of the Southern Indiana/S.E.Ohio sub-regional

Development of Load Shedding Programs

- MISO completes development of Load Shedding Programs
- MISO puts procedures in place for monitoring and implementation of Load Shedding Programs.

Exchange of Forced Outage Information

- MISO completes all necessary agreements, applications, or processes
- MISO implements new procedure(s) with all neighboring entities

Review of Ratings

- MISO to complete the review and matching up of ratings

Comprehensive Flowgate List

- MISO to begin complete review process with Control Areas, Transmission Owners, and neighboring areas
- MISO to implement ongoing process to ensure that list is reviewed and adjusted regularly

Staffing

- Begin full implementation of Shift Supervisor position

19

REQUEST:

19. Regard the preparation of the various components of the cost-benefit analysis supported in witnesses' testimony and exhibits.

    a. Please state the names, corporate affiliation and position of all people involved directly or indirectly in the preparation of this testimony. Include all contacts with outside consultants and government regulators and their staff.

    b. Did MISO receive, directly or indirectly, any input from or have any discussions with FERC Commissioners or FERC staff about the cost-benefit analysis that MISO was preparing for this case, or about any aspect of this case?

    c. If the answer to (b) is yes, please provide all notes, information and any other correspondence by whatever means (electronic and non-electronic) that outline the FERC's and/or their staff input into this process.

RESPONSE:

a.

Name	Corporate Affiliation	Position
James P. Torgerson	MISO	President and Chief Executive Officer
Ronald R. McNamara	MISO	Vice President of Regulatory Affairs
Michael P. Holstein	MISO	Vice President and Chief Financial Officer
Roger C. Harszy	MISO	Executive Director of Planning and Engineering
Paul Gribik	MISO	Director, FTR Markets
Roy L. Jones	MISO	Director, Tariff Administration & Scheduling
Tom Mallinger	MISO	Director, Operations Engineering
Wayne Schug	MISO	Director, Interregional Coordination
Todd Ramey	MISO	Manager, Market Pricing and Analysis
Larry Middleton	MISO	Manager, EMS Applications
Elaine Chambers	MISO	Manager, Tariff Settlements

Witness: Ronald R. McNamara

Name	Corporate Affiliation	Position
Sam Diaz	MISO	Manager, Financial Planning and Analysis
Renuka G. Chatterjee	MISO	Lead EMS Engineer
Robert Benbow, Jr.	MISO	Technical Lead, Reliability Coordination
Stephen Benchluch	MISO	Senior Market Analyst, Market Analysis
Jeff Sprague	MISO	Senior Financial Analyst
Kawah Lau	MISO	Lead Engineer, Markets and Models
Paul A. Centolella	Science Applications International Corporation	Assistant Vice President
Todd D. Davis	Science Applications International Corporation	Assistant Vice President
William R. Keene	Science Applications International Corporation	Senior Energy Analyst
Christopher R. Murphy	Science Applications International Corporation	Junior Energy Analyst
Scott Harvey	LECG, LLC	Director
Hallie Martin	LECG, LLC	Research Associate
Steven Imig	LECG, LLC	Research Assistant
Brian Hutter	LECG, LLC	Research Assistant
James E. Sustman	New Energy Associates, A Siemens Company	Vice President
Gary Moland	New Energy Associates, A Siemens Company	Powerbase Product Manager
J. Neil Copeland	New Energy Associates, A Siemens Company	Senior Consultant
Eugene Meehan	NERA Economic Consulting	Senior Vice President
Jonathan Falk	NERA Economic Consulting	Vice President
Kushal Patel	NERA Economic Consulting	Analyst
John Erwin	NERA Economic Consulting	Analyst
Oksana Kozhemyako	NERA Economic Consulting	Associate Analyst

Witness: Ronald R. McNamara

b. Since the initiation of this proceeding, the persons listed in part (a) above have had contact with FERC Commissioners and Staff on various topics and matters. Some of the FERC contacts have evidenced a general awareness of this proceeding. In particular, at some point before the completion or filing of the benefit-cost analysis, Paul A. Centolella described to a FERC Staff member the kinds of benefits that Midwest ISO was working to quantify.

The Midwest ISO did not receive input from FERC Commissioners or Staff related to the benefit–cost analysis filed in this proceeding. During the course of the project, a FERC Staff member provided a copy of a report prepared for Dominion Virginia Power by Charles River Associates, *The Benefits and Costs of Dominion Virginia Power Joining PJM.* That report was not relied upon in preparing the benefit–cost analysis for this proceeding.

c. A copy of *The Benefits and Costs of Dominion Virginia Power Joining PJM,* prepared for Dominion Virginia Power by Charles River Associates, referenced in part (b) above, and the related email is attached. (N.B. Material protected by the work-product doctrine and irrelevant to the request has been deleted from the headers and footers of the email.)

Witness: Ronald R. McNamara

-----Original Message-----
From: William Meroney [mailto:William.Meroney@ferc.gov]
Sent: Friday, December 05, 2003 3:19 PM
To: Centolella, Paul A.
Subject: RE: Benefit-cost analysis

Here is the study.

And the link to the rest of the PJM filing in the Virginia case.

http://www.pjm-south.com/library/filings.jsp

-----Original Message-----
From: Centolella, Paul A. [mailto:PAUL.A.CENTOLELLA@saic.com]
Sent: Friday, December 05, 2003 3:13 PM
To: William Meroney
Subject: RE: Benefit-cost analysis

Bill,

I do not have it. If you could send me a copy or direct me to where it may be on line that would be appreciated.

Thanks,

Paul

-----Original Message-----
From: William Meroney [mailto:William.Meroney@ferc.gov]
Sent: Friday, December 05, 2003 3:08 PM
To: Centolella, Paul A.
Subject: RE: Benefit-cost analysis

Have you got any of documents from the Kentucky proceeding? I am looking to get a sense of where the Kentucky Commission and LGE/KU are coming from - concerns, arguments, etc.

Have you looked at the PJM response to the Virginia Commission in the Dominion case? I have a copy of the Cost Benefit analysis somewhere if you don't have it.

-----Original Message-----
From: Centolella, Paul A. [mailto:PAUL.A.CENTOLELLA@saic.com]
Sent: Friday, December 05, 2003 1:43 PM
To: William Meroney
Subject: Benefit-cost analysis

Bill,

I appreciate your willingness to assist. Please give me a call if you would like to talk further. My complete contact information is below.

Thanks,

Paul

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THE BENEFITS AND COSTS OF DOMINION VIRGINIA POWER JOINING PJM

PREPARED FOR

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June 25, 2003

CRA Project No. D04310-00

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EXECUTIVE SUMMARY

This is a study of the benefits and costs of Dominion Virginia Power ("DVP") joining the PJM Interconnection, LLC ("PJM") Regional Transmission Organization ("RTO"). The Virginia legislature recently required that such a study be completed before a utility in Virginia joins an RTO. The study was undertaken by Charles River Associates ("CRA") on behalf of DVP.

The study assesses the likely net benefits to DVP's Virginia jurisdictional retail customers ("Virginia Retail Customers") and collectively for all retail and wholesale customers in the DVP control zone ("DVP Zone Customers") of DVP joining PJM. The likely net benefits are also assessed for DVP shareholders. These net benefits are measured over a 10-year study period, from 2005 through 2014, presuming that DVP, along with American Electric Power ("AEP"), Commonwealth Edison and Dayton Power & Light (collectively, "New PJM Entrants"), will be integrated into the PJM market structure by January 2005. In this "Change Case," the four companies are assumed to operate under PJM's market rules, including its congestion management system based on Locational Marginal Pricing ("LMP") and Financial Transmission Rights ("FTR"). The net present value of the results is reported for the first six years of the study period and also for the entire 10-year period. We present the results for two separate periods to focus the reader on the immediate and continuous benefits that are maintained throughout the study period and to isolate the benefit to consumers from reduced capacity costs in the later years, so that the reader can more readily compare results without such benefits. The net benefits of DVP joining PJM are measured against a "Base Case" in which DVP does not join an RTO, nor do the other New PJM Entrants. In both the Base and Change Cases, it is assumed that all Virginia Retail Customers transition from rate-capped generation service to competitive generation service in mid-2007. That is, our study implements Virginia's blueprint for restructuring that is laid out in the Restructuring Act.

The principal conclusions of the study are that DVP joining PJM will lead to the following benefits for DVP Zone Customers, including Virginia Retail Customers:

- ✓ Protection of native load through priority allocation of congestion hedging tools that will protect retail customers from the congestion cost risk that becomes explicitly priced in LMP markets. Congestion charges to DVP Zone Customers, including Virginia Retail Customers, under PJM's LMP congestion management system are more than offset by the congestion hedges received by DVP Zone Customers, including Virginia Retail Customers.

- ✓ Enhanced reliability in the DVP service territory through broader access to real-time PJM generation resources to address both generation and transmission issues.

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- ✓ Improved resource adequacy through the broader PJM market and participation in a larger integrated regional transmission planning process.
- ✓ Significant net benefits to DVP Zone Customers, including Virginia Retail Customers, in reduced net energy and capacity costs, as lower wholesale prices lead directly to retail savings for customers.
- ✓ Reduced wholesale prices for electricity in the DVP service territory and improved access to a broader range of generation supply, which will enhance wholesale and retail competition.

This study quantifies the benefits of DVP joining PJM using a production cost simulation model configured with a detailed representation of the transmission system in the Eastern Interconnection of the United States.[1] This model calculates hourly LMPs for each generator and load bus in the Eastern Interconnection. Inefficiencies in the current market and trading arrangements are captured through certain hurdles to trade. We employed two types of hurdles. The first is an import hurdle, to reflect a strong preference for local commitment of generation units to ensure local reliability. The second is an inter-control zone trade hurdle that reflects current impediments to trade that become larger as the number of transmission wheels increases. We calibrated these hurdles to historical trading patterns between DVP and neighboring control areas. To model the impact of DVP and the other New PJM Entrants joining PJM, we eliminated these hurdles within the expanded PJM market, while leaving them intact for trade with other areas. We estimated benefits and costs explicitly for 4 of the 10 years using this model (the years 2005, 2007, 2010, and 2014) and interpolated for the intervening years.

On the cost side of the equation, we assessed no new administrative costs in the Base Case, even though DVP may be required to create an RTO, or to join a different RTO, if it does not join PJM; any such RTO would have administrative costs. In the Change Case, we have estimated the PJM administrative charges that would be assessed to load, based on various PJM regulatory filings and escalated to account for inflation. The resulting net benefit is the total benefit less these administrative costs.

1 The Eastern Interconnection includes all of the United States east of Colorado, except parts of Texas, and Canada east of Alberta, excluding Québec.

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DVP Customer Net Benefits

The net benefits for DVP Zone Customers reflect two basic energy cost impacts: (1) changes in fuel costs prior to end of the rate-cap period (July 1, 2007 for all Virginia Retail Customers and for most other customers), and (2) changes in the market price of energy after the rate-cap period.

DVP supplies Virginia Retail Customers from the output of DVP's own generating units plus economic purchases from the spot market. As long as the rate-cap period is in effect, customers will not bear the risk of locational marginal pricing and congestion from the output of the DVP generation resources. Such output will be priced, in both the Base and the Change Case, based upon the actual, average cost of fuel for DVP's generating units. Pricing for purchased power, however, changes between the two cases. In the Base Case, off-system purchases are priced at the prevailing spot wholesale energy price in the DVP control zone. In the Change Case, such purchases are priced at the market price of energy as reflected in the DVP Load Zone LMP, and an allocated share of the DVP FTRs is applied in the fuel factor calculation to offset congestion costs customers may incur in conjunction with these purchases. As a result, during the rate-cap period, customers will be shielded from underlying LMP/FTR transactions in the Change Case, but will enjoy any fuel and purchase power cost savings created by the entry into PJM through a reduction in the fuel factor.

After the rate-cap period, Virginia Retail Customers are assumed to purchase all generation services (both in-system and off-system) at market prices in both the Base and Change Cases. In the Base Case, these purchases are charged to customers at the prevailing spot wholesale energy price in the DVP control zone, measured at the generation sources. In the Change Case, all purchases are made at the DVP Load Zone LMP and these purchases are offset by the full value of the DVP FTRs to hedge customers against congestion costs incurred in these purchases.

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Table ES-1: Net Benefits of DVP Joining PJM for DVP Zone Customers

(Millions of Present Value dollars, positive numbers are benefits)

	PV to July 1, 2003	
Virginia Retail Customers	('05-'10)	('05-'14)
Fuel Factor Savings	13.1	13.1
Market Energy Savings:		
Price Basis Change	(76.6)	(196.5)
FTR Value	274.2	515.9
Market Energy Savings	197.6	319.4
Total Energy Savings	210.7	332.4
Capacity Savings	16.2	314.1
Ancillary Savings	-	-
Benefit	226.9	646.5
Net PJM Admin Charge	(116.6)	(169.9)
Net Benefit	110.3	476.6
	PV to July 1, 2003	
DVP Zone Customers	('05-'10)	('05-'14)
Price Basis Change*	(66.8)	(207.7)
FTR Value	337.8	630.0
Total Energy Savings	271.0	422.4
Capacity Savings	18.9	372.6
Ancillary Savings	0.7	1.0
Benefit	290.6	796.0
Net PJM Admin Charge	(163.2)	(238.7)
Net Benefit	127.4	557.2

* Including fuel factor adjustments

In Table ES-1 above, for DVP Zone Customers, including Virginia Retail Customers, the energy savings impact is divided into fuel factor savings and market energy savings. Base rates that are frozen during the rate-cap period are assumed not to change between the Base and the Change Cases and, as such, are not considered in the calculation of net benefits. During the rate-cap period, the fuel factor impact is positive, with customers paying less for fuel and purchased energy if DVP is a member of PJM. After the rate-cap period, customers continue to benefit from a general reduction in energy prices in the Change Case, which significantly reduces total payments for energy. Note that the market energy impact itself is divided into two parts. As discussed above, the first part, labeled "Price Basis Change" reflects the impact of load being charged a competitive energy price at the generator bus in the Base Case, but the energy price at the DVP Load Zone LMP in the Change Case. Since energy prices at load centers tend to be higher than prices at generation buses due to

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transmission congestion, this isolated effect results in a small increase in the payments for energy. However, this impact is more than offset by the second part, labeled "FTR Value", which sets forth the value of the FTRs allocated to native load in the Change Case, with the net result being that native load benefits through a reduction in energy prices.

In addition to this market energy impact, native load also benefits from a reduction in the price of generation capacity. The broader PJM market created by the addition of DVP and the other New PJM Entrants allows for greater load diversity and improved reserve sharing across the region. Consequently, less generation in DVP will need to be built during the study period to meet the same standards of system reliability if DVP joins PJM. In both cases, we required that DVP meet a 12.5 percent capacity reserve requirement, with no less than 2.5 percent internal reserves so that expected peak load and spinning reserves could be met entirely from local supply. Absent the PJM expansion, we forecast that 3,360 MW of new capacity would be needed in DVP between 2006 and 2014. If DVP is part of PJM, however, only 1,668 MW of new capacity need be built.

For reasons discussed in the report, charges for ancillary services and credits for through-and-out transmission revenues are assumed to be the same DVP Zone Customers in the Base and Change Cases, with the net result being that these factors are neutral in this analysis. While it is assumed that ancillary service costs will be the same in the Base and Change Cases,[2] the revenue associated with ancillary services under schedules 2 through 6 is allocated to generation owners based on their relative share of total generation within the DVP control zone. The small increase in ancillary payments received by generators in the DVP control zone reflects an increase in their respective share of generation within the control zone. Transmission revenues are assumed be identical in the Base and Change Cases due to the uncertainty about FERC's future transmission rate policy, but the effect on customer costs is expected to be minimal.[3]

The cost of operating the PJM markets is recovered from all loads through a per MWh charge. These costs are $0.41 to $0.43 per MWh in the expanded PJM (see Table C-2). The PJM administrative charges paid by customers for whom DVP is the load-serving entity are deferred during the 30-month rate-cap period, and then recovered over the following 30 months.

Table ES-2 below shows the annual net benefits from 2005 through 2010 and through 2014 to Virginia Retail Customers and all DVP Zone customers. Net benefits are positive in all years, with a total present value of savings in energy and capacity costs through 2010 of $227 million, and through 2014 of $646 million. These savings are substantially greater than the PJM administrative charge, which has a present value of $117 million through 2010 and $170 million through 2014. On

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2 *See* Testimony of Gregory J. Morgan.

3 *See* Testimony of David F. Koogler.

Executive Summary

net, the present value of benefits to Virginia Retail Customers through 2010 exceeds $110 million, and $477 million through 2014.

Table ES-2: Annual Net Benefits of DVP Joining PJM for DVP Zone Customers
(Millions of dollars, positive numbers are benefits)

Change Case minus Base Case
(in millions of $, positive numbers denote benefits)

	PV to July 1, 2003											
Virginia Retail Customers	('05-'10)	('05-'14)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Fuel Factor Savings	13.1	13.1	4.6	7.7	5.1	-	-	-	-	-	-	-
Market Energy Savings:												
Price Basis Change	(76.6)	(196.5)	-	-	(9.6)	(30.2)	(41.9)	(53.7)	(62.1)	(70.5)	(78.9)	(87.4)
FTR Value	274.2	515.9	-	-	65.1	130.2	135.6	141.0	144.2	147.4	150.5	153.7
Market Energy Savings	197.6	319.4	-	-	55.4	100.0	93.7	87.4	82.1	76.8	71.6	66.3
Total Energy Savings	210.7	332.4	4.6	7.7	60.5	100.0	93.7	87.4	82.1	76.8	71.6	66.3
Capacity Savings	16.2	314.1	-	-	-	-	-	31.5	166.7	251.2	200.1	104.0
Ancillary Savings	-	-	-	-	-	-	-	-	-	-	-	-
Benefit	226.9	646.5	4.6	7.7	60.5	100.0	93.7	118.9	248.8	328.0	271.7	170.3
PJM Admin Charge	(116.6)	(169.9)	(28.5)	(28.6)	(28.6)	(30.1)	(30.7)	(31.2)	(31.9)	(32.5)	(33.2)	(33.8)
Deferral/Recovery	(0.0)	(0.0)	28.5	28.6	(2.9)	(33.3)	(33.3)	0.0	0.0	0.0	0.0	0.0
Net PJM Admin Charge	(116.6)	(169.9)	-	-	(31.6)	(63.4)	(64.0)	(31.2)	(31.9)	(32.5)	(33.2)	(33.8)
Net Benefit	110.3	476.6	4.6	7.7	29.0	36.6	29.7	87.6	216.9	295.5	238.5	136.5
	PV to July 1, 2003											
DVP Zone Customers	('05-'10)	('05-'14)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Price Basis Change*	(66.8)	(207.7)	8.1	12.1	(2.3)	(33.9)	(48.7)	(63.4)	(73.2)	(82.9)	(92.6)	(102.4)
FTR Value	337.8	630.0	2.5	2.8	80.5	158.0	164.5	171.0	174.6	178.3	181.9	185.6
Total Energy Savings	271.0	422.4	10.6	14.9	78.2	124.0	115.8	107.6	101.5	95.4	89.3	83.2
Capacity Savings	18.9	372.6	-	-	-	-	-	36.9	196.6	297.9	241.1	121.7
Ancillary Savings	0.7	1.0	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Benefit	290.6	796.0	10.7	15.1	78.4	124.2	116.0	144.7	298.2	393.5	330.6	205.2
PJM Admin Charge	(163.2)	(238.7)	(39.6)	(40.0)	(40.2)	(42.1)	(43.0)	(43.9)	(45.0)	(46.0)	(47.1)	(48.1)
Deferral/Recovery	0.0	0.0	35.6	35.7	(3.7)	(41.6)	(41.6)	-	-	-	-	-
Net PJM Admin Charge	(163.2)	(238.7)	(4.0)	(4.2)	(43.9)	(83.8)	(84.7)	(43.9)	(45.0)	(46.0)	(47.1)	(48.1)
Net Benefit	127.4	557.2	6.7	10.9	34.5	40.5	31.3	100.7	253.3	347.4	283.6	157.1

* Including fuel factor adjustments

Virginia Retail Customers account for about 80 percent of DVP's overall load. Consequently, both the benefits and costs shown for Virginia Retail Customers in the above table are about 20 percent lower than the benefits and costs reported for all DVP Zone Customers.

DVP Shareholder Net Benefits

The net benefits for DVP shareholders also take into account two basic energy cost impacts: (1) changes in fuel factor revenue net of fuel factor-related costs, including consideration in the Change Case of LMP payments, LMP receipts and FTR value, and (2) changes in market energy sales revenue net of related generation production costs (*i.e.*, fuel, variable O&M and emission allowances). DVP shareholders also are affected by changes in the market price for generation capacity. As mentioned, total ancillary service receipts for the DVP zone are assumed to remain the same. There is a small impact on DVP shareholders as a result of differences in DVP's share of generation (the basis upon which ancillary revenues from schedules 2-6 are allocated) between the Base and Change Cases. The results for shareholders are summarized in Table ES-3.

Table ES-3: Net Benefits of DVP Joining PJM for DVP Shareholders
(Millions of Present Value dollars, positive numbers are benefits)

	PV to July 1, 2003	
DVP Shareholders	('05-'10)	('05-'14)
Net Energy Revenue	(122.3)	(250.5)
Net Capacity Revenue	(16.4)	(306.7)
Net Ancillary Revenue	2.7	3.6
Net Benefit	(136.0)	(553.6)

As shown in the table, shareholders can be expected to lose benefits under the PJM case in both the energy market and the capacity market. This is because both energy prices and capacity prices are expected to decline under PJM. There is a small positive impact on DVP shareholders from ancillary services as a result of differences in DVP's share of generation between the Base and Change Cases. The expected net impact on shareholders is a negative $136 million in net present value over the first 6 years of the study period (negative $554 million for the entire 10-year period).

Effects on Wholesale Electricity Markets

The benefits discussed above arise from the improved integration of the electricity markets facilitated by PJM. The primary benefits to the Commonwealth, though, stem from improved utilization of generation outside the state that displaces more costly internal generation. In addition, there is a benefit created by the capacity market in DVP and integration of DVP into the PJM capacity pool, which results in a deferral and reduction of the cost of building new generation resources while continuing to ensure the same level of system reliability.

The increase in flows into the DVP control zone from the Base to the Change Case is shown in Figures ES-1 and ES-2 on page 14. Figure ES-1 plots the average net interchange between control zones in 2007 in the Base Case; Figure ES-2 shows the flows in the Change Case, after the expansion of PJM. Improving the use of the interfaces between AEP, PJM and DVP allows a 39 percent increase of net imports by DVP, primarily because net imports from AEP rise from 1,200 MW to 1,647 MW.

The improved coordination of regional generation under PJM in the Change Case leads directly to two effects on the DVP wholesale power markets. First, the energy generated within the DVP control zone declines by 4,500 GWh. This shift reflects savings both in periods of low- to moderate-demand, when additional low-cost power from the west and north can be imported, and in periods of high-demand, when lower-cost peaking or cycling units from PJM may displace relatively more expensive DVP units. Second, and related, the average incremental cost to serve load in the DVP control zone is lower in the Change Case than in the Base Case by approximately $1.50 per MWh. This decline in the wholesale price of electricity in the DVP control zone is the primary source of energy market savings and, indeed, savings overall.

Congestion Pricing and FTRs

The Key Transmission Constraints that Result in Locational Price Differences in DVP are Located Outside of Virginia

In the PJM market design, locational price differences are created by transmission constraints. The MAPS modeling conducted by CRA for this study indicates that transmission constraints are minimal within the DVP control zone. However, price separation frequently occurs within Virginia, chiefly created by key transmission constraints located outside of the DVP control zone. The most important of these constraints are located in PJM West (West Virginia): the AP South Interface and the Beddington-Black Oak Voltage Interface. No constraint within the DVP control zone is binding during more than 10 percent of the hours in our 2005 modeling case, and only two constraints are binding in more than 100 hours. By contrast, the flow across the Black Oak-Beddington constraint is at its limit in more than 6,000 hours.

As a general matter, these transmission constraints outside of the DVP control zone do not unduly affect reliability in the DVP control zone or elsewhere. If they did, the constraints would have been mitigated under standard transmission reliability planning. However, the constraints do result in economic costs by creating transmission congestion that limits the physical ability in many hours for the lowest cost generators to generate as much as they are physically able. That is, congestion results in higher cost generation replacing lower cost generation in order to avoid violating transmission constraints.

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As certain DVP generators, in particular Mt. Storm and Bath County, inject power into the transmission system, the interconnected nature of the transmission system dictates that a portion of that power must pass through these key transmission constraints outside of Virginia. Efficient congestion pricing will lower the LMP at the generator locations that most affect these constraints when they begin to bind. This pricing signal provides an efficient means for only the lowest cost generators (*i.e.*, those with production costs lower than the LMP) to generate up to the point at which the constraint binds. In the absence of LMP, this binding constraint is managed through the use of transmission line-loading relief ("TLRs"), internal redispatch of DVP units, and other operational procedures that generally do not yield the most efficient, lowest-cost outcome. Today, these higher costs are passed on to customers through the fuel factor; under the PJM system, they will be reflected in locational prices and will be hedged through FTRs.

Congestion Charges in the DVP Control Zone Under PJM's LMP Congestion Management System are More than Offset by FTR Value

Our modeling indicates that binding constraints outside of the DVP control zone result in LMP differentials within the DVP control zone. As shown in Table ES-4, the average annual difference between hourly DVP Load Zone LMPs and DVP Generation LMPs is $1.38 per MWh in 2005, and ranges from $1.38 to $1.71 per MWh during the 2005 through 2014 period.[4] These LMP differentials result in congestion costs for the DVP load of $117 million in 2005, and a present value over the 2005 through 2010 period of $525 million ($783 million for the entire 10-year period).

Table ES-4: Comparison of Congestion Cost and FTR Value

(Millions of dollars)

	PV to July 1, 2003 ('05-'10)	PV to July 1, 2003 ('05-'14)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Load Price ($/MWh)			$34.39	$34.70	$35.01	$37.86	$40.72	$43.57	$45.98	$48.38	$50.78	$53.19
Gen Price ($/MWh)			$33.01	$33.29	$33.58	$36.34	$39.10	$41.87	$44.31	$46.75	$49.19	$51.62
Difference ($/MWh)			$1.38	$1.40	$1.43	$1.52	$1.61	$1.71	$1.67	$1.63	$1.60	$1.56
DVP Load (GWh)			84,969	86,727	88,484	90,106	91,729	93,351	95,251	97,151	99,051	100,952
Congestion Cost Paid by DVP (M$)	524.8	782.7	117.1	121.7	126.3	137.0	148.0	159.3	159.1	158.8	158.3	157.7
Congest Cost Paid by Others (M$)	70.3	104.9	12.4	18.9	25.2	21.1	16.7	11.9	15.7	19.7	23.8	28.0
DVP FTR Value (no PJM Allocation)	595.1	887.6	129.5	140.5	151.5	158.1	164.6	171.2	174.8	178.5	182.1	185.7
DVP Share of PJM System Excess	27.7	40.7	6.6	6.8	7.0	7.1	7.3	7.5	7.7	7.9	8.1	8.3
DVP FTR Value	622.8	928.3	136.2	147.3	158.5	165.2	172.0	178.7	182.5	186.3	190.2	194.0

To offset these congestion charges, PJM will allocate to DVP a set of FTRs to the DVP load zone. PJM allocates FTRs to all PJM network load up to the total peak of the network load. This allocation reflects the fact that network customers have paid over the years for the existing transmis-

4 These hourly LMP differences are weighted by hourly DVP load to determine the annual average. The hourly generation LMP is a weighted average of the LMPs of all generation operating in that hour in the DVP control area.

sion system. DVP requested that PJM conduct an analysis of what FTRs it could be allocated to hedge congestion costs incurred to serve its load. Based on the analysis performed by PJM of the likely set of FTRs to be provided to DVP, we calculate that the value of the DVP FTRs will be $129 million in 2005, with a present value over the 2005 through 2010 period of $595 million ($888 million for the 10-year period).

Thus, the value of the FTRs exceeds the congestion in the DVP control zone by $12 million in 2005 and $70 million in present value over the 2005 through 2010 period ($105 million for the 10-year period). This is because the DVP load is network load with full rights to FTRs on the PJM system. Non-network load on the transmission system created, for example, by spot sales transactions do not have similar FTR rights to offset the congestion caused by their transactions. The congestion payments from such unhedged transactions are remitted to FTR holders, such as DVP. In addition to the directly assigned FTRs, DVP will obtain from PJM a share of the FTR revenue received by PJM from auctioned "unallocated" FTRs. These unallocated FTRs exist and are sold when the FTR has not been claimed by a network customer, the FTR is simultaneously feasible with other FTRs that are claimed, and the FTR has positive value. Based on the historical level of these revenues in PJM, adjusted for the increased size of PJM in the Change Case, we estimate that DVP's share of these unallocated FTRs will account for $6.7 million in FTR auction revenues in 2005, with a present value over the 2005 through 2010 period of $27.7 million ($40.7 million over the 10-year period).

In sum, we calculate that the DVP zone will incur congestion costs of $525 million over the 2005 through 2010 period ($783 million for the entire 10-year period), but will be allocated FTRs worth $595 million ($888 million for the 10-year period) to compensate for this congestion, and in addition, will be allocated FTR auction revenue of $28 million ($40.7 million over the 10-year period). The resulting gain for DVP is $98 million over the 2005 through 2010 period ($146 million for the 10-year period).

Sensitivity Cases

Table ES-5 reports the results for the two sensitivity cases examined for this study, along with the base results for comparison. The first sensitivity case studies the impact of gas and oil prices being 25 percent higher. Not surprisingly, the higher fuel costs translate directly into higher electricity costs in both the Base and Change Case. When DVP is integrated into a broader market, with better access to diverse generating facilities, this price increase is less than if DVP is an isolated market. The higher gas prices provide more benefit from substitution of cheaper coal-fired generation when DVP joins PJM. This provides higher benefits for customers. Moreover, the impact on shareholders is also positive by comparison to the base results. This is because the higher gas prices result in a reduced level of output from DVP generation even in the Base Case. The impact of

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reducing the trade barriers by joining PJM therefore is positive, meaning that DVP's particular generation portfolio appears to be more competitive in PJM at higher gas prices.

The second sensitivity case posited that peak load was 5 percent higher than the level modeled in the base results, with total energy demand 2 percent higher. A higher level of load increases prices as a general matter, and the differential impact of joining PJM is a reduced level of energy market benefits, higher level of capacity market savings, and larger administrative fees paid to PJM. The energy market impact is due to capacity being closer to reserve margins so that prices are not moderated as much by joining PJM if load happens to be higher. The capacity market impact is due to the fact that reduction in ICAP prices that occurs when joining PJM is more valuable with a higher level of load because more ICAP must be purchased. The administrative cost impact is due to the analytical assumption that such costs are proportional to load. This is likely to be a conservative assumption, however, since if load is higher than expected, the per-unit administrative fee should decline.

Table ES-5: Net Benefits for Sensitivity Cases
(Millions of Present Value dollars, positive numbers are benefits)

	Base Results		High Fuel Price		High Load	
			PV to July 1, 2003			
Virginia Retail Customers	('05-'10)	('05-'14)	('05-'10)	('05-'14)	('05-'10)	('05-'14)
Total Energy Savings	210.7	332.4	245.9	380.4	209.1	142.2
Capacity Savings	16.2	314.1	16.2	314.1	17.0	329.8
Ancillary Savings	-	-	-	-	-	-
Benefit	226.9	646.5	262.1	694.4	226.1	471.9
Net PJM Admin Charge	(116.6)	(169.9)	(116.6)	(169.9)	(118.9)	(173.3)
Net Benefit	110.3	476.6	145.5	524.5	107.2	298.6
DVP Zone Customers	('05-'10)	('05-'14)	('05-'10)	('05-'14)	('05-'10)	('05-'14)
Total Energy Savings	271.0	422.4	313.4	479.5	266.9	185.1
Capacity Savings	18.9	372.6	18.9	372.6	20.0	392.7
Ancillary Savings	0.7	1.0	0.5	0.9	0.5	0.7
Benefit	290.6	796.0	332.8	852.9	287.3	578.5
Net PJM Admin Charge	(163.2)	(238.7)	(163.2)	(238.7)	(166.5)	(243.5)
Net Benefit	127.4	557.2	169.6	614.2	120.8	335.0

In a recent order in the parallel matter of AEP joining PJM, the Virginia Corporations Commission instructed AEP to consider the following sensitivity cases:

Executive Summary

1. Differing load forecasts
2. Differing levels of transmission congestion and associated transmission rights
3. Abnormal vs. normal weather
4. Differing unit outage assumptions
5. Differing fuel cost projections

Our study directly addresses the first and fifth of these cases. The third case, for weather variations, is also addressed through our second sensitivity case. Likewise, the high load sensitivity case provides insights to the effect of unit outages, since a reduction of supply associated with a unit outage is, economically, very similar to an increase in demand. The second case cannot be directly modeled, since transmission congestion is an endogenous outcome, not a model parameter.

QUALITATIVE ISSUES:

Certain aspects of DVP joining PJM cannot be addressed through a quantitative analysis. For these, CRA has considered the benefits and costs through a non-quantitative analysis.

Ongoing Protection of Native Load

In PJM, native load protections will continue that will mitigate certain potential adverse impacts that can occur as a result of a transition from the rate-cap period. Most importantly, FTRs will be available under PJM to offset the congestion costs that are separately priced in an LMP system. PJM has conducted a simultaneous feasibility test of DVP FTRs and has determined that adequate transmission capacity exists to support a full allocation of FTRs to load in DVP's control zone for the entire study period. This FTR allocation is a key factor in ensuring that delivered prices in DVP's service territory remain hedged against the congestion that can occur between generation buses and load buses in the control zone.

In addition, PJM has agreed that load will not be shed within PJM South in order to address capacity deficiencies in other parts of PJM. This means that Virginia customers will not be placed at risk for capacity shortages occurring elsewhere in PJM.

Reliability

PJM offers the opportunity to improve reliability within DVP. DVP will maintain its own transmission control center to address local reliability problems that will not be monitored by PJM.

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Moreover, by joining PJM, customers in the current DVP control zone will have the benefit of an enlarged scope of geographic control of generation that can be used to address transmission system emergencies or generation shortages. The larger scope for generation redispatch in emergency conditions will expand the resources available to PJM operators beyond those currently available to the DVP control zone operator.

Integrated Transmission Planning

PJM offers the opportunity for DVP to participate in a larger regional planning process that will blend DVP's local expertise with the regional views provided by PJM of other transmission owners and stakeholders. Much of this interaction occurs today on an informal basis. Joining PJM will help to formalize this process and improve the regional transmission planning process by focusing new investment to projects that realize the greatest net benefit. This coordination is particularly important for DVP since, as noted earlier, the transmission upgrades most needed to reduce prices in the DVP are located in neighboring states.

Support for Wholesale and Retail Competition

PJM's market structure and settlement system will be a valuable resource in supporting wholesale and retail competition in the future. While this benefit cannot be easily quantified, it is a very important benefit of joining a well-developed RTO, such as PJM. Seamless access to highly liquid trading hubs, such as PJM West, is critical to developing robust wholesale markets serving DVP customers. The centrally-facilitated markets in PJM provide the efficient day-ahead and balancing markets that are needed to continue facilitation of wholesale competition among generators and to ensure that all retail suppliers can compete on an equal basis within Virginia.

Executive Summary

Figure ES-1: Pool-to-Pool All-Hour Average Transfers in 2007 (MW) (Pre-RTO)

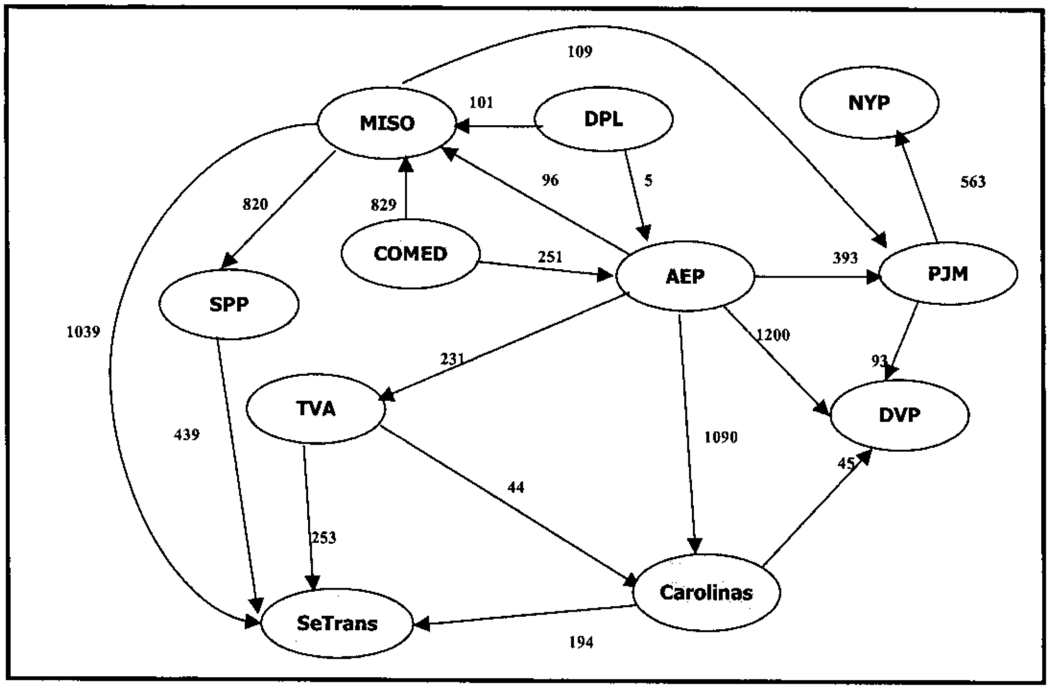
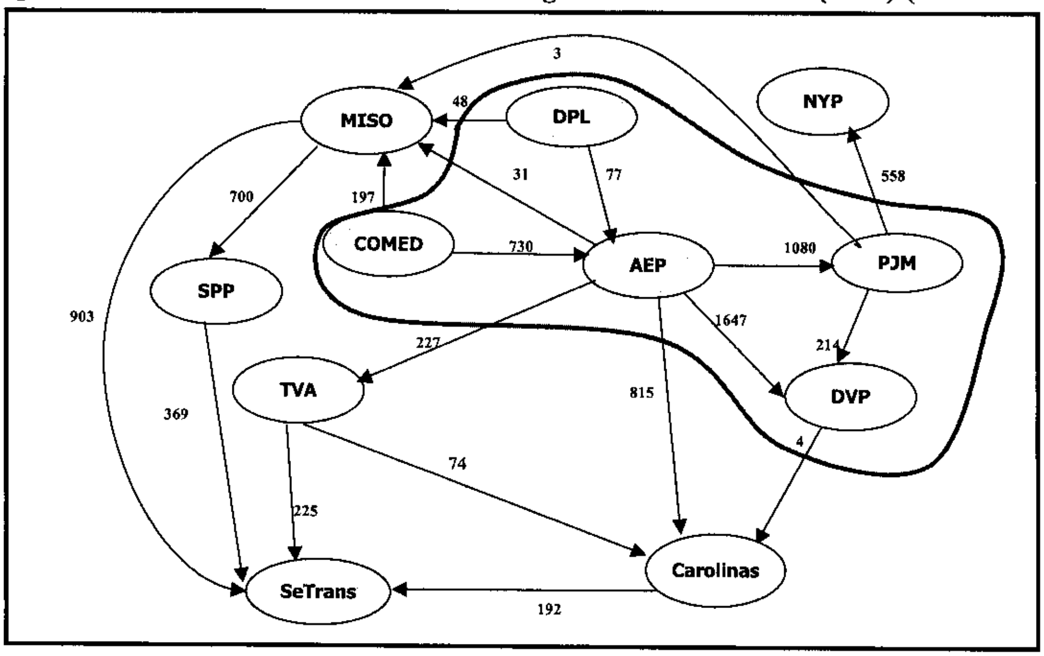


Figure ES-2: Pool-to-Pool All-Hour Average Transfers in 2007 (MW) (Post-RTO)



I. INTRODUCTION

This is a study of the benefits and costs of Dominion Virginia Power ("DVP") joining the PJM Regional Transmission Organization ("RTO"). This study was commissioned by DVP in response to Virginia legislation requiring that such a study be completed and filed with the Virginia State Corporation Commission ("Commission") before DVP joins PJM, which would not occur before July 1, 2004 in any event. The study has been conducted by Charles River Associates, and this report describes the study, its context, methods and results.

The study assesses the likely net benefits of DVP joining PJM for three stakeholder groups: Virginia jurisdictional retail customers ("Virginia Retail Customers"), a combined group consisting of all of DVP's retail and wholesale customers and transmission customers ("DVP Zone Customers"), and DVP shareholders. These net benefits are measured over a 10-year study period presuming that DVP, along with American Electric Power ("AEP"), Commonwealth Edison and Dayton Power & Light (collectively, "New PJM Entrants"), will be integrated into the PJM market structure by January 2005.

CRA has previously conducted a cost-benefit study of RTOs in the southeast on behalf of the Southeastern Association of Regulatory Utility Commissioners ("SEARUC"). That study is available at the website of SEARUC (Go to http://www.state.va.us/scc/searuc/). The SEARUC study did not include Virginia within the geographic area under consideration, which instead focused on the GridSouth, SeTrans and GridFlorida areas. This study and the SEARUC study have been conducted using the same modeling approaches appropriately revised to reflect the economic conditions in the expanded PJM area.

I.A. OVERVIEW

Previous studies of the benefits of RTO formation have considered a wide range of potential benefits, ranging from benefits that can be achieved quickly after market integration to longer-term, dynamic benefits of a broader marketplace.[5] There is ample evidence that substantial "seams" issues exist between non-integrated wholesale electricity markets, even those that have adopted similar underlying market systems such as PJM and New York.[6] Elimination of these inter-market seams is the most certain benefit from integrating the New PJM Entrants into a common market, and the one most readily and accurately quantified. Consequently, these near-term benefits are the principal focus of this study.

5 *See* Appendix D of this study, which summarizes the major RTO cost-benefit studies.

6 *See*, for example, *2002 State of the Market Report, NYISO*, by David B. Patton, Independent Market Advisor (April 2003), pp. 93-89.

Introduction

Other benefits of DVP joining PJM are no less real, but their value is difficult to model or measure. For example, coordinated operation of the transmission grid over a wider area will enhance system reliability, as system operators control more resources to respond to changing system conditions. System planning can take advantage of the greater load diversity of a broader resource pool to ensure the same or higher standards of system reliability with less capital investment. These reliability benefits are not fully captured in the capacity cost savings shown in this study. Integration into a broader market would make Virginia's wholesale and retail electricity markets more open and competitive which could, in turn, promote more efficient investment in transmission and demand-side management and lead to better siting of new generation.[7] Other researchers have linked development of competitive wholesale electricity markets to a material increase in generating unit availability or efficiency.[8] While these longer-term benefits may be significant, we find that there is not yet sufficient information to allow us to quantify these benefits with reasonable certainty. Consequently, we discuss these potential benefits qualitatively only, realizing that the benefits we measure in this study are likely to be conservatively low.

This study uses the GE Multi-Area Production Simulation ("MAPS" or "GE MAPS") model as the primary analytical tool in the analysis. MAPS is a production simulation model with a detailed transmission representation. Assessing transmission conditions is an important objective of the study, and the MAPS model is well known to be highly capable in such matters. The MAPS model used for this study includes substantially all of the generation and transmission in the Eastern Interconnection, with more detailed transmission monitoring of the expanded PJM region.

The study period begins in 2005 and extends through 2014. The study is based on pairs of scenarios—a Base Case and a Change Case. In the Base Case, DVP (and the other New PJM companies—AEP, DPL and Commonwealth Edison) are viewed as not being in PJM. In the Change Case, DVP (and the other New PJM companies) are viewed as being in PJM at the beginning of the study period—2005. The difference between the two cases is used to assess the impact of DVP joining PJM. In addition to this base pair of scenarios, we have studied two sensitivity cases. One of these hypothesizes higher natural gas and petroleum prices, and the other addresses a higher level of load.

Transmission rates are assumed to be de-pancaked within the expanded PJM footprint when DVP joins PJM.[9] Otherwise, transmission rates are assumed to continue as a charge to power movements between RTOs, in particular. Outside of the expanded PJM footprint, we assume RTOs

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7 *See*, for example, William W. Hogan, "Transmission Investment and Competitive Electricity Markets," Center for Business and Government, Harvard University, April 1998; and William W. Hogan, "FERC Policy On Regional Transmission Organizations: Comments In Response To The Notice Of Proposed Rulemaking," FERC Docket No. RM99-2-000, p.41-44.

8 *See* Appendix D, and *2002 State of the Market Report, PJM* (March 5, 2003), pp. 82-83.

9 *See* Testimony of David F. Koogler.

exist in both the Base and Change Cases in most areas of the country, including SeTrans, GridFlorida, MISO, SPP, and the northeast ISOs.[10] In this way, the study focuses on the incremental impact of DVP joining PJM, as opposed to the more general implementation of RTOs in other regions.

The study has prepared detailed MAPS model runs for the years 2005, 2007, 2010, and 2014, and has interpolated between the results for the remaining years in the study period. The results from the MAPS model are detailed hour-by-hour prices, generation and load at each location in the model. These results are processed by a post-processor SAS model, the output of which is summarized by a Financial Evaluation Model ("FEM").

For this study, we have disaggregated the benefits between customers and shareholders, in accordance with the Commission's guidance.[11] This is accomplished using the FEM. This contrasts with the SEARUC study in which customers and shareholders were combined into a single entity for the purpose of reporting financial impacts.

This study explicitly accounts for Firm Transmission Rights ("FTRs") that will be used to hedge transmission congestion costs under PJM. The proposed set of FTRs have been evaluated by PJM to ensure that the studied set is simultaneously feasible—a requirement under the PJM rules. These FTRs are an important component in any risk mitigation strategy undertaken by market participants in the PJM market structure.

In both the Base Case and the Change Case, the study assumes that a rate cap will continue for DVP's Virginia Retail Customers until mid-2007. At that time, retail customers in Virginia are assumed to switch from the rate cap to full market-based competition. As discussed in the next subsection, this Report quantifies several, but not all, aspects of the current RTO policy debate. In other areas, we have not been able to quantify the impacts and instead provide a qualitative analysis intended to inform the Commission in its decision-making process.

The remainder of the Report is organized into six main sections. The next section, Section II, provides an overview of the benefits and costs associated with DVP joining PJM, as well as a discussion of certain issues that are addressed quantitatively. Section III gives an overview of market conditions that form the backdrop to the study. Section IV describes the analytical approach of the study, including the use of the MAPS model and the subsequent financial modeling. Section V contains a discussion of issues not fully quantified in the study. Section VI presents the estimates of benefits and compares these to the cost estimates of forming the RTO. The final section, Section VII, provides our conclusions. In addition, there are three technical appendices describing the GE

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10 The exception to this is the Carolinas, which we modeled as three control areas (Duke, Progress Energy, and South Carolina Electric & Gas), with capacity reserve sharing within the region only.

11 *See* Virginia SCC Case No. PUE-2000-00550, Order for Notice (March 7, 2003), at 13.

MAPS model and detailed results, the financial model, and the detailed results from the financial analysis.

I.B. Regulatory Context

In January 2003, the Virginia legislature passed House Bill No. 2453 that, among other things, requires any utility requesting to transfer ownership or control of transmission facilities to a regional transmission entity to submit a cost-benefit study to the Commission analyzing the economic impact on consumers, including the effects of transmission congestion costs. In a subsequent Order for Notice, the Commission set out certain guidance for AEP in conducting the required cost-benefit study.[12] This study on behalf of DVP has taken account of the Commission's guidance in the AEP Order.

In this context, it is important to note that the Commission, in its AEP Order, required that the cost-benefit study be submitted no later than 90 days after FERC has issued its Standard Market Design rule. Presumably, the Commission intended that the study would be informed by the content of FERC's final rule. Recent guidance from FERC reiterated a basic Wholesale Market Platform based on the use of LMP and FTRs and, more importantly, that FERC is unlikely to make any material change in RTOs, such as PJM, that have already implemented such a market system. Accordingly, this study is unlikely to be made obsolete by FERC's pending rule given that it is grounded in the PJM rules that prevail today and are likely to prevail after FERC's rule is promulgated.

I.C. Other Benefit-Cost Studies of RTOs

Including the SEARUC study, seven other benefit-cost studies of RTOs have been conducted in the past two years or so. Six of these were reviewed in Appendix A of the SEARUC study. These studies were conducted in a manner generally consistent with the approach used in this study. The primary measure of benefits in these studies to date has been the savings in generation production costs. These savings have ranged from around 0.5 percent of total production costs to as much as 2.0 percent.[13] The SEARUC study estimated production cost savings of about 0.5 and 1.0 percent of production costs. In this study, such savings amounted to about 0.4 percent of the production costs within the area of the New PJM Companies.

12 Virginia SCC Case No. PUE-2000-00550, Order for Notice (March 7, 2003).
13 *See* Appendix D for additional details.

II. OVERVIEW OF BENEFITS AND COSTS

II.A. BENEFITS

This study, similar to other RTO cost-benefit studies, focuses on short-run benefits of DVP joining PJM. Certain short-run benefits, such as enhanced system reliability and resource adequacy, as well as longer-term benefits and risks that can be expected from the establishment of competitive wholesale markets, cannot be easily identified and quantified for purposes of this type of study. These other benefits, while real and likely to be substantial, are difficult to model.

Furthermore, most of the long-term benefits at issue, such as improved generation siting decisions, more efficient investment in transmission facilities and demand-side management, and improvements to productivity, are expected to emerge from the institution of competition. Competition in the electricity industry, in turn, has many facets, and it is not possible to attribute the benefits of competition to a particular element. However, participation in RTOs is a necessary foundation for competition in this industry

Accordingly, while it is CRA's belief that the institution of competition in the electricity industry will yield substantial social benefits in the long term, most of these benefits cannot be attributed to RTO participation, per se. Indeed, it seems likely that a significant amount of the benefits of DVP joining PJM would occur over the longer term in ways that we cannot anticipate. Likewise, some risks cannot be quantified. While a short-run study such as this one cannot compute such longer-term benefits and risks, their importance should be recognized.

There are two major sources of the short-run benefits studied and presented here: production cost savings and the pooling of regional capacity markets.

II.A.1. BENEFIT 1: Production Cost Savings

The largest component of the short-run benefits studied here is the reduction in the variable costs (*e.g.*, fuel) of generation that can occur as markets become more transparent and barriers to trade are reduced. This study measures this benefit as the difference in generation production costs between a Change Case and a Base Case as estimated using the GE MAPS model. The MAPS model used in this study incorporates a detailed representation of the Eastern Interconnection transmission grid, along with the dispatch and start-up costs of substantially all interconnected generating units. Because of the size of this model, more transmission constraints have been monitored in and around PJM, given the focus of this study, than in the remainder of the Eastern Interconnection. However, major transmission limits are monitored throughout the East.

Overview of Benefits and Costs

The MAPS model is a single system optimization model. Among other things, this means that MAPS will find the economically efficient unit commitment and generation dispatch to supply load throughout the study area. The current trading patterns in the Eastern Interconnection cannot be as efficient as this because the various control areas are independently conducting their own dispatch operations. These separate dispatch operations create loop flow on one another's transmission systems that contributes to transmission congestion. Such congestion cannot be managed efficiently in real-time under today's dispatch and trading arrangements. Instead, the utilities have developed other approaches, such as Transmission Line Relief ("TLRs"), to manage congestion. These approaches have served the industry well in the past, but are under additional stress with the development of merchant power producers and competitive wholesale power markets. Moreover, current arrangements for the trading of energy between control areas are based on incomplete bilateral markets that cannot be transparent, given the local management of regional congestion problems. The congestion costs created by transactions can only be partially accounted for under current grid operations in most areas. In contrast, PJM's market structure is based on LMP, which is designed to manage such congestion problems in real-time and to help markets become more efficient and transparent.

MAPS is well suited as a model of the generation dispatch that would take place after the New PJM companies are integrated into PJM. However, it cannot depict, without adjustment, the base-case trading arrangements prevailing under local management of congestion in which transactions do not pay the price that reflects the cost of the congestion they create. Accordingly, it is necessary to create a Base Case in MAPS by adding certain elements of inefficiency. In this study, like other studies of RTO benefits conducted previously, we have done this in two ways. First, we modeled individual control areas as having separate unit commitment and dispatch to meet internal load and reserves. Second, net transfers between regions were allowed, but limited by the use of "hurdle" rates. In effect, a hurdle rate is an impediment to trade between control areas, which is modeled as an adder to the transmission rate for transactions between control areas. In part, this hurdle rate reflects direct charges for losses and transmission tariffs; additionally, we assess an additional hurdle to reflect various inefficiencies and costs associated with bilateral trading across control areas. This additional hurdle rate is not actually part of any financial settlement, so it never is actually paid to anyone. Instead, it (together with the wheeling charge) is an input to the unit commitment and dispatch logic of MAPS that represents impediments to trading between control areas. The definition of the hurdle rates for this study is discussed in more detail in Section IV.

These base-case hurdles were chosen so as to calibrate the Base Case to reflect historical patterns of trade between DVP and its neighbors. In the Change Cases in which the New PJM companies join PJM, the import hurdle is eliminated for the four New PJM companies, but is retained for the expanded PJM as a whole; that is, trade between the expanded PJM and neighboring

Overview of Benefits and Costs

control areas is subject to continuing trade hurdles.[14] The import hurdle continues to apply to the pre-existing RTOs and control areas that are not reconfigured in the Change Case. Similarly, the trade hurdles within the expanded PJM are eliminated in the Change Case, aside from a small charge to reflect incremental transmission losses.

Production costs, including the costs of starting a plant and the variable costs of running it, will be lower in the Change Case than in the Base Case with hurdles. The difference between the two cases is used as the measurement of the production cost benefits due to the expansion of PJM.

We do not quantify potentially important benefits of joining PJM that should follow from becoming part of a wholesale market with excellent liquidity and transparent price formation. We assume, both in the Base and Change Cases, that all energy is traded at prices consistent with the spot market price of energy, even though most energy is traded bilaterally rather than in spot markets.[15] In markets where trading is thin and prices are not readily observable, market participants manage market risk through greater reliance on self-scheduling, firm transactions, and other relatively blunt tools; in a given hour, this may lead to some higher cost units operating instead of lower-cost units. By contrast, in a well-developed market such as PJM, there is greater convergence between bilateral and spot prices, and the consequent flexibility of unit commitment and dispatch means that customers can be served at lower total cost. Our study, though, focuses solely on the potential benefits to trade *between* areas, and so it understates potential benefits from improved utilization of resources *within* each control area.

II.A.2. BENEFIT 2: Pooling of Regional Capacity Markets

The second major category of benefits studied here is associated with the regional market for installed capacity requirements. DVP joining PJM is expected to result in certain economies in maintaining the adequacy of generation resources within the DVP control zone. The PJM East control zone is expected to benefit from the load diversity between it and the remainder of the expanded PJM area. These economies have the effect of delaying the need to build generation capacity anywhere within the expanded PJM market area by a few years, as excess capacity resources in resource-long areas of PJM (PJM East and AEP) can serve the a greater share of the

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14 FERC has recently reaffirmed its order that PJM and the Midwest Independent System Operator ("MISO") work to create a single market by October 2004. Our study assumes that seams continue to exist between these two markets, however, reflecting a pragmatic assessment that substantial market seams will likely continue to exist, as they have between PJM and New York despite years of work to reduce seams issues there. MISO is, on net, an exporting region, however, so tighter integration with PJM seems likely to have the effect of increasing the net supply of lower-cost resources available to supply Virginia. Consequently, our modeling choice is likely to be conservative.

15 *See* Testimony of Gregory J. Morgan.

resource needs of DVP. This delay, in turn, can keep the capacity prices in the DVP control zone at moderate levels further into the future.

To estimate the ICAP price impact, this study has used a probabilistic model of ICAP prices that is based on the likelihood of a shortage. The market-clearing price of ICAP is estimated as a weighted average of the capacity price expected to prevail during times of a capacity surplus versus those of a shortage. The price during a period of surplus is based on the estimated cost of moth-balling existing plants, while the price during a period of shortage is based on the cost of a new peaking facility. This pricing model has been used in order to smooth out what would otherwise be sharp, abrupt changes to the ICAP price in response to a very small change in the amount of installed capacity.

The effect of DVP joining PJM is to reduce the market-clearing ICAP prices in the later years of the study period, *i.e.*, in 2010 and later. This reduced price is assumed to apply to all of the capacity that must be purchased by customers in these years, and correspondingly, to all of the capacity that can be sold by DVP in the market place. Although bilateral capacity contracts can hedge price volatility, we assume that they will be priced to reflect expected future capacity prices under the applicable wholesale market structure.

II.B. Distribution of Benefits

Our Financial Evaluation Model processed the output from the physical modeling supported by MAPS in order to assess the benefits for Virginia Retail Customers, DVP Zone Customers, and DVP shareholders. The Financial Evaluation Model does several things:

- Accounts for imports and exports of power in and out of the DVP control zone and ascribes the trade benefits equally between the buying and selling control zones for trade supported by point-to-point transmission service, such as between DVP and CP&L.

- Accounts for the price of purchased power needed to serve native load customers, including power purchased off-system in the Base Case and under the PJM LMP system.

- Accounts for the sale of power both to off-system customers in the Base Case and into the PJM LMP market structure.

- Accounts for the cost of producing power separately for each DVP generating unit, including the cost of fuel, emissions allowances, start up costs and O&M costs.

- Accounts for the fuel factor formula applicable to DVP Zone Customers during the rate-cap period.

Overview of Benefits and Costs

- Accounts for FTRs expected to be allocated to DVP and its native load by PJM.
- Accounts for the need to purchase installed capacity in order to meet planned generation reserve requirements.

A more detailed description of the Financial Evaluation Model is provided in Section IV and Appendix B. Importantly, the output of the Financial Evaluation Model divides the benefits between retail customers and shareholders. The exercise of distributing benefits in this fashion was not undertaken in the SEARUC study because tracking such matters for 17 utilities in 8 state jurisdictions was not feasible.

II.C. Costs

The cost of DVP joining PJM is assumed to be the average administrative costs of PJM following the integration of the New PJM Companies. This administrative charge is estimated by PJM to be lower than the current per-unit charge as a result of the four New PJM Companies being integrated into the PJM market structure. This study has relied on this estimate as filed with FERC as part of the New PJM Companies' Section 205 filing. This cost estimate is also consistent with the recent study released by the U.S. Department of Energy.

These administrative costs are assumed to be paid by customers on a load-ratio share basis, consistent with the remainder of the load in the expanded PJM area. These costs are increased at a 2.5 percent annual rate, to reflect inflation. Administrative costs to customers for whom DVP is the load-serving entity ("DVP Requirements Customers") are assumed to be deferred until mid-2007, at which time the rate cap for DVP's Virginia Retail Customers ends. The deferred costs are assumed to be recovered over a short period beginning in mid-2007. For the purposes of this study, this amortization period is assumed to be 30 months (corresponding to the 30 months of deferrals). However, this assumption is merely a placeholder for whatever approach is adopted at a later time. The assumption about the amortization period will not affect the aggregate net present value results for customers and DVP shareholders over the entire study period, but does impact the result for any particular year. Likewise, the study assumes that the deferrals will accrue interest at a rate of 7 percent, consistent with the interest rate for deferrals in recent FERC filings. Again, this assumption is intended as a placeholder for whatever actual interest might be used later.

III. DESCRIPTION OF CURRENT MARKET

Under Virginia electricity restructuring, all Virginia retail customers currently can choose to shop for retail generation services at market prices. A rate cap is in effect for non-shopping customers until July 2007. Under the rate cap, DVP's base rates are frozen while fuel factor charges are adjusted annually based on projections of actual fuel costs.

As yet, there has been limited shopping for retail generation services in Virginia. Retail pilot programs are underway to encourage more retail shopping in the DVP area prior to 2007. For purposes of this study, it was assumed for simplicity that Virginia Retail Customers would pay rate cap energy prices through mid-2007, and market prices thereafter. Base rates for generation and other services would not change between the Base and Change Cases, thus base rate impacts were not included in the calculation of benefits and costs in this study. As such, the energy-related benefits for Virginia Retail Customers are assessed using differences in fuel factor charges during the rate-cap period and differences in market generation charges after the rate-cap period ends.

III.A. Rate-cap period Energy Benefits and Costs

During the rate-cap period, any change in the fuel factor charges between the Base and Change Cases results in a benefit or cost to retail customers. Changes in fuel factor charges generally result from a change in how specific DVP generating units are dispatched. This change in dispatch leads to fuel cost differences and corresponding changes in the amount and cost of purchases to serve retail load.

Similarly, during the rate-cap period, DVP shareholders recover fuel-related charges and capped base rates from retail customers. Any costs that change between the Base and Change Case and are not assessed to customers through the fuel factor (e.g., emission allowance costs) will impact shareholders, given that base rates are not reset during the rate-cap period. Moreover, in the Change Case during the rate-cap period, shareholders will pay PJM for the load of Virginia Retail Customers at the DVP Load Zone LMP, receive individual generator LMP payments from PJM for DVP generation, and offset the differences in these PJM payments and receipts with the DVP allocation of FTRs. During the rate-cap period, customers will be shielded from these underlying LMP/FTR transactions, but will enjoy any fuel and purchase power cost savings created by the entry into PJM through a reduction in the fuel factor.[16]

[16] As discussed in more detail in Section IV.C, purchase costs included in the fuel factor in the Change Case are adjusted for load zone pricing of the purchases net of allocated FTR value because there will be no other auditable purchase costs to trace in the fuel factor calculations.

Description of Current Market

III.B. Post-Rate Cap Energy Benefits and Costs

Once the rate cap ends, Virginia retail customers are presumed to pay market prices for generation service in both the Base and Change Cases. In the Base Case, retail customers will pay the general market-clearing price for energy in the DVP control zone. In the Change Case, retail customers will pay for energy based on DVP Load Zone LMP and offset any congestion costs from the market-clearing source to the load embodied in those prices using the FTRs allocated to DVP. Similarly, DVP shareholders will sell generation at market prices in both the Base and Change Cases. In the Base Case, the DVP generation will be priced at the general market-clearing price for energy in the DVP control zone. In the Change Case, the energy portion of generation will be priced at each individual generator's LMP.

III.C. Other Economic Benefits and Costs

Aside from energy, other economic benefits and costs considered in this study include capacity benefits, ancillary service charges, and PJM administrative fees.[17] The treatment of capacity costs incurred in meeting peak load and reserve requirements is consistent with the treatment of energy cost impacts. Prior to the end of the rate cap, capacity costs are bundled into the frozen DVP base rates. Thereafter, capacity costs are paid directly by DVP Zone Customers and such costs decrease. PJM administrative charges are assessed to customers in the Change Case. However, the PJM administrative charges assessed to DVP Requirements Customers during the rate-cap period in the Change Case are assumed to be deferred by DVP until July 2007, at which time the charges are recovered with interest over a 30-month period. Ancillary charges were assumed to be passed through to customers in both the Base and Change Cases as incurred; these costs are neutral between the two cases for customers.[18] Generation-related ancillary charges paid by load were assumed to be distributed to generating units in the DVP area in proportion to their market shares.

III.D. Other Customers in the DVP Control Zone

Along with the cost-benefit impact on Virginia Retail Customers, the collective impact on other customers in the DVP control zone, including North Carolina retail customers and wholesale customers, was also assessed. Other than North Carolina retail customers, these customers were assumed to shop for generation services in excess of any self-owned generation by mid-2007.

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17 The potential change in wheeling revenues received by DVP transmission between the two cases was not included in the study results presented herein. The impact is uncertain and likely to be small relative to the other benefits and costs quantified. *See* Testimony of David F. Koogler

18 See Testimony of Gregory J. Morgan.

IV. ANALYTICAL APPROACH

In order to quantify the likely costs and benefits of the proposed transfer of DVP into PJM, CRA needed to develop and refine several analytic models. To model the change in system operations that would result from the market integration, we used GE MAPS running with CRA's proprietary database, discussed in section IV.A below. Interacting with GE MAPS was a model of capacity additions and resulting capacity pricing, which we discuss in section IV.B. Finally, CRA developed a Financial Evaluation Model to assess the incidence of costs and benefits flowing from these two models of the physical system, which we discuss in sections IV.C and IV.D. The three technical appendixes contain further detail about how we used GE MAPS and the Financial Evaluation Model in this study.

IV.A. MODEL OF PHYSICAL SYSTEM OPERATIONS

In order to assess the operational benefits of expanding PJM to include DVP and the other New PJM Entrants, CRA used the GE MAPS model to determine the unit commitment and dispatch in the Base and Change Cases. The GE MAPS model is a security-constrained dispatch model that simulates the hourly chronological operation of an electricity market. It assumes marginal cost bidding, performs a least-cost dispatch subject to thermal and contingency constraints, and calculates hourly, locational-based marginal prices for electricity. The GE MAPS simulation is consistent with the congestion management scheme currently utilized in PJM and the other Northeast ISOs. The model's locational spot price calculation algorithm has been successfully benchmarked against the market price algorithm used in the PJM market.[19]

Models are only as reliable as their data, so CRA has taken extra measures to ensure that the assumptions regarding generation characteristics, transmission representation and limitations, fuel costs, emissions rates and regulations, planned additions and retirements, and NUG contracts were accurate and consistent. Details of these model inputs are discussed in Appendix A.

CRA modeled four years of the ten-year study period: 2005, 2007, 2010 and 2014. We chose 2005 as the earliest full year when DVP could be integrated into PJM, under the terms of the Code of Virginia § 56-579 as amended. Given that DVP's rate cap expires in 2007, we chose to model that year to provide fully detailed information to the financial model, which needed to make separate calculations for the first and second halves of 2007. The year 2014 bounds the ten-year study period, and 2010 provides a mid-point assessment to improve interpolation

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19 The actual PJM transmission representation for an individual hour was input into MAPS, along with actual loads, imports and exports and generator bids. The locational prices calculated by the GE MAPS program matched those produced by the PJM LBMP system for those conditions.

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The principal challenge in modeling commitment and dispatch with a tool as powerful as MAPS is not, surprisingly, finding the security-constrained least-cost dispatch. Instead, the challenge is to find a reasonable representation of the inefficiencies that inevitably exist in real-world markets and, more particularly, how these inefficiencies change when moving from one market system to another. Left to its own devices, MAPS will find and execute all possible trades throughout the entire Eastern Interconnection to minimize total system production cost, subject to meeting all load reliably. Because the current market does not capture all these beneficial trades between market participants and, in particular, across market seams, we have set up our model to add inefficiencies through the use of selective barriers to trade, or "hurdles."

We used financial hurdles to approximate inefficiency in the Base Case stemming from several sources, including:

- Biases toward the use of local control zone resources due to uncertainty and resulting reliability concerns;
- Lack of full coordination among the commitment and dispatch processes of control areas;
- Imperfect economic management of congestion between and within control areas due to loop flows and less-efficient congestion management tools than LMP;
- The lack of market transparency in bilateral markets;
- Transaction costs; and
- Inefficient scheduling of transmission.

For this study, we employed four types of hurdle rates. These are discussed in greater detail in Appendix A. In the unit commitment phase of MAPS, we imposed a $10 per MWh hurdle between control areas in order to reflect the self-commitment practices prevailing today. In the dispatch phase of MAPS, we employed two hurdle rates:

First is an "import hurdle" rate of $3 per MWh is imposed on each control area for any imported power during peak periods ($1 per MWh in off-peak periods). The purpose of this hurdle is to mimic the self commitment that is the basis for current operational practices within each control area, transactions costs associated with searching out and executing bilateral trades, and other impediments to trade that bias dispatch towards internal resources. The import hurdle applies only once to any transaction, regardless of how many control areas were involved in wheeling the power.

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The second type of dispatch hurdle used in this study is a "trade hurdle" rate of $3 per MWh, which is imposed on power transfers between control areas or RTOs in peak periods ($1 per MWh in off-peak periods). This trade hurdle rate reflects impediments to move power between control areas separately from the self-commitment logic embodied in the import hurdle. The trade hurdle is intended to represent both wheeling rates and trade impediments that become pancaked as power is wheeled across multiple control areas. Consequently, this charge is assessed for each control area through which a transaction moves.

Finally, a $1 per MWh fee is imposed at the dispatch phase for line losses for each inter-control area transfer. These three dispatch hurdles are additive, so a trade involving a single wheel would be subject to a total of a $7 per MWh peak-period dispatch hurdle rate—$3 per MWh to be imported, and $3 per MWh to be transferred to an adjoining control area, plus $1 per MWh for line losses. A trade involving a second transfer would be subject to a total hurdle rate of $11 per MWh—the $3 per MWh import hurdle, plus two transfer hurdles of $3 per MWh each and two losses charges of $1 per MWh each.

These hurdles were implemented in MAPS as economic contracts between zones, rather than as incremental line charges or restrictions on the transmission system. This approach has two distinct benefits in interpreting the results. First, the hurdles do not directly affect the locational prices in the model. The only influence the hurdle rates have is through their effect on the commitment and dispatch of the system. Second, the contracts track transfers between zones, rather than physical flows on lines. This feature aligns our contract transfers with the real bilateral contracts we see in today's electricity markets. It also makes tracking of costs and benefits materially more accurate than tracking only physical flows.

To model the integration of the New PJM Entrants into the PJM market system, we eliminated from the Change Case the commitment, trade and import hurdles among the five control zones in the Base Case that comprise the expanded PJM market area, namely PJM, DVP, AEP, DP&L and ComEd. The $1 per MWh line-loss fee remained as the only hurdle, reflecting our view that PJM will implement some version of a distance-dependent transmission loss charge. Commitment and dispatch hurdles from these zones to zones outside the expanded PJM market were not changed.

IV.B. Model of Capacity Prices

An integral part of the PJM market design is its capacity market, through which PJM ensures that there will be sufficient capacity resources offering to supply energy into the PJM energy markets to ensure reliable system operations. Units selected through the capacity auction are required either to bid into the PJM day-ahead market or to self-schedule that capacity. In return, these capacity resources are paid the auction-clearing price for each kilowatt of supply, regardless of whether the resource is actually called upon to supply energy or ancillary services. These payments allow units that never run, or operate infrequently, to cover their fixed costs; otherwise, generation owners might find it more profitable to mothball or close marginal generation resources, reducing the overall reliability of the system.

In modeling this capacity market, we first developed the pattern of new entry by location and time. Secondly, we used this pattern of capacity additions to estimate future capacity prices. The following two sections discuss our approach to each task.

IV.B.1. Determining New Build Requirements

Clearly, the existing fleet of generation resources cannot meet future needs indefinitely. In order to forecast both future energy and capacity prices, CRA needed to project what new generation resources would be built, where, and when.

For the first year of the study period, 2005, CRA assumed that only those units that are under construction currently would be commercially available. New projects that have been halted were not included among the 2005 builds. Although additional projects might conceivably be tabled, other projects not counted may be completed by Summer 2005. Overall, we believe that this is a reasonable and conservative forecast of 2005 resources.

For subsequent years, we assumed that additional capacity resources are brought on-line to maintain required capacity reserves in each control zone.[20] We allowed trades of capacity between directly interconnected zones provided that two conditions were met. First, the imported capacity could not exceed the transfer capability between the two zones. Second, each zone was required to carry internally enough capacity to meet forecast peak load plus a 2.5 percent operating reserve requirement.

This possibility of capacity export means that the location of new builds is not determined unambiguously. In the SEARUC study, we allowed no capacity trading and, consequently, the need for and quantity of new capacity in each zone was deterministic. In this study, we used the following procedure to locate new capacity resources:

1. Build internally to meet load plus operating reserves.

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20 We modeled both MISO and SETRANS as having two separate areas, east and west, to reflect the geographic and electrical separation within those two areas. MISO East corresponds to those areas of MISO in ECAR; MISO West includes those parts in MAIN and MAPP. SETRANS is split between the

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2. Fully utilize trading from resource-long areas. For example, New York can import capacity either from New England or PJM. New England, however, has no other export markets for its surplus capacity, and more than enough to meet New York's capacity shortfall until after PJM itself becomes capacity short. PJM resources, however, can sell to other markets. We therefore first meet New York's shortfall from New England capacity, before considering imports from PJM.

3. When available capacity exports cannot meet remaining capacity requirements in interconnected markets, allocate capacity exports so as to equalize the internal capacity margin in each import market. To a first approximation, this procedure equalizes the expected returns to new generators in each affected area.

In the both the Base and Change Cases, we required that each control zone, including those of the New PJM Entrants, carry internally sufficient capacity to meet peak load plus operating reserve. This rule required new builds in DVP and ComEd, as well as areas outside the expanded PJM market. Additional capacity needed generically in PJM to meet the pool-wide capacity requirement was also sited in these two zones, since they had the lowest internal reserve margins among the PJM sub-areas and, therefore, could be expected to have higher prices for peaking units.

The critical difference between the Base Case and the Change Case in the capacity market is that, owing to the increased load diversity of the expanded PJM market, the level of required reserves declines. In the Base Case, the current PJM is modeled to hold a 17 percent capacity margin, consistent with current requirements. Following the integration of the New PJM Entrants, this requirement is lowered to 12.5 percent for the current PJM market area, resulting in an approximately 15 percent margin above coincident peak for the expanded PJM area. This reduction in capacity requirements frees approximately 3,000 MW of resources that had been needed in PJM East, making additional capacity available to other PJM Member Companies, including DVP. Other required capacity margins outside the current PJM are assumed to be unchanged, so DVP holds a 12.5 percent reserve requirement in both the Base and Change Cases, of which no more than 10 percentage points can be met with external capacity resources.[21]

A second difference between the two cases is that we modify the capacity export rule (#3 above) so that surplus capacity in one area of PJM is used first to meet capacity shortfalls in

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Southern and Entergy areas. The New York Control Area was modeled consistent with its capacity market design as two sub-regions (New York City and Long Island) and an overall New York region.

21 *See* Testimony of Gregory J. Morgan.

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other areas of PJM. Only if PJM is collectively net long will any PJM zone export to a non-PJM zone, reflecting the higher transactions costs of selling external capacity. The practical effect of this change is to divert exports of capacity from AEP, that had been sold to CP&L, Duke, and TVA, are instead sold to DVP, Commonwealth Edison and the current PJM companies.

The pattern of builds across the Eastern Interconnect used in this study is summarized in Table IV-1.

Table IV-1: Pattern of New Capacity Builds by Region
Cumulative Additions, MW

	2007 Base Case	2007 Change Case	2007 Difference	2010 Base Case	2010 Change Case	2010 Difference	2014 Base Case	2014 Change Case	2014 Difference
PJM	0	0	0	0	0	0	2,069	0	-2,069
DVP	0	0	0	310	0	-310	3,360	1,668	-1,692
AEP	0	0	0	0	0	0	0	0	0
DP&L	0	0	0	0	0	0	0	0	0
ComEd	0	0	0	563	87	-476	4,407	2,250	-2,157
CP&L	0	0	0	763	498	-265	3,078	3,227	149
DUKE	846	846	0	2,875	2,856	-19	6,870	7,128	258
SCE&G	0	0	0	0	0	0	1,621	1,621	0
MISO E	0	0	0	0	0	0	5,564	6,280	716
MISO W	0	0	0	0	0	0	8,285	9,085	800
SPP	0	0	0	0	0	0	1,020	1,020	0
SETRANS E	0	0	0	0	0	0	8,840	8,840	0
SETRANS W	0	0	0	0	0	0	0	0	0
TVA	0	0	0	0	0	0	2,410	2,944	534
GFL	0	0	0	3,046	3,046	0	8,684	8,684	0
NEP	0	0	0	0	0	0	0	0	0
NYC	175	175	0	271	271	0	619	619	0
NYL	175	175	0	307	307	0	670	670	0
NYO	0	0	0	0	0	0	368	368	0
Subtotal New PJM	0	0	0	873	87	-786	9,836	3,918	-5,918
Subtotal Other	1,196	1,196	0	7,262	6,978	-284	48,029	50,486	2,457
Total	1,196	1,196	0	8,135	7,065	-1,070	57,865	54,404	-3,461

IV.B.2. Determining PJM Capacity Market Clearing Prices

Under the current capacity market design, the quantity of capacity purchased by PJM is determined administratively, to reach a capacity margin based on engineering analyses. This approach tends to create prices that tip between one of two values:

If the system has more than enough capacity resources to meet the capacity reserve margin, the capacity price is set by the payment needed to keep existing resources from exiting. Specifically, the marginal unit needs to recover its avoidable fixed costs from its combined net

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revenues in the energy, ancillary services and capacity markets. Based on the MAPS runs for this study, we determined that the marginal PJM resource would expect to receive insignificant payments in the energy and ancillary service markets. Consequently, the market-clearing price for capacity, when PJM is net long capacity, should be equal to the avoidable fixed costs of marginal capacity resources.[22] Based on previous CRA studies about PJM capacity, we estimate that this cost is $20 per kilowatt-year. This level may be conservatively high, since observed capacity prices in PJM have frequently been below this level. Using a lower level for the cost of capacity during periods of surplus capacity would increase the benefits to customers from DVP joining PJM.

The other possible state of the capacity markets is that there is an overall shortage of capacity. In order to attract new capacity resources, the capacity price must cover not merely the avoidable fixed costs of the facility, but the fully loaded cost of new entry net of margins the unit could receive in the energy and ancillary services markets. CRA considered, in each market that needed additional capacity resources, whether a combined-cycle unit or a simple gas turbine would require a lower capacity payment. Combined-cycle units have a higher capital cost but are more efficient, allowing them to operate profitable in more hours than a gas turbine. In most markets, including the expanded PJM area, the extra energy margin that a combined-cycle unit could earn did not offset their higher capital charges. Consequently, the capacity market-clearing price was set to the levelized embedded cost of a new gas turbine, less expected net revenue from the energy and ancillary services markets (which were small). CRA estimated that this levelized cost in PJM is approximately $50 per kilowatt-year, which is substantially in agreement with similar calculations other researchers have made for New York and New England.[23]

Stripped down to these basics, one might expect that the capacity prices can only be at one of two levels: a low price when there is sufficient capacity already installed ($20/kW-year), or a high price when new entry is needed ($50/kW-year). If, for example, in 2013 we foresaw the market as 10 MW deficient in the Base Case, but 10 MW in surplus in the Change Case, the simple "price tipping" model would suggest that the entire 21,000 MW of capacity needed for

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22 This conclusion sets aside the sale of capacity to other control areas from PJM, which could allow scarcity pricing in other areas to raise the PJM capacity price. At this time, market rules for trading capacity between markets are insufficiently developed to allow full market integration and price formation across RTO seams. We chose, therefore, to model the PJM capacity market as a stand-alone market.

23 *See* "New York Independent Operator, Inc.'s Filing of Revisions to the ISO Market Administration and Control Area Services Tariff: ICAP Demand Curve," FERC Docket No. ER03-647-000 (March 2003), and E-Acumen, "Peaker Cost Study," ISO-NE Markets Committee Meeting (April 2002). Both estimates will tend to overstate the cost of new Virginia capacity, since construction and operations costs outside the Northeast will be somewhat lower; moreover, since the E-Acumen study was completed, there has been a substantial softening in the market for turbines, which are a substantial capital budget item for a new peaking facility.

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the DVP area should be repriced from $50/kW-year to $20/kW-year, a notional savings to customers of about $630 million.

Such a knife-edge result does not, in our opinion, reasonably reflect the expected value of integrating capacity markets. There are many uncertain variables in our model, including the load forecast, the level of available capacity from each unit in the system,[24] and the development of demand-side capacity resources, that could turn a forecast capacity deficit into a surplus, or vice versa. To reflect these uncertainties about the state of the future capacity markets, we developed a simple probabilistic model to forecast capacity prices.

The model starts from the premise that capacity prices in the PJM auction will be set either at $20/kW-year if there is a capacity surplus, or at $50/kW-year otherwise. We then estimate the probability of each of these two states of the world, assuming that the capacity requirement is centered at our forecast value but has some uncertainty, with a normal random distribution. The forecast uncertainty was assumed to be 0.5 percent in 2003 and to increase by 0.2 percentage points in each subsequent year, so that the standard deviation in 2007 was taken to be 1.3 percent, and in 2014 to be 2.7 percent. These values, in our judgment, reasonably reflect the level of uncertainty intrinsic in long-term load forecasts.

Using this model, we compute the predicted capacity price as the probability-weighted average of the low-price ($20) and high-price ($50) outcomes. If, for example, installed capacity exactly equaled the forecast capacity requirement, there would be a 50 percent chance that the market would be deficient, and a 50 percent chance that the market would be in surplus. We would, therefore, assign a capacity price of $35/kW-year (half of $50 plus half of $20). Table IV-2 below shows the modeled capacity prices in PJM for each year of the study period.

Table IV-2: ICAP Prices
($/kW-year)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Base Case	$21.54	$22.08	$22.63	$23.19	$23.77	$26.38	$37.30	$51.62	$61.57	$66.12
Change Case	$21.54	$22.08	$22.63	$23.19	$23.77	$24.50	$27.53	$37.17	$50.25	$60.34

An underlying assumption of this price formation methodology is the persistence of prices. Once the existing installed capacity is no longer sufficient to meet capacity requirements, new capacity is induced to enter through higher capacity prices. Economists refer to this higher

24 Instead of counting each resource at its faceplate capacity rating, PJM computes Available Capacity from a unit, which takes into account its recent historical forced outage rates.

price as a "trapping state;" once a market needs new capacity, the capacity price remains at the long-term marginal cost of capacity forever. In actual practice, however, we know that investment tends to occur in cycles, with the price correspondingly swinging through extremes. Attempting to model such complex market dynamics is beyond the scope of this study.

