Estimates of the Value of Uninterrupted Service
for
The Mid-West Independent System Operator

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I. INTRODUCTION

The Midwest Independent Transmission System Operator (Midwest ISO) is developing a market based permanent resource adequacy plan based on:

- Providing efficient incentives for jointly optimized short-term energy and operating reserve markets,
- Developing a transparent economic framework for managing shortage conditions, and
- Using forward looking metrics to track resource development of resources and evaluate the effectiveness of market incentives.

Creating a transparent framework for managing shortage conditions will require modifying the way in which load curtailments would be implemented in shortage conditions. Current procedures address extreme shortage conditions from a reliability perspective and call for a sequence of actions to be taken without direct consideration of economic costs (Midwest Independent Transmission System Operator, 2005a). The Midwest ISO's resource adequacy proposal addresses shortages in two primary ways.

First, the proposed framework is designed to provide economic incentives for improving generator availability, expanding price responsive demand, and reducing transmission congestion by allowing supply shortages to be reflected in short-term energy and operating reserve prices. If all available generation was providing energy or contingency reserves, energy and operating reserve prices could be set by a demand bid. A demand bid specifies a load and a price at or above which the energy would not be utilized in a given time period. Demand bids may set prices that are above the cap on generator offers, thereby reflecting the shortage of generation supply and creating efficient and consistent economic incentives.

As supply continues to tighten, there could be conditions when further load reductions from price responsive demand would be either unavailable (i.e. all remaining loads are hedged and/or unable to respond to spot prices) or available only at very high prices. This is an extreme case that is not expected to occur often. Nonetheless, it will be important to investors and market participants to know how such a situation would be managed in terms of both system security and how prices would be determined in such circumstances.

The second major component of the framework for managing shortages specifies that loads will be curtailed in such extreme shortage conditions when the operating reserve and/or energy price at the commercial node through which the load is served would otherwise exceed a pre-determined level known as the "Security Interruption Price." When this occurs the Midwest ISO would direct the local Balancing Authority to curtail sufficient load at that node to keep prices at the Security Interruption Price.

There is some price – potentially a high price – at which load that is ordinarily not price responsive would prefer to be interrupted rather than have the costs of maintaining service rolled into its contracts or rates. For loads that are not equipped with interval meters or not able to see or respond to short-term price signals, it may not be possible to directly observe what that price would be for a given load at a specific time. Nonetheless, there is some price at which customers would prefer interruption to paying the marginal cost for providing service. Moreover, in shortage conditions, system operators need the backstop of being able to curtail loads to protect the power system.

The Midwest ISO proposal is designed to create economically rational rules, consistent with allowing shortage pricing in energy and operating reserve markets, for deciding when curtailments should be implemented:

- Curtailments will occur when and where resources are so tight that required resources and voluntary load reductions are not forthcoming even at very high prices.
- Curtailments occur when prices reach the point when consumers are presumed to prefer interruption to service.
- Customers that have energy under contract and transmission rights, including financial transmission rights (FTRs) from the generation source to their load centers, will realize the full economic benefit of their contracts and transmission rights. Even if such customers were to be curtailed based on the priorities of or under their contracts with the local Balancing Authority, they could benefit from the difference between the elevated spot price of energy and their contract price as well as the value of their FTRs.
- Market participants and regulators will know in advance how high spot prices will be allowed to go before curtailments will be mandated by the RTO.

Under this plan, the Midwest ISO would select either a uniform default Security Interruption Price for all loads or a set of default Security Interruption Prices for curtailing different loads (residential, different C&I sectors, emergency services, etc.) that would be allocated based on the load types served from each commercial node. The proposal calls for there being an opportunity to the extent it is technically feasible to do so for each Balancing Authority to modify its default Security Interruption Price to reflect specific contracts and local regulatory requirements. Procedures would be established for registering such modifications and incorporating such changes in Midwest ISO operating procedures.

The Midwest ISO may consider two factors in setting default Security Interruption Prices. First, the Midwest ISO may consider the level of Security Interruption Prices that would be expected to produce sufficient investment to meet specific Loss of Load Probability (LOLP) targets. Second, the Midwest ISO will consider the value to consumers of the uninterrupted service that incremental resources could provide. The intent is to set default Security Interruption Prices that are designed to achieve a level of resource adequacy consistent with consumer LOLP expectations and above which consumers would generally prefer to be interrupted.

Proposals to address resource adequacy based on a so-called "Energy Only Market" (EOM) design have typically said that RTOs should curtail loads when prices reach the Value of Lost Load (VOLL) (Midwest Independent Transmission System Operator, 2005b; Hogan, 2005). While this approach is conceptually correct, measuring VOLL is complicated.

Consumers do not directly value electrical load or energy. They value the light, heating, cooling, and motive force provided by their electrical fixtures, equipment, and appliances (Kariuki and Allan, 1996a). From the consumers' perspective, the relevant questions are: "What is the value of reliable, uninterrupted electric energy services? And, what costs or losses are incurred when these services are interrupted?"

Moreover, in setting a price at which non-price responsive load should be curtailed, we are attempting to estimate a value that cannot be directly observed. It will be necessary to consider indirect indicators of value. Further, different consumers may place very different values on uninterrupted electrical energy services. Any given consumer may value these services differently depending on season, time of day, the duration and frequency of interruptions, and their ability to anticipate and adjust to the interruption of these services. In setting default Security Interruption Prices, the Midwest ISO will have to take this variation into consideration.

This study examines measures of the value to consumers of having uninterrupted electrical energy service. Examined from the consumers' perspective, this means estimating the cost of electric service outages. The remainder of this discussion provides an overview of some of the previous work in this area. Section III then summarizes the estimates of customer outage costs that were specifically developed for the MISO. Full results for this analysis and a technical discussion of the methods of estimation are provided in the appendices. As part of Section III, we provide a comparison of these estimates with those that have previously appeared in the literature, and a series of caveats concerning our estimates. Section IV provides a set of recommendations for the use of these estimates.

II. BACKGROUND ON THE QUANTIFICATION OF OUTAGE COSTS

Outage costs are the generally used proxy for the largely unobserved value of uninterrupted electricity service. Quantifying the costs and losses from interruptions is an easier task than the direct value measurement of reliability. Although, these costs are not precisely identical to the value of reliability, they are considered reasonably representative measures (Ghajar and Billinton, 2006). Once we have estimated consumer costs associated with the interruption of service during relevant times, it will be possible to estimate the value of marginal kWh of energy in peak periods when markets are tight and shortages might occur. For these reasons, our discussion focuses on the quantification and estimation of outage costs.

Components of outage costs vary based upon the customer class under consideration.[1] Exhibit 1 presents a summary of the major cost components (direct and indirect) for each major class of customer (Munasinghe and Sanghvi, 1988). This listing is by no-means all inclusive, but does provide an understanding of some of the costs associated with an interruption of electrical service. As will be come apparent upon review of this exhibit, many of these costs, particularly for residential customers, are intangible and are function of the context or the characteristics of the entity providing the outage cost valuation. As has been extensively explored in previous studies, the magnitude of individual components are subject to such factors as the duration of an outage, the time of day and season of an outage, and the frequency or expectations of an outage.

Exhibit 1. Direct and Indirect Components of Outage Costs

Primary Electricity User	Direct Components of Outage Costs	Indirect Components of Outage Costs
Residential	a. Inconvenience, lost leisure, stress, etc. b. Out-of-pocket costs • Spoilage • Property damage c. Health and safety effects	Costs to other households and firms.
Industrial, Commercial, and Agricultural Firms	a. Opportunity costs of idle resources such as labor, land, capital b. Shutdown and restart costs c. Spoilage and damage d. Health and safety effects	a. Cost on other firms that are supplied by impacted firm (multiplier effect) b. Costs on consumers if impacted firm supplies a final good c. Health and safety related externalities
Infrastructure and Public Service	a. Opportunity cost of idle resources b. Spoilage and damage	a. Costs to public users of impacted services and institutions b. Health and safety effects c. Potential for social costs stemming from looting, vandalism

Source: Munasinghe and Sanghvi, 1988

[1] These factors have been discussed in substantial detail by others including: Billinton et al., 1986, 1987; Billinton and Wangdee, 2003, 2005; Subramaniam, Billinton, et al., 1985, 1993; Subramaniam, Wacker, et al., 1993.

Characterizing and valuing the demand for service reliability by electricity customers has assumed a significant role in the development of de-regulated markets for electricity. Customer outage costs have been used in the following contexts:

- Economic efficiency dictates that capacity and delivered reliability should be jointly optimized with prices set equal to marginal cost (Crew and Kleindorfer, 1978). Arbitrarily set reliability criteria such as a reserve margin or loss of load probability (LOLP) do not relate the specification of power supply adequacy to economic parameters such as consumer costs, system costs, and electricity prices (Sanghvi, 1983b). As a result, outage costs have gained wide-spread application in planning activities particularly cost/benefit analyses of investments undertaken to ensure or improve system reliability.[2] (See footnote two for examples of the use of outage costs in this context).

- Outage costs play a key role in the pricing of transmission services and development of innovative rates. They have been used in the development of:
    - The allocation of Available Transmission Capacity between firm and interruptible transmission capacity (da Silva et al., 1999);
    - The development of ancillary service markets (Kamat and Oren, 2002);
    - Priority contracting with zone differentiated pricing (Beenstock and Goldin, 1997; Chao et al., 1988; Chao and Wilson, 1987; Deng and Oren, 2001; Woo, 1990; Woo et al., 1998);
    - The design of interruptible rates (Doane et al., 1988a; Woo and Toyama, 1986);
    - Pricing of electricity as a differentiated product, including capacity subscription where reliability is viewed as a product attribute, TOU or Real Time pricing, increasing block rates, and other pricing structures (Doorman, 2005; Ghajar, 1998; Strauss and Oren, 1993; Vogelsang, 2001);
    - Rationing proposals ranging from simple rotating blackouts to sophisticated load shedding during periods of shortage (Chao, 1983; Keane et al., 1988; Oren and Doucet, 1990; Poore et al., 1983; Tishler, 1993).

- In selected market and rate designs, outage costs are a component of spot prices (Billinton and Ghajar, 1994; Ghajar and Billinton, 1994, 1995). Marginal outage costs provide an economic signal to customers of the total costs (i.e., market and social) that will be incurred during periods of incremental load that can not be supplied.