Further, we focus solely on the capacity clearing price for the overall PJM market, defined either narrowly in the Base Case or more broadly in the Change Case. In lieu of an active capacity market in the Base Case, we chose capacity prices in the existing PJM market as the relevant proxy. In the Change Case, it is appropriate to use the expanded PJM clearing price for capacity, since at present PJM does not have locational capacity markets.

IV.C. MODEL OF FINANCIAL EFFECTS

As noted in Section III, base rates for generation and other services would not change between the Base and Change Cases, thus base rate impacts were not included in the calculation of benefits and costs. Effectively then, Virginia Retail Customer benefits and costs, as well as other DVP Zone Customers covered by the DVP fuel factor, are assessed using fuel factor charges during the rate-cap period and market generation charges after the rate cap ends. The calculations used to derive these respective charges are outlined below.

Fuel Factor Charges

The fuel factor charges are calculated as the fuel cost of the DVP generating units plus the cost of additional "off-system" purchases needed to meet DVP load, net of the fuel cost incurred in making off-system sales. Other production-related costs considered in the dispatch decision for DVP generating units, but not considered in the DVP fuel factor, include emission allowances and variable O&M. As noted below, in the Change Case there are adjustments made to the fuel factor calculation to reflect the use of LMP and FTRs with respect to purchased power only.

Despite the annual advance assessment of fuel factor charges in practice in Virginia, fuel factor charges in this study were projected based on actual hourly fuel costs and purchased power costs. In effect, an exact advance assessment was assumed. While such an exact assessment is not possible, there is no reason to believe that any error in the advance assessment would be greater or lesser between the Base and Change Cases.

Market Energy Costs

Once the rate cap ends, customers are assumed to pay DVP control zone market energy prices in the Base Case. In the Change Case, customers pay the DVP Load Zone LMP, rather than market energy prices, and receive the full allotment of DVP FTRs to compensate for any difference in load zone prices and energy prices at the generator bus caused by congestion. The net effect of these two factors yields the market energy savings shown in the Change Case.

IV.D. Benefit and Cost Measures for Customers and Shareholders

Customers Prior to End of the Rate Cap

Energy Benefits/Costs. In the Base Case, prior to the end of the rate cap, customers are simply assessed traditional fuel factor charges, comprised of the actual fuel costs at DVP units plus the cost of purchased power used to serve customers. Reductions to the fuel factor charges are made for off-system sales. In the Change Case, prior to the end of the rate cap, the only change from the Base Case is that purchased power is priced at the market price of energy as reflected in the DVP Load Zone LMP, rather than the prevailing market clearing price for generators in the DVP control zone used in the Base Case. When there is congestion, the DVP Load Zone LMP generally will exceed energy prices paid to generators, but shareholders absorb any congestion cost associated with delivering in-system power during the rate-cap period. For purchases of energy from generators not owned by DVP, customers are compensated for this congestion cost embodied in the zonal price by an allocation in the fuel factor calculation of a share of the DVP FTR value.[25] This method of pricing purchases for the fuel factor was used because there will be no other auditable source of purchase cost information in the Change Case other than the DVP Load Zone LMP and offsetting FTR value.

Other Benefits/Costs: Prior to the end of the rate cap, capacity-related costs incurred in meeting reserve requirements are embedded in the frozen DVP rates in the Base and Change Cases; any variance in these costs is absorbed by shareholders. Prevailing ancillary charges are assessed to customers in both the Base and Change Cases and are unchanged.[26] PJM administrative charges are assessed to customers in the Change Case. However, the PJM administrative charges assessed to DVP Requirements Customers during the rate-cap period in the Change Case are assumed to be deferred by DVP until July 2007, at which time the charges are recovered with interest over a 30-month period.

Customers After the Rate Cap Ends

Energy Benefits/Costs. Once the rate cap ends, customers are assumed to pay prevailing DVP control zone energy prices in the Base Case, set at the average generation bus price in the

25 The share is calculated as the hourly fuel factor purchases as a percent of the hourly load served under the fuel factor multiplied by hourly FTR value.

26 *See* Testimony of Gregory J. Morgan.

zone. In the Change Case, customers pay the DVP Load Zone LMP, rather than an average of generation bus prices, and receive the full allotment of DVP FTRs to compensate for any difference in DVP Load Zone energy prices and energy prices at generation buses caused by congestion. The net effect of these two factors yields the market energy savings in the Change Case.

Other Benefits/Costs: In both the Base and Change Cases, customers are assumed to pay the prevailing capacity price for the capacity needed to meet their peak load plus reserve requirements and to pay prevailing ancillary service charges. As in the rate-cap period, ancillary service charges to DVP Zone Customers will be unchanged or decline after the rate cap ends. The PJM administrative charge is assessed to customers in the Change Case.

This study quantifies reductions solely to the wholesale costs that retailers (including DVP) must pay for energy, capacity and ancillary services to serve DVP Zone Customers. The retail price charged to customers will also reflect other costs of wholesaling and retailing energy, such as customer service centers, risk management and billing. We have assumed that these markups would be similar in the Base and Change Cases. This is a conservative assumption, since our experience is that some elements of the total delivered energy cost would be reduced when their customers are in a large, well-functioning market like PJM.

Shareholders

The net benefit to DVP shareholders also can be thought of in two distinct categories: effect on energy revenues and on capacity payments.

Energy Benefits/Costs. As discussed earlier, the fundamental effect of moving from the Base Case to the Change Case is to lower wholesale energy prices in the DVP control zone, in particular the price paid to DVP's Mount Storm and Bath County facilities. Furthermore, generation output from DVP generation declines in the Change Case, as it is displaced in many hours by imports of lower-cost electricity. Since DVP units receive lower energy prices on a smaller sales base, there is a decline in net energy margins earned by DVP shareholders. During the rate-cap period, these lost energy margins are offset to a small degree by savings in certain production related costs such as emission allowances that are not currently included in the DVP fuel factor.

During the rate-cap period, shareholders also have the obligation to supply Virginia Retail Customers with energy at capped rates. In the Base Case, this obligation can be met largely through generation from DVP facilities. In the Change Case, however, DVP must pay to PJM its load zone LMP for the Virginia Retail Customers, including any congestion costs embedded in the zonal LMP. This congestion cost borne by shareholders is hedged through the

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FTRs that PJM allocates to DVP, net of FTRs allocated to offset congestion costs related to off-system purchases in the fuel factor as discussed in more detail previously.

After the rate cap ends, customers pay their own congestion costs and collect FTR revenues.

Capacity Benefits/Costs. Following the rate-cap period, DVP generating units receive capacity payments benchmarked to the prevailing capacity clearing price in PJM. As discussed in Section IV.B, these capacity prices are expected to be systematically lower in the Change Case, reflecting the fact that fewer new capacity resources will be required in order to uphold identical system reliability standards. Consequently, beginning in 2010 and continuing through the end of the study period, capacity revenues to DVP generating units are lower in the Change Case than in the Base Case. Since DVP units are not the only source of capacity for DVP Zone Customers, however, the decline in DVP capacity revenues is less than the decline in capacity payments made by DVP Zone Customers.

Other Customers in DVP Area

Along with the benefit-cost impact on Virginia Retail Customers, the collective impact on other customers in the DVP control zone, including North Carolina retail customers and wholesale customers, was also assessed. Other than North Carolina retail customers, these customers were assumed to shop for generation services in excess of any self-owned generation by mid-2007. The same analysis outlined above was applied in assessing the collective costs and benefits for these other customers.

V. ISSUES NOT FULLY QUANTIFIED

The issues and impacts associated with DVP joining PJM are numerous and complex. While this study has quantified the major impacts, particularly those in the short-term, it has not been possible to address all of the issues through formal quantitative analysis. This section discusses the qualitative aspects of several issues that have not been modeled explicitly, but nonetheless may bear on the costs and benefits of DVP's PJM participation.

It should be noted that the results of this study are subject to a margin of error due to various assumptions that must always be made in any modeling study. Possible sources of error include incomplete monitoring of transmission constraints, incomplete data on generation characteristics, fuel price forecast margin of error, uncertainty as to actual FTR allocations and payments in the future and errors in forecasting RTO costs. The net effect of these sources of error cannot be quantified. In modeling these complex matters, however, we have attempted to make conservative assumptions, that is, towards understating the potential net benefits of PJM membership to consumers.

V.A. Measurement of Benefits

In this study, the overall social benefit of DVP joining PJM is measured as the reduction generation production costs and savings in the building of future generation capacity. These social benefits are allocated to DVP's customers and shareholders based on various factors, such as the Virginia rate cap until mid-2007, forecasted changes in market prices in the DVP control zone as a result of the expansion of PJM, changing trade patterns, and so on.

V.B. Installed Capacity Market

In this study, we have used the concept of an Installed Capacity ("ICAP") market, more or less as it has been developed in the original PJM area in both the Base and Change Cases. Regardless of the precise administrative design, we believe that the developer of any new generation built in the future to meet a long-term resource adequacy requirement would have to be paid for the capacity costs of the facilities. This may not take the form of a conventional ICAP payment, but we believe that the economic effect would be effectively the same if new capacity were to be attracted into the market to meet reserve requirements. Therefore, we have not considered alternative versions of the ICAP concept, such as the forward market proposal currently under consideration by the Resource Adequacy Market working group of the ISOs of PJM, New York and New England.

Issues Not Fully Quantified

Accordingly, in this study we use the term ICAP market and ICAP price as a proxy for the payments needed by new generation (when such generation is required to meet installed capacity requirements) to recover the capital costs of entry not otherwise recovered through the energy market. As such, other mechanisms could be considered as equivalent to the function of the ICAP market in this study, which is to create a mechanism whereby native load pays for certain investments if they are needed by native load in the first instance.

V.C. Ongoing Protection of Native Load

Membership in PJM will continue native load protections that will mitigate certain potential adverse impacts that can occur as a result of a transition to market-oriented supply arrangements. Most importantly, Firm Transmission Rights ("FTRs") will be available under PJM to offset the congestion costs that occur on an LMP system. PJM has conducted a simultaneous feasibility test of DVP FTRs and has determined that adequate transmission capacity exists to support a full allocation of FTRs to load in DVP's control zone throughout the study period. This FTR allocation is a key factor in ensuring that delivered prices in DVP's service territory remain hedged against the congestion that can occur between generation buses and load buses.

Another major element of the financial risk management program that has been assumed in this study is an appropriate and continuing allocation of external FTRs. PJM business rules ensure that the load-serving entities of network customers (such as DVP Zone Customers) have a right to FTRs that hedge congestion costs to those customers. As discussed in more detail below in Section VI.A.1, PJM has determined that DVP can obtain sufficient FTRs throughout the study period to hedge congestion risk fully. PJM plans to change these business rules in the near future, but PJM's study of FTR allocation under these new business rules leaves DVP's FTR allocation unaffected. While additional changes at some future date may materially alter how FTRs are allocated, we have no way to assess this risk. We believe, however, that the PJM review process will continue to provide substantial protection for native load even if the PJM business practices are revised.

For the purposes of this study, we assume that DVP will receive a load-ratio share of the surplus value of the FTRs that are not allocated under current PJM practice. A representative from PJM has estimated that the surplus value in PJM's FTR auctions is likely to be about $50 million per year after PJM is expanded to include all four New PJM companies. DVP's load-ratio share of this amount would be about $6.1 million per year.

Apart from these FTR considerations, it is important to recognize that PJM has agreed that load will not be shed within PJM South in order to address capacity deficiencies in other pats of PJM. This means that Virginia customers will not be placed at risk for capacity shortages occurring elsewhere in PJM.

V.D. Reliability

Membership in PJM offers the opportunity for DVP to ensure improved reliability. DVP will maintain its own transmission control center to address local reliability problems that will not be monitored by PJM. Moreover, by joining PJM, customers in the current DVP control zone will have the benefit of an enlarged scope of geographic control of generation that can be used to address transmission system emergencies. The larger scope for generation redispatch in emergency conditions will expand the resources available to PJM operators beyond those currently available to the DVP control zone operator.

V.E. Integrated Transmission Planning

PJM offers the opportunity for DVP to participate in a larger regional planning process that will blend DVP's local expertise with the regional views provided by PJM of other transmission owners and stakeholders. Much of this interaction occurs today on an informal basis. Joining PJM will help to formalize this process and improve the regional transmission planning process by focusing new investment to projects that realize the greatest net benefit. This coordination is particular important for Virginia since the transmission upgrades most needed to reduce prices in the Commonwealth are located in neighboring states.

V.F. Support for Wholesale and Retail Competition

PJM's market structure and settlement system will be a valuable resource in supporting retail competition in the future. While this benefit cannot be easily quantified, it is one of the most important benefits to joining a well-developed RTO, such as PJM. The centrally facilitated markets in PJM provide the efficient day-ahead and balancing markets that are needed to ensure that all retail suppliers can compete on an equal basis within Virginia.

Furthermore, DVP's membership in an independent RTO such as PJM is important to the development of competition among generators within its control zone. PJM's stable market platform provides transparent prices, liquid spot markets, independent governance, and open access to transmission. Without these assurances, private investors will be reluctant to build new generation needed to meet the future energy needs of the Commonwealth.

Issues Not Fully Quantified

V.G. Enhanced Generation Technology And Availability Improvements

Improvements to generation technology may be facilitated generally by the development of a competitive wholesale electricity market. Adding Virginia into PJM would enhance wholesale competition both by providing merchant generators with greater integration into a large and liquid wholesale market, and by providing clear locational prices that signal the need for new resources in particular places. Expanded wholesale competition can be expected to propel improvements in technology and unit efficiencies over time. The steady march of technological improvements is a significant source of consumer benefits over time. PJM and the other northeast markets, where vigorous competition in a locational pricing system have been adopted, have seen marked improvement in unit availability and increased investment in existing units to increase their competitiveness.[27] While the importance of this advancement could hardly be overstated, it has not been addressed in this study because of the difficulty in quantifying the long-term benefits of these investments.

V.H. Demand Response Benefits

A critical component in the development of competitive electricity markets is allowing the demand side of the market to participate fully in spot markets. This issue has not been quantified in this study because, in part, of the difficulty of quantifying such benefits in a pure production-cost model.[28] An important element of a successful demand response program is the ability to provide customers with price information that is directly linked to the incremental cost of providing their power. Further, this information needs to be available both in real-time, to allow for automated price response (such as commercial reductions in air-conditioning load), and day-ahead, to allow industrial users to revise production schedules in response to energy prices, for example. Our Base Case, however, does not include the costs that would be needed to create an independent market system necessary to create and post these real-time and day-ahead prices for a stand-alone DVP region; rather, DVP Zone Load Customers would continue to be served on an averaged-cost basis that suppresses price signals to customers and, consequently, provides a poor basis for developing effective demand-side management. Our estimates of the benefits of joining PJM are, therefore, conservative in excluding either the benefits from such demand-side management programs or the costs of developing day-ahead and real-time incremental prices in the DVP control zone. Demand management programs may provide material benefits in enhancing grid reliability and reducing price spikes that may lead to high retail prices.

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27 See *2002 State of the Market, PJM,* (March 2003), pp.82-84.

28 Production-cost models such as MAPS do not capture well the hourly volatility created by unexpected surges in demand, unit outages, or loss of critical transmission facilities. It is these spikes, however, that are best addressed by demand-side measures.

Issues Not Fully Quantified

V.I. Improved Generation Siting and Transmission Investment

Over the longer term, the price signals provided by LMP can be expected to promote more efficient siting decisions on the part of developers both of generation and transmission. This effect is not explicitly studied here, but we expect that it will be an important source of benefits over the long term. Under the LMP signals provided in the PJM market structure, generators will have a direct and observable incentive to locate where the generator price is high. In today's market, this price signal is averaged over a wide area, and any locational differences in such average prices are highly muted, at best. In contrast, LMP has the effect of disaggregating the price signals given to each individual generator so that market participants can evaluate the advantages and disadvantages of various locations. Likewise, on the transmission side, the explicit pricing of transmission congestion allows utilities or private transmission investors to measure directly the costs created by particular transmission bottlenecks, which can then be compared to the investment costs for relieving those constraints. Such locational prices are a key to improved siting decisions on the part of future transmission and generation developers that can be expected to benefit Virginia customers, as well as others in the expanded PJM.

V.J. Benefits From Integration With an Established Market

It is appropriate to note that this study contrasts the net economic benefits of a Change Case that is fully consistent with federal regulatory directions, versus a Base Case that is not. Although FERC has not yet issued any final order regarding implementation of wholesale market standards, nor has it yet been tested whether FERC has the authority to mandate such standards on jurisdictional utilities, there is clear federal intent that all utilities join an established RTO or join together with neighboring utilities to create one. Moreover, Virginia law requires that DVP join or establish an RTO.[29] DVP is interconnected with only one approved RTO: PJM. While DVP could conceivably work with other utilities to its south to build a new RTO, there are material costs to designing, implementing and securing regulatory approvals for a new RTO. We have, conservatively, not included such costs in our Base Case.

V.K. Improved Deployment of DVP Capital

Integration of DVP into the PJM markets may allow DVP to shift its capital budgeting to more efficiently allocate its resources. As noted in Section IV.B, integration into PJM allows for a material decline (approximately $1 billion) in the amount of capital investment required in new generation while maintaining the same or better levels of system reliability. An additional $1 billion of investment in new generation facilities will be needed even if DVP joins PJM, but outside investment in Virginia generation will be much more likely when that generation has full

29 § 56-579(A) of the Code of Virginia.

Issues Not Fully Quantified

access to the liquid and transparent PJM wholesale markets. Joining PJM will encourage greater retail and wholesale competition through, among other things, improved coordination of transmission use and clear price signals to both generators and consumers. This may reduce needed capital investment from DVP, allowing capital to be directed to other purposes. Likewise, DVP has more choices to deploy capital to enhance shareholder value in liquid and transparent wholesale markets such as PJM.

VI. RESULTS OF THE BENEFIT-COST STUDY

Only a portion of the large amount of numerical results from this study can be discussed in the context of this report. To economize on space, most of the results shown are incremental changes from the Base Case (pre-RTO) to the Change Case (post-RTO). Summary results from each of the sensitivity cases are presented later in this section. Dollar amounts presented in the tables and text below are in nominal dollars for each year, while summary, 6-year and 10-year results are the net present value to July 1, 2003. A 10 percent discount rate is used to calculate the net present values.

VI.A. SUMMARY OF BENEFITS AND COSTS

Table VI-1 shows the benefits and costs of DVP joining PJM. These are reported for Virginia Retail Customers and all DVP Zone Customers annually for 2005 through 2014, and for the present value of those years to July 1, 2003.[30] Benefits are reported in three basic categories: 1) energy cost impacts, including the impact on the fuel factor; 2) capacity cost impacts, including the impact of purchasing required reserves; and 3) ancillary service cost impacts, and other miscellaneous charges. The cost of joining PJM is reflected in the PJM administrative charges in the Change Case. It is assumed that no costs are incurred in the Base Case, even though it is possible that DVP might be pressured to form an RTO even if it does not join PJM. In any case, the net benefits are total benefits less the PJM administrative costs.

Virginia Retail Customers account for nearly 80 percent of DVP's annual load. Accordingly, its benefits and costs are also approximately 80 percent of the total benefits and costs of DVP Zone Customers.

VI.A.1. Energy Cost Impacts

Most of the benefit to DVP's Virginia Retail Customers, $211 million in the first 6 years of the study and $332 million for the 10-year period, is due to lower energy payments that result from DVP joining PJM. These benefits result from the reduction in energy market prices in the Change Case when DVP joins PJM.

[30] Results for merchant generators are not included in the results of the DVP control area or elsewhere in this analysis. Such an analysis was outside the scope of this report.

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Table VI-1: Annual Benefits of DVP Joining PJM for DVP Zone Customers

Change Case minus Base Case
(in millions of $, positive numbers denote benefits)

	PV to July 1, 2003 ('05-'10)	PV to July 1, 2003 ('05-'14)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Virginia Retail Customers												
Fuel Factor Savings	13.1	13.1	4.6	7.7	5.1	-	-	-	-	-	-	-
Market Energy Savings:												
Price Basis Change	(76.6)	(196.5)	-	-	(9.6)	(30.2)	(41.9)	(53.7)	(62.1)	(70.5)	(78.9)	(87.4)
FTR Value	274.2	515.9	-	-	65.1	130.2	135.6	141.0	144.2	147.4	150.5	153.7
Market Energy Savings	197.6	319.4	-	-	55.4	100.0	93.7	87.4	82.1	76.8	71.6	66.3
Total Energy Savings	210.7	332.4	4.6	7.7	60.5	100.0	93.7	87.4	82.1	76.8	71.6	66.3
Capacity Savings	16.2	314.1	-	-	-	-	-	31.5	166.7	251.2	200.1	104.0
Ancillary Savings	-	-	-	-	-	-	-	-	-	-	-	-
Benefit	226.9	646.5	4.6	7.7	60.5	100.0	93.7	118.9	248.8	328.0	271.7	170.3
PJM Admin Charge	(116.6)	(169.9)	(28.5)	(28.6)	(28.6)	(30.1)	(30.7)	(31.2)	(31.9)	(32.5)	(33.2)	(33.8)
Deferral/Recovery	(0.0)	(0.0)	28.5	28.6	(2.9)	(33.3)	(33.3)	0.0	0.0	0.0	0.0	0.0
Net PJM Admin Charge	(116.6)	(169.9)	-	-	(31.6)	(63.4)	(64.0)	(31.2)	(31.9)	(32.5)	(33.2)	(33.8)
Net Benefit	110.3	476.6	4.6	7.7	29.0	36.6	29.7	87.6	216.9	295.5	238.5	136.5
	PV to July 1, 2003 ('05-'10)	PV to July 1, 2003 ('05-'14)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
DVP Zone Customers												
Price Basis Change*	(66.8)	(207.7)	8.1	12.1	(2.3)	(33.9)	(48.7)	(63.4)	(73.2)	(82.9)	(92.6)	(102.4)
FTR Value	337.8	630.0	2.5	2.8	80.5	158.0	164.5	171.0	174.6	178.3	181.9	185.6
Total Energy Savings	271.0	422.4	10.6	14.9	78.2	124.0	115.8	107.6	101.5	95.4	89.3	83.2
Capacity Savings	18.9	372.6	-	-	-	-	-	36.9	196.6	297.9	241.1	121.7
Ancillary Savings	0.7	1.0	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Benefit	290.6	796.0	10.7	15.1	78.4	124.2	116.0	144.7	298.2	393.5	330.6	205.2
PJM Admin Charge	(163.2)	(238.7)	(39.6)	(40.0)	(40.2)	(42.1)	(43.0)	(43.9)	(45.0)	(46.0)	(47.1)	(48.1)
Deferral/Recovery	0.0	0.0	35.6	35.7	(3.7)	(41.6)	(41.6)	-	-	-	-	-
Net PJM Admin Charge	(163.2)	(238.7)	(4.0)	(4.2)	(43.9)	(83.8)	(84.7)	(43.9)	(45.0)	(46.0)	(47.1)	(48.1)
Net Benefit	127.4	557.2	6.7	10.9	34.5	40.5	31.3	100.7	253.3	347.4	283.6	157.1

* Including fuel factor adjustments

The energy cost impacts are sub-divided into two categories: 1) fuel factor impacts, and 2) market energy impacts. The market energy impact is reported in the table in two parts: a Price Basis Change component and an FTR Value component. The Price Basis Change component reflects a difference in how the delivered price of energy is expected to be formulated in the Base versus the Change Case. In the Base Case, the delivered price of energy is expected to reflect the prevailing competitive price of the energy component of generation within the DVP control zone. In the Change Case, however, the delivered price of energy necessarily will be based on the DVP Load Zone LMP as determined by PJM. Under the PJM LMP system, load prices generally can be expected to exceed the average generation bus prices throughout the DVP control zone due to transmission congestion. Accordingly, the difference in delivered price between the two cases in part will reflect a switch from a generator-based price to a load-based price. This impact tends to

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increase the delivered price to customers. However, FTR value allocated to native load offsets this switch in the basis for delivered prices, yielding an overall market energy savings in the Change Case.

Prior to July 1, 2007, when the rate cap ends for DVP's Virginia Retail Customers, these two components of the market energy savings are zero, since these customers are not exposed to LMP for in-system generation and receive the benefit of FTRs for off-system purchases. The table divides this benefit into two parts. The first part is the fuel factor savings, which is not a factor after mid-2007.

The second part of the post-2007 benefit is the market energy savings, which in turn has the two parts mentioned above. After mid-2007, the table reports an increase in the cost of energy associated with the Price Basis Change. As shown in Table VI-2, energy prices in the DVP control zone generally are lower as a result of DVP joining PJM. The generator prices are reduced by $0.61 to $1.35 per MWh, as shown in the table. Despite this general reduction in generator prices, the shift in the basis for delivered prices in the two cases results in an increase before the FTR impact is assessed of between $0.14 and $0.96 per MWh. FTRs provide an offsetting gain of between $1.71 and $1.84 per MWh, resulting in a net reduction of energy costs of between $0.88 and $1.57 per MWh. For example, in 2010 in the Base Case, purchases are made at the DVP spot wholesale energy price of $42.97 per MWh (see Table VI-2). In the Change Case, these same purchases are made at the DVP Load Zone LMP price of $43.57 per MWh, but DVP customers receive the value of FTRs, which serve as a credit of $1.83 per MWh. The combined impact is a $1.23 per MWh decline in the average price of energy.

Table VI-2: Generation and Load Prices in DVP

Base Case	2nd Half of 2007	2010	2014
Avg DVP Gen Price ($/MWh)	$38.06	$42.97	$52.23
Change Case			
Avg DVP Gen Price ($/MWh)	$36.70	$41.87	$51.62
Avg DVP Load Price ($/MWh)	$38.20	$43.57	$53.19
FTR Value ($/MWh of Load) to DVP Customers	($1.71)	($1.83)	($1.84)
Change Case minus Base Case			
Avg DVP Gen Price ($/MWh)	($1.35)	($1.10)	($0.61)
Avg DVP Load Price Basis Change ($/MWh)	$0.14	$0.60	$0.96
Avg DVP Load Price w/ FTR ($/MWh)	($1.57)	($1.23)	($0.88)

Table VI-3 shows how constraints within and outside of the DVP control zone affect LMPs at selected Virginia locations. The top line shows the price, averaged across all hours, among the

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locations of $30.88.[31] The next section of the table shows the average impact over the year that each binding constraints within Virginia had on each LMP. In general, there is very little difference in prices among Virginia locations that can be attributed to internal constraints.

The third section of Table VI-3 shows the LMP impact of constraints outside of Virginia. The APS South and Black Oak-Beddington constraints are the most frequently binding and contribute the most to locational price differences in the DVP control zone. Generation from units in the western part of the DVP territory, Mt. Storm and Bath County, increases the flow on these interfaces, exacerbating the congestion. Hence, a negative price signal is embedded in these LMPs. Generation from units at locations further to the east tends to decrease the flow across these constraints and relieve congestion; as a result, eastern LMPs include a positive price signal.

Table VI-3: Effect of Transmission Constraints on Virginia LMPs and Price Differentials (2005 Post-RTO Case)

	Hours Limited	Mount Storm	Bath County	Clover	Possum Point	North Anna	Yorktown	Surry
Average Price Across Generator Set		$30.88	$30.88	$30.88	$30.88	$30.88	$30.88	$30.88
Average Generator Bus Price		$27.48	$29.31	$30.46	$33.46	$32.49	$31.51	$31.42
Total Congestion		**($3.39)**	**($1.56)**	**($0.42)**	**$2.58**	**$1.62**	**$0.63**	**$0.55**
Congestion from Constraints in Virginia Power Area								
Lexington-Cloverdale for Outage of Pruntytown-Mt. Storm	820	0.04	0.17	(0.09)	(0.03)	(0.02)	(0.03)	(0.04)
FG 1710 Chesterfield-Tyler 230	64	(0.00)	(0.00)	0.01	(0.00)	(0.00)	(0.00)	0.00
Lexington-Cloverdale for Outage of Mt. Storm-Valley	202	(0.01)	0.04	(0.01)	(0.01)	(0.00)	(0.00)	(0.00)
FG 1718 Chuckatuk-Suffolk 230 kV	36	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)
Total Impact of VAP Constraints		***0.03***	***0.21***	***(0.09)***	***(0.04)***	***(0.02)***	***(0.04)***	***(0.04)***
Congestion from Constraints Outside Virginia								
APS South Interface	1,284	(1.58)	(0.47)	0.16	0.67	0.59	0.32	0.31
Black Oak Beddington Voltage Interface	6,652	(1.60)	(1.29)	(0.64)	1.98	1.06	0.29	0.20
Kanawa-Matt Funk for Outage of Broadford-J Ferry	560	(0.04)	0.06	0.02	(0.03)	(0.01)	0.00	0.00
FG 5 PJM Western Interface	484	(0.02)	(0.01)	(0.00)	0.02	0.01	0.00	0.00
Kanawa-Matt Funk for Outage of Baker-Broadford	164	(0.01)	0.02	0.01	(0.01)	(0.00)	0.00	0.00
Other Contraints		(0.15)	(0.08)	0.12	(0.01)	0.00	0.06	0.06
Total Impact of Outside Constraints		***(3.42)***	***(1.77)***	***(0.32)***	***2.62***	***1.64***	***0.68***	***0.58***

The sum of the congestion impacts of all internal Virginia and other external constraints gives the total deviation for each location from the average LMP. The DVP zonal LMP, which is equal to the weighted average across all load buses, will differ from generator prices depending on the location of demand. The DVP zonal price and the price difference relative to each of the

[31] The price shown is the average price among these generators, which is somewhat below the DVP Load Zone LMP of $33.01. Use here of the generator prices allows for more direct comparison of the effects of individual constraints on locational prices at each generator. To see how congestion affects load prices, and what offsetting FTRs are available, refer to Table VI-4.

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generators are shown at the top of Table VI-3. Because the load is distributed more heavily in higher-priced eastern locations, the load LMP is higher than many Virginia generator LMPs.

Our modeling indicates that binding constraints outside of the DVP control zone result in LMP differentials within the DVP control zone. As shown in Table VI-4, the average annual difference between hourly DVP Load Zone LMPs and DVP Generation LMPs is $1.38 per MWh in 2005, and ranges from $1.38 to $1.71 per MWh during the 2005 through 2014 period.[32] These LMP differentials result in congestion costs for the DVP load of $117 million in 2005, and a present value over the 2005 through 2010 period of $525 million ($783 million for the entire 10-year period).

Table VI-4: Congestion Cost and Offsetting FTR Value

	PV to July 1, 2003 ('05-'10)	PV to July 1, 2003 ('05-'14)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Load Price ($/MWh)			$34.39	$34.70	$35.01	$37.86	$40.72	$43.57	$45.98	$48.38	$50.78	$53.19
Gen Price ($/MWh)			$33.01	$33.29	$33.58	$36.34	$39.10	$41.87	$44.31	$46.75	$49.19	$51.62
Difference ($/MWh)			$1.38	$1.40	$1.43	$1.52	$1.61	$1.71	$1.67	$1.63	$1.60	$1.56
DVP Load (GWh)			84,969	86,727	88,484	90,106	91,729	93,351	95,251	97,151	99,051	100,952
Congestion Cost Paid by DVP (M$)	524.8	782.7	117.1	121.7	126.3	137.0	148.0	159.3	159.1	158.8	158.3	157.7
Congest Cost Paid by Others (M$)	70.3	104.9	12.4	18.9	25.2	21.1	16.7	11.9	15.7	19.7	23.8	28.0
DVP FTR Value (no PJM Allocation)	595.1	887.6	129.5	140.5	151.5	158.1	164.6	171.2	174.8	178.5	182.1	185.7
DVP Share of PJM System Excess	27.7	40.7	6.6	6.8	7.0	7.1	7.3	7.5	7.7	7.9	8.1	8.3
DVP FTR Value	622.8	928.3	136.2	147.3	158.5	165.2	172.0	178.7	182.5	186.3	190.2	194.0

To offset these congestion charges, PJM will allocate to DVP a set of FTRs that point from the DVP generating units to the DVP load zone. This treatment reflects the fact that network customers have paid over the years for the existing transmission system. PJM annually allocates FTRs to all PJM network load from their network resources, up to the total peak of the network load. Under current business rules of PJM, FTRs can be requested only from designated network capacity resources to the point of native load offtake on the grid. Prior to allocating these rights each year, PJM performs a power flow analysis to ensure that all FTR requests from network load, plus firm transmission rights, are simultaneously feasible; through this test, PJM ensures that it is not allocating more FTRs on the transmission system than the system can, in fact, accommodate. DVP requested that PJM conduct such an analysis of what FTRs DVP could be allocated to hedge congestion costs within its system. In particular, to maximize the potential value of DVP's FTR award from PJM, DVP requested a full allocation of FTRs from units in the west of DVP's control zone, with the remaining FTRs allocated pro rata among DVP's eastern generation. Based on the analysis, PJM concluded that this set of FTRs was simultaneously feasible with all other FTRs on the system, including those expected to be awarded to other New PJM Entrants, and that it was reasonable to carry this allocation forward for the entire study period.

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32 These hourly LMP differences are weighted by hourly DVP load to determine the annual average. The hourly generation LMP is a weighted average of the LMPs of all generation operating in that hour in the DVP control area.

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PJM is currently implementing a change in its business rules that would allow network customers more flexibility in requesting FTRs. As a sensitivity test, DVP requested that PJM develop an alternative FTR allocation, under which all PJM network customers were allowed to select any source during the annual allocation process. PJM's analysis assumed that all of these network customers would select FTR sources that had the highest historical price differences with respect to their respective load zones, thus creating the possibility that these requests could interfere with Dominion's desired FTR allocation. PJM concluded, however, that even in this adverse case DVP could still obtain those FTRs needed to provide a full hedge against potential congestion costs under the LMP system for deliveries from DVP's main generating stations, for the entire study period.

We calculate that the value of those DVP FTRs will be $130 million in 2005, with a present value over the 2005 through 2010 period of $595 million ($888 million for the 10-year period). Thus, the value of the FTRs exceeds the congestion in the DVP control zone by $12 million in 2005 and $70 million in present value over the 2005 through 2010 period ($105 million for the 10-year period). Of these allocated FTRs, nearly all the value is concentrated on the FTRs associated with the Mt. Storm and Bath County units and, to a lesser extent, the Clover facility. This result follows directly from the pattern of LMPs within the DVP control zone shown above in Table VI-3. DVP is able to retain this value because it serves network load with full rights to FTRs on the relevant portions of the PJM system. Non-network load on the transmission system created, for example, by spot sales transactions do not have similar FTR rights to offset the congestion caused by their transactions and the revenue from such non-network load's use of the transmission system is part of the revenue pool that is distributed to FTR holders.

In addition to the directly assigned FTRs, DVP will obtain from PJM a share of the FTR revenue received by PJM from auctioned "unallocated" FTRs. These unallocated FTRs exist and are sold when: (1) the FTR is not claimed by network customer, (2) the FTR is simultaneously feasible with other FTRs that are claimed, and (3) the FTR has positive value. Based on the historical level of these revenues to current PJM Member Companies, adjusted for the increased size of PJM in the Change Case, we calculate that DVP load will receive $6.6 million in FTR auction revenues in 2005, with a present value over the 2005 through 2010 period of $27.7 million ($40.7 million over the 10-year period).

In sum, we calculate that the DVP load will incur congestion costs of $525 million over the 2005 through 2010 period ($783 million for the entire 10-year period), but will be allocated FTRs worth $595 million ($888 million for the 10-year period) to compensate for this congestion, and in addition, will be allocated FTR auction revenue of $28 million ($41 million over the 10-year period). The resulting gain for DVP load is $98 million over the 2005 through 2010 period ($146 million for the 10-year period).

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For DVP's Virginia Retail Customers, the value of the offsetting FTRs is $274 million in present value over the first 6 years of the study period ($516 million for the 10-year period)—more than compensating for any congestion costs incurred in these purchases.

Apart from price effects occurring within the DVP control zone, these results for both customers and shareholders are driven by improved opportunities to import power into the DVP control zone. As shown in Table VI-5 below, in the Base Case in 2007, DVP is a net importer of an average of 1,338 MWh in each hour. In the Change Case, DVP is a net importer of an average of 1,857 MWh in each hour. Note that DVP is interconnected with AEP, PJM (East and West) and CP&L. By joining PJM, the trade barriers between DVP and the PJM area, and also between DVP and AEP (which this study assumes joins PJM by the beginning of 2005, roughly the same timing as DVP), are lowered with the result that more low-cost energy from those regions can be imported economically into DVP. This increased level of trade between and among PJM (East and West), AEP and DVP results in lower prices in the DVP area, and it also creates trade opportunities between DVP and CP&L. The latter impacts are shared between the importing and exporting regions as described in Appendix B.

Table VI-5: Average Hourly Net Imports Into DVP

	2005	2007	2010	2014
Base Case				
From AEP	1,233	1,200	1,096	921
From Classic PJM	55	93	111	253
From CP&L	63	45	22	(25)
TOTAL	1,350	1,338	1,229	1,149
Change Case				
From AEP	1,727	1,647	1,490	1,245
From Classic PJM	133	214	345	544
From CP&L	(2)	(4)	(20)	(45)
TOTAL	1,858	1,857	1,815	1,744

VI.A.2. Capacity Cost Impacts

Apart from these energy market impacts, native load customers also benefit from a reduction in the price of generation capacity under PJM as seen in Table VI-6. As reported in the table, ICAP prices in the Base and Change Cases are identical until 2010, when there is a need for additional capacity in the DVP control zone. When this additional capacity is needed in 2010, ICAP prices are lower under PJM than in the Base Case because the expanded PJM area experiences certain load-diversity benefits and improved reserve sharing.

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This ICAP price differences beginning in 2010 result in a savings of $16.2 million for Virginia Retail Customers over the first 6 years of the study ($314.1 million for the 10-year period), as shown in Table VI-1.

Table VI-6: ICAP Prices
($/kW-year)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Base Case	$21.54	$22.08	$22.63	$23.19	$23.77	$26.38	$37.30	$51.62	$61.57	$66.12
Change Case	$21.54	$22.08	$22.63	$23.19	$23.77	$24.50	$27.53	$37.17	$50.25	$60.34

VI.A.3. Ancillary Services Impacts and Other Impacts

The total cost of ancillary services has been assumed to not change as DVP joins PJM because the required quantity of ancillary services that must be procured within the control zone is unchanged between in the Base and Change Cases, and the costs remain the same.[33] However, the allocation of the revenues for providing ancillary services under schedules 2 through 6 does change.

There is a small benefit associated with ancillary services for DVP Zone customers. While it is assumed that ancillary services rates will be the same in the Base and Change Cases, the revenues associated with ancillary services under schedules 2 through 6 are allocated to generation owners based on their relative share of total generation within the DVP control zone. The small increase in ancillary payments received by generators in the DVP control zone reflects an increase in their respective share of generation within the control zone.

This allocation results in DVP shareholders receiving more ancillary service revenue (from schedules 2 through 6). This occurs because DVP-owned generators provide a larger share of generation within the DVP control zone under PJM, which yields, in turn, more ancillary service revenue.[34]

One ancillary service, Operating Reserves, is computed across the whole of PJM. Operating Reserves charges pay for units needed to assure system reliability but that would not receive enough payments in the markets for energy and ancillary services to cover its bid operating costs. Most of these costs are created by the need to adapt system operations to unexpected conditions. The model used in this study, however, does not include unforeseen conditions; therefore, it cannot meaningfully estimate the impact on Operating Reserves. As a general matter, though, unexpected changes

33 *See* Testimony of Gregory J. Morgan.

34 While DVP's total generation in the Change Case is less than it is in the Base Case, its share of total generation is higher in the Change Case. This higher share of generation comes at the expense of merchant generators.

in load, tripped unit, or transmission outages will have smaller effects in a larger pool, in which the system operators have more options to address the change in system conditions. We would expect, therefore, that Operating Reserves costs for Virginia, which are currently carried in the fuel factor, would likely stay the same or fall under integrated dispatch with PJM.[35]

Through-and-out transmission revenues are assumed to be identical in the Base and Change Case, and as a result, no impact is shown for these revenues. This assumption is due to the uncertainty about FERC's future transmission rate policy.[36]

VI.A.4. PJM Administrative Charge

The cost of being a member of PJM is reflected in the PJM administrative charge. These costs are charged to load in all years of the Change Case, when DVP is presumed to join PJM. The $116.6 million cost in the first six years of the study ($169.9 million for the 10-year period) is netted against benefits for Virginia Requirements Customers to determine their net benefits. As discussed earlier, the administrative charges for DVP Requirements Customers are deferred for the first 30 months, with this deferral collected over the following 30 months.

VI.B. Results for DVP Zone Customers

As seen in Table VI-7, DVP Zone customers have a total benefit of $290.6 million and a net benefit of $127.4 million over the first 6 years of the study ($796.0 million total benefit and $557.2 million net benefit over ten years), after subtracting the PJM administrative charges of $163.2 million ($238.7 million over ten years).

Prior to mid-2007, the majority of DVP Zone customers receive energy savings through the fuel factor. When the rate cap ends, these market energy savings continue for DVP Zone Customers. These savings are enhanced by capacity savings that begin when ICAP prices in the Base and Change Cases diverge in 2010. The PJM administrative charge is deferred in the first 2.5 years of the study for all DVP Requirements Customers; non-requirements customers incur the PJM administrative fee without deferral.

35 *See* Testimony of Gregory J. Morgan.
36 *See* Testimony of David F. Koogler.

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Table VI-7: Net Benefits of DVP Joining PJM for DVP Zone Customers

DVP Zone Customers	PV to July 1, 2003 ('05-'10)	PV to July 1, 2003 ('05-'14)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Total Energy Savings	271.0	422.4	10.6	14.9	78.2	124.0	115.8	107.6	101.5	95.4	89.3	83.2
Capacity Savings	18.9	372.6	-	-	-	-	-	36.9	196.6	297.9	241.1	121.7
Ancillary Savings	0.7	1.0	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Benefit	290.6	796.0	10.7	15.1	78.4	124.2	116.0	144.7	298.2	393.5	330.6	205.2
PJM Admin Charge	(163.2)	(238.7)	(39.6)	(40.0)	(40.2)	(42.1)	(43.0)	(43.9)	(45.0)	(46.0)	(47.1)	(48.1)
Deferral/Recovery	0.0	0.0	35.6	35.7	(3.7)	(41.6)	(41.6)	-	-	-	-	-
Net PJM Admin Charge	(163.2)	(238.7)	(4.0)	(4.2)	(43.9)	(83.8)	(84.7)	(43.9)	(45.0)	(46.0)	(47.1)	(48.1)
Net Benefit	127.4	557.2	6.7	10.9	34.5	40.5	31.3	100.7	253.3	347.4	283.6	157.1

VI.C. SHAREHOLDER RESULTS

Table VI-8 shows the results for DVP's shareholders. Throughout the study period, there are lowered prices in the DVP control zone following integration into PJM, and reduced sales from DVP generating units. These lowered energy prices, combined with lower total generation from DVP units, lead to a reduction of about $80 million in annual net energy market revenues to DVP generation. Prior to the removal of the rate cap in mid-2007, shareholders also have the obligation to serve Virginia Retail Customers at capped rates. Consequently, in the Change Case, shareholders are exposed to congestion charges included in DVP Load Zone LMPs with respect to all load served from DVP generators. As described earlier, customers are not exposed to DVP Load Zone LMP with respect to service from DVP generators during the fuel factor years. As a result, shareholders retain DVP's FTRs (except those allocated to the fuel factor to insulate off-system purchases from congestion costs) as a hedge against congestion costs embedded in the DVP Load Zone LMP. These FTRs have a projected value in excess of congestion costs associated with bringing generation from DVP units to meet Virginia Retail Customers' demand, yielding a positive net energy impact on shareholders prior to the end of the rate cap.

In addition to these energy market impacts, DVP's shareholders also experience a lower level of revenue from the capacity market in the final years of the study period, 2010 to 2014. While the reduction in ICAP prices shown above in Table VI-6 provides a benefit to DVP's customers, it reduces ICAP revenues that can be expected by DVP's shareholders. Altogether, these various impacts results in a loss of $136 million over the first 6 years of the study period ($554 million for the 10-year period) for DVP's shareholders, as reported in Table VI-8. Other owners of capacity, such as merchant generators, similarly would receive lower ICAP revenues as a result of this effect; however, these impacts have not been studied for this Report.

There is a small benefit associated with ancillary services for DVP shareholders. While it is assumed that ancillary services rates will be the same in the Base and Change Cases, the revenues associated with ancillary services under schedules 2 through 6 are allocated to generation owners based on their relative share of total generation within the DVP control zone. The small increase in

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ancillary payments received by DVP-owned generators reflects an increase in their respective share of generation within the control zone.[37]

Table VI-8: Net Benefits of DVP Joining PJM for DVP Shareholders

	Change Case minus Base Case *(in millions of $, positive numbers denote benefits)*											
	PV to July 1, 2003											
DVP Shareholders	('05-'10)	('05-'14)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Net Energy Revenue	(122.3)	(250.5)	26.4	27.6	(32.0)	(85.9)	(84.1)	(82.3)	(80.8)	(79.4)	(77.9)	(76.5)
Net Capacity Revenue	(16.4)	(306.7)	-	-	-	-	-	(31.9)	(165.6)	(245.7)	(193.5)	(97.7)
Net Ancillary Revenue	2.7	3.6	0.5	0.6	0.6	0.7	0.9	1.0	0.8	0.6	0.4	0.2
Net Benefit	(136.0)	(553.6)	26.8	28.2	(31.4)	(85.1)	(83.2)	(113.2)	(245.6)	(324.5)	(271.0)	(174.0)

The reduced energy revenues are attributable to two primary factors: 1) higher-cost DVP-generation being displaced by lower-cost generation in PJM in the Change Case; and 2) lower prices in the Change Case as a result of the displacement of higher-cost generation. As can be seen in Table VI-9 below, generation from DVP-owned units (and those units under NUG contracts to DVP) declines from the Base Case to the Change Case by approximately 3,000 GWh per year. The capacity in the Base and Change Cases are identical so this creates a lower capacity factor for DVP-owned generators.[38] Additionally, the higher-cost DVP generation being displaced by lower cost generation from within PJM leads to lower prices paid to DVP generators. The generation and load prices in the Base and Change Cases are displayed in Table VI-2 above.

Table VI-9: Generation Statistics for DVP-Owned Generation

DVP-Owned Generation	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Base Case										
Generation (GWh)	72,761	74,261	75,761	76,999	78,238	79,476	80,896	82,316	83,736	85,156
Capacity (MW)	18,188	18,134	18,081	18,030	17,978	17,927	17,924	17,921	17,918	17,915
Capacity Factor	45.7%	46.7%	47.8%	48.8%	49.7%	50.6%	51.5%	52.4%	53.3%	54.3%
Change Case										
Generation (GWh)	69,233	70,763	72,293	73,555	74,818	76,080	77,299	78,517	79,736	80,954
Capacity (MW)	18,188	18,134	18,081	18,030	17,978	17,927	17,924	17,921	17,918	17,915
Capacity Factor	43.5%	44.5%	45.6%	46.6%	47.5%	48.4%	49.2%	50.0%	50.8%	51.6%
Change Case less Base Case										
Generation (GWh)	(3,527)	(3,498)	(3,468)	(3,444)	(3,420)	(3,396)	(3,597)	(3,799)	(4,000)	(4,202)
Capacity (MW)	-	-	-	-	-	-	-	-	-	-
Capacity Factor	-2.2%	-2.2%	-2.2%	-2.2%	-2.2%	-2.2%	-2.3%	-2.4%	-2.5%	-2.7%

37 While DVP-owned generation produces less energy in the Change Case than in the Base Case, its share of total generation is higher in the Change Case. This higher share of generation comes at the expense of merchant generators.

38 DVP-owned capacity declines only as a result of the expiration of NUG contracts. As NUG contracts expire, it is assumed that those units effectively operate as merchant generators. Actual generation owned by DVP (exclusive of NUG contracts) actually increases slightly.

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Moreover, by joining PJM, customers in the current DVP control zone will have the benefit of an enlarged scope of geographic control of generation that can be used to address transmission system emergencies or generation shortages. The larger scope for generation redispatch in emergency conditions will expand the resources available to PJM operators beyond those currently available to the DVP control zone operator.

Integrated Transmission Planning

PJM offers the opportunity for DVP to participate in a larger regional planning process that will blend DVP's local expertise with the regional views provided by PJM of other transmission owners and stakeholders. Much of this interaction occurs today on an informal basis. Joining PJM will help to formalize this process and improve the regional transmission planning process by focusing new investment to projects that realize the greatest net benefit. This coordination is particularly important for DVP since, as noted earlier, the transmission upgrades most needed to reduce prices in the DVP are located in neighboring states.

Support for Wholesale and Retail Competition

PJM's market structure and settlement system will be a valuable resource in supporting wholesale and retail competition in the future. While this benefit cannot be easily quantified, it is a very important benefit of joining a well-developed RTO, such as PJM. Seamless access to highly liquid trading hubs, such as PJM West, is critical to developing robust wholesale markets serving DVP customers. The centrally-facilitated markets in PJM provide the efficient day-ahead and balancing markets that are needed to continue facilitation of wholesale competition among generators and to ensure that all retail suppliers can compete on an equal basis within Virginia.

Executive Summary

Figure ES-1: Pool-to-Pool All-Hour Average Transfers in 2007 (MW) (Pre-RTO)

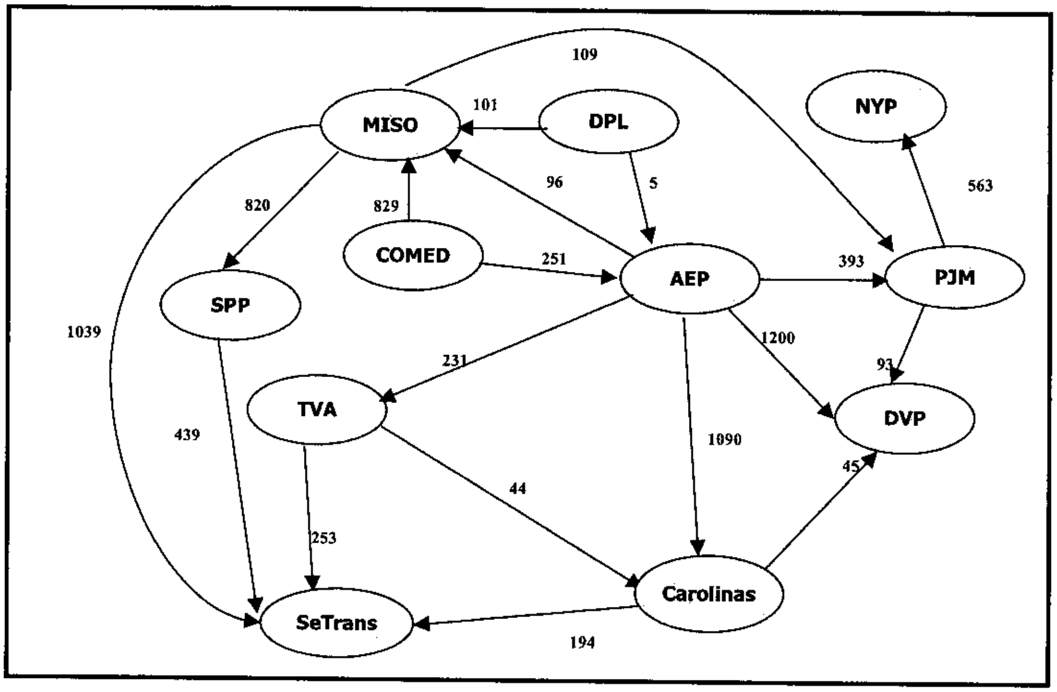
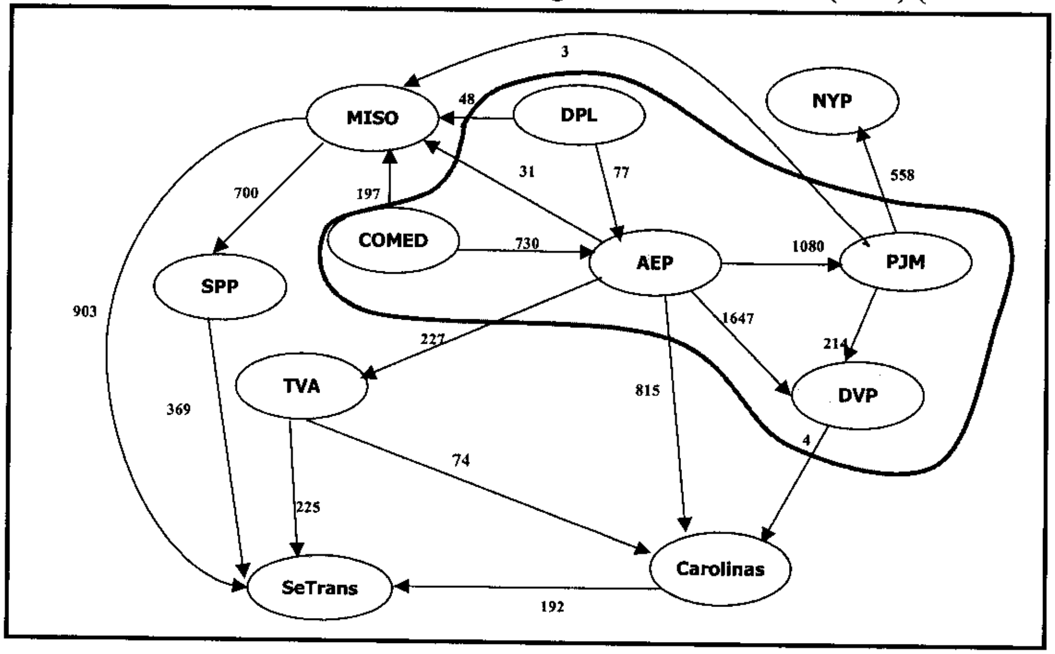


Figure ES-2: Pool-to-Pool All-Hour Average Transfers in 2007 (MW) (Post-RTO)



Introduction

I. INTRODUCTION

This is a study of the benefits and costs of Dominion Virginia Power ("DVP") joining the PJM Regional Transmission Organization ("RTO"). This study was commissioned by DVP in response to Virginia legislation requiring that such a study be completed and filed with the Virginia State Corporation Commission ("Commission") before DVP joins PJM, which would not occur before July 1, 2004 in any event. The study has been conducted by Charles River Associates, and this report describes the study, its context, methods and results.

The study assesses the likely net benefits of DVP joining PJM for three stakeholder groups: Virginia jurisdictional retail customers ("Virginia Retail Customers"), a combined group consisting of all of DVP's retail and wholesale customers and transmission customers ("DVP Zone Customers"), and DVP shareholders. These net benefits are measured over a 10-year study period presuming that DVP, along with American Electric Power ("AEP"), Commonwealth Edison and Dayton Power & Light (collectively, "New PJM Entrants"), will be integrated into the PJM market structure by January 2005.

CRA has previously conducted a cost-benefit study of RTOs in the southeast on behalf of the Southeastern Association of Regulatory Utility Commissioners ("SEARUC"). That study is available at the website of SEARUC (Go to http://www.state.va.us/scc/searuc/). The SEARUC study did not include Virginia within the geographic area under consideration, which instead focused on the GridSouth, SeTrans and GridFlorida areas. This study and the SEARUC study have been conducted using the same modeling approaches appropriately revised to reflect the economic conditions in the expanded PJM area.

I.A. OVERVIEW

Previous studies of the benefits of RTO formation have considered a wide range of potential benefits, ranging from benefits that can be achieved quickly after market integration to longer-term, dynamic benefits of a broader marketplace.[5] There is ample evidence that substantial "seams" issues exist between non-integrated wholesale electricity markets, even those that have adopted similar underlying market systems such as PJM and New York.[6] Elimination of these inter-market seams is the most certain benefit from integrating the New PJM Entrants into a common market, and the one most readily and accurately quantified. Consequently, these near-term benefits are the principal focus of this study.

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5 *See* Appendix D of this study, which summarizes the major RTO cost-benefit studies.

6 *See*, for example, *2002 State of the Market Report, NYISO*, by David B. Patton, Independent Market Advisor (April 2003), pp. 93-89.

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Other benefits of DVP joining PJM are no less real, but their value is difficult to model or measure. For example, coordinated operation of the transmission grid over a wider area will enhance system reliability, as system operators control more resources to respond to changing system conditions. System planning can take advantage of the greater load diversity of a broader resource pool to ensure the same or higher standards of system reliability with less capital investment. These reliability benefits are not fully captured in the capacity cost savings shown in this study. Integration into a broader market would make Virginia's wholesale and retail electricity markets more open and competitive which could, in turn, promote more efficient investment in transmission and demand-side management and lead to better siting of new generation.[7] Other researchers have linked development of competitive wholesale electricity markets to a material increase in generating unit availability or efficiency.[8] While these longer-term benefits may be significant, we find that there is not yet sufficient information to allow us to quantify these benefits with reasonable certainty. Consequently, we discuss these potential benefits qualitatively only, realizing that the benefits we measure in this study are likely to be conservatively low.

This study uses the GE Multi-Area Production Simulation ("MAPS" or "GE MAPS") model as the primary analytical tool in the analysis. MAPS is a production simulation model with a detailed transmission representation. Assessing transmission conditions is an important objective of the study, and the MAPS model is well known to be highly capable in such matters. The MAPS model used for this study includes substantially all of the generation and transmission in the Eastern Interconnection, with more detailed transmission monitoring of the expanded PJM region.

The study period begins in 2005 and extends through 2014. The study is based on pairs of scenarios—a Base Case and a Change Case. In the Base Case, DVP (and the other New PJM companies—AEP, DPL and Commonwealth Edison) are viewed as not being in PJM. In the Change Case, DVP (and the other New PJM companies) are viewed as being in PJM at the beginning of the study period—2005. The difference between the two cases is used to assess the impact of DVP joining PJM. In addition to this base pair of scenarios, we have studied two sensitivity cases. One of these hypothesizes higher natural gas and petroleum prices, and the other addresses a higher level of load.

Transmission rates are assumed to be de-pancaked within the expanded PJM footprint when DVP joins PJM.[9] Otherwise, transmission rates are assumed to continue as a charge to power movements between RTOs, in particular. Outside of the expanded PJM footprint, we assume RTOs

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7 *See*, for example, William W. Hogan, "Transmission Investment and Competitive Electricity Markets," Center for Business and Government, Harvard University, April 1998; and William W. Hogan, "FERC Policy On Regional Transmission Organizations: Comments In Response To The Notice Of Proposed Rulemaking," FERC Docket No. RM99-2-000, p.41-44.

8 *See* Appendix D, and *2002 State of the Market Report, PJM* (March 5, 2003), pp. 82-83.

9 *See* Testimony of David F. Koogler.

exist in both the Base and Change Cases in most areas of the country, including SeTrans, GridFlorida, MISO, SPP, and the northeast ISOs.[10] In this way, the study focuses on the incremental impact of DVP joining PJM, as opposed to the more general implementation of RTOs in other regions.

The study has prepared detailed MAPS model runs for the years 2005, 2007, 2010, and 2014, and has interpolated between the results for the remaining years in the study period. The results from the MAPS model are detailed hour-by-hour prices, generation and load at each location in the model. These results are processed by a post-processor SAS model, the output of which is summarized by a Financial Evaluation Model ("FEM").

For this study, we have disaggregated the benefits between customers and shareholders, in accordance with the Commission's guidance.[11] This is accomplished using the FEM. This contrasts with the SEARUC study in which customers and shareholders were combined into a single entity for the purpose of reporting financial impacts.

This study explicitly accounts for Firm Transmission Rights ("FTRs") that will be used to hedge transmission congestion costs under PJM. The proposed set of FTRs have been evaluated by PJM to ensure that the studied set is simultaneously feasible—a requirement under the PJM rules. These FTRs are an important component in any risk mitigation strategy undertaken by market participants in the PJM market structure.

In both the Base Case and the Change Case, the study assumes that a rate cap will continue for DVP's Virginia Retail Customers until mid-2007. At that time, retail customers in Virginia are assumed to switch from the rate cap to full market-based competition. As discussed in the next sub-section, this Report quantifies several, but not all, aspects of the current RTO policy debate. In other areas, we have not been able to quantify the impacts and instead provide a qualitative analysis intended to inform the Commission in its decision-making process.

The remainder of the Report is organized into six main sections. The next section, Section II, provides an overview of the benefits and costs associated with DVP joining PJM, as well as a discussion of certain issues that are addressed quantitatively. Section III gives an overview of market conditions that form the backdrop to the study. Section IV describes the analytical approach of the study, including the use of the MAPS model and the subsequent financial modeling. Section V contains a discussion of issues not fully quantified in the study. Section VI presents the estimates of benefits and compares these to the cost estimates of forming the RTO. The final section, Section VII, provides our conclusions. In addition, there are three technical appendices describing the GE

10 The exception to this is the Carolinas, which we modeled as three control areas (Duke, Progress Energy, and South Carolina Electric & Gas), with capacity reserve sharing within the region only.

11 *See* Virginia SCC Case No. PUE-2000-00550, Order for Notice (March 7, 2003), at 13.

Introduction

MAPS model and detailed results, the financial model, and the detailed results from the financial analysis.

I.B. Regulatory Context

In January 2003, the Virginia legislature passed House Bill No. 2453 that, among other things, requires any utility requesting to transfer ownership or control of transmission facilities to a regional transmission entity to submit a cost-benefit study to the Commission analyzing the economic impact on consumers, including the effects of transmission congestion costs. In a subsequent Order for Notice, the Commission set out certain guidance for AEP in conducting the required cost-benefit study.[12] This study on behalf of DVP has taken account of the Commission's guidance in the AEP Order.

In this context, it is important to note that the Commission, in its AEP Order, required that the cost-benefit study be submitted no later than 90 days after FERC has issued its Standard Market Design rule. Presumably, the Commission intended that the study would be informed by the content of FERC's final rule. Recent guidance from FERC reiterated a basic Wholesale Market Platform based on the use of LMP and FTRs and, more importantly, that FERC is unlikely to make any material change in RTOs, such as PJM, that have already implemented such a market system. Accordingly, this study is unlikely to be made obsolete by FERC's pending rule given that it is grounded in the PJM rules that prevail today and are likely to prevail after FERC's rule is promulgated.

I.C. Other Benefit-Cost Studies of RTOs

Including the SEARUC study, seven other benefit-cost studies of RTOs have been conducted in the past two years or so. Six of these were reviewed in Appendix A of the SEARUC study. These studies were conducted in a manner generally consistent with the approach used in this study. The primary measure of benefits in these studies to date has been the savings in generation production costs. These savings have ranged from around 0.5 percent of total production costs to as much as 2.0 percent.[13] The SEARUC study estimated production cost savings of about 0.5 and 1.0 percent of production costs. In this study, such savings amounted to about 0.4 percent of the production costs within the area of the New PJM Companies.

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12 Virginia SCC Case No. PUE-2000-00550, Order for Notice (March 7, 2003).
13 *See* Appendix D for additional details.

II. OVERVIEW OF BENEFITS AND COSTS

II.A. BENEFITS

This study, similar to other RTO cost-benefit studies, focuses on short-run benefits of DVP joining PJM. Certain short-run benefits, such as enhanced system reliability and resource adequacy, as well as longer-term benefits and risks that can be expected from the establishment of competitive wholesale markets, cannot be easily identified and quantified for purposes of this type of study. These other benefits, while real and likely to be substantial, are difficult to model.

Furthermore, most of the long-term benefits at issue, such as improved generation siting decisions, more efficient investment in transmission facilities and demand-side management, and improvements to productivity, are expected to emerge from the institution of competition. Competition in the electricity industry, in turn, has many facets, and it is not possible to attribute the benefits of competition to a particular element. However, participation in RTOs is a necessary foundation for competition in this industry

Accordingly, while it is CRA's belief that the institution of competition in the electricity industry will yield substantial social benefits in the long term, most of these benefits cannot be attributed to RTO participation, per se. Indeed, it seems likely that a significant amount of the benefits of DVP joining PJM would occur over the longer term in ways that we cannot anticipate. Likewise, some risks cannot be quantified. While a short-run study such as this one cannot compute such longer-term benefits and risks, their importance should be recognized.

There are two major sources of the short-run benefits studied and presented here: production cost savings and the pooling of regional capacity markets.

II.A.1. BENEFIT 1: Production Cost Savings

The largest component of the short-run benefits studied here is the reduction in the variable costs (*e.g.*, fuel) of generation that can occur as markets become more transparent and barriers to trade are reduced. This study measures this benefit as the difference in generation production costs between a Change Case and a Base Case as estimated using the GE MAPS model. The MAPS model used in this study incorporates a detailed representation of the Eastern Interconnection transmission grid, along with the dispatch and start-up costs of substantially all interconnected generating units. Because of the size of this model, more transmission constraints have been monitored in and around PJM, given the focus of this study, than in the remainder of the Eastern Interconnection. However, major transmission limits are monitored throughout the East.

Overview of Benefits and Costs

The MAPS model is a single system optimization model. Among other things, this means that MAPS will find the economically efficient unit commitment and generation dispatch to supply load throughout the study area. The current trading patterns in the Eastern Interconnection cannot be as efficient as this because the various control areas are independently conducting their own dispatch operations. These separate dispatch operations create loop flow on one another's transmission systems that contributes to transmission congestion. Such congestion cannot be managed efficiently in real-time under today's dispatch and trading arrangements. Instead, the utilities have developed other approaches, such as Transmission Line Relief ("TLRs"), to manage congestion. These approaches have served the industry well in the past, but are under additional stress with the development of merchant power producers and competitive wholesale power markets. Moreover, current arrangements for the trading of energy between control areas are based on incomplete bilateral markets that cannot be transparent, given the local management of regional congestion problems. The congestion costs created by transactions can only be partially accounted for under current grid operations in most areas. In contrast, PJM's market structure is based on LMP, which is designed to manage such congestion problems in real-time and to help markets become more efficient and transparent.

MAPS is well suited as a model of the generation dispatch that would take place after the New PJM companies are integrated into PJM. However, it cannot depict, without adjustment, the base-case trading arrangements prevailing under local management of congestion in which transactions do not pay the price that reflects the cost of the congestion they create. Accordingly, it is necessary to create a Base Case in MAPS by adding certain elements of inefficiency. In this study, like other studies of RTO benefits conducted previously, we have done this in two ways. First, we modeled individual control areas as having separate unit commitment and dispatch to meet internal load and reserves. Second, net transfers between regions were allowed, but limited by the use of "hurdle" rates. In effect, a hurdle rate is an impediment to trade between control areas, which is modeled as an adder to the transmission rate for transactions between control areas. In part, this hurdle rate reflects direct charges for losses and transmission tariffs; additionally, we assess an additional hurdle to reflect various inefficiencies and costs associated with bilateral trading across control areas. This additional hurdle rate is not actually part of any financial settlement, so it never is actually paid to anyone. Instead, it (together with the wheeling charge) is an input to the unit commitment and dispatch logic of MAPS that represents impediments to trading between control areas. The definition of the hurdle rates for this study is discussed in more detail in Section IV.

These base-case hurdles were chosen so as to calibrate the Base Case to reflect historical patterns of trade between DVP and its neighbors. In the Change Cases in which the New PJM companies join PJM, the import hurdle is eliminated for the four New PJM companies, but is retained for the expanded PJM as a whole; that is, trade between the expanded PJM and neighboring

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control areas is subject to continuing trade hurdles.[14] The import hurdle continues to apply to the pre-existing RTOs and control areas that are not reconfigured in the Change Case. Similarly, the trade hurdles within the expanded PJM are eliminated in the Change Case, aside from a small charge to reflect incremental transmission losses.

Production costs, including the costs of starting a plant and the variable costs of running it, will be lower in the Change Case than in the Base Case with hurdles. The difference between the two cases is used as the measurement of the production cost benefits due to the expansion of PJM.

We do not quantify potentially important benefits of joining PJM that should follow from becoming part of a wholesale market with excellent liquidity and transparent price formation. We assume, both in the Base and Change Cases, that all energy is traded at prices consistent with the spot market price of energy, even though most energy is traded bilaterally rather than in spot markets.[15] In markets where trading is thin and prices are not readily observable, market participants manage market risk through greater reliance on self-scheduling, firm transactions, and other relatively blunt tools; in a given hour, this may lead to some higher cost units operating instead of lower-cost units. By contrast, in a well-developed market such as PJM, there is greater convergence between bilateral and spot prices, and the consequent flexibility of unit commitment and dispatch means that customers can be served at lower total cost. Our study, though, focuses solely on the potential benefits to trade *between* areas, and so it understates potential benefits from improved utilization of resources *within* each control area.

II.A.2. BENEFIT 2: Pooling of Regional Capacity Markets

The second major category of benefits studied here is associated with the regional market for installed capacity requirements. DVP joining PJM is expected to result in certain economies in maintaining the adequacy of generation resources within the DVP control zone. The PJM East control zone is expected to benefit from the load diversity between it and the remainder of the expanded PJM area. These economies have the effect of delaying the need to build generation capacity anywhere within the expanded PJM market area by a few years, as excess capacity resources in resource-long areas of PJM (PJM East and AEP) can serve the a greater share of the

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14 FERC has recently reaffirmed its order that PJM and the Midwest Independent System Operator ("MISO") work to create a single market by October 2004. Our study assumes that seams continue to exist between these two markets, however, reflecting a pragmatic assessment that substantial market seams will likely continue to exist, as they have between PJM and New York despite years of work to reduce seams issues there. MISO is, on net, an exporting region, however, so tighter integration with PJM seems likely to have the effect of increasing the net supply of lower-cost resources available to supply Virginia. Consequently, our modeling choice is likely to be conservative.

15 *See* Testimony of Gregory J. Morgan.

resource needs of DVP. This delay, in turn, can keep the capacity prices in the DVP control zone at moderate levels further into the future.

To estimate the ICAP price impact, this study has used a probabilistic model of ICAP prices that is based on the likelihood of a shortage. The market-clearing price of ICAP is estimated as a weighted average of the capacity price expected to prevail during times of a capacity surplus versus those of a shortage. The price during a period of surplus is based on the estimated cost of moth-balling existing plants, while the price during a period of shortage is based on the cost of a new peaking facility. This pricing model has been used in order to smooth out what would otherwise be sharp, abrupt changes to the ICAP price in response to a very small change in the amount of installed capacity.

The effect of DVP joining PJM is to reduce the market-clearing ICAP prices in the later years of the study period, *i.e.*, in 2010 and later. This reduced price is assumed to apply to all of the capacity that must be purchased by customers in these years, and correspondingly, to all of the capacity that can be sold by DVP in the market place. Although bilateral capacity contracts can hedge price volatility, we assume that they will be priced to reflect expected future capacity prices under the applicable wholesale market structure.

II.B. Distribution of Benefits

Our Financial Evaluation Model processed the output from the physical modeling supported by MAPS in order to assess the benefits for Virginia Retail Customers, DVP Zone Customers, and DVP shareholders. The Financial Evaluation Model does several things:

- Accounts for imports and exports of power in and out of the DVP control zone and ascribes the trade benefits equally between the buying and selling control zones for trade supported by point-to-point transmission service, such as between DVP and CP&L.
- Accounts for the price of purchased power needed to serve native load customers, including power purchased off-system in the Base Case and under the PJM LMP system.
- Accounts for the sale of power both to off-system customers in the Base Case and into the PJM LMP market structure.
- Accounts for the cost of producing power separately for each DVP generating unit, including the cost of fuel, emissions allowances, start up costs and O&M costs.
- Accounts for the fuel factor formula applicable to DVP Zone Customers during the rate-cap period.

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- Accounts for FTRs expected to be allocated to DVP and its native load by PJM.
- Accounts for the need to purchase installed capacity in order to meet planned generation reserve requirements.

A more detailed description of the Financial Evaluation Model is provided in Section IV and Appendix B. Importantly, the output of the Financial Evaluation Model divides the benefits between retail customers and shareholders. The exercise of distributing benefits in this fashion was not undertaken in the SEARUC study because tracking such matters for 17 utilities in 8 state jurisdictions was not feasible.

II.C. COSTS

The cost of DVP joining PJM is assumed to be the average administrative costs of PJM following the integration of the New PJM Companies. This administrative charge is estimated by PJM to be lower than the current per-unit charge as a result of the four New PJM Companies being integrated into the PJM market structure. This study has relied on this estimate as filed with FERC as part of the New PJM Companies' Section 205 filing. This cost estimate is also consistent with the recent study released by the U.S. Department of Energy.

These administrative costs are assumed to be paid by customers on a load-ratio share basis, consistent with the remainder of the load in the expanded PJM area. These costs are increased at a 2.5 percent annual rate, to reflect inflation. Administrative costs to customers for whom DVP is the load-serving entity ("DVP Requirements Customers") are assumed to be deferred until mid-2007, at which time the rate cap for DVP's Virginia Retail Customers ends. The deferred costs are assumed to be recovered over a short period beginning in mid-2007. For the purposes of this study, this amortization period is assumed to be 30 months (corresponding to the 30 months of deferrals). However, this assumption is merely a placeholder for whatever approach is adopted at a later time. The assumption about the amortization period will not affect the aggregate net present value results for customers and DVP shareholders over the entire study period, but does impact the result for any particular year. Likewise, the study assumes that the deferrals will accrue interest at a rate of 7 percent, consistent with the interest rate for deferrals in recent FERC filings. Again, this assumption is intended as a placeholder for whatever actual interest might be used later.

III. DESCRIPTION OF CURRENT MARKET

Under Virginia electricity restructuring, all Virginia retail customers currently can choose to shop for retail generation services at market prices. A rate cap is in effect for non-shopping customers until July 2007. Under the rate cap, DVP's base rates are frozen while fuel factor charges are adjusted annually based on projections of actual fuel costs.

As yet, there has been limited shopping for retail generation services in Virginia. Retail pilot programs are underway to encourage more retail shopping in the DVP area prior to 2007. For purposes of this study, it was assumed for simplicity that Virginia Retail Customers would pay rate cap energy prices through mid-2007, and market prices thereafter. Base rates for generation and other services would not change between the Base and Change Cases, thus base rate impacts were not included in the calculation of benefits and costs in this study. As such, the energy-related benefits for Virginia Retail Customers are assessed using differences in fuel factor charges during the rate-cap period and differences in market generation charges after the rate-cap period ends.

III.A. Rate-cap period Energy Benefits and Costs

During the rate-cap period, any change in the fuel factor charges between the Base and Change Cases results in a benefit or cost to retail customers. Changes in fuel factor charges generally result from a change in how specific DVP generating units are dispatched. This change in dispatch leads to fuel cost differences and corresponding changes in the amount and cost of purchases to serve retail load.

Similarly, during the rate-cap period, DVP shareholders recover fuel-related charges and capped base rates from retail customers. Any costs that change between the Base and Change Case and are not assessed to customers through the fuel factor (e.g., emission allowance costs) will impact shareholders, given that base rates are not reset during the rate-cap period. Moreover, in the Change Case during the rate-cap period, shareholders will pay PJM for the load of Virginia Retail Customers at the DVP Load Zone LMP, receive individual generator LMP payments from PJM for DVP generation, and offset the differences in these PJM payments and receipts with the DVP allocation of FTRs. During the rate-cap period, customers will be shielded from these underlying LMP/FTR transactions, but will enjoy any fuel and purchase power cost savings created by the entry into PJM through a reduction in the fuel factor.[16]

[16] As discussed in more detail in Section IV.C, purchase costs included in the fuel factor in the Change Case are adjusted for load zone pricing of the purchases net of allocated FTR value because there will be no other auditable purchase costs to trace in the fuel factor calculations.

III.B. Post-Rate Cap Energy Benefits and Costs

Once the rate cap ends, Virginia retail customers are presumed to pay market prices for generation service in both the Base and Change Cases. In the Base Case, retail customers will pay the general market-clearing price for energy in the DVP control zone. In the Change Case, retail customers will pay for energy based on DVP Load Zone LMP and offset any congestion costs from the market-clearing source to the load embodied in those prices using the FTRs allocated to DVP. Similarly, DVP shareholders will sell generation at market prices in both the Base and Change Cases. In the Base Case, the DVP generation will be priced at the general market-clearing price for energy in the DVP control zone. In the Change Case, the energy portion of generation will be priced at each individual generator's LMP.

III.C. Other Economic Benefits and Costs

Aside from energy, other economic benefits and costs considered in this study include capacity benefits, ancillary service charges, and PJM administrative fees.[17] The treatment of capacity costs incurred in meeting peak load and reserve requirements is consistent with the treatment of energy cost impacts. Prior to the end of the rate cap, capacity costs are bundled into the frozen DVP base rates. Thereafter, capacity costs are paid directly by DVP Zone Customers and such costs decrease. PJM administrative charges are assessed to customers in the Change Case. However, the PJM administrative charges assessed to DVP Requirements Customers during the rate-cap period in the Change Case are assumed to be deferred by DVP until July 2007, at which time the charges are recovered with interest over a 30-month period. Ancillary charges were assumed to be passed through to customers in both the Base and Change Cases as incurred; these costs are neutral between the two cases for customers.[18] Generation-related ancillary charges paid by load were assumed to be distributed to generating units in the DVP area in proportion to their market shares.

III.D. Other Customers in the DVP Control Zone

Along with the cost-benefit impact on Virginia Retail Customers, the collective impact on other customers in the DVP control zone, including North Carolina retail customers and wholesale customers, was also assessed. Other than North Carolina retail customers, these customers were assumed to shop for generation services in excess of any self-owned generation by mid-2007.

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17 The potential change in wheeling revenues received by DVP transmission between the two cases was not included in the study results presented herein. The impact is uncertain and likely to be small relative to the other benefits and costs quantified. *See* Testimony of David F. Koogler

18 See Testimony of Gregory J. Morgan.

IV. ANALYTICAL APPROACH

In order to quantify the likely costs and benefits of the proposed transfer of DVP into PJM, CRA needed to develop and refine several analytic models. To model the change in system operations that would result from the market integration, we used GE MAPS running with CRA's proprietary database, discussed in section IV.A below. Interacting with GE MAPS was a model of capacity additions and resulting capacity pricing, which we discuss in section IV.B. Finally, CRA developed a Financial Evaluation Model to assess the incidence of costs and benefits flowing from these two models of the physical system, which we discuss in sections IV.C and IV.D. The three technical appendixes contain further detail about how we used GE MAPS and the Financial Evaluation Model in this study.

IV.A. Model of Physical System Operations

In order to assess the operational benefits of expanding PJM to include DVP and the other New PJM Entrants, CRA used the GE MAPS model to determine the unit commitment and dispatch in the Base and Change Cases. The GE MAPS model is a security-constrained dispatch model that simulates the hourly chronological operation of an electricity market. It assumes marginal cost bidding, performs a least-cost dispatch subject to thermal and contingency constraints, and calculates hourly, locational-based marginal prices for electricity. The GE MAPS simulation is consistent with the congestion management scheme currently utilized in PJM and the other Northeast ISOs. The model's locational spot price calculation algorithm has been successfully benchmarked against the market price algorithm used in the PJM market.[19]

Models are only as reliable as their data, so CRA has taken extra measures to ensure that the assumptions regarding generation characteristics, transmission representation and limitations, fuel costs, emissions rates and regulations, planned additions and retirements, and NUG contracts were accurate and consistent. Details of these model inputs are discussed in Appendix A.

CRA modeled four years of the ten-year study period: 2005, 2007, 2010 and 2014. We chose 2005 as the earliest full year when DVP could be integrated into PJM, under the terms of the Code of Virginia § 56-579 as amended. Given that DVP's rate cap expires in 2007, we chose to model that year to provide fully detailed information to the financial model, which needed to make separate calculations for the first and second halves of 2007. The year 2014 bounds the ten-year study period, and 2010 provides a mid-point assessment to improve interpolation

19 The actual PJM transmission representation for an individual hour was input into MAPS, along with actual loads, imports and exports and generator bids. The locational prices calculated by the GE MAPS program matched those produced by the PJM LBMP system for those conditions.

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The principal challenge in modeling commitment and dispatch with a tool as powerful as MAPS is not, surprisingly, finding the security-constrained least-cost dispatch. Instead, the challenge is to find a reasonable representation of the inefficiencies that inevitably exist in real-world markets and, more particularly, how these inefficiencies change when moving from one market system to another. Left to its own devices, MAPS will find and execute all possible trades throughout the entire Eastern Interconnection to minimize total system production cost, subject to meeting all load reliably. Because the current market does not capture all these beneficial trades between market participants and, in particular, across market seams, we have set up our model to add inefficiencies through the use of selective barriers to trade, or "hurdles."

We used financial hurdles to approximate inefficiency in the Base Case stemming from several sources, including:

- Biases toward the use of local control zone resources due to uncertainty and resulting reliability concerns;
- Lack of full coordination among the commitment and dispatch processes of control areas;
- Imperfect economic management of congestion between and within control areas due to loop flows and less-efficient congestion management tools than LMP;
- The lack of market transparency in bilateral markets;
- Transaction costs; and
- Inefficient scheduling of transmission.

For this study, we employed four types of hurdle rates. These are discussed in greater detail in Appendix A. In the unit commitment phase of MAPS, we imposed a $10 per MWh hurdle between control areas in order to reflect the self-commitment practices prevailing today. In the dispatch phase of MAPS, we employed two hurdle rates:

First is an "import hurdle" rate of $3 per MWh is imposed on each control area for any imported power during peak periods ($1 per MWh in off-peak periods). The purpose of this hurdle is to mimic the self commitment that is the basis for current operational practices within each control area, transactions costs associated with searching out and executing bilateral trades, and other impediments to trade that bias dispatch towards internal resources. The import hurdle applies only once to any transaction, regardless of how many control areas were involved in wheeling the power.

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The second type of dispatch hurdle used in this study is a "trade hurdle" rate of $3 per MWh, which is imposed on power transfers between control areas or RTOs in peak periods ($1 per MWh in off-peak periods). This trade hurdle rate reflects impediments to move power between control areas separately from the self-commitment logic embodied in the import hurdle. The trade hurdle is intended to represent both wheeling rates and trade impediments that become pancaked as power is wheeled across multiple control areas. Consequently, this charge is assessed for each control area through which a transaction moves.

Finally, a $1 per MWh fee is imposed at the dispatch phase for line losses for each inter-control area transfer. These three dispatch hurdles are additive, so a trade involving a single wheel would be subject to a total of a $7 per MWh peak-period dispatch hurdle rate—$3 per MWh to be imported, and $3 per MWh to be transferred to an adjoining control area, plus $1 per MWh for line losses. A trade involving a second transfer would be subject to a total hurdle rate of $11 per MWh—the $3 per MWh import hurdle, plus two transfer hurdles of $3 per MWh each and two losses charges of $1 per MWh each.

These hurdles were implemented in MAPS as economic contracts between zones, rather than as incremental line charges or restrictions on the transmission system. This approach has two distinct benefits in interpreting the results. First, the hurdles do not directly affect the locational prices in the model. The only influence the hurdle rates have is through their effect on the commitment and dispatch of the system. Second, the contracts track transfers between zones, rather than physical flows on lines. This feature aligns our contract transfers with the real bilateral contracts we see in today's electricity markets. It also makes tracking of costs and benefits materially more accurate than tracking only physical flows.

To model the integration of the New PJM Entrants into the PJM market system, we eliminated from the Change Case the commitment, trade and import hurdles among the five control zones in the Base Case that comprise the expanded PJM market area, namely PJM, DVP, AEP, DP&L and ComEd. The $1 per MWh line-loss fee remained as the only hurdle, reflecting our view that PJM will implement some version of a distance-dependent transmission loss charge. Commitment and dispatch hurdles from these zones to zones outside the expanded PJM market were not changed.

IV.B. Model of Capacity Prices

An integral part of the PJM market design is its capacity market, through which PJM ensures that there will be sufficient capacity resources offering to supply energy into the PJM energy markets to ensure reliable system operations. Units selected through the capacity auction are required either to bid into the PJM day-ahead market or to self-schedule that capacity. In

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return, these capacity resources are paid the auction-clearing price for each kilowatt of supply, regardless of whether the resource is actually called upon to supply energy or ancillary services. These payments allow units that never run, or operate infrequently, to cover their fixed costs; otherwise, generation owners might find it more profitable to mothball or close marginal generation resources, reducing the overall reliability of the system.

In modeling this capacity market, we first developed the pattern of new entry by location and time. Secondly, we used this pattern of capacity additions to estimate future capacity prices. The following two sections discuss our approach to each task.

IV.B.1. Determining New Build Requirements

Clearly, the existing fleet of generation resources cannot meet future needs indefinitely. In order to forecast both future energy and capacity prices, CRA needed to project what new generation resources would be built, where, and when.

For the first year of the study period, 2005, CRA assumed that only those units that are under construction currently would be commercially available. New projects that have been halted were not included among the 2005 builds. Although additional projects might conceivably be tabled, other projects not counted may be completed by Summer 2005. Overall, we believe that this is a reasonable and conservative forecast of 2005 resources.

For subsequent years, we assumed that additional capacity resources are brought on-line to maintain required capacity reserves in each control zone.[20] We allowed trades of capacity between directly interconnected zones provided that two conditions were met. First, the imported capacity could not exceed the transfer capability between the two zones. Second, each zone was required to carry internally enough capacity to meet forecast peak load plus a 2.5 percent operating reserve requirement.

This possibility of capacity export means that the location of new builds is not determined unambiguously. In the SEARUC study, we allowed no capacity trading and, consequently, the need for and quantity of new capacity in each zone was deterministic. In this study, we used the following procedure to locate new capacity resources:

1. Build internally to meet load plus operating reserves.

20 We modeled both MISO and SETRANS as having two separate areas, east and west, to reflect the geographic and electrical separation within those two areas. MISO East corresponds to those areas of MISO in ECAR; MISO West includes those parts in MAIN and MAPP. SETRANS is split between the

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2. Fully utilize trading from resource-long areas. For example, New York can import capacity either from New England or PJM. New England, however, has no other export markets for its surplus capacity, and more than enough to meet New York's capacity shortfall until after PJM itself becomes capacity short. PJM resources, however, can sell to other markets. We therefore first meet New York's shortfall from New England capacity, before considering imports from PJM.

3. When available capacity exports cannot meet remaining capacity requirements in interconnected markets, allocate capacity exports so as to equalize the internal capacity margin in each import market. To a first approximation, this procedure equalizes the expected returns to new generators in each affected area.

In the both the Base and Change Cases, we required that each control zone, including those of the New PJM Entrants, carry internally sufficient capacity to meet peak load plus operating reserve. This rule required new builds in DVP and ComEd, as well as areas outside the expanded PJM market. Additional capacity needed generically in PJM to meet the pool-wide capacity requirement was also sited in these two zones, since they had the lowest internal reserve margins among the PJM sub-areas and, therefore, could be expected to have higher prices for peaking units.

The critical difference between the Base Case and the Change Case in the capacity market is that, owing to the increased load diversity of the expanded PJM market, the level of required reserves declines. In the Base Case, the current PJM is modeled to hold a 17 percent capacity margin, consistent with current requirements. Following the integration of the New PJM Entrants, this requirement is lowered to 12.5 percent for the current PJM market area, resulting in an approximately 15 percent margin above coincident peak for the expanded PJM area. This reduction in capacity requirements frees approximately 3,000 MW of resources that had been needed in PJM East, making additional capacity available to other PJM Member Companies, including DVP. Other required capacity margins outside the current PJM are assumed to be unchanged, so DVP holds a 12.5 percent reserve requirement in both the Base and Change Cases, of which no more than 10 percentage points can be met with external capacity resources.[21]

A second difference between the two cases is that we modify the capacity export rule (#3 above) so that surplus capacity in one area of PJM is used first to meet capacity shortfalls in

Southern and Entergy areas. The New York Control Area was modeled consistent with its capacity market design as two sub-regions (New York City and Long Island) and an overall New York region.

21 *See* Testimony of Gregory J. Morgan.

other areas of PJM. Only if PJM is collectively net long will any PJM zone export to a non-PJM zone, reflecting the higher transactions costs of selling external capacity. The practical effect of this change is to divert exports of capacity from AEP, that had been sold to CP&L, Duke, and TVA, are instead sold to DVP, Commonwealth Edison and the current PJM companies.

The pattern of builds across the Eastern Interconnect used in this study is summarized in Table IV-1.

Table IV-1: Pattern of New Capacity Builds by Region

Cumulative Additions, MW

	2007			2010			2014		
	Base Case	Change Case	Difference	Base Case	Change Case	Difference	Base Case	Change Case	Difference
PJM	0	0	0	0	0	0	2,069	0	-2,069
DVP	0	0	0	310	0	-310	3,360	1,668	-1,692
AEP	0	0	0	0	0	0	0	0	0
DP&L	0	0	0	0	0	0	0	0	0
ComEd	0	0	0	563	87	-476	4,407	2,250	-2,157
CP&L	0	0	0	763	498	-265	3,078	3,227	149
DUKE	846	846	0	2,875	2,856	-19	6,870	7,128	258
SCE&G	0	0	0	0	0	0	1,621	1,621	0
MISO E	0	0	0	0	0	0	5,564	6,280	716
MISO W	0	0	0	0	0	0	8,285	9,085	800
SPP	0	0	0	0	0	0	1,020	1,020	0
SETRANS E	0	0	0	0	0	0	8,840	8,840	0
SETRANS W	0	0	0	0	0	0	0	0	0
TVA	0	0	0	0	0	0	2,410	2,944	534
GFL	0	0	0	3,046	3,046	0	8,684	8,684	0
NEP	0	0	0	0	0	0	0	0	0
NYC	175	175	0	271	271	0	619	619	0
NYL	175	175	0	307	307	0	670	670	0
NYO	0	0	0	0	0	0	368	368	0
Subtotal New PJM	0	0	0	873	87	-786	9,836	3,918	-5,918
Subtotal Other	1,196	1,196	0	7,262	6,978	-284	48,029	50,486	2,457
Total	1,196	1,196	0	8,135	7,065	-1,070	57,865	54,404	-3,461

IV.B.2. Determining PJM Capacity Market Clearing Prices

Under the current capacity market design, the quantity of capacity purchased by PJM is determined administratively, to reach a capacity margin based on engineering analyses. This approach tends to create prices that tip between one of two values:

If the system has more than enough capacity resources to meet the capacity reserve margin, the capacity price is set by the payment needed to keep existing resources from exiting. Specifically, the marginal unit needs to recover its avoidable fixed costs from its combined net

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revenues in the energy, ancillary services and capacity markets. Based on the MAPS runs for this study, we determined that the marginal PJM resource would expect to receive insignificant payments in the energy and ancillary service markets. Consequently, the market-clearing price for capacity, when PJM is net long capacity, should be equal to the avoidable fixed costs of marginal capacity resources.[22] Based on previous CRA studies about PJM capacity, we estimate that this cost is $20 per kilowatt-year. This level may be conservatively high, since observed capacity prices in PJM have frequently been below this level. Using a lower level for the cost of capacity during periods of surplus capacity would increase the benefits to customers from DVP joining PJM.

The other possible state of the capacity markets is that there is an overall shortage of capacity. In order to attract new capacity resources, the capacity price must cover not merely the avoidable fixed costs of the facility, but the fully loaded cost of new entry net of margins the unit could receive in the energy and ancillary services markets. CRA considered, in each market that needed additional capacity resources, whether a combined-cycle unit or a simple gas turbine would require a lower capacity payment. Combined-cycle units have a higher capital cost but are more efficient, allowing them to operate profitable in more hours than a gas turbine. In most markets, including the expanded PJM area, the extra energy margin that a combined-cycle unit could earn did not offset their higher capital charges. Consequently, the capacity market-clearing price was set to the levelized embedded cost of a new gas turbine, less expected net revenue from the energy and ancillary services markets (which were small). CRA estimated that this levelized cost in PJM is approximately $50 per kilowatt-year, which is substantially in agreement with similar calculations other researchers have made for New York and New England.[23]

Stripped down to these basics, one might expect that the capacity prices can only be at one of two levels: a low price when there is sufficient capacity already installed ($20/kW-year), or a high price when new entry is needed ($50/kW-year). If, for example, in 2013 we foresaw the market as 10 MW deficient in the Base Case, but 10 MW in surplus in the Change Case, the simple "price tipping" model would suggest that the entire 21,000 MW of capacity needed for

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22 This conclusion sets aside the sale of capacity to other control areas from PJM, which could allow scarcity pricing in other areas to raise the PJM capacity price. At this time, market rules for trading capacity between markets are insufficiently developed to allow full market integration and price formation across RTO seams. We chose, therefore, to model the PJM capacity market as a stand-alone market.

23 *See* "New York Independent Operator, Inc.'s Filing of Revisions to the ISO Market Administration and Control Area Services Tariff: ICAP Demand Curve," FERC Docket No. ER03-647-000 (March 2003), and E-Acumen, "Peaker Cost Study," ISO-NE Markets Committee Meeting (April 2002). Both estimates will tend to overstate the cost of new Virginia capacity, since construction and operations costs outside the Northeast will be somewhat lower; moreover, since the E-Acumen study was completed, there has been a substantial softening in the market for turbines, which are a substantial capital budget item for a new peaking facility.

Results of the Benefit-Cost Study

VI.D. Sensitivity Case Results – High Fuel Price Case

To address some of the uncertainty with respect to long-term natural gas and oil prices, a sensitivity case is analyzed in which natural gas and oil prices are increased 25 percent above those that are used in the Base Results. Not surprisingly, the higher fuel costs translate directly into higher electricity costs in both the Base and Change Case. When DVP is integrated into a broader market, with better access to diverse generating facilities, this price increase is less than if DVP is an isolated market. The higher gas prices provide more benefit from substitution of cheaper coal-fired generation when DVP joins PJM. This provides higher benefits for customers.

As shown in Table VI-10, the total benefits to Virginia Retail Customers are $262.1 million in the first 6 years of the study period ($694.4 million in the 10-year period). The net benefits are $145.5 million in the first 6 years of the study period ($524.5 million in the 10-year period). The total and net benefits reflect an increase of almost $35 million compared to the 6-year net benefits in the Base Results (see Table VI-1). The difference is entirely attributable to increased energy savings (capacity savings and PJM administrative charges are identical to those in the Base Results). The higher fuel costs of natural gas-fired units increase the marginal cost difference between those units and coal-fired units. In the Change Case, when DVP is part of PJM, DVP customers are better able to take advantage of lower cost imports from within PJM.

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Table VI-10: Summary Benefits of DVP Joining PJM for DVP Zone Customers (High Fuel Price Sensitivity Case)

Change Case minus Base Case
(in millions of $, positive numbers denote benefits)

	PV to July 1, 2003											
Virginia Retail Customers	('05-'10)	('05-'14)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Fuel Factor Savings	22.1	22.1	10.1	12.1	6.8	-	-	-	-	-	-	-
Market Energy Savings:												
Price Basis Change	(141.4)	(322.8)	-	-	(29.2)	(64.0)	(72.0)	(80.1)	(93.3)	(106.5)	(119.7)	(132.9)
FTR Value	365.2	681.1	-	-	85.7	172.8	181.1	189.4	191.4	193.4	195.4	197.4
Market Energy Savings	223.8	358.3	-	-	56.6	108.8	109.1	109.3	98.1	86.9	75.7	64.5
Total Energy Savings	245.9	380.4	10.1	12.1	63.3	108.8	109.1	109.3	98.1	86.9	75.7	64.5
Capacity Savings	16.2	314.1	-	-	-	-	-	31.5	166.7	251.2	200.1	104.0
Ancillary Savings	-	-	-	-	-	-	-	-	-	-	-	-
Benefit	262.1	694.4	10.1	12.1	63.3	108.8	109.1	140.8	264.8	338.1	275.8	168.5
PJM Admin Charge	(116.6)	(169.9)	(28.5)	(28.6)	(28.6)	(30.1)	(30.7)	(31.2)	(31.9)	(32.5)	(33.2)	(33.8)
Deferral/Recovery	-	-	28.5	28.6	(2.9)	(33.3)	(33.3)	-	-	-	-	-
Net PJM Admin Charge	(116.6)	(169.9)	-	-	(31.6)	(63.4)	(64.0)	(31.2)	(31.9)	(32.5)	(33.2)	(33.8)
Net Benefit	145.5	524.5	10.1	12.1	31.8	45.4	45.1	109.6	232.9	305.6	242.7	134.7
DVP Zone Customers	('05-'10)	('05-'14)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Price Basis Change*	(136.5)	(352.3)	14.6	17.0	(25.2)	(75.8)	(85.5)	(95.2)	(111.0)	(126.7)	(142.4)	(158.1)
FTR Value	449.9	831.9	3.3	3.7	106.0	209.6	219.6	229.6	231.8	234.0	236.2	238.3
Total Energy Savings	313.4	479.5	18.0	20.7	80.9	133.8	134.1	134.4	120.9	107.3	93.7	80.2
Capacity Savings	18.9	372.6	-	-	-	-	-	36.9	196.6	297.9	241.1	121.7
Ancillary Savings	0.5	0.9	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Benefit	332.8	852.9	18.0	20.8	81.0	134.0	134.3	171.5	317.6	405.4	335.1	202.2
PJM Admin Charge	(163.2)	(238.7)	(39.6)	(40.0)	(40.2)	(42.1)	(43.0)	(43.9)	(45.0)	(46.0)	(47.1)	(48.1)
Deferral/Recovery	-	-	35.6	35.7	(3.7)	(41.6)	(41.6)	-	-	-	-	-
Net PJM Admin Charge	(163.2)	(238.7)	(4.0)	(4.2)	(43.9)	(83.8)	(84.7)	(43.9)	(45.0)	(46.0)	(47.1)	(48.1)
Net Benefit	169.6	614.2	14.0	16.6	37.1	50.2	49.6	127.5	272.6	359.3	288.0	154.1

* Including fuel factor adjustments

VI.E. Sensitivity Case Results – High Load Case

A second sensitivity case is analyzed with higher unexpected demand. In this case, peak load is 5 percent higher than that used in the Base Results and total demand is 2 percent higher. As shown in Table VI-11, the total benefits to Virginia Retail Customers are $226.1 million in the first 6 years of the study period ($471.9 million in the 10-year period). The net benefits are $107.2 million in the first 6 years of the study period ($298.6 million in the 10-year period). The total and net benefits reflect a slight decrease compared to the 6-year net benefits in the Base Results (see Table VI-1). The increased load increases prices generally. Higher-cost units are forced to generate to meet the increased load. As the higher load is "unexpected," the available capacity is closer to reserve margins so that prices are not moderated as much by joining PJM. DVP customers also incur higher PJM administrative charges as this cost has been modeled on a dollar per MWh of load

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basis. It is possible that the rate would be reduced if load were higher than expected, thus minimizing any cost difference with respect to the PJM administrative charge.

Table VI-11: Summary Benefits of DVP Joining PJM for DVP Zone Customers (High Load Sensitivity Case)

Change Case minus Base Case

(in millions of $, positive numbers denote benefits)

	PV to July 1, 2003											
Virginia Retail Customers	('05-'10)	('05-'14)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Fuel Factor Savings	13.9	13.9	6.1	7.7	4.5	-	-	-	-	-	-	-
Market Energy Savings:												
Price Basis Change	(108.4)	(489.1)	-	-	(17.9)	(45.9)	(57.4)	(68.9)	(138.2)	(207.6)	(276.9)	(346.3)
FTR Value	303.7	617.3	-	-	72.9	144.8	149.8	154.8	170.8	186.7	202.7	218.7
Market Energy Savings	195.2	128.3	-	-	55.0	98.9	92.4	85.9	32.5	(20.8)	(74.2)	(127.6)
Total Energy Savings	209.1	142.2	6.1	7.7	59.4	98.9	92.4	85.9	32.5	(20.8)	(74.2)	(127.6)
Capacity Savings	17.0	329.8	-	-	-	-	-	33.1	175.0	263.7	210.1	109.2
Ancillary Savings	-	-	-	-	-	-	-	-	-	-	-	-
Benefit	226.1	471.9	6.1	7.7	59.4	98.9	92.4	119.0	207.6	242.9	135.9	(18.4)
PJM Admin Charge	(118.9)	(173.3)	(29.0)	(29.1)	(29.2)	(30.7)	(31.3)	(31.9)	(32.5)	(33.2)	(33.8)	(34.5)
Deferral/Recovery	-	-	29.0	29.1	(3.0)	(34.0)	(34.0)	-	-	-	-	-
Net PJM Admin Charge	(118.9)	(173.3)	-	-	(32.2)	(64.7)	(65.3)	(31.9)	(32.5)	(33.2)	(33.8)	(34.5)
Net Benefit	107.2	298.6	6.1	7.7	27.2	34.2	27.2	87.1	175.1	209.7	102.1	(52.8)
DVP Zone Customers	('05-'10)	('05-'14)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Price Basis Change*	(106.5)	(567.5)	9.1	11.3	(13.9)	(53.2)	(67.4)	(81.6)	(166.4)	(251.1)	(335.8)	(420.6)
FTR Value	373.5	752.7	2.5	2.8	90.0	175.5	181.6	187.6	206.7	225.9	245.0	264.1
Total Energy Savings	266.9	185.1	11.6	14.1	76.1	122.3	114.1	106.0	40.4	(25.3)	(90.9)	(156.5)
Capacity Savings	20.0	392.7	-	-	-	-	-	38.9	207.2	314.0	253.9	128.4
Ancillary Savings	0.5	0.7	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2
Benefit	287.3	578.5	11.8	14.2	76.2	122.4	114.3	145.1	247.7	288.8	163.2	(28.0)
PJM Admin Charge	(166.5)	(243.5)	(40.4)	(40.8)	(41.0)	(43.0)	(43.9)	(44.8)	(45.9)	(46.9)	(48.0)	(49.0)
Deferral/Recovery	-	-	36.3	36.4	(3.8)	(42.5)	(42.5)	-	-	-	-	-
Net PJM Admin Charge	(166.5)	(243.5)	(4.1)	(4.3)	(44.8)	(85.4)	(86.4)	(44.8)	(45.9)	(46.9)	(48.0)	(49.0)
Net Benefit	120.8	335.0	7.7	9.9	31.4	36.9	27.9	100.2	201.9	241.9	115.2	(77.0)

* Including fuel factor adjustments

VI.F. Other Sensitivity Cases

In a recent order in the parallel matter of AEP joining PJM, the Virginia Corporations Commission instructed AEP to consider the following sensitivity cases:

1. differing load forecasts
2. differing levels of transmission congestion and associated transmission rights
3. abnormal vs. normal weather
4. differing unit outage assumptions
5. differing fuel cost projections

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Our study directly addresses the first and fifth of these cases. The third case, for weather variations, is also addressed through our second sensitivity case. Likewise, the high load sensitivity case provides insights to the effect of unit outages, since a reduction of supply associated with a unit outage is, economically, very similar to an increase in demand. The second case cannot be directly modeled, since transmission congestion is an endogenous outcome, not a model parameter.

VII. CONCLUSIONS

This study indicates that DVP Zone Customers, including Virginia Retail Customers, will receive near-term benefits from DVP joining PJM, and that these benefits will be substantially more than the administrative costs of PJM participation:

- Reduced wholesale energy prices will save Virginia Retail Customers $198 million through 2010 and $319 million through 2014 on the energy portion of their charges. All DVP Zone Customers save $271 million through 2010 and $422 million through 2014.
- Lower capacity payments will further reduce charges to consumers, with the greatest effect in later years. Over the ten years covered by the study, Virginia Retail Customers save $314 million in capacity payments and DVP Zone Customers save $373 million.
- After netting out PJM administrative costs, we see quantifiable savings to Virginia Retail Customers of $110 million through 2010 and $477 million through 2014. DVP Zone Customers collectively will save $127 million through 2010 and $557 million through 2014.

Apart from these quantitative, short-run benefits, there are a variety of other factors that offer real, but difficult to quantify, benefits to DVP customers if DVP were to join PJM. Among these are:

- Enhanced reliability in the DVP service territory through efficient congestion management, restrictions on load shedding in PJM South and a continuation of a local control center to address local reliability.
- Improved resource adequacy through the broader PJM market created by the addition of the New PJM Entrants allowing for greater load diversity, improved reserve sharing across the region, and participation in a larger integrated regional transmission planning process.
- Improved access to a broader range of generation suppliers, which can be expected to enhance the competitiveness of both wholesale and retail markets.
- The potential for improvements to the efficiency of installed capacity markets, reflecting investment in generation to enhance its productivity, beyond those that have been incorporated into the formal modeling.
- Enhanced investment and participation in demand-side management programs, in response to clear and time-specific price signals.

Conclusions

- The potential for improved siting decisions on the part of future generation and transmission developers, allowing more efficient investment based on transparent and independent pricing.
- Potential cost savings from joining an established, proven RTO, rather than incurring the costs and uncertainties of developing an alternative response to regulatory requirements.
- Opportunity for improved substitution of market investment in Virginia markets for regulated DVP investment, creating more opportunities for DVP to deploy its capital to enhance shareholder value.

The study also finds that the key transmission constraints that result in locational price differences in Virginia are located outside of Virginia. Although these constraints do not pose reliability concerns, they impose substantial economic costs. DVP's membership in PJM would assure that these costs are fully considered in regional transmission planning processes that can address these constraints in the future. In the interim, congestion charges in the DVP control zone under PJM's LMP congestion management system are more than offset by the FTR value received by DVP customers.

In conclusion, after a comprehensive examination of the comparative costs and benefits of DVP joining PJM, we find that PJM membership will offer substantial and continuing net benefits to Virginia Retail Customers and DVP Zone Customers.

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APPENDIX A GE MAPS DESCRIPTION

A.1. DESCRIPTION OF GE MAPS MODEL

An overview of the GE MAPS model was provided in section IV of this report. Here we provide more detail about how the model combines its inputs to project hourly locational prices and unit generation, and we list some of the key input assumptions used in the model. The first section of this appendix describes some assumptions implicit in the GE MAPS modeling approach (*e.g.*, how maintenance is scheduled, how operating reserve requirements are imposed), while the second details some of the fundamental input assumptions, such as fuel prices and loads.

Basic Model Representation

The GE MAPS model is a security-constrained dispatch model that simulates the hourly chronological operation of an electricity market. Based on unit-level marginal cost bids, the model performs a least-cost dispatch subject to thermal and contingency constraints and calculates hourly, locational-based marginal prices for electricity. Nodal prices and unit level generation data can be aggregated to whatever level is desired (utility, region, state, *etc.*). Zonal load prices can be calculated either as load-weighted averages or as simple averages of locational prices. The GE MAPS simulation is consistent with the congestion management scheme currently utilized in PJM and the other Northeast ISOs. The model's locational spot price calculation algorithm has been successfully benchmarked against the market price algorithm used in the PJM market.[39]

CRA used the Eastern Interconnection version of the MAPS model in our analysis.[40] All modeling and analyses were done at the greatest level of detail possible (*e.g.*, individual company/control zone), given the limitations of our input data.[41] We combined companies into pools

39 The actual PJM transmission representation for an individual hour was input into MAPS, along with actual loads, imports and exports and generator bids. The locational prices calculated by the GE MAPS program matched those produced by the PJM LBMP system for those conditions.

40 The Eastern Interconnection includes all NERC regions, except the Western Systems Coordinating Council (WSCC) and the Electric Reliability Council of Texas (ERCOT). The electrical operations of all areas in the Eastern Interconnection are electrically synchronized with each other (except Hydro Québec), but are not synchronized with those in either ERCOT or the WSCC. Transmission ties with ERCOT, the WSCC and Hydro Québec are through DC ties. The GE MAPS Model of the Eastern Interconnection does not individual generators and loads for the interconnected and synchronized Canadian regions (Ontario, Manitoba, Saskatchewan, and New Brunswick), but rather includes supply curves that captures exports from these regions into the U.S. markets.

41 Traditional transmission modeling and data reporting arrangements form the basis for all modeling efforts. For example, if an individual company/organization traditionally reports its loads as part of a larger control area, we use that designation in our analyses. Similarly for transmission related information, the control areas in the AC

for commitment and dispatch, where each pool represents either an RTO or independent control zone. RTOs were modeled to correspond to existing ISOs, proposed RTOs as defined in current filings, and public announcements regarding RTO membership plans by individual utilities. Companies without existing definitive plans about their RTO membership were modeled as independent control zones.

Table A-16 at the end of this appendix shows how companies were grouped into RTOs and control zones. The three northeast ISO markets, namely ISO-NE, NYISO, and PJM, were modeled as individual RTOs. In our Base Case, PJM was modeled with its current footprint; in the change case, the PJM footprint was expanded to include Virginia Power (DVP), American Electric Power (AEP), Dayton Power & Light (DP&L), and Commonwealth Edison (ComEd). The remaining ECAR and MAIN companies, along with the MAPP companies, were combined to form the Midwest ISO RTO (MISO). The SeTRANS and GridFlorida RTOs were also assumed to go forward. SPP and TVA were each assumed to maintain their current composition, but function as RTOs.

Duke Power, Carolina Power & Light (CP&L), and South Carolina Electric & Gas (SCE&G) were treated as individual control areas, with Santee Cooper also included in the SCE&G area. In the Base Case in which DVP, AEP, DP&L, and ComEd were not integrated into PJM, each of these companies was treated as an individual control zone.

Least-Cost Commitment and Dispatch

The GE MAPS model commits and dispatches generation units to minimize production costs on a system-wide basis, but allows constraints on pool-to-pool transactions to be specified in order to capture pool-level commitment and dispatch and other impediments to trade.[42] As a result, unless constraints that impede trade are specified, all physically feasible, economically beneficial transactions will take place among various entities in the Eastern Interconnection. Because the current market does not capture all economically beneficial trades between utilities, and since trade across RTO seams is not perfectly coordinated, we implemented hurdle rates to restrict commitment and dispatch efficiencies inherent in the model's operation.

These hurdles must be met before either an RTO or a company (operating outside an RTO) will rely on generation from outside its area to meet internal load. Hence, each pool's unit commitment and dispatch will only reflect the availability of economic external generation if the resulting

power flow (which is a key input to MAPS) provide the only basis available for aggregating transmission related outputs from the model. If the individual buses of a company/organization are considered as part of a larger control area in typical load flow modeling, we model those buses as part of the larger control area.

42 "System-wide" commitment and dispatch encompasses the entire Eastern Interconnect.

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cost-savings from utilizing that capacity exceeds the hurdle. Hurdles apply to pool-to-pool transactions in both the Base and Change Cases. However, because the PJM pool expands in the change case to include DVP, ComEd, DP&L, and AEP, the hurdles among these companies and the existing PJM companies are removed.

We imposed two types of hurdles and the level of each varies between peak and off-peak periods and between the commitment and dispatch phases. The first type hurdle, which we have termed "trade hurdles," applies to each trade between directly interconnected pools and therefore becomes larger as the number of transmission wheels increases. Trade hurdles reflect the cost of obtaining firm transmission and impediments associated with securing transmission rights. Trade hurdles apply in both commitment and dispatch and were set to $3/MWh on peak and $1/MWh off-peak.

We refer to hurdles of the second as "import hurdles." Import hurdles are an additional penalty assessed to each pool on positive net imports. The penalty is assessed for each MWh by which a pool's load exceeds its internal generation, and hence is a fixed hurdle on pool-to-pool trades that does not pancake with the number of wheels required for the transfer. The effect of these hurdles is to require an additional amount of savings, even after the trade hurdles have been satisfied, before a pool will utilize external generation. These hurdles capture the margin on trades that must be available before the parties are willing to execute a deal.

In order to capture a bias toward committing local resources for meeting peak loads, in commitment we set import hurdles to $10/MWh on peak and $1/MWh off peak. Each pool is assumed to commit generation to serve its own load except in those instances where a savings of $10 per MWh can be achieved through imports from another control area. If attractive purchases or sales are available, the requisite units are committed (or decommitted) and made available for (or excluded from) the hourly dispatch. In order to allow the export of available, low-cost capacity that has been committed but is not fully utilized to occur with relatively less trading friction, we imposed import hurdles in dispatch of $3/MWh on-peak and $1/MWh off-peak.

We also imposed penalties on trades to simulate the effect of incremental losses. The loss charges were applied to transfers out of or through a pool.[43] We implemented the charges by assessing a $1/MWh trade hurdle on all transfers between directly connected pools. Even though other

[43] GE MAPS has the capability to use a set of fixed loss factors based on the specified load flow case and scales these factors up or down as the load increases or decreases with respect to the base case (i.e., it assumes a linear relationship between transmission losses and load on the system). As long as the power flows on transmission lines do not change direction, this is a reasonable approximation, but in much of the study region, flows can reverse direction depending on the season, the time of day, and unit availability. As a result, the GE MAPS logic to calculate marginal losses was not used, and the impact on market clearing prices of changing physical losses was not determined. Rather, only financial fees for losses were incorporated into the Production Cost Analysis.

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hurdles are removed, loss charges among the PJM subregions are maintained in the change case to reflect losses within the expanded RTO.

Table A-1 summarizes the level of all the hurdles by type and time period.

Table A-1: Hurdle Rates on Pool-to-Pool Transactions

	Commitment		Dispatch	
	Peak	Off-Peak	Peak	Off-Peak
Trade Hurdles	3	1	3	1
Penalty for Losses	1	1	1	1
Import Hurdles	10	1	3	1

Operating Reserves

MAPS accounts for spinning and non-spinning reserve requirements in its commitment and dispatch. The spinning reserve market affects the energy market prices because the units that provide spinning reserve cannot produce electricity under normal conditions.[44] As a result, energy prices in MAPS are higher when reserve markets are modeled.

In both the Base and Change Case, operating reserve requirements were specified for each pool as 2.5 percent of hourly load, all of which must be met with spinning resources. Additionally, in the change case, we imposed locational operating reserve requirements. PJM (East and West), ComEd, AEP, DP&L, and DVP were each required to provide operating reserves internally. The methodology implicitly maintains the Base Case reserve requirements and precludes benefits from reserve sharing across the expanded PJM.

We assumed that only a limited percentage of generation units' capacity can provide spinning reserves due to ramp-up constraints that prevent units from reaching their full capacity for delivering energy within the ten minutes period required for operating reserves. We specified a ramp rate for each unit and allowed it to hold operating reserves equal to amount the unit cam ramp in ten minutes. The ramp rate varies by unit type, as listed in Table A-2.

44 Non-spinning reserve requirements rarely influence MAPS energy prices in areas like the eastern U.S., with a reasonably large supply of quick-starting gas turbines.

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Table A-2: Generator Ramp Rates by Unit Type

Unit Type	Ramp Rate (MW/Minute)
Coal	6
Combined Cycle	25
Gas Turbines	9
Nuclear	0
Other	0
Peaking Units	0
Steam Gas/Oil	6
Steam Other	6

Maintenance Scheduling for Thermal Generation Units

The GE MAPS feature of scheduling maintenance of thermal generation units was used to levelize the reserve margin across the weeks of each year.[45] We assumed that maintenance within each pool (*i.e.*, RTO or independent control zone) is scheduled such that reserves within the pool are levelized on an annual basis. For example, if a region's load peaks in the summer, it will schedule little or no maintenance in that season; similarly, if a company's load peaks in the summer and winter, it will schedule no maintenance in these two seasons.

Generation from Conventional Hydro and Pumped Storage Units

Hourly generation levels for each hydro unit were determined by the GE MAPS model for each of the scenarios and years modeled. The GE MAPS model takes monthly generation totals for each hydro unit together with limits on their maximum and minimum generation levels and schedules hydro generation against the load shape for the pool in which the unit is located. The GE MAPS model generally does not dispatch hydro generation to relieve transmission congestion. However, if the locational price at the generation unit is very low (less than $5/MWh), then MAPS backs down generation from that unit to relieve congestion; under these circumstances, backing down the hydro unit is the most economic and may be the only alternative to relieving congestion. Also, GE MAPS does not increase generation from hydro resources to relieve congestion. This modeling assumption impacts each of the scenarios equally because only thermal units are used for congestion management in all scenarios.

GE MAPS dispatches pumped storage units based on load and committed thermal generation in the surrounding region. The model approximates the price elasticity for each hour over the course of a week using the stack of available generating units in the surrounding region and finds the corre-

45 The weekly reserve margin is capacity available during that week minus the week's peak load.

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sponding operating pattern for pumped storage units that minimizes total production cost. The model honors the physical characteristics of each unit, including pumping and generating capacities, pumping efficiency, and reservoir storage limits. When developing the schedule, the model does not directly account for transmission limits, but rather restricts the set of generators it considers to be available to ramp up for pumping or ramp down when the pumped storage units generate to those in the local region of each unit. Once the pumping and generating pattern has been developed, the model does honor all transmission constraints when meeting the schedule as part of the dispatch process. However, because the scheduling algorithm does not directly account for the availability of transmission in each hour, the optimization is only an approximation and as a result contains some noise.

In order to avoid potentially spurious benefits or costs between the Base and Change Cases stemming from the optimization of Bath County Pumped Storage unit operations, CRA used a stylized schedule for this unit and held it constant among all cases.[46] Based on initial runs with various pumping and generating schedules for the unit, a schedule was developed that performed reasonably well in all cases, but was not biased towards either case. The schedule honors all physical operating characteristics of the unit and balances pumping requirements with energy output. All other pumped storage hydro units were optimized using the standard GE MAPS algorithm.

A.2. KEY INPUT ASSUMPTIONS

As inputs to the model, CRA began with GE's complete database for the Eastern Interconnection power system, which is based in part on data from RDI. We have modified this database based on our analysis of public data and model results to ensure data integrity, validity, and consistency of plant operations with historical market data. In addition, we have incorporated data provided by Dominion Virginia Power.

The following is a list of the major components of the model. The list is followed by a description of each component and the associated data sources.

(1) Load Inputs

(2) Thermal Unit Characteristics

(3) Planned Additions and Retirements

(4) Fuel Price Forecasts

[46] Bath County is a 2520 MW pumped storage facility located in western Virginia. DVP owns two-thirds of this facility, with the remainder owned by Allegheny.

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(5) Transmission System Representation

(6) Environmental Regulations

(7) Hydro Unit Output

(8) NUG Contracts

Load Inputs

Peak loads and annual energy demands were based on forecasts reported in the 2001 NERC ES&D. Since published data do not extend to the end of our study period (i.e., 2014), forecasts were extended based on the projected growth over the reported forecast period (2002-2011). Table A-3 shows the regional peak load and annual energy totals assumed in each of the years modeled.

Table A-3: Peak Loads and Annual Energy Demand, by Region

	2005		2007		2010		2014	
Control Zone/RTO	Peak Load (MW)	Annual Energy (GWh)	Peak Load (MW)	Annual Energy (GWh)	Peak Load (MW)	Annual Energy (GWh)	Peak Load (MW)	Annual Energy (GWh)
DVP Zone	18,156	92,845	18,911	96,784	19,914	102,289	21,378	110,705
AEP	20,478	124,204	21,180	128,794	22,191	135,212	23,756	144,228
DP&L	3,165	17,227	3,279	17,697	3,367	18,203	3,595	19,277
ComEd	22,942	102,350	23,888	105,250	25,380	109,650	27,200	115,695
PJM (MAAC+APS)	66,274	348,582	68,577	359,149	72,070	375,148	76,943	398,385
MISO	131,232	724,968	135,878	745,573	142,503	782,171	153,377	835,104
CP&L	12,965	66,506	13,288	69,367	14,128	73,647	15,298	79,606
DUKE + CEPCI	22,373	112,912	22,930	117,770	24,381	125,035	26,400	135,154
SCE&G+Santee Cooper	8,541	45,464	8,753	47,420	9,307	50,346	10,078	54,420
TVA	31,612	176,641	33,173	183,091	35,503	192,701	38,368	205,865
SETRANS	74,335	408,431	77,933	426,494	83,521	455,481	91,481	495,010
SPP	42,257	210,934	43,715	217,065	46,826	233,001	50,614	251,219
GFL	38,282	209,759	39,910	221,485	42,585	237,493	46,523	262,592
ISO-NE	24,161	132,085	24,777	136,162	25,813	142,242	27,508	149,743
NYISO	32,218	162,160	32,948	165,880	33,957	171,600	35,382	179,340

Individual company load shapes are based on actual 1997 hourly load data as reported by the companies. The GE MAPS model adjusts each company's historical hourly load shape to fit the peak and annual energy numbers specified for that company for the year being modeled. The hourly load data created by that process for each company is then used as an input for the GE MAPS hourly simulation.

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Thermal Unit Characteristics

GE MAPS models generation units in detail, in order to accurately simulate their operational patterns and thereby project realistic hourly prices. The following characteristics are modeled:

- Unit type (steam, combined-cycle, combustion turbine, cogeneration, *etc.*)
- Full load heat rates and heat rate curves.
- Summer and winter capacities.
- Operation and maintenance costs.
- Forced and planned outage rates.
- Minimum up and down times.
- Quick start and spinning reserve capabilities.
- Startup costs.

Sources for thermal unit data include the EIA-411, EIA-867, and EIA-412 forms, the FERC Form 1, and the REA-12 forms. When unit-specific data were unavailable, we developed generic heat rate curves for different unit types based on available data for similar units. CRA specified unit forced and planned outage rates for each type based on an analysis of NERC's "Generating Availability Data System" data set. Table A-4 shows the outages our outage rate assumptions for each unit type.

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Table A-4: Outage Rate Assumptions

Unit Type	Size	Forced Outage Rate	Planned Outage Rate
Coal	0 - 100 MW	5.0%	7.2%
Coal	100 - 500 MW	7.0%	7.2%
Coal	500 MW +	7.0%	7.2%
Steam Gas/Oil	0 - 100 MW	5.0%	6.7%
Steam Gas/Oil	100 - 500 MW	7.0%	6.7%
Steam Gas/Oil	500 MW +	7.0%	6.7%
Combined Cycle	0 - 100 MW	3.5%	4.8%
Combined Cycle	100 - 500 MW	3.5%	4.8%
Combined Cycle	500 MW +	3.5%	4.8%
Nuclear	0 - 100 MW	7.0%	7.0%
Nuclear	100 - 500 MW	7.0%	7.0%
Nuclear	500 MW +	7.0%	7.0%
Gas Turbines	0 - 100 MW	5.0%	1.5%
Gas Turbines	100 - 500 MW	2.5%	1.5%
Gas Turbines	500 MW +	2.5%	1.5%
Other Peaking Units	0 - 100 MW	4.0%	1.5%
Other Peaking Units	100 - 500 MW	4.0%	1.5%
Other Peaking Units	500 MW +	4.0%	1.5%
Other	0 - 100 MW	5.0%	6.7%
Other	100 - 500 MW	5.0%	6.7%
Other	500 MW +	5.0%	6.7%

A listing of all generators in the DVP control zone is provided in Table A-17 at the end of this appendix.

Planned Additions and Retirements

Planned entries and retirements impact the fuel mix of installed capacity and the composition of plants on the margin. Most retirements are oil or steam gas plants, which are likely to be replaced by combined-cycle gas plants.[47] We added new capacity to the model in the years through 2005 based only on existing projects that are currently under construction.[48] Additional generic new capacity was added in the years after 2007 only as needed to meet regional reserve requirements in each case.

We assumed all new capacity would take the form of either gas-fired combined-cycle (CC) or simple-cycle gas turbines (GT), based on the relative economics of their entry. We balanced the entry of CC and GT units in each region consistent with an equilibrium in which each new unit earns

47 Planned retirements were specified based on information in RDI's Base Case Database.
48 As reported in RDI's NewGen Database.

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a sufficient margin from energy and capacity sales to cover its capital costs over a 30-year period. We assumed that a new CC would require a margin (energy revenues plus capacity revenues minus variable O&M, fuel, and emissions allowance costs) of $85 per kW in each year in order to cover its capital costs and its annual fixed O&M costs and that a new GT would require a margin of $50 per kW per year. These were derived based on an assumed cost of $560 per kW for CC units and $365 per kW for GTs, excluding interest during construction.

Unit additions and retirements modeled are summarized in Tables A-18 and A-19 at the end of this appendix.

Fuel Price Forecasts

The opportunity cost of fuel consumed for generation (i.e., or the current spot price of fuel) is generally the largest component of a unit's marginal cost bid. To project these variable fuel costs, we used forecasts of spot fuel prices at regional hubs, and further refined these based on historical differentials between price points around each hub. For oil and gas, we used estimates of the price delivered to generators on a regional basis, while for coal, we used plant specific price forecasts.

Coal Prices

CRA specified coal prices on the plant-level coal prices using forecasts of the fuel costs for each plant from RDI. RDI's forecasts are based on the historical and expected fuel type used at each plant and regional, delivered price of each type of coal. The forecasts account for potential fuel switch in response to environmental regulations. Where plant-level forecasts were not available, we used RDI's regional coal price forecast. Table A-5 shows the default regional annual coal-prices used in the study.

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Table A-5: RDI-Based Regional Coal Forecast ($2002/mmBtu)

Region	2005	2007	2010	2014
East Central Area Reliability Coord Agrmn	1.18	1.17	1.16	1.16
Entergy	1.23	1.22	1.17	1.17
Florida Reliabilty Coordinating Council	1.71	1.69	1.65	1.65
MAIN Sub Region	1.13	1.11	1.06	1.06
Mid-Continent Area Power Pool	0.87	0.88	0.85	0.85
New Brunswick	1.76	1.72	1.66	1.66
New England Power Pool	1.76	1.72	1.66	1.66
New York Power Pool	1.48	1.45	1.44	1.44
SPP Northern Subregion	0.89	0.89	0.86	0.86
PJM Interconnect PA-NJ-MD	1.32	1.30	1.28	1.28
SPP South Subregion	1.13	1.12	1.08	1.08
Southern Subregion	1.50	1.48	1.43	1.43
Tennessee Valley Authority	1.26	1.24	1.21	1.21
Virginia/Carolinas Subregion	1.47	1.44	1.43	1.43

Gas and Oil Prices

The key underlying forecasts are projected prices for crude oil and for natural gas (Henry Hub). All other forecasts are derived from these two basic forecasts using projected basis differentials.

To derive #2 fuel oil prices for electric generation, we used state-specific basis differentials developed based on EIA Form 423 data and assumed the price follows the same trajectory as crude oil prices. Our # 6 fuel oil forecast is based recent New York Harbor prices. Because residual oil is a close substitute for natural gas in many dual-fuel electric generators and industrial facilities, we trended future #6 oil prices based on the price of natural gas. Table A-6 presents CRA forecasts for #6 and #2 fuel oil.

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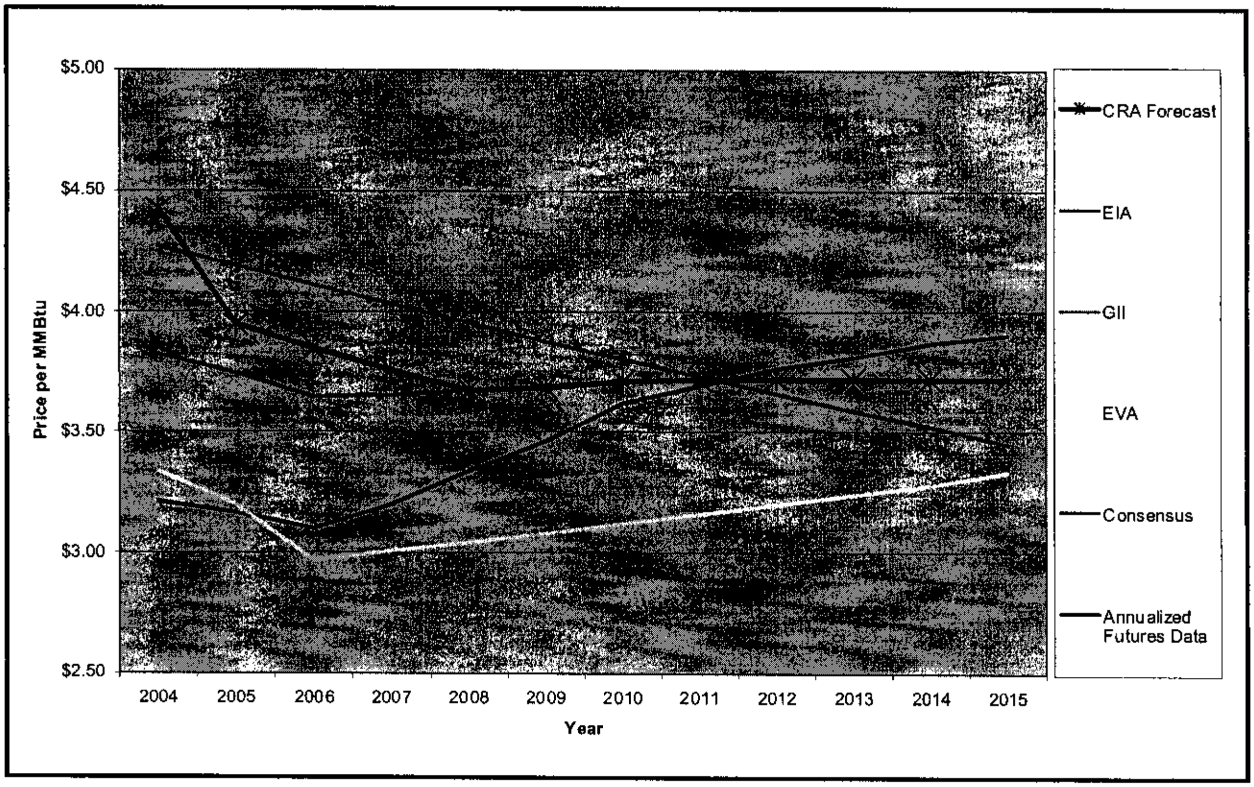
Table A-6: Fuel Oil Prices

	FO2 Prices				FO6 Prices			
	2005	2007	2010	2014	2005	2007	2010	2014
ECAR	4.83	4.63	4.57	4.58	3.20	3.06	3.03	3.03
FRCC	4.75	4.55	4.49	4.50	3.20	3.06	3.03	3.03
MAAC	4.69	4.49	4.44	4.45	3.20	3.06	3.03	3.03
MAIN	4.62	4.64	4.66	4.73	3.20	3.06	3.03	3.03
MAPP	5.01	5.03	5.06	5.14	3.20	3.06	3.03	3.03
NPCC	4.97	4.99	5.02	5.10	3.20	3.06	3.03	3.03
SERC	4.83	4.85	4.87	4.95	3.20	3.06	3.03	3.03
SPP	4.82	4.84	4.87	4.94	3.20	3.06	3.03	3.03
SOUTHERN	4.83	4.85	4.87	4.95	3.20	3.06	3.03	3.03
TVA	4.83	4.85	4.87	4.95	3.20	3.06	3.03	3.03
VACAR	4.83	4.85	4.87	4.95	3.20	3.06	3.03	3.03

Figure A-1 shows CRA's forecast for the spot price of natural gas at Henry Hub. The forecast is a composition of NYMEX futures prices in the short term, and an average among various, publicly-available long-term forecasts in the remaining year.

Figure A-1: Comparison of Natural Gas Price Forecasts



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The burner-tip price for natural gas is a sum of two components—regional price and local delivery charges (which reflect unavoidable LDC and/or lateral charge). CRA's forecasted regional gas prices are derived from the Henry Hub forecast and projected basis differentials for each region derived from historical regional price data. Our natural gas regions and their corresponding price points are identified in Tables A-7 and A-8. Basis differentials and regional delivered gas prices are shown in Table A-20 at the end of this appendix.

Table A-7: Definition of Gas Price Regions

	Regional Mapping						
	1	**2**	**3**	**4**	**5**	**6**	**7**
New England	MA	ME	NH	VT	RI	CT	
Eastern NY	NY						
NYC[1]	NY						
Eastern PA/NJ[2]	PA	NJ					
Western NY/PA	NY	PA					
DC, DE, MD	DC	DE	MD				
WV, KY	WV	KY	VA				
NC, VA	NC	VA					
SC, GA	SC	GA					
Southeast[3]	LA	AL	TN	KY	MS	AR	FL
Florida	FL						
Midcontinent	IA	MT	NE	OK	KS	MO	
Midwest	MI	OH	IN	IL			
Upper Midwest	MN	WI	ND	SD			
Rockies	MT	WY	CO	UT			
Southwest	NM	AZ	NV				
East Texas	TX						
West Texas	TX						
PNW	WA	ID	OR	NV			
Northern CA	CA						
Southern CA	CA						
Western Canada	CN						

[1]Con Ed, Long Island Lighting
[2]Includes PP&L, Exelon, UGI, GPU's Portland Gilbert, Sayerville and Titus areas
[3]Includes Southern Co. plants in the FL panhandle

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Table A-8: Sources for Historical Regional Gas Price Data

Region	Price Point
Henry Hub	Bloomberg Natural Gas Henry Hub Spot Price
New England	Algonquin Gates (Bloomberg)
Eastern NY	Avg of Transco Z6 non NY and Iroquois Wright station (2/3 weighting on Z6 due to location of gen stations)
NYC	Bloomberg Trnasco Zone 6
Eastern PA/NJ	Average between NYC [4] and Leidy
Western NY/PA	Bloomberg Dominion Leidy Pa. Natural gas Spot Price
DC, DE, MD	Tetco M3
WV, KY	Platts Gas Daily, COLUMBIA, APP, MONTHLY AVERAGE OF DAILY AVERAGE SPOT GAS PRICE
NC, VA	Priced as a discount to Tetco M3
SC, GA	Platts SOUTHEAST, AVERAGE, DELIVERED TO PIPELINE, SPOT GAS PRICE
Southeast	Platts FLORIDA GATES VIA FGT, MONTHLY AVERAGE OF DAILY AVERAGE SPOT GAS PRICE
Florida	Bloomberg Mid-Continent Natural Gas Spot Price Average
Midcontinent	Bloomberg Mid-Continent Natural Gas Spot Price/Chicago City Gate
Midwest	Average between Chicago [13] and AECO [22]
Upper Midwest	Mixed sources. Bloomberg Colorado Interstate Gas North System Natural Gas Daily Spot Price; Nat Gas Week Colorado Interstate Kanda WY
Rockies	Mixed sources. Bloomberg Natural Gas San Juan Basin Spot Price. Post 1998 Nat Gas Week Blanco NM
Southwest	Bloomberg Natural Gas Katy Spot Price
East Texas	Bloomberg Natural Gas Waha Hub Spot Price
West Texas	Bloomberg Spot Natural Gas Price Huntingdon BC/Sumas WA USD
PNW	Mixed sources. Platts MALIN, OREGON, PG&E LINE 400, AVG, CITY-GATE, SPOT GAS PRICE. Post 2001 Nat Gas week PGT Malin
Northern CA	Platts Gas Daily, SOUTHERN CALIFORNIA LARGE PACKAGES, MONTHLY AVERAGE OF DAILY AVERAGE SPOT GAS PRICE
Southern CA	Bloomberg Spot Natural Gas Price/AECO C Hub USD
Western Canada	Priced at a discount to NC, VA

Transmission System Representation

GE MAPS honors designated transmission constraints in its commitment and dispatch of generating units. We used a combination of GE's standard transmission representation for the Eastern Interconnection, transmission constraints from publicly available regional studies, and specific transmission information provided by Dominion. Constraints included:

- Thermal limits on all 500 kV lines in the study region.
- NERC flowgates throughout the Eastern Interconnect.

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- Contingencies and thermal limits identified by GE's contingency processor as potentially problematic.
- Contingencies listed in the VACAR-TVA-SOUTHERN Study Group's 2003 Summer Study published in February 2000.
- Contingencies listed in the June 1998 VACAR-ECAR-MAAC Study Committee's Interregional Transmission System Reliability Assessment.
- Binding transmission constraints posted on the PJM website.
- Other important constraints identified by Dominion.

We also accounted for several voltage and stability constraints within PJM by limiting the flow on selected interfaces to levels below their thermal ratings. The Black Oak-Beddington line, AP South Interface, and PJM East, West, and Central Interfaces were all monitored with limits set to levels consistent with PJM historical operations.

In order to restrict trade between regions to commercially feasible levels, we also limited pool-to-pool transfers. Based on TTC limits reported on OASIS, transfer limits reported in regional transmission studies, NERC reliability assessments, and guidance from Dominion, we imposed the transfer limits shown in Figure A-2. Note that pool-to-pool transfers are also limited by the physical transmission limits described above. However, the MAPS model may in some hours use physically available transmission capacity more efficiently than can generally be accomplished in current markets, even with the hurdles we have implemented. Hence, these additional transfer limits were intended to capture practical commercial limits on the amount of power that can be moved across seams during periods in which physical limits do not bind.

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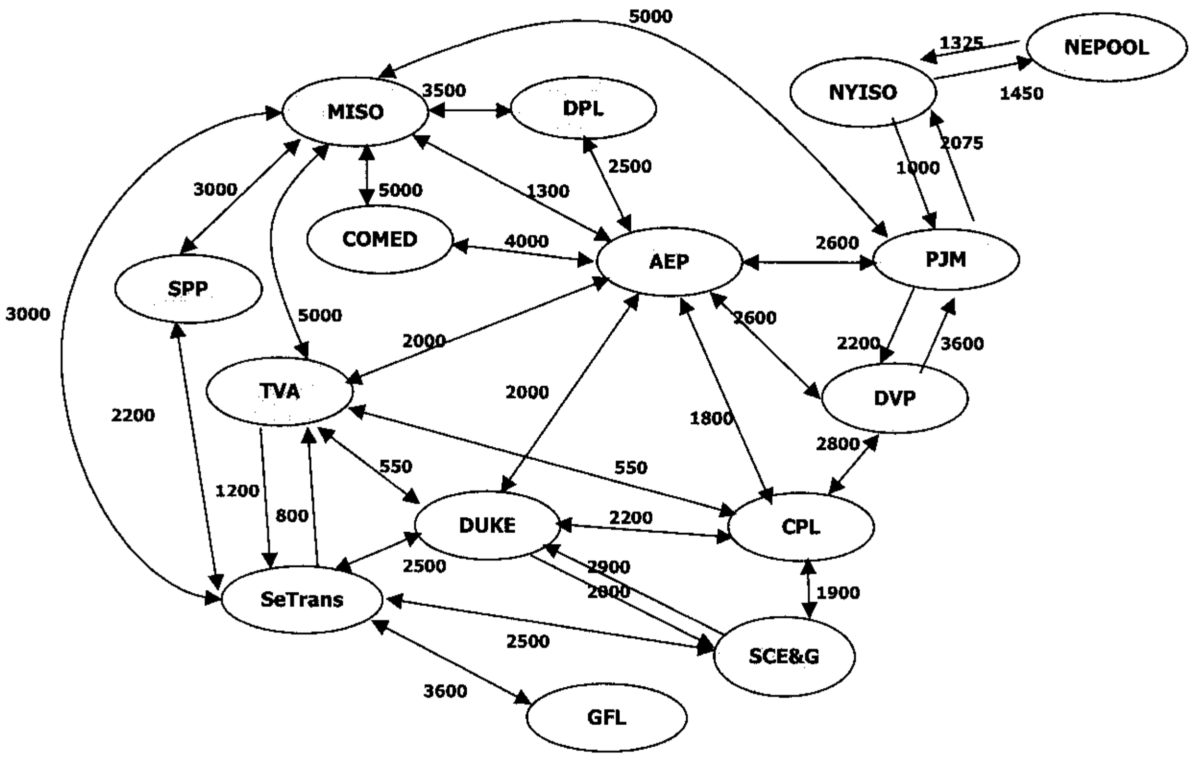
Figure A-2: Maximum Economic Transfers Between Adjacent RTOs or Control Areas in MW



Environmental Regulations

The opportunity cost of tradable SO_2 and NO_X allowances were added to the variable costs of all affected units, based on their current emission rates, and projected emission allowance prices.[49] We assumed the prices of SO_2 and NO_X allowances as shown in Table A-9. These allowance prices are based on current trading prices and projections of allowance prices in future years that are consistent with our fuel price forecasts and the continuation of current emissions limits.[50]

49 NO_X adders were applied to units in regions affected by the NO_X SIP (State Implementation Plan) Call. Adders were included only during the NO_X season (May through September).

50 In particular, the NO_X SIP Call, the Title IV national SO_2 cap, and Title V unit-level NO_X emissions limits.

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Table A-9: NOX and SO2 Allowance Prices

Market	2003	2004	2005	2007	2010	2014
SO2[1]	$157	$134	$110	$135	$180	$194
SIP Call[2]	$0	$4,800	$4,800	$3,332	$3,741	$4,230
OTR[3]	$7,170	$4,800	$4,800	$3,332	$3,741	$4,230

[1]2003-2007 RDI BaseCase
[2]2004 - 2005 from March 2003 Airtrends. Post 2006 price from RDI BaseCase
[3]Cantor Fitzgerald 3/24/03. OTR assumed to fully merge with SIP call market starting in 2004

Projected Hydro Output

CRA used the basic MAPS modeling approach for conventional hydro units, which accounts for environmental and operating constraints, such as maximum and minimum river flows. Monthly maximum and minimum generation and total energy are supplied to GE MAPS, and the model schedules the units to meet these requirements and shave peak loads. We used historical seasonal patterns for each individual hydro unit as a proxy for future seasonal generation (monthly GWh). The historical data were taken from EIA-759 form information as reported in the RDI database.

For pumped storage units, we used the generating and pumping capacities, reservoir sizes, and efficiency levels as specified in the standard GE MAPS database. Where appropriate, CRA refined the specified capacity and operating characteristic assumptions for the Bath County facility based on input from Dominion. As note above, the operation of the Bath County unit followed a pre-specified, stylized schedule, and the standard MAPS procedure determined the dispatch for all other pumped storage units.

NUG Contracts

Based on guidance from Dominion, CRA modeled certain contractual details for NUGs within DVP control zone. We modeled all must-take NUGs as fully dispatched, up to capacity factors consistent with historical operation. Also, the operation of dispatchable NUGs reflected specified contract energy prices rather than the plants' variable operating costs. In other words, the NUGS were dispatched whenever the contract energy price fell below the market price of energy, making them economic sources of power for Dominion. We assumed that NUG contracts scheduled to expire during the study period would not be renewed and that the plants would operate on a merchant basis following the expiry.

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A.3. MAPS MODELING RESULTS

As discussed in section IV of the report, the benefits to Virginia that stem from joining the expanded PJM RTO are driven by increased ability access lower cost generation from neighboring regions without substantial impediments to trades, along with the offset to congestion costs provided by FTR revenue. Several modeling results illustrate the changes in the unit dispatch and trade patterns that occur that occur between the Base and Change Cases in Virginia and other areas throughout the eastern interconnection.

This section present several key outputs from the GE MAPS wholesale market model including:

- DVP area net imports.
- Average pool-to-pool transfers.
- Generation by unit type and region.
- LMPs for each regional market.
- Binding transmission constraints and congestion.

Pattern of DVP Imports and Regional Transfers

Table A-10 shows net transfers into the DVP control zone from each neighboring region. The net imports follow a consistent pattern. Virginia is a net importer of power, with the largest portion of imports coming from (or through) the AEP area.[51] Net imports increase during off-peak hours, as inexpensive power for pumping the Bath County units can be provided by low cost generators that are otherwise not fully utilized during lower load periods and imported into the DVP area. During peak hours, flows into Virginia decrease as Bath County switches from pumping to generating and more of the low cost generation to the west is needed to meet local load.

[51] All transfers were modeled as being between first-tier control areas. For example, as shown in figures ES-1 and ES-2, flows from ComEd to AEP increase following PJM expansion, but these flows are, in effect, wheeled through to DVP an PJM Classic

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Table A-10: Average DVP Zone Net Imports, by Source (MW)

Period	Imports/Transfers	2005 Base Case	2007 Base Case	2010 Base Case	2014 Base Case	2005 Change Case	2007 Change Case	2010 Change Case	2014 Change Case
Off-Peak	Average Net Imports to DVP Zone	1,783	1,842	1,933	2,021	2,104	2,164	2,214	2,280
	Average Transfers from AEP	1,583	1,602	1,693	1,601	1,963	1,911	1,928	1,803
	Average Transfers from PJM	82	130	159	375	109	227	268	505
	Average Transfers from CPL	118	110	81	45	32	26	19	(28)
On-Peak	Average Net Imports to DVP Zone	874	784	455	190	1,587	1,519	1,376	1,154
	Average Transfers from AEP	847	758	438	173	1,467	1,357	1,009	632
	Average Transfers from PJM	25	53	59	120	159	200	428	587
	Average Transfers from CPL	2	(27)	(43)	(103)	(39)	(37)	(62)	(64)
All-Hours	Average Net Imports to DVP Zone	1,350	1,338	1,229	1,149	1,858	1,857	1,815	1,744
	Average Transfers from AEP	1,233	1,200	1,096	921	1,727	1,647	1,490	1,245
	Average Transfers from PJM	55	93	111	253	133	214	345	544
	Average Transfers from CPL	63	45	22	(25)	(2)	(4)	(20)	(45)

Removing impediments to trade between the DVP area and the other PJM companies makes imports more attractive, and as a result flows into Virginia increase by approximately 40 percent. The increase is greatest during peak hours, when the initial trade barriers were the highest.

Figures A-3 and A-4 show the pattern of net transfers throughout the eastern interconnection. Within the expanded PJM, the AEP area is the largest net exporter, and as expected, lowering the costs of exporting to PJM, as captured in the various hurdles, causes AEP net exports to increase. In both the Base and Change Cases, the expanded PJM region is a combined net exporter, but net exports are lower in the change case. In the change case when trade barriers between areas within PJM are removed, the exporting areas both export more overall and redirect some of the exports previously sent to areas outside PJM to internal destination. The redirection of transfers to other PJM companies stems from asymmetric hurdles between areas within PJM and areas external markets; removing the internal PJM hurdles makes internal trade relatively more attractive.

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Figure A-3: Pool to Pool All-Hour Average Transfers (MW) – 2005 Base Case

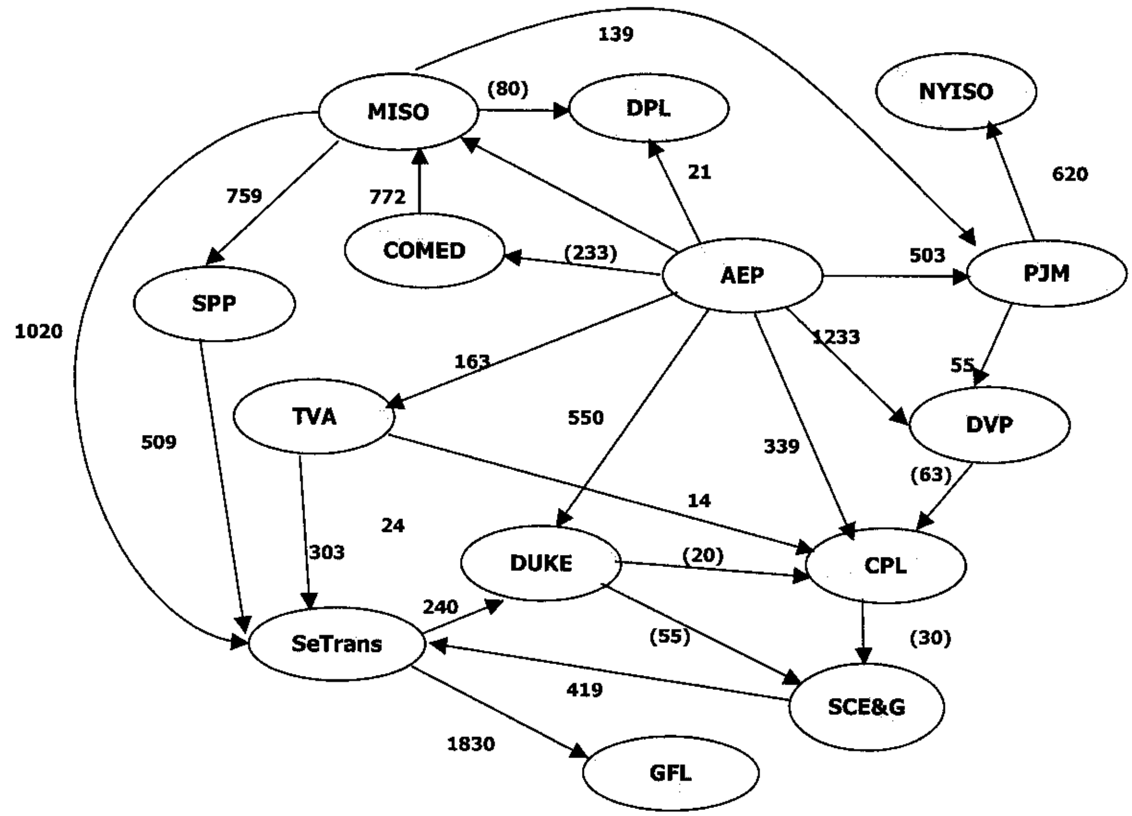

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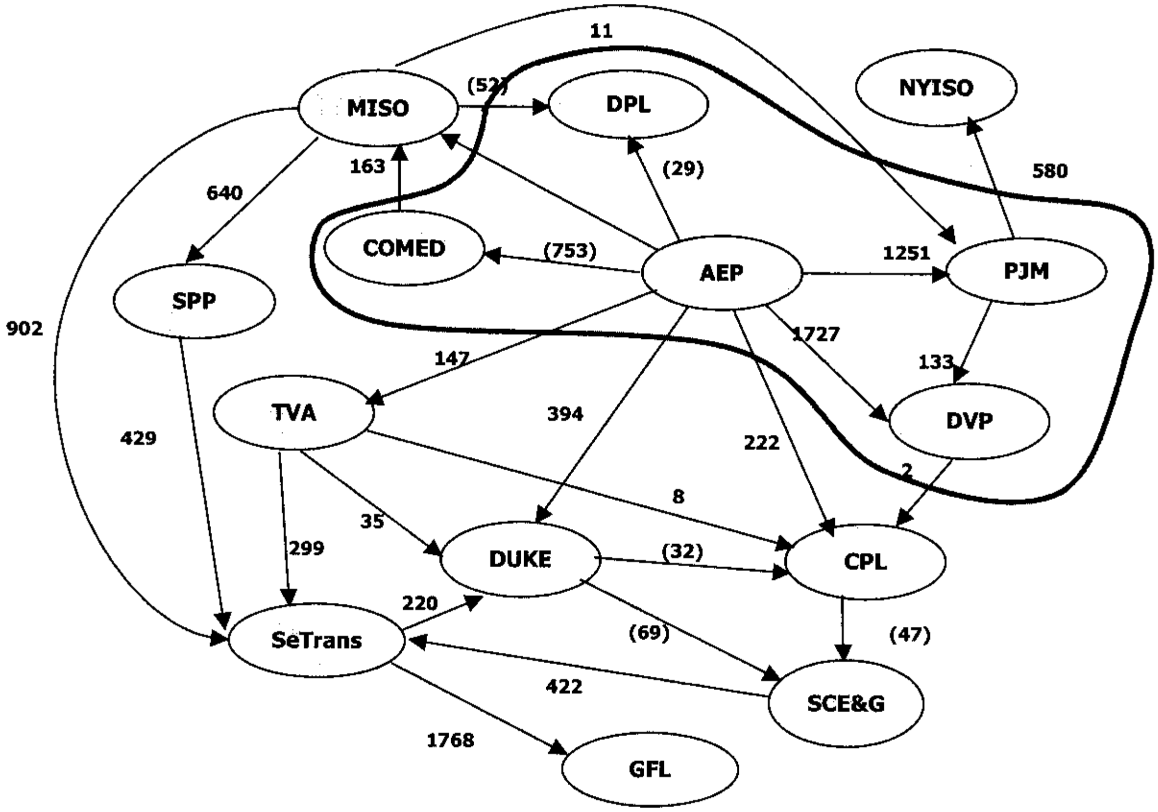
Figure A-4: Pool to Pool All-Hour Average Transfers (MW) – 2005 Change Case



Generation by Unit Type and Region

Table A-11 shows generation by unit type both within the expanded PJM footprint and the rest of the Eastern Interconnection. Consistent with the shift in pool-to-pool transfers between the Base and Change Cases shown in Figures A-3 and A-4, total generation decreases in the expanded PJM region and increased elsewhere. Throughout the Eastern Interconnection, coal generation increases when intra-PJM hurdles are removed, displacing generation among mid-merit combined cycle units and gas- and oil-fired steam generators.

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Table A-11: Generation by Type (GWh)

		2005			2007			2010			2014		
Capacity Pool	TYPE	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)
Non-PJM	CC	205,293	208,194	2,901	239,935	242,690	2,755	308,407	311,457	3,050	395,371	396,340	968
	Coal	1,319,544	1,323,220	3,676	1,345,791	1,349,415	3,624	1,368,591	1,372,031	3,439	1,382,225	1,384,345	2,120
	Hydro	100,956	100,956	-	100,956	100,956	-	100,956	100,956	-	100,956	100,956	-
	New CC	-	-	-	-	-	-	6,435	6,472	37	23,415	23,445	30
	New CT	-	-	-	254	282	28	4,845	4,838	(8)	36,014	36,930	916
	Nuke	411,993	411,988	(5)	411,866	411,869	3	412,234	412,259	25	412,095	412,102	7
	Other	61,995	61,996	1	62,011	62,012	2	61,987	61,991	4	61,971	61,985	13
	Peaker	9,241	9,245	4	15,487	15,624	137	25,853	26,304	451	30,834	31,095	261
	PSH	16,333	16,343	9	16,021	16,068	47	15,010	14,976	(34)	12,366	12,609	243
	ST/G/O/D	102,143	103,120	976	113,000	114,197	1,198	126,968	127,646	678	155,009	156,339	1,330
Non-PJM Total		2,227,498	2,235,060	7,563	2,305,320	2,313,113	7,792	2,431,287	2,438,928	7,642	2,610,256	2,616,145	5,889
PJM (Expanded)	CC	25,336	21,748	(3,588)	31,475	27,455	(4,020)	42,721	39,789	(2,932)	63,638	63,002	(637)
	Coal	411,478	408,872	(2,606)	424,429	422,018	(2,411)	441,217	439,105	(2,112)	453,020	451,925	(1,095)
	Hydro	8,074	8,074	-	8,074	8,074	-	8,074	8,074	-	8,074	8,074	-
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
	New CT	-	-	-	-	-	-	498	16	(483)	3,729	1,744	(1,985)
	Nuke	239,973	239,975	2	239,971	239,968	(3)	239,948	239,944	(4)	239,860	239,857	(3)
	Other	9,356	9,308	(48)	9,502	9,481	(22)	9,510	9,500	(10)	9,540	9,528	(12)
	Peaker	1,201	1,125	(77)	1,947	1,883	(63)	3,406	3,355	(50)	5,209	5,180	(29)
	PSH	7,893	7,886	(7)	7,855	7,850	(4)	8,138	8,153	15	7,827	7,848	21
	ST/G/O/D	13,347	12,225	(1,122)	18,607	17,470	(1,138)	26,051	24,093	(1,959)	36,447	34,785	(1,661)
	Wind	339	333	(7)	339	332	(7)	338	334	(4)	345	342	(3)
PJM Total		716,998	709,546	(7,452)	742,200	734,532	(7,668)	779,902	772,364	(7,538)	827,690	822,285	(5,405)
Eastern Interconnection	CC	230,629	229,942	(687)	271,411	270,145	(1,265)	351,128	351,246	118	459,010	459,341	332
	Coal	1,731,022	1,732,092	1,070	1,770,220	1,771,433	1,212	1,809,808	1,811,135	1,327	1,835,245	1,836,269	1,025
	Hydro	109,030	109,030	-	109,030	109,030	-	109,030	109,030	-	109,030	109,030	-
	New CC	-	-	-	-	-	-	6,435	6,472	37	23,415	23,445	30
	New CT	-	-	-	254	282	28	5,344	4,853	(491)	39,743	38,674	(1,069)
	Nuke	651,966	651,963	(3)	651,837	651,838	0	652,181	652,203	22	651,955	651,959	4
	Other	71,350	71,304	(47)	71,513	71,493	(20)	71,497	71,491	(7)	71,511	71,513	1
	Peaker	10,442	10,370	(72)	17,433	17,507	74	29,259	29,660	401	36,043	36,275	231
	PSH	24,226	24,229	2	23,876	23,918	42	23,148	23,129	(19)	20,193	20,457	264
	ST/G/O/D	115,490	115,345	(145)	131,607	131,667	60	153,020	151,739	(1,281)	191,456	191,124	(332)
	Wind	339	333	(7)	339	332	(7)	338	334	(4)	345	342	(3)
EI Total		2,944,496	2,944,606	111	3,047,520	3,047,644	124	3,211,188	3,211,293	104	3,437,946	3,438,430	484

Within the expanded PJM, the removal of trade barriers leads to a substantial decrease in the amount of generation among mid-merit combined cycle units and gas- and oil-fired steam generators. Somewhat surprisingly coal-fired generation within PJM also decreases. To help illustrate the shifts in generation behind this result Table A-12 shows the output by each type of generator within the individual PJM areas. In the areas with surplus low cost coal-fired generation, AEP, DP&L, and ComEd, coal-fired generation increases, while in PJM (East and West) and DVP, some coal-fired generation is displaced by lower-cost sources during off-peak periods. Outside of PJM, generation among coal, combined cycle, and steam units increases substantially to make up for the decreased transfers from the PJM areas. Table A-21 at the end of this appendix show generation by unit type for each pool in the Eastern Interconnect.

Appendix A GE MAPS Description

Table A-12: Generation by Type and PJM Region (GWh)

		2005			2007			2010			2014		
Capacity Pool	TYPE -	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)
AEP	CC	195	707	511	257	912	655	1,304	2,928	1,624	3,510	7,179	3,669
	Coal	130,287	132,465	2,178	135,631	137,062	1,431	141,082	140,863	(219)	144,530	144,637	107
	Hydro	1,284	1,284	-	1,284	1,284	-	1,284	1,284	-	1,284	1,284	-
	Nuke	15,885	15,885	-	15,888	15,888	-	15,913	15,913	-	15,885	15,885	-
	Other	214	214	(0)	214	214	(0)	214	214	-	213	214	0
	Peaker	-	-	-	-	0	0	20	19	(0)	61	88	27
	PSH	730	728	(2)	710	711	1	620	619	(1)	481	481	0
	ST/G/O/D	0	0	(0)	0	1	0	1	3	1	1	4	3
	New CT	-	-	-	-	-	-	-	-	-	-	-	-
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
AEP Sum		148,595	151,282	2,687	153,984	156,071	2,087	160,438	161,842	1,404	165,965	169,771	3,806
COMED	CC	1,666	1,109	(557)	2,227	1,465	(762)	2,929	2,430	(498)	3,906	3,696	(211)
	Coal	27,944	28,588	644	29,975	30,816	840	33,144	34,154	1,010	35,142	35,704	562
	Nuke	80,330	80,332	2	80,364	80,364	-	80,299	80,296	(4)	80,280	80,278	(3)
	Peaker	177	78	(99)	345	165	(179)	539	364	(175)	1,080	447	(633)
	ST/G/O/D	1,093	335	(758)	1,783	565	(1,218)	3,922	1,021	(2,901)	6,824	3,647	(3,178)
	New CT	-	-	-	-	-	-	106	16	(90)	835	241	(594)
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
COMED Sum		111,211	110,443	(768)	114,695	113,376	(1,319)	120,939	118,280	(2,658)	128,068	124,012	(4,056)
DP&L	Coal	17,682	17,874	192	18,560	18,727	166	19,712	20,046	334	20,765	20,886	121
	Other	45	45	-	45	45	-	45	45	-	45	45	-
	Peaker	-	-	-	11	-	(11)	25	22	(4)	128	48	(81)
	New CT	-	-	-	-	-	-	-	-	-	-	-	-
DP&L Sum		17,727	17,919	192	18,616	18,772	155	19,782	20,112	330	20,938	20,979	41
PJM	CC	17,950	16,345	(1,605)	21,890	20,245	(1,644)	28,772	27,699	(1,074)	41,889	41,252	(637)
	Coal	194,502	190,457	(4,045)	198,190	194,756	(3,435)	203,688	201,286	(2,402)	207,748	206,384	(1,364)
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	5,599	5,599	-	5,599	5,599	-	5,599	5,599	-	5,599	5,599	-
	Nuke	117,393	117,393	-	117,470	117,467	(3)	117,419	117,419	-	117,446	117,446	-
	Other	6,907	6,907	-	6,913	6,912	(0)	6,907	6,907	-	6,914	6,911	(3)
	Peaker	306	352	45	651	736	84	1,100	1,345	245	1,838	2,654	816
	PSH	4,663	4,659	(5)	4,645	4,639	(6)	4,701	4,717	16	4,528	4,549	20
	ST/G/O/D	7,512	8,031	519	11,026	11,998	972	15,112	16,849	1,737	21,283	23,453	2,171
	Wind	339	333	(7)	339	332	(7)	338	334	(4)	345	342	(3)
	New CT	-	-	-	-	-	-	-	-	-	942	-	(942)
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
PJM Sum		355,173	350,075	(5,098)	366,724	362,685	(4,038)	383,637	382,156	(1,482)	408,533	408,590	57
DVP Zone	CC	5,525	3,587	(1,938)	7,102	4,833	(2,268)	9,716	6,733	(2,983)	14,332	10,875	(3,458)
	Coal	41,062	39,488	(1,574)	42,071	40,657	(1,414)	43,592	42,757	(835)	44,834	44,313	(521)
	Hydro	1,192	1,192	-	1,192	1,192	-	1,192	1,192	-	1,192	1,192	-
	Nuke	26,364	26,364	-	26,249	26,249	-	26,316	26,316	-	26,249	26,249	-
	Other	2,189	2,142	(47)	2,330	2,309	(21)	2,344	2,334	(10)	2,367	2,358	(9)
	Peaker	718	695	(23)	940	982	42	1,721	1,605	(116)	2,103	1,943	(159)
	PSH	2,500	2,500	-	2,500	2,500	-	2,817	2,817	-	2,818	2,818	-
	ST/G/O/D	4,741	3,859	(882)	5,797	4,905	(892)	7,016	6,220	(795)	8,339	7,682	(657)
	New CT	-	-	-	-	-	-	393	-	(393)	1,952	1,503	(449)
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
DVP Sum		84,292	79,827	(4,465)	88,180	83,628	(4,553)	95,106	89,974	(5,132)	104,187	98,934	(5,253)

As illustrated in Table A-13, the more efficient commitment and dispatch that is facilitated by removing trade barriers leads to lower overall production costs for the Eastern Interconnection. On the pool level, changes in generation costs mirror the shift in energy production, with production costs increasing in regions with lower-cost generation, and falling in areas where generators run less. Within the expanded PJM, change case production costs are substantially lower in the DVP and PJM classic areas, as companies in these areas purchase more of their energy from external sources and generate less.