[2] (Ball et al., 1997; Bernstein and Hegazy, 1988; Billinton and Oteng-Adjei, 1988, 1991; Dalton et al., 1996; Debnath and Goel, 1995; Eua-arporn, 2005; Forte et al., 1995; Goel and Billinton, 1993; Goel and Billinton, 1994; Gouni and Torrion, 1988; Kariuki and Allan, 1996a; Keane and Woo, 1992; Munasinghe, 1980b, 1988; Neudorf et al., 1995; Oteng-Adjei and Billinton, 1990; Poland, 1988; Sarkar, 1996; Telson, 1975; Tishler, 1993; Vojdani et al., 1996; Wang and Min, 2000)

Since outage costs can be viewed from several different economic perspectives,[3] a number of different methods have been applied to their measurement. Methods previously applied in studies quantifying outage costs may be categorized into four groups based upon the estimation technique employed (Caves et al., 1990). Those methods include:

1) Survey methods provide the primary source of data on outage costs to consumers (Caves et al., 1990). Survey methods overcome many of the objections to other methods or techniques. For example, surveys can collect information such that costs may be linked to duration, frequency, and timing of an outage. Also, surveys may be used to collect information defining a distribution of costs within the population.

   Surveys may take many forms, but the primary forms applied to outage cost quantification include: (1) direct approaches where customers are asked to assign a dollar value to the costs that might be incurred during an outage (e.g., in the industrial sector, costs might include lost production or damage to equipment and materials); (2) contingent valuation where customers are asked about their valuation of a hypothetical (or non-market priced) good through a 'willingness to accept' or 'willingness to pay'; and, (3) contingent ranking (choice) methods where customers are asked to rank a series of outage options with each option associated with a rate increase or decrease in reliability (Caves et al., 1992).

   Each of these forms of a survey has advantages and disadvantages depending upon the context of application. For example, industrial and commercial customers may be able to fairly accurately assess direct costs of an outage. However, indirect costs of outages, such as multiplier effects, are usually not accounted for. Further, customers (particularly in the residential sector) may have difficulty consistently valuing a hypothetical situation posed in a contingent valuation survey particularly if the hypothetical is unrealistic or they have little or no experience in such situations (Andersson and Taylor, 1986; Doane et al., 1988a; Woo et al., 1991). Within the economics community, the choice between willingness to accept (WTA) and willingness to pay (WTP) as a value remains a subject of debate (Coursey et al., 1987). In applied settings, these two measures have resulted in divergent results with customers requiring substantially higher compensation (WTA) for a loss of quality than they are willing to pay (WTP) for an equivalent gain. These measures converge as consumers gain experience with a situation with the WTP measure subject to the least change. As a result, the WTP measure is viewed as the more stable and probably more accurate measure (Caves et al., 1990).

[3] Outage costs have been viewed as a loss of consumer welfare as a result of an outage. Viewing outage costs from this perspective leads to the measurement of a customer's willingness to pay to avoid an interruption (Crew and Kleindorfer, 1978; Sherman and Visscher, 1978). Similarly, since electricity is also an intermediate good in the production of goods and services, an outage costs have been viewed as an opportunity loss of production (Munasinghe and Gellerson, 1979).

All survey methods have limitations (Caves et al., 1990). Customers, no matter what their class, with little prior experience with outages may have difficulty fully identifying and assessing the costs of an outage. Consumers often report placing a higher value on avoiding the loss of current levels of reliability (as in WTA surveys) than what they would pay for additional reliability (e.g. WTP), and this results in asymmetrical valuations of losses and gains (Hartman et al., 1990; Wacker and Billinton, 1989a; Wacker et al., 1985). Further, survey results can be affected by the wording of the questions used in the survey. Finally, surveys are limited because they provide information on customer attitudes and intentions, and not actual behavior – which there may be no opportunity to observe.

2) <u>Proxy methods</u> where an observable behavior is used to approximate the cost of an outage. For example, industrial customers purchase back-up generation until the expected marginal cost of additional back-up power equals the expected marginal cost of an outage event (Bental and Ravid, 1982). Purchase of a back-up generator would be evidence of 'revealed preference' towards avoiding an outage (Beenstock et al., 1997; Matsukawa and Fujii, 1994). However, proxy methods often reveal little detail about consumer preferences and may provide only an upper or lower bound on outage cost estimates. For conversion to an outage cost, this particular proxy requires numerous assumptions, and does not include the effects of the duration or timing of an outage event, or customer characteristics, or the effects of forewarning.

   Other proxies for outage costs that have been used previously include: (1) the ratio of output to electricity consumption (Telson, 1975); (2) the price of electricity; (3) the value of production in the home where electricity is viewed as an input to the production of household services; (4) the wage rate where outage costs to residential customers primarily result from a loss of leisure (Munasinghe, 1980a); and, (5) consumer's expectations of service reliability (Goett et al., 1988). All of these proxies have specific draw-backs and can be viewed as either an upper or lower bound on outage costs. For example, the use of the ratio of output to electricity consumption assumes that there is no substitute between electricity and other factors of production, ignores the costs of damage to equipment and materials during an outage, and assumes that lost sales or production cannot be recovered at some later date (Bental and Ravid, 1982). As another example of the difficulties associated with a proxy, the value of production in the home assumes that a fairly complete listing of household services along with market values can be obtained (Caves et al., 1990). And, further that these services cannot be readily shifted from a point of electricity service interruption to another period.

3) <u>Consumer surplus</u> methods have been an attempt to bypass the problem of lack of survey data by estimating value based upon observations of price elasticity (Caves et al., 1990). These methods are based on the concept that observations of consumer response to longer term changes in prices will reveal information about the lost value when electricity is unavailable. These methods have the advantages that they are based on actual observed behavior. However, there are three serious

limitations that have severely restricted their use: (1) a consumer's demand curve (and the implied outage cost estimates) depend upon the advance warning customer's receive of a price change, and current demand estimates are based on changes that are well known in advance (not unannounced interruptions); (2) demand curves in the literature have been estimated primarily with monthly or annual data, and as a result, underestimate a consumer's ability to adapt to short term power interruptions and potentially overstate outage costs; and, (3) estimated demand elasticities are valid in the interval represented in the data set used in estimation and may not be representative for zero usage.

4) Reliability demand models explicitly include the quality of service in a demand model. However, because US reliability levels have been uniformly high, these models have not been applied in this country (Caves et al., 1990). The only application of this model type has occurred in developing countries, and due to the specification (e.g., use of dummy variables) outage costs have been very difficult to infer.

III. Estimated costs for the Mid-West

A. Discussion of Estimation Results

The remainder of this report covers the estimated outage costs prepared on behalf of the MISO. The combination of these costs into a weighted average can be performed using either the peak demand ($/kW) or peak hour ($/peak period kWh) distribution for short duration interruptions such as those that might be anticipated during tight supply conditions. As a result, damage functions may be produced at various levels of geographic or spatial disaggregation.

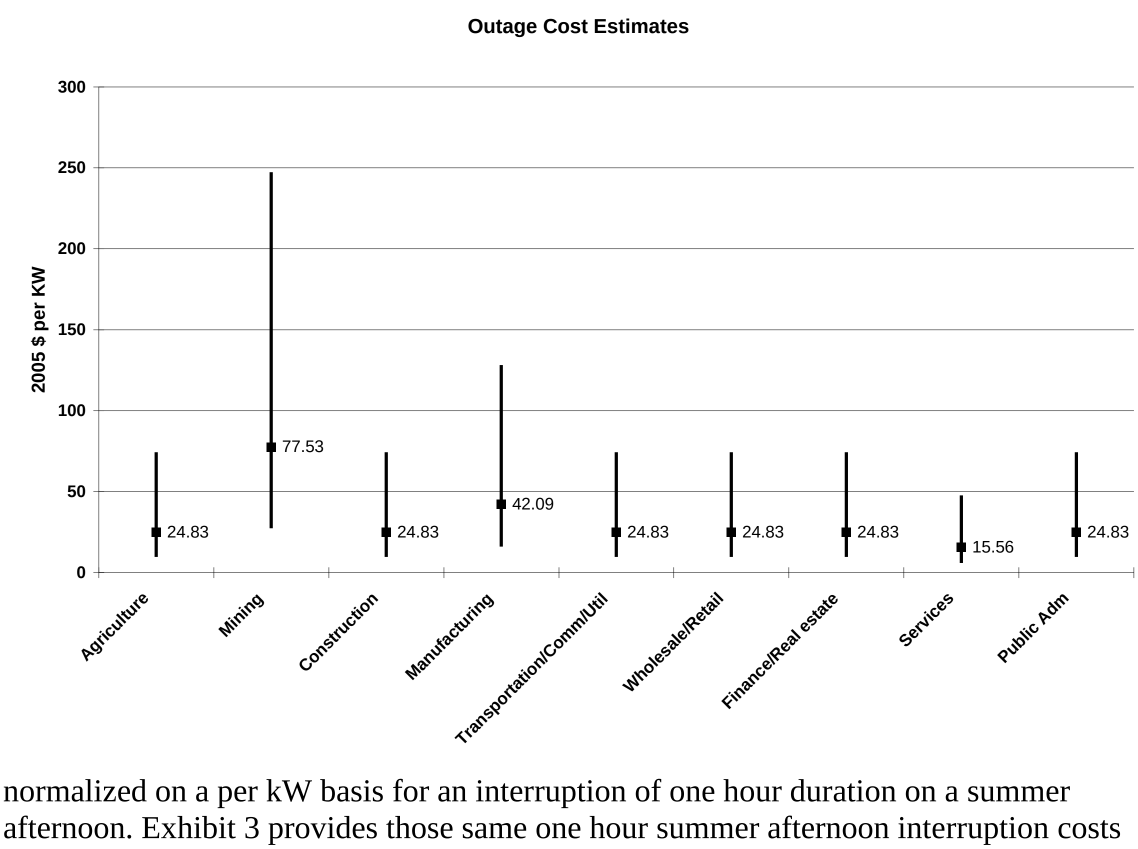
For this work, in Appendix A, we have presented the outage costs for large commercial and industrial facilities (over 1 million kWh annual consumption), small commercial and industrial facilities (under 1 million kWh annual consumption), and residential customer classes. We did not have the data to estimate outage costs for infrastructure or public services. Since ranges of uncertainty and probabilistic techniques are used in cost/benefit analyses and adequacy studies,[4] the costs presented in Exhibits 2-7, and in Appendix A, are presented as distributions. Costs for each customer class were estimated for interruption events of one, two, and three hours duration during a summer afternoon. The interruption costs for one hour have also been normalized to $/kW during a summer afternoon. Additional outage costs for other daily time periods (i.e., morning, night) and seasons (i.e., winter, spring) may be generated utilizing the models that were built to provide these estimates.

[4] Probabilistic techniques require the development and use of distributions of the required inputs. As these techniques have gained acceptance, development of distributions of outage costs has become a more important issue (Goel, 1998).