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Table A-13: Generation Production Costs by Zone ($M)

	2005			2007			2010			2014		
Capacity Pool	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)
AEP	2,099	2,180	80	2,133	2,195	61	2,305	2,368	64	2,495	2,638	142
COMED	1,102	1,046	(56)	1,148	1,071	(77)	1,298	1,179	(119)	1,525	1,363	(162)
CPL	957	984	28	998	1,021	23	1,117	1,142	25	1,370	1,395	25
DP&L	338	341	2	332	334	2	368	375	7	405	404	(1)
DUKE	1,133	1,150	17	1,182	1,195	13	1,340	1,351	11	1,611	1,634	23
GFL	4,814	4,829	15	5,111	5,115	4	5,576	5,586	10	6,535	6,542	7
MISO E	5,546	5,578	32	5,618	5,654	36	6,227	6,277	50	7,100	7,115	15
MISO W	4,310	4,327	17	4,452	4,467	15	4,930	4,945	15	5,674	5,711	37
ISO-NE	2,483	2,483	(0)	2,544	2,542	(2)	2,738	2,738	1	3,010	3,011	0
NYC	839	848	9	835	843	8	875	885	10	951	963	12
NYL	383	385	2	386	387	1	423	423	0	485	487	1
NYO	1,646	1,654	8	1,667	1,663	(4)	1,803	1,796	(7)	1,986	1,977	(10)
PJM	5,025	4,919	(106)	5,178	5,103	(75)	5,770	5,767	(3)	6,663	6,692	29
SCE&G	828	840	12	845	860	15	911	924	13	1,034	1,048	15
SETRANS E	4,465	4,525	60	4,681	4,761	80	5,209	5,281	72	6,065	6,096	31
SETRANS W	2,245	2,223	(22)	2,469	2,450	(19)	2,871	2,841	(30)	3,465	3,462	(3)
SPP	3,018	3,028	10	3,159	3,169	10	3,597	3,606	9	4,212	4,223	10
TVA	2,267	2,275	9	2,331	2,342	11	2,603	2,612	9	3,016	3,015	(1)
DVP Zone	1,331	1,186	(146)	1,409	1,263	(146)	1,628	1,448	(180)	1,969	1,776	(192)
Total	44,831	44,800	(31)	46,478	46,435	(43)	51,587	51,544	(43)	59,573	59,551	(21)

Locational Spot Prices and Congestion

The change in the pattern of generation between the Base and Change Cases is also reflected in location prices throughout the eastern interconnection. Table A-14 reports each pool's all-hours average LMP. Prices decrease substantially in the importing areas of the expanded PJM, and prices increase in AEP, reflecting its additional exports. Outside of the expanded PJM, prices are generally higher, as net imports decrease and higher cost local generation is relied upon more.

Table A-14: All-Hours Average Spot Prices by Pool

	2005			2007			2010			2014		
Capacity Pool	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)
AEP	20.98	21.79	0.81	21.14	22.10	0.95	23.85	24.83	0.98	28.21	28.31	0.10
COMED	20.62	20.56	(0.06)	20.87	20.87	(0.01)	23.33	23.63	0.30	27.30	27.22	(0.08)
CPL	27.69	28.23	0.55	28.58	29.35	0.77	31.67	32.59	0.92	36.30	36.78	0.48
DP&L	21.05	21.34	0.28	20.82	21.52	0.70	23.20	24.24	1.03	27.19	27.58	0.39
DUKE	27.83	28.38	0.55	28.71	29.37	0.66	31.78	32.48	0.70	36.49	36.84	0.35
GFL	34.31	34.38	0.07	40.80	40.84	0.05	36.50	36.56	0.06	38.03	38.06	0.02
MISO E	22.14	22.30	0.16	22.37	22.60	0.23	24.98	25.30	0.31	28.77	28.91	0.15
MISO W	23.67	23.78	0.11	24.54	24.66	0.12	29.23	29.36	0.12	31.25	31.35	0.10
ISO-NE	33.10	33.09	(0.01)	32.62	32.63	0.01	33.21	33.17	(0.04)	34.20	34.21	0.01
NYC	34.30	34.34	0.04	33.09	33.17	0.09	34.09	34.15	0.07	35.75	35.85	0.10
NYL	36.58	36.53	(0.05)	35.48	35.47	(0.01)	36.86	36.85	(0.00)	38.25	38.22	(0.04)
NYO	30.14	29.93	(0.21)	29.50	29.35	(0.15)	30.44	30.34	(0.11)	31.55	31.45	(0.09)
PJM	26.91	26.64	(0.27)	26.93	26.79	(0.14)	29.14	29.33	0.19	31.96	32.86	0.90
SCE&G	26.70	27.19	0.49	27.44	28.02	0.57	30.16	30.75	0.59	33.96	34.33	0.37
SETRANS E	28.86	28.98	0.13	29.42	29.55	0.13	31.53	31.62	0.08	34.89	34.95	0.06
SETRANS W	29.41	29.42	0.01	29.77	29.79	0.02	31.15	31.20	0.05	32.69	32.66	(0.03)
SPP	26.64	26.73	0.09	27.10	27.22	0.12	29.11	29.23	0.11	31.52	31.60	0.08
TVA	25.98	26.10	0.13	26.26	26.46	0.20	28.74	28.90	0.16	31.85	31.83	(0.02)
DVP Zone	30.61	29.10	(1.51)	31.09	29.60	(1.49)	33.62	32.65	(0.98)	37.11	36.39	(0.72)
Total	27.08	27.10	0.02	27.77	27.84	0.08	29.85	30.00	0.15	32.53	32.68	0.15

The regional prices shown in Table A-14 also help illustrate the typical pattern of power flows and congestion within the expanded PJM area. As power flows from the lower cost coal-fired source in the west to load in the eastern part of the region, the east-west transmission capacity becomes fully utilized, resulting in congestion and separation among LMPs. In particular, transmission facilities in the western portion of PJM are fully more utilized, with substantial congestion on the Black Oak to Beddington and AP South interfaces, over which flows need to be constrained due to voltage and stability limits.

The Black Oak-Beddington and AP South constraints are also the greatest source of congestion costs and the primary cause of price separations within the DVP control zone. In fact, flows on transmission lines with DVP are rarely at their limits and contribute very little to congestion costs. Table A-15 shows the transmission constraints that contribute most to differences among the LMPs within Virginia. Prices are shown for a collection of locations throughout the DVP area, along with the contribution of each constraint to the price differential between that location's LMP and the area-wide average LMP. Locations in the western part of the control zone have much lower LMPs on average than locations in the east, and congestion on Black Oak-Beddington and AP South are the primary sources of the price difference.

Table A-15: Effect of Transmission Constraints on DVP LMPs

	Hours Limited	Mount Storm	Bath County	Clover	Possum Point	North Anna	Yorktown	Surry
Average Price Across Generator Set		28.67	28.67	28.67	28.67	28.67	28.67	28.67
Average Generator Bus Price		25.52	27.22	28.28	31.07	30.17	29.26	29.18
Total Congestion		**(3.15)**	**(1.45)**	**(0.39)**	**2.40**	**1.50**	**0.59**	**0.51**
Congestion from Constraints in Virginia Power Area								
Lexington-Cloverdale for Outage of Pruntytown-Mt. Storm	820	0.04	0.15	(0.08)	(0.02)	(0.02)	(0.03)	(0.03)
FG 1710 Chesterfiled-Tyler 230	64	(0.00)	(0.00)	0.01	(0.00)	(0.00)	(0.00)	0.00
Lexington-Cloverdale for Outage of Mt. Storm-Valley	202	(0.01)	0.04	(0.01)	(0.01)	(0.00)	(0.00)	(0.00)
FG 1718 Chuchatuk-Suffolk 230 kV	36	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)
Total Impact of DVP Constraints		***0.02***	***0.19***	***(0.09)***	***(0.03)***	***(0.02)***	***(0.04)***	***(0.03)***
Congestion from Constraints Outside Virginia								
APS South Interface	1,284	(1.47)	(0.43)	0.15	0.62	0.55	0.30	0.29
Black Oak Beddington Voltage Interface	6,652	(1.49)	(1.20)	(0.59)	1.84	0.98	0.27	0.19
Kanawa-Matt Funk for Outage of Broadford-J Ferry	560	(0.04)	0.06	0.02	(0.03)	(0.01)	0.00	0.00
FG 5 PJM Western Interface	484	(0.02)	(0.01)	(0.00)	0.01	0.01	0.00	0.00
Kanawa-Matt Funk for Outage of Baker-Broadford	164	(0.01)	0.02	0.01	(0.01)	(0.00)	0.00	0.00
Other Contraints		(0.14)	(0.07)	0.12	(0.01)	0.00	0.05	0.06
Total Impact of Outside Constraints		**(3.18)**	**(1.64)**	**(0.30)**	**2.43**	**1.52**	**0.63**	**0.54**

A.4. SENSITIVITY CASES

CRA ran sensitivity cases with higher load and higher gas and oil prices. In the high load case, peak loads were assumed to be 5 percent higher and annual energy 2 percent higher. In the high fuel price case, we assumed generators paid 25 percent higher prices for natural gas and oil.

Appendix A GE MAPS Description

Summary results analogous to those present for the primary case are shown in Tables A-22 through A-30 and Figures A-5 through A-29 at the end of this appendix.

Appendix B Financial Model Description

APPENDIX B FINANCIAL MODEL DESCRIPTION

B.1. OVERVIEW

The Financial Model is an Excel-based model that relies upon inputs from the MAPS model to measure changes in revenues and costs for relevant stakeholders resulting from DVP and the other New PJM Entrants joining PJM in 2005. Changes in revenues and costs are calculated by comparing the Change Case results in which the New PJM Entrants are a part of PJM to a Base Case in which they are not a part of PJM. Since the focus of this analysis is on the *change* in revenues and costs and not the absolute levels in the Base and Change Cases the analysis focuses primarily on *incremental* revenues and costs. As such, items that do not change from the Base Case to the Change Case, such as base rates during the rate freeze period, are not included in the analysis. Net benefits are calculated for Virginia Retail Customers, DVP control zone customers ("DVP Zone Customers") and DVP shareholders.[52]

The Financial Model measures changes in revenues and costs over a 10-year period commencing in 2005 and continuing through 2014. Annual results for each of the 10 years are calculated in addition to a 6-year net present value and a 10-year net present value (discounted to July 1, 2003). The Financial Model relies on inputs from MAPS. MAPS simulates the operation of the electricity system in the Eastern Interconnect in the Base and Change Cases to derive hourly generation by unit, hourly unit generation production costs (fuel, variable O&M, start-up costs and emissions trading costs), hourly location-specific prices for each generation and load bus on the transmission system and hourly flows between interconnected control areas. For each case, MAPS model runs were conducted for 2005, 2007, 2010 and 2014. The remaining years in the analysis (2006, 2008, 2009, 2011, 2012 and 2013) are then interpolated from the MAPS model runs in the surrounding years.

B.2. MAPS OUTPUTS USED IN THE FINANCIAL MODEL

All hourly generation, cost and price data in the Financial Model are outputs from the MAPS model. This data is post-processed using a SAS model to summarize and format the hourly data prior to its inclusion in the Financial Model. The following hourly outputs from the MAPS model are used in the Financial Model:

52 Results for merchant generators are not included in the results of the DVP control zone or elsewhere in this analysis. Such an analysis was outside the scope of this report.

Appendix B Financial Model Description

1. Hourly generation in MWh, separately calculated for DVP-owned units, units under NUG contracts to DVP, and other generation from units located in the DVP control zone.

2. Hourly production costs, separately calculated for DVP-owned units, units under NUG contracts to DVP[53] and other non-merchant generator units located in the DVP control zone.

3. Hourly weighted average DVP energy price, calculated as the weighted average generation bus price of each generating unit in the DVP control zone, weighted by each unit's generation in a given hour.[54]

4. Hourly load prices, there is a single load price within the DVP control zone in each hour.

5. Hourly flows into and out of the DVP control zone, separately calculated for each zone that is interconnected with DVP.[55]

6. Hourly price differentials on flows into and out of the DVP control zone, separately calculated for each zone that is interconnected with DVP.

Additionally, annual capacity is an input into the Financial Model from the MAPS model, with separate annual capacity data for DVP-owned capacity (including capacity under NUG contracts) and other non-merchant generator capacity located in the DVP control zone.

B.3. Other Inputs into the Financial Model

The Financial Model also relies upon a number of inputs that do not come from the MAPS model:

1. DVP Control Zone Ancillary Services Rates, Schedule 1 rates are, based on current DVP OATT rates, $0.02 per MWh, based on current DVP OATT rates, and are kept constant through 2008 after which the rate grows with inflation. The rate is the same in the Base and Change Cases. See Table C-2.

53 Production costs for units under NUG contracts to DVP are based on the contractual price for must-take units and the contractual fuel cost for dispatchable units, with relevant escalation factors.

54 Energy prices at hydro units were not included in the weighted average calculation in hours in which they were pumping rather than generating and thus had "negative" generation.

55 Interconnected areas with DVP are CP&L, AEP and PJM Classic.

Appendix B Financial Model Description

2. DVP Control Zone Ancillary Services Rates, Schedules 2 – 6 rates are, based on current DVP OATT rates, $0.80 per MWh and are kept constant through 2008 after which the rate grows with inflation. The rate is the same in the Base and Change Cases. See Table C-2.

3. PJM Administrative Charge, based on PJM budgeted costs and projected load, including the New PJM Entrants. Rates are $0.43 per MWh in 2005, $0.42 per MWh in 2006, $0.41 per MWh in 2007, $0.42 per MWh in 2008 and then held constant at $0.42 per MWh in real dollars thereafter. See Table C-2.

4. Wheeling rates, based on off-peak NF OATT energy rates. Rates are as follows: DVP ($1.46 per MWh), PJM and New PJM ($1.50 per MWh), CP&L ($1.23 per MWh) and AEP ($1.95 per MWh). A rate of $0.50 per MWh is applied to all trades in off-peak hours.[56] These rates are all in 2002 dollars and apply to both the Base and Change Case. These rates are held constant through 2008 after which the rates grow with inflation. See Table C-1.

5. Load shares, shares of load by customer are based on energy load forecasts for 2005 through 2012 (2013 and 2014 shares use the load forecast for 2012). Shares of 1CP and 12CP load are based on actual 2001 load shares for each customer type. DVP's share of New PJM is based on estimated load in New PJM in 2005.

6. ICAP Prices, ICAP prices for 2005, 2007 and 2010 are derived from a probabilistic ICAP model. The ICAP prices apply for the entire DVP control zone. ICAP prices used in the analysis are $20.00 per kW-year (in 2002 dollars) for 2005 through 2009 in both the Base and Change Cases. Beginning in 2010, ICAP prices rise above the $20.00 per kW-year level, with greater increases in the Base Case compared to the Change Case. See Table VI-5.

7. End of Rate Cap Dates, the DVP Zone Customers that are evaluated in the Financial Model are assumed to transition from rate cap pricing to market pricing for energy at one of three times. Certain wholesale customers are assumed to transition at the beginning of the study period, January 1, 2005. Most other customers are assumed to transition beginning on July 1, 2007. North Carolina retail customers are assumed to not transition during the study period. For simplicity, all customers under rate cap pricing are assumed to purchase energy at the rate cap prices.

56 Off-peak hours for purposes of this analysis include midnight to 6 am and 10 pm to midnight on Monday through Friday, and all day on Saturday and Sunday.

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8. Inflation and discount rate, the assumed inflation rate is 2.5 percent per year and the discount rate used in all net present value calculations is 10.0 percent.

B.4. Annual Calculations – DVP Zone Customers[57]

Fuel Factor Calculations During Rate-Capped Period

Prior to the end of the rate cap, the primary source of benefits in moving to the Change Case from the Base for DVP Zone Customers operating under a DVP fuel factor are captured in a Fuel Factor calculation. The Fuel Factor includes the following costs and credits:

1. Unit Fuel, actual fuel costs for DVP-owned units.
2. NUG Energy Charges, contract prices multiplied by actual hourly generation for must-take NUG contracts, plus contract fuel costs multiplied by actual hourly generation for dispatchable NUG contracts.
3. Purchases for Load, includes imports and purchases from non-DVP-owned generation inside the DVP control zone (*e.g.*, from merchants). In the Base Case, purchases are made at the prevailing spot wholesale energy price in the DVP control zone. In the Change Case, purchases are made at the DVP Load Zone LMP and offset by allocated FTRs to compensate for any congestion costs incurred in these purchases. The purchase costs of imports also include a credit for trade savings that is assumed to be one-half of the price difference between the exporting and importing control areas less the prevailing wheeling rate (trade savings are discussed in more detail below).
4. Sales Cost Credit, credit for the cost of energy sales to non-DVP load (*e.g.*, exports and sales to non-requirements wholesale customers). Calculated as the quantity of sales to non-DVP load multiplied by the highest marginal cost of generation up to the quantity of sales to non-DVP load.
5. Other, includes gas pipeline demand charges and nuclear decommissioning charges.

Costs Other than Fuel Factor

Other costs tracked for DVP Zone Customers include the following:

57 Exceptions to the calculations below are detailed later in this Appendix.

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1. Market Energy Purchases for DVP Zone Customers whose rate cap has ended.. In the Base Case, calculated as annual load multiplied by the prevailing spot wholesale energy price in the DVP control zone. In the Change Case, calculated as annual load multiplied by the DVP Load Zone LMP and offset by the full value of the customers' FTRs to compensate for any congestion costs incurred in these purchases.

    a. Offsetting FTR Value for DVP Zone Customers whose rate cap has ended is calculated as the difference in the DVP Load Zone LMP and the generation bus price, multiplied by the presumed FTR award by PJM (discussed in more detail below). See Tables VI-3, C-3 and C-4.

2. Market Capacity Purchases for DVP Zone Customers whose rate cap has ended. Market Capacity Purchases are calculated by multiplying the annual peak load by the ICAP price multiplied by one plus the reserve margin.

3. Ancillary Payments, calculated as annual load multiplied by the sum of the ancillary services rates for Schedule 1 and Schedules 2 through 6. Cost applies equally before and after the rate freeze time period, and in the Base and Change Cases. Ancillary Services under Schedules 2 through 6 are provided by generators and as such revenues are paid to generators. Changes in generation patterns and hence the share of generation within the DVP control zone could re-allocate these revenues so that incremental benefits or costs attributable to ancillary services can appear.

4. PJM Administrative Cost, applies only to the Change Case, when DVP is a part of PJM. Calculated as annual load multiplied by the PJM Administrative Charge. For DVP Zone customers that own generation, fuel, variable O&M, start-up costs and emissions trading costs are captured for these units. In the Change Case, the sale of this generation at LMP is captured. Capacity credits at ICAP prices for these units are also captured.

Impact on Virginia Retail Customers

The impact on Virginia customers is allocated as described below:

1. Items in the Fuel Factor are allocated based on Virginia Retail Customers' share of load among DVP customers subject to the Fuel Factor.

2. Virginia

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3. Market Energy Purchases, Market Capacity Purchases, Ancillary Payments and PJM Administrative Charges are assessed based on Virginia Retail Customers' load.

4. Virginia Offsetting FTR Value is allocated based on the Virginia Retail Customers' share of DVP requirements load.

B.5. Annual Calculations – DVP Shareholders

DVP shareholders' revenues and costs in the Base Case include the following:

1. Fuel Factor Revenue, includes the Fuel Factor costs of DVP customers. After July 1, 2007, this only includes revenues from North Carolina retail customers.

2. Energy Sales Revenue, calculated as energy sales to non-DVP load (*e.g.*, exports and sales to non-requirements wholesale customers) multiplied by the prevailing spot wholesale energy price in the DVP control zone. Energy Sales Revenue also includes a credit for trade savings on exports.

3. Purchase Costs, include imports and purchases from non-DVP-owned generation inside the DVP control zone for DVP customers whose rate cap period has not ended. Purchases are made at the prevailing spot wholesale energy price in the DVP control zone, but include a credit for import trade savings.

4. Production Costs and NUG Energy, include the total production costs of DVP-owned generation and the contract prices multiplied by actual generation for must-take NUG contracts plus contract fuel costs multiplied by actual generation for dispatchable NUG contracts.

5. Ancillary Services Revenue, including all of the revenue from Schedule 1 Ancillary Services and DVP's share of generation in the DVP control zone multiplied by the Ancillary Services Revenue for Schedules 2 – 6.

6. Net ICAP Revenue (Cost), includes the sale (purchase) of excess (short) capacity relative to DVP's peak load for customers whose rate cap has not ended multiplied by one plus the reserve margin.

DVP shareholders' revenues and costs in the Change Case include the following:

1. Fuel Factor Revenue is calculated as in the Base Case.

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2. Energy Sales Revenue is calculated as unit energy output multiplied by each unit's LMP, for all DVP generators (including NUGs). Energy Sales Revenue also includes a credit for trade savings on exports.

3. Purchase Costs, including imports and purchases from non-DVP-owned generation inside the DVP control zone, during the rate-cap period only. Purchases are made at the DVP Load Zone LMP. Purchase costs also include a credit for import trade savings. Offsetting FTR value, which also applies only during the rate-cap period, is calculated as the difference in the DVP Load Zone LMP and the generation bus price, multiplied by the presumed FTR award by PJM and allocated to the fuel factor based on purchases.

4. Production Costs and NUG Energy, are calculated as in the Base Case.

5. Ancillary Services Revenue, is calculated as in the Base Case.

6. Net ICAP Revenue, includes the PJM ICAP Charge and PJM ICAP Revenue. The PJM ICAP Charge is calculated as the ICAP price multiplied by, the peak load for customers whose rate cap has not ended multiplied by one plus the reserve margin. PJM ICAP Revenue is calculated as the ICAP price multiplied by DVP's total capacity (including NUGs under contract).

7. PJM Administrative Costs are ultimately fully allocated to customers and as a result there is no impact on DVP shareholders, other than the maintenance of a deferral account.

B.6. Key Assumptions

Allocation of Trade Savings

Cross-seam trades occur because higher prices in one area attract lower cost generation. Such trades benefit the importer, which has access to lower priced generation than is available otherwise, and the exporter, which receives a higher price for its generation. Savings from these purchases and sales are allocated to the importer and exporter using a split-savings approach. In other words, 50 percent of the savings is allocated to the exporter and 50 percent is allocated to the importer.

As it pertains to DVP, purchase savings on imports are measured using the price difference on contract flows between regions as determined in the MAPS model. The price difference reflects

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the higher price of generation in the importing area relative to the exporting area. The transmission charge of the exporter is subtracted from the price difference before the purchase savings are split.

Sales savings on exports are also measured using the price difference on contract flows. The transmission charge of DVP is subtracted from the price difference before the sales savings are split.

Exports from the DVP control zone are assumed to be from DVP-owned generation and merchant generation. Generation owned by others within the DVP control zone is assumed to generate only to meet their internal load and hence does not export. The split between DVP-owned generation and merchant generation is based on their relative share of generation in each hour.

FTR Awards

In the Change Case when DVP is part of PJM there is a presumption that DVP and other load in the control area would be awarded FTRs to compensate for any congestion costs incurred in market energy purchases. PJM conducted a preliminary analysis to determine the quantity of FTRs that would be awarded to DVP network resources. CRA has modified those preliminary awards to match with DVP's peak load in 2005, 2007 and 2010. In 2005, FTR awards were scaled down for all units, with the exception of Bath County and Mount Storm, such that the total FTRs awarded equaled DVP's peak load. These same units for which the FTR awards were scaled down in 2005 later grew at the same rate as DVP's peak load for 2007 and 2010.

PJM did not conduct a similar preliminary analysis of FTR awards for other load in the DVP control zone. Instead CRA has estimated the FTR awards to this other load based on the summer capacity of non-DVP-owned units in the control zone and the associated peak load that these units serve.

APPENDIX C ASSUMPTIONS AND DETAILED FINANCIAL RESULTS

This section includes tables showing relevant inputs and detailed results.

Table C-1: Transmission Rates (Base and Change Cases)

Area	Base Case	Change Case	
DVP	$1.46	$1.46	per MWh in 2002$
Classic PJM	$1.50	NA	per MWh in 2002$
New PJM	NA	$1.50	per MWh in 2002$
CP&L	$1.23	$1.23	per MWh in 2002$
Off-Peak	***$0.50***	***$0.50***	per MWh in 2002$
Assumed to grow with inflation after 2008			

Table C-2: Ancillary Service Rates and PJM Administrative Charges

		DVP	PJM	
VAP Zone Ancillary Service Rate (Sch. 1)		$0.02	$0.02	per MWh
VAP Zone Ancillary Service Rate (Sch. 2-6)		$0.80	$0.80	per MWh
	2005	2006	2007	2008
PJM Admin Charge ($/MWh)	$0.43	$0.42	$0.41	$0.42

Appendix C Assumptions and Detailed Financial Results

Table C-3: DVP FTR Quantities by MAPS Unit

DVP Unit	2005 FTR MW Provided	2007 FTR MW Provided	2010 FTR MW Provided	2014 FTR MW Provided	DVP Unit	2005 FTR MW Provided	2007 FTR MW Provided	2010 FTR MW Provided	2014 FTR MW Provided
BATHCVAP	1548.0	1548.0	1548.0	1548.0	COVINGT5	10.1	10.6	11.3	12.3
MTSTORM1	545.0	545.0	545.0	545.0	COVINGT6	10.1	10.6	11.3	12.3
MTSTORM2	545.0	545.0	545.0	545.0	CHESTFD3	91.8	96.6	102.8	112.0
MTSTORM3	536.0	536.0	536.0	536.0	CGNRICH2	81.8	86.0	91.6	99.7
SURRY01	708.4	744.9	793.3	864.0	DARBYTO1	80.5	84.6	90.1	98.1
SURRY02	712.8	749.5	798.2	869.3	DARBYTO2	80.5	84.6	90.1	98.1
YORKTOW3	717.2	754.1	803.1	874.6	DARBYTO3	80.5	84.6	90.1	98.1
CHESTFD6	586.8	617.0	657.1	715.7	DARBYTO4	80.5	84.6	90.1	98.1
NTHBRANC	67.3	70.8	75.4	82.1	ROANOST1	19.7	20.7	22.0	24.0
CLOVER02	192.8	202.8	215.9	235.2	APPOMAT1	33.2	34.9	37.2	40.5
CLOVER01	192.8	202.8	215.9	235.2	KITTYGT1	24.5	25.7	27.4	29.9
MECKLEN1	57.7	60.7	64.6	70.4	KITTYGT2	24.5	25.7	27.4	29.9
GASTONPD	196.8	206.9	220.4	240.0	DOSWECC1	324.6	341.3	363.5	395.9
BREMOBL4	139.9	147.1	156.7	170.7	DOSWECC2	324.6	341.3	363.5	395.9
PANDARCC	173.2	182.1	193.9	211.2	GRAVELN2	24.5	25.7	27.4	29.9
ROANOKVP	146.2	153.8	163.8	178.3	CHESAP10	25.4	26.7	28.4	30.9
LGEALTAV	54.8	57.7	61.4	66.9	CHESAPE7	25.4	26.7	28.4	30.9
COMMONA1	91.0	95.6	101.9	110.9	CHESAPE8	25.4	26.7	28.4	30.9
GORDONCC	251.7	264.7	281.9	307.0	CHESAPE9	25.4	26.7	28.4	30.9
HOPEWECC	346.0	363.8	387.4	422.0	CHESAGT1	16.6	17.5	18.6	20.3
MULTITR1	35.0	36.8	39.2	42.7	CHESAGT2	15.7	16.6	17.6	19.2
MULTITR2	35.0	36.8	39.2	42.7	CHESAGT4	15.7	16.6	17.6	19.2
CHESAST4	193.3	203.2	216.4	235.7	CHESAPE6	15.7	16.6	17.6	19.2
ROANOKPD	84.0	88.3	94.0	102.4	GRAVELN1	14.9	15.6	16.6	18.1
CHESTFD5	272.9	286.9	305.6	332.8	NTHNECK1	16.6	17.5	18.6	20.3
BREMOBL3	64.7	68.0	72.5	78.9	NTHNECK2	16.6	17.5	18.6	20.3
DCBATTL2	50.3	52.9	56.3	61.3	NTHNECK3	16.6	17.5	18.6	20.3
DCBATTL1	50.3	52.9	56.3	61.3	NTHNECK4	16.6	17.5	18.6	20.3
BELLMEAD	218.6	229.9	244.8	266.7	DOSWELL1	149.6	157.2	167.5	182.4
CHESAPE3	141.7	149.0	158.7	172.8	ALEXARL1	8.7	9.2	9.8	10.7
CHESTFD8	205.5	216.1	230.1	250.7	ALEXARL2	8.7	9.2	9.8	10.7
YORKTOW2	150.4	158.2	168.4	183.5	POSSUGT1	14.0	14.7	15.7	17.1
CHESTFD7	202.9	213.3	227.2	247.5	POSSUGT2	14.0	14.7	15.7	17.1
YORKTOW1	142.6	149.9	159.6	173.9	POSSUGT3	14.0	14.7	15.7	17.1
LGESOUTH	54.8	57.7	61.4	66.9	POSSUGT4	14.0	14.7	15.7	17.1
CHESAST1	97.1	102.1	108.7	118.4	POSSUGT5	14.0	14.7	15.7	17.1
CHESAST2	97.1	102.1	108.7	118.4	POSSUGT6	14.0	14.7	15.7	17.1
PORTSMO1	47.2	49.7	52.9	57.6	CAROLNE1	155.7	163.7	174.3	189.9
CHESTFD4	149.6	157.2	167.5	182.4	CAROLNE2	155.7	163.7	174.3	189.9
ROANOKV1	39.4	41.5	44.2	48.1	I95ENER1	69.1	72.6	77.4	84.3
LOWMOOR1	15.7	16.6	17.6	19.2	POSSUMP3	91.8	96.6	102.8	112.0
LOWMOOR2	15.7	16.6	17.6	19.2	BIRCHWO1	211.8	222.7	237.2	258.3
LOWMOOR3	15.7	16.6	17.6	19.2	FAUQUIC3	155.7	163.7	174.3	189.9
LOWMOOR4	15.7	16.6	17.6	19.2	FAUQUIC1	155.7	163.7	174.3	189.9
CGNRICH1	101.0	106.2	113.1	123.2	FAUQUIC2	155.7	163.7	174.3	189.9
CGNHOPEW	76.1	80.0	85.2	92.8	FAUQUIC4	155.7	163.7	174.3	189.9
GRAVELN3	80.5	84.6	90.1	98.1	POSSUMP4	193.3	203.2	216.4	235.7
GRAVELN4	80.5	84.6	90.1	98.1	NTHANNA2	709.0	745.4	793.9	864.6
GRAVELN5	80.5	84.6	90.1	98.1	NTHANNA1	715.1	751.9	800.8	872.2
GRAVELN6	80.5	84.6	90.1	98.1	POSSUMP5	700.5	736.6	784.5	854.4
COVINGT1	10.1	10.6	11.3	12.3	POSSUMP6	393.6	413.8	440.7	480.0
COVINGT2	10.1	10.6	11.3	12.3					
COVINGT3	10.1	10.6	11.3	12.3					
COVINGT4	10.1	10.6	11.3	12.3	**Totals**	10,744	11,134	11,651	12,406

Appendix C Assumptions and Detailed Financial Results

Table C-4: Other DVP Control Zone FTR Quantities by MAPS Unit

ODEC Unit	2005 FTR MW Provided	2007 FTR MW Provided	2010 FTR MW Provided	2014 FTR MW Provided
JKERRVAP	98.0	102.1	107.5	105.9
CLOVER02	211.7	220.5	232.2	228.7
CLOVER01	211.7	220.5	232.2	228.7
BOSWTAV1	75.6	78.7	82.9	81.7
BOSWTAV2	75.6	78.7	82.9	81.7
BOSWTAV3	75.6	78.7	82.9	81.7
BOSWTAV4	75.6	78.7	82.9	81.7
BOSWTAV5	144.0	150.0	157.9	155.6
NTHANNA1	103.0	107.3	113.0	111.3
NTHANNA2	102.1	106.4	112.0	110.3
REMINGM1	144.0	150.0	157.9	155.6
REMINGM2	144.0	150.0	157.9	155.6
REMINGM3	144.0	150.0	157.9	155.6
REMINGM4	-	-	-	155.6
	1,605	1,672	1,760	1,890

Appendix D Other Studies of RTO Benefits/Costs

APPENDIX D OTHER STUDIES OF RTO BENEFITS/COSTS

This appendix is based broadly on the CRA survey of RTO cost-benefits studies that was conducted in conjunction with the SEARUC study. This has been updated to include the SEARUC study itself as well as the more recent United States Department of Energy ("DOE") study.

In all, there have been eight other studies, besides this study on behalf of Dominion Virginia Power, that have addressed the potential benefits, and in some cases the costs of forming RTOs. Three of these studies (Mirant, NYISO and PJM) analyzed the benefits of forming a single Northeast RTO consisting of PJM, NYISO and ISO-NE. Another study evaluated the net benefits of merging the NYISO and ISO-NE into a single RTO. The fifth study evaluated the benefits and costs of forming RTO West. In contrast to these five studies, which addressed the benefits of forming individual RTOs, the three remaining studies examined the benefits and costs of instituting multiple RTOs. The ICF study, commissioned by FERC, studied the benefits of instituting RTOs throughout the continental U.S. The SEARUC study, conducted by CRA, studied the benefits and costs associated with three southeastern RTOs. Finally, the DOE studied the benefits and costs of implementing FERC's Standard Market Design throughout the continental U.S. at the request of Congress.

The Mirant and NYISO studies used historical data as a basis for calculating the potential benefits of a Northeast RTO. These studies analyzed a single year of operations. In contrast, the other studies used production cost models to simulate future electric system operations and prices under different market/policy scenarios. Benefits of alternative RTO policies were determined by comparing costs and prices in the RTO policy case(s) to those where the status quo was maintained. The PJM and RTO West studies analyzed a single year and the study analyzing the merger of the NYISO and ISO-NE analyzed the years 2005 and 2010. In contrast to these studies of individual years, the ICF and DOE studies had 20-year time horizons, while the SEARUC study had a 10-year period.

The Mirant and NY ISO studies relied upon statistical analyses of historical data and are not easily compared to this study. The remaining studies used forward-looking approaches that have many similarities to this study, which are discussed below.

DOE STUDY

The U.S. Congress requested that DOE study the benefits and costs of FERC's proposed SMD rule. The DOE study was conducted with the assistance of several outside, independent consultants. DOE analyzed the impacts of the proposed SMD using both quantitative and non-quantitative approaches. The quantitative analysis was conducted using two formal models. Most of the benefits were estimated using DOE's Policy Office Electricity Modeling System

Appendix D Other Studies of RTO Benefits/Costs

("POEMS"), which is based on the Energy Information Administration's National Energy Modeling System ("NEMS"). The POEMS modeling was conducted by OnLocation, Inc. POEMS has many advantages as a long-run electricity simulation model, but it is limited in its ability to represent the electricity transmission system. POEMS uses a transportation modeling logic that does not account for the parallel path flow of power in the grid. To address this limitation, DOE also studied the impact of the proposed SMD rule using the GE-MAPS model that incorporates real power flow information and transmission constraints into the analysis. In this regard, the DOE study is similar to this study on behalf of Dominion that is based on the MAPS model. DOE limited the MAPS modeling to the first 4 years of the 20-year study period in order to address near term issues in greater detail. In effect, DOE relied on POEMS for long-term results and relied on both POEMS and MAPS for near term results.

The modeling approach used in the DOE study is similar to that employed here. Both the POEMS and MAPS modeling efforts were based on the use of "hurdle rates" to represent the economic inefficiencies inherent in the base case—limitations on trading opportunities in the absence of the proposed SMD rule. These trading impediments or hurdles then were reduced to assess the impact of implementing the SMD rule. The hurdle rates in the DOE study were $10 per MWh in the unit-commitment phase of the MAPS model, and $5 per MWh in the dispatch phase in the Eastern Interconnection and somewhat lower in the Western Interconnection. These are comparable to the hurdle rates used for this study. In particular, the commitment hurdle is the same, while the dispatch hurdle has been refined for this study in that it uses both pancaked hurdle rates (trade hurdles) and non-pancaked hurdle rates (import hurdles) in the dispatch phase. As a consequence, the hurdle rate for moving power to a first-tier market is somewhat higher in this study than in the DOE study, but is somewhat lower for power movements to second-tier markets and beyond.

The DOE study, similar to this study, modeled adoption of SMD by considering trade hurdles to be effectively zero within an RTO and at the above-described levels for trade between RTOs or between control areas in the base case. Additionally, the DOE study made two other assumptions regarding further efficiencies, which we did not include in this study. The DOE study assumed that the engineering efficiency of steam-driven generation facilities would improve under SMD relative to the base case. Coal-fired steam generation is assumed to improve by 2 percent, while gas-fired steam generation is assumed to improve by 4 percent. The DOE study reports a sensitivity case in which this efficiency assumption is not made. Moreover, the DOE study assumed that five percent additional scheduled transmission capacity would become available within RTOs under SMD on the grounds that a single system operator would be better able to fully utilize existing physical capacity by comparison to the conservative operation of the system today in which one operator is not entirely certain of the operations of its neighbor.

The DOE study examined three sensitivity cases. In one, the assumption about 5-percent additional transmission capacity was dropped (called "SMD w/o 5% T" in Table D-1 below). In the

Appendix D Other Studies of RTO Benefits/Costs

second, the assumption about generation efficiency improvements was dropped (called "SMD w/o GEI" in the table below). In the third sensitivity, the 5-percent additional transmission capacity was expanded to become an assumption that capacity would be larger by 10 percent. The DOE study focused on consumer benefits, reporting the results for consumers on both a national level and for 16 separate regions of the country. The study also reported the savings in production costs, which is equivalent to aggregate social benefits for both consumers and producers. Consumer benefits were larger than social benefits because producers earned a lower level of profits under SMD as a result of lower wholesale prices. The national results for both consumer benefits and social benefits are reported in the table below.

Table D-1: Benefits from DOE Study

Consumer Benefits from DOE Study
($ Millions Annually)

	Consumer Benefits			Net Consumer Benefits		
Scenario	Near	Mid	Long	Near	Mid	Long
SMD	$ 1,799	$ 1,588	$ 1,482	$ 1,037	$ 826	$ 720
SMD w/o 5% T	$ 1,797	$ 1,588	$ 1,490	$ 1,035	$ 826	$ 728
SMD w/o GEI	$ 1,458	$ 915	$ 965	$ 696	$ 153	$ 203
SMD w/ 10% T	$ 1,850	$ 1,666	$ 1,505	$ 1,088	$ 904	$ 743
RTO Costs	$ 762	$ 762	$ 762			

Source: DOE Study, Appendix A, p. 32, table for Figure 3.10

Social Benefits from DOE Study
($ Millions Annually)

	Social Benefits			Net Social Benefits		
Scenario	Near	Mid	Long	Near	Mid	Long
SMD	$ 1,095	$ 1,092	$ 926	$ 333	$ 330	$ 164
SMD w/o 5% T	$ 1,094	$ 1,090	$ 925	$ 332	$ 328	$ 163
SMD w/o GEI	$ 773	$ 591	$ 458	$ 11	$ (171)	$ (304)
SMD w/ 10% T	$ 1,144	$ 1,136	$ 959	$ 382	$ 374	$ 197

Source: DOE Study, Appendix A, p. 32, table for Figure 3.18

Appendix D Other Studies of RTO Benefits/Costs

Consumer benefits are significantly positive. Lower wholesale prices in the change case, however, results in net losses for producers. Overall, social benefits are positive or roughly at a breakeven level, especially in the sensitivity case in which the assumption about generation efficiency improvements is dropped.

SEARUC STUDY

The SEARUC study was conducted by CRA and GE Power Systems Engineering Consulting on behalf of the Southeastern Association of Regulatory Utility Commissioners. This study examined the impacts of forming three RTOs in the southeast—SeTrans, GridSouth and GridFlorida.

The SEARUC study assessed the short-run benefits of forming southeastern RTOs using the GE-MAPS model and a methodology similar that employed for this study. A base case was calibrated to historical usage patterns of generation using hurdle rates that are similar to those in this study. In particular, the same $10 per MWh hurdle rate was used for the unit-commitment phase of MAPS. The dispatch hurdle rate in the SEARUC study was about $7-$8 per MWh consisting of a $5 per MWh rate to reflect trade impediments, a $1 per MWh rate for line losses, and a $1-$2 per MWh transmission rate. This hurdle rate was pancaked in the SEARUC study. In this study for DVP, the dispatch hurdle rate has been separated into a pancaked trade hurdle and a non-pancaked import hurdle. As such, the methodology used here is somewhat improved over that adopted in the SEARUC study.

The market structure in the SEARUC was similar to that in this study. For example, the hurdle rates do not apply for trades within RTOs (except for line losses), but do impact trades that cross RTOs boundaries (or boundaries between control areas in the base case). The SEARUC study examined several sensitivity cases. The most important of these assessed the impacts of Participant Funding and the level of merchant plants in the Entergy and Southern Company areas that decide to remain in the market.

The Participant Funding issue was a purely financial matter about who pays for the expansion of the transmission gird needed to integrate merchant generation capacity for the purpose of becoming a network resource for native load customers. The timing of when such investment would be made in the future was impacted by whether native load customers paid for such investment in the first instance, or whether the merchant generation paid for it with subsequent recovery in delivered power rates. If native load paid for such investment initially, the study concluded that the large excess of merchant capacity in the area would result in excessive levels of transmission investment being made earlier than needed. In contrast, Participant Funding, in which the merchant generators paid for the investment as an initial matter, would delay such investment until it was needed to integrate the network resources keeping in pace with future growth in native load. This difference in

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the timing of the transmission investment resulted in benefits to native load—not needing to pay for transmission investment in advance of when it is needed.

The other major sensitivity examined in the SEARUC study was the level of merchant plants deciding to go forward. The Entergy-Southern Company area had about 24,000 MW of excess merchant capacity at the time of the study. Since the study, this level has been reduced slightly, but the remaining excess is still quite large. The uncertainty about the amount of such capacity that might decide to remain in the market versus withdrawing until a later date was addressed through a sensitivity case in which the assumed level of merchant plants was about 7,500 MW smaller. This assumption had a significant impact on the results, with benefits generally being smaller for the reduced level of merchant participation in the market.

The results of the SEARUC study are summarized in Table D-2, which is Table ES-1 from the executive summary of the SEARUC study.

Table D-2: Benefits from SEARUC Study
Net 2004-2013 Benefits in RTO Cases in Comparison to No RTO Base Case
(Millions of 2003 Present Value Dollars)[58]

SCENARIO		SeTrans		Grid South	Grid Florida	SEARUC		Eastern Inter-Connect.
		Native Load	Total			Native Load	Total	
2	3 RTOs w/o SMD	(889)	(704)	(372)	(273)	(1,534)	(1,349)	(1,088)
3	3 RTOs w/SMD	352	150	(286)	(25)	40	(162)	497
5	3 RTOs w/SMD & Participant Funding	1,623	1,421	(286)	(25)	1,311	1,109	1,768
3 v. 2: SMD Impact		*1,241*	*854*	*85*	*248*	*1,574*	*1,187*	*1,585*
5 v. 3: Participant Funding Impact		*1,271*	*1,271*	*0*	*0*	*1,271*	*1,271*	*1,271*

Table D-2 shows that the SeTrans area could be expected to benefit from the institution of RTOs and SMD, but that the GridSouth and GridFlorida areas would not. The GridFlorida area would basically break even, while GridSouth appears to have negative benefits. The bottom line in Table D-2 shows that the impact of Participant Funding is significant in the SeTrans area, in

58 Numbers in this table, and in the tables throughout this report, may not add due to rounding.

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particular. The other areas are not impacted by Participant Funding because they do not have the excess merchant generation capacity that is the source of the issue.

Table D-3 shows the impact of the reduced level of merchant generation from the SEARUC study. The benefits in the SeTrans area are significantly smaller if fewer merchant plants decide to go forward. The GridSouth and GridFlorida areas also impacted with a lower level of benefits as a general matter. This was due to a smaller price impact from instituting RTOs/SMD if a smaller level of generation is bottled up in the Entergy/Southern Company areas as an initial matter.

Table D-3: Alternative SEARUC Benefit Measure
Net 2004-2013 Benefits in RTO Cases in Comparison to No RTO Base Case
With 7,500 MW Less SeTrans Merchant Capacity
(Millions of 2003 Present Value Dollars)

SCENARIO		SeTrans		Grid South	Grid Florida	SEARUC		Eastern Inter-Connect.
		Native Load	Total			Native Load	Total	
9	3 RTOs w/SMD	3	170	(357)	(148)	(501)	(335)	(348)
10	3 RTOs w/SMD & Participant Funding	972	1,138	(357)	(148)	467	633	621
10 v. 9: Participant Funding Impact		*969*	*969*	*0*	*0*	*969*	*969*	*969*

PJM STUDY

The PJM study was designed to estimate the impact of implementing a Northeast RTO – which would include PJM, the NYISO and ISO-NE. The study focused on near term market price impacts and used the GE Multi-Area Production Simulation (GE MAPS) model to simulate hourly locational marginal prices across the region.

The study modeled the period from January to December 2001 (8,760 hours) so that the model could be calibrated to more closely match actual, observed flows on the transmission system, assuming that each region undertook a separate commitment and dispatch. The study used a centralized unit commitment and dispatch process to represent the operation of a single Northeast RTO for the same period. Results from the two runs for 2001 were compared as a basis for establishing benefits.

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Three measures were evaluated in particular: the delivered costs of electricity to load, generation production costs and the revenues earned by generators within the region. The base case results indicated an overall benefit to forming a single Northeast RTO. While the study showed a net benefit for the entire region, the distribution of costs and benefits differed substantially among the existing ISOs. On net, load and generation in the NYISO experienced a $22 million loss, while the net impact on load and generation in both PJM and ISO-NE was positive. Specifically, New York consumers benefited, as well as generators in PJM and New England. In contrast, load in PJM and New England faced higher costs under the single RTO, while generators in New York had lower earnings.

NYISO/ISO-NE Study

ISO New England ("ISO-NE") and the New York ISO ("NYISO") conducted an assessment of the effects on the wholesale electricity market and the organizational impacts of forming a proposed Northeast Regional Transmission Organization ("NERTO"). The study was undertaken in response to an agreement reached between the ISO-NE and NYISO Boards of Directors in January 2002 (the "January Agreement"). The January Agreement established a plan to institute numerous market improvements, resolve seams issues, standardize market designs, create the conditions for improved market relations with several Canadian Provinces and, subject to an economic evaluation, form an RTO with a single dispatch.

The study identifies the potential costs of implementing NERTO as well as the savings from the market efficiencies and operational consolidation expected to result from NERTO. The primary focus of the study was on the combination of the NYISO and ISO-NE. However, the study did evaluate a "Three-Way RTO," which added PJM to the mix. The impacts of the market changes were shown for the years 2005 and 2010 both on a region-wide and on an individual ISO basis.

The study found a substantial difference in prices and costs between New York, New England and PJM in 2005 in the base case – with New York prices well above those in New England and PJM. The price/cost differential reflects the installation of over 10,000 MW of new more efficient generating capacity in New England and the much smaller amount of capacity additions in New York, while lower PJM prices result from its large mix of coal fired generation and better access to coal-fired generation in the Midwest.

With this starting point, the study found annual regional savings of $203 million for the "Three-Way RTO in 2005 and $220 million for New York and New England, for the NERTO configuration, as shown in Table D-4.[59] As shown in the table, the annual savings are very different

59 Page 10 of the NERTO study. Benefits are defined as the savings in wholesale power costs. Benefits are shown for both the "Three-Way RTO" configuration and the NERTO (NYISO and ISO-NE, only) configuration.

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for the three regions. New York has a reduction in its power costs in both configurations, while New England and PJM have increases. The benefits to New York are largest in the Three-Way RTO configuration, while PJM's cost increased the most under that configuration. The Three-Way RTO configuration moderates the increase for New England as New York draws more on imports from PJM. It should also be noted that PJM costs still rise under the NERTO configuration.

Table D-4: Benefits from NERTO Study
Annual Savings in Wholesale Power Costs ($ millions)

2005					
Configuration	New York	New England	PJM	New England & New York Sub-Total[1]	Three Region Total[1]
Three-Way RTO[2]	367	-28	-136	339	203
NERTO[3]	282	-62	-97	220	123

2010					
Configuration	New York	New England	PJM	New England & New York Sub-Total[1]	Three Region Total[1]
Three-Way RTO[4]	186	23	-144	209	65
NERTO[5]	147	3	-107	150	43

Notes:
1. New England and New York sub-total and three region total not shown in the original NERTO report table.
2. Includes reserve benefits of: New York - $9 million, New England $14 million, PJM $10 million and $5 million in organizational savings for all three regions.
3. Includes reserve benefits of: New York - $9 million, New England $14 million and $5 million in organizational savings for both regions.
4. Includes reserve benefits of: New York - $9 million, New England $14 million, PJM $10 million and $18 million in organizational savings for all three regions.
3. Includes reserve benefits of: New York - $9 million, New England $14 million and $18 million in organizational savings for both regions.

Annual savings decline substantially by 2010 with the addition of more efficient (lower cost) generation in New York after 2005, which begins to equalize generation costs/prices across the regions. The annual savings for the Three-Way RTO decline to $65 million (from $203 million in 2005), while savings for New York and New England in the NERTO configuration decline to $150 million from $220 million in 2005.

Power cost savings between the two configurations can be attributed to differences in the current and projected mix of generation across the three regions. In both 2005 and 2010, New York realizes the largest share of benefits from market changes related to an RTO. This is because New

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York's older, higher-cost generation would be displaced by lower-cost, coal-fired generation from PJM and lower cost natural gas-fired generation from New England. For example, under the NERTO configuration in 2005 with single dispatch, New York would import more than 4 percent of its energy from New England. The New England to New York transfers cause New England's energy prices to rise slightly in the near term, but these increases would be partially offset by savings from shared operating reserves and organizational consolidation.

As new, lower-cost generation is added in New York, there would be fewer opportunities for lower-cost generators from New England and PJM to reduce costs in New York, thus causing prices to equalize across the regions.

RTO West Study

Tabors Caramanis & Associates (TCA) conducted a cost/benefit analysis for the member utilities of RTO West. The primary aim of the study was to assess the benefits in the RTO West and WSCC regions from establishing RTO West. Market simulations were conducted using GE MAPS to model the RTO West and WSCC regions. A base case ("Without RTO West") was developed, the results of which were then compared to a scenario that assumed the implementation of RTO West – "With RTO West" – to quantify the estimation of benefits.

The MAPS model was used to find hourly production cost forecasts at each major transmission bus in the West. Benefits were measured as the differences in the energy costs of load net of generators' operating margin.

The results indicated benefits from RTO West implementation in all western regions, except for California. In every region there were savings to native load customers, with the greatest savings in the RTO West region (including British Columbia). On the other hand, in every region generators were expected to see a decline in their net revenue, particularly in California and the RTO West region. However, the total savings to load was greater than the net lost revenue to generators.

A number of sensitivities were run to assess the impact of changes in physical conditions (low water/high gas price and new generation in Montana) as well as the impact of various benefit drivers on the overall benefits. The results indicated that the two main benefit drivers in the analysis were the elimination of pancaked transmission loss charges and the increase in reserve sharing. The elimination of pancaked transmission loss charges had a significant impact on reducing congestion charges, while increased reserve sharing dramatically lowered production costs.

The RTO West analysis also included a detailed benchmark assessment of RTO start up and operating costs. The study estimated that, on average, the annual cost to operate RTO West, including the amortized start up costs, would be $127 – $143 million, or $0.45 per MWh to $0.51 per

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MWh of annual energy demand. The higher end of the cost estimate included the benchmark average when the startup and operating costs of the CAISO were included.

ICF Study

In order to directly address the issue of RTO benefits on a national level, FERC commissioned ICF to conduct a nation-wide RTO cost/benefit analysis. The study was designed to assess the long-term benefits of RTO formation, with a twenty-year study period (2002-2021).

The study was conducted using the Integrated Planning Model (IPM). IPM is ICF's proprietary production cost model that produces unit commitment and economic dispatch decisions based on various assumptions and inputs affecting market supply and demand. However, IPM does not use a detailed representation of the transmission system. Instead it assumes that any generation can be used to serve any load within a generation region (for example, there is no representation of any transmission constraints within the Entergy or Southern Company control areas and there are no transmission constraints with the entire FRCC region). Between each pair of interconnected regions, the model uses a single path with a rated capacity to represent the more complex transmission network that actually interconnects the two regions. This type of model is sometimes described as a transport model or a "bubble" model.

Historical 2000 data was used to calibrate the IPM model, adjusting transmission hurdle rates (wheeling rates + market inefficiencies) between regions so that modeled generation output was within 5 percent of actual generation output. A baseline was established to which several RTO policy cases then were compared. The policy scenarios, included:

- A **Transmission Only** case – which eliminated the hurdle rates used in the Base Case and included no transmission charges between sub-regions within RTOs and a $2 per MWh charge between RTOs. Transmission capacity among sub-regions within an RTO was assumed to increase by 5 percent over the base case, while transmission capacity between RTOs was not modified. The amount of capacity that could be shared between regions was assumed to increase to 100 percent of the transfer capability as compared to 75 percent in the base case. In addition, reserve margins were assumed to decline to 13 percent instead of the 15 percent in the base case.

- The **RTO Policy** case – included all of the assumptions from the Transmission Only case and the assumption that heat rates for all fossil-fired units would improve by a total of 6.0 percent by 2010 and the availability of these units is assumed to increase by 2.5 percent.

- The **Demand Response** case – in addition to the assumptions in the RTO Policy case, price-sensitive demand response was assumed to reduce regional peak demand by 3.5 percent.

Appendix D Other Studies of RTO Benefits/Costs

Two further sensitivities based on the RTO Policy scenario were run to measure the impact of larger and smaller RTOs. The larger RTO sensitivity assumed three RTOs as defined by the Eastern and Western Interconnections, plus ERCOT. The smaller RTO sensitivity included the eight RTO/ISO regions at the time the study was conducted.

Resulting savings were estimated by comparing the system-level production costs generated in the base case to those generated under each of the policy scenarios. As would be expected the Transmission Only case produced the smallest amount of benefits. The differences in costs between the Base Case and the Transmission Only case are shown in Table D-5 for each of the production cost categories reported by ICF. In addition, the table contains separate sub-totals for the variable production costs (fuel costs and variable O&M costs) and for the fixed/capital costs reported by ICF.

Table D-5: Production Costs from ICF Study
Differences in System Level Annualized Production Costs:
Transmission Only Case vs. Base Case

Difference in Annual Production Costs (million $)					
Cost Category	2004	2006	2010	2015	2020
Fixed Costs	(14)	(13)	(79)	(120)	(235)
Variable Costs	(21)	(15)	(15)	(1)	6
Fuel Costs	(320)	(269)	(306)	(149)	(80)
Capital Costs	(50)	(59)	(366)	(536)	(981)
Total System Costs	(404)	(356)	(766)	(806)	(1,290)
Variable Cost Subtotal	(341)	(284)	(321)	(150)	(74)
Fixed/Cap Cost Subtotal	(64)	(72)	(445)	(656)	(1,216)

Share of Annual Difference for Each Cost Category (% of Annual Difference)					
Cost Category	2004	2006	2010	2015	2020
Fixed Costs	3%	4%	10%	15%	18%
Variable Costs	5%	4%	2%	0%	0%
Fuel Costs	79%	76%	40%	18%	6%
Capital Costs	12%	17%	48%	67%	76%
Total System Costs	100%	100%	100%	100%	100%
Variable Cost Subtotal	84%	80%	42%	19%	6%
Fixed/Cap Cost Subtotal	16%	20%	58%	81%	94%

The top panel in the table lists the annual production costs savings created by the Transmission Only case. The second panel illustrates the relative contribution of each cost category to the total production cost savings in each year. The reduction in variable production costs reflects the

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combined impact of removing the hurdle rates and increasing the transmission capacity within the various RTOs. In 2004 variable production costs are reduced by $341 million across the US in the Transmission Only case. Those savings decline to $284 million in 2006 and then rebound to $321 million in 2010. These reductions represent 0.58 percent, 0.48 percent and 0.47 percent of total Base Case variable production costs in 2004, 2006 and 2010, respectively.

The impact of the change in assumptions for capacity sharing and reserve margins can be seen in 2010, when fixed/capacity cost savings total $366 million and represent 58 percent of the total annual savings. The fixed/capacity cost savings dominate total annual savings in the years beyond 2010, representing 81 percent of the annual savings in 2015 and 94 percent in 2020.

Table D-6: Benefits from ICF Study
Differences in System Level Annualized Production Costs:
RTO Policy Case vs. Base Case (millions 2000$)

Difference in Annual Production Costs (million $)					
	2004	2006	2010	2015	2020
Fixed Costs	(39)	(54)	(183)	(263)	(477)
Variable Costs	20	25	7	8	15
Fuel Costs	(896)	(1,920)	(4,250)	(4,928)	(5,364)
Capital Costs	(166)	(241)	(809)	(1,135)	(1,643)
Total System Costs	(1,079)	(2,189)	(5,235)	(6,317)	(7,469)
Variable Cost Subtotal	(876)	(1,895)	(4,243)	(4,920)	(5,349)
Fixed/Cap Cost Subtotal	(205)	(295)	(992)	(1,398)	(2,120)

As illustrated in Table D-6 the differences in production costs between the RTO Policy case and the Base Case are substantially larger than those for the Transmission Only case. As could be expected, the assumed improvement in heat rates and availability for all fossil-fired units, significantly reduces fuel costs relative to the base case – reaching over $4 billion annually by 2010 and representing over 80 percent of the annual cost savings. Since the only difference between the RTO Policy case and the Transmission Only case is the change in assumptions regarding fossil-fired generation efficiency and availability, it is possible to isolate the impact of that assumption by comparing the results for those two cases directly.

Total system costs for the Base Case, RTO Policy case and the Transmission Only cases are depicted in Table D-7 for reference, along with the differences in the costs for each year.

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Table D-7: Key ICF Assumptions
Impact of Assumed Improvements in Fossil-fired Unit Heat Rates and Availability

Annual Production Costs and Differences (million $)					
	2004	2006	2010	2015	2020
Total System Costs					
Base Case	89,493	94,161	109,489	129,374	149,758
Transmission Only	89,089	93,805	108,723	128,568	148,468
RTO Policy	88,414	91,972	104,254	123,057	142,289
Difference in Total System Costs					
Transmission Only vs Base Case	(404)	(356)	(766)	(806)	(1,290)
RTO Policy vs Base Case	(1,079)	(2,189)	(5,235)	(6,317)	(7,469)
Impact of Heat Rate and Availability Improvements	(675)	(1,833)	(4,469)	(5,511)	(6,179)
Impact of Heat Rate and Availability Improvements As Percentage of Total RTO Policy Benefits	63%	84%	85%	87%	83%

The assumed differences in heat rates and availability lead to the vast majority of benefits in the RTO Policy case. For example, these improvements increase savings by over $1.8 billion in 2006 – representing 84 percent of the total savings in the RTO Policy case. The overwhelming contribution of these assumptions continues throughout the remainder of the period analyzed.

Table A-16: RTOs and Control Zones

RTO/Control Zone	Abbreviation	Companies/Zones
Carolina Power & Light	CP&L	Carolina Power & Light Co.
Duke Control Zone	Duke	Central Electric Power Coop.
		Duke Energy Corp.
Grid Florida	GFL	Florida Power Corp.
		Florida Power & Light Co.
		Florida Municipal Power Agency
		Gainesville Regional Utilities
		Kissimmee Utility Authority
		Lakeland Electric & Water
		Orlando Utilities Comm.
		Seminole Electric Coop.
		Tampa Electric Co.
Midwest ISO	MISO	American Municipal Power
		AmerenUE
		Basin Electric Power Coop.
		Big Rivers Electric Corp.
		Buckeye Power Co.
		Consumers Energ Co.
		Central Illinois Light Co.
		Central Illinois PSC
		Cincinnati Gas & Electric Co.
		Detroit Edison Co.
		Dairyland Power Coop.
		Electric Energy, Inc.
		East Kentucky Power Coop.
		FirstEnergy Corp.
		Great River Energy
		Hoosier Energy Rural Electric Coop.
		Hutchinson Utilities Comm.
		Central Iowa Power Coop.
		Illinois Power Co.
		Indianapolis Power & Light Co.
		Interstate Power Co.
		Kentucky Utilities Co.
		Lansing Board of Water and Light
		Lincoln Electric System
		Louisville Gas & Electric Co.
		Madison Gas & Electric Co.
		Montana-Dakota Utilities Co.
		Municipal Energy Agency Of Nebraska
		MidAmerican Energy Co.
		Minnkota Power Coop.
		Minnesota Power Inc.
		Muscatine Power & Water
		Northern Indiana Public Service Co.
		Nebraska Public Power District
		Northern States Power Co.
		Northwestern Public Service Co.
		Omaha Public Power District

Table A-16: RTOs and Control Zones

RTO/Control Zone	Abbreviation	Companies/Zones
		Otter Tail Power Co.
		Ohio Valley Electric Corp.
		PSI Energy, Inc.
		Southern Indiana Gas & Electric Co.
		Southern Minnesota Municipal Power Agency
		Southern Illinois Power Coop.
		Springfield Water, Light & Power Dept.
		St. Joseph Light & Power Co.
		Union Electric Co.
		Upper Peninsula Power
		Western Area Power Association
		Wisconsin Public Service Co.
		Wisconsin Electric Power Co.
		Wisconsin Power & Light Co.
		Wisconsin Public Power Inc.
		Wolverine Power Supply Coop.
		Wabash Valley Power Assoc.
ISO-New England	ISO-NE	Boston Edison Co.
		Bangor Hydro-Electric Co.
		Cambridge Electric Light Co.
		Central Maine Power Co.
		Commonwealth Electric Co.
		Central Vermont Public Service Corp.
		Eastern Utilities Associates
		Green Mountain Power Corp.
		Massachusetts Municipal Wholesale Electric Co.
		National Grid USA
		Northeast Utilities
		United Illuminating Co.
New York ISO	NYISO	NYISO - Capital Zone
		NYISO - Central Zone
		NYISO - Dunwoodie Zone
		NYISO - Hudson Valley
		NYISO - Long Island
		NYISO - Millwood Zone
		NYISO - Genesee Zone
		NYISO - Mohawk Valley
		NYISO - North Zone
		NYISO - NY City
		NYISO - West Zone
PJM Interconnection	PJM	American Electric Coop. Inc.
		Atlantic City Electric Co.
		Allegheny Energy, Inc.
		Baltimore Gas & Electric Co.
		Commonwealth Electric Co.
		Dayton Power & Light Co.
		Delmarva Power & Light Co.
		Duquesne Light Co.
		GPU Corp. East

Table A-16: RTOs and Control Zones

RTO/Control Zone	Abbreviation	Companies/Zones
		GPU Corp. West
		Old Dominion Electric Coop.
		Peco Energy Co.
		Potomac Electric Power Co.
		PPL Electric Utility
		Public Service Electric & Gas Co.
		Virginia Electric & Power Co.
	SCE&G	South Carolina Electric & Gas Co.
SeTrans RTO	SETRANS	Associated Electric Coop.
		Alabama Electric Coop.
		Cajun Electric Power Coop.
		Entergy Corp.
		Jacksonville Electric Authority
		Oglethorpe Power Corp.
		South Carolina Public
		South Mississippi Electric Power Assoc.
		Southern Company
		Sam Rayburn G&T Inc.
		Tallahassee Electric Operations
		Walton Electric M. Co.
Southwest Power Pool	SPP	Arkansas Electric Coop. Corp.
		Central LA Electric Co.
		Central & South West Corp.
		Empire District Electric Co.
		Grand River Dam Authority
		Independence Power & Light Dept.
		Kansas City Board of Public Utilities
		Kansas City Power & Light Co.
		Lafayette Utilities System
		Louisiana Energy & Power Authority
		Midwest Energy, Inc.
		Missouri Public Service Co.
		Northeast Texas Electric Coop.
		Oklahoma Gas & Electric Co.
		Public Service Co. of Oklahoma
		Springfield City Utilities
		Sunflower Electric Power Corp.
		Southwestern Power Administration
		Southwestern Public Service Co.
		Western Farmers Electric Coop.
		WestPlains Energy
		Western Resources, Inc.
Tennessee Valley Authority	TVA	Tennessee Valley Authority

Table A-17: New Capacity Additions 2000-2005

MAPS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date
	New Units in VAP						
MANASSAS	MANASSAS IC LUMP		VA	Peaking Units	30	30	1/1/2000
FAUQUIC1	REMINGTON 1	FAUQUIER	VA	Peaking Units	145	178	7/5/2000
FAUQUIC2	REMINGTON 2	FAUQUIER	VA	Peaking Units	145	178	7/5/2000
FAUQUIC3	REMINGTON 3	FAUQUIER	VA	Peaking Units	145	178	7/5/2000
FAUQUIC4	REMINGTON 4	FAUQUIER	VA	Peaking Units	145	178	7/5/2000
DOSWELL1	DOSWELL COMBINED CYCLE FACI	HANOVER	VA	Peaking Units	153.9	171	6/7/2001
CAROLNE1	CAROLINE COUNTY II (DOMGEN)	CAROLINE	VA	Peaking Units	145	178	7/1/2001
CAROLNE2	CAROLINE COUNTY II (DOMGEN)	CAROLINE	VA	Peaking Units	145	178	7/1/2001
POSSUMG3	POSSUM POINT (Conversion to Gas)	PRINCE WILLIAM	VA	Steam Gas/Oil	101	105	5/1/2003
POSSUMG4	POSSUM POINT (Conversion to Gas)	PRINCE WILLIAM	VA	Steam Gas/Oil	221	221	5/1/2003
POSSUMP6	POSSUM POINT 6	PRINCE WILLIAM	VA	Combined Cycle	405	450	5/1/2003
BOSWTAV1	BOSWELLS TAVERN (LOUISA COU	LOUISA	VA	Peaking Units	78.75	85	6/1/2003
BOSWTAV2	BOSWELLS TAVERN (LOUISA COU	LOUISA	VA	Peaking Units	78.75	85	6/1/2003
BOSWTAV3	BOSWELLS TAVERN (LOUISA COU	LOUISA	VA	Peaking Units	78.75	85	6/1/2003
BOSWTAV4	BOSWELLS TAVERN (LOUISA COU	LOUISA	VA	Peaking Units	78.75	85	6/1/2003
BOSWTAV5	BOSWELLS TAVERN (LOUISA COU	LOUISA	VA	Peaking Units	150	170	6/1/2003
FLUVANN1	TENASKA VIRGINIA PARTNERS 1	FLUVANNA	VA	Combined Cycle	300	300	6/1/2004
FLUVANN2	TENASKA VIRGINIA PARTNERS 2	FLUVANNA	VA	Combined Cycle	300	300	6/1/2004
FLUVANN3	TENASKA VIRGINIA PARTNERS 3	FLUVANNA	VA	Combined Cycle	300	300	6/1/2004
REMINGM1	REMINGTON MARSH RUN 1	FAUQUIER	VA	Peaking Units	150	170	10/1/2004
REMINGM2	REMINGTON MARSH RUN 2	FAUQUIER	VA	Peaking Units	150	170	10/1/2004
REMINGM3	REMINGTON MARSH RUN 3	FAUQUIER	VA	Peaking Units	150	170	10/1/2004
REMINGM4	REMINGTON MARSH RUN 4	FAUQUIER	VA	Peaking Units	150	170	1/1/2014
	New Units in AEP						
/ERSD1	RIVERSIDE	LAWRENCE	KY	Peaking Units	186.5	186.5	1/1/2001
..VERSD2	RIVERSIDE	LAWRENCE	KY	Peaking Units	186.5	186.5	1/1/2001
RIVERSD3	RIVERSIDE	LAWRENCE	KY	Peaking Units	186.5	186.5	1/1/2001
WOLFHIL1	WOLF HILLS	WASHINGTON	VA	Peaking Units	50	50	1/1/2001
WOLFHIL2	WOLF HILLS	WASHINGTON	VA	Peaking Units	50	50	1/1/2001
WOLFHIL3	WOLF HILLS	WASHINGTON	VA	Peaking Units	50	50	1/1/2001
WOLFHIL4	WOLF HILLS	WASHINGTON	VA	Peaking Units	50	50	1/1/2001
WOLFHIL5	WOLF HILLS	WASHINGTON	VA	Peaking Units	50	50	1/1/2001
BIGSANDY	Big Sandy (CPI)		WV	Peaking Units	300	300	8/10/2001
WASHNGT1	WASHINGTON (DUPC)	WASHINGTON	OH	Combined Cycle	558	620	6/1/2002
BUCHANN1	BUCHANAN COUNTY (ALLEGHENY)	BUCHANAN	VA	Peaking Units	81	90	6/25/2002
VANWERT1	VAN WERT COUNTY	VAN WERT	OH	Peaking Units	153	170	8/1/2002
VANWERT2	VAN WERT COUNTY	VAN WERT	OH	Peaking Units	153	170	8/1/2002
VANWERT3	VAN WERT COUNTY	VAN WERT	OH	Peaking Units	153	170	8/1/2002
WATERFD1	WATERFORD (PSEGP)	WASHINGTON	OH	Combined Cycle	270	300	5/1/2003
WATERFD2	WATERFORD (PSEGP)	WASHINGTON	OH	Combined Cycle	270	300	5/1/2003
WATERFD6	WATERFORD (PSEGP)	WASHINGTON	OH	Combined Cycle	270	300	5/1/2003
HANGING1	HANGING ROCK	LAWRENCE	OH	Combined Cycle	558	620	6/1/2003
HANGING2	HANGING ROCK	LAWRENCE	OH	Combined Cycle	558	620	6/1/2003
LAWRENB1	LAWRENCEBURG	DEARBORN	IN	Combined Cycle	508.5	565	6/1/2003
LAWRENB2	LAWRENCEBURG	DEARBORN	IN	Combined Cycle	508.5	565	6/1/2003
ROLLING1	ROLLING HILLS	VINTON	OH	Peaking Units	144	160	6/1/2003
ROLLING2	ROLLING HILLS	VINTON	OH	Peaking Units	144	160	6/1/2003
ROLLING3	ROLLING HILLS	VINTON	OH	Peaking Units	144	160	6/1/2003
ROLLING4	ROLLING HILLS	VINTON	OH	Peaking Units	144	160	6/1/2003
ROLLING5	ROLLING HILLS	VINTON	OH	Peaking Units	144	160	6/1/2003
DRESDEC1	DRESDEN ENERGY CENTER	MUSKINGUM	OH	Combined Cycle	601.2	668	9/1/2003
FREMONT1	FREMONT ENERGY CENTER	SANDUSKY	OH	Combined Cycle	630	700	3/1/2005
	New Units in DPL						

Table A-17: New Capacity Additions 2000-2005

MAPS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date
GREENVI1	GREENVILLE ELECTRIC GENERAT	DARKE	OH	Peaking Units	50	50	1/1/2000
GREENVI2	GREENVILLE ELECTRIC GENERAT	DARKE	OH	Peaking Units	50	50	1/1/2000
GREENVI3	GREENVILLE ELECTRIC GENERAT	DARKE	OH	Peaking Units	50	50	1/1/2000
GREENVI4	GREENVILLE ELECTRIC GENERAT	DARKE	OH	Peaking Units	50	50	1/1/2000
MADISON1	MADISON GENERATING STATION	BUTLER	OH	Peaking Units	80	80	1/1/2000
MADISON2	MADISON GENERATING STATION	BUTLER	OH	Peaking Units	80	80	1/1/2000
MADISON3	MADISON GENERATING STATION	BUTLER	OH	Peaking Units	80	80	1/1/2000
MADISON4	MADISON GENERATING STATION	BUTLER	OH	Peaking Units	80	80	1/1/2000
MADISON5	MADISON GENERATING STATION	BUTLER	OH	Peaking Units	80	80	1/1/2000
MADISON6	MADISON GENERATING STATION	BUTLER	OH	Peaking Units	80	80	1/1/2000
MADISON7	MADISON GENERATING STATION	BUTLER	OH	Peaking Units	80	80	1/1/2000
MADISON8	MADISON GENERATING STATION	BUTLER	OH	Peaking Units	80	80	1/1/2000
CHESTER1	CHESTER TOWNSHIP	WELLS	IN	Peaking Units	50	50	1/1/2001
CHESTER2	CHESTER TOWNSHIP	WELLS	IN	Peaking Units	50	50	1/1/2001
CHESTER3	CHESTER TOWNSHIP	WELLS	IN	Peaking Units	50	50	1/1/2001
CHESTER4	CHESTER TOWNSHIP	WELLS	IN	Peaking Units	50	50	1/1/2001
DARBYGE1	DARBY GENERATING STATION	PICKAWAY	OH	Peaking Units	80	80	1/1/2001
DARBYGE2	DARBY GENERATING STATION	PICKAWAY	OH	Peaking Units	80	80	1/1/2001
DARBYGE3	DARBY GENERATING STATION	PICKAWAY	OH	Peaking Units	80	80	1/1/2001
DARBYGE4	DARBY GENERATING STATION	PICKAWAY	OH	Peaking Units	80	80	1/1/2001
DARBYGE5	DARBY GENERATING STATION	PICKAWAY	OH	Peaking Units	80	80	6/1/2002
DARBYGE6	DARBY GENERATING STATION	PICKAWAY	OH	Peaking Units	80	80	6/1/2002
TAITDT01	TAIT	MONTGOMERY	OH	Peaking Units	72	80	12/1/2002
TAITDT02	TAIT	MONTGOMERY	OH	Peaking Units	72	80	12/1/2002
TAITDT03	TAIT	MONTGOMERY	OH	Peaking Units	72	80	12/1/2002
TAITDT04	TAIT	MONTGOMERY	OH	Peaking Units	72	80	12/1/2002
	New Units in ComEd						
...ORRISC1	MORRIS COGENERATION PLANT	GRUNDY	IL	Combined Cycle	159.28	176.98	3/30/2000
LINCOLE1	LINCOLN ENERGY CENTER	WILL	IL	Peaking Units	74.7	83	6/1/2000
LINCOLE2	LINCOLN ENERGY CENTER	WILL	IL	Peaking Units	74.7	83	6/1/2000
LINCOLE3	LINCOLN ENERGY CENTER	WILL	IL	Peaking Units	74.7	83	6/1/2000
LINCOLE4	LINCOLN ENERGY CENTER	WILL	IL	Peaking Units	74.7	83	6/1/2000
LINCOLE5	LINCOLN ENERGY CENTER	WILL	IL	Peaking Units	74.7	83	6/1/2000
LINCOLE6	LINCOLN ENERGY CENTER	WILL	IL	Peaking Units	74.7	83	6/1/2000
LINCOLE7	LINCOLN ENERGY CENTER	WILL	IL	Peaking Units	74.7	83	6/1/2000
LINCOLE8	LINCOLN ENERGY CENTER	WILL	IL	Peaking Units	74.7	83	6/1/2000
ROCKFOR1	ROCKFORD (INDOPE)	WINNEBAGO	IL	Peaking Units	180	200	6/1/2000
ROCKFOR2	ROCKFORD (INDOPE)	WINNEBAGO	IL	Peaking Units	90	100	6/1/2000
ROCKYRP1	ROCKY ROAD POWER, LLC	KANE	IL	Peaking Units	90	100	7/15/2000
LEEGENS1	LEE GENERATING STATION	LEE	IL	Peaking Units	72	80	6/1/2001
LEEGENS2	LEE GENERATING STATION	LEE	IL	Peaking Units	72	80	6/1/2001
LEEGENS3	LEE GENERATING STATION	LEE	IL	Peaking Units	72	80	6/1/2001
LEEGENS4	LEE GENERATING STATION	LEE	IL	Peaking Units	72	80	6/1/2001
LEEGENS5	LEE GENERATING STATION	LEE	IL	Peaking Units	72	80	6/1/2001
LEEGENS6	LEE GENERATING STATION	LEE	IL	Peaking Units	72	80	6/1/2001
LEEGENS7	LEE GENERATING STATION	LEE	IL	Peaking Units	72	80	6/1/2001
LEEGENS8	LEE GENERATING STATION	LEE	IL	Peaking Units	72	80	6/1/2001
RELIAUR1	RELIANT ENERGY AURORA LP	DU PAGE	IL	Peaking Units	153.9	171	6/1/2001
RELIAUR2	RELIANT ENERGY AURORA LP	DU PAGE	IL	Peaking Units	153.9	171	6/1/2001
RELIAUR3	RELIANT ENERGY AURORA LP	DU PAGE	IL	Peaking Units	153.9	171	6/1/2001
RELIAUR4	RELIANT ENERGY AURORA LP	DU PAGE	IL	Peaking Units	153.9	171	6/1/2001
RELIAUR6	RELIANT ENERGY AURORA LP	DU PAGE	IL	Peaking Units	40.5	45	6/1/2001
RELIAUR7	RELIANT ENERGY AURORA LP	DU PAGE	IL	Peaking Units	40.5	45	6/1/2001
RELIAUR8	RELIANT ENERGY AURORA LP	DU PAGE	IL	Peaking Units	40.5	45	6/1/2001
RELIAUR9	RELIANT ENERGY AURORA LP	DU PAGE	IL	Peaking Units	40.5	45	6/1/2001

Table A-17: New Capacity Additions 2000-2005

MAPS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date
RELIAR10	RELIANT ENERGY AURORA LP	DU PAGE	IL	Peaking Units	40.5	45	6/1/2001
CHICAGC1	CHICAGO (CONPOW)	COOK	IL	Peaking Units	45	50	7/22/2001
CHICAGC2	CHICAGO (CONPOW)	COOK	IL	Peaking Units	45	50	7/22/2001
CHICAGC3	CHICAGO (CONPOW)	COOK	IL	Peaking Units	45	50	7/22/2001
CHICAGC4	CHICAGO (CONPOW)	COOK	IL	Peaking Units	45	50	7/22/2001
CHICAGC5	CHICAGO (CONPOW)	COOK	IL	Peaking Units	45	50	7/22/2001
CHICAGC6	CHICAGO (CONPOW)	COOK	IL	Peaking Units	45	50	7/22/2001
COOKCOU1	COOK COUNTY	COOK	IL	Peaking Units	136.8	152	3/1/2002
RELIAUR5	RELIANT ENERGY AURORA LP	DU PAGE	IL	Peaking Units	40.5	45	3/1/2002
COOKCOU2	COOK COUNTY	COOK	IL	Peaking Units	136.8	152	3/20/2002
KENDALC1	KENDALL COUNTY PROJECT	KENDALL	IL	Combined Cycle	262.8	292	4/15/2002
KENDALC2	KENDALL COUNTY PROJECT	KENDALL	IL	Combined Cycle	262.8	292	4/15/2002
KENDALC3	KENDALL COUNTY PROJECT	KENDALL	IL	Combined Cycle	262.8	292	4/15/2002
CRETEEP1	CRETE ENERGY PARK	WILL	IL	Peaking Units	76.5	85	6/1/2002
CRETEEP2	CRETE ENERGY PARK	WILL	IL	Peaking Units	76.5	85	6/1/2002
CRETEEP3	CRETE ENERGY PARK	WILL	IL	Peaking Units	76.5	85	6/1/2002
CRETEEP4	CRETE ENERGY PARK	WILL	IL	Peaking Units	76.5	85	6/1/2002
ROCKFD23	ROCKFORD II	WINNEBAGO	IL	Peaking Units	149.4	166	6/1/2002
ZIONENC1	ZION ENERGY CENTER	LAKE	IL	Peaking Units	150	165	6/25/2002
ZIONENC2	ZION ENERGY CENTER	LAKE	IL	Peaking Units	150	165	6/25/2002
ELGINGT2	ELGIN	COOK	IL	Peaking Units	105.3	117	7/1/2002
STHCHIC1	SOUTH CHICAGO	COOK	IL	Peaking Units	151.2	168	7/1/2002
STHCHIC2	SOUTH CHICAGO	COOK	IL	Peaking Units	151.2	168	7/1/2002
UNIVPAR1	UNIVERSITY PARK	WILL	IL	Peaking Units	158.4	176	7/25/2002
UNIVPAR2	UNIVERSITY PARK	WILL	IL	Peaking Units	158.4	176	7/25/2002
UNIVPAR3	UNIVERSITY PARK	WILL	IL	Peaking Units	158.4	176	7/25/2002
GINGT3	ELGIN	COOK	IL	Peaking Units	105.3	117	8/1/2002
KENDALC4	KENDALL COUNTY PROJECT	KENDALL	IL	Combined Cycle	262.8	292	8/15/2002
ELGINGT4	ELGIN	COOK	IL	Peaking Units	105.3	117	9/1/2002
ELGINGT1	ELGIN	COOK	IL	Peaking Units	105.3	117	10/1/2002
ZIONENC3	ZION ENERGY CENTER	LAKE	IL	Peaking Units	150	150	6/1/2003
	New Units in PJM						
BURLNGT1	BURLINGTON (PSEG)	BURLINGTON	NJ	Peaking Units	46.5	46.5	1/1/2000
BURLNGT2	BURLINGTON (PSEG)	BURLINGTON	NJ	Peaking Units	46.5	46.5	1/1/2000
BURLNGT3	BURLINGTON (PSEG)	BURLINGTON	NJ	Peaking Units	46.5	46.5	1/1/2000
BURLNGT4	BURLINGTON (PSEG)	BURLINGTON	NJ	Peaking Units	46.5	46.5	1/1/2000
COMMNCH1	COMMONWEALTH CHESAPEAKE PRO	ACCOMACK	VA	Peaking Units	45	45	1/1/2000
COMMNCH2	COMMONWEALTH CHESAPEAKE PRO	ACCOMACK	VA	Peaking Units	45	45	1/1/2000
COMMNCH3	COMMONWEALTH CHESAPEAKE PRO	ACCOMACK	VA	Peaking Units	45	45	1/1/2000
DELWREC5	DELAWARE CITY	NEW CASTLE	DE	Combined Cycle	113.75	113.75	1/1/2000
DELWREC6	DELAWARE CITY	NEW CASTLE	DE	Combined Cycle	113.75	113.75	1/1/2000
DELWREC7	DELAWARE CITY	NEW CASTLE	DE	Combined Cycle	5.48	5.48	1/1/2000
GREENMO8	GREEN MOUNTAIN WIND FARM	SOMERSET	PA	Other	10	10	1/1/2000
HUNLOCK1	HUNLOCK CREEK	LUZERNE	PA	Peaking Units	44	44	1/1/2000
LINDENG5	LINDEN (PSEG)	UNION	NJ	Peaking Units	80	80	1/1/2000
LINDENG6	LINDEN (PSEG)	UNION	NJ	Peaking Units	80	80	1/1/2000
AESWARR1	AES WARRIOR RUN INC.	ALLEGANY	MD	Coal	180	180	2/1/2000
ALLEGHE1	ALLEGHENY ENERGY 8 & 9	FAYETTE	PA	Peaking Units	44	44	8/15/2000
ALLEGHE2	ALLEGHENY ENERGY 8 & 9	FAYETTE	PA	Peaking Units	44	44	8/15/2000
ARCHIBD1	ARCHIBALD COGENERATION PLAN	LACKAWANNA	PA	Peaking Units	45	45	1/1/2001
GREENKN1	GREEN KNIGHT ENERGY CENTER	NORTHAMPTON	PA	Peaking Units	9.5	9.5	1/1/2001
KEARNY01	KEARNY (PSEG)	HUDSON	NJ	Peaking Units	85.4	85.4	1/1/2001
KEARNY02	KEARNY (PSEG)	HUDSON	NJ	Peaking Units	85.4	85.4	1/1/2001
MILLRUN1	MILL RUN WINDPOWER	FAYETTE	PA	Other	15	15	1/1/2001
ROCKLAN1	ROCKLAND TOWNSHIP			Peaking Units	50	50	1/1/2001