Our estimates were generated utilizing published statistical models for residential, commercial, and industrial customers, and publicly available data for the independent variables included in the model. Full details on the estimation process used are provided in Appendix B. The published statistical model was generated from a meta-database developed using 24 studies conducted by eight electric utilities between 1989 and 2002 (Lawton, Sullivan et al., 2003). This analysis was performed under the auspices of Lawrence Berkeley National Laboratory for the Energy Storage Program, Office of Electric Transmission and Distribution, US Department of Energy. The study was designed to make available a ready source for outage cost estimates to utilities without outage cost data. Similar studies have shown that such statistical models do have reasonable explanatory power and, if appropriately applied, can be transferred to other areas (Sullivan et al., 1996). To capture the variability of outage costs in the MISO, distributions of various independent variables such as household income were taken from publicly available sources for the Midwest Census region.

Exhibits 2 and 3 provide summaries of the estimation results for large commercial and industrial facilities in the Midwest. Exhibit 2 provides the distribution of costs

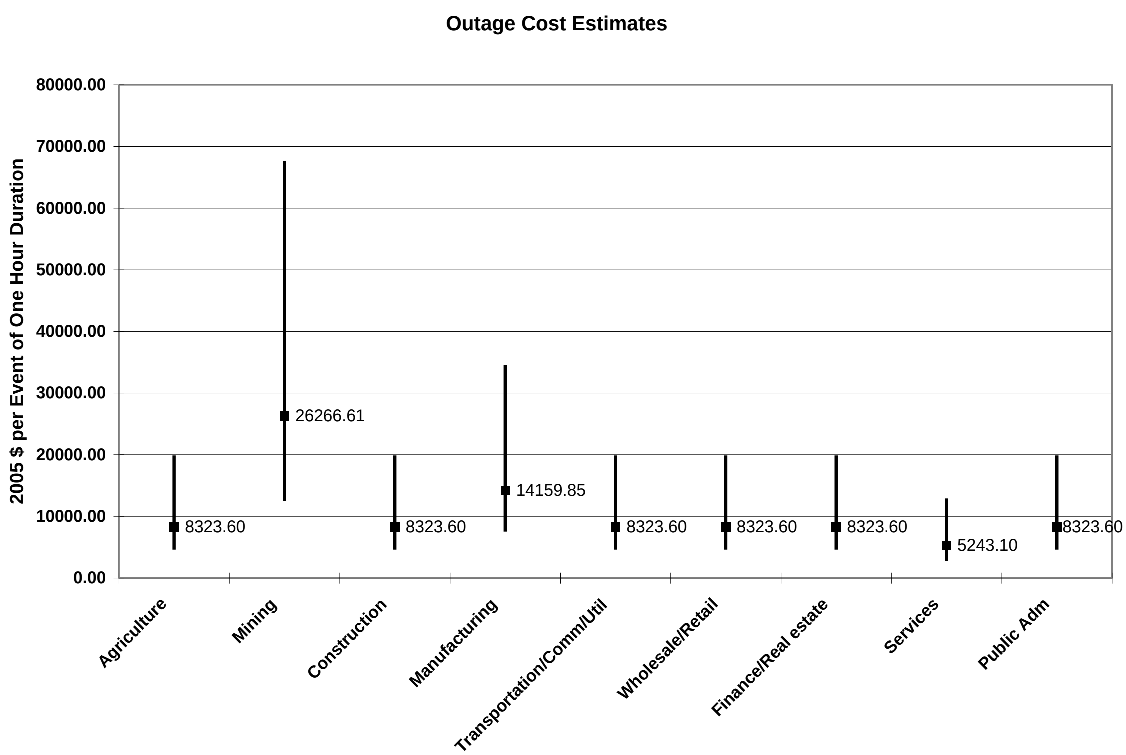
Exhibit 2. Outage Cost Estimates for Large Commercial and Industrial Facilities in the Midwest: 2005 $ per kW for a one hour interruption on a summer afternoon (median values given)



normalized on a per kW basis for an interruption of one hour duration on a summer afternoon. Exhibit 3 provides those same one hour summer afternoon interruption costs on a per event basis. Per event costs reflect the different levels of summer afternoon demand in each sector among other factors. Nine different industrial groups are included and are defined as follows: Agriculture (SIC 01-09); Mining (SIC 10-14); Construction (SIC 15-17); Manufacturing (SIC 20-39); Transportation, Communications, and Utilities (SIC 40-49); Wholesale/Retail (SIC 50-59); Finance/Real Estate (SIC 60-67); Services (70-89); and Public Administration (SIC 91-97). Large commercial and industrial facilities are defined as those facilities with an annual electricity consumption of one million or more kWh.

The ranges presented on both Exhibits 2 and 3 are from the fifth to the ninety-fifth percentile of estimated costs for each commercial or industrial sector group. The median value for each range (sectoral group) is presented. All values are 2005 constant dollars. Median values for a one hour interruption during a summer afternoon range from $15.56 to $77.53 per kW. Mining displays the highest median value and greatest variability, while Services has the lowest median value and the least variability.

Exhibit 3. Outage Cost Estimates for Large Commercial and Industrial Facilities in the Midwest: 2005 $ per event for a one hour interruption on a summer afternoon (median values given)



Exhibits 4 and 5 provide the same information for small commercial and industrial facilities in the Midwest. Small commercial and industrial facilities are defined as those facilities with less than one million kWh of annual electricity consumption. Once again, ranges are presented from the fifth to ninety-fifth percentiles with the median values indicated. Median values for small commercial and industrial facilities range from $15.25 to $49.51 per kW.

Two factors should be noted when comparing the results from large and small commercial and industrial facilities. First, although, distributions from both are truncated (i.e., at the lower end of electricity usage for large facilities, and at the upper end for small facilities), the results for small facilities show greater variability. This is a result of the underlying distributions of annual electricity consumption and employment per establishment. Those distributions have greater variability between sector groupings for small commercial and industrial facilities. Second, as indicated in Appendix B, more of the estimated coefficients for the sector groupings were significant in the small commercial and industrial model as compared with the same coefficients for large commercial and industrial facilities. As discussed in the 'caveats' section of this report, within commercial and industrial groups, one of the best explanatory variables for this type of model is SIC category at the two digit or greater level. However, the statistical models presented in Lawton, Sullivan, et al., 2003 that were used in this effort did not include that information. Therefore, we were unable to determine what portion of the variability in our estimates of outage costs may be attributable to that factor.

Exhibit 4. Outage Cost Estimates for Small Commercial and Industrial Facilities in the Midwest: 2005 $ per kW for a one hour interruption on a summer afternoon (median values given)

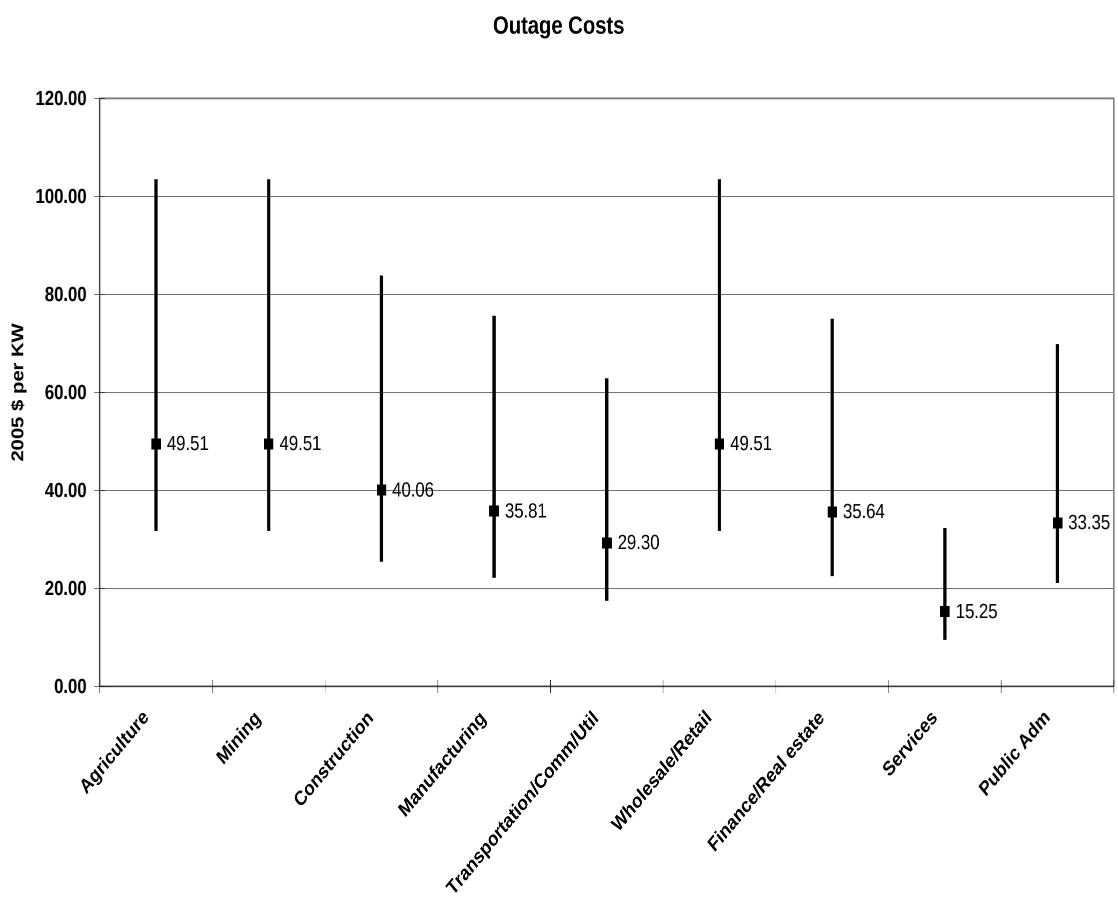
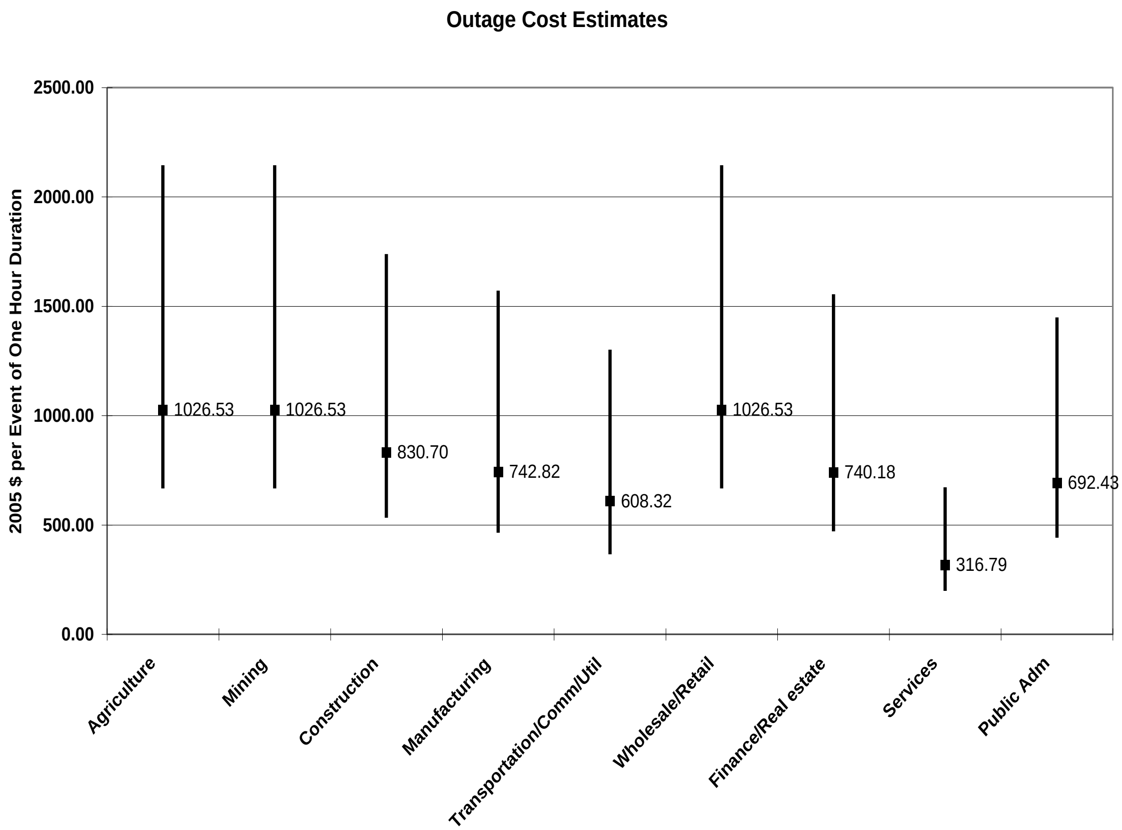