Table A-17: New Capacity Additions 2000-2005

MAPS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date
ROCKLAN2	ROCKLAND TOWNSHIP			Peaking Units	50	50	1/1/2001
ROCKLAN3	ROCKLAND TOWNSHIP			Peaking Units	50	50	1/1/2001
ROCKLAN4	ROCKLAND TOWNSHIP			Peaking Units	50	50	1/1/2001
ROCKLAN5	ROCKLAND TOWNSHIP			Peaking Units	50	50	1/1/2001
SOMERST1	SOMERSET WIND PROJECT	SOMERSET	PA	Other	9	9	1/1/2001
WILMING1	WILMINGTON	NEW CASTLE	DE	Peaking Units	111	111	6/1/2001
WILMING2	WILMINGTON	NEW CASTLE	DE	Peaking Units	111	111	6/1/2001
COMMNCH4	COMMONWEALTH CHESAPEAKE PRO	ACCOMACK	VA	Peaking Units	45	45	6/15/2001
COMMNCH5	COMMONWEALTH CHESAPEAKE PRO	ACCOMACK	VA	Peaking Units	45	45	6/15/2001
COMMNCH6	COMMONWEALTH CHESAPEAKE PRO	ACCOMACK	VA	Peaking Units	45	45	6/15/2001
KRAFTFO1	KRAFT FOODS COGENERATION	KENT	DE	Peaking Units	44	44	7/17/2001
KRAFTFO2	KRAFT FOODS COGENERATION	KENT	DE	Peaking Units	44	44	7/17/2001
WILMING3	WILMINGTON	NEW CASTLE	DE	Peaking Units	112	112	7/31/2001
HANDSOM1	Handsome Lake Energy		PA	Peaking Units	50	50	8/1/2001
HANDSOM2	Handsome Lake Energy		PA	Peaking Units	50	50	8/1/2001
HANDSOM3	Handsome Lake Energy		PA	Peaking Units	50	50	8/1/2001
HANDSOM4	Handsome Lake Energy		PA	Peaking Units	50	50	8/1/2001
HANDSOM5	Handsome Lake Energy		PA	Peaking Units	50	50	8/1/2001
COMMNCH7	COMMONWEALTH CHESAPEAKE PRO	ACCOMACK	VA	Peaking Units	45	45	8/17/2001
GUILFORD	Guilford Township		PA	Peaking Units	88	88	11/30/2001
LINDNCO1	LINDEN COGEN PLANT (ECOAST)	UNION	NJ	Peaking Units	153	170	1/1/2002
IRONWOD1	IRONWOOD PROJECT	LEBANON	PA	Combined Cycle	700	700	1/31/2002
HAZELTN1	HAZELTON	LUZERNE	PA	Peaking Units	25	25	2/1/2002
HAZELTN2	HAZELTON	LUZERNE	PA	Peaking Units	25	25	2/1/2002
HAZELTN3	HAZELTON	LUZERNE	PA	Peaking Units	25	25	2/1/2002
HAZELTN4	HAZELTON	LUZERNE	PA	Peaking Units	25	25	2/1/2002
ZELTO1	HAZELTON	LUZERNE	PA	Peaking Units	90	100	2/1/2002
LEASNT1	PLEASANTS COUNTY	PLEASANTS	WV	Peaking Units	153	170	2/1/2002
PLEASNT2	PLEASANTS COUNTY	PLEASANTS	WV	Peaking Units	153	170	2/1/2002
SMYRNA01	SMYRNA			Peaking Units	40.5	45	2/1/2002
LIBERTY1	LIBERTY ELECTRIC PROJECT	DELAWARE	PA	Combined Cycle	450	500	5/1/2002
WILMNGT1	WILMINGTON	NEW CASTLE	DE	Combined Cycle	450	500	5/17/2002
ARMSTRN1	ARMSTRONG COUNTY	ARMSTRONG	PA	Peaking Units	148.5	165	6/1/2002
ARMSTRN2	ARMSTRONG COUNTY	ARMSTRONG	PA	Peaking Units	148.5	165	6/1/2002
ARMSTRN3	ARMSTRONG COUNTY	ARMSTRONG	PA	Peaking Units	148.5	165	6/1/2002
ARMSTRN4	ARMSTRONG COUNTY	ARMSTRONG	PA	Peaking Units	148.5	165	6/1/2002
BERGEN02	BERGEN	BERGEN	NJ	Combined Cycle	450	500	6/1/2002
REDOAK01	RED OAK	MIDDLESEX	NJ	Combined Cycle	747	830	9/15/2002
ONTELAU1	ONTELAUNEE ENERGY CENTER	BERKS	PA	Combined Cycle	490.5	545	10/1/2002
MNT_WIND	Mountaineer Wind Energy Center		WV	Wind	66	66	12/31/2002
BETHLEC1	BETHLEHEM (CIV)	NORTHAMPTON	PA	Peaking Units	333	333	1/1/2003
LAKEWDC1	LAKEWOOD COGENERATION L/P	OCEAN	NJ	Peaking Units	149.94	166.6	1/30/2003
LAKEWDC2	LAKEWOOD COGENERATION L/P	OCEAN	NJ	Peaking Units	149.94	166.6	1/30/2003
LAKEWDC3	LAKEWOOD COGENERATION L/P	OCEAN	NJ	Peaking Units	149.94	166.6	1/30/2003
ROCKSPR1	Rock Springs		MD	Peaking Units	170	170	2/28/2003
ROCKSPR2	Rock Springs		MD	Peaking Units	170	170	2/28/2003
BETHLEC2	BETHLEHEM (CIV)	NORTHAMPTON	PA	Peaking Units	333	333	3/1/2003
MOOSICM1	MOOSIC MOUNTAIN	WAYNE	PA	Other	50	50	3/1/2003
BETHLEH1	BETHLEHEM (CIV)	NORTHAMPTON	PA	Combined Cycle	495	550	5/1/2003
LINDENP1	LINDEN (PSEGF)	UNION	NJ	Combined Cycle	533.7	593	5/1/2003
LINDENP2	LINDEN (PSEGF)	UNION	NJ	Combined Cycle	533.7	593	5/1/2003
ESSEXENE	Essex Energy		NJ	Peaking Units	5.6	5.6	6/1/2003
GERMANCC	German		PA	Combined Cycle	640	640	6/1/2003
HUNTERS1	HUNTERSTOWN	ADAMS	PA	Combined Cycle	720	800	6/1/2003
LOWERMB1	LOWER MOUNT BETHEL	NORTHAMPTON	PA	Combined Cycle	540	600	6/1/2003

Table A-17: New Capacity Additions 2000-2005

MAPS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date
ROCKSPR3	Rock Springs		MD	Peaking Units	170	170	6/1/2003
ROCKSPR4	Rock Springs		MD	Peaking Units	170	170	6/1/2003
SPRINGD1	SPRINGDALE	ALLEGHENY	PA	Combined Cycle	486	540	10/1/2003
FALLSTW1	FALLS TOWNSHIP	BUCKS	PA	Combined Cycle	495	550	3/1/2004
MARCUSR1	MARCUS HOOK REFINERY COGEN	DELAWARE	PA	Combined Cycle	216.9	241	3/1/2004
MARCUSR2	MARCUS HOOK REFINERY COGEN	DELAWARE	PA	Combined Cycle	216.9	241	3/1/2004
MARCUSR3	MARCUS HOOK REFINERY COGEN	DELAWARE	PA	Combined Cycle	216.9	241	3/1/2004
FALLSTW2	FALLS TOWNSHIP	BUCKS	PA	Combined Cycle	495	550	6/1/2004
SEWARD01	SEWARD (RELIANT)	INDIANA	PA	Coal	520	520	9/1/2004
	New Units in CP&L						
ASHEVLE1	ASHEVILLE	BUNCOMBE	NC	Peaking Units	144	160	3/1/2000
WAYNECT1	WAYNE COUNTY (CP&L)	WAYNE	NC	Peaking Units	180	200	6/2/2000
WAYNECT2	WAYNE COUNTY (CP&L)	WAYNE	NC	Peaking Units	180	200	6/2/2000
WAYNECT3	WAYNE COUNTY (CP&L)	WAYNE	NC	Peaking Units	180	200	6/2/2000
WAYNECT4	WAYNE COUNTY (CP&L)	WAYNE	NC	Peaking Units	83.7	93	6/2/2000
RICHMND1	RICHMOND PLANT (CPLC)	RICHMOND	NC	Peaking Units	139.5	155	5/29/2001
RICHMND2	RICHMOND PLANT (CPLC)	RICHMOND	NC	Peaking Units	139.5	155	5/29/2001
RICHMND3	RICHMOND PLANT (CPLC)	RICHMOND	NC	Peaking Units	139.5	155	5/29/2001
RICHMND4	RICHMOND PLANT (CPLC)	RICHMOND	NC	Peaking Units	139.5	155	5/29/2001
ROWANGT1	ROWAN	ROWAN	NC	Peaking Units	155	155	5/29/2001
ROWANGT2	ROWAN	ROWAN	NC	Peaking Units	155	155	5/29/2001
ROWANGT3	ROWAN	ROWAN	NC	Peaking Units	155	155	5/29/2001
RICHMND5	RICHMOND PLANT (CPLC)	RICHMOND	NC	Combined Cycle	423	470	5/30/2002
RICHMND6	RICHMOND PLANT (CPLC)	RICHMOND	NC	Peaking Units	139.5	155	5/30/2002
ROWANCC4	ROWAN	ROWAN	NC	Combined Cycle	423	470	1/1/2003
	New Units in Duke						
.OADRE1	BROAD RIVER ENERGY CENTER	CHEROKEE	SC	Peaking Units	180	200	6/1/2000
BROADRE2	BROAD RIVER ENERGY CENTER	CHEROKEE	SC	Peaking Units	180	200	6/1/2000
BROADRE3	BROAD RIVER ENERGY CENTER	CHEROKEE	SC	Peaking Units	45	50	6/1/2000
ROCKGHM1	ROCKINGHAM POWER PLANT	ROCKINGHAM	NC	Peaking Units	180	200	7/12/2000
ROCKGHM2	ROCKINGHAM POWER PLANT	ROCKINGHAM	NC	Peaking Units	180	200	7/12/2000
ROCKGHM3	ROCKINGHAM POWER PLANT	ROCKINGHAM	NC	Peaking Units	72	80	7/12/2000
ROCKGHM4	ROCKINGHAM POWER PLANT	ROCKINGHAM	NC	Peaking Units	180	200	7/17/2000
ROCKGHM5	ROCKINGHAM POWER PLANT	ROCKINGHAM	NC	Peaking Units	108	120	7/17/2000
BROADRE4	BROAD RIVER ENERGY CENTER	CHEROKEE	SC	Peaking Units	157.5	175	6/15/2001
BROADRE5	BROAD RIVER ENERGY CENTER	CHEROKEE	SC	Peaking Units	157.5	175	6/15/2001
JOHNSRN1	JOHN S RAINEY GENERATING ST	ANDERSON	SC	Combined Cycle	450	500	1/1/2002
JOHNSRN2	JOHN S RAINEY GENERATING ST	ANDERSON	SC	Peaking Units	135	150	3/1/2002
JOHNSRN3	JOHN S RAINEY GENERATING ST	ANDERSON	SC	Peaking Units	135	150	5/1/2002
MILLCRK1	MILL CREEK STATION	CHEROKEE	SC	Peaking Units	72	80	12/31/2002
MILLCRK2	MILL CREEK STATION	CHEROKEE	SC	Peaking Units	72	80	12/31/2002
MILLCRK3	MILL CREEK STATION	CHEROKEE	SC	Peaking Units	72	80	12/31/2002
MILLCRK4	MILL CREEK STATION	CHEROKEE	SC	Peaking Units	72	80	12/31/2002
MILLCRK5	MILL CREEK STATION	CHEROKEE	SC	Peaking Units	72	80	4/1/2003
MILLCRK6	MILL CREEK STATION	CHEROKEE	SC	Peaking Units	72	80	4/1/2003
MILLCRK7	MILL CREEK STATION	CHEROKEE	SC	Peaking Units	72	80	4/1/2003
MILLCRK8	MILL CREEK STATION	CHEROKEE	SC	Peaking Units	72	80	4/1/2003
JOHNSRN4	JOHN S RAINEY GENERATING ST	ANDERSON	SC	Peaking Units	72	80	1/1/2004
JOHNSRN5	JOHN S RAINEY GENERATING ST	ANDERSON	SC	Peaking Units	72	80	1/1/2004
JOHNSRN6	JOHN S RAINEY GENERATING ST	ANDERSON	SC	Peaking Units	72	80	1/1/2004
	New Units in SCE&G						
URQUHAR1	URQUHART - SCEG	AIKEN	SC	Combined Cycle	202.5	225	6/3/2002
URQUHAR2	URQUHART - SCEG	AIKEN	SC	Combined Cycle	202.5	225	6/3/2002
COLUMBE1	COLUMBIA ENERGY CENTER	CALHOUN	SC	Combined Cycle	450	500	6/1/2003
JASPERC1	JASPER COUNTY	JASPER	SC	Combined Cycle	787.5	875	6/1/2004

Table A-17: New Capacity Additions 2000-2005

MAPS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date
	New Units in MISO (ECAR)						
491E48T9	491 E. 48TH STREET	OTTAWA	MI	Peaking Units	80	80	6/1/2000
ASHTABU1	ASHTABULA (TRCISO)	ASHTABULA	OH	Peaking Units	28	28	2/28/2001
BELLERR3	BELLE RIVER	ST. CLAIR	MI	Peaking Units	144	160	8/1/2002
BELLERR4	BELLE RIVER	ST. CLAIR	MI	Peaking Units	144	160	8/1/2002
BOWLINA1	BOWLING GREEN (AMP)	WOOD	OH	Peaking Units	32	32	7/11/2000
BOWLING1	BOWLING GREEN (USGECO)	WOOD	OH	Peaking Units	33	33	1/1/2000
BOWLING2	BOWLING GREEN (USGECO)	WOOD	OH	Peaking Units	16.5	16.5	1/1/2000
BROWNKU4	BROWN (KUC)	MERCER	KY	Peaking Units	133	133	1/1/2001
BROWNSG1	BROWN (SIGE)	POSEY	IN	Peaking Units	72	80	7/30/2002
CARBONL1	CARBON LIMESTONE LANDFILL	MAHONING	OH	Combined Cycle	20.8	20.8	1/1/2001
CEREDOG1	CEREDO	WAYNE	WV	Peaking Units	85	85	1/1/2001
CEREDOG2	CEREDO	WAYNE	WV	Peaking Units	85	85	1/1/2001
CEREDOG3	CEREDO	WAYNE	WV	Peaking Units	85	85	1/1/2001
CEREDOG4	CEREDO	WAYNE	WV	Peaking Units	85	85	1/1/2001
CEREDOG5	CEREDO	WAYNE	WV	Peaking Units	85	85	1/1/2001
CEREDOG6	CEREDO	WAYNE	WV	Peaking Units	85	85	1/1/2001
CLAUDEV7	CLAUDE VANDYKE (BURNIPS)	ALLEGAN	MI	Peaking Units	24	24	8/28/2001
COVERT01	COVERT	VAN BUREN	MI	Combined Cycle	360	400	6/1/2003
COVERT02	COVERT	VAN BUREN	MI	Combined Cycle	360	400	6/1/2003
COVERT03	COVERT	VAN BUREN	MI	Combined Cycle	360	400	6/1/2003
DEARBOC1	DEARBORN INDUSTRIAL GENERAT	WAYNE	MI	Combined Cycle	550	550	1/1/2001
DEARBOR1	DEARBORN DIST GEN FACILITY	WAYNE	MI	Peaking Units	37.7	37.7	1/1/2001
DTECHIN1	DTE East China		MI	Peaking Units	80	80	6/1/2002
DTECHIN2	DTE East China		MI	Peaking Units	80	80	6/1/2002
DTECHIN3	DTE East China		MI	Peaking Units	80	80	6/1/2002
ECHIN4	DTE East China		MI	Peaking Units	80	80	6/1/2002
DYNEGYB1	DYNEGY - BLUEGRASS	OLDHAM	KY	Peaking Units	180	186	6/1/2002
DYNEGYB2	DYNEGY - BLUEGRASS	OLDHAM	KY	Peaking Units	180	186	6/1/2002
DYNEGYB3	DYNEGY - BLUEGRASS	OLDHAM	KY	Peaking Units	100.8	186	6/1/2002
FOOTHIL1	FOOTHILLS GENERATING PROJEC	LAWRENCE	KY	Peaking Units	144	160	4/1/2002
FOOTHIL2	FOOTHILLS GENERATING PROJEC	LAWRENCE	KY	Peaking Units	153	170	4/1/2002
GALIONG1	GALION	CRAWFORD	OH	Peaking Units	33	33	1/1/2000
GALIONG2	GALION	CRAWFORD	OH	Peaking Units	16.5	16.5	1/1/2000
GAYLORDW	Gaylord [WPSC]		MI	Peaking Units	75	75	6/1/2001
GEORGEJ1	GEORGE JOHNSON	OSCEOLA	MI	Peaking Units	25	25	1/1/2000
GEORGEJ2	GEORGE JOHNSON	OSCEOLA	MI	Peaking Units	25	25	1/1/2000
GEORGET1	GEORGETOWN	MARION	IN	Peaking Units	88	88	1/1/2000
GEORGET2	GEORGETOWN	MARION	IN	Peaking Units	88	88	1/1/2000
GEORGET3	GEORGETOWN	MARION	IN	Peaking Units	88	88	1/1/2000
GEORGET4	GEORGETOWN	MARION	IN	Peaking Units	80	80	1/1/2001
HAMILTON	HAMILTON (AMP)	BUTLER	OH	Peaking Units	32	32	1/1/2000
HARDING8	HARDING STREET		IN	Peaking Units	155	155	5/31/2002
HAWESVI1	HAWESVILLE MILL	HANCOCK	KY	Steam Gas/Oil	60	60	1/1/2001
HENRYGT1	HENRY	HENRY	IN	Peaking Units	45	45	1/1/2001
HENRYGT2	HENRY	HENRY	IN	Peaking Units	45	45	1/1/2001
HENRYGT3	HENRY	HENRY	IN	Peaking Units	45	45	1/1/2001
HOOSFAIR	Hoosier Energy Fairview		IN	Peaking Units	16.43	16.43	6/15/2001
HOOSMIDW	Hoosier Energy Midway		IN	Peaking Units	16	16	6/15/2001
IRONSIDE	Ironside Energy		IN	Peaking Units	50	50	1/1/2002
JACKSON1	JACKSON	JACKSON	MI	Combined Cycle	338.4	376	6/1/2002
JACKSON2	JACKSON	JACKSON	MI	Peaking Units	162	180	6/1/2002
JKSMITG2	J.K. SMITH	CLARK	KY	Peaking Units	85.4	85.4	1/1/2001
JKSMITG3	J.K. SMITH	CLARK	KY	Peaking Units	85	85	1/1/2001
LAFARGE1	LAFARGE GYPSUM	CAMPBELL	KY	Peaking Units	5.2	5.2	1/1/2000

Table A-17: New Capacity Additions 2000-2005

MAPS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date
LORAINL1	LORAIN LANDFILL	LORAIN	OH	Combined Cycle	7.8	7.8	1/1/2001
MACKINA1	MACKINAW CITY	EMMET	MI	Other	3.3	3.3	12/3/2001
NAPOLEO1	NAPOLEON	HENRY	OH	Peaking Units	33	33	1/1/2000
NAPOLEO2	NAPOLEON	HENRY	OH	Peaking Units	16.5	16.5	1/1/2000
NOBLEVL1	NOBLESVILLE	HAMILTON	IN	Combined Cycle	270	300	6/1/2003
OHIOAMP1	OHIO (AMP)	NOT APPLICABLE	OH	Peaking Units	21.6	21.6	1/1/2000
OHIOAMP2	OHIO (AMP)	NOT APPLICABLE	OH	Peaking Units	16.2	16.2	1/1/2000
PADDYS13	PADDYS RUN	JEFFERSON	KY	Peaking Units	151	151	1/1/2001
RENAIS10	RENAISSANCE POWER PROJECT	MONTCALM	MI	Peaking Units	153	170	6/1/2002
RENAISS7	RENAISSANCE POWER PROJECT	MONTCALM	MI	Peaking Units	153	170	6/1/2002
RENAISS8	RENAISSANCE POWER PROJECT	MONTCALM	MI	Peaking Units	153	170	6/1/2002
RENAISS9	RENAISSANCE POWER PROJECT	MONTCALM	MI	Peaking Units	153	170	6/1/2002
RICHLAN1	RICHLAND PEAKING	DEFIANCE	OH	Peaking Units	130	130	1/1/2000
RICHLAN2	RICHLAND PEAKING	DEFIANCE	OH	Peaking Units	130	130	1/1/2000
RICHLAN3	RICHLAND PEAKING	DEFIANCE	OH	Peaking Units	130	130	1/1/2000
SPURLCK1	SPURLOCK	MASON	KY	Coal	250	250	4/1/2005
SUGARCK1	SUGAR CREEK	VIGO	IN	Combined Cycle	450	500	6/1/2003
SUGARCK3	SUGAR CREEK	VIGO	IN	Peaking Units	153	170	6/1/2002
SUGARCK4	SUGAR CREEK	VIGO	IN	Peaking Units	153	170	6/1/2002
SUMPTER1	SUMPTER TOWNSHIP	WAYNE	MI	Peaking Units	76.5	85	6/1/2002
SUMPTER2	SUMPTER TOWNSHIP	WAYNE	MI	Peaking Units	76.5	85	6/1/2002
SUMPTER3	SUMPTER TOWNSHIP	WAYNE	MI	Peaking Units	76.5	85	6/1/2002
SUMPTER4	SUMPTER TOWNSHIP	WAYNE	MI	Peaking Units	76.5	85	6/1/2002
TRAVERS1	TRAVERSE CITY	GRAND TRAVERSE	MI	Peaking Units	45	50	11/1/2002
TRIMBLC4	TRIMBLE COUNTY	TRIMBLE	KY	Peaking Units	135	150	6/1/2002
TRIMBLC5	TRIMBLE COUNTY	TRIMBLE	KY	Peaking Units	135	150	6/1/2002
RMILL1	VERMILLION GENERATING STATI	VERMILLION	IN	Peaking Units	80	80	1/1/2000
ERMILL2	VERMILLION GENERATING STATI	VERMILLION	IN	Peaking Units	80	80	1/1/2000
VERMILL3	VERMILLION GENERATING STATI	VERMILLION	IN	Peaking Units	80	80	1/1/2000
VERMILL4	VERMILLION GENERATING STATI	VERMILLION	IN	Peaking Units	80	80	1/1/2000
VERMILL5	VERMILLION GENERATING STATI	VERMILLION	IN	Peaking Units	80	80	1/1/2000
VERMILL6	VERMILLION GENERATING STATI	VERMILLION	IN	Peaking Units	80	80	1/1/2000
VERMILL7	VERMILLION GENERATING STATI	VERMILLION	IN	Peaking Units	80	80	1/1/2000
VERMILL8	VERMILLION GENERATING STATI	VERMILLION	IN	Peaking Units	80	80	1/1/2000
WAYNECA1	WAYNE COUNTY AIRPORT	WAYNE	MI	Peaking Units	15.3	17	3/1/2002
WHITINR1	WHITING REFINERY (PRIENE)	LAKE	IN	Combined Cycle	490.5	545	1/31/2002
WOODCOU1	WOOD COUNTY	WOOD	OH	Peaking Units	153	170	6/1/2002
WOODCOU2	WOOD COUNTY	WOOD	OH	Peaking Units	153	170	6/1/2002
WOODCOU3	WOOD COUNTY	WOOD	OH	Peaking Units	153	170	6/1/2002
WOODCOU4	WOOD COUNTY	WOOD	OH	Peaking Units	153	170	6/1/2002
WORTHIN1	WORTHINGTON PLANT	GREENE	IN	Peaking Units	45	45	1/1/2000
WORTHIN2	WORTHINGTON PLANT	GREENE	IN	Peaking Units	45	45	1/1/2000
WORTHIN3	WORTHINGTON PLANT	GREENE	IN	Peaking Units	45	45	1/1/2000
WORTHIN4	WORTHINGTON PLANT	GREENE	IN	Peaking Units	45	45	1/1/2000
WSTFORK1	WEST FORK	KNOX	IN	Peaking Units	135	135	1/1/2000
WSTFORK2	WEST FORK	KNOX	IN	Peaking Units	135	135	1/1/2000
WSTFORK3	WEST FORK	KNOX	IN	Peaking Units	135	135	1/1/2000
WSTFORK4	WEST FORK	KNOX	IN	Peaking Units	135	135	1/1/2000
WSTLORG1	WEST LORAIN	LORAIN	OH	Peaking Units	85	85	1/1/2001
WSTLORG2	WEST LORAIN	LORAIN	OH	Peaking Units	85	85	1/1/2001
WSTLORG3	WEST LORAIN	LORAIN	OH	Peaking Units	85	85	1/1/2001
WSTLORG4	WEST LORAIN	LORAIN	OH	Peaking Units	85	85	1/1/2001
WSTLORG5	WEST LORAIN	LORAIN	OH	Peaking Units	85	85	1/1/2001
ZEELAND1	ZEELAND (MIR)	OTTAWA	MI	Peaking Units	170	170	1/1/2001
ZEELAND2	ZEELAND (MIR)	OTTAWA	MI	Peaking Units	170	170	1/1/2001

Table A-17: New Capacity Additions 2000-2005

MAPS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date
ZEELND01	ZEELAND (MIR)	OTTAWA	MI	Combined Cycle	478.8	532	8/12/2002
ZEELND02	ZEELAND (MIR)	OTTAWA	MI	Combined Cycle	360	400	6/1/2002
ZEELND03	ZEELAND (MIR)	OTTAWA	MI	Combined Cycle	387	430	6/1/2002
ZILWAUK1	ZILWAUKEE	SAGINAW	MI	Peaking Units	29	29	1/1/2000
ZILWAUK2	ZILWAUKEE	SAGINAW	MI	Peaking Units	12.12	12.12	1/1/2000
	New Units in MISO (MAIN)						
AESMEDV1	AESMEDINA VALLEY	TAZEWELL	IL	Combined Cycle	36	40	6/20/2001
AESMEDV2	AESMEDINA VALLEY	TAZEWELL	IL	Peaking Units	28.35	31.5	6/1/2001
ALSEYGT1	ALSEY	SCOTT	IL	Peaking Units	18.9	21	6/1/2000
APPLETN1	APPLETON PAPER-LOCKS MILL	OUTAGAMIE	WI	Peaking Units	43.2	48	4/1/2002
AUDRAIN1	AUDRAIN	AUDRAIN	MO	Peaking Units	81	90	6/6/2001
AUDRAIN2	AUDRAIN	AUDRAIN	MO	Peaking Units	81	90	6/6/2001
AUDRAIN3	AUDRAIN	AUDRAIN	MO	Peaking Units	81	90	6/6/2001
AUDRAIN4	AUDRAIN	AUDRAIN	MO	Peaking Units	81	90	6/6/2001
AUDRAIN5	AUDRAIN	AUDRAIN	MO	Peaking Units	81	90	6/6/2001
AUDRAIN6	AUDRAIN	AUDRAIN	MO	Peaking Units	81	90	6/6/2001
AUDRAIN7	AUDRAIN	AUDRAIN	MO	Peaking Units	81	90	6/6/2001
AUDRAIN8	AUDRAIN	AUDRAIN	MO	Peaking Units	81	90	6/6/2001
COLUMSS1	COLUMBIA SUBSTATION	BOONE	MO	Peaking Units	80	80	9/4/2001
COLUMSS2	Columbia Substation		MO	Peaking Units	80	80	9/4/2001
ELWOOGT5	ELWOOD	WILL	IL	Peaking Units	150	150	7/15/2001
ELWOOGT6	ELWOOD	WILL	IL	Peaking Units	150	150	7/15/2001
ELWOOGT7	ELWOOD	WILL	IL	Peaking Units	150	150	7/15/2001
ELWOOGT8	ELWOOD	WILL	IL	Peaking Units	150	150	7/15/2001
ELWOOGT9	ELWOOD	WILL	IL	Peaking Units	150	150	7/15/2001
GERMNTW1	GERMANTOWN	WASHINGTON	WI	Peaking Units	76.5	85	5/1/2000
GERMNTW2	GERMANTOWN	WASHINGTON	WI	Peaking Units	45	50	8/1/2000
GIBSON1	Gibson		IL	Peaking Units	117	135	6/30/2000
GIBSON2	Gibson		IL	Peaking Units	117	135	6/30/2000
GOOSECR1	GOOSE CREEK ENERGY CENTER	PIATT	IL	Peaking Units	76.5	85	1/30/2003
GOOSECR2	GOOSE CREEK ENERGY CENTER	PIATT	IL	Peaking Units	76.5	85	6/1/2003
GOOSECR3	GOOSE CREEK ENERGY CENTER	PIATT	IL	Peaking Units	76.5	85	6/1/2003
GOOSECR4	GOOSE CREEK ENERGY CENTER	PIATT	IL	Peaking Units	76.5	85	6/1/2003
GOOSECR5	GOOSE CREEK ENERGY CENTER	PIATT	IL	Peaking Units	76.5	85	6/1/2003
GOOSECR6	GOOSE CREEK ENERGY CENTER	PIATT	IL	Peaking Units	76.5	85	6/1/2003
GRANDTW1	GRAND TOWER	JACKSON	IL	Combined Cycle	238.5	265	12/1/2001
GRANDTW2	GRAND TOWER	JACKSON	IL	Combined Cycle	258.3	287	6/29/2001
GRANDTW3	GRAND TOWER	JACKSON	IL	Peaking Units	12.24	13.6	12/1/2001
GRANDTW4	GRAND TOWER	JACKSON	IL	Peaking Units	8.1	9	6/29/2001
GREATRE1	GREAT RIVER ENERGY - PLEASA	MOWER	MN	Peaking Units	137.2	140	5/1/2001
GREATRE2	GREAT RIVER ENERGY - PLEASA	MOWER	MN	Peaking Units	137.2	140	5/1/2001
GREATRE3	GREAT RIVER ENERGY - PLEASA	MOWER	MN	Peaking Units	111.6	124	5/1/2002
HOLLAND1	HOLLAND ENERGY	SHELBY	IL	Combined Cycle	603	670	6/1/2002
INDIATW1	INDIANTOWN WINDPOWER PROJEC			Other	50	50	12/1/2002
LAKEFLJ1	LAKEFIELD JUNCTION GENERAT	MARTIN	MN	Peaking Units	82.8	92	6/15/2001
LAKEFLJ2	LAKEFIELD JUNCTION GENERAT	MARTIN	MN	Peaking Units	82.8	92	6/15/2001
LAKEFLJ3	LAKEFIELD JUNCTION GENERAT	MARTIN	MN	Peaking Units	82.8	92	6/15/2001
LAKEFLJ4	LAKEFIELD JUNCTION GENERAT	MARTIN	MN	Peaking Units	82.8	92	6/15/2001
LAKEFLJ5	LAKEFIELD JUNCTION GENERAT	MARTIN	MN	Peaking Units	82.8	92	6/15/2001
LAKEFLJ6	LAKEFIELD JUNCTION GENERAT	MARTIN	MN	Peaking Units	82.8	92	6/15/2001
MARION01	MARION (SIPC)	WILLIAMSON	IL	Coal	18	18	3/1/2003
MEPIGTF1	MEPI GT FACILITY	MASSAC	IL	Peaking Units	64.8	72	8/1/2000
MEPIGTF2	MEPI GT FACILITY	MASSAC	IL	Peaking Units	64.8	72	8/1/2000
MEPIGTF3	MEPI GT FACILITY	MASSAC	IL	Peaking Units	64.8	72	8/1/2000
MEPIGTF4	MEPI GT FACILITY	MASSAC	IL	Peaking Units	45.9	51	8/1/2000

Table A-17: New Capacity Additions 2000-2005

MAPS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date
MEPIGTF5	MEPI GT FACILITY	MASSAC	IL	Peaking Units	45.9	51	8/1/2000
MERAMC01	MERAMEC	ST. LOUIS	MO	Peaking Units	43.2	48	6/1/2000
MONTFRW1	MONTFORT WIND FARM	IOWA	WI	Other	25.5	25.5	5/15/2001
NEENAH01	NEENAH	WINNEBAGO	WI	Peaking Units	135	150	5/8/2000
NEENAH02	NEENAH	WINNEBAGO	WI	Peaking Units	135	150	5/8/2000
PATOKA01	PATOKA	MARION	IL	Peaking Units	105.3	117	4/10/2001
PATOKA02	PATOKA	MARION	IL	Peaking Units	105.3	117	5/25/2001
PENOCREK	Peno Creek		MO	Peaking Units	192	192	5/24/2002
PINCKNV1	PINCKNEYVILLE	PERRY	IL	Peaking Units	158.4	176	6/30/2000
PINCKNV2	PINCKNEYVILLE	PERRY	IL	Peaking Units	32.4	36	6/18/2001
PINCKNV3	PINCKNEYVILLE	PERRY	IL	Peaking Units	32.4	36	6/26/2001
PINCKNV4	PINCKNEYVILLE	PERRY	IL	Peaking Units	32.4	36	6/27/2001
PINCKNV5	PINCKNEYVILLE	PERRY	IL	Peaking Units	32.4	36	8/28/2001
PULLIAM9	PULLIAM	BROWN	WI	Peaking Units	83	83	6/1/2003
RACCOON1	RACCOON CREEK ENERGY CENTER	CLAY	IL	Peaking Units	72	80	6/1/2002
RACCOON2	RACCOON CREEK ENERGY CENTER	CLAY	IL	Peaking Units	72	80	6/1/2002
RACCOON3	RACCOON CREEK ENERGY CENTER	CLAY	IL	Peaking Units	72	80	7/1/2002
RACCOON4	RACCOON CREEK ENERGY CENTER	CLAY	IL	Peaking Units	72	80	8/13/2002
RELIAES1	RELIANT ENERGY SHELBY COUNT	SHELBY	IL	Peaking Units	180	200	7/14/2000
RELIAES2	RELIANT ENERGY SHELBY COUNT	SHELBY	IL	Peaking Units	126	140	7/14/2000
RIVEREC1	RIVERSIDE ENERGY CENTER	ROCK	WI	Combined Cycle	540	600	6/1/2004
ROCKGEC1	ROCKGEN ENERGY CENTER	DANE	WI	Peaking Units	153	170	5/1/2001
ROCKGEC2	ROCKGEN ENERGY CENTER	DANE	WI	Peaking Units	153	170	5/1/2001
ROCKGEC3	ROCKGEN ENERGY CENTER	DANE	WI	Peaking Units	153	170	5/1/2001
STELMO01	ST ELMO	FAYETTE	IL	Peaking Units	40.5	45	6/1/2000
TOPIOWA1	TOP OF IOWA WIND FARM	WORTH	IA	Other	80	80	12/4/2001
UNIVMIS1	UNIVERSITY OF MISSOURI-COLU	BOONE	MO	Peaking Units	23.4	26	4/15/2002
VENICE01	VENICE (AUEP)	MADISON	IL	Peaking Units	43.2	48	6/1/2002
WSTMARN1	WEST MARINETTE (MGE)	MARINETTE	WI	Peaking Units	74.7	83	6/1/2000
	New Units in MISO (MAPP)						
BLACKDG3	BLACK DOG	DAKOTA	MN	Combined Cycle	261	290	6/15/2002
BROADWAY	Broadway Generation Plant		MN	Peaking Units	12	12	6/1/2003
CASCADE2	Cascade Creek		MN	Peaking Units	50	50	5/23/2002
CASSCNTY	Cass County		NE	Peaking Units	330	330	6/1/2003
CORDENG1	CORDOVA ENERGY	ROCK ISLAND	IL	Combined Cycle	483.39	537.1	6/14/2001
CWBURDP1	C.W. Burdick		NE	Peaking Units	40	40	3/15/2003
CWBURDP2	C.W. Burdick		NE	Peaking Units	40	40	3/15/2003
ELKMNDS1	ELK MOUND STATION	CHIPPEWA	WI	Peaking Units	36.9	41	5/30/2001
ELKMNDS2	ELK MOUND STATION	CHIPPEWA	WI	Peaking Units	36.9	41	6/6/2001
FREMNT_1	Fremont 1		NE	Peaking Units	42	42	6/1/2003
GREADES2	GREATER DES MOINES ENERGY C	POLK	IA	Peaking Units	180	200	6/1/2003
GREADES3	GREATER DES MOINES ENERGY C	POLK	IA	Peaking Units	126	140	6/1/2003
KIMBALL1	KIMBALL WIND	KIMBALL	NE	Other	14	14	9/1/2002
KNOXVLI1	KNOXVILLE INDUSTRIAL (MIDAM	MARION	IA	Peaking Units	16	16	6/1/2000
LUNDQUS1	LUNDQUIST	NOT APPLICABLE	IA	Peaking Units	20	20	6/1/2000
MANKAT01	MANKATO	BLUE EARTH	MN	Peaking Units	10.53	11.7	1/31/2002
MARKETS1	MARKET STREET ENERGY COMPAN	RAMSEY	MN	Other	25	25	12/1/2002
MNRIVERS	Minnesota River Station		MN	Peaking Units	43	43	1/1/2002
NTHHOME1	NORTHOME WOOD PLANT	KOOCHICHING	MN	Other	20	20	11/1/2002
POTLACC1	POTLATCH CLOQUET COGEN	CARLTON	MN	Combined Cycle	21.6	24	5/31/2001
POWERIO1	POWER IOWA 1	NOT APPLICABLE	IA	Combined Cycle	450	500	6/1/2004
SALTVAL2	SALT VALLEY GENERATING STAT	LANCASTER	NE	Peaking Units	41.5	45	5/1/2004
SALTVAL3	SALT VALLEY GENERATING STAT	LANCASTER	NE	Peaking Units	90	90	6/1/2003
SARPYGT1	SARPY	SARPY	NE	Peaking Units	90	100	5/26/2000
SHENAND1	SHENANDOAH	PAGE	VA	Peaking Units	20	20	6/1/2000

Table A-17: New Capacity Additions 2000-2005

MAPS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date
SHENANDO	Shenandoah		IA	Peaking Units	20	20	6/1/2000
SOLWAYP1	SOLWAY POWER PLANT	BELTRAMI	MN	Peaking Units	39.6	44	6/1/2003
TACONTH1	TACONITE HARBOR POWER PLANT	COOK	MN	Coal	62.5	67.5	2/7/2002
TACONTH2	TACONITE HARBOR POWER PLANT	COOK	MN	Coal	62.5	67.5	4/1/2002
TACONTH3	TACONITE HARBOR POWER PLANT	COOK	MN	Coal	62.5	67.5	6/5/2002
	New Units in FRCC						
ELDORAD1	EL DORADO (FPL)			Combined Cycle	114	114	1/1/2000
MCINTSL1	MCINTOSH (LALW)	POLK	FL	Coal	120	120	1/1/2000
WINSTON1	WINSTON DISTRIBUTED GEN	POLK	FL	Peaking Units	52	52	1/1/2000
HARDEEP1	HARDEE POWER STATION - SEC1	HARDEE	FL	Peaking Units	72	90	5/20/2000
SOPURDM1	S.O. PURDOM	WAKULLA	FL	Combined Cycle	233	262	8/1/2000
POLKGT02	POLK	POLK	FL	Peaking Units	160	180	8/15/2000
FORTMY10	FORT MYERS	LEE	FL	Peaking Units	150	170	11/1/2000
FORTMY11	FORT MYERS	LEE	FL	Peaking Units	300	340	12/1/2000
INTERCC1	INTERCESSION CITY	OSCEOLA	FL	Peaking Units	80	94	12/13/2000
INTERCC2	INTERCESSION CITY	OSCEOLA	FL	Peaking Units	80	94	12/14/2000
INTERCC3	INTERCESSION CITY	OSCEOLA	FL	Peaking Units	80	94	12/17/2000
INTERCC4	INTERCESSION CITY P15	OSCEOLA	FL	Peaking Units	154	184	12/17/2000
FORTMY12	FORT MYERS	LEE	FL	Peaking Units	150	170	2/1/2001
FORTMY13	FORT MYERS	LEE	FL	Peaking Units	150	170	3/1/2001
FORTMYR9	FORT MYERS	LEE	FL	Peaking Units	150	170	4/1/2001
MCINTSL4	MCINTOSH (LALW)	POLK	FL	Peaking Units	180	200	4/16/2001
MCINTSL5	MCINTOSH (LALW)	POLK	FL	Peaking Units	44.1	49	4/16/2001
JOHNRKL1	JOHN R. KELLY	ALACHUA	FL	Combined Cycle	104.4	116	5/31/2001
FIELDST1	FIELD STREET	VOLUSIA	FL	Peaking Units	36	40	6/1/2001
ANEIPP5	CANE ISLAND POWER PARK	OSCEOLA	FL	Peaking Units	153	170	6/6/2001
RTINF5	MARTIN (FLPL)	MARTIN	FL	Peaking Units	149	181	6/20/2001
MARTINF6	MARTIN (FLPL)	MARTIN	FL	Peaking Units	149	181	6/20/2001
CRYSTRV1	CRYSTAL RIVER	CITRUS	FL	Coal	100	100	10/1/2001
FORTMYR2	FORT MYERS	LEE	FL	Combined Cycle	651	652	10/1/2001
FORTMYR3	FORT MYERS	LEE	FL	Combined Cycle	901	904	10/1/2001
RELEOSC2	RELIANT ENERGY OSCEOLA	OSCEOLA	FL	Peaking Units	159	170	12/1/2001
RELEOSC3	RELIANT ENERGY OSCEOLA	OSCEOLA	FL	Peaking Units	159	170	12/1/2001
PAYNECK1	PAYNE CREEK GENERATING FACI	HARDEE	FL	Combined Cycle	488	572	1/1/2002
CANEIPP1	CANE ISLAND POWER PARK	OSCEOLA	FL	Combined Cycle	225	250	1/25/2002
PASCOPR1	PASCO POWER PROJECT	PASCO	FL	Peaking Units	158	158	3/1/2002
PASCOPR2	PASCO POWER PROJECT	PASCO	FL	Peaking Units	158	158	3/1/2002
PASCOPR3	PASCO POWER PROJECT	PASCO	FL	Peaking Units	158	158	3/1/2002
RELEOSC1	RELIANT ENERGY OSCEOLA	OSCEOLA	FL	Peaking Units	159	170	3/1/2002
POLKGT03	POLK	POLK	FL	Peaking Units	160	180	5/1/2002
VANDOLH2	VANDOLAH POWER PROJECT	HARDEE	FL	Peaking Units	153	170	6/1/2002
VANDOLH3	VANDOLAH POWER PROJECT	HARDEE	FL	Peaking Units	153	170	6/1/2002
DESOTGC1	DESOTO GENERATING CO. (PREN	DE SOTO	FL	Peaking Units	150	170	6/1/2002
DESOTGC2	DESOTO GENERATING CO. (PREN	DE SOTO	FL	Peaking Units	150	170	6/1/2002
OLEANDP1	OLEANDER POWER FACILITY	BREVARD	FL	Peaking Units	155	182	6/1/2002
OLEANDP2	OLEANDER POWER FACILITY	BREVARD	FL	Peaking Units	155	182	6/1/2002
OLEANDP3	OLEANDER POWER FACILITY	BREVARD	FL	Peaking Units	155	182	6/1/2002
OLEANDP4	OLEANDER POWER FACILITY	BREVARD	FL	Peaking Units	155	182	6/1/2002
VANDOLH1	VANDOLAH POWER PROJECT	HARDEE	FL	Peaking Units	153	170	6/1/2002
VANDOLH4	VANDOLAH POWER PROJECT	HARDEE	FL	Peaking Units	153	170	6/1/2002
SANFRDF3	SANFORD (FPL)	VOLUSIA	FL	Combined Cycle	1030	1116	6/15/2002
AUBURDP1	AUBURNDALE POWER PARTNERS L	POLK	FL	Peaking Units	121.5	135	7/31/2002
FORTMYR5	FORT MYERS	LEE	FL	Peaking Units	170	170	1/1/2003
FORTMYR6	FORT MYERS	LEE	FL	Peaking Units	170	170	1/1/2003
GANNONC1	GANNON	HILLSBOROUGH	FL	Combined Cycle	737	742	6/1/2003

Table A-17: New Capacity Additions 2000-2005

MAPS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date
SANFRDF4	SANFORD (FPL)	VOLUSIA	FL	Combined Cycle	1030	1116	6/1/2003
OSPREYE1	OSPREY ENERGY CENTER	POLK	FL	Combined Cycle	486	540	10/1/2003
STANTN01	STANTON	ORANGE	FL	Combined Cycle	700	700	10/1/2003
HINESCC2	Hines Energy Complex	POLK	FL	Combined Cycle	516	582	11/1/2003
GANNONC2	GANNON	HILLSBOROUGH	FL	Combined Cycle	1042	1072	6/1/2004
MCINTSL2	MCINTOSH (LALW)	POLK	FL	Combined Cycle	332.1	369	1/1/2005
	New Units in ISO-NE						
ANDROEC3	ANDROSCOGGIN ENERGY CENTER	FRANKLIN	ME	Peaking Units	54.46	54.46	1/1/2000
BERKSHP1	BERKSHIRE POWER	HAMPDEN	MA	Combined Cycle	252	252	1/1/2000
BUKSPTE1	BUCKSPORT ENERGY	HANCOCK	ME	Peaking Units	174	174	1/1/2000
FALLRIV1	FALL RIVER COGEN PLANT	BRISTOL	MA	Combined Cycle	6.7	6.7	1/1/2000
MAINEIN1	MAINE INDEPENDENCE STATION	PENOBSCOT	ME	Combined Cycle	519	519	1/1/2000
NEWENGW1	NEW ENGLAND WIND ENERGY STA	CUMBERLAND	ME	Other	20	20	1/1/2000
TIVERTN1	TIVERTON POWER PLANT	NEWPORT	RI	Combined Cycle	88.72	88.72	1/1/2000
BLACKST1	BLACKSTONE (AMNAPO)	WORCESTER	MA	Combined Cycle	290	290	1/1/2001
BLACKST2	BLACKSTONE (AMNAPO)	WORCESTER	MA	Combined Cycle	290	290	1/1/2001
WALLNGF1	WALLINGFORD	NEW HAVEN	CT	Peaking Units	44	44	1/1/2001
WALLNGF2	WALLINGFORD	NEW HAVEN	CT	Peaking Units	44	44	1/1/2001
WALLNGF3	WALLINGFORD	NEW HAVEN	CT	Peaking Units	44	44	1/1/2001
WALLNGF4	WALLINGFORD	NEW HAVEN	CT	Peaking Units	44	44	1/1/2001
WALLNGF5	WALLINGFORD	NEW HAVEN	CT	Peaking Units	44	44	1/1/2001
WALLNGF6	WALLINGFORD	NEW HAVEN	CT	Peaking Units	44	44	1/1/2001
WSTBROK1	WESTBROOK POWER PLANT	CUMBERLAND	ME	Combined Cycle	540	540	1/1/2001
MILLENN1	MILLENNIUM POWER PARTNERS,	WORCESTER	MA	Combined Cycle	360	360	4/5/2001
WALLING1	WALLINGFORD	NEW HAVEN	CT	Peaking Units	180	200	1/15/2002
MILFORD3	MILFORD (EPPSCO)	NEW HAVEN	CT	Combined Cycle	489.6	544	3/1/2002
WING01	NEWINGTON (COEDDE)	ROCKINGHAM	NH	Combined Cycle	472.5	525	3/1/2002
AKEROA4	LAKE ROAD	WINDHAM	CT	Combined Cycle	237.6	264	5/1/2002
LAKEROA5	LAKE ROAD	WINDHAM	CT	Combined Cycle	237.6	264	5/1/2002
KENDLSQ1	KENDALL SQUARE	MIDDLESEX	MA	Combined Cycle	210.6	234	6/1/2002
RIHOPEE1	RI HOPE ENERGY	PROVIDENCE	RI	Combined Cycle	522	535	6/1/2002
WESTSPR1	WEST SPRINGFIELD	HAMPDEN	MA	Peaking Units	45	45	6/7/2002
WESTSPR2	WEST SPRINGFIELD	HAMPDEN	MA	Peaking Units	45	45	6/7/2002
LAKEROA6	LAKE ROAD	WINDHAM	CT	Combined Cycle	237.6	264	6/14/2002
FORERIV1	FORE RIVER	NORFOLK	MA	Combined Cycle	450	500	8/1/2002
FORERIV2	FORE RIVER	NORFOLK	MA	Combined Cycle	225	250	8/1/2002
BELLINC1	BELLINGHAM	NORFOLK	MA	Combined Cycle	261	290	11/1/2002
BELLINC2	BELLINGHAM	NORFOLK	MA	Combined Cycle	261	290	12/31/2002
LONDOND1	AES LONDONDERRY	ROCKINGHAM	NH	Combined Cycle	648	720	2/28/2003
MERIDEN1	MERIDEN POWER	NEW HAVEN	CT	Combined Cycle	489.6	544	3/1/2003
MYSTICC1	MYSTIC	MIDDLESEX	MA	Combined Cycle	750	750	4/1/2003
MYSTICC2	MYSTIC	MIDDLESEX	MA	Combined Cycle	750	750	4/1/2003
	New Units in NYISO						
MADISNW1	MADISON WINDPOWER PROJECT	MADISON	NY	Other	11.5	11.5	1/1/2000
UPNYWF11	UPPER NEW YORK WIND FARM	WYOMING	NY	Other	6.6	6.6	1/1/2000
23RDSTR1	23RD STREET	KINGS	NY	Peaking Units	39.95	39.95	1/1/2001
23RDSTR2	23RD STREET	KINGS	NY	Peaking Units	39.95	39.95	1/1/2001
CANASTO1	CANASTOTA	MADISON	NY	Other	30	30	1/1/2001
CARLSON1	CARLSON	CHAUTAUQUA	NY	Peaking Units	43	43	1/1/2001
HARLEMR1	HARLEM RAIL	BRONX	NY	Peaking Units	39.95	39.95	1/1/2001
HARLEMR2	HARLEM RAIL	BRONX	NY	Peaking Units	39.95	39.95	1/1/2001
HELLGTE1	HELL GATE	BRONX	NY	Peaking Units	39.95	39.95	1/1/2001
HELLGTE2	HELL GATE	BRONX	NY	Peaking Units	39.95	39.95	1/1/2001
LINDENC9	LINDEN COGEN PLANT (ECOAST)	UNION	NJ	Peaking Units	180	180	1/1/2001
PILGRMS1	PILGRIM STATE HOSPITAL			Peaking Units	44	44	1/1/2001

Table A-17: New Capacity Additions 2000-2005

.PS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date
RIVERST1	RIVER STREET (NYPA)	KINGS	NY	Peaking Units	44	44	1/1/2001
VERNONB1	VERNON BOULEVARD	QUEENS	NY	Peaking Units	39.95	39.95	1/1/2001
VERNONB2	VERNON BOULEVARD	QUEENS	NY	Peaking Units	39.95	39.95	1/1/2001
VIRGNAA1	VIRGINIA AVENUE	NEW YORK	NY	Peaking Units	44	44	1/1/2001
CARLSNN1	CARLSON	CHAUTAUQUA	NY	Peaking Units	63.9	71	1/15/2002
BETHPAG1	BETHPAGE (TBG - GRUMMAN)	NASSAU	NY	Peaking Units	39.6	44	5/1/2002
EFBARRE1	E.F. BARRETT	NASSAU	NY	Peaking Units	71.1	79	5/1/2002
PORTJFF1	PORT JEFFERSON	SUFFOLK	NY	Peaking Units	71.1	79	5/1/2002
SHOREHA1	SHOREHAM			Peaking Units	71.91	79.9	5/1/2002
BAYSWAT1	BAYSWATER CLEAN ENERGY CENT	QUEENS	NY	Peaking Units	39.6	44	6/1/2002
GLENWOO1	GLENWOOD	NASSAU	NY	Peaking Units	35.1	39	6/1/2002
GLENWOO2	GLENWOOD	NASSAU	NY	Peaking Units	35.1	39	6/1/2002
EDGEWEG1	EDGEWOOD ELECTRIC GENERATIN	SUFFOLK	NY	Peaking Units	71.1	79	7/24/2002
RAVENSW1	RAVENSWOOD	KINGS	NY	Combined Cycle	225	250	6/1/2003
ATHENGP1	ATHENS GENERATING PLANT	GREENE	NY	Combined Cycle	328.5	365	7/1/2003
ATHENGP2	ATHENS GENERATING PLANT	GREENE	NY	Combined Cycle	328.5	365	7/1/2003
ATHENGP3	ATHENS GENERATING PLANT	GREENE	NY	Combined Cycle	328.5	365	7/1/2003
EASTRIV1	EAST RIVER	NEW YORK	NY	Peaking Units	162	180	1/1/2004
EASTRIV2	EAST RIVER	NEW YORK	NY	Peaking Units	162	180	1/1/2004
ALBANSS1	ALBANY STEAM STATION	ALBANY	NY	Combined Cycle	241	267	6/1/2005
ALBANSS2	ALBANY STEAM STATION	ALBANY	NY	Combined Cycle	241	267	6/1/2005
ALBANSS3	ALBANY STEAM STATION	ALBANY	NY	Combined Cycle	241	267	6/1/2005
	New Units in SETRANS (Entergy)						
ACADIA01	ACADIA	ST. LANDRY	LA	Combined Cycle	558	620	6/1/2002
ACADIA02	ACADIA	ST. LANDRY	LA	Combined Cycle	558	620	8/5/2002
ATTALAE1	ATTALA ENERGY CENTER	ATTALA	MS	Combined Cycle	459	510	6/1/2001
[illegible]UCV1	BAYOU COVE	JEFFERSON DAVIS	LA	Peaking Units	72	80	10/15/2002
[illegible]UCV2	BAYOU COVE	JEFFERSON DAVIS	LA	Peaking Units	72	80	10/15/2002
BAYOUCV3	BAYOU COVE	JEFFERSON DAVIS	LA	Peaking Units	72	80	10/15/2002
BAYOUCV4	BAYOU COVE	JEFFERSON DAVIS	LA	Peaking Units	72	80	10/15/2002
BIGCJN11	BIG CAJUN 1	POINTE COUPEE	LA	Peaking Units	108	120	6/6/2001
BIGCJN12	BIG CAJUN 1	POINTE COUPEE	LA	Peaking Units	108	120	6/6/2001
BRANDBG4	BRANDY BRANCH GENERATING ST	DUVAL	FL	Peaking Units	158	191	5/31/2001
BRANDBG5	BRANDY BRANCH GENERATING ST	DUVAL	FL	Peaking Units	158	191	5/31/2001
BRANDBG6	BRANDY BRANCH GENERATING ST	DUVAL	FL	Peaking Units	158	191	10/12/2001
CALCASU1	CALCASIEU GENERATION PROJEC	CALCASIEU	LA	Peaking Units	139.5	155	5/31/2000
CALCASU2	CALCASIEU GENERATION PROJEC	CALCASIEU	LA	Peaking Units	148.5	165	5/15/2001
CARVILE1	CARVILLE ENERGY CENTER	IBERVILLE	LA	Combined Cycle	234.9	261	5/1/2003
CARVILE2	CARVILLE ENERGY CENTER	IBERVILLE	LA	Combined Cycle	234.9	261	5/1/2003
CARVILE3	CARVILLE ENERGY CENTER	IBERVILLE	LA	Combined Cycle	109.8	122	5/1/2002
CHOUTEU1	CHOUTEAU (AECI)	MAYES	OK	Combined Cycle	477	530	7/21/2000
COTTONW1	COTTONWOOD ENERGY	NEWTON	TX	Combined Cycle	555.75	617.5	2/1/2003
COTTONW2	COTTONWOOD ENERGY	NEWTON	TX	Combined Cycle	555.75	617.5	2/1/2003
CROSSEC1	CROSSROADS ENERGY CENTER	COAHOMA	MS	Peaking Units	75	80	6/30/2002
CROSSEC2	CROSSROADS ENERGY CENTER	COAHOMA	MS	Peaking Units	75	80	6/30/2002
CROSSEC3	CROSSROADS ENERGY CENTER	COAHOMA	MS	Peaking Units	75	80	7/31/2002
CROSSEC4	CROSSROADS ENERGY CENTER	COAHOMA	MS	Peaking Units	75	80	7/31/2002
HINDSEF1	HINDS ENERGY FACILITY	HINDS	MS	Combined Cycle	450	500	6/1/2001
HOLDENP1	HOLDEN POWER PLANT	JOHNSON	MO	Peaking Units	96.3	107	5/31/2002
HOLDENP2	HOLDEN POWER PLANT	JOHNSON	MO	Peaking Units	96.3	107	5/31/2002
HOLDENP3	HOLDEN POWER PLANT	JOHNSON	MO	Peaking Units	96.3	107	5/31/2002
HOTSPRF2	HOT SPRING ENERGY FACILITY	HOT SPRING	AR	Combined Cycle	558	620	5/31/2002
HOTSPRP1	HOT SPRINGS POWER	GARLAND	AR	Combined Cycle	648	720	7/1/2004
JDKENND1	J.D. KENNEDY	DUVAL	FL	Peaking Units	158	191	4/1/2000
LOUISI21	LOUISIANA 2	EAST BATON ROUGE	LA	Steam Gas/Oil	140	140	7/1/2000

Table A-17: New Capacity Additions 2000-2005

MAPS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date
NROCCGF1	NROC COGEN FACILITY	JEFFERSON	TX	Combined Cycle	72	80	8/1/2001
OUACHIT1	OUACHITA POWER PLANT	OUACHITA	LA	Combined Cycle	720	800	11/1/2002
PERRYVP1	PERRYVILLE POWER STATION	OUACHITA	LA	Peaking Units	153	170	6/15/2001
PERRYVP3	PERRYVILLE POWER STATION	OUACHITA	LA	Combined Cycle	502.2	558	7/1/2002
PINEBLF1	PINE BLUFF ENERGY CENTER (S	JEFFERSON	AR	Combined Cycle	198	220	9/24/2001
RSCOGEN1	RS COGEN	CALCASIEU	LA	Combined Cycle	403.2	448	8/1/2002
SABINEC1	SABINE COGENERATION FACILIT	ORANGE	TX	Combined Cycle	90	100	1/15/2000
SABINER1	SABINE RIVER WORKS (COGLPO)	ORANGE	TX	Combined Cycle	378	420	11/28/2001
SHELLGM1	SHELL GEISMAR	ASCENSION	LA	Combined Cycle	36	40	8/1/2002
SHELLGM2	SHELL GEISMAR	ASCENSION	LA	Combined Cycle	36	40	8/1/2002
STERGT10	STERLINGTON (NRG)	OUACHITA	LA	Peaking Units	17	17	6/15/2000
STERLGT1	STERLINGTON (NRG)	OUACHITA	LA	Peaking Units	22.22	22.22	6/15/2000
STERLGT2	STERLINGTON (NRG)	OUACHITA	LA	Peaking Units	22.22	22.22	6/15/2000
STERLGT3	STERLINGTON (NRG)	OUACHITA	LA	Peaking Units	22.22	22.22	7/15/2000
STERLGT4	STERLINGTON (NRG)	OUACHITA	LA	Peaking Units	22.22	22.22	8/15/2000
STERLGT5	STERLINGTON (NRG)	OUACHITA	LA	Peaking Units	22.22	22.22	3/1/2001
STERLGT6	STERLINGTON (NRG)	OUACHITA	LA	Peaking Units	22.22	22.22	3/1/2001
STERLGT7	STERLINGTON (NRG)	OUACHITA	LA	Peaking Units	22.22	22.22	7/15/2001
STERLGT8	STERLINGTON (NRG)	OUACHITA	LA	Peaking Units	22.22	22.22	7/15/2001
STERLGT9	STERLINGTON (NRG)	OUACHITA	LA	Peaking Units	17	17	7/15/2001
STFRANS1	ST FRANCIS	DUNKLIN	MO	Combined Cycle	234	260	6/1/2001
STHAVEN1	SOUTHAVEN (DUENNO)	DE SOTO	MS	Peaking Units	72	80	5/30/2002
STHAVEN2	SOUTHAVEN (DUENNO)	DE SOTO	MS	Peaking Units	72	80	5/30/2002
STHAVEN3	SOUTHAVEN (DUENNO)	DE SOTO	MS	Peaking Units	72	80	5/30/2002
STHAVEN4	SOUTHAVEN (DUENNO)	DE SOTO	MS	Peaking Units	72	80	5/30/2002
STHAVEN5	SOUTHAVEN (DUENNO)	DE SOTO	MS	Peaking Units	72	80	5/30/2002
[illegible]VEN6	SOUTHAVEN (DUENNO)	DE SOTO	MS	Peaking Units	72	80	5/30/2002
[illegible]AVEN7	SOUTHAVEN (DUENNO)	DE SOTO	MS	Peaking Units	72	80	5/30/2002
STHAVEN8	SOUTHAVEN (DUENNO)	DE SOTO	MS	Peaking Units	72	80	5/30/2002
STHHAVN1	SOUTHAVEN (COGENT)	DE SOTO	MS	Combined Cycle	240.3	267	6/1/2003
STHHAVN2	SOUTHAVEN (COGENT)	DE SOTO	MS	Combined Cycle	240.3	267	6/1/2003
STHHAVN3	SOUTHAVEN (COGENT)	DE SOTO	MS	Combined Cycle	239.4	266	6/1/2003
TAFTPRO1	TAFT PROJECT	ST. CHARLES	LA	Combined Cycle	700.2	778	9/1/2002
UNIONPP2	UNION POWER PARTNERS	UNION	AR	Combined Cycle	495	550	1/27/2003
UNIONPP3	UNION POWER PARTNERS	UNION	AR	Combined Cycle	495	550	4/1/2003
UNIONPP4	UNION POWER PARTNERS	UNION	AR	Combined Cycle	495	550	6/1/2003
UNIONPP5	UNION POWER PARTNERS	UNION	AR	Combined Cycle	495	550	8/1/2003
WARRNPP1	WARREN POWER PROJECT (ENWHO	WARREN	MS	Peaking Units	67.5	75	8/13/2001
WARRNPP2	WARREN POWER PROJECT (ENWHO	WARREN	MS	Peaking Units	67.5	75	8/13/2001
WARRNPP3	WARREN POWER PROJECT (ENWHO	WARREN	MS	Peaking Units	67.5	75	8/13/2001
WARRNPP4	WARREN POWER PROJECT (ENWHO	WARREN	MS	Peaking Units	67.5	75	8/13/2001
WASHPAR1	WASHINGTON PARISH ENERGY CE	WASHINGTON	LA	Combined Cycle	253.8	282	7/1/2004
WASHPAR2	WASHINGTON PARISH ENERGY CE	WASHINGTON	LA	Combined Cycle	253.8	282	7/1/2004
WRIGHTV1	WRIGHTSVILLE POWER FACILITY	PULASKI	AR	Combined Cycle	322.2	358	6/25/2002
WRIGHTV2	WRIGHTSVILLE POWER FACILITY	PULASKI	AR	Combined Cycle	172.8	192	6/25/2002
	New Units in SETRANS (SOCO)						
AUTAUGA1	AUTAUGAVILLE	AUTAUGA	AL	Combined Cycle	567	630	6/1/2003
AUTAUGA2	AUTAUGAVILLE	AUTAUGA	AL	Combined Cycle	567	630	6/1/2003
BACONTO1	BACONTON	MITCHELL	GA	Peaking Units	126.9	141	6/1/2000
BACONTO2	BACONTON	MITCHELL	GA	Peaking Units	42.3	47	7/1/2000
BARRYAL1	BARRY (ALAP)	MOBILE	AL	Combined Cycle	483.3	537	5/31/2000
BARRYAL2	BARRY (ALAP)	MOBILE	AL	Combined Cycle	483.3	537	5/1/2001
CALHOUN1	CALHOUN POWER CO (FPL)	CALHOUN	AL	Peaking Units	157	167	6/1/2003
CALHOUN2	CALHOUN POWER CO (FPL)	CALHOUN	AL	Peaking Units	157	167	6/1/2003
CALHOUN3	CALHOUN POWER CO (FPL)	CALHOUN	AL	Peaking Units	157	167	6/1/2003

Table A-17: New Capacity Additions 2000-2005

MAPS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date
CALHOUN4	CALHOUN POWER CO (FPL)	CALHOUN	AL	Peaking Units	157	167	6/1/2003
DAHLBRG1	DAHLBERG	JACKSON	GA	Peaking Units	180	200	6/1/2000
DAHLBRG2	DAHLBERG	JACKSON	GA	Peaking Units	180	200	6/1/2000
DAHLBRG3	DAHLBERG	JACKSON	GA	Peaking Units	72	80	6/1/2000
DAHLBRG4	DAHLBERG	JACKSON	GA	Peaking Units	72	80	6/20/2000
DAHLBRG5	DAHLBERG	JACKSON	GA	Peaking Units	72	80	7/1/2000
DAHLBRG6	DAHLBERG	JACKSON	GA	Peaking Units	144	160	11/1/2001
DOYLEPT1	DOYLE PLANT	WALTON	GA	Peaking Units	180	200	6/15/2000
DOYLEPT2	DOYLE PLANT	WALTON	GA	Peaking Units	81	90	6/15/2000
DOYLEPT3	DOYLE PLANT	WALTON	GA	Peaking Units	72	80	7/30/2000
EFFINGH1	EFFINGHAM COUNTY	EFFINGHAM	GA	Combined Cycle	480	530	6/1/2003
ENTERPE1	ENTERPRISE ENERGY FACILITY	CLARKE	MS	Peaking Units	72	80	6/15/2002
ENTERPE2	ENTERPRISE ENERGY FACILITY	CLARKE	MS	Peaking Units	72	80	6/15/2002
ENTERPE3	ENTERPRISE ENERGY FACILITY	CLARKE	MS	Peaking Units	72	80	6/15/2002
ENTERPE4	ENTERPRISE ENERGY FACILITY	CLARKE	MS	Peaking Units	72	80	6/15/2002
ENTERPE5	ENTERPRISE ENERGY FACILITY	CLARKE	MS	Peaking Units	72	80	6/15/2002
ENTERPE6	ENTERPRISE ENERGY FACILITY	CLARKE	MS	Peaking Units	72	80	6/15/2002
ENTERPE7	ENTERPRISE ENERGY FACILITY	CLARKE	MS	Peaking Units	72	80	6/15/2002
ENTERPE8	ENTERPRISE ENERGY FACILITY	CLARKE	MS	Peaking Units	72	80	6/15/2002
GOATRCK1	GOAT ROCK (GPCO)	HARRIS	GA	Combined Cycle	513	570	6/1/2005
GOATRCK3	GOAT ROCK (GPCO)	HARRIS	GA	Combined Cycle	513	570	6/1/2002
GOATRCK4	GOAT ROCK (GPCO)	HARRIS	GA	Combined Cycle	513	570	6/1/2003
HEARDCP1	HEARD COUNTY POWER PLANT	HEARD	GA	Peaking Units	150.3	167	6/1/2001
HEARDCP2	HEARD COUNTY POWER PLANT	HEARD	GA	Peaking Units	150.3	167	6/1/2001
HEARDCP3	HEARD COUNTY POWER PLANT	HEARD	GA	Peaking Units	149.4	166	6/1/2001
H[illegible]LABE1	HILLABEE ENERGY CENTER	TALLAPOOSA	AL	Combined Cycle	693	770	12/1/2003
[illegible]BAYU1	HOG BAYOU ENERGY CENTER	MOBILE	AL	Combined Cycle	198	220	7/15/2001
L[illegible]SINS1	LANSING SMITH (GUPC)	BAY	FL	Combined Cycle	450	500	4/22/2002
MONROEC1	MONROE (CPLC)	MONROE	GA	Peaking Units	135	150	6/6/2001
MONROEC2	MONROE (CPLC)	MONROE	GA	Peaking Units	135	150	6/6/2001
MONROEC3	MONROE (CPLC)	MONROE	GA	Peaking Units	135	150	6/6/2001
MONROEM1	MONROE (MONPOW)	WALTON	GA	Peaking Units	144	160	3/31/2001
MURRAYE1	MURRAY ENERGY FACILITY (DUK	MURRAY	GA	Combined Cycle	540	600	3/1/2003
MURRAYE2	MURRAY ENERGY FACILITY (DUK	MURRAY	GA	Combined Cycle	540	600	3/1/2003
SANDERV1	SANDERSVILLE STATION (DUKE)	WASHINGTON	GA	Peaking Units	72	80	6/15/2002
SANDERV2	SANDERSVILLE STATION (DUKE)	WASHINGTON	GA	Peaking Units	72	80	6/15/2002
SANDERV3	SANDERSVILLE STATION (DUKE)	WASHINGTON	GA	Peaking Units	72	80	6/15/2002
SANDERV4	SANDERSVILLE STATION (DUKE)	WASHINGTON	GA	Peaking Units	72	80	6/15/2002
SANDERV5	SANDERSVILLE STATION (DUKE)	WASHINGTON	GA	Peaking Units	72	80	6/15/2002
SANDERV6	SANDERSVILLE STATION (DUKE)	WASHINGTON	GA	Peaking Units	72	80	6/15/2002
SANDERV7	SANDERSVILLE STATION (DUKE)	WASHINGTON	GA	Peaking Units	72	80	6/15/2002
SANDERV8	SANDERSVILLE STATION (DUKE)	WASHINGTON	GA	Peaking Units	72	80	6/15/2002
SANTARS1	SANTA ROSA (SKYSER)	SANTA ROSA	FL	Combined Cycle	216	240	9/1/2002
SEGENCP1	SE GENERATING CORP	DECATUR	GA	Peaking Units	72	80	7/1/2000
SEWELLC1	SEWELL CREEK ENERGY CENTER	POLK	GA	Peaking Units	180	200	7/1/2000
SEWELLC2	SEWELL CREEK ENERGY CENTER	POLK	GA	Peaking Units	117	130	7/1/2000
SEWELLC3	SEWELL CREEK ENERGY CENTER	POLK	GA	Peaking Units	117	130	9/15/2000
SYLVARE1	SYLVARENA	SMITH	MS	Peaking Units	38.7	43	6/1/2003
SYLVARE2	SYLVARENA	SMITH	MS	Peaking Units	38.7	43	6/1/2003
SYLVARE3	SYLVARENA	SMITH	MS	Peaking Units	38.7	43	6/1/2003
TALBOTE1	TALBOT ENERGY FACILITY	TALBOT	GA	Peaking Units	99	110	5/15/2002
TALBOTE2	TALBOT ENERGY FACILITY	TALBOT	GA	Peaking Units	99	110	5/15/2002
TALBOTE3	TALBOT ENERGY FACILITY	TALBOT	GA	Peaking Units	99	110	6/1/2002
TALBOTE4	TALBOT ENERGY FACILITY	TALBOT	GA	Peaking Units	99	110	6/6/2002
TALBOTE5	TALBOT ENERGY FACILITY	TALBOT	GA	Peaking Units	99	110	6/1/2003

Table A-17: New Capacity Additions 2000-2005

MAPS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date
TALBOTE6	TALBOT ENERGY FACILITY	TALBOT	GA	Peaking Units	99	110	6/1/2003
TENASCA1	TENASKA CENTRAL ALABAMA GEN	AUTAUGA	AL	Combined Cycle	765	850	6/1/2003
TENASGG1	TENASKA GEORGIA	HEARD	GA	Peaking Units	140.4	156	6/1/2001
TENASGG2	TENASKA GEORGIA	HEARD	GA	Peaking Units	140.4	156	6/1/2001
TENASGG3	TENASKA GEORGIA	HEARD	GA	Peaking Units	140.4	156	8/15/2001
TENASGG4	TENASKA GEORGIA	HEARD	GA	Peaking Units	140.4	156	6/1/2002
TENASGG5	TENASKA GEORGIA	HEARD	GA	Peaking Units	140.4	156	6/1/2002
TENASGG6	TENASKA GEORGIA	HEARD	GA	Peaking Units	140.4	156	6/1/2002
TENASLH1	TENASKA LINDSAY HILL GENERA	AUTAUGA	AL	Combined Cycle	761.4	846	5/1/2002
TENASLH2	TENASKA LINDSAY HILL GENERA	AUTAUGA	AL	Combined Cycle	311.4	346	5/15/2002
THEODRC1	THEODORE COGEN	MOBILE	AL	Combined Cycle	216	240	12/23/2000
VANNPWP1	VANN POWER PLANT	COVINGTON	AL	Combined Cycle	450	500	1/1/2002
VICTORJ1	VICTOR J. DANIEL	JACKSON	MS	Combined Cycle	450	500	4/1/2001
VICTORJ2	VICTOR J. DANIEL	JACKSON	MS	Combined Cycle	450	500	4/1/2001
WANSLE01	WANSLEY	HEARD	GA	Combined Cycle	509.4	566	6/1/2002
WANSLE02	WANSLEY	HEARD	GA	Combined Cycle	509.4	566	6/1/2002
WANSLEM1	WANSLEY (MEAG)	HEARD	GA	Combined Cycle	452.7	503	5/1/2004
WANSLEO1	WANSLEY [OGLE]	HEARD	GA	Combined Cycle	468.9	521	3/1/2003
WASHCPP1	WASHINGTON COUNTY POWER PLA	WASHINGTON	GA	Peaking Units	152	170	6/1/2002
WASHCPP2	WASHINGTON COUNTY POWER PLA	WASHINGTON	GA	Peaking Units	152	170	6/1/2002
WASHCPP3	WASHINGTON COUNTY POWER PLA	WASHINGTON	GA	Peaking Units	152	170	6/1/2002
WASHCPP4	WASHINGTON COUNTY POWER PLA	WASHINGTON	GA	Peaking Units	152	170	6/1/2002
WSTGERG1	WEST GEORGIA GENERATING FAC	UPSON	GA	Peaking Units	180	200	6/7/2000
WSTGERG2	WEST GEORGIA GENERATING FAC	UPSON	GA	Peaking Units	180	200	6/7/2000
WSTGERG3	WEST GEORGIA GENERATING FAC	UPSON	GA	Peaking Units	180	200	6/7/2000
WSTGERG4	WEST GEORGIA GENERATING FAC	UPSON	GA	Peaking Units	72	80	6/7/2000
	New Units in SPP						
GORDONE1	GORDON EVANS	SEDGWICK	KS	Peaking Units	132.66	147.4	6/1/2000
HAWTHRN3	HAWTHORN	JACKSON	MO	Peaking Units	69.3	77	6/30/2000
HAWTHRN2	HAWTHORN	JACKSON	MO	Combined Cycle	242.1	269	7/11/2000
HAWTHRN5	HAWTHORN	JACKSON	MO	Peaking Units	31.5	35	7/11/2000
HORSESL1	HORSESHOE LAKE	OKLAHOMA	OK	Peaking Units	85.5	95	7/30/2000
MUSTNG01	MUSTANG	OKLAHOMA	OK	Steam Gas/Oil	115	115	7/30/2000
MASSEGL1	MASSENGALE	LUBBOCK	TX	Combined Cycle	55.8	62	9/7/2000
ANADRK11	ANADARKO I	CADDO	OK	Peaking Units	81	90	5/8/2001
ONEOKLC1	ONEOK - LOGAN COUNTY PEAKIN			Peaking Units	180	200	5/16/2001
ONEOKLC2	ONEOK - LOGAN COUNTY PEAKIN			Peaking Units	90	100	5/16/2001
FULTONA1	FULTON (AEC)	HEMPSTEAD	AR	Peaking Units	137.7	153	5/26/2001
MCCLAIN1	MCCLAIN ENERGY FACILITY	MCCLAIN	OK	Combined Cycle	450	500	6/1/2001
GORDONE2	GORDON EVANS	SEDGWICK	KS	Peaking Units	135.45	150.5	6/12/2001
HAWTHRN1	HAWTHORN	JACKSON	MO	Coal	540	540	6/30/2001
STATLNE1	STATELINE (EMDE)	JASPER	MO	Combined Cycle	451.8	502	7/2/2001
NTHEST01	NORTHEASTERN	ROGERS	OK	Combined Cycle	420.3	467	7/15/2001
ARIESGT1	ARIES	CASS	MO	Peaking Units	180	200	7/16/2001
ARIESGT2	ARIES	CASS	MO	Peaking Units	154.8	172	7/16/2001
GRAYCNT1	GRAY COUNTY	GRAY	KS	Other	110	110	12/17/2001
LLANOEC1	LLANO ESTACADO	CARSON	TX	Other	80	80	12/28/2001
EASTEXC1	EASTEX COGENERATION FACILIT	HARRISON	TX	Combined Cycle	396	440	12/30/2001
GREENCE1	GREEN COUNTRY ENERGY PROJEC	TULSA	OK	Combined Cycle	239.4	266	2/10/2002
GREENCE2	GREEN COUNTRY ENERGY PROJEC	TULSA	OK	Combined Cycle	240.3	267	2/10/2002
GREENCE3	GREEN COUNTRY ENERGY PROJEC	TULSA	OK	Combined Cycle	240.3	267	2/10/2002
ARIESCC3	ARIES	CASS	MO	Combined Cycle	531.9	591	3/1/2002
ARIESGT6	ARIES	CASS	MO	Combined Cycle	36.9	41	3/1/2002
RUSSIDP1	RUSSELL INDUSTRIAL PARK	RUSSELL	KS	Combined Cycle	13.5	15	3/1/2002
MCCARTN1	MCCARTNEY GENERATING STATIO	GREENE	MO	Peaking Units	90	100	4/1/2002

Table A-17: New Capacity Additions 2000-2005

MAPS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date
ONETAGS1	ONETA GENERATING STATION	WAGONER	OK	Combined Cycle	513	570	7/15/2002
ONETAGS2	ONETA GENERATING STATION	WAGONER	OK	Combined Cycle	513	570	3/1/2003
THOMFIT1	THOMAS FITZHUGH	FRANKLIN	AR	Peaking Units	153	170	4/1/2003
EMPIREE1	EMPIRE ENERGY CENTER	JASPER	MO	Peaking Units	45	50	5/1/2003
EMPIREE2	EMPIRE ENERGY CENTER	JASPER	MO	Peaking Units	45	50	5/1/2003
PITTSBP1	PITTSBURG POWER PLANT	PITTSBURG	OK	Combined Cycle	330.3	367	6/1/2003
PITTSBP2	PITTSBURG POWER PLANT	PITTSBURG	OK	Combined Cycle	119.7	133	6/1/2003
KIAMICH1	KIAMICHI ENERGY FACILITY	PITTSBURG	OK	Combined Cycle	269.55	299.5	6/1/2003
KIAMICH2	KIAMICHI ENERGY FACILITY	PITTSBURG	OK	Combined Cycle	269.55	299.5	6/1/2003
KIAMICH3	KIAMICHI ENERGY FACILITY	PITTSBURG	OK	Combined Cycle	269.55	299.5	6/1/2003
KIAMICH4	KIAMICHI ENERGY FACILITY	PITTSBURG	OK	Combined Cycle	269.55	299.5	6/1/2003
REDBUD01	REDBUD	OKLAHOMA	OK	Combined Cycle	1080	1200	6/1/2003
PAOLAGT1	PAOLA	MIAMI	KS	Peaking Units	75.6	84	6/1/2003
HARRISC1	HARRISON COUNTY POWER PROJE	HARRISON	TX	Combined Cycle	468	520	6/1/2003
DOWPALQ1	DOW PLAQUEMINE (AEP)	IBERVILLE	LA	Combined Cycle	810	900	8/15/2003
	New Units in TVA						
ACKERMN1	ACKERMAN	CHOCTAW	MS	Combined Cycle	450	500	1/1/2005
ACKERMN2	ACKERMAN	CHOCTAW	MS	Combined Cycle	180	200	1/1/2005
ASHLAND1	ASHLAND [MAGNEN]	BENTON	MS	Combined Cycle	810	900	6/1/2003
BATESVL1	BATESVILLE GENERATION FACIL	PANOLA	MS	Combined Cycle	450	500	8/15/2000
BATESVL2	BATESVILLE GENERATION FACIL	PANOLA	MS	Combined Cycle	303.3	337	8/15/2000
BOLIVAR1	BOLIVAR	HARDEMAN	TN	Peaking Units	18	20	6/30/2001
CALEDN01	CALEDONIA	LOWNDES	MS	Combined Cycle	240.3	267	6/1/2003
CALEDN02	CALEDONIA	LOWNDES	MS	Combined Cycle	240.3	267	6/1/2003
CALEDN03	CALEDONIA	LOWNDES	MS	Combined Cycle	239.4	266	6/1/2003
CALVECT1	CALVERT CITY PLANT - APC	MARSHALL	KY	Peaking Units	23.4	26	4/6/2000
DECATEC1	DECATUR ENERGY CENTER	MORGAN	AL	Combined Cycle	450	500	6/1/2002
DECATEC2	DECATUR ENERGY CENTER	MORGAN	AL	Combined Cycle	715	794	6/1/2003
GALLATN1	GALLATIN (TVA)	SUMNER	TN	Peaking Units	180	200	6/1/2000
GALLATN2	GALLATIN (TVA)	SUMNER	TN	Peaking Units	90	100	6/1/2000
GLEASN01	GLEASON	WEAKLEY	TN	Peaking Units	180	200	6/1/2000
GLEASN02	GLEASON	WEAKLEY	TN	Peaking Units	180	200	6/1/2000
GLEASN03	GLEASON	WEAKLEY	TN	Peaking Units	99	110	6/1/2000
HAYWOEC1	HAYWOOD ENERGY CENTER	HAYWOOD	TN	Combined Cycle	450	500	6/1/2004
JOHNSNV1	JOHNSONVILLE (TVA)	HUMPHREYS	TN	Peaking Units	180	200	6/1/2000
JOHNSNV2	JOHNSONVILLE (TVA)	HUMPHREYS	TN	Peaking Units	90	100	6/1/2000
LAGONC10	LAGOON CREEK	HAYWOOD	TN	Peaking Units	78.75	87.5	6/21/2001
LAGONC11	LAGOON CREEK	HAYWOOD	TN	Peaking Units	78.75	87.5	6/21/2001
LAGONC12	LAGOON CREEK	HAYWOOD	TN	Peaking Units	78.75	87.5	6/21/2001
LAGOONC1	LAGOON CREEK	HAYWOOD	TN	Peaking Units	78.75	87.5	6/21/2001
LAGOONC2	LAGOON CREEK	HAYWOOD	TN	Peaking Units	78.75	87.5	6/21/2001
LAGOONC3	LAGOON CREEK	HAYWOOD	TN	Peaking Units	78.75	87.5	6/21/2001
LAGOONC4	LAGOON CREEK	HAYWOOD	TN	Peaking Units	78.75	87.5	6/21/2001
LAGOONC5	LAGOON CREEK	HAYWOOD	TN	Peaking Units	78.75	87.5	6/21/2001
LAGOONC6	LAGOON CREEK	HAYWOOD	TN	Peaking Units	78.75	87.5	6/21/2001
LAGOONC7	LAGOON CREEK	HAYWOOD	TN	Peaking Units	78.75	87.5	6/21/2001
LAGOONC8	LAGOON CREEK	HAYWOOD	TN	Peaking Units	78.75	87.5	6/21/2001
LAGOONC9	LAGOON CREEK	HAYWOOD	TN	Peaking Units	78.75	87.5	6/21/2001
MARSHCN1	MARSHALL COUNTY (DUENMC)	MARSHALL	KY	Peaking Units	72	80	6/24/2002
MARSHCN2	MARSHALL COUNTY (DUENMC)	MARSHALL	KY	Peaking Units	72	80	6/24/2002
MARSHCN3	MARSHALL COUNTY (DUENMC)	MARSHALL	KY	Peaking Units	72	80	6/24/2002
MARSHCN4	MARSHALL COUNTY (DUENMC)	MARSHALL	KY	Peaking Units	72	80	6/24/2002
MARSHCN5	MARSHALL COUNTY (DUENMC)	MARSHALL	KY	Peaking Units	72	80	6/24/2002
MARSHCN6	MARSHALL COUNTY (DUENMC)	MARSHALL	KY	Peaking Units	72	80	6/24/2002
MARSHCN7	MARSHALL COUNTY (DUENMC)	MARSHALL	KY	Peaking Units	72	80	6/24/2002

Table A-17: New Capacity Additions 2000-2005

MAPS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date
MARSHCN8	MARSHALL COUNTY (DUENMC)	MARSHALL	KY	Peaking Units	72	80	6/24/2002
MEMPHRF1	MEMPHIS REFINERY	SHELBY	TN	Combined Cycle	71.1	79	6/1/2003
MIDDLEP1	MIDDLEPOINT LANDFILL	NOT APPLICABLE	TN	Peaking Units	4.68	5.2	4/9/2001
MISSISF1	MISSISSIPPI FUEL CELL PLANT	NOT APPLICABLE	MS	Combined Cycle	12	12	6/1/2003
MORGANE1	MORGAN ENERGY CENTER	MORGAN	AL	Combined Cycle	711	790	5/1/2003
PADUCAH1	PADUCAH			Peaking Units	180	200	1/1/2005
PADUCAH2	PADUCAH			Peaking Units	180	200	1/1/2005
PADUCAH3	PADUCAH			Peaking Units	180	200	1/1/2005
REDHILL1	RED HILLS GENERATION FACILI	CHOCTAW	MS	Coal	440	440	3/15/2002
RELECHO1	RELIANT ENERGY CHOCTAW COUN	CHOCTAW	MS	Combined Cycle	720	800	11/1/2003
SCOOBAP1	SCOOBA PEAKER	KEMPER	MS	Peaking Units	153	170	6/1/2002
SCOOBAP2	SCOOBA PEAKER	KEMPER	MS	Peaking Units	153	170	6/1/2002

Table A-18: Retirements 2000-2005

...PS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date	Retirement Date
	Retirements in VAP							
POSSUMP1	POSSUM POINT 1	PRINCE WILLIAM	VA	Steam Gas/Oil	74	74	1/1/1948	5/1/2003
POSSUMP2	POSSUM POINT 2	PRINCE WILLIAM	VA	Steam Gas/Oil	69	71	1/1/1951	5/1/2003
POSSUMP3	POSSUM POINT 3	PRINCE WILLIAM	VA	Coal	101	105	1/1/1955	5/1/2003
POSSUMP4	POSSUM POINT 4	PRINCE WILLIAM	VA	Coal	221	221	1/1/1962	5/1/2003
	Retirements in AEP							
SEARSLO3	SEARS LOGISTICS SERVICES	FRANKLIN	OH	Peaking Units	17.05	18.46	1/1/1972	1/8/2000
GLENLYN5	GLEN LYN	GILES	VA	Coal	90	95	1/1/1944	12/31/2004
	Retirements in Duke							
BUCKNC07	BUCK (NC)	ROWAN	NC	Peaking Units	31	31	1/1/1970	12/1/2004
BUCKNC08	BUCK (NC)	ROWAN	NC	Peaking Units	31	31	1/1/1970	12/1/2004
BUCKNC09	BUCK (NC)	ROWAN	NC	Peaking Units	31	31	1/1/1970	12/1/2004
LEESC05	LEE (SC)	ANDERSON	SC	Peaking Units	30	30	1/1/1968	12/1/2004
LEESC06	LEE (SC)	ANDERSON	SC	Peaking Units	30	30	1/1/1968	12/1/2004
LINCOLN1	LINCOLN COMBUSTION	LINCOLN	NC	Peaking Units	75	99	1/1/1995	12/1/2004
RIVERB10	RIVERBEND	GASTON	NC	Peaking Units	30	30	1/1/1969	12/1/2004
RIVERB11	RIVERBEND	GASTON	NC	Peaking Units	30	30	1/1/1969	12/1/2004
RIVERBE8	RIVERBEND	GASTON	NC	Peaking Units	30	30	1/1/1969	12/1/2004
RIVERBE9	RIVERBEND	GASTON	NC	Peaking Units	30	30	1/1/1969	12/1/2004
BUZZARD6	BUZZARD ROOST	NEWBERRY	SC	Peaking Units	22	22	1/1/1971	12/1/2005
BUZZARD7	BUZZARD ROOST	NEWBERRY	SC	Peaking Units	22	22	1/1/1971	12/1/2005
BUZZARD8	BUZZARD ROOST	NEWBERRY	SC	Peaking Units	22	22	1/1/1971	12/1/2005
BUZZARD9	BUZZARD ROOST	NEWBERRY	SC	Peaking Units	22	22	1/1/1971	12/1/2005
	Retirements in PJM							
P NGT7	BURLINGTON (PSEG)	BURLINGTON	NJ	Steam Gas/Oil	180	185	1/1/1955	3/1/2000
REC1	DELAWARE CITY	NEW CASTLE	DE	Coal	28.5	28.5	1/1/1956	4/30/2000
DELWREC2	DELAWARE CITY	NEW CASTLE	DE	Coal	28.5	28.5	1/1/1956	4/30/2000
LINDEN05	LINDEN (PSEG)	UNION	NJ	Peaking Units	46	60	1/1/1970	6/1/2000
LINDEN06	LINDEN (PSEG)	UNION	NJ	Peaking Units	46	60	1/1/1970	6/1/2000
RINGGOL1	RINGGOLD	JEFFERSON	PA	Peaking Units	15	15	1/1/1990	9/1/2000
WILMING1	WILMINGTON	NEW CASTLE	DE	Peaking Units	111	111	6/1/2001	5/31/2002
WILMING2	WILMINGTON	NEW CASTLE	DE	Peaking Units	111	111	6/1/2001	5/31/2002
WILMING3	WILMINGTON	NEW CASTLE	DE	Peaking Units	112	112	7/31/2001	5/31/2002
LINDEN01	LINDEN (PSEG)	UNION	NJ	Steam Gas/Oil	168	180	1/1/1957	5/1/2003
LINDEN02	LINDEN (PSEG)	UNION	NJ	Steam Gas/Oil	247	250	1/1/1957	5/1/2003
AESBVPA3	AES BV PARTNERS BEAVER VALL	BEAVER	PA	Coal	100.26	107	1/1/1987	5/31/2003
BETHLEC1	BETHLEHEM (CIV)	NORTHAMPTON	PA	Peaking Units	333	333	1/1/2003	6/1/2003
SEWARD04	SEWARD (RELIANT)	INDIANA	PA	Coal	60	62	1/1/1950	9/30/2003
SEWARD05	SEWARD (RELIANT)	INDIANA	PA	Coal	136	137	1/1/1957	9/30/2003
RIEGEL01	RIEGEL	HUNTERDON	NJ	Peaking Units	21	21	1/1/1970	7/1/2004
HUNLOCK3	HUNLOCK CREEK	LUZERNE	PA	Coal	48	48	1/1/1959	12/1/2004
DICKRSN4	DICKERSON	MONTGOMERY	MD	Peaking Units	13	13	1/1/1967	12/31/2004
DICKRSN5	DICKERSON	MONTGOMERY	MD	Peaking Units	139	167	1/1/1992	12/31/2004
DICKRSN6	DICKERSON	MONTGOMERY	MD	Peaking Units	139	167	1/1/1993	12/31/2004
ELRAMA01	ELRAMA	WASHINGTON	PA	Coal (Scrubbed)	97	100	1/1/1952	12/31/2004
ELRAMA02	ELRAMA	WASHINGTON	PA	Coal (Scrubbed)	97	100	1/1/1953	12/31/2004
ELRAMA03	ELRAMA	WASHINGTON	PA	Coal (Scrubbed)	109	112	1/1/1954	12/31/2004
ELRAMA04	ELRAMA	WASHINGTON	PA	Coal (Scrubbed)	171	175	1/1/1960	12/31/2004
	Retirements in MISO (ECAR)							
BLACKDO1	BLACK DOG	DAKOTA	MN	Coal	75	64	1/1/1952	1/1/2000
MORRIGT1	MORRIS COGENERATION PLANT	GRUNDY	IL	Peaking Units	78	78	1/1/1990	6/1/2000
MORRIGT2	MORRIS COGENERATION PLANT	GRUNDY	IL	Peaking Units	78	78	1/1/1990	6/1/2000
MORRIGT3	MORRIS COGENERATION PLANT	GRUNDY	IL	Peaking Units	78	78	1/1/1990	6/1/2000
WYANDOT4	WYANDOTTE (WYAN)	WAYNE	MI	Steam Gas/Oil	10.5	11.5	1/1/1948	10/1/2000
WYANDOT6	WYANDOTTE (WYAN)	WAYNE	MI	Coal	7.5	7.5	1/1/1969	10/1/2000

Table A-18: Retirements 2000-2005

...APS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date	Retirement Date
GRANDTO3	GRAND TOWER	JACKSON	IL	Coal	82	82	1/1/1951	6/29/2001
AESMEDV2	AESMEDINA VALLEY	TAZEWELL	IL	Peaking Units	28.35	31.5	6/1/2001	7/15/2001
GRANDTO4	GRAND TOWER	JACKSON	IL	Coal	104	104	1/1/1958	12/1/2001
MIAMIWA1	MIAMI WABASH	WABASH	IN	Peaking Units	16	17	1/1/1968	12/31/2001
MIAMIWA2	MIAMI WABASH	WABASH	IN	Peaking Units	16	17	1/1/1968	12/31/2001
MIAMIWA3	MIAMI WABASH	WABASH	IN	Peaking Units	15	17	1/1/1968	12/31/2001
MIAMIWA4	MIAMI WABASH	WABASH	IN	Peaking Units	15	17	1/1/1968	12/31/2001
MIAMIWA5	MIAMI WABASH	WABASH	IN	Peaking Units	15	18	1/1/1969	12/31/2001
MIAMIWA6	MIAMI WABASH	WABASH	IN	Peaking Units	16	18	1/1/1969	12/31/2001
MITCHE11	MITCHELL (NIPS)	LAKE	IN	Coal	110	110	1/1/1970	12/31/2001
MITCHEL4	MITCHELL (NIPS)	LAKE	IN	Steam Gas/Oil	125	125	1/1/1956	12/31/2001
MITCHEL5	MITCHELL (NIPS)	LAKE	IN	Coal	125	125	1/1/1959	12/31/2001
MITCHEL6	MITCHELL (NIPS)	LAKE	IN	Coal	125	125	1/1/1959	12/31/2001
MITCHEL9	MITCHELL (NIPS)	LAKE	IN	Peaking Units	17	17	1/1/1966	12/31/2001
WABASH07	WABASH RIVER	VIGO	IN	Peaking Units	8	8	1/1/1967	12/31/2001
VERMIGT1	VERMILION	VERMILION	IL	Peaking Units	10	12	1/1/1967	1/1/2002
ZEELAND1	ZEELAND (MIR)	OTTAWA	MI	Peaking Units	170	170	1/1/2001	6/1/2002
ZEELAND2	ZEELAND (MIR)	OTTAWA	MI	Peaking Units	170	170	1/1/2001	6/1/2002
BLACKDO2	BLACK DOG	DAKOTA	MN	Coal	101	88	1/1/1954	6/15/2002
LAKERDM3	LAKE ROAD (MO)	BUCHANAN	MO	Steam Gas/Oil	11	8	1/1/1962	12/1/2002
BEMORROA	B.E. MORROW	KALAMAZOO	MI	Peaking Units	14	17	1/1/1968	12/31/2002
BEMORROB	B.E. MORROW	KALAMAZOO	MI	Peaking Units	14	17	1/1/1969	12/31/2002
CAMPBELA	CAMPBELL (CEC)	OTTAWA	MI	Peaking Units	13	17	1/1/1968	12/31/2002
GAYLORD1	GAYLORD	OTSEGO	MI	Peaking Units	14	17	1/1/1966	12/31/2002
GAYLORD2	GAYLORD	OTSEGO	MI	Peaking Units	14	17	1/1/1966	12/31/2002
GAYLORD3	GAYLORD	OTSEGO	MI	Peaking Units	14	17	1/1/1966	12/31/2002
GAYLORD4	GAYLORD	OTSEGO	MI	Peaking Units	14	17	1/1/1966	12/31/2002
GAYLORD5	GAYLORD	OTSEGO	MI	Peaking Units	14	17	1/1/1968	12/31/2002
[illegible]AITS1	STRAITS	EMMET	MI	Peaking Units	16	21	1/1/1969	12/31/2002
[illegible]FOR1	THETFORD	GENESEE	MI	Peaking Units	30	37	1/1/1970	12/31/2002
[illegible]TFOR2	THETFORD	GENESEE	MI	Peaking Units	29	37	1/1/1970	12/31/2002
THETFOR3	THETFORD	GENESEE	MI	Peaking Units	30	37	1/1/1970	12/31/2002
THETFOR4	THETFORD	GENESEE	MI	Peaking Units	30	37	1/1/1970	12/31/2002
THETFOR5	THETFORD	GENESEE	MI	Peaking Units	15	17	1/1/1971	12/31/2002
THETFOR6	THETFORD	GENESEE	MI	Peaking Units	15	17	1/1/1971	12/31/2002
THETFOR7	THETFORD	GENESEE	MI	Peaking Units	14	17	1/1/1971	12/31/2002
THETFOR8	THETFORD	GENESEE	MI	Peaking Units	15	18	1/1/1971	12/31/2002
THETFOR9	THETFORD	GENESEE	MI	Peaking Units	14	17	1/1/1971	12/31/2002
WEADOCKA	WEADOCK	BAY	MI	Peaking Units	13	17	1/1/1968	12/31/2002
WHITINGA	WHITING (CEC)	MONROE	MI	Peaking Units	13	17	1/1/1968	12/31/2002
EDWARDS6	EDWARDSPORT	KNOX	IN	Coal	40	40	1/1/1944	12/31/2003
EDWARDS7	EDWARDSPORT	KNOX	IN	Coal	45	45	1/1/1949	12/31/2003
EDWARDS8	EDWARDSPORT	KNOX	IN	Coal	75	75	1/1/1951	12/31/2003
NOBLESV1	NOBLESVILLE	HAMILTON	IN	Coal	45	45	1/1/1950	5/31/2004
NOBLESV2	NOBLESVILLE	HAMILTON	IN	Coal	45	45	1/1/1950	5/31/2004
CONNEVL1	CONNERSVILLE	FAYETTE	IN	Peaking Units	42	49	1/1/1972	12/31/2004
CONNEVL2	CONNERSVILLE	FAYETTE	IN	Peaking Units	43	49	1/1/1972	12/31/2004
SALTVAL3	SALT VALLEY GENERATING STAT	LANCASTER	NE	Peaking Units	90	90	6/1/2003	5/1/2004
PORTWAS1	PORT WASHINGTON	OZAUKEE	WI	Coal (Scrubbed)	80	80	1/1/1935	1/1/2005
PORTWAS2	PORT WASHINGTON	OZAUKEE	WI	Coal	83	83	1/1/1943	1/1/2005
PORTWAS3	PORT WASHINGTON	OZAUKEE	WI	Coal	83	84	1/1/1948	1/1/2005
PORTWAS4	PORT WASHINGTON	OZAUKEE	WI	Coal (Scrubbed)	80	80	1/1/1949	1/1/2005
HOOTLAK1	HOOT LAKE	OTTER TAIL	MN	Coal	7.55	7.55	1/1/1948	5/1/2005
	Retirements in SETRANS (Entergy)							
HMOSES01	HAMILTON MOSES	ST. FRANCIS	AR	Steam Gas/Oil	72	72	1/1/1951	12/1/2001
HMOSES02	HAMILTON MOSES	ST. FRANCIS	AR	Steam Gas/Oil	72	72	1/1/1951	12/1/2001
DELTA01	DELTA (MS)	BOLIVAR	MS	Steam Gas/Oil	99	99	1/1/1953	12/1/2003
LKCATHE3	LAKE CATHERINE	HOT SPRING	AR	Steam Gas/Oil	100	100	1/1/1953	12/1/2003
CLYNCH01	CECIL LYNCH	PULASKI	AR	Steam Gas/Oil	110	110	1/1/1954	12/1/2004

Table A-18: Retirements 2000-2005

MAPS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date	Retirement Date
HCOUCH02	HARVEY COUCH	LAFAYETTE	AR	Steam Gas/Oil	125	125	1/1/1954	12/1/2004
NINEMIL3	NINEMILE POINT	JEFFERSON	LA	Steam Gas/Oil	125	125	1/1/1955	12/1/2005
MABELVA3	MABELVALE	PULASKI	AR	Peaking Units	16	16	1/1/1970	12/31/2005
	Retirements in SETRANS (SOCO)							
KENNED10	J.D. KENNEDY	DUVAL	FL	Steam Gas/Oil	129	129	1/1/1961	4/1/2000
STHSIDE4	SOUTHSIDE	DUVAL	FL	Steam Gas/Oil	67	67	1/1/1958	10/26/2001
STHSIDE5	SOUTHSIDE	DUVAL	FL	Steam Gas/Oil	142	142	1/1/1964	10/26/2001
SWEATT0A	SWEATT	LAUDERDALE	MS	Peaking Units	35	43.5	1/1/1971	1/1/2002
ARKWRI03	ARKWRIGHT	BIBB	GA	Coal	44.3	44.3	1/1/1948	1/1/2003
ARKWRI04	ARKWRIGHT	BIBB	GA	Coal	43.2	43.2	1/1/1948	1/1/2003
ARKWRI5A	ARKWRIGHT	BIBB	GA	Peaking Units	15.47	18.02	1/1/1969	1/1/2003
ARKWRI5B	ARKWRIGHT	BIBB	GA	Peaking Units	15.47	18.02	1/1/1969	1/1/2003
ARKWRST1	ARKWRIGHT	BIBB	GA	Coal	41.9	41.9	1/1/1941	1/1/2003
ARKWRST2	ARKWRIGHT	BIBB	GA	Coal	40.9	40.9	1/1/1942	1/1/2003
ATKINS03	ATKINSON	COBB	GA	Steam Gas/Oil	62.8	62.8	1/1/1945	1/1/2003
ATKINS04	ATKINSON	COBB	GA	Steam Gas/Oil	59.9	59.9	1/1/1948	1/1/2003
ATKINS5A	ATKINSON	COBB	GA	Peaking Units	34.55	42.56	1/1/1970	1/1/2003
ATKINS5B	ATKINSON	COBB	GA	Peaking Units	34.55	42.56	1/1/1970	1/1/2003
ATKINST2	ATKINSON	COBB	GA	Steam Gas/Oil	57.2	57.2	1/1/1941	1/1/2003
CRIST01	CRIST	ESCAMBIA	FL	Steam Gas/Oil	25.6	25.6	1/1/1945	1/1/2003
EATON02	EATON	FORREST	MS	Steam Gas/Oil	25	25	1/1/1947	1/1/2003
MITCHLS1	MITCHELL (GPCO)	DOUGHERTY	GA	Coal	21.2	21.2	1/1/1948	1/1/2003
MITCHLS2	MITCHELL (GPCO)	DOUGHERTY	GA	Coal	20.1	20.1	1/1/1949	1/1/2003
EATON03	EATON	FORREST	MS	Steam Gas/Oil	24.4	24.4	1/1/1949	1/1/2005
RIVERSS4	RIVERSIDE (SAEP)	CHATHAM	GA	Steam Gas/Oil	19.3	19.3	1/1/1926	1/1/2005
RIVERSS5	RIVERSIDE (SAEP)	CHATHAM	GA	Steam Gas/Oil	9	9	1/1/1936	1/1/2005
RIVERSS6	RIVERSIDE (SAEP)	CHATHAM	GA	Steam Gas/Oil	16.3	16.3	1/1/1949	1/1/2005
RSS7	RIVERSIDE (SAEP)	CHATHAM	GA	Steam Gas/Oil	21	21	1/1/1954	1/1/2005
RSS8	RIVERSIDE (SAEP)	CHATHAM	GA	Steam Gas/Oil	40.4	40.4	1/1/1956	1/1/2005
	Retirements in SPP							
LOVINGT1	NORTH LOVINGTON	LEA	NM	Steam Gas/Oil	16	16	1/1/1962	1/1/2000
LOVINGT2	NORTH LOVINGTON	LEA	NM	Steam Gas/Oil	33	33	1/1/1966	1/1/2000
MUSTSTN2	MUSTANG STATION	YOAKUM	TX	Peaking Units	261	290	6/1/1999	4/20/2000
HAWTHOR6	HAWTHORN	JACKSON	MO	Peaking Units	142	162	1/1/1997	7/15/2000
STATELI2	STATELINE (MO)	JASPER	MO	Peaking Units	152	152	1/1/1997	6/20/2001
NTHESTN1	NORTHEASTERN	ROGERS	OK	Steam Gas/Oil	157	157	1/1/1961	7/14/2001
TUCULUMP	TUCUMCARI	QUAY	NM	Peaking Units	13	13	1/1/1975	8/1/2001
RUSSLUMP	RUSSELL	RUSSELL	KS	Peaking Units	26.6	26.6	1/1/1956	9/2/2001
NATCLUMP	NATCHITOCHES	NATCHITOCHES	LA	Steam Gas/Oil	8.6	8.6	1/1/1972	12/1/2001
SOUTHWE2	SOUTHWESTERN	CADDO	OK	Steam Gas/Oil	80	80	1/1/1954	12/1/2001
ARIESGT1	ARIES	CASS	MO	Peaking Units	180	200	7/16/2001	3/1/2002
ARIESGT2	ARIES	CASS	MO	Peaking Units	154.8	172	7/16/2001	3/1/2002
NATCHI10	NATCHITOCHES	NATCHITOCHES	LA	Steam Gas/Oil	24	24	1/1/1972	4/1/2002
NATCHIT8	NATCHITOCHES	NATCHITOCHES	LA	Steam Gas/Oil	7	7	1/1/1962	4/1/2002
NATCHIT9	NATCHITOCHES	NATCHITOCHES	LA	Steam Gas/Oil	11	11	1/1/1966	4/1/2002
NICHOTX2	NICHOLS STATION	POTTER	TX	Steam Gas/Oil	106	106	1/1/1962	8/1/2002
KNOXLEE2	KNOX LEE	GREGG	TX	Steam Gas/Oil	25	25	1/1/1950	12/1/2002
KNOXLEE3	KNOX LEE	GREGG	TX	Steam Gas/Oil	25	25	1/1/1952	12/1/2002
MCPH2GT1	MCPHERSON 2	MCPHERSON	KS	Peaking Units	52.9	60	1/1/1973	12/1/2002
MCPH2GT2	MCPHERSON 2	MCPHERSON	KS	Peaking Units	50.9	60	1/1/1976	12/1/2002
MCPH2GT3	MCPHERSON 2	MCPHERSON	KS	Peaking Units	52	60	1/1/1979	12/1/2002
PLANTX01	PLANT X (TX)	LAMB	TX	Steam Gas/Oil	48	48	1/1/1952	12/1/2002
FITZHUGH	THOMAS FITZHUGH	FRANKLIN	AR	Steam Gas/Oil	59	59	1/1/1963	5/31/2003
LONESTAR	LONE STAR	MORRIS	TX	Steam Gas/Oil	50	50	1/1/1954	12/1/2003
PLANTX02	PLANT X (TX)	LAMB	TX	Steam Gas/Oil	102	102	1/1/1953	1/1/2004
PLANTX04	PLANT X (TX)	LAMB	TX	Steam Gas/Oil	191	191	1/1/1964	1/1/2004
LIEBER03	LIEBERMAN	CADDO	LA	Steam Gas/Oil	112	112	1/1/1957	12/1/2004
LIEBER04	LIEBERMAN	CADDO	LA	Steam Gas/Oil	110	110	1/1/1959	12/1/2004
NTHESTN2	NORTHEASTERN	ROGERS	OK	Steam Gas/Oil	480	480	1/1/1970	12/1/2004

Table A-18: Retirements 2000-2005

MAPS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date	Retirement Date
WELEETK4	WELEETKA	OKFUSKEE	OK	Peaking Units	55	55	1/1/1975	12/1/2004
WILKES02	WILKES	MARION	TX	Steam Gas/Oil	357	357	1/1/1970	12/1/2004
PLANTX03	PLANT X (TX)	LAMB	TX	Steam Gas/Oil	103	103	1/1/1955	1/1/2005
CUNGHAM2	CUNNINGHAM	LEA	NM	Steam Gas/Oil	196	196	1/1/1965	8/1/2005
KNOXLEE4	KNOX LEE	GREGG	TX	Steam Gas/Oil	77	77	1/1/1956	12/1/2005
LIEBER01	LIEBERMAN	CADDO	LA	Steam Gas/Oil	25	25	1/1/1947	12/1/2005
MCPHER21	MCPHERSON 2	MCPHERSON	KS	Steam Gas/Oil	26.6	26.6	1/1/1963	12/1/2005
WELEETK5	WELEETKA	OKFUSKEE	OK	Peaking Units	54	54	1/1/1976	12/1/2005
WELEETK6	WELEETKA	OKFUSKEE	OK	Peaking Units	54	54	1/1/1976	12/1/2005
WILKES03	WILKES	MARION	TX	Steam Gas/Oil	348	348	1/1/1971	12/1/2005
	Retirements in TVA							
ELIZABE1	ELIZABETHTON PLANT	CARTER	TN	Coal	24	24	1/1/1988	4/1/2000
DECATEC1	DECATUR ENERGY CENTER	MORGAN	AL	Combined Cycle	450	500	6/1/2002	6/1/2003
	Retirements in GFL							
TSMITHS4	TOM G SMITH	PALM BEACH	FL	Steam Gas/Oil	32	33	1/1/1971	4/1/2000
CANEIPP5	CANE ISLAND POWER PARK	OSCEOLA	FL	Peaking Units	153	170	6/6/2001	8/15/2001
FTMYST01	FORT MYERS	LEE	FL	Steam Gas/Oil	141	142	1/1/1958	9/1/2001
FTMYST02	FORT MYERS	LEE	FL	Steam Gas/Oil	391	394	1/1/1969	9/1/2001
MCINTSL4	MCINTOSH (LALW)	POLK	FL	Peaking Units	180	200	4/16/2001	9/15/2001
MCINTSL5	MCINTOSH (LALW)	POLK	FL	Peaking Units	44.1	49	4/16/2001	9/15/2001
FORTMY10	FORT MYERS	LEE	FL	Peaking Units	150	170	11/1/2000	10/1/2001
FORTMY11	FORT MYERS	LEE	FL	Peaking Units	300	340	12/1/2000	10/1/2001
FORTMY12	FORT MYERS	LEE	FL	Peaking Units	150	170	2/1/2001	10/1/2001
FORTMY13	FORT MYERS	LEE	FL	Peaking Units	150	170	3/1/2001	10/1/2001
FORTMYR9	FORT MYERS	LEE	FL	Peaking Units	150	170	4/1/2001	10/1/2001
SANFORD4	SANFORD (FPL)	VOLUSIA	FL	Steam Gas/Oil	384	390	1/1/1972	12/31/2001
[illegible]ORD5	SANFORD (FPL)	VOLUSIA	FL	Steam Gas/Oil	390	394	1/1/1974	12/31/2001
[illegible]ERS5	HOOKERS POINT	HILLSBOROUGH	FL	Steam Gas/Oil	67	67	1/1/1955	1/1/2003
LARSEN07	LARSEN MEMORIAL	POLK	FL	Steam Gas/Oil	49.2	51.2	1/1/1966	3/1/2003
GANNON05	GANNON	HILLSBOROUGH	FL	Coal	227	232	1/1/1965	1/1/2004
GANNON06	GANNON	HILLSBOROUGH	FL	Coal	362	372	1/1/1967	1/1/2004
AVNPARK1	AVON PARK	HIGHLANDS	FL	Peaking Units	25	30	1/1/1968	12/1/2004
AVNPARK2	AVON PARK	HIGHLANDS	FL	Peaking Units	25	30	1/1/1968	12/1/2004
BAYBORO1	BAYBORO	PINELLAS	FL	Peaking Units	54	58	1/1/1973	12/1/2004
BAYBORO2	BAYBORO	PINELLAS	FL	Peaking Units	54	58	1/1/1973	12/1/2004
BAYBORO3	BAYBORO	PINELLAS	FL	Peaking Units	54	58	1/1/1973	12/1/2004
BAYBORO4	BAYBORO	PINELLAS	FL	Peaking Units	54	58	1/1/1973	12/1/2004
TURNER01	G.E. TURNER	VOLUSIA	FL	Peaking Units	13	16	1/1/1970	12/1/2004
TURNER02	G.E. TURNER	VOLUSIA	FL	Peaking Units	13	16	1/1/1970	12/1/2004
GANNON01	GANNON	HILLSBOROUGH	FL	Coal	119	119	1/1/1957	1/1/2005
GANNON02	GANNON	HILLSBOROUGH	FL	Coal	98	98	1/1/1958	1/1/2005
GANNON03	GANNON	HILLSBOROUGH	FL	Coal	145	145	1/1/1960	1/1/2005
GANNON04	GANNON	HILLSBOROUGH	FL	Coal	159	169	1/1/1963	1/1/2005
MARTINF5	MARTIN (FLPL)	MARTIN	FL	Peaking Units	149	181	6/20/2001	6/1/2005
MARTINF6	MARTIN (FLPL)	MARTIN	FL	Peaking Units	149	181	6/20/2001	6/1/2005
	Retirements in ISO-NE							
SOMERSJ1	SOMERSET	BRISTOL	MA	Peaking Units	19.7	22	1/1/1970	5/1/2000
REFERBUS	REFERENCE BUS			Other	1	1	1/1/1999	12/31/2000
WSTSPRF1	WEST SPRINGFIELD	HAMPDEN	MA	Steam Gas/Oil	51	51.5	1/1/1949	9/1/2001
WSTSPRF2	WEST SPRINGFIELD	HAMPDEN	MA	Steam Gas/Oil	51	51.5	1/1/1952	9/1/2001
MYSTIC04	MYSTIC	MIDDLESEX	MA	Steam Gas/Oil	135	135	1/1/1957	3/1/2002
MYSTIC05	MYSTIC	MIDDLESEX	MA	Steam Gas/Oil	115	115	1/1/1959	3/1/2002
MYSTIC06	MYSTIC	MIDDLESEX	MA	Steam Gas/Oil	138	138.28	1/1/1961	3/1/2002
KENDALL1	KENDALL SQUARE	MIDDLESEX	MA	Steam Gas/Oil	18	17	1/1/1949	6/1/2002
KENDALL2	KENDALL SQUARE	MIDDLESEX	MA	Steam Gas/Oil	19	21	1/1/1951	6/1/2002
KENDALL3	KENDALL SQUARE	MIDDLESEX	MA	Steam Gas/Oil	26	26	1/1/1958	6/1/2002
CANALSN2	CANAL (SENENG)	BARNSTABLE	MA	Steam Gas/Oil	551.38	586	1/1/1976	12/31/2002

Table A-18: Retirements 2000-2005

...APS Unit Name	Plant Name	County	State	Unit Type	Summer Cap (MW)	Winter Cap (MW)	Installation Date	Retirement Date
	Retirements in NYC							
WATERS16	WATERSIDE (CONED)	NEW YORK	NY	Steam Gas/Oil	69	69	1/1/1992	12/31/2001
WATERSD8	WATERSIDE (CONED)	NEW YORK	NY	Steam Gas/Oil	47	47	1/1/1949	12/31/2001
WATERSD9	WATERSIDE (CONED)	NEW YORK	NY	Steam Gas/Oil	47	47	1/1/1949	12/31/2001
ASTOGSO2	ASTORIA GENERATING STATION	QUEENS	NY	Steam Gas/Oil	171	175	1/1/1954	12/31/2003
ASTOGSO3	ASTORIA GENERATING STATION	QUEENS	NY	Steam Gas/Oil	353	361	1/1/1958	12/31/2003
ASTOGSO4	ASTORIA GENERATING STATION	QUEENS	NY	Steam Gas/Oil	361	369	1/1/1961	12/31/2004
ASTOGSO5	ASTORIA GENERATING STATION	QUEENS	NY	Steam Gas/Oil	361	369	1/1/1962	12/31/2004
	Retirements in NYO							
ALBANYS1	ALBANY STEAM STATION	ALBANY	NY	Steam Gas/Oil	96.7	100.7	1/1/1952	12/31/2002
ALBANYS2	ALBANY STEAM STATION	ALBANY	NY	Steam Gas/Oil	96.5	100.75	1/1/1952	12/31/2002
ALBANYS3	ALBANY STEAM STATION	ALBANY	NY	Steam Gas/Oil	97.25	100	1/1/1953	12/31/2002
ALBANYS4	ALBANY STEAM STATION	ALBANY	NY	Steam Gas/Oil	98.25	100	1/1/1954	12/31/2002
	Retirements in SCE&G							
URQUAHA1	URQUHART - SCEG	AIKEN	SC	Coal	245	265	1/1/1953	5/31/2002
URQUAHA1	URQUHART - SCEG	AIKEN	SC	Coal	245	265	1/1/1953	5/31/2002

Table A-19: Basis Differentials and Regional Natural Gas Prices

Month	Henry Hub	Plant Gate Prices New England Basis & Plant Gate Deliv. Cost	New England Dlvrd Price	Eastern NY Basis & Plant Gate Deliv. Cost	Eastern NY Dlvrd Price	NYC Basis & Plant Gate Deliv. Cost	NYC Dlvrd Price	Eastern PA/NJ Basis & Plant Gate Deliv. Cost	Eastern PA/NJ Dlvrd Price	Western NY/PA Basis & Plant Gate Deliv. Cost	Western NY/PA Dlvrd Price	DC, DE, MD Basis & Plant Gate Deliv. Cost	DC, DE, MD Dlvrd Price	WV, KY Basis & Plant Gate Deliv. Cost	WV, KY Dlvrd Price
Jan 2005	4.11	1.27	5.38	0.80	4.91	1.64	5.75	0.97	5.08	0.60	4.72	0.93	5.04	0.27	4.38
Feb 2005	4.10	1.28	5.38	0.81	4.91	1.64	5.75	0.98	5.08	0.61	4.72	0.94	5.04	0.27	4.37
Mar 2005	3.94	0.61	4.55	0.51	4.45	0.51	4.45	0.30	4.24	0.31	4.25	0.41	4.34	0.29	4.23
Apr 2005	3.93	0.62	4.55	0.52	4.45	0.52	4.45	0.31	4.24	0.32	4.25	0.41	4.34	0.29	4.22
May 2005	3.92	0.62	4.55	0.53	4.45	0.53	4.45	0.32	4.24	0.32	4.25	0.42	4.34	0.29	4.21
Jun 2005	3.88	0.51	4.39	0.39	4.26	0.42	4.29	0.70	4.58	0.23	4.11	0.33	4.21	0.24	4.12
Jul 2005	3.88	0.51	4.39	0.39	4.26	0.42	4.29	0.70	4.58	0.23	4.11	0.33	4.21	0.24	4.12
Aug 2005	3.87	0.52	4.39	0.39	4.26	0.42	4.29	0.71	4.58	0.24	4.11	0.34	4.21	0.24	4.11
Sep 2005	3.90	0.65	4.55	0.55	4.45	0.55	4.45	0.34	4.24	0.35	4.25	0.44	4.34	0.29	4.19
Oct 2005	3.89	0.66	4.55	0.56	4.45	0.56	4.45	0.35	4.24	0.36	4.25	0.45	4.34	0.29	4.18
Nov 2005	3.88	0.59	4.48	0.50	4.38	0.58	4.46	0.41	4.30	0.47	4.35	0.44	4.32	0.29	4.17
Dec 2005	4.03	1.31	5.34	0.90	4.93	1.45	5.48	0.76	4.79	0.40	4.43	0.93	4.95	0.26	4.29
Jan 2007	3.92	1.25	5.17	0.79	4.71	1.60	5.52	0.95	4.87	0.60	4.51	0.92	4.83	0.27	4.18
Feb 2007	3.91	1.26	5.17	0.80	4.71	1.61	5.52	0.96	4.87	0.60	4.51	0.92	4.83	0.27	4.18
Mar 2007	3.75	0.61	4.37	0.51	4.27	0.52	4.28	0.31	4.07	0.31	4.07	0.41	4.16	0.29	4.04
Apr 2007	3.75	0.62	4.37	0.52	4.27	0.53	4.28	0.32	4.07	0.32	4.07	0.42	4.16	0.29	4.04
May 2007	3.74	0.63	4.37	0.53	4.27	0.54	4.28	0.33	4.07	0.33	4.07	0.43	4.16	0.29	4.03
Jun 2007	3.70	0.52	4.22	0.39	4.09	0.43	4.13	0.69	4.39	0.24	3.93	0.34	4.04	0.24	3.94
Jul 2007	3.70	0.52	4.22	0.39	4.09	0.43	4.13	0.69	4.39	0.24	3.93	0.34	4.04	0.24	3.94
Aug 2007	3.69	0.53	4.22	0.40	4.09	0.44	4.13	0.70	4.39	0.24	3.93	0.35	4.04	0.24	3.93
Sep 2007	3.72	0.65	4.37	0.55	4.27	0.56	4.28	0.35	4.07	0.35	4.07	0.45	4.16	0.29	4.00
Oct 2007	3.71	0.66	4.37	0.56	4.27	0.57	4.28	0.36	4.07	0.36	4.07	0.46	4.16	0.29	4.00
Nov 2007	3.70	0.60	4.30	0.50	4.20	0.58	4.29	0.42	4.12	0.46	4.16	0.44	4.14	0.29	3.99
Dec 2007	3.84	1.29	5.13	0.89	4.73	1.43	5.27	0.75	4.59	0.40	4.24	0.91	4.75	0.26	4.10
Jan 2010	3.83	1.28	5.11	0.83	4.65	1.63	5.46	0.99	4.82	0.63	4.46	0.95	4.78	0.26	4.09
Feb 2010	3.83	1.28	5.11	0.83	4.65	1.63	5.46	0.99	4.82	0.63	4.46	0.95	4.78	0.26	4.09
Mar 2010	3.68	0.64	4.32	0.54	4.22	0.55	4.23	0.34	4.02	0.34	4.02	0.44	4.12	0.29	3.97
Apr 2010	3.68	0.64	4.32	0.54	4.22	0.55	4.23	0.34	4.02	0.34	4.02	0.43	4.12	0.29	3.97
May 2010	3.68	0.64	4.32	0.54	4.22	0.55	4.23	0.34	4.02	0.33	4.02	0.43	4.12	0.29	3.97
Jun 2010	3.65	0.52	4.17	0.39	4.04	0.43	4.08	0.69	4.34	0.24	3.89	0.34	3.99	0.24	3.89
Jul 2010	3.65	0.52	4.17	0.39	4.04	0.43	4.08	0.69	4.34	0.24	3.89	0.34	3.99	0.24	3.89
Aug 2010	3.65	0.52	4.17	0.39	4.04	0.43	4.08	0.69	4.34	0.24	3.89	0.34	3.99	0.24	3.89
Sep 2010	3.68	0.64	4.32	0.54	4.22	0.55	4.23	0.34	4.02	0.33	4.02	0.43	4.12	0.29	3.97
Oct 2010	3.68	0.64	4.32	0.54	4.22	0.55	4.23	0.34	4.02	0.33	4.02	0.43	4.12	0.29	3.97
Nov 2010	3.69	0.57	4.26	0.47	4.16	0.56	4.24	0.39	4.07	0.43	4.11	0.41	4.10	0.29	3.97
Dec 2010	3.83	1.24	5.08	0.85	4.68	1.38	5.21	0.71	4.54	0.36	4.19	0.87	4.70	0.26	4.10
Jan 2014	3.84	1.28	5.12	0.82	4.66	1.63	5.47	0.99	4.83	0.63	4.47	0.95	4.79	0.26	4.10
Feb 2014	3.84	1.28	5.12	0.82	4.66	1.63	5.47	0.99	4.83	0.63	4.47	0.95	4.79	0.26	4.10
Mar 2014	3.69	0.64	4.33	0.54	4.23	0.55	4.24	0.34	4.03	0.33	4.03	0.43	4.13	0.29	3.98
Apr 2014	3.69	0.64	4.33	0.54	4.23	0.55	4.24	0.34	4.03	0.33	4.03	0.43	4.13	0.29	3.98
May 2014	3.69	0.64	4.33	0.54	4.23	0.55	4.24	0.34	4.03	0.33	4.03	0.43	4.13	0.29	3.98
Jun 2014	3.66	0.52	4.18	0.39	4.05	0.43	4.09	0.69	4.35	0.24	3.89	0.34	4.00	0.24	3.90
Jul 2014	3.66	0.52	4.18	0.39	4.05	0.43	4.09	0.69	4.35	0.24	3.89	0.34	4.00	0.24	3.90
Aug 2014	3.66	0.52	4.18	0.39	4.05	0.43	4.09	0.69	4.35	0.24	3.89	0.34	4.00	0.24	3.90
Sep 2014	3.69	0.64	4.33	0.54	4.23	0.55	4.24	0.34	4.03	0.33	4.03	0.43	4.13	0.29	3.98
Oct 2014	3.69	0.64	4.33	0.54	4.23	0.55	4.24	0.34	4.03	0.33	4.03	0.43	4.13	0.29	3.98
Nov 2014	3.69	0.57	4.26	0.47	4.16	0.56	4.25	0.39	4.08	0.43	4.12	0.41	4.10	0.29	3.98
Dec 2014	3.84	1.25	5.08	0.85	4.69	1.38	5.22	0.71	4.55	0.37	4.20	0.87	4.71	0.26	4.10

Month	NC,VA Basis & Plant Gate Deliv. Cost	NC,VA Dlvrd Price	SC, GA Basis & Plant Gate Deliv. Cost	SC, GA Dlvrd Price	Southeast Basis & Plant Gate Deliv. Cost	Southeast Dlvrd Price	Florida Basis & Plant Gate Deliv. Cost	Florida Dlvrd Price	Midcontinent Basis & Plant Gate Deliv. Cost	Midcontinent Dlvrd Price	Midwest Basis & Plant Gate Deliv. Cost	Midwest Dlvrd Price	Upper Midwest Basis & Plant Gate Deliv. Cost	Upper Midwest Dlvrd Price	East Texas Basis & Plant Gate Deliv. Cost	East Texas Dlvrd Price
Jan 2005	0.76	4.87	0.68	4.80	0.23	4.34	0.20	4.31	(0.04)	4.07	0.08	4.19	(0.19)	3.92	(0.11)	4.00
Feb 2005	0.77	4.87	0.69	4.80	0.24	4.34	0.21	4.31	(0.04)	4.07	0.09	4.19	(0.18)	3.92	(0.10)	4.00
Mar 2005	0.37	4.30	0.30	4.24	0.20	4.14	0.19	4.13	0.01	3.95	0.12	4.06	(0.16)	3.78	0.02	3.96
Apr 2005	0.37	4.30	0.31	4.24	0.21	4.14	0.19	4.13	0.02	3.95	0.13	4.06	(0.15)	3.78	0.03	3.96
May 2005	0.38	4.30	0.31	4.24	0.22	4.14	0.20	4.13	0.03	3.95	0.14	4.06	(0.14)	3.78	0.04	3.96
Jun 2005	0.31	4.18	0.24	4.12	0.18	4.06	0.39	4.27	0.02	3.90	0.08	3.96	(0.27)	3.61	0.05	3.93
Jul 2005	0.31	4.18	0.24	4.12	0.18	4.06	0.39	4.27	0.02	3.90	0.08	3.96	(0.27)	3.61	0.05	3.93
Aug 2005	0.31	4.18	0.25	4.12	0.19	4.06	0.40	4.27	0.02	3.90	0.09	3.96	(0.26)	3.61	0.06	3.93
Sep 2005	0.41	4.30	0.34	4.24	0.24	4.14	0.23	4.13	0.05	3.95	0.16	4.06	(0.12)	3.78	0.06	3.96
Oct 2005	0.41	4.30	0.34	4.24	0.25	4.14	0.23	4.13	0.06	3.95	0.17	4.06	(0.11)	3.78	0.07	3.96
Nov 2005	0.40	4.29	0.33	4.22	0.29	4.17	0.22	4.10	(0.10)	3.78	(0.00)	3.88	(0.19)	3.70	(0.06)	3.82
Dec 2005	0.76	4.79	0.68	4.71	0.22	4.25	0.21	4.24	0.21	4.23	0.31	4.34	(0.11)	3.92	0.13	4.16
Jan 2007	0.75	4.67	0.67	4.59	0.23	4.15	0.30	4.22	(0.04)	3.88	0.11	4.02	(0.19)	3.73	(0.10)	3.81
Feb 2007	0.76	4.67	0.68	4.59	0.24	4.15	0.31	4.22	(0.03)	3.88	0.11	4.02	(0.18)	3.73	(0.10)	3.81
Mar 2007	0.37	4.12	0.30	4.06	0.20	3.96	0.28	4.04	0.01	3.76	0.14	3.89	(0.16)	3.59	0.02	3.78
Apr 2007	0.38	4.12	0.31	4.06	0.21	3.96	0.29	4.04	0.02	3.76	0.15	3.89	(0.15)	3.59	0.03	3.78
May 2007	0.39	4.12	0.32	4.06	0.22	3.96	0.30	4.04	0.03	3.76	0.16	3.89	(0.15)	3.59	0.04	3.78
Jun 2007	0.31	4.01	0.25	3.94	0.18	3.88	0.48	4.18	0.02	3.71	0.10	3.80	(0.26)	3.43	0.05	3.75
Jul 2007	0.31	4.01	0.25	3.94	0.18	3.88	0.48	4.18	0.02	3.71	0.10	3.80	(0.26)	3.43	0.05	3.75
Aug 2007	0.32	4.01	0.25	3.94	0.19	3.88	0.49	4.18	0.02	3.71	0.11	3.80	(0.26)	3.43	0.06	3.75
Sep 2007	0.41	4.12	0.34	4.06	0.24	3.96	0.32	4.04	0.05	3.76	0.18	3.89	(0.12)	3.59	0.06	3.78
Oct 2007	0.42	4.12	0.35	4.06	0.25	3.96	0.33	4.04	0.06	3.76	0.19	3.89	(0.12)	3.59	0.07	3.78
Nov 2007	0.40	4.11	0.34	4.04	0.28	3.99	0.31	4.02	(0.10)	3.61	0.02	3.72	(0.19)	3.51	(0.06)	3.64
Dec 2007	0.75	4.59	0.67	4.51	0.22	4.06	0.31	4.15	0.20	4.04	0.32	4.16	(0.12)	3.73	0.13	3.97
Jan 2010	0.79	4.62	0.71	4.54	0.27	4.10	0.34	4.17	(0.00)	3.83	0.15	3.97	(0.15)	3.68	(0.06)	3.76
Feb 2010	0.79	4.62	0.71	4.54	0.27	4.10	0.34	4.17	(0.00)	3.83	0.15	3.97	(0.15)	3.68	(0.06)	3.76
Mar 2010	0.39	4.08	0.33	4.01	0.23	3.91	0.31	3.99	0.03	3.72	0.16	3.85	(0.14)	3.54	0.05	3.73
Apr 2010	0.39	4.08	0.33	4.01	0.23	3.91	0.31	3.99	0.03	3.72	0.16	3.85	(0.14)	3.54	0.05	3.73
May 2010	0.39	4.08	0.33	4.01	0.22	3.91	0.31	3.99	0.03	3.72	0.16	3.85	(0.14)	3.54	0.04	3.73
Jun 2010	0.31	3.96	0.25	3.90	0.18	3.83	0.48	4.13	0.02	3.67	0.10	3.75	(0.26)	3.39	0.05	3.70
Jul 2010	0.31	3.96	0.25	3.90	0.18	3.83	0.48	4.13	0.02	3.67	0.10	3.75	(0.26)	3.39	0.05	3.70
Aug 2010	0.31	3.96	0.25	3.90	0.18	3.83	0.48	4.13	0.02	3.67	0.10	3.75	(0.26)	3.39	0.05	3.70
Sep 2010	0.39	4.08	0.32	4.01	0.22	3.91	0.31	3.99	0.03	3.72	0.16	3.85	(0.14)	3.54	0.04	3.73
Oct 2010	0.39	4.08	0.32	4.01	0.22	3.91	0.31	3.99	0.03	3.72	0.16	3.85	(0.14)	3.54	0.04	3.73
Nov 2010	0.37	4.06	0.31	3.99	0.25	3.94	0.28	3.97	(0.12)	3.56	(0.01)	3.68	(0.22)	3.47	(0.09)	3.60
Dec 2010	0.70	4.53	0.63	4.46	0.18	4.01	0.27	4.10	0.15	3.99	0.28	4.11	(0.16)	3.68	0.08	3.92
Jan 2014	0.79	4.62	0.71	4.55	0.27	4.10	0.34	4.18	(0.00)	3.83	0.14	3.98	(0.15)	3.69	(0.07)	3.77
Feb 2014	0.79	4.62	0.71	4.55	0.27	4.10	0.34	4.18	(0.00)	3.83	0.14	3.98	(0.15)	3.69	(0.07)	3.77
Mar 2014	0.39	4.08	0.32	4.02	0.22	3.92	0.31	4.00	0.03	3.72	0.16	3.85	(0.14)	3.55	0.04	3.74
Apr 2014	0.39	4.08	0.32	4.02	0.22	3.92	0.31	4.00	0.03	3.72	0.16	3.85	(0.14)	3.55	0.04	3.74
May 2014	0.39	4.08	0.32	4.02	0.22	3.92	0.31	4.00	0.03	3.72	0.16	3.85	(0.14)	3.55	0.04	3.74
Jun 2014	0.31	3.97	0.25	3.91	0.18	3.84	0.48	4.13	0.02	3.67	0.10	3.76	(0.26)	3.39	0.05	3.71
Jul 2014	0.31	3.97	0.25	3.91	0.18	3.84	0.48	4.13	0.02	3.67	0.10	3.76	(0.26)	3.39	0.05	3.71
Aug 2014	0.31	3.97	0.25	3.91	0.18	3.84	0.48	4.13	0.02	3.67	0.10	3.76	(0.26)	3.39	0.05	3.71
Sep 2014	0.39	4.08	0.33	4.02	0.22	3.92	0.31	4.00	0.03	3.72	0.16	3.85	(0.14)	3.55	0.04	3.74
Oct 2014	0.39	4.08	0.33	4.02	0.22	3.92	0.31	4.00	0.03	3.72	0.16	3.85	(0.14)	3.55	0.05	3.74
Nov 2014	0.38	4.07	0.31	4.00	0.25	3.94	0.29	3.98	(0.12)	3.57	(0.01)	3.69	(0.22)	3.47	(0.09)	3.60
Dec 2014	0.71	4.54	0.63	4.47	0.18	4.02	0.27	4.11	0.16	3.99	0.28	4.12	(0.15)	3.68	0.09	3.92

Attachment to LGE/KU #19(c)
Witness: McNamara

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Table A-20: Generating Units in VAP Area

MAPS Name	Ownership	Unit Name	Type	Summer Capacity (MW)	Winter Capacity (MW)	Installation Date	Retirement Date	Notes
BELLMEAD	Dominion	BELL MEADE	CC	230.26	250	1/1/1991	12/31/2100	
CHESTFD7	Dominion	CHESTERFIELD 7	CC	197	232	1/1/1990	12/31/2100	
CHESTFD8	Dominion	CHESTERFIELD 8	CC	200	235	1/1/1992	12/31/2100	
POSSUMP6	Dominion	POSSUM POINT 6	CC	405	450	5/1/2003	12/31/2100	
BREMOBL3	Dominion	BREMO BLUFF 3	Coal	71	74	1/1/1950	12/31/2100	
BREMOBL4	Dominion	BREMO BLUFF 4	Coal	156	160	1/1/1958	12/31/2100	
CHESAST1	Dominion	CHESAPEAKE ENERGY CENTER 1	Coal	111	111	1/1/1953	12/31/2100	
CHESAST2	Dominion	CHESAPEAKE ENERGY CENTER 2	Coal	111	111	1/1/1954	12/31/2100	
CHESAPE3	Dominion	CHESAPEAKE ENERGY CENTER 3	Coal	156	162	1/1/1959	12/31/2100	
CHESAST4	Dominion	CHESAPEAKE ENERGY CENTER 4	Coal	217	221	1/1/1962	12/31/2100	
CHESTFD3	Dominion	CHESTERFIELD 3	Coal	100	105	1/1/1952	12/31/2100	
CHESTFD4	Dominion	CHESTERFIELD 4	Coal	166	171	1/1/1960	12/31/2100	
CHESTFD5	Dominion	CHESTERFIELD 5	Coal	310	312	1/1/1964	12/31/2100	
CHESTFD6	Dominion	CHESTERFIELD 6	Coal	658	671	1/1/1969	12/31/2100	
CLOVER01	Dominion	CLOVER 1	Coal	441	441	1/1/1995	12/31/2100	50% ODEC
CLOVER02	Dominion	CLOVER 2	Coal	441	441	1/1/1996	12/31/2100	50% ODEC
LGEALTAV	Dominion	LG&E WESTMORELAND-ALTAVISTA	Coal	62.7	62.7	1/1/1992	12/31/2100	
LGEHOPEW	Dominion	LG&E WESTMORELAND-HOPEWELL	Coal	62.7	62.7	1/1/2006	12/31/2100	
LGESOUTH	Dominion	LG&E WESTMORELAND-SOUTHAMPTN	Coal	62.7	62.7	1/1/1992	12/31/2100	
MTSTORM1	Dominion	MOUNT STORM 1	Coal	524	545	1/1/1965	12/31/2100	
MTSTORM2	Dominion	MOUNT STORM 2	Coal	533	545	1/1/1966	12/31/2100	
MTSTORM3	Dominion	MOUNT STORM 3	Coal	521	536	1/1/1973	12/31/2100	
POSSUMG3	Dominion	POSSUM POINT 3	Coal	101	105	1/1/1955	5/1/2003	Converted to Gas
POSSUMG4	Dominion	POSSUM POINT 4	Coal	221	221	1/1/1962	5/1/2003	Converted to Gas
YORKTOW1	Dominion	YORKTOWN 1	Coal	159	163	1/1/1957	12/31/2100	
YORKTOW2	Dominion	YORKTOWN 2	Coal	167	172	1/1/1959	12/31/2100	
NTHBRANC	Dominion	NORTH BRANCH PROJECT	Waste Coal	74	77	1/1/1992	12/31/2100	
BATHCVAP	Dominion	BATH COUNTY	PSH	2520	2520	1/1/1990	12/31/2100	60% Dominion, 40% APS
CUSHAWPD	Dominion	CUSHAW	Hydro	2	2	1/1/1990	12/31/2100	
GASTONPD	Dominion	GASTON (NC)	Hydro	225	225	1/1/1990	12/31/2100	
NTHANNAH	Dominion	NORTH ANNA HYDRO	Hydro	1	1	1/1/1990	12/31/2100	
ROANOKPD	Dominion	ROANOKE RAPIDS	Hydro	99	99	1/1/1990	12/31/2100	
NTHANNA1	Dominion	NORTH ANNA 1	Nuke	925	925	1/1/1978	4/1/2018	11.6% ODEC
NTHANNA2	Dominion	NORTH ANNA 2	Nuke	917	917	1/1/1980	8/21/2020	11.6% ODEC
SURRY01	Dominion	SURRY 1	Nuke	810	810	1/1/1972	5/25/2012	
SURRY02	Dominion	SURRY 2	Nuke	815	815	1/1/1973	1/29/2013	
CAROLNE1	Dominion	LADYSMITH 1	Peaker	145	178	7/1/2001	12/31/2100	
CAROLNE2	Dominion	LADYSMITH 2	Peaker	145	178	7/1/2001	12/31/2100	
CHESAGT1	Dominion	CHESAPEAKE GT01	Peaker	15	19	1/1/1967	12/31/2100	
CHESAGT2	Dominion	CHESAPEAKE GT02	Peaker	15	18	1/1/1969	12/31/2100	
CHESAGT4	Dominion	CHESAPEAKE GT04	Peaker	15	18	1/1/1969	12/31/2100	
CHESAPE6	Dominion	CHESAPEAKE GT06	Peaker	15	18	1/1/1969	12/31/2100	
CHESAPE7	Dominion	CHESAPEAKE GT07	Peaker	21	29	1/1/1969	12/31/2100	
CHESAPE8	Dominion	CHESAPEAKE GT08	Peaker	21	29	1/1/1969	12/31/2100	
CHESAPE9	Dominion	CHESAPEAKE GT09	Peaker	21	29	1/1/1970	12/31/2100	

Table A-20: Generating Units in VAP Area

MAPS Name	Ownership	Unit Name	Type	Summer Capacity (MW)	Winter Capacity (MW)	Installation Date	Retirement Date	Notes
CHESAP10	Dominion	CHESAPEAKE GT10	Peaker	21	29	1/1/1970	12/31/2100	
DARBYTO1	Dominion	DARBYTOWN 1	Peaker	72	92	1/1/1990	12/31/2100	
DARBYTO2	Dominion	DARBYTOWN 2	Peaker	72	92	1/1/1990	12/31/2100	
DARBYTO3	Dominion	DARBYTOWN 3	Peaker	72	92	1/1/1990	12/31/2100	
DARBYTO4	Dominion	DARBYTOWN 4	Peaker	72	92	1/1/1990	12/31/2100	
FAUQUIC1	Dominion	REMINGTON 1	Peaker	145	178	7/5/2000	12/31/2100	
FAUQUIC2	Dominion	REMINGTON 2	Peaker	145	178	7/5/2000	12/31/2100	
FAUQUIC3	Dominion	REMINGTON 3	Peaker	145	178	7/5/2000	12/31/2100	
FAUQUIC4	Dominion	REMINGTON 4	Peaker	145	178	7/5/2000	12/31/2100	
GRAVELN1	Dominion	GRAVEL NECK 1	Peaker	15	17	1/1/1970	12/31/2100	
GRAVELN2	Dominion	GRAVEL NECK 2	Peaker	22	28	1/1/1970	12/31/2100	
GRAVELN3	Dominion	GRAVEL NECK 3	Peaker	73	92	1/1/1989	12/31/2100	
GRAVELN4	Dominion	GRAVEL NECK 4	Peaker	73	92	1/1/1989	12/31/2100	
GRAVELN5	Dominion	GRAVEL NECK 5	Peaker	73	92	1/1/1989	12/31/2100	
GRAVELN6	Dominion	GRAVEL NECK 6	Peaker	73	92	1/1/1989	12/31/2100	
KITTYGT1	Dominion	KITTY HAWK 1	Peaker	22	28	1/1/1971	12/31/2100	
KITTYGT2	Dominion	KITTY HAWK 2	Peaker	22	28	1/1/1971	12/31/2100	
LOWMOOR1	Dominion	LOW MOOR 1	Peaker	15	18	1/1/1971	12/31/2100	
LOWMOOR2	Dominion	LOW MOOR 2	Peaker	15	18	1/1/1971	12/31/2100	
LOWMOOR3	Dominion	LOW MOOR 3	Peaker	15	18	1/1/1971	12/31/2100	
LOWMOOR4	Dominion	LOW MOOR 4	Peaker	15	18	1/1/1971	12/31/2100	
MTSTOJF1	Dominion	MOUNT STORM GT1	Peaker	12	16	1/1/1967	12/31/2100	
NTHNECK1	Dominion	NORTHERN NECK 1	Peaker	16	19	1/1/1971	12/31/2100	
NTHNECK2	Dominion	NORTHERN NECK 2	Peaker	16	19	1/1/1971	12/31/2100	
NTHNECK3	Dominion	NORTHERN NECK 3	Peaker	16	19	1/1/1971	12/31/2100	
NTHNECK4	Dominion	NORTHERN NECK 4	Peaker	16	19	1/1/1971	12/31/2100	
POSSUGT1	Dominion	POSSUM POINT GT1	Peaker	13	16	1/1/1968	12/31/2100	
POSSUGT2	Dominion	POSSUM POINT GT2	Peaker	13	16	1/1/1968	12/31/2100	
POSSUGT3	Dominion	POSSUM POINT GT3	Peaker	13	16	1/1/1968	12/31/2100	
POSSUGT4	Dominion	POSSUM POINT GT4	Peaker	13	16	1/1/1968	12/31/2100	
POSSUGT5	Dominion	POSSUM POINT GT5	Peaker	13	16	1/1/1968	12/31/2100	
POSSUGT6	Dominion	POSSUM POINT GT6	Peaker	13	16	1/1/1968	12/31/2100	
POSSUMP1	Dominion	POSSUM POINT 1	ST/G/O/D	74	74	1/1/1948	5/1/2003	Retired w new CC
POSSUMP2	Dominion	POSSUM POINT 2	ST/G/O/D	69	71	1/1/1951	5/1/2003	Retired w new CC
POSSUMP3	Dominion	POSSUM POINT 3	ST/G/O/D	101	105	5/1/2003	12/31/2100	Converted to Gas
POSSUMP4	Dominion	POSSUM POINT 4	ST/G/O/D	221	221	5/1/2003	12/31/2100	Converted to Gas
POSSUMP5	Dominion	POSSUM POINT 5	ST/G/O/D	786	801	1/1/1975	12/31/2100	
YORKTOW3	Dominion	YORKTOWN 3	ST/G/O/D	818	820	1/1/1974	12/31/2100	
DOSWECC1	NUG	DOSWELL COMBINED CYCLE FACILITY CC 1	CC	302.5	363	1/1/1992	12/31/2100	5/5/2017 Term End
DOSWECC2	NUG	DOSWELL COMBINED CYCLE FACILITY CC 2	CC	302.5	363	1/1/1992	12/31/2100	5/5/2017 Term End
GORDONCC	NUG	GORDONSVILLE ENERGY L.P.	CC	217	288	1/1/1994	12/31/2100	5/31/2024 Term End
HOPEWECC	NUG	HOPEWELL COGENERATION	CC	337	400	1/1/1993	12/31/2100	7/30/2015 Term End
BIRCHWO1	NUG	BIRCHWOOD POWER FACILITY 1	Coal	238	242	1/1/1996	12/31/2100	11/14/2021 Term End
CGNHOPEW	NUG	COGENTRIX HOPEWELL 1	Coal	92.5	92.5	1/1/1987	12/31/2100	1/9/2008 Term End

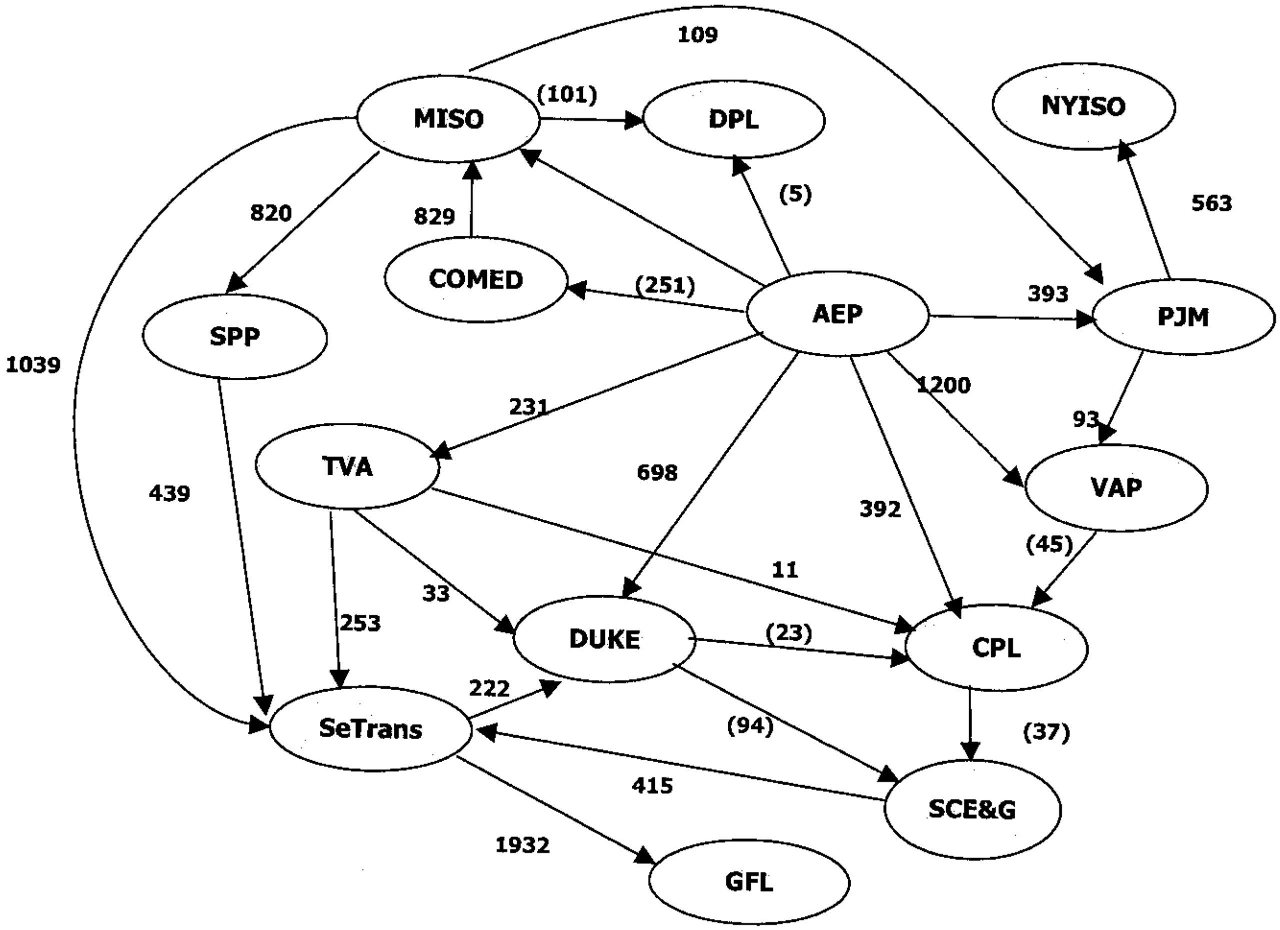
Table A-20: Generating Units in VAP Area

MAPS Name	Ownership	Unit Name	Type	Summer Capacity (MW)	Winter Capacity (MW)	Installation Date	Retirement Date	Notes
CGNRICH1	NUG	COGENTRIX RICHMOND 1	Coal	115.5	115.5	1/1/1992	12/31/2100	7/31/2017 Term End
CGNRICH2	NUG	COGENTRIX RICHMOND 2	Coal	93.5	93.5	1/1/1992	12/31/2100	7/31/2017 Term End
DCBATTL1	NUG	DC BATTLE (COG ROCKY MT) 1	Coal	57.5	57.5	1/1/1990	12/31/2100	10/14/2015 Term End
DCBATTL2	NUG	DC BATTLE (COG ROCKY MT) 2	Coal	57.5	57.5	1/1/1990	12/31/2100	10/14/2015 Term End
MECKLEN1	NUG	MECKLENBURG 1	Coal	66	66	1/1/1992	12/31/2100	11/5/2017 Term End
MECKLEN2	NUG	MECKLENBURG 2	Coal	66	66	1/1/1992	12/31/2100	11/5/2017 Term End
PARK5002	NUG	PARK 500 DIVISION 1	Coal	6	6	1/1/1984	12/31/2100	12/30/2003 Term End
PARK5001	NUG	PARK 500 DIVISION 2	Coal	6	6	1/1/1983	12/31/2100	12/30/2003 Term End
PORTSMO1	NUG	COGENTRIX PORTSMOUTH 1	Coal	57.5	57.5	1/1/1988	12/31/2100	6/8/2008 Term End
PORTSMO2	NUG	COGENTRIX PORTSMOUTH 2	Coal	57.5	57.5	1/1/1988	12/31/2100	6/8/2008 Term End
ROANOKVP	NUG	ROANOKE VALLEY PROJECT	Coal	165	167.21	1/1/1994	12/31/2100	5/28/2019 Term End
ROANOKV1	NUG	ROANOKE VALLEY II	Coal	44	45.1	1/1/1995	12/31/2100	5/31/2020 Term End
ALEXARL1	NUG	ALEXANDRIA/ARLINGTON MSW 1	Other	10	10	1/1/1988	12/31/2100	1/28/2023 Term End
ALEXARL2	NUG	ALEXANDRIA/ARLINGTON MSW 2	Other	10	10	1/1/1988	12/31/2100	1/28/2023 Term End
APPOMAT1	NUG	APPOMATTOX COGEN-STONE CONT	Other	38	38	1/1/1981	12/31/2100	10/25/2004 Term End
COVINGT1	NUG	WESTVACO COVINGTON 1	Other	11.5	11.5	1/1/1990	12/31/2100	12/26/2003 Term End
COVINGT2	NUG	WESTVACO COVINGTON 2	Other	11.5	11.5	1/1/1990	12/31/2100	12/26/2003 Term End
COVINGT3	NUG	WESTVACO COVINGTON 3	Other	11.5	11.5	1/1/1990	12/31/2100	12/26/2003 Term End
COVINGT4	NUG	WESTVACO COVINGTON 4	Other	11.5	11.5	1/1/1990	12/31/2100	12/26/2003 Term End
COVINGT5	NUG	WESTVACO COVINGTON 5	Other	11.5	11.5	1/1/1990	12/31/2100	12/26/2003 Term End
COVINGT6	NUG	WESTVACO COVINGTON 6	Other	11.5	11.5	1/1/1990	12/31/2100	12/26/2003 Term End
I95ENER1	NUG	I-95 ENERGY-COVANTA FAIRFAX	Other	79	79	1/1/1990	12/31/2100	5/31/2015 Term End
MULTITR1	NUG	MULTITRADE OF PITTSYLVANIA	Other	39.8	39.8	1/1/1994	12/31/2100	6/14/2019 Term End
MULTITR2	NUG	MULTITRADE OF PITTSYLVANIA	Other	39.8	39.8	1/1/1994	12/31/2100	6/14/2019 Term End
SPSAPOW1	NUG (Netted from VAP Load Forecast)	NORFOLK NAVAL SHIPYARD 1	Other	18.6	20	1/1/1987	12/31/2100	
SPSAPOW2	NUG (Netted from VAP Load Forecast)	NORFOLK NAVAL SHIPYARD 2	Other	18.6	20	1/1/1987	12/31/2100	
SPSAPOW3	NUG (Netted from VAP Load Forecast)	NORFOLK NAVAL SHIPYARD 3	Other	18.6	20	1/1/1987	12/31/2100	
PLYMOUT4	NUG	WEYERHAUSER PLYMOUTH NC 4	Other	4.73	4.73	1/1/1949	12/31/2100	7/26/2004 Term End
PLYMOUT6	NUG	WEYERHAUSER PLYMOUTH NC 6	Other	4.73	4.73	1/1/1956	12/31/2100	7/26/2004 Term End
PLYMOUT7	NUG	WEYERHAUSER PLYMOUTH NC 7	Other	4.73	4.73	1/1/1952	12/31/2100	7/26/2004 Term End
PLYMOUT8	NUG	WEYERHAUSER PLYMOUTH NC 8	Other	4.73	4.73	1/1/1964	12/31/2100	7/26/2004 Term End
PLYMOUT9	NUG	WEYERHAUSER PLYMOUTH NC 9	Other	4.73	4.73	1/1/1976	12/31/2100	7/26/2004 Term End
PLYMOU10	NUG	WEYERHAUSER PLYMOUTH NC 10	Other	4.73	4.73	1/1/1978	12/31/2100	7/26/2004 Term End
CHESAPP6	NUG (Netted from VAP Load Forecast)	CHESAPEAKE PAPER PRODUCTS 06	Other	5.7	5.7	1/1/1937	12/31/2100	
CHESAPP8	NUG (Netted from VAP Load Forecast)	CHESAPEAKE PAPER PRODUCTS 08	Other	5	5	1/1/1954	12/31/2100	
CHESAPP9	NUG (Netted from VAP Load Forecast)	CHESAPEAKE PAPER PRODUCTS 09	Other	9.6	10	1/1/1960	12/31/2100	
CHESPP10	NUG (Netted from VAP Load Forecast)	CHESAPEAKE PAPER PRODUCTS 10	Other	24	25	1/1/1968	12/31/2100	
CHESAP11	NUG (Netted from VAP Load Forecast)	CHESAPEAKE PAPER PRODUCTS 11	Other	14.4	15	1/1/1977	12/31/2100	
CHESAP12	NUG (Netted from VAP Load Forecast)	CHESAPEAKE PAPER PRODUCTS 12	Other	42.7	46	1/1/1985	12/31/2100	
COMMONA1	NUG	COMMONWEALTH ATLANTIC LIMIT 1	Peaker	104	125	1/1/1992	12/31/2100	6/4/2017 Term End
COMMONA2	NUG	COMMONWEALTH ATLANTIC LIMIT 2	Peaker	104	125	1/1/1992	12/31/2100	6/4/2017 Term End
COMMONA3	NUG	COMMONWEALTH ATLANTIC LIMIT 3	Peaker	104	125	1/1/1992	12/31/2100	6/4/2017 Term End
DOSWELL1	NUG	DOSWELL COMBINED CYCLE FACILITY 1	Peaker	155	182	6/7/2001	12/31/2100	12/31/2005 Term End
FRANKLI1	NUG (Netted from VAP Load Forecast)	FRANKLIN FINE PAPER 1	Other	5	5	1/1/1937	12/31/2100	
FRANKLI6	NUG (Netted from VAP Load Forecast)	FRANKLIN FINE PAPER 6	Other	9.01	9.38	1/1/1950	12/31/2100	

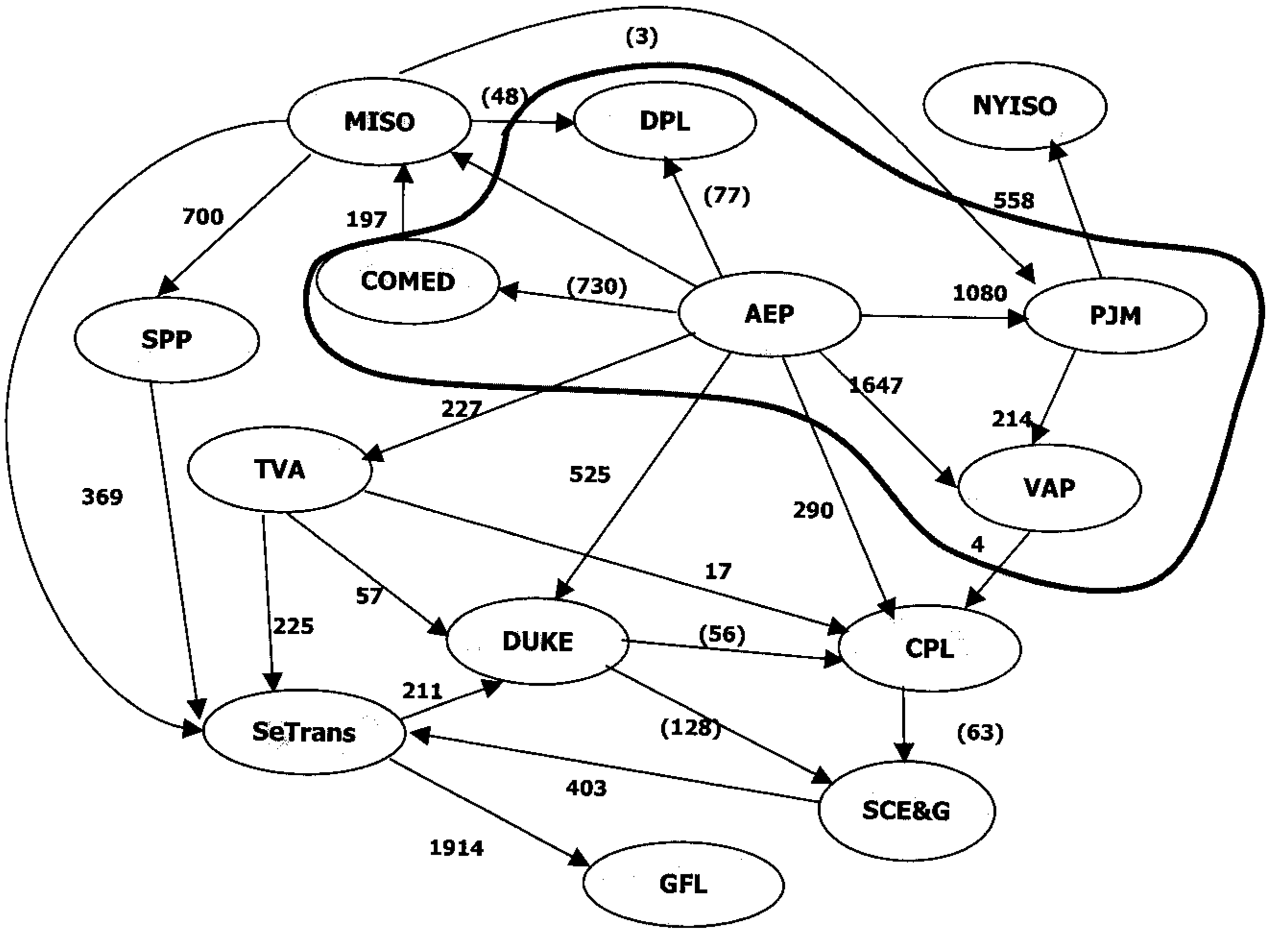
Table A-20: Generating Units in VAP Area