Exhibit 5. Outage Cost Estimates for Small Commercial and Industrial Facilities in the Midwest: 2005 $ per event for a one hour interruption on a summer afternoon (median values given)



Exhibits 6 and 7 provide the estimated outage costs for residential consumers in the Midwest. Exhibit 6 provides the one hour duration scenario normalized to a per kW basis. Median costs for events with a duration of one, two, and three hours range from $3.76 to $5.41. The median cost per kW during a one hour interruption on a summer afternoon is $1.47. And, costs for an event of one hour range from $2.58 (fifth percentile) to $11.43 (ninety-fifth percentile). Exhibit 7 provides the distributions of willingness to pay per event for three different duration lengths (one, two, and three hours) during summer afternoons. As presented in this exhibit, there is a non-linear relationship between duration and outage costs with a fixed component that is incurred when the outage occurs.

Exhibit 6. Distribution of Residential Willingness to Pay (Outage Cost) Estimates for Residential Consumers in the Midwest: 2005 $ per kW for a one hour interruption on a summer afternoon

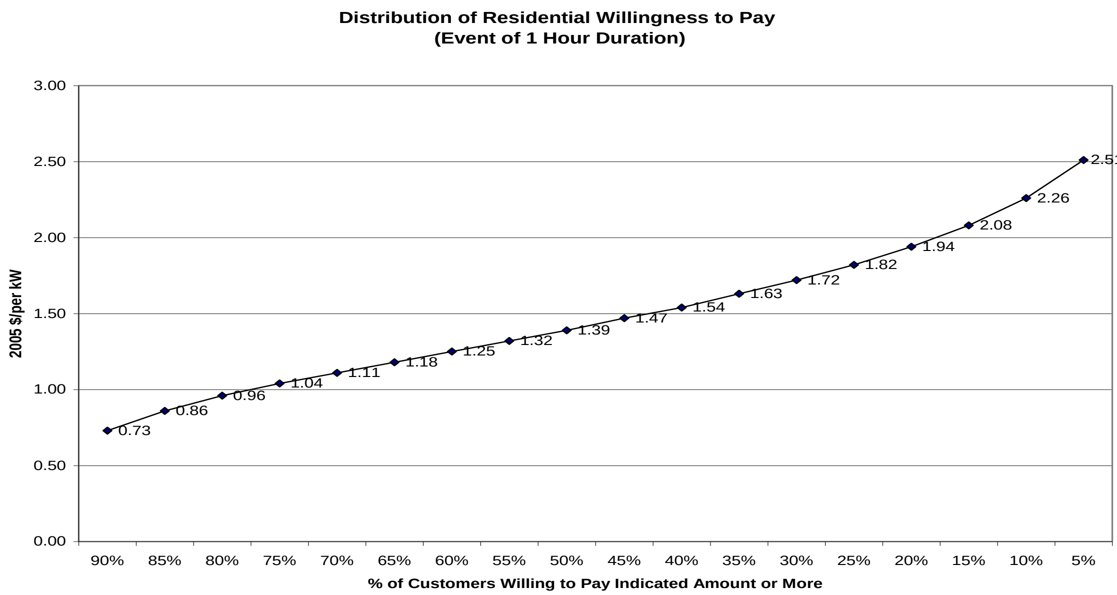
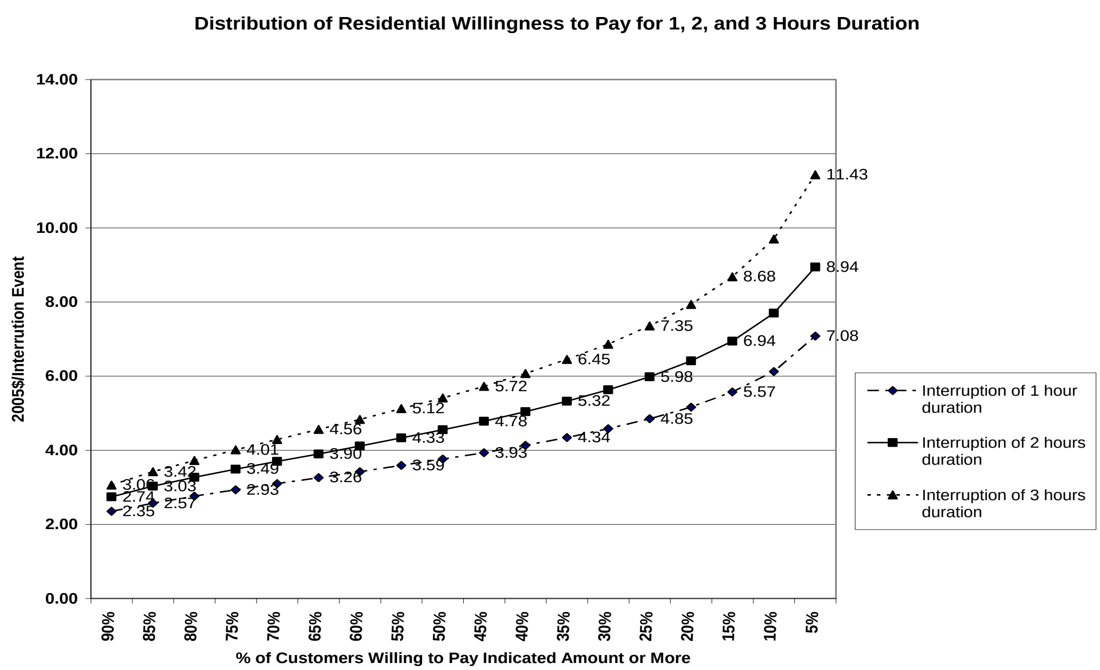


Exhibit 7. Distribution of Residential Willingness to Pay Estimates for Residential Consumers in the Midwest: 2005 $ per event of varying durations for interruptions on a summer afternoon



B. COMPARISON OF RESULTS WITH PREVIOUS ESTIMATES

Exhibits 8, 9, 10, and 11 compare our estimates reported here with estimates from previous outage cost studies reported in the literature. In comparing outage cost estimates it is important to evaluate costs for systems of similar development, and generated using similar methods (Caves et al., 1990). Therefore, we have restricted our reporting to those estimates from the US, Canada, and the UK. Also, the majority of these estimates were derived using survey data. We have also indicated beside each measure whether it is a direct cost estimate, a willingness-to-pay, or a willingness-to-accept measure. This provides an easier comparison between like measures. All of the estimates from the literature were escalated to 2005 $, and foreign estimates were converted to US currency utilizing published purchasing power parities from the OECD. This process has ensured that our estimated values are comparable in constant dollars to previously published outage cost values.

When comparing our results with the prior results on Exhibits 8 through 11, one should note that we are reporting the median values for our estimates. Estimates taken from the literature are usually reported as the average or mean. As a result, the values are not directly comparable. We do provide in Appendix A, the mean values for each sector grouping by scenario in addition to the median values. We feel that the median values (50 percent of facilities below and 50 percent of facilities above) provide a better indicator than the mean values that incorporate a some anomalously high estimated costs. Median results were lower than the estimated means.

For the purpose of direct comparison for industrial and commercial outage cost estimates, Exhibits 8 and 10 report our estimates and then estimates from the literature for the same size consumers. Estimates for large commercial and industrial facilities with an annual consumption of over one million kWh are reported in Exhibit 8; estimates for small commercial and industrial facilities with an annual consumption of less than one million kWh are reported in Exhibit 10. Exhibit 9 reports values for agricultural, commercial, and industrial facilities without specification of the annual energy consumption which was not usually reported.

Evaluating Exhibits 8 and 10, on a cost per event basis, our estimates (medians) are lower than those reported on average for facilities of with the same range of annual electricity consumption. However, if our estimates are evaluated in light of the estimates for facilities without regard to annual energy consumption reported in Exhibit 9, our estimates are well within the range of previously reported estimates. Evaluation of the $/kW measure indicates that once again our estimates are within the range of previous estimates. Since our estimates are reported by industrial group, some of the variability that is concealed in some previously reported averages is revealed.