MAPS Name	Ownership	Unit Name	Type	Summer Capacity (MW)	Winter Capacity (MW)	Installation Date	Retirement Date	Notes
FRANKLI7	NUG (Netted from VAP Load Forecast)	FRANKLIN FINE PAPER 7	Other	15.02	15.63	1/1/1958	12/31/2100	
FRANKLI8	NUG (Netted from VAP Load Forecast)	FRANKLIN FINE PAPER 8	Other	31.14	32.4	1/1/1970	12/31/2100	
FRANKLI9	NUG (Netted from VAP Load Forecast)	FRANKLIN FINE PAPER 9	Other	26.91	28	1/1/1977	12/31/2100	
PANDARCC	NUG	PANDA-ROSEMARY	CC	165	198	1/1/1990	12/31/2100	12/26/2015 Term End
ROANOST1	NUG	INTL PAPER ROANOKE RAPIDS	Coal	14	14	1/1/1966	12/31/2100	8/26/2006 Term End
I95LNDFL	NUG	I-95 LANDFILL	Other	3.2	3.2	3/1/1993	12/31/2100	12/31/2011 Term End
I95LNDF2	NUG	I-95 LANDFILL PHASE II	Other	3.2	3.2	1/1/1992	12/31/2100	2/9/2013 Term End
SCOTTENE	NUG	SCOTT ENERGY	Other	2.5	2	12/1/1989	12/31/2100	12/28/2015 Term End
SUFFLKLF	NUG	SUFFOLK LANDFILL	Other	3.2	3.28	11/1/1994	12/31/2100	11/3/2014 Term End
WPP3RICH	NUG	WPP 3 RICHMOND PLANT	Other	2.93	3	7/1/1991	12/31/2100	8/26/2013 Term End
BRASFLDD	NUG	BRASFIELD DAM	Hydro	3	3	1/1/1990	12/31/2100	10/11/2013 Term End
EMPORIAH	NUG	EMPORIA HYDRO	Hydro	1	1	1/1/1990	12/31/2100	3/30/2006 Term End
SCHOOLFD	NUG	SCHOOLFIELD DAM	Hydro	3	3	1/1/1990	12/31/2100	11/30/2015 Term End
FLUVANN1	Merchant	TENASKA VIRGINIA PARTNERS 1	CC	300	300	6/1/2004	12/31/2100	
FLUVANN2	Merchant	TENASKA VIRGINIA PARTNERS 2	CC	300	300	6/1/2004	12/31/2100	
FLUVANN3	Merchant	TENASKA VIRGINIA PARTNERS 3	CC	300	300	6/1/2004	12/31/2100	
BOSWTAV1	ODEC	BOSWELL'S TAVERN (LOUISA CO) 1	Peaker	78.75	85	6/1/2003	12/31/2100	
BOSWTAV2	ODEC	BOSWELL'S TAVERN (LOUISA CO) 2	Peaker	78.75	85	6/1/2003	12/31/2100	
BOSWTAV3	ODEC	BOSWELL'S TAVERN (LOUISA CO) 3	Peaker	78.75	85	6/1/2003	12/31/2100	
BOSWTAV4	ODEC	BOSWELL'S TAVERN (LOUISA CO) 4	Peaker	78.75	85	6/1/2003	12/31/2100	
BOSWTAV5	ODEC	BOSWELL'S TAVERN (LOUISA CO) 5	Peaker	150	170	6/1/2003	12/31/2100	
REMINGM1	ODEC	REMINGTON MARSH RUN 1	Peaker	150	170	10/1/2004	12/31/2100	
REMINGM2	ODEC	REMINGTON MARSH RUN 2	Peaker	150	170	10/1/2004	12/31/2100	
REMINGM3	ODEC	REMINGTON MARSH RUN 3	Peaker	150	170	10/1/2004	12/31/2100	
REMINGM4	ODEC	REMINGTON MARSH RUN 4	Peaker	150	170	1/1/2014	12/31/2100	
PLEASANV	Harrisonburg Electric	PLEASANT VALLEY (HARRISNBRG)	Peaker	14	14	1/1/1998	12/31/2100	
MTCLINT1	Harrisonburg Electric	MT. CLINTON (HARRISONBURG)	Peaker	14	14	1/1/1999	12/31/2100	
MANASSAS	Manassas Electric Dept.	AGGREGATED MANASSAS ICs	Peaker	30	30	1/1/2000	12/31/2100	
JKERRVAP	SEPA	JOHN H. KERR	Hydro	146	146	1/1/1990	1/1/2100	

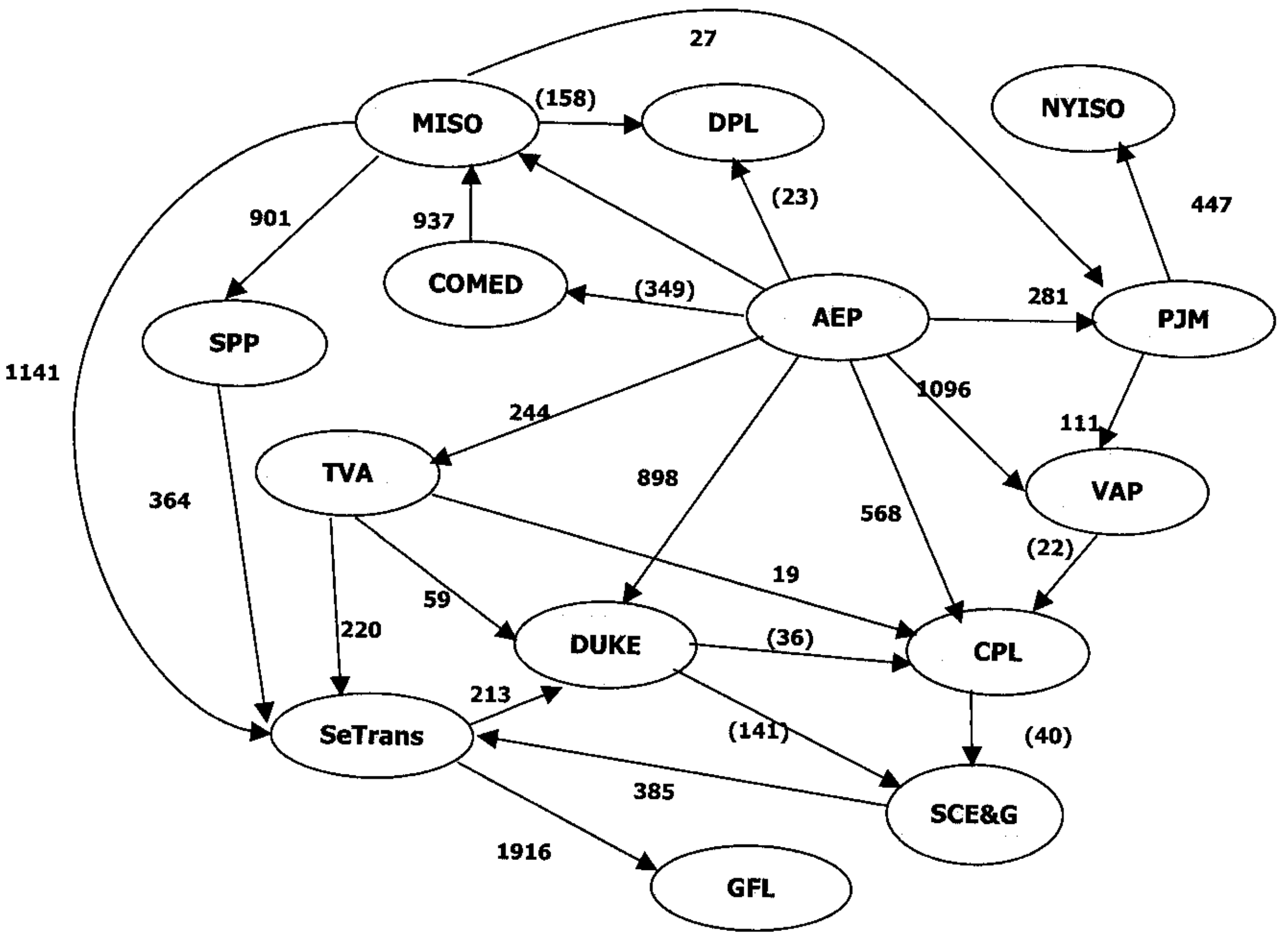
Pool to Pool All-Hour Average Transfers (MW)
7 Base Case



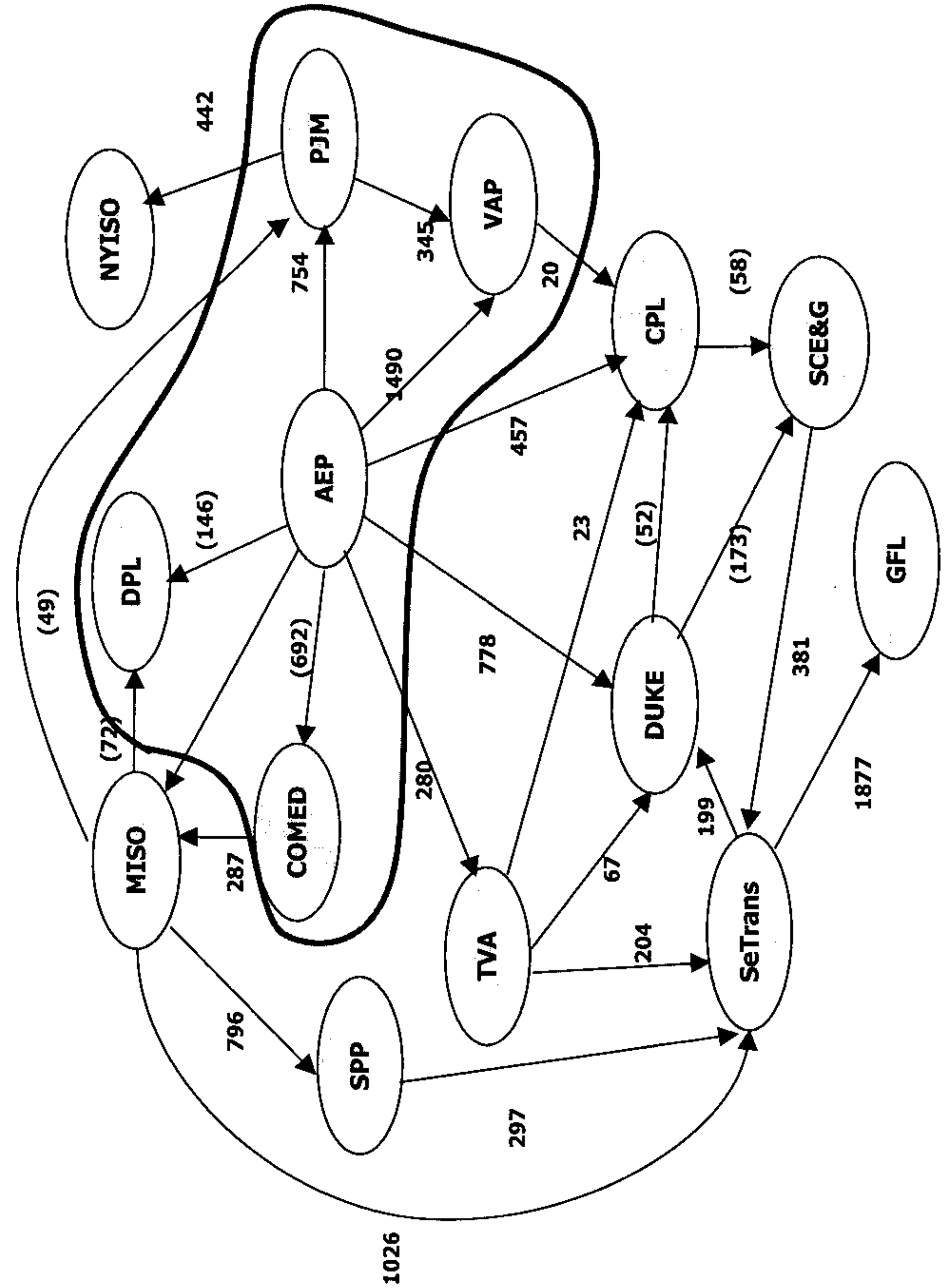
Pool to Pool All-Hour Average Transfers (MW)
7 Change Case



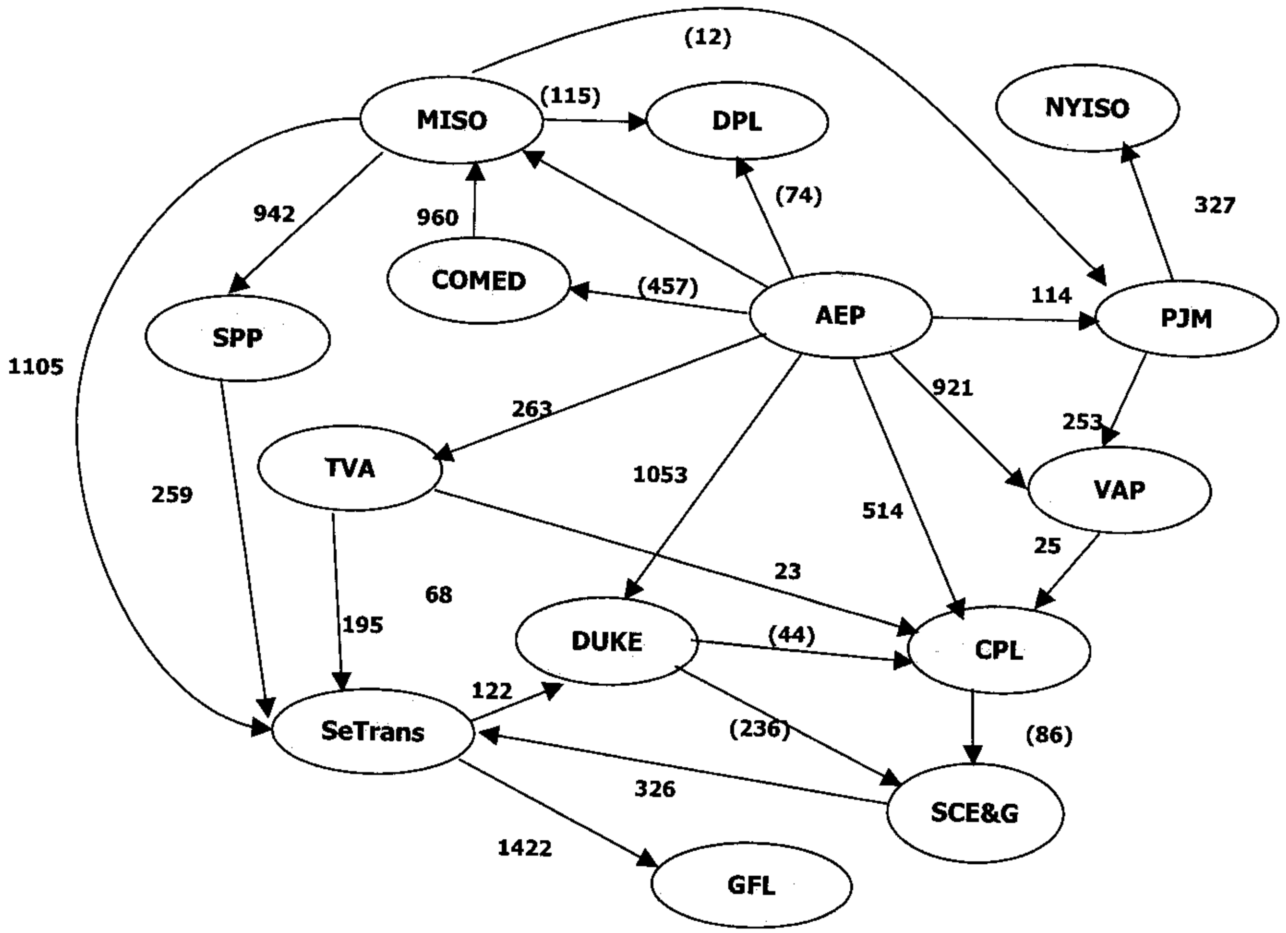
Pool to Pool All-Hour Average Transfers (MW)
0 Base Case



Pool to Pool All-Hour Average Transfers (MW)
2010 Change Case



Pool to Pool All-Hour Average Transfers (MW)
4 Base Case



Pool to Pool All-Hour Average Transfers (MW)
4 Change Case

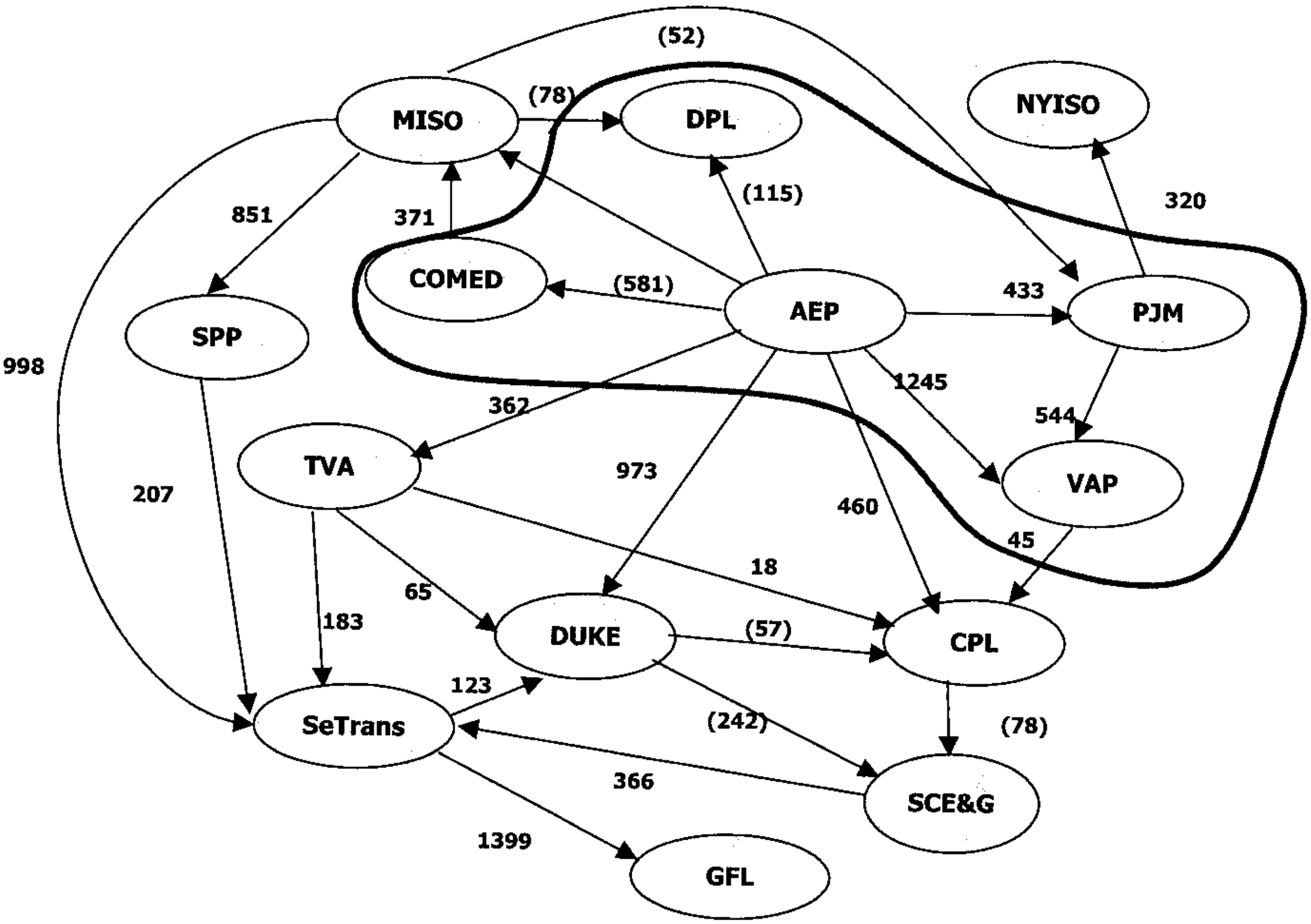


Table A-21: Generation by Type and Pool (GWh)

		2005			2007			2010			2014		
Capacity Pool	TYPE -	2005 Base	2005 Change	Delta (Change - Base)	2007 Base	2007 Change	Delta (Change - Base)	2010 Base	2010 Change	Delta (Change - Base)	2014 Base	2014 Change	Delta (Change - Base)
AEP	CC	195	707	511	257	912	655	1,304	2,928	1,624	3,510	7,179	3,669
	Coal	130,287	132,465	2,178	135,631	137,062	1,431	141,082	140,863	(219)	144,530	144,637	107
	Hydro	1,284	1,284	-	1,284	1,284	-	1,284	1,284	-	1,284	1,284	-
	Nuke	15,885	15,885	-	15,888	15,888	-	15,913	15,913	-	15,885	15,885	-
	Other	214	214	(0)	214	214	(0)	214	214	-	213	214	0
	Peaker	-	-	-	-	0	0	20	19	(0)	61	88	27
	PSH	730	728	(2)	710	711	1	620	619	(1)	481	481	0
	ST/G/O/D	0	0	(0)	0	1	0	1	3	1	1	4	3
	New CT	-	-	-	-	-	-	-	-	-	-	-	-
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
AEP Sum		148,595	151,282	2,687	153,984	156,071	2,087	160,438	161,842	1,404	165,965	169,771	3,806
COMED	CC	1,666	1,109	(557)	2,227	1,465	(762)	2,929	2,430	(498)	3,906	3,696	(211)
	Coal	27,944	28,588	644	29,975	30,816	840	33,144	34,154	1,010	35,142	35,704	562
	Nuke	80,330	80,332	2	80,364	80,364	-	80,299	80,296	(4)	80,280	80,278	(3)
	Peaker	177	78	(99)	345	165	(179)	539	364	(175)	1,080	447	(633)
	ST/G/O/D	1,093	335	(758)	1,783	565	(1,218)	3,922	1,021	(2,901)	6,824	3,647	(3,178)
	New CT	-	-	-	-	-	-	106	16	(90)	835	241	(594)
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
COMED Sum		111,211	110,443	(768)	114,695	113,376	(1,319)	120,939	118,280	(2,658)	128,068	124,012	(4,056)
CPL	CC	1,530	2,087	557	2,152	2,570	418	3,044	3,395	351	4,259	4,376	117
	Coal	34,977	35,155	178	36,738	36,916	178	37,848	38,006	159	39,383	39,497	114
	Hydro	949	949	-	949	949	-	949	949	-	949	949	-
	Nuke	24,491	24,491	-	24,494	24,494	-	24,519	24,519	-	24,507	24,507	-
	Other	2,512	2,512	-	2,504	2,504	-	2,509	2,509	(1)	2,509	2,509	0
	Peaker	379	415	36	668	747	78	1,137	1,357	221	1,531	1,618	87
	New CT	-	-	-	-	-	-	560	498	(62)	3,537	3,814	277
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
CPL Sum		64,838	65,610	772	67,504	68,179	675	70,566	71,233	667	76,675	77,269	594
DP&L	Coal	17,682	17,874	192	18,560	18,727	166	19,712	20,046	334	20,765	20,886	121
	Other	45	45	-	45	45	-	45	45	-	45	45	-
	Peaker	-	-	-	11	-	(11)	25	22	(4)	128	48	(81)
	New CT	-	-	-	-	-	-	-	-	-	-	-	-
DP&L Sum		17,727	17,919	192	18,616	18,772	155	19,782	20,112	330	20,938	20,979	41

Attachment to LGE/KU #19(c)
Witness: McNamara

Table A-21: Generation by Type and Pool (GWh)

Capacity Pool	TYPE -	2005 Base	2005 Change	2005 Delta (Change - Base)	2007 Base	2007 Change	2007 Delta (Change - Base)	2010 Base	2010 Change	2010 Delta (Change - Base)	2014 Base	2014 Change	2014 Delta (Change - Base)
DUKE	CC	990	1,276	287	1,465	1,627	162	2,034	2,132	98	2,851	2,903	53
	Coal	50,497	50,731	233	52,169	52,373	203	53,477	53,618	142	54,954	55,040	85
	Hydro	4,265	4,265	-	4,265	4,265	-	4,265	4,265	-	4,265	4,265	-
	Nuke	53,021	53,021	-	52,958	52,958	-	53,031	53,031	-	53,054	53,054	-
	Other	56	56	-	56	56	-	56	56	-	57	57	0
	Peaker	536	569	33	786	827	41	1,588	1,645	57	3,307	3,432	125
	PSH	3,665	3,677	12	3,494	3,547	53	3,236	3,231	(5)	2,332	2,308	(24)
	ST/G/O/D	4	6	1	2	4	1	8	9	2	10	11	1
	New CT	-	-	-	205	233	28	1,460	1,497	38	3,795	4,047	251
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
DUKE Sum		113,035	113,601	566	115,401	115,890	489	119,156	119,486	331	124,624	125,116	491
GFL	CC	63,040	63,319	280	67,521	67,571	51	72,380	72,507	127	79,002	79,071	69
	Coal	55,677	55,778	101	56,264	56,313	49	56,513	56,572	58	57,107	57,120	13
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	214	214	-	214	214	-	214	214	-	214	214	-
	Nuke	29,964	29,964	-	29,897	29,897	-	29,929	29,929	-	29,886	29,886	-
	Other	3,147	3,147	-	3,150	3,150	-	3,147	3,147	-	3,148	3,148	-
	Peaker	2,067	2,050	(17)	4,897	4,884	(13)	4,424	4,473	49	3,178	3,205	27
	ST/G/O/D	39,627	39,812	185	42,647	42,712	65	44,974	45,023	49	49,240	49,300	60
	New CT	-	-	-	-	-	-	2,699	2,710	12	7,958	7,960	2
	New CC	-	-	-	-	-	-	6,435	6,472	37	20,370	20,407	37
GFL Sum		193,737	194,284	548	204,590	204,742	152	220,716	221,048	332	250,104	250,311	207
MISO E	CC	3,654	3,689	34	5,369	5,471	103	10,497	10,938	441	19,597	19,749	152
	Coal	317,718	319,634	1,916	326,664	328,666	2,002	340,013	342,181	2,169	351,778	353,087	1,308
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	2,658	2,658	-	2,658	2,658	-	2,658	2,658	-	2,658	2,658	-
	Nuke	29,335	29,335	-	29,324	29,324	-	29,279	29,279	-	29,334	29,334	-
	Other	2,456	2,456	-	2,451	2,451	-	2,454	2,454	-	2,455	2,456	1
	Peaker	416	399	(16)	771	762	(9)	1,343	1,332	(10)	2,704	2,478	(226)
	PSH	5,234	5,234	(0)	5,072	5,084	12	4,718	4,715	(3)	3,846	3,829	(17)
	ST/G/O/D	1,076	1,128	53	1,830	1,850	20	3,843	3,898	55	8,404	8,387	(17)
	New CT	-	-	-	-	-	-	-	-	-	765	737	(28)
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
MISO E Sum		362,546	364,532	1,986	374,138	376,266	2,128	394,805	397,456	2,651	421,541	422,715	1,174

Table A-21: Generation by Type and Pool (GWh)

		2005			2007			2010			2014		
Capacity Pool	TYPE -	2005 Base	2005 Change	Delta (Change - Base)	2007 Base	2007 Change	Delta (Change - Base)	2010 Base	2010 Change	Delta (Change - Base)	2014 Base	2014 Change	Delta (Change - Base)
MISO W	CC	6,582	6,722	139	8,558	8,686	128	13,140	13,247	106	18,334	18,417	83
	Coal	283,317	284,023	706	288,503	289,180	677	292,908	293,582	674	301,069	301,556	487
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	15,458	15,458	-	15,458	15,458	-	15,458	15,458	-	15,458	15,458	-
	Nuke	56,909	56,903	(6)	56,946	56,950	4	56,941	56,967	26	56,905	56,915	9
	Other	10,576	10,577	1	10,584	10,586	2	10,559	10,564	4	10,566	10,578	12
	Peaker	3,927	3,919	(8)	5,161	5,174	13	10,951	11,015	64	10,135	10,327	191
	PSH	661	660	(2)	670	673	3	672	674	2	673	669	(5)
	ST/G/O/D	277	295	18	455	468	12	1,290	1,294	5	1,663	1,700	37
	New CT	-	-	-	-	-	-	-	-	-	11,811	12,189	378
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
MISO W Sum		377,707	378,557	850	386,336	387,175	839	401,919	402,800	881	426,615	427,808	1,193
ISO-NE	CC	25,943	25,968	24	28,074	27,992	(82)	34,313	34,329	16	38,941	38,652	(290)
	Coal	21,568	21,550	(18)	21,810	21,776	(34)	22,067	22,062	(4)	22,102	22,103	1
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	7,261	7,261	-	7,261	7,261	-	7,261	7,261	-	7,261	7,261	-
	Nuke	33,909	33,909	-	33,884	33,883	(1)	33,963	33,963	-	33,989	33,989	-
	Other	14,314	14,314	-	14,322	14,322	-	14,317	14,317	-	14,311	14,311	-
	Peaker	-	-	-	-	-	-	-	-	-	-	-	-
	PSH	1,125	1,122	(3)	1,053	1,046	(7)	1,019	1,010	(9)	867	884	17
	ST/G/O/D	16,801	16,771	(30)	18,701	18,794	93	18,148	18,145	(3)	20,603	20,952	350
	New CT	-	-	-	-	-	-	-	-	-	-	-	-
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
ISO-NE Sum		120,921	120,894	(27)	125,104	125,073	(31)	131,087	131,087	(0)	138,074	138,151	77
NYC	CC	6,174	6,304	130	6,429	6,533	105	6,819	6,944	124	7,297	7,381	84
	Other	179	179	-	179	179	-	179	179	-	179	179	-
	Peaker	342	338	(5)	219	225	6	274	265	(9)	483	493	9
	ST/G/O/D	18,223	18,367	144	19,237	19,403	165	20,157	20,393	236	21,505	21,785	281
	New CT	-	-	-	29	29	(0)	58	59	1	157	165	8
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
NYC Sum		24,918	25,188	269	26,094	26,369	276	27,488	27,840	352	29,620	30,002	381
NYL	CC	1,502	1,508	7	1,530	1,544	14	1,608	1,608	0	1,690	1,690	0
	Other	992	992	-	991	991	-	991	991	-	988	988	-
	Peaker	152	150	(3)	128	128	(0)	226	221	(5)	303	311	8

Table A-21: Generation by Type and Pool (GWh)

Capacity Pool	TYPE -	2005 Base	2005 Change	2005 Delta (Change - Base)	2007 Base	2007 Change	2007 Delta (Change - Base)	2010 Base	2010 Change	2010 Delta (Change - Base)	2014 Base	2014 Change	2014 Delta (Change - Base)
	ST/G/O/D	8,199	8,237	37	8,790	8,802	12	9,605	9,607	2	10,862	10,887	24
	New CT	-	-	-	20	20	0	70	73	3	206	204	(2)
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
NYL Sum		10,845	10,886	41	11,460	11,486	26	12,500	12,501	1	14,050	14,080	31
NYO	CC	10,934	11,204	271	11,898	11,711	(187)	13,800	13,772	(28)	15,957	15,798	(159)
	Coal	26,150	25,821	(330)	26,643	26,384	(259)	27,290	27,053	(237)	27,558	27,406	(152)
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	28,623	28,623	-	28,623	28,623	-	28,623	28,623	-	28,623	28,623	-
	Nuke	37,813	37,813	1	37,718	37,718	(0)	37,741	37,740	(1)	37,718	37,715	(2)
	Other	2,408	2,408	(0)	2,403	2,403	(0)	2,402	2,402	(0)	2,398	2,398	0
	Peaker	1	1	0	0	0	0	2	2	0	5	5	0
	PSH	2,008	2,014	6	2,013	2,017	4	1,861	1,846	(15)	1,693	1,699	6
	ST/G/O/D	7,858	8,119	261	9,373	9,713	340	10,200	10,298	98	12,456	12,490	33
	New CT	-	-	-	-	-	-	-	-	-	59	99	40
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
NYO Sum		115,795	116,003	208	118,670	118,569	(102)	121,918	121,736	(183)	126,466	126,232	(234)
PJM	CC	17,950	16,345	(1,605)	21,890	20,245	(1,644)	28,772	27,699	(1,074)	41,889	41,252	(637)
	Coal	194,502	190,457	(4,045)	198,190	194,756	(3,435)	203,688	201,286	(2,402)	207,748	206,384	(1,364)
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	5,599	5,599	-	5,599	5,599	-	5,599	5,599	-	5,599	5,599	-
	Nuke	117,393	117,393	-	117,470	117,467	(3)	117,419	117,419	-	117,446	117,446	-
	Other	6,907	6,907	-	6,913	6,912	(0)	6,907	6,907	-	6,914	6,911	(3)
	Peaker	306	352	45	651	736	84	1,100	1,345	245	1,838	2,654	816
	PSH	4,663	4,659	(5)	4,645	4,639	(6)	4,701	4,717	16	4,528	4,549	20
	ST/G/O/D	7,512	8,031	519	11,026	11,998	972	15,112	16,849	1,737	21,283	23,453	2,171
	Wind	339	333	(7)	339	332	(7)	338	334	(4)	345	342	(3)
	New CT	-	-	-	-	-	-	-	-	-	942	-	(942)
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
PJM Sum		355,173	350,075	(5,098)	366,724	362,685	(4,038)	383,637	382,156	(1,482)	408,533	408,590	57
SCE&G	CC	1,935	2,180	245	2,617	2,987	370	3,749	4,081	331	5,263	5,466	202
	Coal	36,724	36,867	143	37,938	38,070	132	38,746	38,854	108	39,534	39,595	61
	Hydro	875	875	-	875	875	-	875	875	-	875	875	-
	Nuke	7,611	7,611	-	7,610	7,610	-	7,609	7,609	-	7,650	7,650	-
	Other	1,004	1,004	-	1,007	1,007	-	1,008	1,008	-	1,006	1,006	-

Table A-21: Generation by Type and Pool (GWh)

		2005			2007			2010			2014		
Capacity Pool	TYPE -	2005 Base	2005 Change	Delta (Change - Base)	2007 Base	2007 Change	Delta (Change - Base)	2010 Base	2010 Change	Delta (Change - Base)	2014 Base	2014 Change	Delta (Change - Base)
	Peaker	9	10	1	31	33	2	59	69	10	24	31	7
	PSH	948	941	(7)	886	884	(2)	803	793	(10)	504	520	16
	ST/G/O/D	6	9	3	28	29	1	40	44	4	59	64	4
	New CT	-	-	-	-	-	-	-	-	-	766	889	124
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
SCE&G Sum		49,113	49,498	386	50,991	51,495	504	52,890	53,333	443	55,681	56,095	414
SETRANS E	CC	18,168	19,452	1,284	23,209	25,276	2,067	36,790	38,971	2,181	55,618	56,530	912
	Coal	186,069	186,481	412	191,153	191,474	321	190,531	190,758	227	181,389	181,500	111
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	9,179	9,179	-	9,179	9,179	-	9,179	9,179	-	9,179	9,179	-
	Nuke	45,935	45,935	-	46,039	46,039	-	46,072	46,072	-	46,029	46,029	-
	Other	8,842	8,842	-	8,847	8,847	-	8,856	8,856	-	8,840	8,840	-
	Peaker	381	390	10	1,488	1,517	28	3,254	3,281	28	4,632	4,672	40
	PSH	315	312	(3)	298	288	(10)	272	273	1	145	144	(0)
	ST/G/O/D	4,560	4,658	98	4,815	4,957	142	5,853	5,925	72	6,427	6,491	64
	New CT	-	-	-	-	-	-	-	-	-	5,373	5,331	(42)
	New CC	-	-	-	-	-	-	-	-	-	3,045	3,038	(7)
SETRANS E Sum		273,448	275,249	1,801	285,029	287,577	2,548	300,806	303,315	2,510	320,675	321,753	1,077
SETRANS W	CC	31,610	30,898	(713)	39,824	39,064	(760)	50,547	49,502	(1,045)	64,096	63,520	(576)
	Coal	56,497	56,586	89	56,517	56,531	14	57,393	57,397	5	58,095	58,086	(9)
	Hydro	581	581	-	581	581	-	581	581	-	581	581	-
	Nuke	38,906	38,906	-	38,920	38,920	-	39,055	39,055	-	39,016	39,016	-
	Other	1,608	1,608	-	1,610	1,610	-	1,606	1,606	-	1,606	1,606	-
	Peaker	634	612	(22)	702	694	(9)	993	1,012	19	1,410	1,420	10
	ST/G/O/D	1,815	1,936	121	2,218	2,431	213	4,879	4,906	27	9,781	10,147	366
	New CT	-	-	-	-	-	-	-	-	-	-	-	-
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
SETRANS W Sum		131,651	131,126	(525)	140,372	139,830	(542)	155,054	154,059	(995)	174,586	174,376	(210)
SPP	CC	26,796	27,017	221	33,017	33,223	206	45,171	45,296	124	58,991	59,146	154
	Coal	146,368	146,403	35	143,750	143,858	109	142,381	142,456	76	138,289	138,337	48
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	11,041	11,041	-	11,041	11,041	-	11,041	11,041	-	11,041	11,041	-
	Nuke	9,358	9,358	-	9,337	9,337	-	9,381	9,381	-	9,337	9,337	-
	Other	11,249	11,249	-	11,252	11,252	-	11,245	11,245	-	11,254	11,254	-

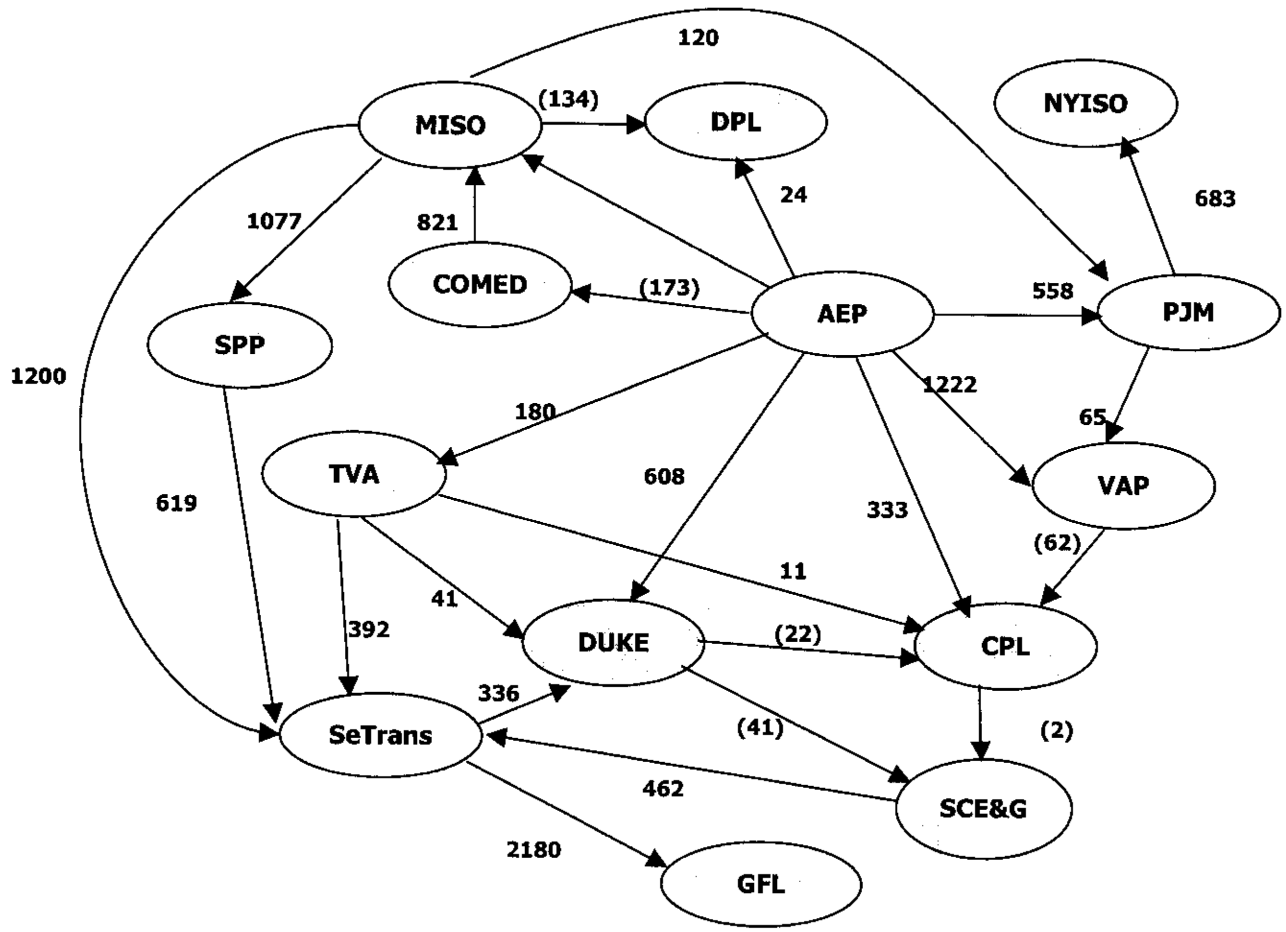
Table A-21: Generation by Type and Pool (GWh)

Capacity Pool	TYPE -	2005 Base	2005 Change	2005 Delta (Change - Base)	2007 Base	2007 Change	2007 Delta (Change - Base)	2010 Base	2010 Change	2010 Delta (Change - Base)	2014 Base	2014 Change	2014 Delta (Change - Base)
	Peaker	263	266	2	415	386	(29)	1,118	1,118	(0)	1,969	2,003	34
	ST/G/O/D	3,696	3,782	86	4,903	5,035	132	7,973	8,103	131	14,000	14,126	126
	New CT	-	-	-	-	-	-	-	-	-	329	320	(9)
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
SPP Sum		208,770	209,115	344	213,714	214,131	418	228,309	228,639	330	245,208	245,562	354
TVA	CC	6,435	6,570	134	8,275	8,436	162	14,514	14,735	222	23,475	23,643	168
	Coal	103,982	104,192	210	107,644	107,874	230	109,426	109,490	64	110,966	111,020	54
	Hydro	19,852	19,852	-	19,852	19,852	-	19,852	19,852	-	19,852	19,852	-
	Nuke	44,740	44,740	-	44,738	44,738	-	44,713	44,713	-	44,671	44,671	-
	Other	2,653	2,653	-	2,655	2,655	-	2,656	2,656	-	2,655	2,655	0
	Peaker	133	127	(6)	219	247	28	485	514	29	1,152	1,101	(52)
	PSH	2,377	2,383	6	2,536	2,529	(7)	2,428	2,435	6	2,306	2,556	250
	ST/G/O/D	-	-	-	-	-	-	-	-	-	-	-	-
	New CT	-	-	-	-	-	-	-	-	-	1,259	1,176	(83)
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
TVA Sum		180,173	180,517	343	185,918	186,332	413	194,074	194,395	321	206,337	206,675	338
VAP	CC	5,525	3,587	(1,938)	7,102	4,833	(2,268)	9,716	6,733	(2,983)	14,332	10,875	(3,458)
	Coal	41,062	39,488	(1,574)	42,071	40,657	(1,414)	43,592	42,757	(835)	44,834	44,313	(521)
	Hydro	1,192	1,192	-	1,192	1,192	-	1,192	1,192	-	1,192	1,192	-
	Nuke	26,364	26,364	-	26,249	26,249	-	26,316	26,316	-	26,249	26,249	-
	Other	2,189	2,142	(47)	2,330	2,309	(21)	2,344	2,334	(10)	2,367	2,358	(9)
	Peaker	718	695	(23)	940	982	42	1,721	1,605	(116)	2,103	1,943	(159)
	PSH	2,500	2,500	-	2,500	2,500	-	2,817	2,817	-	2,818	2,818	-
	ST/G/O/D	4,741	3,859	(882)	5,797	4,905	(892)	7,016	6,220	(795)	8,339	7,682	(657)
	New CT	-	-	-	-	-	-	393	-	(393)	1,952	1,503	(449)
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
VAP Sum		84,292	79,827	(4,465)	88,180	83,628	(4,553)	95,106	89,974	(5,132)	104,187	98,934	(5,253)

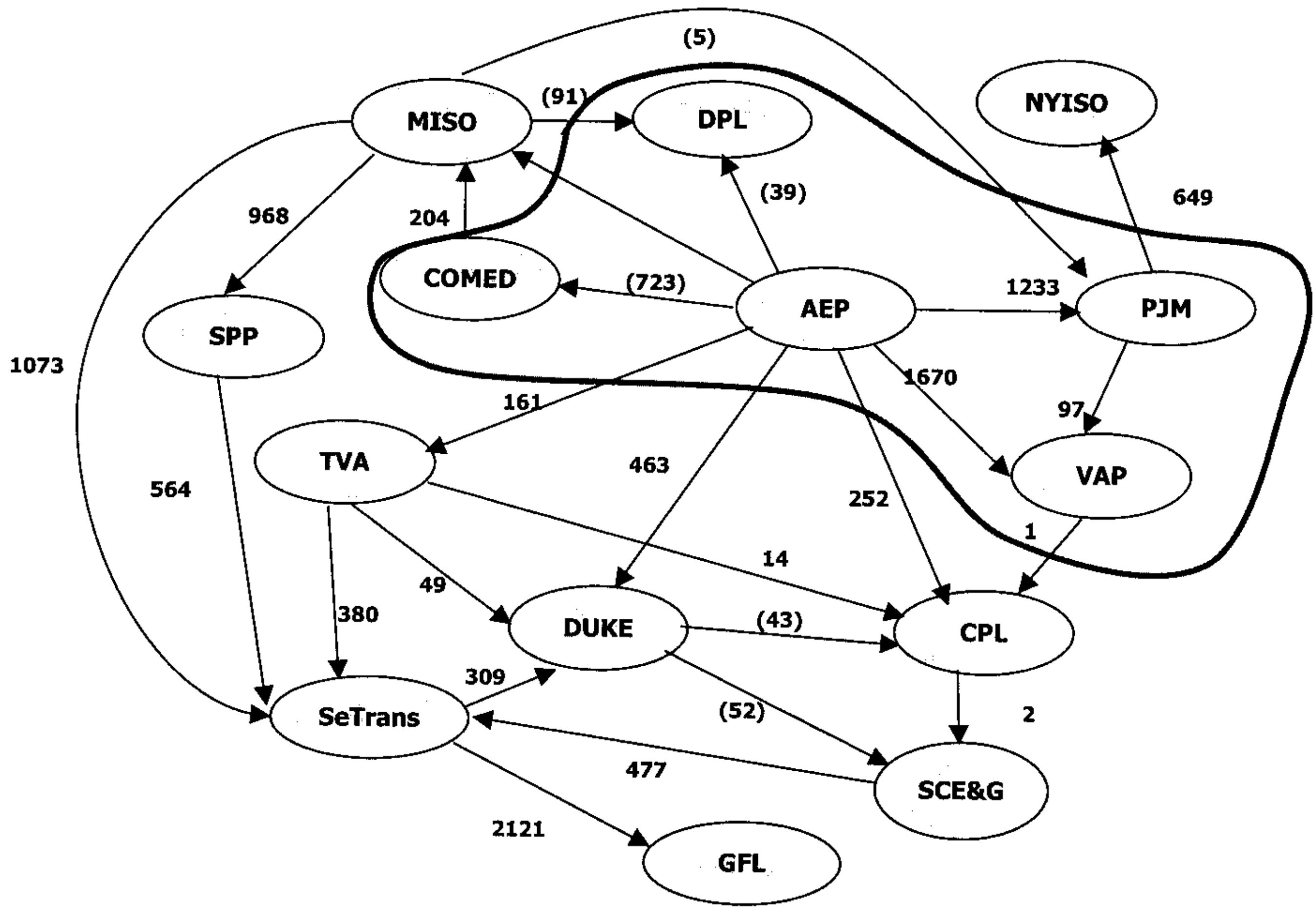
Table A-22: Average VAP Net Imports by Source (MW) 2005-2014, High Fuel Prices

Period	Imports/Transfers	2005 Base Case	2007 Base Case	2010 Base Case	2014 Base Case	2005 Change Case	2007 Change Case	2010 Change Case	2014 Change Case
Off-Peak	Average of VAP Net Imports	1,764	1,805	1,954	2,015	2,061	2,095	2,173	2,226
	Average Transfers from AEP	1,566	1,551	1,705	1,558	1,935	1,847	1,906	1,739
	Average Transfers from PJM	85	155	183	413	89	227	271	525
	Average Transfers from CPL	112	100	66	44	37	21	(3)	(38)
On-Peak	Average of VAP Net Imports	893	760	493	233	1,440	1,373	1,235	1,043
	Average Transfers from AEP	843	733	445	200	1,378	1,275	865	524
	Average Transfers from PJM	43	58	103	175	105	169	464	675
	Average Transfers from CPL	7	(31)	(55)	(142)	(43)	(70)	(95)	(156)
All-Hours	Average of VAP Net Imports	1,349	1,307	1,258	1,166	1,765	1,751	1,726	1,662
	Average Transfers from AEP	1,222	1,161	1,105	911	1,670	1,575	1,410	1,160
	Average Transfers from PJM	65	108	145	300	97	199	363	597
	Average Transfers from CPL	62	37	9	(45)	(1)	(22)	(47)	(94)

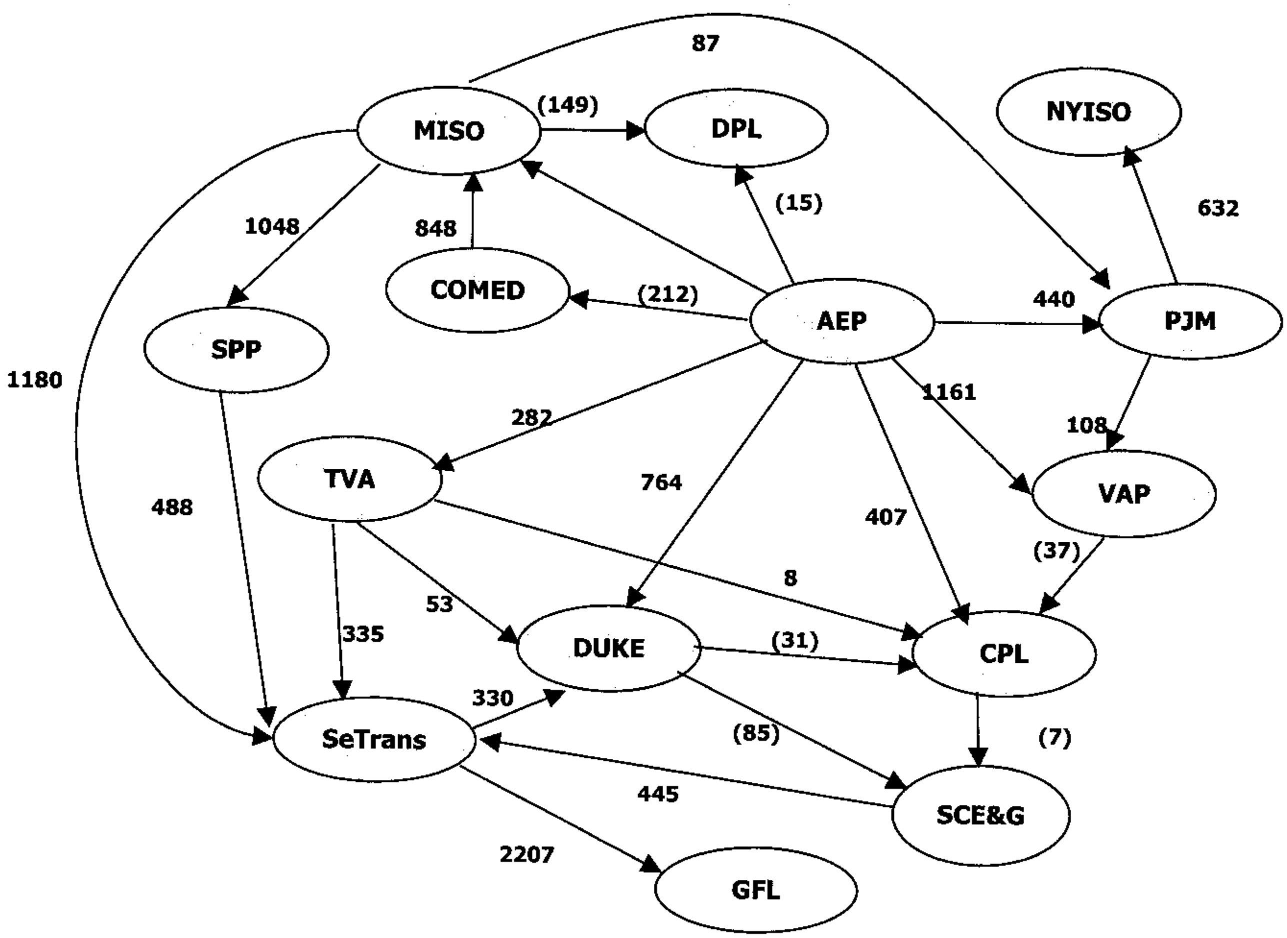
Pool to Pool All-Hour Average Transfers (MW)
5 High Fuel/Base



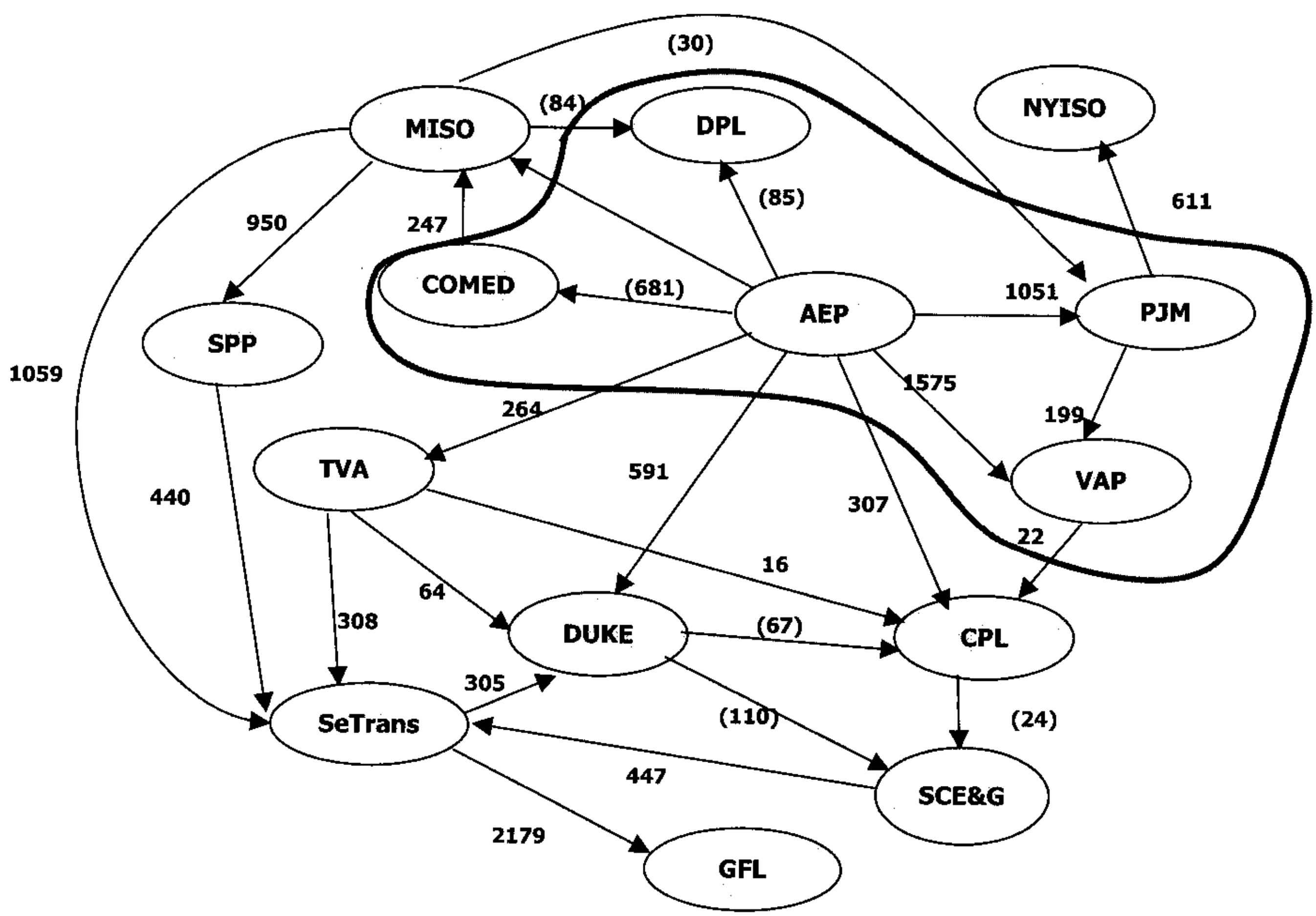
l to Pool All-Hour Average Transfers (MW)
₂₀05 High Fuel/Change



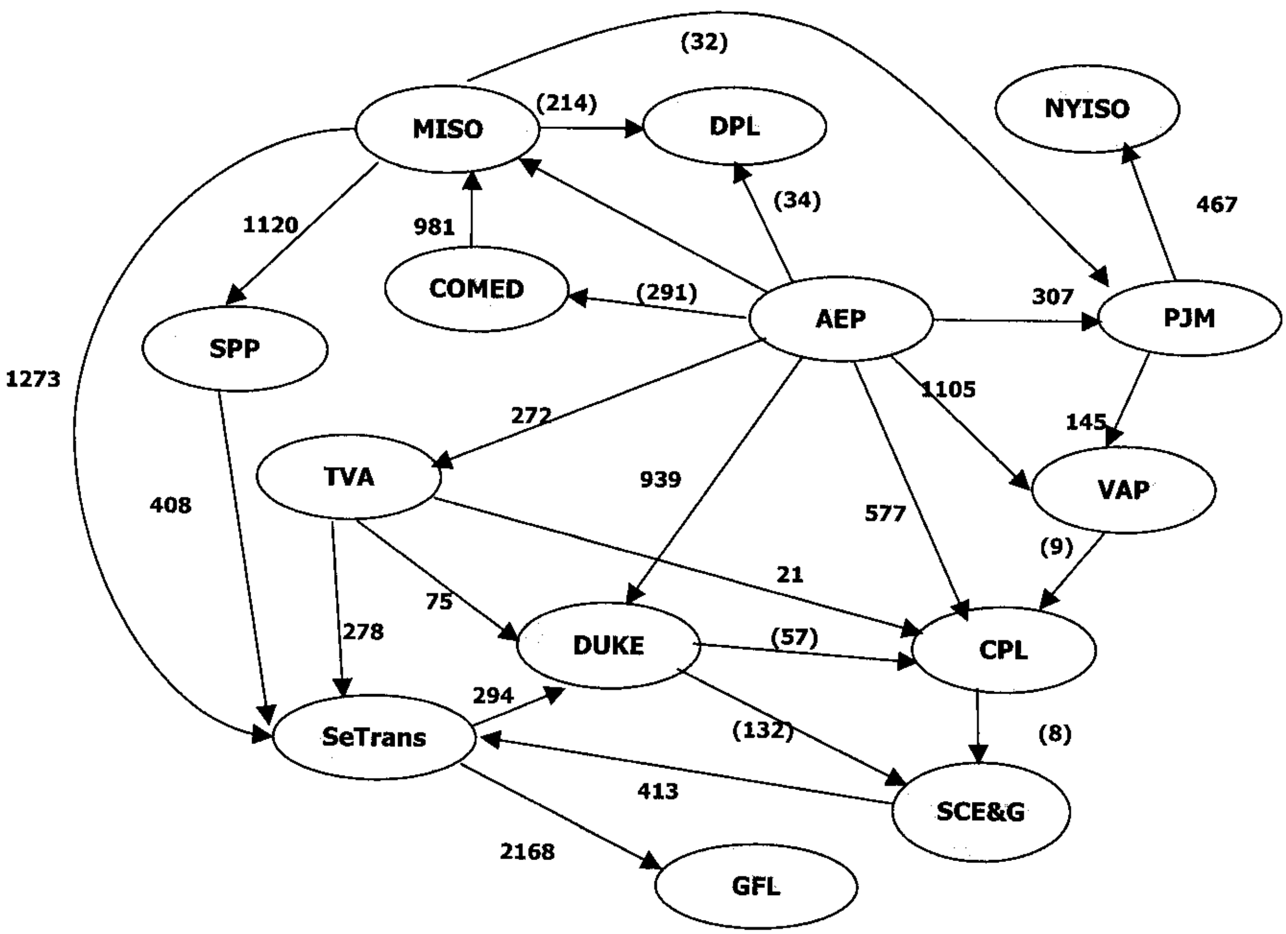
ɪl to Pool All-Hour Average Transfers (MW)
ᴞ07 High Fuel/Base



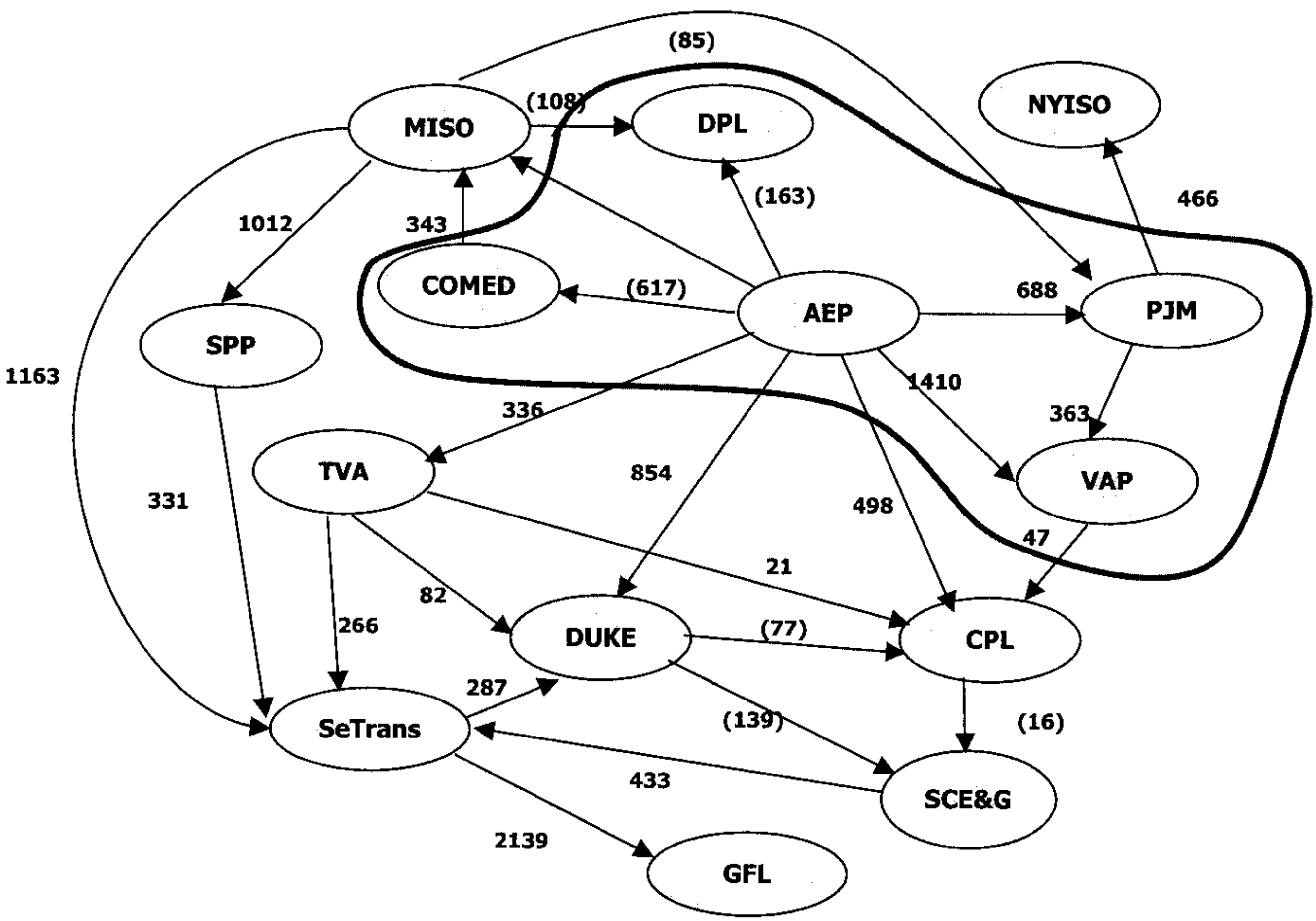
ɔl to Pool All-Hour Average Transfers (MW)
ƨ007 High Fuel/Change



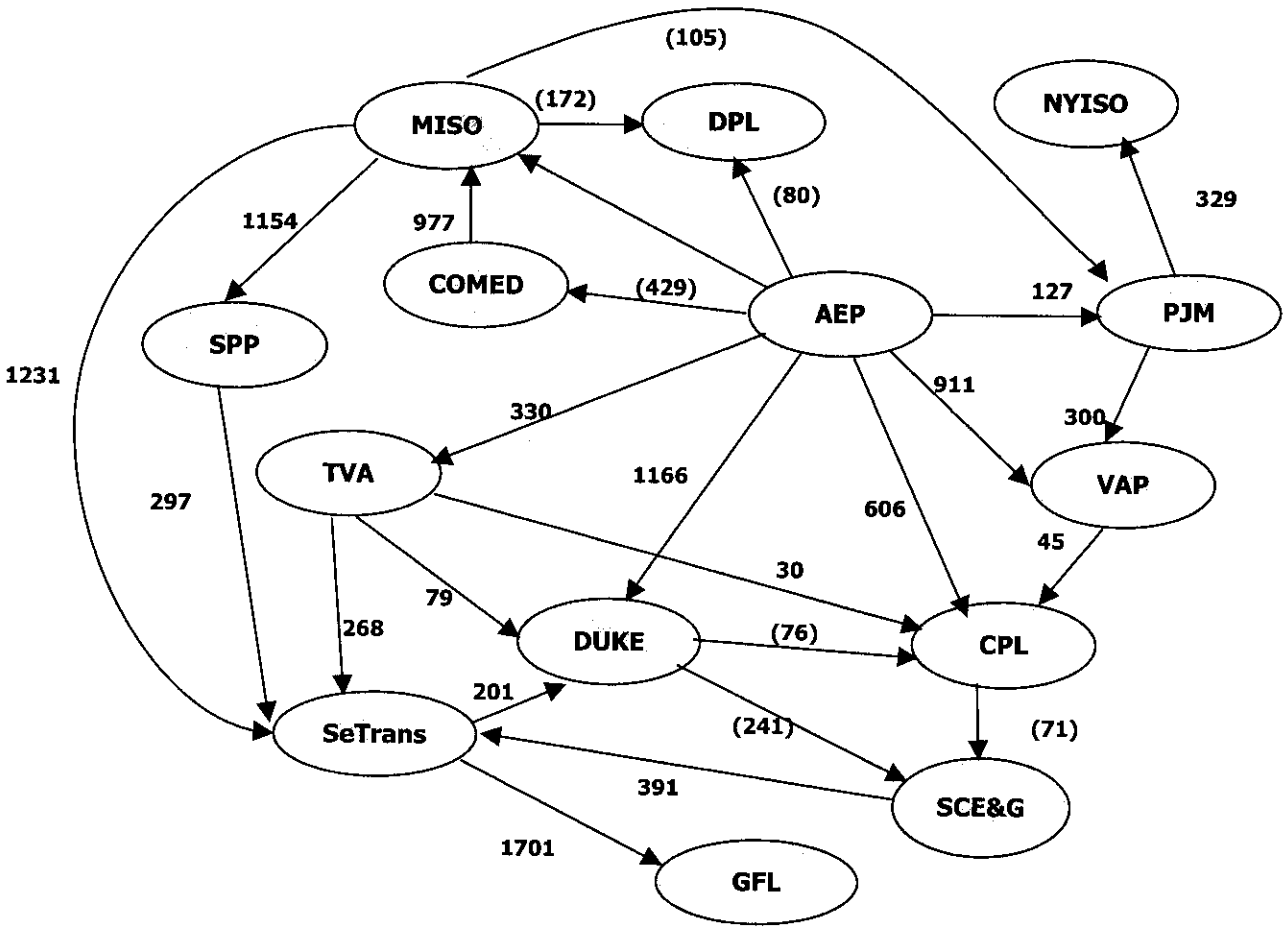
ı to Pool All-Hour Average Transfers (MW)
ɀ010 High Fuel/Base



ı to Pool All-Hour Average Transfers (MW)
ƨ010 High Fuel/Change



ɪl to Pool All-Hour Average Transfers (MW)
2014 High Fuel/Base



ɔl to Pool All-Hour Average Transfers (MW)
ـu14 High Fuel/Change

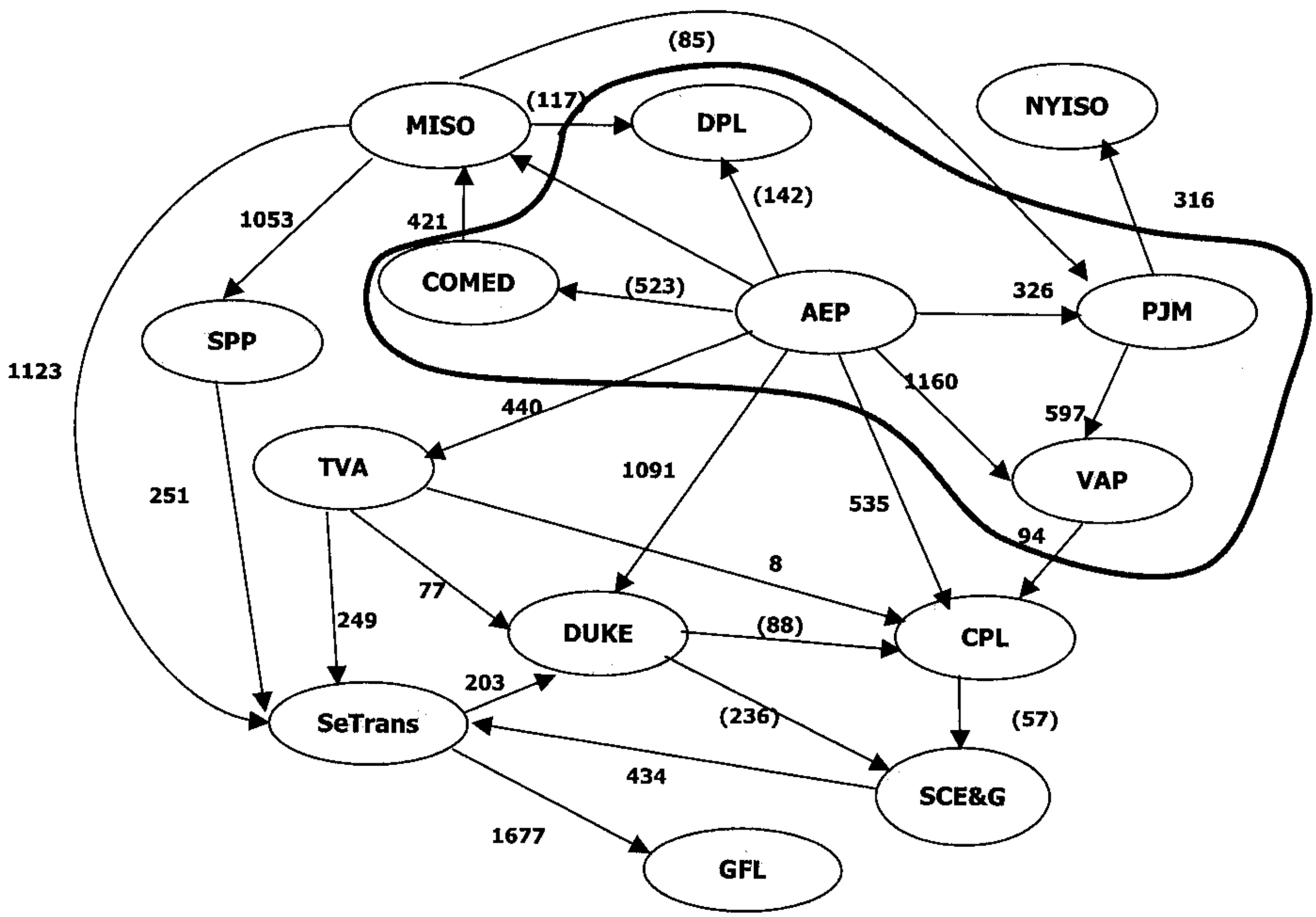


Table A-23: Generation by Type and Pool (GWh), High Fuel Prices

Capacity Pool	TYPE	2005 Base Case	2005 Change Case	2005 Delta (Change - Base)	2007 Base Case	2007 Change Case	2007 Delta (Change - Base)	2010 Base Case	2010 Change Case	2010 Delta (Change - Base)	2014 Base Case	2014 Change Case	2014 Delta (Change - Base)
Non-PJM	CC	193,665	196,743	3,078	229,789	232,917	3,128	298,980	301,730	2,750	387,043	388,281	1,238
	Coal	1,331,021	1,334,905	3,884	1,354,481	1,358,170	3,688	1,377,395	1,380,625	3,230	1,391,696	1,393,401	1,705
	Hydro	100,956	100,956	-	100,956	100,956	(0)	100,956	100,956	-	100,956	100,956	-
	New CC	-	-	-	-	-	-	6,432	6,446	14	23,299	23,334	35
	New CT	-	-	-	252	257	4	4,731	4,710	(21)	33,499	34,642	1,142
	Nuke	411,921	411,926	5	411,791	411,808	18	412,133	412,153	20	412,004	412,010	6
	Other	61,990	61,992	2	61,999	62,001	2	61,970	61,971	1	61,953	61,963	10
	Peaker	8,201	8,180	(21)	14,511	14,552	40	24,324	24,600	276	28,385	28,942	557
	PSH	17,069	17,094	25	16,771	16,853	82	15,421	15,426	5	13,841	13,807	(34)
	ST/G/O/D	100,103	100,771	668	111,532	112,421	889	125,567	126,277	710	153,581	154,648	1,067
Non-PJM Total		2,224,925	2,232,567	7,642	2,302,081	2,309,933	7,852	2,427,909	2,434,895	6,987	2,606,256	2,611,982	5,726
PJM (Expanded)	CC	22,164	19,224	(2,940)	29,113	26,026	(3,087)	40,086	38,412	(1,674)	62,621	61,564	(1,057)
	Coal	416,816	413,175	(3,641)	429,065	425,807	(3,258)	446,002	443,393	(2,609)	458,180	456,631	(1,549)
	Hydro	8,074	8,074	-	8,074	8,074	-	8,074	8,074	-	8,074	8,074	-
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
	New CT	-	-	-	-	-	-	481	15	(466)	3,670	1,796	(1,874)
	Nuke	239,971	239,975	4	239,971	239,971	1	239,946	239,941	(5)	239,858	239,857	(2)
	Other	9,372	9,340	(32)	9,514	9,506	(7)	9,522	9,519	(3)	9,554	9,546	(7)
	Peaker	1,127	1,044	(83)	1,888	1,831	(57)	3,285	3,233	(52)	4,709	5,018	308
	PSH	8,157	8,163	6	8,033	8,012	(21)	8,313	8,333	20	7,967	7,995	29
	ST/G/O/D	13,962	13,187	(775)	19,235	18,003	(1,232)	26,586	24,487	(2,099)	37,162	35,625	(1,537)
	Wind	337	329	(8)	336	330	(6)	337	333	(3)	343	340	(3)
PJM Total		719,981	712,512	(7,469)	745,229	737,561	(7,667)	782,633	775,741	(6,892)	832,139	826,447	(5,691)
Eastern Interconnection	CC	215,829	215,967	138	258,901	258,943	42	339,066	340,142	1,076	449,664	449,845	181
	Coal	1,747,836	1,748,080	243	1,783,546	1,783,976	430	1,823,398	1,824,018	621	1,849,876	1,850,032	157
	Hydro	109,030	109,030	-	109,030	109,030	(0)	109,030	109,030	-	109,030	109,030	-
	New CC	-	-	-	-	-	-	6,432	6,446	14	23,299	23,334	35
	New CT	-	-	-	252	257	4	5,212	4,725	(487)	37,169	36,438	(731)
	Nuke	651,892	651,901	9	651,761	651,779	18	652,078	652,094	15	651,862	651,866	4
	Other	71,362	71,333	(30)	71,513	71,508	(5)	71,492	71,490	(2)	71,507	71,509	2
	Peaker	9,328	9,224	(104)	16,400	16,383	(17)	27,609	27,833	224	33,094	33,959	865
	PSH	25,226	25,257	31	24,803	24,865	61	23,734	23,759	25	21,807	21,802	(5)
	ST/G/O/D	114,065	113,958	(107)	130,767	130,424	(343)	152,154	150,765	(1,389)	190,743	190,273	(470)
	Wind	337	329	(8)	336	330	(6)	337	333	(3)	343	340	(3)
EI Total		2,944,906	2,945,079	173	3,047,310	3,047,495	185	3,210,541	3,210,636	95	3,438,394	3,438,429	35

Table A-24: Generation by Type and Pool (GWh), High Fuel

		2005			2007			2010			2014		
Capacity Pool	TYPE	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)
AEP	CC	167	514	347	264	789	526	1,380	2,673	1,293	4,793	7,091	2,298
	Coal	132,267	133,331	1,065	137,298	137,869	571	142,526	141,915	(611)	146,128	145,833	(295)
	Hydro	1,284	1,284	-	1,284	1,284	-	1,284	1,284	-	1,284	1,284	-
	Nuke	15,885	15,885	-	15,888	15,888	-	15,913	15,913	-	15,885	15,885	-
	Other	213	213	(0)	214	213	(0)	214	214	-	214	213	(0)
	Peaker	-	-	-	1	3	2	19	21	2	31	90	59
	PSH	786	784	(2)	752	750	(1)	674	676	2	528	525	(3)
	ST/G/O/D	0	0	0	1	1	0	1	3	2	2	4	2
	New CT	-	-	-	-	-	-	-	-	-	-	-	-
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
AEP Sum		150,602	152,012	1,410	155,700	156,797	1,097	162,010	162,698	688	168,864	170,925	2,061
COMED	CC	1,201	674	(528)	1,943	1,209	(734)	2,758	2,134	(624)	3,767	3,363	(405)
	Coal	28,526	29,144	618	30,360	31,111	751	33,599	34,408	809	35,600	36,041	441
	Nuke	80,328	80,332	4	80,363	80,364	1	80,297	80,292	(5)	80,278	80,277	(2)
	Peaker	163	86	(77)	301	168	(133)	470	356	(114)	919	421	(498)
	ST/G/O/D	884	292	(592)	1,564	539	(1,026)	3,610	897	(2,713)	6,677	3,586	(3,090)
	New CT	-	-	-	-	-	-	90	15	(74)	726	248	(477)
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
COMED Sum		111,103	110,528	(575)	114,532	113,391	(1,141)	120,824	118,103	(2,721)	127,967	123,937	(4,030)
CPL	CC	1,236	1,737	501	1,841	2,337	496	2,847	3,149	302	4,024	4,139	115
	Coal	35,577	35,676	99	37,176	37,301	125	38,369	38,471	102	39,960	40,021	60
	Hydro	949	949	-	949	949	-	949	949	-	949	949	-
	Nuke	24,491	24,491	-	24,494	24,494	-	24,519	24,519	-	24,507	24,507	-
	Other	2,512	2,512	-	2,504	2,504	-	2,509	2,509	(1)	2,509	2,509	0
	Peaker	299	310	11	573	630	57	1,048	1,162	114	1,174	1,290	117
	New CT	-	-	-	-	-	-	477	400	(77)	2,853	3,196	344
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
CPL Sum		65,064	65,675	610	67,537	68,215	678	70,719	71,160	441	75,976	76,611	636
DP&L	Coal	18,137	18,305	168	19,062	19,106	44	20,311	20,512	201	21,373	21,469	96
	Other	45	45	-	45	45	-	45	45	-	45	45	-
	Peaker	-	-	-	11	1	(10)	19	23	4	77	40	(37)
	New CT	-	-	-	-	-	-	-	-	-	-	-	-
DP&L Sum		18,182	18,350	168	19,118	19,152	34	20,375	20,581	206	21,495	21,554	59

Table A-24: Generation by Type and Pool (GWh), High Fuel

		2005			2007			2010			2014		
Capacity Pool	TYPE	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)
DUKE	CC	776	1,033	257	1,242	1,513	271	1,855	1,957	102	2,702	2,804	102
	Coal	51,256	51,411	154	52,870	53,002	132	54,112	54,180	68	55,566	55,584	19
	Hydro	4,265	4,265	-	4,265	4,265	-	4,265	4,265	-	4,265	4,265	-
	Nuke	53,021	53,021	-	52,958	52,958	-	53,031	53,031	-	53,054	53,054	-
	Other	56	56	-	56	56	-	56	56	-	57	57	0
	Peaker	409	429	20	677	718	41	1,390	1,444	54	2,625	2,851	226
	PSH	3,791	3,794	3	3,618	3,680	63	3,322	3,332	9	2,558	2,509	(49)
	ST/G/O/D	3	4	1	2	2	0	7	8	1	4	10	6
	New CT	-	-	-	206	210	4	1,442	1,475	33	3,447	3,696	249
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
DUKE Sum		113,577	114,012	436	115,894	116,404	510	119,483	119,749	266	124,277	124,830	553
GFL	CC	61,644	61,806	162	66,268	66,372	105	71,415	71,429	14	78,343	78,372	29
	Coal	55,811	55,896	85	56,289	56,373	84	56,545	56,617	71	57,113	57,118	5
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	214	214	-	214	214	-	214	214	-	214	214	-
	Nuke	29,964	29,964	-	29,889	29,897	9	29,929	29,929	-	29,886	29,886	-
	Other	3,147	3,147	-	3,148	3,150	2	3,147	3,147	-	3,148	3,148	-
	Peaker	1,833	1,832	(1)	4,726	4,690	(36)	4,045	4,074	29	3,044	3,063	19
	ST/G/O/D	38,064	38,318	254	41,665	41,743	78	44,083	44,196	113	48,622	48,661	40
	New CT	-	-	-	-	-	-	2,691	2,713	21	7,040	7,138	98
	New CC	-	-	-	-	-	-	6,432	6,446	14	20,269	20,288	19
GFL Sum		190,678	191,179	501	202,199	202,441	241	218,502	218,765	263	247,679	247,889	209
MISO E	CC	3,019	3,220	201	4,911	5,077	166	9,902	10,295	393	18,966	19,234	268
	Coal	321,465	323,678	2,213	329,611	331,721	2,110	343,140	345,250	2,110	354,919	356,109	1,190
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	2,658	2,658	-	2,658	2,658	-	2,658	2,658	-	2,658	2,658	-
	Nuke	29,335	29,335	-	29,324	29,324	-	29,279	29,279	-	29,334	29,334	-
	Other	2,456	2,456	-	2,451	2,451	-	2,454	2,454	-	2,455	2,456	1
	Peaker	357	325	(32)	706	674	(32)	1,156	1,176	20	2,185	2,060	(125)
	PSH	5,498	5,501	3	5,207	5,200	(7)	4,951	4,942	(9)	4,047	4,036	(11)
	ST/G/O/D	794	736	(58)	1,498	1,463	(35)	3,405	3,508	103	7,977	7,980	3
	New CT	-	-	-	-	-	-	-	-	-	730	753	22
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
MISO E Sum		365,581	367,908	2,327	376,367	378,568	2,202	396,946	399,562	2,616	423,272	424,620	1,347