Exhibit 11 provides similar prior estimates from the literature of residential customer willingness-to-pay compared to our results. Once again we are comparing median values with average values; but, average values for our estimates are reported in Appendix A. Once again our estimates are within the range of previously reported values

Exhibit 8. Estimates for Large Commercial and Industrial Facilities in the Midwest Compared with Previous Estimates (electricity consumption of more than one million kWh per year)

Citation/Source	Year of Survey	Region	Season	Sample Size	2005 $/kW Peak	2005 $/kWh Unserved	2005 $/Event
Estimated from this project (Median value given with other distribution characteristics provided in Appendix A)							
Agriculture (SIC 01 – 09)		Midwest	Summer afternoon		24.83	N/A	8,323.60
Mining (SIC 10 – 14)		Midwest	Summer afternoon		77.53	N/A	26,266.61
Construction (SIC 15 – 17)		Midwest	Summer afternoon		24.83	N/A	8,323.60
Manufacturing (SIC 20 – 39)		Midwest	Summer afternoon		42.09	N/A	14,159.85
Transportation/Communication/Utilities (SIC 40 – 49)		Midwest	Summer afternoon		24.83	N/A	8,323.60
Wholesale/Retail (SIC 50 – 59)		Midwest	Summer afternoon		24.83	N/A	8,323.60
Finance/Real estate (SIC 60 – 67)		Midwest	Summer afternoon		24.83	N/A	8,323.60
Services (SIC 70 – 89)		Midwest	Summer afternoon		15.56	N/A	5,243.10
Public Administration (SIC 91 – 97)		Midwest	Summer afternoon		24.83	N/A	8,323.60
Literature							
Lawton, Sullivan et al., 2003	1986-2000	US All Region	N/A	2,728	16.85	N/A	65,118.13
Lawton, Sullivan et al., 2003	1986-2000	US Northwest	N/A	834	19.46	N/A	31,058.26
Lawton, Sullivan et al., 2003	1986-2000	US Southwest	N/A	190	23.80	N/A	56,352.42
Lawton, Sullivan et al., 2003	1986-2000	US Southeast	N/A	1,352	16.10	N/A	93,879.84
Lawton, Sullivan et al., 2003	1986-2000	US West	N/A	120	35.52	N/A	57,249.01
Lawton, Sullivan et al., 2003	1986-2000	US Midwest	N/A	232	12.48	N/A	31,195.20
Sullivan et al., 1996	1992	USA (not specified)	N/A	198	N/A	N/A	54,927.60
Sullivan et al., 1996	1992	USA (not specified)	N/A	198	N/A	N/A	31,978.81

Exhibit 9. Estimates of Outage Costs from the Literature for Industrial and Commercial Facilities: No Size (Annual Energy Consumption) Indicated

Citation/Source	Sector	Year of Survey	Region	Season	Sample Size	2005 $/kW Peak	2005 $/kWh Unserved	2005 $/Event
Samotyj, 2001	Digital Economy	2001	US All Region	N/A	985	N/A	N/A	8,596.07 (Dir)
Energy and Environmental Economics Inc., 2005	Industrial	1999	California	Summer weekday/afternoon	N/A	N/A	25.64 (Dir)	N/A
Energy and Environmental Economics Inc., 2005	Industrial and Commercial	1999	California	Summer weekday/afternoon	N/A	N/A	10.34 (WTP)	N/A
Energy and Environmental Economics Inc., 2005	Industrial and Commercial	1999	California	Summer weekday/evening	N/A	N/A	9.93 (WTP)	N/A
Energy and Environmental Economics Inc., 2005	Industrial and Commercial	1999	California	Summer weekday/afternoon	N/A	N/A	257.33 (Dir)	N/A
Energy and Environmental Economics Inc., 2005	Industrial and Commercial	1999	California	Summer weekday/evening	N/A	N/A	432.89 (Dir)	N/A
Tollefson, Billinton, Wacker et al., 1994	Industrial	1991	Canada	N/A	819	N/A	N/A	3,812.18 (Dir)
Burns and Gross, 1990	Industrial	1983-9	California	Summer	N/A	N/A	11.19 (Dir)	N/A
Kariuki and Allan, 1996d	Industrial	1992	United Kingdom	N/A	119	N/A	N/A	9,638.77 (Dir)
Sullivan et al., 1996	Industrial	1992-3	North Carolina	Summer	1,080	5.01 (Dir)	N/A	6,184.73 (Dir)
Woo and Pupp, 1992	Industrial	1990	New York, USA	Summer / 2 PM	N/A	N/A	11.48 (Dir)	16,506.00 (Dir)
Woo and Pupp, 1992	Industrial	1990	New York, USA	Winter / 8 PM	N/A	N/A	13.37 (Dir)	12,333.83 (Dir)
Woo and Pupp, 1992	Industrial	1987	California, USA	Summer afternoon	N/A	N/A	91.21 (Dir)	22,758.75 (Dir)
Woo and Pupp, 1992	Industrial	1987	California, USA	Summer afternoon	N/A	N/A	N/A	13,510.35 (Dir)
Woo and Pupp, 1992	Industrial	1987	California, USA	Summer afternoon	N/A	N/A	N/A	7,692.30 (Dir)
Energy and Environmental Economics Inc., 2005	Agricultural	2000	California	Summer weekday/afternoon	N/A	N/A	11.89 (Dir)	N/A
Billinton and Oteng-Adjei, 1988	Agricultural	1985	Canada	N/A	N/A	21.00 (Dir)	N/A	N/A

Citation/Source	Sector	Year of Survey	Region	Season	Sample Size	2005 $/kW Peak	2005 $/kWh Unserved	2005 $/Event
Burns and Gross, 1990	Agricultural	1983-9	California	Summer	N/A	N/A	5.83(Dir)	N/A
Energy and Environmental Economics Inc., 2005	Commercial	2000	California	Summer weekday/afternoon	N/A	N/A	68.20(Dir)	N/A
Kariuki and Allan, 1996d	Commercial	1992	United Kingdom	N/A	203	N/A	N/A	237.61(Dir)
Sullivan et al., 1996	Commercial	1992-93	North Carolina	Summer	210	29.26(Dir)	N/A	841.04(Dir)
Tollefson, Billinton, Wacker et al., 1994	Commercial	1991	Canada	N/A	657	N/A	N/A	1,356.62(Dir)
Woo and Pupp, 1992	Commercial	1988	California, USA	Summer afternoon	N/A	N/A	5.12(Dir)	6,807.15(Dir)
Woo and Pupp, 1992	Commercial	1988	California, USA	Summer afternoon	N/A	N/A	N/A	4,465.13(Dir)
Woo and Pupp, 1992	Commercial	1988	California, USA	Summer afternoon	N/A	N/A	N/A	3,929.63(Dir)
Billinton and Oteng-Adjei, 1988	Commercial	1985	Canada	N/A	N/A	24.81(Dir)	N/A	N/A
Burns and Gross, 1990	Commercial	1983-89	California	Summer	N/A	N/A	65.52(Dir)	N/A
Billinton and Oteng-Adjei, 1988	Government & Institutions	1985	Canada	N/A	N/A	2.18(Dir)	N/A	N/A
Gates et al., 1999	Government & Institutions	1995	Canada	N/A	288	N/A	N/A	1,163.09(Dir)
Billinton and Oteng-Adjei, 1988	Office Buildings	1985	Canada	N/A	N/A	30.75(Dir)	N/A	N/A

Note: Costs differentiated in terms of type: Direct(Dir), WTP(WTP), and WTA(WTA)

Note: Extensive bibliographies of previous studies of outage costs may be found in (Billinton et al., 1983; Tollefson, Billinton, and Wacker, 1994).

Exhibit 10. Estimated Outage Costs for Small Commercial and Industrial Facilities Compared to Previous Estimates (less than one million kWh per year)

Citation/Source	Year of Survey	Region	Season	Sample Size	2005 $/kW Peak	2005 $/kWh Unserved	2005 $/Event
Estimated from this project (Median value given with other distribution characteristics provided in Appendix A)							
Agriculture (SIC 01 – 09)		Midwest	Summer afternoon		49.51	N/A	1,026.53
Mining (SIC 10 – 14)		Midwest	Summer afternoon		49.51	N/A	1,026.53
Construction (SIC 15 – 17)		Midwest	Summer afternoon		40.06	N/A	830.70
Manufacturing (SIC 20 – 39)		Midwest	Summer afternoon		35.81	N/A	742.82
Transportation/Communication/Utilities (SIC 40 – 49)		Midwest	Summer afternoon		29.30	N/A	608.32
Wholesale/Retail (SIC 50 – 59)		Midwest	Summer afternoon		49.51	N/A	1,026.53
Finance/Real estate (SIC 60 – 67)		Midwest	Summer afternoon		35.64	N/A	740.18
Services (SIC 70 – 89)		Midwest	Summer afternoon		15.25	N/A	316.79
Public Administration (SIC 91 – 97)		Midwest	Summer afternoon		33.35	N/A	692.43
Literature							
Lawton, Sullivan et al., 2003	1986-2000	US All Regions	N/A	10,849	43.45	N/A	2,018.64
Lawton, Sullivan et al., 2003	1986-2000	US Northwest	N/A	3,596	19.99	N/A	1,830.54
Lawton, Sullivan et al., 2003	1986-2000	US Southwest	N/A	3,064	72.07	N/A	2,362.01
Lawton, Sullivan et al., 2003	1986-2000	US Southeast	N/A	3,363	28.00	N/A	1,611.54
Lawton, Sullivan et al., 2003	1986-2000	US West	N/A	411	110.50	N/A	4,973.34
Lawton, Sullivan et al., 2003	1986-2000	US Midwest	N/A	415	4.62	N/A	1,486.20

Note: All costs are direct costs.

Exhibit 11. Estimates for Residential Consumers in the Midwest Compared with Previous Estimates

Source	Year of Survey	Region	Season	Sample Size	2005 $/kW Peak	2005 $/kWh Unserved	2005 $/Event
Estimated from this project (Median value given with other distribution characteristics provided in Appendix A)		Midwest	Summer Afternoon		1.47(WTP)	N/A	3.76(WTP)
Literature							
Lawton, Sullivan et al., 2003	1989-2000	US (All regions)	Winter	11,368	N/A	N/A	9.09(WTP)/16.96(WTA)
Lawton, Sullivan et al., 2003	1989-2000	US (All regions)	Summer	11,368	N/A	N/A	7.21(WTP)/10.42(WTA)
Lawton, Sullivan et al., 2003	1989-2000	US (All regions)	All	11,368	N/A	N/A	7.61(WTP)/11.60(WTA)
Lawton, Sullivan et al., 2003	1989-2000	US (All regions)	No season/ Weekday	11,368	N/A	N/A	7.56(WTP)/11.56(WTA)
Lawton, Sullivan et al., 2003	1989-2000	US (All regions)	No season/ Weekend	11,368	N/A	N/A	8.50(WTP)/11.94(WTA)
Lawton, Sullivan et al., 2003	1989-2000	Northwest US	N/A	11,368	N/A	N/A	8.38(WTP)/14.84(WTA)
Lawton, Sullivan et al., 2003	1989-2000	Southwest US	N/A	11,368	N/A	N/A	7.74(WTP)
Lawton, Sullivan et al., 2003	1989-2000	Southeast US	N/A	11,368	N/A	N/A	7.91(WTP)/10.32(WTA)
Lawton, Sullivan et al., 2003	1989-2000	West US	N/A	11,368	N/A	N/A	2.49(WTP)
Energy and Environmental Economics Inc., 2005	2000	California	Summer Weekday/evening	N/A	N/A	5.27(Dir)	N/A
Energy and Environmental Economics Inc., 2005	2000	California	Summer afternoon	N/A	N/A	5.27(Dir)	N/A
Energy and Environmental Economics Inc., 2005	1999	California	Summer afternoon	N/A	N/A	4.86(WTP)/10.24(WTA)	N/A
Energy and Environmental Economics Inc., 2005	1999	California	Summer Weekday/evening	N/A	N/A	4.76(WTP)/10.03(WTA)	N/A
Energy and Environmental Economics Inc., 2005	1992	California	Summer Weekday/evening	N/A	N/A	3.80(WTP)	N/A
Energy and Environmental Economics Inc., 2005	1992	California	Summer Weekday/evening	N/A	N/A	8.79(Dir)	N/A
Tollefson, Billinton, Wacker et al., 1994	1991	Canada	Winter	1,817	N/A	N/A	1.46(Dir)
Kariuki and Allan, 1996d	1992	United Kingdom	N/A	4,014	N/A	N/A	1.57(Dir)
Sullivan et al., 1996	1992-3	North Carolina	Summer	1,584	2.62(Dir)	N/A	6.83(Dir)
Tollefson, Billinton, Wacker et al., 1994	1991	Canada	Winter	1,817	N/A	N/A	1.46(Dir)

Source	Year of Survey	Region	Season	Sample Size	2005 $/kW Peak	2005 $/kWh Unserved	2005 $/Event
Burns and Gross, 1990	1983-9	California	Summer	N/A	N/A	6.69(Dir)	N/A
Doane et al., 1988b	1986	California	Winter Evening	1,500	N/A	N/A	5.26(WTP)/19.16(WTA)
Doane et al., 1988b	1986	California	Summer Afternoon	1,500	N/A	N/A	2.92(WTP)/6.52(WTA)
Doane et al., 1988b	1986	California	Summer Afternoon	1,500	N/A	N/A	1.75(WTP)/4.97(WTA)
Woo and Pupp, 1992	1988	California, USA	Winter Evening	N/A	N/A	28.65(Dir)	19.14(Dir)
Woo and Pupp, 1992	1988	California, USA	Winter Morning	N/A	N/A	6.82(Dir)	21.81(Dir)
Woo and Pupp, 1992	1988	California, USA	Summer Afternoon	N/A	N/A	8.68(Dir)	6.52(Dir)
Billinton and Oteng-Adjei, 1988	1985	Canada	N/A	N/A	0.84(Dir)	N/A	N/A
Woo and Pupp, 1992	1983	Wisconsin, USA	Summer/ 12 noon	N/A	N/A	0.27(Dir)	0.58(Dir)
Woo and Pupp, 1992	1983	Wisconsin, USA	Summer/ 8 AM	N/A	N/A	0.36(Dir)	0.58(Dir)
Woo and Pupp, 1992	1983	Wisconsin, USA	Summer / 4 PM	N/A	N/A	0.49(Dir)	1.23(Dir)

Note: Costs differentiated in terms of type: Direct(Dir), WTP(WTP), and WTA(WTA)

Note: Extensive bibliographies of previous studies of outage costs may be found in (Billinton et al., 1983; Tollefson, Billinton, and Wacker, 1994) of willingness-to-pay. As illustrated on Exhibit 11, there is a consistent discrepancy between WTP and WTA measures which reflects a generally observed difference between the higher value associated with giving up a service currently enjoyed compared to the willingness to pay for higher quality service.

C. CAVEATS FOR ESTIMATES OF OUTAGE COSTS

As with any economic analysis, there are caveats that need to be observed. When reviewing the results presented here for the Midwest, the following caveats need to be considered:

- The estimates presented here are derived from a statistical analysis of a meta-data set (Lawton, Sullivan et al., 2003). In developing such a data set, researchers are required to reconcile different survey instruments. This process necessarily loses some of the detailed information collected.

- These estimates do not fully value the complete economic costs of an outage. Outage costs consist of two components: (a) short-term outage costs, and (b) long-term adaptive costs (Sanghvi, 1982, 1983a; Sanghvi, 1983b)**.** Outage costs, as generally referred to in the literature and generally collected, are short-term outage costs. In the long-run, it has been argued that firms or consumers with expectations of interruption will pursue mitigation options such as voltage regulators, back-up generation, and demand-side measures.

  Short-term outage costs collected from customers with adaptive measures in place differ (in magnitude) than those collected from customers without such measures. The estimated models provided in Lawton, Sullivan, et al., 2003 did not make a distinction between customers with and without adaptive measures. As a result, we could not disaggregate between the two types of costs in our estimates, and thus our estimates should only be viewed as short-term outage costs.

- The estimates of outage costs presented in the graphics and in the appendices are only for summer afternoons (assumed to be peak or a system extreme on the MISO system). Other analyses of outage costs have shown that temporal variation (i.e., the time of day and season when interruption occurs) results in significant variations in cost. For example, outage costs for the industrial sector occurring during hours of reduced production can result in outage cost reductions of 9% to 26% (Jonnavithula and Billinton, 1997). Therefore, the estimates presented in this report may be viewed as the case where the system is probably operating at or near capacity, i.e., ‘worst case.’

- Outages from different sources (i.e., transmission and distribution versus generation) have very different outage costs. For example in a study of one major utility that announces generation short-falls one hour prior to an outage over radio and TV, outage costs from a generation short-fall were approximately 9% for residential, and slightly less than 55% for commercial and industrial of the outage costs from transmission and distribution failures (Sullivan et al., 1996). These observations were confirmed in Canada where savings of up to 34% in industrial outage costs were achieved if a two-day notice was given allowing for a controlled shut-down (Kariuki and Allan, 1996c, 1996d).

The estimated outage cost models in Lawton, Sullivan, et al., 2003 used for our estimates did not distinguish between sources of a failure. This is primarily a function of the survey instruments used in the collection of outage cost data. Therefore, we were not able to incorporate this feature in our estimates. The estimates presented in this report should be considered as ‘outage costs for all sources of failure.

To the extent that Security Interruption Price levels may be reached as a result of shortages of generation and demand response resources, it often should be possible to anticipate and provide consumers notice of such shortages. For circumstances in which consumers have been provided notice of likely curtailments, our estimates, particularly for commercial and industrial outage costs, may be higher than the direct short-term outage costs that such customers actually experience.

- Outage costs have been observed to change over time (Lawton, Eto et al., 2003). From the analysis of a US sample, for commercial and industrial facilities costs per event and costs per kW have declined for any number of reasons including the wider implementation of energy efficiency measures and distributed generation. However, there are also a growing number of end use applications that require high reliability and could broaden the distribution of outage costs. Willingness-to-pay measures for residential customers have increased over a ten to fifteen year time-span. These changes may be due to the numerous demographic and socioeconomic changes and greater dependence on electricity (Caves et al., 1992). The estimated outage cost models in Lawton, Sullivan, et al., 2003 used for our estimates did not specify these types of time-dependent trends. Therefore, we were not able to incorporate this factor into our estimates. It may be appropriate to update outage costs periodically based on new survey data.

- The dominant instrument for collecting outage cost data are surveys which are largely a self-assessment or self-reporting process. Self-assessments in some cases may be subject to incentives for strategic misrepresentation (i.e., customers without the responsibility of actually paying the full cost of improving reliability may have the motive to exaggerate outage costs). Or, interviewees may simply be unaware of some costs or unable to devote the necessary time to develop complete responses (Beenstock et al., 1997; Caves et al., 1992). Direct cost estimates generally reflect current levels of service reliability (Chowdhury and Koval, 1999). High levels of reliability such as those present in the US mean that respondents may have little experience assessing the costs of an outage. Finally, commercial and industrial data sets often only include direct costs. Depending upon the group being surveyed, direct costs may be only a fraction of the total cost, with indirect costs being larger (Munasinghe and Sanghvi, 1988). Despite these limitations, survey data represent the best available source of information on consumer perceived outage costs, given that for most consumers the cost of service interruptions cannot be directly observed.

The accuracy of any point estimate (a single value) needs to be viewed with caution. As a result, we have presented the user with distributions of costs (in Appendix A). Judgment will need to be applied in selecting default Security Interruption Price levels based on these distributions.

- A number of factors result in variation in residential customer valuations of outage costs. Examples of these factors include (Billinton et al., 1987; Ghajar et al., 1996; Kariuki and Allan, 1996b; Wacker et al., 1983):
    - Apartment dwellers have lower cost estimates than other residential consumers;
    - Outage costs are positively correlated with the number of members of a household;
    - Outage costs decrease with the age of the respondent (perhaps this is correlated with the lower incomes of elderly respondents); and
    - Male respondents have a lower outage cost or willingness-to-pay when compared to female or joint respondents.

  Unfortunately, these and other respondent or building stock characteristics were not identified in the estimated models presented in Lawton, Sullivan, et al., 2003.

- Previous analyses of these sectors have noted that SIC category, particularly for categorizations at the two and three digit level, is the variable which is most strongly and consistently correlated with levels of outage costs and best explains variation within these sectors (Sullivan et al., 1996; Wacker and Billinton, 1989b). For example:

    - Within agricultural (for Canada), poultry and egg farmers have outage costs on the order of five times the average, greenhouses have values that are 12 to 13 times the average, and nurseries have values that are 4 times the average (Kos et al., 1991; Wacker and Billinton, 1989b).
    - Within manufacturing (for Israel) where SIC's are broken out, chemicals, non-metallic minerals, and textiles had outage costs that were one-half of the average for manufacturing, while clothing and electrical equipment manufacturing exhibited outage costs ranging from 1.5 to nearly three times the average in magnitude (Tishler, 1993).
    - On the other hand, for Taiwan, outage costs for facilities producing food, chemicals, and electronic machinery ranged from 35% to almost 70% above the average, while other sectors such as fabric production, paper products, cement, and metallic products ranged from a few percent below the average to as much as 70% of the average (Hsu et al., 1994).

Depending upon the presence and levels of a given industrial, commercial, or agricultural activity in an area, outage costs for a given sector may vary. For the estimates presented in this report, however, we were not able to attribute levels of outage costs at this level of detail. The estimated models in Lawton, Sullivan, et al., 2003 only categorized activities at the most aggregate level, e.g., manufacturing combined SIC 20-39. Therefore, it may be appropriate, to the extent technologically feasible, to permit local variations in Security Interruption Prices that can take into consideration local variations in sector composition.

IV. CONCLUSIONS

From our literature review and the development of MISO-specific estimates for outage costs, we can conclude the following:

- It is possible to estimate distributions of outage costs for residential, commercial, and industrial customers in the MISO utilizing parameters estimated from a national database. As indicated by comparison with previous estimates of outage costs extracted from the literature, the median values of these estimates for the MISO are well within the range of costs observed by others and presented in the academic literature.

- Estimated distributions of outage costs provide a reasonable basis for estimating the value that consumers place on uninterrupted electric service and should be considered in selecting default Security Interruption Prices. While consumer expectations for generally high reliability and the lack of data on long-term adaptive costs might lead to a preference for Security Interruption Prices at or above median outage cost estimates, policymakers should be cautious about setting Security Interruption Prices in the upper portion of the distributions for commercial and industrial customers. In many instances, it should be possible to anticipate and provide consumers advance notice of anticipated shortage conditions. Advance notice can significantly reduce short-term commercial and industrial outage costs.