Table A-24: Generation by Type and Pool (GWh), High Fuel

		2005			2007			2010			2014		
Capacity Pool	TYPE	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)
MISO W	CC	5,872	6,061	189	8,085	8,221	136	12,442	12,621	179	17,806	17,982	176
	Coal	284,524	285,350	826	289,244	289,968	724	293,767	294,485	718	302,179	302,516	337
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	15,458	15,458	-	15,458	15,458	-	15,458	15,458	-	15,458	15,458	-
	Nuke	56,836	56,841	5	56,881	56,890	9	56,844	56,864	20	56,813	56,820	7
	Other	10,571	10,573	2	10,575	10,575	1	10,542	10,543	2	10,548	10,557	9
	Peaker	3,405	3,412	7	4,673	4,687	14	10,419	10,429	10	9,713	9,881	168
	PSH	673	674	1	692	690	(2)	681	683	2	688	680	(8)
	ST/G/O/D	252	261	9	430	444	14	1,280	1,277	(2)	1,652	1,684	32
	New CT	-	-	-	-	-	-	-	-	-	11,492	11,776	284
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
MISO W Sum		377,590	378,630	1,039	386,038	386,933	896	401,433	402,361	928	426,348	427,353	1,005
ISO-NE	CC	24,838	24,878	40	26,500	26,481	(20)	33,071	33,084	13	37,666	37,316	(350)
	Coal	21,593	21,568	(25)	21,866	21,841	(25)	22,059	22,059	0	22,130	22,131	1
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	7,261	7,261	-	7,261	7,261	-	7,261	7,261	-	7,261	7,261	-
	Nuke	33,909	33,909	-	33,884	33,884	-	33,963	33,963	-	33,989	33,989	-
	Other	14,314	14,314	-	14,322	14,322	-	14,317	14,317	-	14,311	14,311	-
	Peaker	-	-	-	-	-	-	-	-	-	-	-	-
	PSH	1,047	1,046	(1)	1,061	1,062	0	853	855	1	790	806	16
	ST/G/O/D	17,048	17,025	(23)	19,124	19,188	64	18,469	18,457	(12)	20,988	21,382	395
	New CT	-	-	-	-	-	-	-	-	-	-	-	-
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
ISO-NE Sum		120,009	120,000	(9)	124,018	124,039	20	129,993	129,995	2	137,134	137,196	62
NYC	CC	6,186	6,270	84	6,384	6,491	107	6,792	6,882	90	7,319	7,365	45
	Other	179	179	-	179	179	-	179	179	-	179	179	-
	Peaker	330	330	1	198	202	4	247	246	(1)	441	452	11
	ST/G/O/D	18,355	18,335	(19)	19,000	19,184	184	20,131	20,276	145	21,473	21,684	211
	New CT	-	-	-	28	27	(1)	58	58	1	158	160	3
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
NYC Sum		25,050	25,115	65	25,790	26,083	293	27,407	27,642	234	29,569	29,840	270
NYL	CC	1,504	1,506	3	1,546	1,552	6	1,609	1,610	1	1,686	1,691	5
	Other	992	992	-	991	991	-	991	991	-	988	988	-
	Peaker	144	140	(3)	124	122	(2)	203	202	(1)	273	274	1

Table A-24: Generation by Type and Pool (GWh), High Fuel

		2005			2007			2010			2014		
Capacity Pool	TYPE	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)
	ST/G/O/D	8,214	8,250	36	8,787	8,804	17	9,639	9,620	(19)	10,923	10,929	6
	New CT	-	-	-	18	20	2	63	64	1	180	185	5
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
NYL Sum		10,853	10,889	36	11,466	11,489	23	12,505	12,487	(18)	14,051	14,068	17
NYO	CC	10,272	10,569	297	11,149	11,259	110	13,115	13,085	(29)	15,289	15,191	(98)
	Coal	26,608	26,284	(324)	27,075	26,803	(271)	27,834	27,610	(224)	28,310	28,171	(139)
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	28,623	28,623	-	28,623	28,623	(0)	28,623	28,623	-	28,623	28,623	-
	Nuke	37,813	37,814	1	37,716	37,717	1	37,737	37,737	0	37,719	37,718	(2)
	Other	2,408	2,408	0	2,403	2,403	-	2,402	2,402	-	2,398	2,398	-
	Peaker	1	1	(0)	0	0	(0)	1	1	0	4	4	0
	PSH	2,068	2,080	11	2,063	2,069	6	1,935	1,932	(3)	1,778	1,782	3
	ST/G/O/D	7,505	7,896	391	9,395	9,586	190	10,193	10,368	175	12,352	12,424	72
	New CT	-	-	-	-	-	-	-	-	-	63	107	45
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
NYO Sum		115,298	115,674	376	118,424	118,461	36	121,840	121,759	(81)	126,536	126,417	(119)
PJM	CC	15,943	14,572	(1,371)	20,249	19,233	(1,016)	26,850	26,772	(78)	40,187	40,290	103
	Coal	196,141	192,132	(4,010)	199,585	196,220	(3,365)	205,507	203,160	(2,346)	209,701	208,341	(1,360)
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	5,599	5,599	-	5,599	5,599	-	5,599	5,599	-	5,599	5,599	-
	Nuke	117,393	117,393	-	117,470	117,470	-	117,419	117,419	-	117,446	117,446	-
	Other	6,907	6,907	-	6,913	6,913	-	6,907	6,907	-	6,914	6,911	(3)
	Peaker	312	343	30	662	706	44	1,158	1,320	162	1,800	2,606	806
	PSH	4,871	4,879	8	4,781	4,762	(19)	4,822	4,840	18	4,620	4,651	31
	ST/G/O/D	8,289	8,831	541	11,825	12,433	608	15,976	17,261	1,285	22,142	24,199	2,057
	Wind	337	329	(8)	336	330	(6)	337	333	(3)	343	340	(3)
	New CT	-	-	-	-	-	-	-	-	-	1,023	-	(1,023)
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
PJM Sum		355,794	350,984	(4,810)	367,422	363,668	(3,754)	384,575	383,613	(963)	409,775	410,384	609
SCE&G	CC	1,827	1,961	134	2,495	2,812	317	3,542	3,810	267	5,346	5,512	166
	Coal	36,943	37,090	147	38,105	38,261	156	38,978	39,063	85	39,881	39,912	31
	Hydro	875	875	-	875	875	-	875	875	-	875	875	-
	Nuke	7,611	7,611	-	7,610	7,610	-	7,609	7,609	-	7,650	7,650	-
	Other	1,004	1,004	-	1,007	1,007	-	1,008	1,008	-	1,006	1,006	-

Table A-24: Generation by Type and Pool (GWh), High Fuel

Capacity Pool	TYPE	2005 Base Case	2005 Change Case	2005 Delta (Change - Base)	2007 Base Case	2007 Change Case	2007 Delta (Change - Base)	2010 Base Case	2010 Change Case	2010 Delta (Change - Base)	2014 Base Case	2014 Change Case	2014 Delta (Change - Base)
	Peaker	7	7	(0)	24	28	5	64	72	9	27	32	5
	PSH	964	978	14	901	911	11	849	853	4	627	616	(11)
	ST/G/O/D	8	9	1	24	28	5	49	54	5	50	64	15
	New CT	-	-	-	-	-	-	-	-	-	1,049	1,080	31
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
SCE&G Sum		49,240	49,536	296	51,040	51,533	493	52,976	53,346	370	56,511	56,748	237
SETRANS E	CC	16,530	17,638	1,108	22,388	24,036	1,648	35,867	37,503	1,636	54,571	55,511	940
	Coal	188,144	188,573	429	192,465	192,779	314	191,518	191,754	236	182,305	182,385	80
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	9,179	9,179	-	9,179	9,179	-	9,179	9,179	-	9,179	9,179	-
	Nuke	45,935	45,935	-	46,039	46,039	-	46,072	46,072	-	46,029	46,029	-
	Other	8,842	8,842	-	8,847	8,847	-	8,856	8,856	-	8,839	8,839	(1)
	Peaker	428	416	(12)	1,436	1,444	8	3,246	3,273	27	4,785	4,859	74
	PSH	433	423	(10)	355	369	14	294	290	(4)	163	163	-
	ST/G/O/D	4,592	4,662	70	4,843	4,930	87	6,086	5,992	(94)	6,628	6,699	71
	New CT	-	-	-	-	-	-	-	-	-	5,110	5,144	34
	New CC	-	-	-	-	-	-	-	-	-	3,030	3,045	16
SETRANS E Sum		274,083	275,668	1,584	285,552	287,623	2,071	301,118	302,918	1,800	320,639	321,854	1,215
SETRANS W	CC	29,993	29,697	(295)	38,525	37,871	(654)	49,871	49,219	(651)	63,661	63,267	(394)
	Coal	56,062	56,120	58	56,110	56,171	61	57,136	57,111	(25)	57,927	57,928	1
	Hydro	581	581	-	581	581	-	581	581	-	581	581	-
	Nuke	38,906	38,906	-	38,920	38,920	-	39,055	39,055	-	39,016	39,016	-
	Other	1,608	1,608	-	1,610	1,610	-	1,606	1,606	-	1,606	1,606	-
	Peaker	656	644	(12)	775	762	(13)	985	988	3	1,392	1,405	13
	ST/G/O/D	1,829	1,695	(135)	2,155	2,269	115	4,609	4,814	205	9,352	9,390	38
	New CT	-	-	-	-	-	-	-	-	-	-	-	-
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
SETRANS W Sum		129,635	129,251	(384)	138,676	138,184	(491)	153,841	153,373	(468)	173,535	173,193	(342)
SPP	CC	25,178	25,437	259	31,616	31,777	160	43,954	44,069	114	58,007	58,212	205
	Coal	146,482	146,559	78	143,904	144,043	139	142,535	142,614	79	138,426	138,480	54
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	11,041	11,041	-	11,041	11,041	-	11,041	11,041	-	11,041	11,041	-
	Nuke	9,358	9,358	-	9,337	9,337	-	9,381	9,381	-	9,337	9,337	-
	Other	11,249	11,249	-	11,252	11,252	-	11,245	11,245	-	11,254	11,254	-

Table A-24: Generation by Type and Pool (GWh), High Fuel

Capacity Pool	TYPE	2005 Base Case	2005 Change Case	2005 Delta (Change - Base)	2007 Base Case	2007 Change Case	2007 Delta (Change - Base)	2010 Base Case	2010 Change Case	2010 Delta (Change - Base)	2014 Base Case	2014 Change Case	2014 Delta (Change - Base)
	Peaker	206	202	(4)	370	343	(27)	1,033	1,015	(18)	1,787	1,823	36
	ST/G/O/D	3,439	3,579	140	4,608	4,779	170	7,615	7,706	91	13,560	13,739	179
	New CT	-	-	-	-	-	-	-	-	-	288	296	8
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
SPP Sum		206,952	207,425	473	212,128	212,571	443	226,804	227,070	266	243,699	244,181	482
TVA	CC	4,791	4,930	139	6,837	7,116	279	12,697	13,018	321	21,657	21,686	29
	Coal	106,556	106,700	145	109,766	109,905	140	111,401	111,411	9	112,979	113,046	67
	Hydro	19,852	19,852	-	19,852	19,852	-	19,852	19,852	-	19,852	19,852	-
	Nuke	44,740	44,740	-	44,738	44,738	-	44,713	44,713	-	44,671	44,671	-
	Other	2,653	2,653	-	2,655	2,655	-	2,656	2,656	-	2,655	2,655	0
	Peaker	126	131	5	231	252	21	487	518	31	936	949	13
	PSH	2,596	2,599	3	2,873	2,870	(3)	2,535	2,540	4	3,190	3,215	25
	ST/G/O/D	-	-	-	-	-	-	-	-	-	-	-	-
	New CT	-	-	-	-	-	-	-	-	-	1,090	1,110	20
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
TVA Sum		181,314	181,607	292	186,952	187,389	437	194,342	194,708	366	207,030	207,183	153
VAP	CC	4,853	3,464	(1,388)	6,657	4,794	(1,862)	9,098	6,833	(2,265)	13,874	10,820	(3,054)
	Coal	41,745	40,263	(1,482)	42,761	41,501	(1,259)	44,060	43,397	(662)	45,377	44,946	(431)
	Hydro	1,192	1,192	-	1,192	1,192	-	1,192	1,192	-	1,192	1,192	-
	Nuke	26,364	26,364	-	26,249	26,249	-	26,316	26,316	-	26,249	26,249	-
	Other	2,206	2,175	(32)	2,342	2,335	(7)	2,356	2,353	(3)	2,381	2,377	(4)
	Peaker	652	616	(36)	914	954	40	1,620	1,513	(107)	1,882	1,861	(21)
	PSH	2,500	2,500	-	2,500	2,500	-	2,817	2,817	-	2,818	2,818	-
	ST/G/O/D	4,788	4,064	(724)	5,844	5,030	(815)	6,999	6,326	(673)	8,342	7,837	(506)
	New CT	-	-	-	-	-	-	392	-	(392)	1,922	1,548	(374)
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
VAP Sum		84,300	80,638	(3,663)	88,458	84,555	(3,903)	94,849	90,747	(4,102)	104,037	99,647	(4,390)

Table A-25: Generation Cost ($k), High Fuel

Capacity Pool	2005 Base Case	2005 Change Case	2005 Delta (Change - Base)	2007 Base Case	2007 Change Case	2007 Delta (Change - Base)	2010 Base Case	2010 Change Case	2010 Delta (Change - Base)	2014 Base Case	2014 Change Case	2014 Delta (Change - Base)
AEP	2,152,216	2,201,423	49,207	2,174,579	2,215,008	40,430	2,351,521	2,403,291	51,770	2,619,628	2,718,016	98,388
COED	1,108,962	1,053,096	(55,866)	1,165,885	1,084,256	(81,629)	1,341,785	1,196,294	(145,492)	1,608,930	1,415,169	(193,761)
CPL	971,802	999,776	27,974	1,013,408	1,040,625	27,217	1,151,828	1,170,810	18,982	1,398,797	1,432,658	33,861
DP&L	349,812	353,424	3,611	342,903	343,497	594	381,822	386,922	5,100	419,636	419,626	(10)
DUKE	1,148,830	1,165,325	16,495	1,204,323	1,220,565	16,242	1,380,280	1,390,844	10,564	1,651,434	1,684,779	33,345
GFL	5,515,566	5,533,680	18,114	5,909,656	5,915,765	6,109	6,481,555	6,491,597	10,042	7,642,129	7,652,451	10,322
MISO E	5,643,742	5,685,392	41,650	5,709,443	5,749,788	40,345	6,376,537	6,432,344	55,806	7,363,701	7,390,981	27,280
MISO W	4,366,728	4,389,203	22,475	4,536,743	4,554,301	17,557	5,104,385	5,121,042	16,657	5,982,797	6,020,467	37,669
ISO-NE	2,808,023	2,808,515	493	2,885,796	2,885,707	(89)	3,126,949	3,127,074	125	3,455,234	3,455,988	754
NYC	1,036,892	1,040,310	3,418	1,015,608	1,026,537	10,929	1,074,106	1,082,635	8,529	1,165,409	1,175,844	10,435
NYL	468,178	470,467	2,289	472,529	473,677	1,149	517,806	516,858	(949)	593,292	594,319	1,026
NYO	1,769,810	1,792,930	23,121	1,823,211	1,825,313	2,102	1,981,478	1,979,805	(1,673)	2,202,679	2,198,882	(3,797)
PJM	5,224,665	5,124,655	(100,010)	5,432,629	5,365,272	(67,358)	6,116,894	6,145,587	28,694	7,190,830	7,254,348	63,519
SCE&G	844,834	853,855	9,021	865,596	882,677	17,080	939,723	953,100	13,377	1,116,618	1,126,218	9,600
SETRANS E	4,613,851	4,672,872	59,021	4,871,900	4,949,744	77,844	5,520,836	5,583,171	62,335	6,596,703	6,640,607	43,904
SETRANS W	2,431,892	2,410,698	(21,194)	2,720,684	2,697,497	(23,186)	3,226,171	3,211,210	(14,962)	3,961,933	3,950,995	(10,937)
SPP	3,148,178	3,165,538	17,361	3,342,461	3,358,038	15,577	3,894,867	3,903,052	8,185	4,665,475	4,683,400	17,925
TVA	2,321,835	2,330,848	9,013	2,386,493	2,400,950	14,457	2,694,341	2,707,600	13,259	3,166,439	3,171,888	5,449
VAP	1,419,034	1,283,605	(135,429)	1,528,822	1,382,388	(146,434)	1,765,262	1,591,656	(173,606)	2,174,809	1,984,186	(190,623)
Total	47,344,848	47,335,611	(9,237)	49,402,670	49,371,607	(31,063)	55,428,146	55,394,890	(33,256)	64,976,472	64,970,820	(5,652)

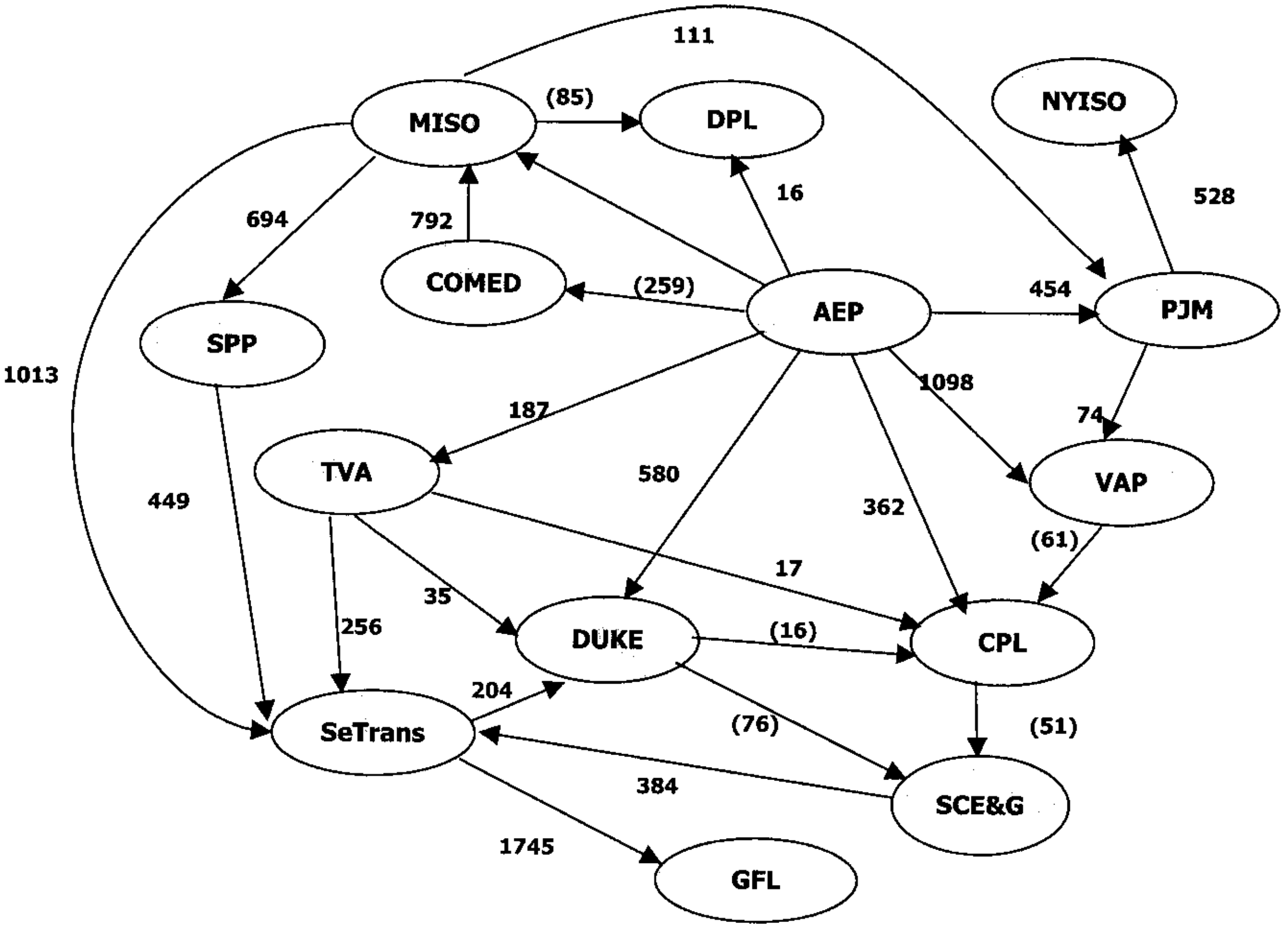
Table A-26: Average Spot Prices ($/MWh), High Fuel

	2005			2007			2010			2014		
Capacity Pool	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)
AEP	22.51	23.16	0.65	23.21	23.97	0.76	26.71	27.37	0.66	31.99	32.17	0.18
COED	21.88	21.65	(0.23)	22.61	22.38	(0.23)	25.90	25.80	(0.10)	30.96	30.75	(0.20)
CPL	30.67	31.09	0.42	32.02	32.73	0.71	35.88	37.08	1.20	41.83	42.35	0.52
DP&L	22.31	22.63	0.32	22.63	23.28	0.65	25.82	26.65	0.84	30.83	31.27	0.44
DUKE	30.71	31.16	0.45	32.08	32.74	0.66	35.92	36.71	0.80	42.02	42.43	0.40
GFL	39.66	39.73	0.07	46.75	46.77	0.02	42.64	42.67	0.03	44.79	44.81	0.02
MISO E	23.45	23.67	0.22	24.05	24.32	0.27	27.46	27.74	0.28	32.29	32.52	0.23
MISO W	25.64	25.80	0.16	27.00	27.13	0.13	33.05	33.12	0.08	35.89	36.01	0.13
ISO-NE	38.47	38.45	(0.02)	37.96	37.96	0.00	38.50	38.48	(0.02)	39.86	39.94	0.08
NYC	40.00	39.97	(0.04)	38.54	38.65	0.10	39.65	39.69	0.04	41.92	42.01	0.09
NYL	42.88	42.82	(0.06)	41.72	41.70	(0.02)	43.25	44.08	0.84	45.06	45.04	(0.02)
NYO	34.16	33.82	(0.34)	33.45	33.27	(0.17)	34.66	34.49	(0.17)	36.25	36.15	(0.10)
PJM	29.89	29.51	(0.38)	30.15	29.95	(0.21)	32.99	33.26	0.27	36.69	37.57	0.88
SCE&G	30.01	30.39	0.39	31.11	31.74	0.63	34.66	35.27	0.61	39.90	40.28	0.38
SETRANS E	32.25	32.40	0.15	33.23	33.40	0.17	36.05	36.31	0.26	40.64	40.70	0.06
SETRANS W	33.16	33.19	0.03	33.87	33.95	0.07	35.74	35.80	0.06	38.13	38.14	0.02
SPP	29.83	29.85	0.02	30.68	30.75	0.07	33.38	33.46	0.08	36.57	36.67	0.10
TVA	28.52	28.63	0.11	29.31	29.54	0.23	32.59	32.79	0.20	36.75	36.77	0.02
VAP	34.24	32.37	(1.87)	35.07	33.56	(1.50)	38.30	37.61	(0.69)	42.97	42.28	(0.69)
Total	30.14	30.12	(0.02)	31.18	31.23	0.06	33.96	34.13	0.17	37.53	37.70	0.17

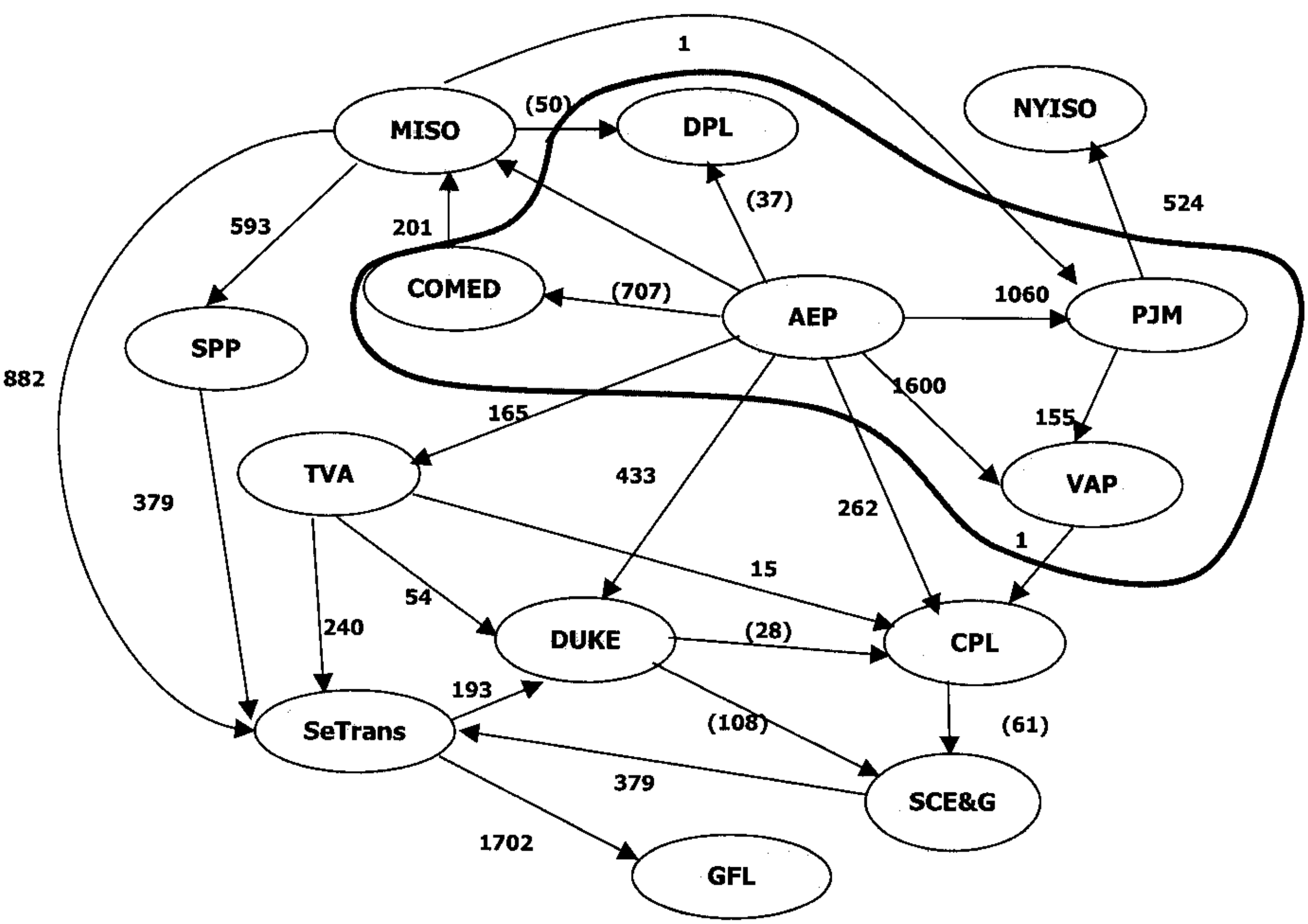
Table A-27: Average VAP Net Imports by Source (MW) 2005-2014, High Load

Period	Imports/Transfers	2005 Base Case	2007 Base Case	2010 Base Case	2014 Base Case	2005 Change Case	2007 Change Case	2010 Change Case	2014 Change Case
Off-Peak	Average of VAP Net Imports	1,722	1,770	1,906	1,980	2,063	2,106	2,197	2,259
	Average Transfers from AEP	1,494	1,521	1,624	1,526	1,918	1,862	1,882	1,750
	Average Transfers from PJM	100	154	191	432	98	224	313	553
	Average Transfers from CPL	128	96	90	22	46	20	2	(43)
On-Peak	Average of VAP Net Imports	697	584	346	137	1,413	1,303	1,238	1,068
	Average Transfers from AEP	663	555	334	140	1,249	1,071	729	544
	Average Transfers from PJM	45	68	95	109	218	282	622	576
	Average Transfers from CPL	(12)	(39)	(83)	(112)	(54)	(50)	(114)	(52)
All-Hours	Average of VAP Net Imports	1,234	1,206	1,163	1,102	1,753	1,723	1,740	1,692
	Average Transfers from AEP	1,098	1,061	1,010	866	1,600	1,485	1,333	1,176
	Average Transfers from PJM	74	113	145	278	155	252	460	564
	Average Transfers from CPL	61	32	8	(42)	(1)	(13)	(53)	(48)

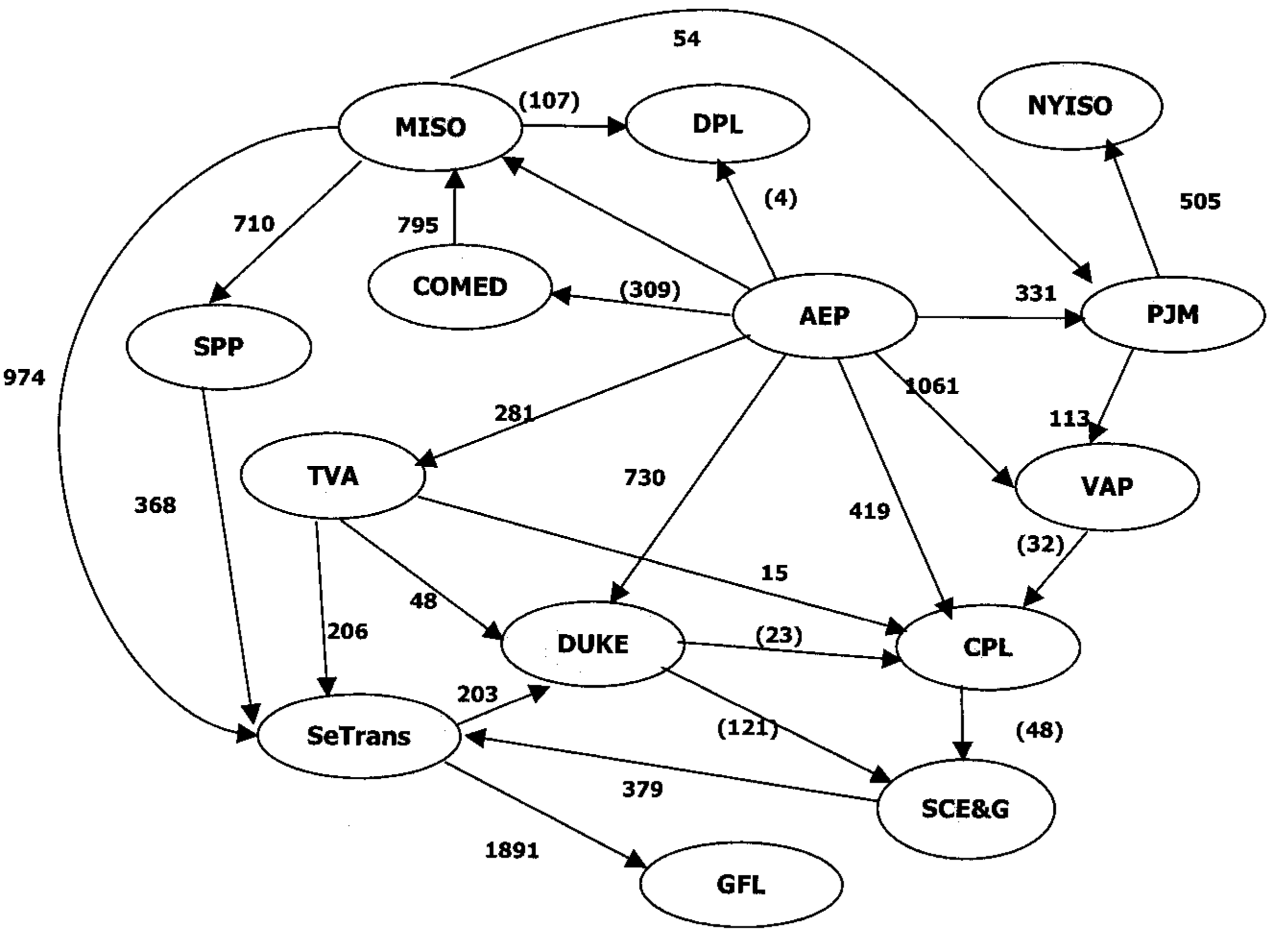
ı to Pool All-Hour Average Transfers (MW)
2005 High Load/Base



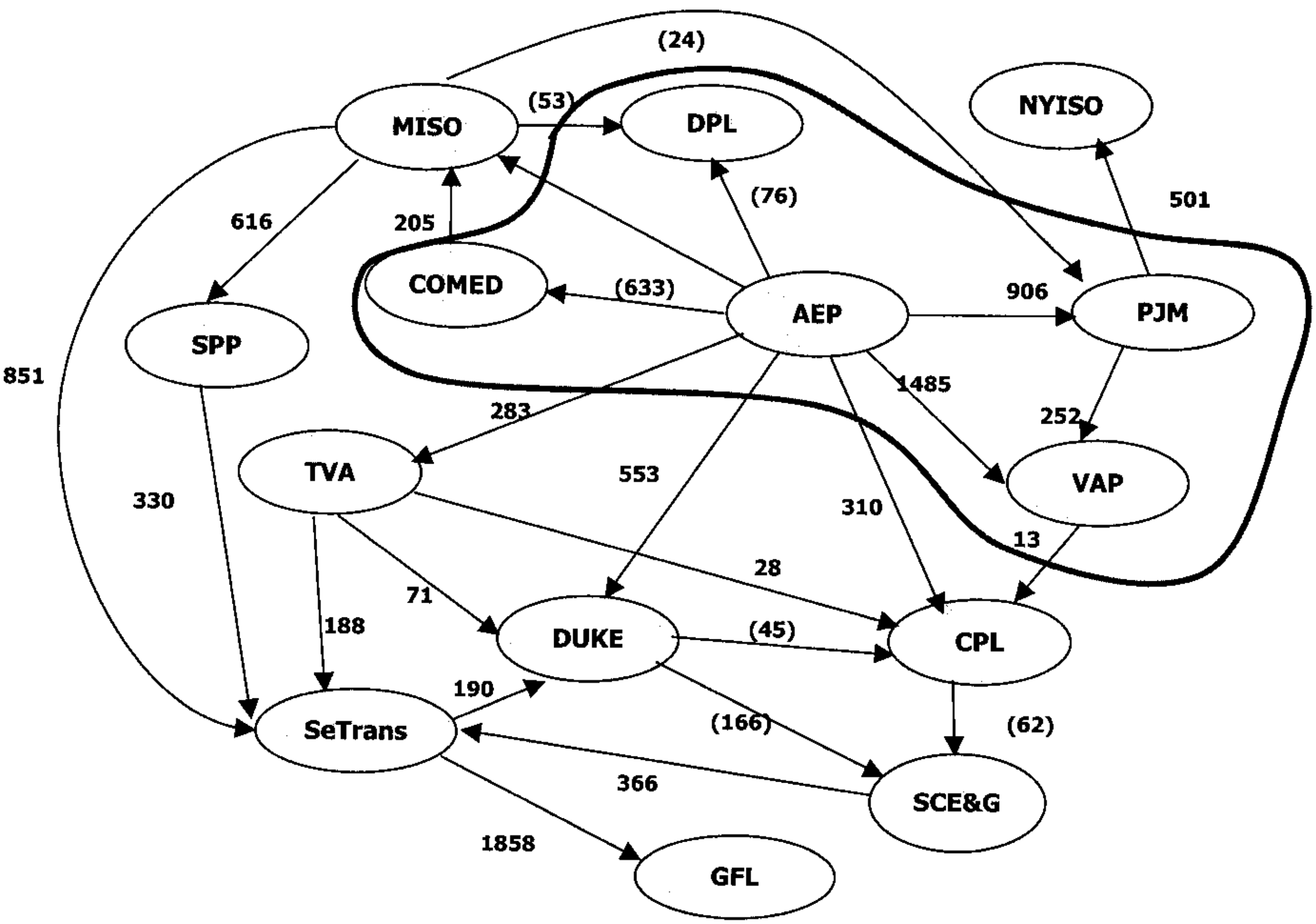
ol to Pool All-Hour Average Transfers (MW)
2005 High Load/Change



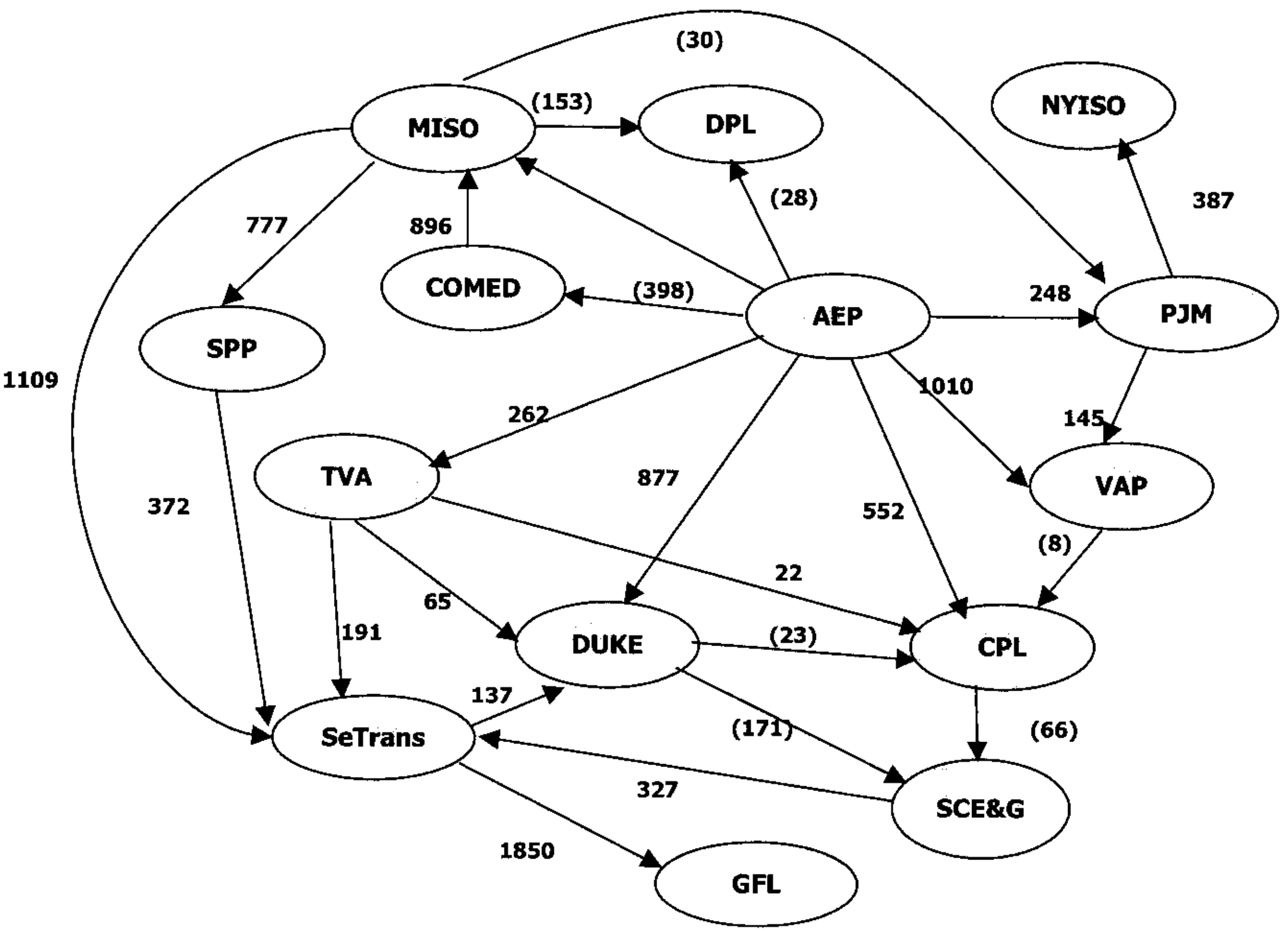
l to Pool All-Hour Average Transfers (MW)
2007 High Load/Base



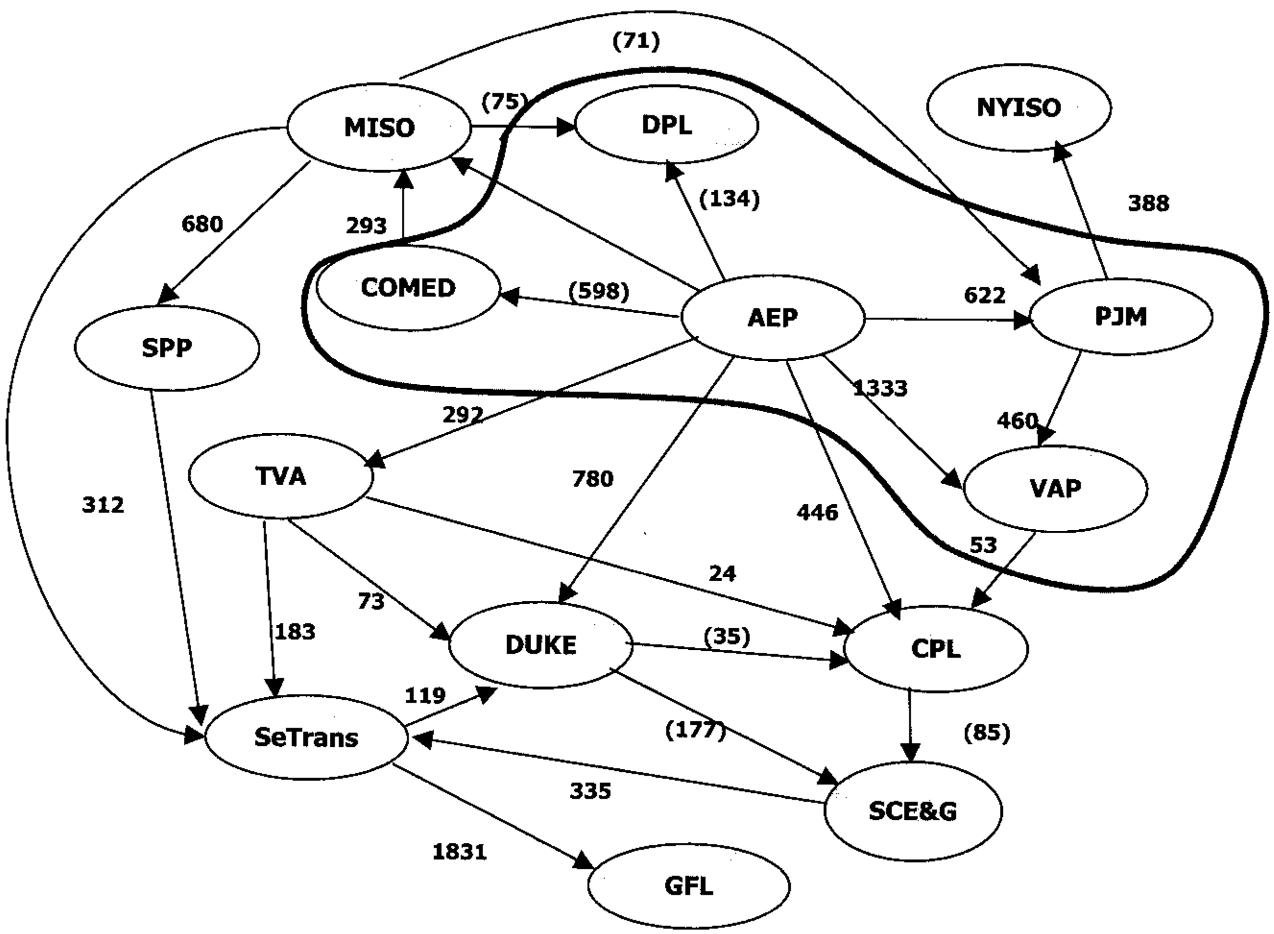
l to Pool All-Hour Average Transfers (MW)
2007 High Load/Change



›l to Pool All-Hour Average Transfers (MW)
2010 High Load/Base



ɩl to Pool All-Hour Average Transfers (MW)
ƨυ10 High Load/Change



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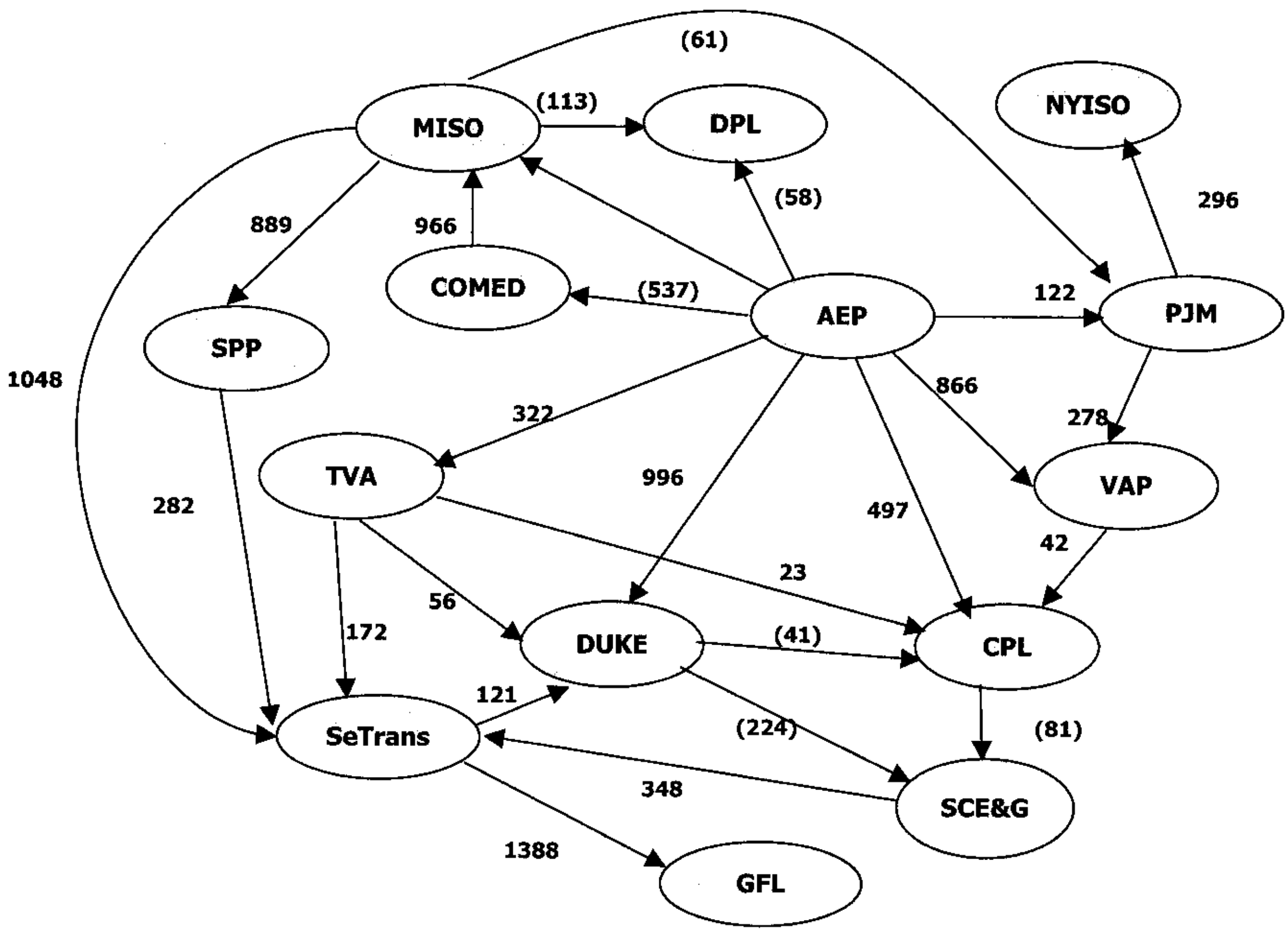
2014 High Load/Base



l to Pool All-Hour Average

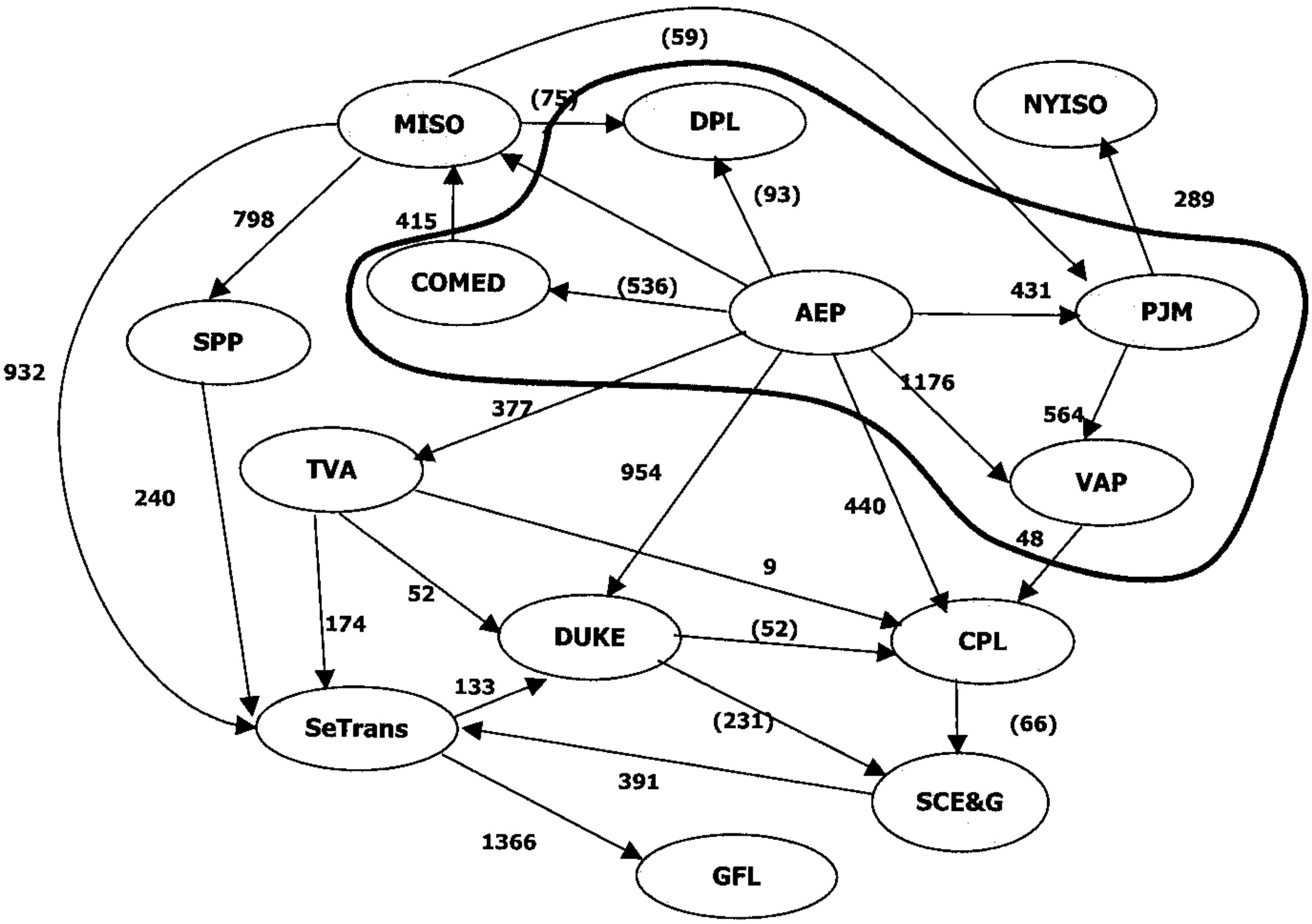


Table A-28: Generation by Type and Pool (GWh), High Load

Capacity Pool	TYPE	2005 Base Case	2005 Change Case	2005 Delta (Change - Base)	2007 Base Case	2007 Change Case	2007 Delta (Change - Base)	2010 Base Case	2010 Change Case	2010 Delta (Change - Base)	2014 Base Case	2014 Change Case	2014 Delta (Change - Base)
	CC	231,512	234,109	2,597	266,969	269,759	2,791	335,612	338,144	2,532	414,807	415,943	1,135
	Coal	1,323,143	1,326,698	3,555	1,346,190	1,349,580	3,390	1,365,218	1,368,522	3,303	1,376,704	1,378,545	1,841
	Hydro	100,956	100,956	-	100,956	100,956	-	100,956	100,956	-	100,956	100,956	-
	New CC	-	-	-	-	-	-	6,411	6,417	6	23,675	23,708	33
	New CT	-	-	-	466	484	18	6,562	6,349	(214)	47,583	49,149	1,565
	Nuke	411,983	411,981	(2)	411,822	411,827	5	412,078	412,084	6	412,037	412,038	1
	Other	61,952	61,954	2	61,997	61,998	1	61,979	61,985	5	61,973	61,982	9
	Peaker	15,033	15,094	61	23,998	24,336	338	38,020	38,474	454	44,519	44,969	450
	PSH	17,082	17,107	25	16,673	16,687	13	15,921	15,910	(10)	13,637	13,609	(28)
	ST/G/O/D	112,055	112,831	776	123,343	124,495	1,152	140,166	140,971	805	169,515	170,224	709
Non-PJM Total		2,273,717	2,280,731	7,014	2,352,414	2,360,121	7,707	2,482,922	2,489,811	6,888	2,665,407	2,671,122	5,715
PJM (Expanded)	CC	32,117	28,792	(3,325)	38,673	35,420	(3,253)	51,448	50,210	(1,237)	71,923	72,724	801
	Coal	412,848	410,874	(1,974)	425,047	423,079	(1,967)	439,957	437,718	(2,238)	450,656	448,949	(1,706)
	Hydro	8,074	8,074	-	8,074	8,074	-	8,074	8,074	-	8,074	8,074	-
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
	New CT	-	-	-	-	-	-	612	22	(590)	5,373	2,289	(3,085)
	Nuke	239,964	239,968	4	239,953	239,951	(2)	239,872	239,868	(4)	239,780	239,777	(4)
	Other	9,359	9,329	(29)	9,502	9,491	(11)	9,511	9,503	(7)	9,536	9,525	(11)
	Peaker	2,048	1,866	(182)	3,283	3,020	(263)	5,355	5,068	(287)	8,294	7,792	(502)
	PSH	7,893	7,899	6	7,899	7,899	0	8,143	8,156	13	7,804	7,849	45
	ST/G/O/D	18,274	16,888	(1,386)	24,372	22,302	(2,070)	30,803	28,360	(2,443)	41,869	40,778	(1,091)
	Wind	339	332	(7)	335	329	(6)	333	329	(4)	344	341	(3)
PJM Total		730,917	724,023	(6,893)	757,138	749,566	(7,572)	794,107	787,310	(6,797)	843,655	838,099	(5,555)
Eastern Interconnection	CC	263,629	262,901	(728)	305,641	305,179	(462)	387,059	388,355	1,295	486,731	488,667	1,937
	Coal	1,735,991	1,737,572	1,581	1,771,237	1,772,659	1,422	1,805,175	1,806,240	1,065	1,827,359	1,827,494	135
	Hydro	109,030	109,030	-	109,030	109,030	-	109,030	109,030	-	109,030	109,030	-
	New CC	-	-	-	-	-	-	6,411	6,417	6	23,675	23,708	33
	New CT	-	-	-	466	484	18	7,174	6,370	(804)	52,957	51,437	(1,519)
	Nuke	651,947	651,950	2	651,775	651,778	3	651,950	651,951	2	651,818	651,815	(2)
	Other	71,311	71,284	(27)	71,500	71,489	(10)	71,490	71,488	(2)	71,509	71,507	(2)
	Peaker	17,082	16,961	(121)	27,281	27,356	75	43,375	43,542	167	52,813	52,761	(52)
	PSH	24,975	25,006	31	24,572	24,586	14	24,064	24,067	3	21,441	21,458	17
	ST/G/O/D	130,329	129,719	(610)	147,715	146,797	(918)	170,968	169,331	(1,637)	211,384	211,002	(382)
	Wind	339	332	(7)	335	329	(6)	333	329	(4)	344	341	(3)
EI Total		3,004,633	3,004,754	121	3,109,552	3,109,687	135	3,277,030	3,277,120	91	3,509,061	3,509,221	160

Table A-29: Generation by Type and Pool (GWh), High Load

Capacity Pool	TYPE -	2005 Base Case	2005 Change Case	2005 Delta (Change - Base)	2007 Base Case	2007 Change Case	2007 Delta (Change - Base)	2010 Base Case	2010 Change Case	2010 Delta (Change - Base)	2014 Base Case	2014 Change Case	2014 Delta (Change - Base)
AEP	CC	579	1,485	906	830	1,930	1,099	2,278	4,240	1,962	5,586	10,454	4,868
	Coal	131,081	132,571	1,491	136,231	137,403	1,171	140,841	140,490	(351)	144,074	143,882	(191)
	Hydro	1,284	1,284	-	1,284	1,284	-	1,284	1,284	-	1,284	1,284	-
	Nuke	15,885	15,885	-	15,885	15,885	-	15,913	15,913	-	15,884	15,884	-
	Other	214	214	(0)	213	213	(0)	214	214	-	214	214	-
	Peaker	-	-	-	24	34	10	176	233	57	251	304	54
	PSH	729	731	2	718	718	(1)	618	618	0	465	463	(2)
	ST/G/O/D	1	1	0	2	2	0	3	5	2	4	8	4
	New CT	-	-	-	-	-	-	-	-	-	-	-	-
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
AEP Sum		149,772	152,170	2,398	155,188	157,468	2,280	161,326	162,995	1,670	167,760	172,493	4,732
COMED	CC	2,258	1,776	(482)	2,656	2,113	(543)	3,261	3,015	(246)	4,344	4,079	(265)
	Coal	28,550	29,565	1,015	30,245	31,190	946	33,231	34,166	935	34,991	35,473	482
	Nuke	80,327	80,331	4	80,342	80,340	(2)	80,249	80,245	(4)	80,282	80,277	(6)
	Peaker	323	178	(145)	487	263	(224)	857	587	(270)	2,031	844	(1,188)
	ST/G/O/D	2,184	557	(1,627)	3,281	846	(2,435)	5,434	1,649	(3,785)	7,958	5,254	(2,704)
	New CT	-	-	-	-	-	-	160	22	(139)	1,527	391	(1,136)
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
COMED Sum		113,641	112,407	(1,235)	117,011	114,753	(2,257)	123,192	119,683	(3,509)	131,134	126,318	(4,816)
CPL	CC	2,194	2,612	419	2,768	3,110	342	3,578	3,797	219	4,600	4,664	64
	Coal	35,098	35,242	143	36,736	36,913	177	37,687	37,814	127	39,110	39,209	99
	Hydro	949	949	-	949	949	-	949	949	-	949	949	-
	Nuke	24,491	24,491	-	24,494	24,494	-	24,476	24,476	-	24,507	24,507	-
	Other	2,511	2,511	-	2,506	2,506	-	2,508	2,513	5	2,506	2,506	(1)
	Peaker	847	873	26	1,278	1,442	165	1,857	2,084	227	2,258	2,426	168
	New CT	-	-	-	-	-	-	853	647	(206)	4,585	5,109	524
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
CPL Sum		66,090	66,678	588	68,730	69,414	685	71,907	72,279	372	78,514	79,369	855
DP&L	Coal	18,106	18,260	155	18,920	19,091	171	19,957	20,202	245	20,794	20,903	109
	Other	45	45	-	45	45	-	45	45	-	45	45	-
	Peaker	8	-	(8)	38	17	(20)	150	162	13	334	208	(126)
	New CT	-	-	-	-	-	-	-	-	-	-	-	-
DP&L Sum		18,159	18,306	147	19,003	19,153	151	20,152	20,409	257	21,173	21,157	(17)

Table A-29: Generation by Type and Pool (GWh), High Load

Capacity Pool	TYPE -	2005 Base Case	2005 Change Case	2005 Delta (Change - Base)	2007 Base Case	2007 Change Case	2007 Delta (Change - Base)	2010 Base Case	2010 Change Case	2010 Delta (Change - Base)	2014 Base Case	2014 Change Case	2014 Delta (Change - Base)
DUKE	CC	1,454	1,636	181	1,756	1,915	158	2,287	2,337	50	2,980	3,037	56
	Coal	50,666	50,859	193	52,325	52,551	226	53,456	53,593	137	54,821	54,889	67
	Hydro	4,265	4,265	-	4,265	4,265	-	4,265	4,265	-	4,265	4,265	-
	Nuke	53,021	53,021	-	52,958	52,958	-	53,031	53,031	-	53,054	53,054	-
	Other	57	57	-	56	56	-	56	56	-	57	57	0
	Peaker	980	1,023	43	1,371	1,438	67	2,368	2,593	225	4,770	4,778	8
	PSH	3,789	3,807	17	3,579	3,595	16	3,292	3,312	20	2,447	2,440	(7)
	ST/G/O/D	9	10	2	9	10	1	13	13	0	15	18	2
	New CT	-	-	-	386	403	16	2,059	2,064	5	5,571	5,775	204
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
DUKE Sum		114,240	114,677	437	116,706	117,192	486	120,829	121,265	436	127,981	128,312	331
GFL	CC	64,622	64,809	187	68,828	68,960	132	73,812	73,848	36	79,783	79,862	79
	Coal	55,142	55,209	66	55,793	55,874	82	56,219	56,285	66	56,804	56,823	19
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	214	214	-	214	214	-	214	214	-	214	214	-
	Nuke	29,966	29,966	-	29,896	29,896	-	29,953	29,953	-	29,885	29,885	-
	Other	3,147	3,147	-	3,150	3,150	-	3,147	3,147	-	3,147	3,147	-
	Peaker	3,563	3,566	2	7,173	7,171	(2)	6,424	6,476	52	4,883	4,892	9
	ST/G/O/D	42,002	42,123	121	44,295	44,363	68	46,349	46,363	14	50,247	50,260	12
	New CT	-	-	-	-	-	-	3,447	3,434	(14)	10,032	10,100	68
	New CC	-	-	-	-	-	-	6,411	6,417	6	20,603	20,606	3
GFL Sum		198,657	199,035	377	209,349	209,629	280	225,978	226,138	160	255,600	255,790	190
MISO E	CC	6,314	6,410	96	8,816	9,201	385	14,889	15,224	335	22,470	22,570	101
	Coal	319,766	321,577	1,812	327,778	329,588	1,809	339,242	341,278	2,036	349,941	351,213	1,272
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	2,658	2,658	-	2,658	2,658	-	2,658	2,658	-	2,658	2,658	-
	Nuke	29,319	29,319	-	29,323	29,323	-	29,290	29,290	-	29,334	29,334	-
	Other	2,454	2,454	-	2,455	2,455	-	2,457	2,457	-	2,454	2,455	1
	Peaker	695	663	(32)	1,122	1,143	21	2,199	2,289	90	4,976	4,843	(133)
	PSH	5,229	5,232	3	5,085	5,076	(10)	4,669	4,654	(15)	4,025	3,999	(27)
	ST/G/O/D	2,133	2,273	140	3,282	3,351	70	5,971	6,149	178	10,648	10,548	(101)
	New CT	-	-	-	-	-	-	-	-	-	1,891	1,901	10
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
MISO E Sum		368,567	370,586	2,019	380,520	382,796	2,276	401,374	403,999	2,625	428,397	429,520	1,123

Table A-29: Generation by Type and Pool (GWh), High Load

		2005			2007			2010			2014		
Capacity Pool	TYPE -	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)
MISO W	CC	9,163	9,411	248	11,217	11,299	82	15,298	15,358	60	19,876	19,948	72
	Coal	286,340	286,944	604	289,929	290,585	657	293,571	294,201	630	301,110	301,509	399
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	15,458	15,458	-	15,458	15,458	-	15,458	15,458	-	15,458	15,458	-
	Nuke	56,845	56,845	0	56,919	56,924	5	56,805	56,812	7	56,886	56,883	(2)
	Other	10,566	10,567	1	10,571	10,572	1	10,560	10,561	1	10,555	10,564	9
	Peaker	5,796	5,800	4	7,863	7,908	45	15,554	15,482	(73)	13,696	14,000	304
	PSH	671	668	(3)	678	685	8	688	686	(2)	678	674	(4)
	ST/G/O/D	605	608	3	859	866	6	1,862	1,873	11	2,148	2,193	45
	New CT	-	-	-	-	-	-	-	-	-	14,912	15,475	564
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
MISO W Sum		385,444	386,302	858	393,494	394,298	804	409,796	410,431	635	435,318	436,704	1,386
ISO-NE	CC	27,926	27,908	(18)	30,153	29,989	(165)	36,218	36,236	18	41,117	41,071	(46)
	Coal	21,345	21,352	7	21,557	21,540	(17)	21,862	21,859	(2)	21,908	21,901	(7)
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	7,261	7,261	-	7,261	7,261	-	7,261	7,261	-	7,261	7,261	-
	Nuke	33,909	33,909	-	33,883	33,882	(1)	33,963	33,963	-	33,979	33,979	-
	Other	14,300	14,300	-	14,314	14,314	-	14,319	14,319	-	14,309	14,309	-
	Peaker	-	-	-	-	-	-	-	-	-	0	1	1
	PSH	1,361	1,368	7	1,284	1,287	3	1,251	1,258	7	1,076	1,071	(5)
	ST/G/O/D	17,582	17,641	59	19,475	19,633	158	19,267	19,286	19	21,680	21,819	138
	New CT	-	-	-	-	-	-	-	-	-	-	-	-
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
ISO-NE Sum		123,684	123,739	55	127,927	127,906	(21)	134,140	134,181	42	141,331	141,412	81
NYC	CC	6,434	6,523	89	6,594	6,690	96	6,998	7,058	60	7,453	7,543	91
	Other	179	179	-	179	179	-	179	179	-	179	179	-
	Peaker	469	467	(3)	355	361	6	486	480	(6)	683	702	20
	ST/G/O/D	18,867	19,044	176	19,819	19,990	171	21,006	21,164	158	22,319	22,503	184
	New CT	-	-	-	45	45	1	104	106	2	221	225	4
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
NYC Sum		25,950	26,212	263	26,992	27,266	274	28,773	28,987	214	30,854	31,153	299
NYL	CC	1,483	1,492	9	1,527	1,526	(0)	1,606	1,606	0	1,661	1,660	(1)
	Other	988	988	-	991	991	-	987	987	-	989	989	-
	Peaker	211	208	(3)	203	204	1	281	279	(2)	430	428	(2)

Table A-29: Generation by Type and Pool (GWh), High Load

		2005			2007			2010			2014		
Capacity Pool	TYPE -	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)
	ST/G/O/D	8,779	8,783	4	9,429	9,475	46	10,278	10,287	9	11,492	11,506	15
	New CT	-	-	-	35	35	1	100	98	(1)	274	274	(1)
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
NYL Sum		11,461	11,471	10	12,185	12,232	47	13,252	13,258	6	14,847	14,858	11
NYO	CC	12,127	12,094	(33)	13,178	13,027	(151)	14,758	14,748	(10)	17,427	17,342	(85)
	Coal	25,891	25,700	(190)	26,387	26,200	(187)	27,074	26,870	(204)	27,296	27,129	(167)
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	28,623	28,623	-	28,623	28,623	-	28,623	28,623	-	28,623	28,623	-
	Nuke	37,819	37,817	(2)	37,706	37,707	1	37,729	37,728	(1)	37,706	37,710	4
	Other	2,401	2,402	1	2,402	2,402	-	2,402	2,402	(0)	2,397	2,397	(0)
	Peaker	3	3	(1)	2	2	0	4	4	(1)	25	23	(2)
	PSH	2,037	2,040	3	2,046	2,050	4	1,899	1,896	(3)	1,806	1,815	9
	ST/G/O/D	9,704	9,734	30	10,919	11,141	222	11,658	11,753	95	13,416	13,415	(0)
	New CT	-	-	-	-	-	-	-	-	-	101	151	50
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
NYO Sum		118,604	118,413	(192)	121,263	121,152	(111)	124,147	124,024	(123)	128,797	128,605	(192)
PJM	CC	22,225	20,731	(1,494)	26,386	25,068	(1,318)	34,747	34,673	(74)	46,545	45,939	(605)
	Coal	194,000	190,797	(3,203)	197,444	194,514	(2,930)	202,406	200,211	(2,195)	206,032	204,540	(1,492)
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	5,599	5,599	-	5,599	5,599	-	5,599	5,599	-	5,599	5,599	-
	Nuke	117,388	117,388	-	117,476	117,476	-	117,393	117,393	-	117,365	117,367	2
	Other	6,902	6,902	-	6,908	6,908	-	6,904	6,904	-	6,907	6,904	(2)
	Peaker	619	665	45	1,249	1,305	56	1,857	2,132	275	2,947	3,937	990
	PSH	4,664	4,668	4	4,681	4,682	1	4,709	4,722	13	4,521	4,568	46
	ST/G/O/D	10,452	11,452	1,001	14,574	15,574	1,000	17,759	19,610	1,851	25,287	27,326	2,038
	Wind	339	332	(7)	335	329	(6)	333	329	(4)	344	341	(3)
	New CT	-	-	-	-	-	-	-	-	-	1,240	-	(1,240)
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
PJM Sum		362,187	358,534	(3,653)	374,652	371,455	(3,197)	391,707	391,573	(134)	416,787	416,521	(266)
SCE&G	CC	2,476	2,738	262	3,132	3,495	363	4,311	4,585	274	5,510	5,700	189
	Coal	36,508	36,660	153	37,705	37,812	107	38,514	38,600	86	39,282	39,328	46
	Hydro	875	875	-	875	875	-	875	875	-	875	875	-
	Nuke	7,611	7,611	-	7,610	7,610	-	7,609	7,609	-	7,650	7,650	-
	Other	1,004	1,004	-	1,007	1,007	-	1,007	1,007	-	1,005	1,005	-

Table A-29: Generation by Type and Pool (GWh), High Load

Capacity Pool	TYPE -	2005 Base Case	2005 Change Case	2005 Delta (Change - Base)	2007 Base Case	2007 Change Case	2007 Delta (Change - Base)	2010 Base Case	2010 Change Case	2010 Delta (Change - Base)	2014 Base Case	2014 Change Case	2014 Delta (Change - Base)
	Peaker	35	41	6	79	83	4	128	143	15	55	74	19
	PSH	987	983	(5)	912	898	(13)	822	810	(12)	565	572	7
	ST/G/O/D	25	27	2	65	69	4	105	102	(3)	82	84	1
	New CT	-	-	-	-	-	-	-	-	-	1,255	1,340	85
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
SCE&G Sum		49,522	49,940	418	51,383	51,848	465	53,372	53,732	360	56,279	56,627	348
SETRANS E	CC	22,051	23,961	1,910	28,225	30,078	1,853	40,635	42,679	2,045	58,235	59,217	982
	Coal	185,268	185,740	472	190,095	190,377	282	189,214	189,493	278	180,095	180,186	91
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	9,179	9,179	-	9,179	9,179	-	9,179	9,179	-	9,179	9,179	-
	Nuke	45,953	45,953	-	46,039	46,039	-	46,072	46,072	-	46,029	46,029	-
	Other	8,841	8,841	-	8,851	8,851	-	8,852	8,852	(0)	8,842	8,842	-
	Peaker	1,062	1,056	(6)	2,581	2,603	21	4,268	4,219	(49)	6,142	6,172	30
	PSH	430	430	0	363	369	5	594	595	1	369	363	(6)
	ST/G/O/D	4,888	5,044	156	5,396	5,523	127	6,345	6,401	56	7,022	7,073	51
	New CT	-	-	-	-	-	-	-	-	-	6,547	6,544	(3)
	New CC	-	-	-	-	-	-	-	-	-	3,072	3,102	30
SETRANS E Sum		277,671	280,204	2,532	290,730	293,019	2,289	305,159	307,490	2,331	325,531	326,706	1,175
SETRANS W	CC	36,277	35,252	(1,025)	43,415	42,526	(889)	55,230	54,154	(1,076)	66,373	65,634	(739)
	Coal	56,613	56,662	49	56,667	56,680	13	57,236	57,234	(2)	57,830	57,834	5
	Hydro	581	581	-	581	581	-	581	581	-	581	581	-
	Nuke	38,950	38,950	-	38,919	38,919	-	39,054	39,054	-	39,016	39,016	-
	Other	1,606	1,606	-	1,606	1,606	-	1,606	1,606	-	1,608	1,608	-
	Peaker	671	662	(9)	779	777	(2)	1,298	1,326	27	1,809	1,793	(15)
	ST/G/O/D	2,611	2,609	(1)	3,637	3,678	40	6,936	7,144	208	13,428	13,659	231
	New CT	-	-	-	-	-	-	-	-	-	-	-	-
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
SETRANS W Sum		137,309	136,323	(986)	145,604	144,767	(838)	161,942	161,099	(843)	180,645	180,126	(519)
SPP	CC	30,338	30,438	100	36,786	36,962	177	48,337	48,630	293	61,446	61,718	272
	Coal	145,769	145,860	91	143,151	143,216	64	141,824	141,884	60	137,590	137,587	(3)
	HRM	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	11,041	11,041	-	11,041	11,041	-	11,041	11,041	-	11,041	11,041	-
	Nuke	9,358	9,358	-	9,337	9,337	-	9,381	9,381	-	9,337	9,337	-
	Other	11,247	11,247	-	11,252	11,252	-	11,245	11,245	-	11,271	11,271	-

Table A-29: Generation by Type and Pool (GWh), High Load

		2005			2007			2010			2014		
Capacity Pool	TYPE -	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)
	Peaker	413	427	14	650	655	5	1,914	1,852	(62)	2,750	2,764	14
	ST/G/O/D	4,851	4,935	83	6,157	6,396	239	10,373	10,434	60	17,014	17,145	130
	New CT	-	-	-	-	-	-	-	-	-	442	448	6
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
SPP Sum		213,017	213,305	288	218,375	218,859	484	234,116	234,467	351	250,890	251,309	418
TVA	CC	8,653	8,825	172	10,575	10,981	406	17,654	17,883	229	25,877	25,977	100
	Coal	104,738	104,892	154	108,067	108,243	176	109,319	109,409	91	110,918	110,939	21
	Hydro	19,852	19,852	-	19,852	19,852	-	19,852	19,852	-	19,852	19,852	-
	Nuke	44,740	44,740	-	44,738	44,738	-	44,713	44,713	-	44,655	44,655	(0)
	Other	2,652	2,652	-	2,655	2,655	-	2,653	2,653	-	2,653	2,653	(0)
	Peaker	287	305	18	542	549	6	1,239	1,248	10	2,042	2,072	30
	PSH	2,578	2,580	2	2,727	2,727	-	2,706	2,699	(7)	2,670	2,674	4
	ST/G/O/D	-	-	-	-	-	-	3	3	-	3	3	(0)
	New CT	-	-	-	-	-	-	-	-	-	1,753	1,808	54
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
TVA Sum		183,501	183,847	346	189,157	189,745	588	198,139	198,461	322	210,423	210,633	210
VAP	CC	7,055	4,800	(2,255)	8,800	6,309	(2,491)	11,162	8,283	(2,879)	15,449	12,252	(3,197)
	Coal	41,112	39,681	(1,432)	42,207	40,882	(1,325)	43,521	42,650	(871)	44,765	44,151	(615)
	Hydro	1,192	1,192	-	1,192	1,192	-	1,192	1,192	-	1,192	1,192	-
	Nuke	26,364	26,364	-	26,249	26,249	-	26,316	26,316	-	26,249	26,249	-
	Other	2,197	2,168	(29)	2,336	2,325	(11)	2,348	2,341	(7)	2,370	2,362	(8)
	Peaker	1,098	1,024	(74)	1,486	1,400	(86)	2,315	1,954	(362)	2,731	2,499	(232)
	PSH	2,500	2,500	-	2,500	2,500	-	2,817	2,817	-	2,818	2,818	-
	ST/G/O/D	5,638	4,878	(760)	6,515	5,880	(635)	7,608	7,097	(511)	8,619	8,191	(429)
	New CT	-	-	-	-	-	-	451	-	(451)	2,606	1,898	(708)
	New CC	-	-	-	-	-	-	-	-	-	-	-	-
VAP Sum		87,156	82,606	(4,550)	91,284	86,737	(4,548)	97,730	92,649	(5,081)	106,800	101,611	(5,188)

Table A-30: Generation Cost ($k), High Load

	2005			2007			2010			2014		
Capacity Pool	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)
AEP	2,144,573	2,226,788	82,215	2,175,404	2,245,632	70,228	2,353,124	2,428,550	75,426	2,579,007	2,753,606	174,599
COED	1,189,850	1,110,059	(79,791)	1,235,062	1,126,569	(108,493)	1,380,978	1,233,999	(146,979)	1,650,963	1,452,103	(198,859)
CPL	1,012,142	1,033,292	21,150	1,054,118	1,078,016	23,898	1,187,803	1,200,919	13,116	1,466,794	1,506,597	39,803
DP&L	349,677	350,954	1,277	341,363	343,352	1,989	379,726	386,085	6,359	416,230	413,610	(2,619)
DUKE	1,178,378	1,190,219	11,841	1,233,939	1,247,844	13,904	1,420,263	1,436,235	15,972	1,771,795	1,786,734	14,939
GFL	5,024,318	5,034,683	10,365	5,327,473	5,334,811	7,338	5,807,643	5,812,144	4,501	6,787,905	6,795,172	7,267
MISO E	5,765,006	5,800,346	35,340	5,857,312	5,903,418	46,107	6,485,398	6,538,782	53,384	7,416,760	7,430,092	13,332
MISO W	4,557,034	4,574,338	17,304	4,708,783	4,723,090	14,307	5,266,119	5,270,964	4,845	6,063,481	6,112,092	48,612
ISO-NE	2,583,826	2,583,887	62	2,643,879	2,639,984	(3,895)	2,841,106	2,841,505	399	3,128,981	3,131,623	2,642
NYC	881,396	889,326	7,931	870,256	878,705	8,449	925,601	932,011	6,409	1,002,387	1,012,286	9,898
NYL	410,505	410,983	478	416,062	417,984	1,921	454,862	455,055	193	521,240	521,870	629
NYO	1,756,947	1,749,662	(7,285)	1,766,646	1,761,792	(4,853)	1,886,662	1,881,737	(4,925)	2,068,199	2,061,425	(6,774)
PJM	5,302,495	5,231,085	(71,410)	5,484,139	5,425,745	(58,394)	6,093,667	6,135,571	41,905	7,025,441	7,047,366	21,924
SCE&G	848,664	862,232	13,567	866,379	880,433	14,054	933,026	943,703	10,677	1,062,654	1,076,103	13,449
SETRANS E	4,640,401	4,722,865	82,464	4,904,012	4,972,946	68,933	5,378,776	5,444,578	65,802	6,261,722	6,293,860	32,138
SETRANS W	2,437,053	2,400,814	(36,239)	2,640,737	2,613,308	(27,429)	3,108,879	3,086,356	(22,523)	3,680,816	3,667,319	(13,497)
SPP	3,178,786	3,187,179	8,393	3,332,837	3,345,622	12,784	3,816,567	3,823,932	7,365	4,435,765	4,448,181	12,416
TVA	2,371,574	2,381,176	9,602	2,434,342	2,450,133	15,791	2,737,170	2,747,373	10,203	3,157,283	3,164,881	7,598
VAP	1,452,510	1,302,389	(150,122)	1,533,235	1,387,915	(145,321)	1,738,333	1,558,351	(179,982)	2,085,664	1,897,900	(187,764)
Total	47,085,135	47,042,278	(42,858)	48,825,979	48,777,298	(48,681)	54,195,703	54,157,852	(37,851)	62,583,086	62,572,821	(10,265)

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Table A-31: Average Spot Prices ($/MWh), High Load

	2005			2007			2010			2014		
Capacity Pool	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)	Base Case	Change Case	Delta (Change - Base)
AEP	22.07	22.97	0.90	22.31	23.34	1.03	25.25	26.02	0.77	29.23	29.31	0.08
COED	21.76	21.87	0.11	22.06	22.11	0.05	24.58	24.74	0.15	28.41	28.18	(0.23)
CPL	29.19	29.75	0.56	30.38	31.18	0.80	33.72	34.54	0.82	37.48	38.54	1.05
DP&L	22.02	22.47	0.45	22.05	22.71	0.66	24.48	25.41	0.93	28.33	28.50	0.16
DUKE	29.22	29.78	0.56	30.55	31.29	0.75	33.74	34.35	0.61	37.50	38.21	0.70
GFL	36.71	36.74	0.03	49.02	49.07	0.05	43.35	43.19	(0.16)	38.82	39.11	0.29
MISO E	23.29	23.47	0.19	23.56	23.82	0.26	26.09	26.32	0.24	29.96	30.07	0.11
MISO W	25.56	25.66	0.10	26.35	26.46	0.12	34.34	34.13	(0.22)	33.85	33.99	0.14
ISO-NE	33.03	33.06	0.03	32.48	32.56	0.08	33.05	32.99	(0.07)	34.11	34.00	(0.11)
NYC	35.24	35.36	0.12	33.32	33.36	0.04	34.57	34.61	0.04	37.40	37.67	0.27
NYL	37.14	37.22	0.07	35.37	35.36	(0.02)	36.64	36.60	(0.04)	39.25	39.23	(0.03)
NYO	30.08	30.00	(0.07)	29.49	29.38	(0.11)	30.44	30.32	(0.12)	31.79	31.65	(0.14)
PJM	27.68	27.49	(0.19)	27.74	27.70	(0.04)	30.07	30.22	0.15	33.20	34.77	1.57
SCE&G	27.99	28.50	0.51	29.22	29.83	0.61	32.41	33.11	0.70	34.88	35.65	0.77
SETRANS E	29.40	29.50	0.10	30.29	30.40	0.11	32.35	32.38	0.03	35.57	35.61	0.03
SETRANS W	29.70	29.74	0.04	29.90	29.95	0.05	31.32	31.38	0.05	32.76	32.69	(0.07)
SPP	27.14	27.25	0.11	27.56	27.63	0.07	30.04	30.08	0.04	32.28	32.29	0.01
TVA	26.77	26.90	0.13	27.12	27.27	0.14	29.69	29.84	0.14	32.81	32.81	0.00
VAP	31.58	30.23	(1.35)	32.38	31.05	(1.33)	35.02	33.99	(1.03)	38.43	38.69	0.27
Total	28.11	28.16	0.06	29.20	29.30	0.10	31.79	31.83	0.04	33.68	33.96	0.29