- However, our estimates are limited by the factors represented in the published parameter estimates. Therefore, the costs presented in this report should be viewed as default estimates to be refined in light of local circumstances and as updated surveys and additional data become available.

- Further, we recommend for the future that the MISO pursue on the RTO-level recommendations made on a national basis by researchers at Lawrence Berkeley National Laboratory (LaCommare and Eto, 2004) for:
    - Coordinated RTO-wide collection of current information on the cost of reliability events: This information may be collected through surveys which have an appropriate statistical design and refined through public input.

- Consistent definition and recording of the duration and frequency of reliability events including power quality events: Proper identification should aid in the information collection efforts and analysis of outage costs.
- Improved collection of information on the costs and efforts by consumers to reduce their vulnerability to reliability events: This information will provide an understanding of the adaptive or long-run component of outage costs.

Estimates of outage costs should be updated periodically based on data collected in the Midwest ISO footprint.

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Appendix A. Results of Estimation of Outage Damage Costs

Exhibits A-1, A-2, and A-3 present detailed estimation results for large commercial and industrial facilities, small commercial and industrial facilities, and residential consumers, respectively. These tables provide descriptive statistics for each type of estimate such as the mean, standard deviation, various percentile including the fiftieth (or median), and maximum and minimum values. As a result, distributions of each type of cost estimate have been described. Additional descriptive statistics (such as skewness and kurtosis) and a more detailed disaggregation of percentiles for each distribution are available upon request.

For each category of end-user (e.g., residential), four different types of estimates of damage costs in 2005 constant dollars were provided assuming that an interruption occurred during a summer afternoon (coincident with the system peak). Those estimates include: (1) per KW costs for a one hour duration; (2) costs for an event of one hour duration; (3) costs for an event of two hours; and (3) costs for an event of three hours. Costs for both the large and small commercial and industrial classes are direct costs of an interruption; costs for residential consumers are willingness to pay. These values were estimated utilizing the methods and data described in Appendix B of this document.

Exhibit A-1. Estimates for Large Commercial and Industrial Facilities (2005 $)

Sector	Type of estimate	Mean	Standard deviation	5 %tile	20%tile	50%tile (Median)	80%tile	95%tile	Maximum	Minimum
Large Commercial and Industrial (> 1000000 kWh annual consumption)	**Direct costs of an interruption through survey**									
Agriculture (SIC 01 – 09)	2005$/kW peak (1 hour duration)	31.07	22.52	9.56	14.47	24.83	43.33	74.34	348.71	4.04
Mining (SIC 10 – 14)	2005$/kW peak (1 hour duration)	99.97	79.14	27.32	43.93	77.53	140.32	247.24	1362.77	7.53
Construction (SIC 15 – 17)	2005$/kW peak (1 hour duration)	31.07	22.52	9.56	14.47	24.83	43.33	74.34	348.71	4.04
Manufacturing (SIC 20 – 39)	2005$/kW peak (1 hour duration)	53.11	39.18	15.91	24.38	42.09	74.21	128.15	570.18	5.98
Transportation/ Communication/ Utilities (SIC 40 – 49)	2005$/kW peak (1 hour duration)	31.07	22.52	9.56	14.47	24.83	43.33	74.34	348.71	4.04
Wholesale/ Retail (SIC 50 – 59)	2005$/kW peak (1 hour duration)	31.07	22.52	9.56	14.47	24.83	43.33	74.34	348.71	4.04
Finance/ Real estate (SIC 60 – 67)	2005$/kW peak (1 hour duration)	31.07	22.52	9.56	14.47	24.83	43.33	74.34	348.71	4.04

Sector	Type of estimate	Mean	Standard deviation	5 %tile	20%tile	50%tile (Median)	80%tile	95%tile	Maximum	Minimum
Services (SIC 70 – 89)	2005$/kW peak (1 hour duration)	19.69	14.69	5.82	9.00	15.56	27.56	47.55	271.05	2.15
Public Administration (SIC 91 – 97)	2005$/kW peak (1 hour duration)	31.07	22.52	9.56	14.47	24.83	43.33	74.34	348.71	4.04
Agriculture (SIC 01 – 09)	2005$/event (1 hour duration)	9790.24	5230.34	4578.55	5797.49	8323.60	12943.28	19887.32	76429.73	2889.32
Mining (SIC 10 – 14)	2005$/event (1 hour duration)	31498.94	19170.00	12451.24	17395.27	26266.61	42382.20	67681.73	451838.78	4687.31
Construction (SIC 15 – 17)	2005$/event (1 hour duration)	9790.24	5230.34	4578.55	5797.49	8323.60	12943.28	19887.32	76429.73	2889.32
Manufacturing (SIC 20 – 39)	2005$/event (1 hour duration)	16739.20	9237.21	7499.34	9763.86	14159.85	22204.20	34564.88	155821.41	4052.53
Transportation/ Communication/ Utilities (SIC 40 – 49)	2005$/event (1 hour duration)	9790.24	5230.34	4578.55	5797.49	8323.60	12943.28	19887.32	76429.73	2889.32
Wholesale/ Retail (SIC 50 – 59)	2005$/event (1 hour duration)	9790.24	5230.34	4578.55	5797.49	8323.60	12943.28	19887.32	76429.73	2889.32
Finance/ Real estate (SIC 60 – 67)	2005$/event (1 hour duration)	9790.24	5230.34	4578.55	5797.49	8323.60	12943.28	19887.32	76429.73	2889.32
Services (SIC 70 – 89)	2005$/event (1 hour duration)	6202.03	3456.40	2731.47	3597.55	5243.10	8256.95	12890.44	55500.88	1433.88
Public Administration (SIC 91 – 97)	2005$/event (1 hour duration)	9790.24	5230.34	4578.55	5797.49	8323.60	12943.28	19887.32	76429.73	2889.32

Sector	Type of estimate	Mean	Standard deviation	5 %tile	20%tile	50%tile (Median)	80%tile	95%tile	Maximum	Minimum
Agriculture (SIC 01 – 09)	2005$/event (2 hour duration)	15810.64	8509.44	7300.21	9327.30	13426.53	20976.41	32292.41	134720.33	4142.63
Mining (SIC 10 – 14)	2005$/event (2 hour duration)	50854.70	30867.31	19899.31	27880.80	42454.79	68599.87	109859.55	538190.63	7358.98
Construction (SIC 15 – 17)	2005$/event (2 hour duration)	15810.64	8509.44	7300.21	9327.30	13426.53	20976.41	32292.41	134720.33	4142.63
Manufacturing (SIC 20 – 39)	2005$/event (2 hour duration)	27011.23	14945.30	12020.56	15706.83	22832.60	35948.56	55684.72	229425.41	6626.69
Transportation/ Communication/ Utilities (SIC 40 – 49)	2005$/event (2 hour duration)	15810.64	8509.44	7300.21	9327.30	13426.53	20976.41	32292.41	134720.33	4142.63
Wholesale/ Retail (SIC 50 – 59)	2005$/event (2 hour duration)	15810.64	8509.44	7300.21	9327.30	13426.53	20976.41	32292.41	134720.33	4142.63
Finance/ Real estate (SIC 60 – 67)	2005$/event (2 hour duration)	15810.64	8509.44	7300.21	9327.30	13426.53	20976.41	32292.41	134720.33	4142.63
Services (SIC 70 – 89)	2005$/event (2 hour duration)	10012.58	5600.15	4394.32	5780.51	8466.15	13315.10	20770.99	79156.82	2185.19
Public Administration (SIC 91 – 97)	2005$/event (2 hour duration)	15810.64	8509.44	7300.21	9327.30	13426.53	20976.41	32292.41	134720.33	4142.63
Agriculture (SIC 01 – 09)	2005$/event (3 hour duration)	23944.86	13108.36	10803.04	14047.03	20279.32	31752.02	49133.97	213019.23	5910.62
Mining (SIC 10 – 14)	2005$/event (3 hour duration)	77072.23	47566.22	29530.53	41930.22	64225.08	103718.14	167778.17	734219.13	11509.42
Construction (SIC 15 – 17)	2005$/event (3 hour duration)	23944.86	13108.36	10803.04	14047.03	20279.32	31752.02	49133.97	213019.23	5910.62

Sector	Type of estimate	Mean	Standard deviation	5 %tile	20%tile	50%tile (Median)	80%tile	95%tile	Maximum	Minimum
Manufacturing (SIC 20 – 39)	2005$/event (3 hour duration)	40939.90	23020.79	17788.96	23610.78	34546.62	54693.63	85506.52	436425.69	9628.27
Transportation/ Communication/ Utilities (SIC 40 – 49)	2005$/event (3 hour duration)	23944.86	13108.36	10803.04	14047.03	20279.32	31752.02	49133.97	213019.23	5910.62
Wholesale/ Retail (SIC 50 – 59)	2005$/event (3 hour duration)	23944.86	13108.36	10803.04	14047.03	20279.32	31752.02	49133.97	213019.23	5910.62
Finance/ Real estate (SIC 60 – 67)	2005$/event (3 hour duration)	23944.86	13108.36	10803.04	14047.03	20279.32	31752.02	49133.97	213019.23	5910.62
Services (SIC 70 – 89)	2005$/event (3 hour duration)	15166.84	8652.78	6497.13	8707.27	12778.82	20210.95	31638.55	165689.59	2703.70
Public Administration (SIC 91 – 97)	2005$/event (3 hour duration)	23944.86	13108.36	10803.04	14047.03	20279.32	31752.02	49133.97	213019.23	5910.62

Exhibit A-2. Estimates for Small Commercial and Industrial Direct Costs of Interruption (2005 $)

Sector	Type of estimate	Mean	Standard deviation	5%tile	20%tile	50%tile (Median)	80%tile	95%tile	Maximum	Minimum
Small and Medium Commercial and Industrial (< 1000000 kWh annual consumption)	**Direct costs of an interruption through survey**									
Agriculture (SIC 01 – 09)	2005$/kW peak (1 hour duration)	56.16	25.35	31.73	38.54	49.51	68.21	103.50	339.23	17.91
Mining (SIC 10 – 14)	2005$/kW peak (1 hour duration)	56.16	25.35	31.73	38.54	49.51	68.21	103.50	339.23	17.91
Construction (SIC 15 – 17)	2005$/kW peak (1 hour duration)	45.44	20.70	25.41	31.05	40.06	55.34	83.87	269.43	13.54
Manufacturing (SIC 20 – 39)	2005$/kW peak (1 hour duration)	40.64	18.89	22.16	27.47	35.81	49.93	75.63	246.82	13.32
Transportation/ Communication/ Utilities (SIC 40 – 49)	2005$/kW peak (1 hour duration)	33.33	16.01	17.46	22.08	29.30	41.23	62.87	202.68	9.45
Wholesale/ Retail (SIC 50 – 59)	2005$/kW peak (1 hour duration)	56.16	25.35	31.73	38.54	49.51	68.21	103.50	339.23	17.91
Finance/ Real estate (SIC 60 – 67)	2005$/kW peak (1 hour duration)	40.50	18.57	22.48	27.61	35.64	49.47	75.01	259.71	12.13
Services (SIC 70 – 89)	2005$/kW peak (1 hour duration)	17.33	8.06	9.45	11.71	15.25	21.24	32.32	111.13	5.43
Public Administration (SIC 91 – 97)	2005$/kW peak (1 hour duration)	37.87	17.35	21.08	25.77	33.35	46.21	69.87	219.33	11.81
Agriculture (SIC 01 – 09)	2005$/event (1 hour duration)	1165.51	522.32	666.42	805.28	1026.53	1411.34	2144.92	6791.66	407.71
Mining (SIC 10 – 14)	2005$/event (1 hour duration)	1165.51	522.32	666.42	805.28	1026.53	1411.34	2144.92	6791.66	407.71
Construction (SIC 15 – 17)	2005$/event (1 hour duration)	942.91	426.58	532.96	648.59	830.70	1144.67	1738.38	5425.18	308.32
Manufacturing (SIC 20 – 39)	2005$/event (1 hour duration)	843.43	389.51	463.86	571.83	742.82	1031.82	1571.77	5085.15	279.47

Sector	Type of estimate	Mean	Standard deviation	5%tile	20%tile	50%tile (Median)	80%tile	95%tile	Maximum	Minimum
Transportation/ Communication/ Utilities (SIC 40 – 49)	2005$/event (1 hour duration)	691.75	330.01	365.76	460.44	608.32	852.53	1300.90	4322.90	200.36
Wholesale/ Retail (SIC 50 – 59)	2005$/event (1 hour duration)	1165.51	522.32	666.42	805.28	1026.53	1411.34	2144.92	6791.66	407.71
Finance/ Real estate (SIC 60 – 67)	2005$/event (1 hour duration)	840.55	382.80	470.81	575.95	740.18	1023.04	1554.93	5199.54	269.33
Services (SIC 70 – 89)	2005$/event (1 hour duration)	359.62	166.14	198.27	244.23	316.79	439.86	671.70	2224.82	112.40
Public Administration (SIC 91 – 97)	2005$/event (1 hour duration)	785.80	357.51	441.30	537.99	692.43	954.47	1449.17	4391.22	268.83
Agriculture (SIC 01 – 09)	2005$/event (2 hour duration)	1700.12	805.90	940.64	1151.65	1483.33	2070.90	3189.61	9670.24	574.40
Mining (SIC 10 – 14)	2005$/event (2 hour duration)	1700.12	805.90	940.63	1151.65	1483.33	2070.90	3189.61	9670.24	574.40
Construction (SIC 15 – 17)	2005$/event (2 hour duration)	1375.27	656.35	752.73	927.16	1201.01	1676.70	2593.09	7808.77	443.50
Manufacturing (SIC 20 – 39)	2005$/event (2 hour duration)	1230.42	600.60	659.33	819.49	1072.55	1510.72	2345.76	7500.53	371.26
Transportation/ Communication/ Utilities (SIC 40 – 49)	2005$/event (2 hour duration)	1009.03	507.65	518.43	660.46	878.96	1245.90	1940.19	6545.19	264.82
Wholesale/ Retail (SIC 50 – 59)	2005$/event (2 hour duration)	1700.12	805.90	940.63	1151.65	1483.33	2070.90	3189.61	9670.24	574.40
Finance/ Real estate (SIC 60 – 67)	2005$/event (2 hour duration)	1225.86	589.06	666.85	823.27	1070.18	1500.94	2313.50	7202.96	406.00
Services (SIC 70 – 89)	2005$/event (2 hour duration)	524.42	255.03	281.51	349.32	457.15	644.24	995.93	3147.58	145.30

Sector	Type of estimate	Mean	Standard deviation	5%tile	20%tile	50%tile (Median)	80%tile	95%tile	Maximum	Minimum
Public Administration (SIC 91 – 97)	2005$/event (2 hour duration)	1146.42	550.82	621.82	771.55	997.71	1402.07	2171.54	6604.36	376.93
Agriculture (SIC 01 – 09)	2005$/event (3 hour duration)	2365.16	1170.77	1262.12	1568.35	2048.41	2907.99	4541.05	15593.62	723.31
Mining (SIC 10 – 14)	2005$/event (3 hour duration)	2365.16	1170.77	1262.12	1568.35	2048.41	2907.99	4541.05	15593.62	723.31
Construction (SIC 15 – 17)	2005$/event (3 hour duration)	1913.41	955.36	1011.02	1262.17	1657.63	2356.29	3673.46	13841.70	577.62
Manufacturing (SIC 20 – 39)	2005$/event (3 hour duration)	1711.47	869.36	885.69	1115.66	1482.14	2120.97	3303.85	12318.97	495.00
Transportation/ Communication/ Utilities (SIC 40 – 49)	2005$/event (3 hour duration)	1403.06	731.56	700.84	899.39	1210.65	1752.17	2746.22	10105.79	344.74
Wholesale/ Retail (SIC 50 – 59)	2005$/event (3 hour duration)	2365.16	1170.77	1262.12	1568.35	2048.41	2907.99	4541.05	15593.62	723.31
Finance/ Real estate (SIC 60 – 67)	2005$/event (3 hour duration)	1705.00	852.53	896.17	1120.58	1476.46	2106.58	3286.51	11744.64	481.70
Services (SIC 70 – 89)	2005$/event (3 hour duration)	729.43	369.24	376.24	476.39	631.26	902.90	1415.55	4680.74	214.81
Public Administration (SIC 91 – 97)	2005$/event (3 hour duration)	1594.37	796.92	839.37	1048.49	1379.28	1966.60	3070.93	10387.42	480.49

Exhibit A-3. Estimates of Willingness to Pay (2005 $) for Residential Sector

Sector	Type of estimate	Mean	Standard deviation	5%tile	20%tile	50%tile (Median)	80%tile	95%tile	Maximum	Minimum
Residential	**Willingness to Pay**									
	2005$/kW peak (1 hour duration	1.60	0.71	0.73	1.04	1.47	2.08	2.93	9.52	0.0
	2005$/event (1 hour duration)	4.06	1.62	2.05	2.76	3.76	5.16	7.08	20.28	0.0
	2005$/event (2 hour duration)	4.96	2.15	2.35	3.27	4.55	6.41	8.94	31.71	0.0
	2005 $/event (3 hour duration)	6.02	2.92	2.58	3.72	5.41	7.93	11.43	38.74	0.0

Appendix B: Documentation of Data and Methods of Calculation

Commercial and Industrial Facilities

a) Methods of Estimation for large commercial and industrial facilities (annual consumption of more than one million kWh)

Estimates of direct costs to large commercial and industrial facilities of an outage were performed using the coefficients presented in Table 3-4 of Lawton, Sullivan, et al., 2003. Two models are presented in this table. However, upon examination of the test statistics, and the significance levels of the parameter estimates, the decision was made to use the results of Model Two. Model Two allows for the estimation of sector-grouped outage costs as identified by categories of two-digit Standard Industrial Classifications. And, the significance of some of the estimated parameters for the additional variables for specific sector groupings indicates that Model Two probably does a better job of explaining the variance of the data.

For reference purposes, the coefficients used in this effort are presented in Exhibit B-1. These coefficients (and their standard errors) were used in a simulation framework along with distributions of the number of employees at a facility and the annual kWh consumption by a facility. Following standard practice, coefficients insignificant at the 10% level or higher were not used in the estimation process; these coefficients are so indicated on Table B-1. Distributions for both number of employees at a facility and the annual kWh consumption by a facility were truncated to those facilities estimated to use more than one million kWh per year. Data for both variables were taken from publicly available sources (see next section on data sources), and were restricted to the Midwest Census Division.

Use of the parameters in Exhibit B-1 allows the estimation of the direct costs from an interruption for large commercial and industrial facilities. As noted in the discussion (in the main body of this report) on the methods of collection of outage cost data, although estimates of direct costs encompass or include the majority of costs, they do not include the indirect costs that might occur as a result of an interruption. Further, these costs are subject to various limitations. However, as Lawton, Sullivan, et al., 2003, point out, these are the types of costs that are collected the majority of the time.

The coefficients in Exhibit B-1 were estimated using a Tobit specification. This type of specification allows for a truncated dependent variable, or the possibility that a small commercial or industrial facility may report an outage cost of zero. As indicated by other analyses, as many as 20 to 30% of commercial and industrial facilities (all sizes) may report an outage cost of zero (Caves et al., 1990). Use of a Tobit allows for estimation of unbiased parameters under conditions such as these where the distribution of the dependent variable is truncated. And, for the simulations implemented for this project, the distribution of estimated outage costs was also truncated at zero. For the estimation of the original parameters, the dependent variable (e.g., outage costs) was transformed using a natural log transformation prior to estimation. This assures that the distribution of the error term is normal. Thus, the anti-log of our estimated outage cost measure was taken at the end to obtain a currency value. Since the Lawton, Sullivan, et al., 2003 effort was performed with 2002 $, our estimates were constructed in those dollars, and escalated to 2005 $ using the CPI for all urban consumers (United States Department of Labor, 2006). Other deflators could be used, but this is the method used by Lawton, Sullivan, et al., 2003.

Exhibit B-1. Coefficients Used in Estimation of Large Commercial and Industrial Outage Costs

Predictor	Parameter	Standard Error
Intercept	7.6941	0.1542
Duration (hours)	0.5771	0.0357
Duration Squared	-0.0331	0.0032
Number of employees	0.0006	0.0001
Annual kWh	2.2500E-08	0.0036
Interaction Duration and kWh	-1.3000E-10*	0.0009
Morning	-0.4319	0.1144
Night	1.4464	0.1739
Weekend	-0.6482	0.1441
Winter	0.8376	0.0901
Manufacturing (SIC 20 – 39)	0.5292	0.1166
Mining (SIC 10 – 14)	1.1378	0.2484
Construction (SIC 15 – 17)	0.9168*	0.808
Transportation/Communications/Utilities (SIC 40-49)	-0.1930*	0.1585
Finance/Insurance/Real Estate (SIC 60 – 70)	0.3252*	0.2841
Services (SIC 70 – 89)	-0.4661	0.1363
Public Administration (SIC91-97)	0.0253*	0.2431

Taken from Table 3-4, page 20, Lawton, Sullivan, et al., 2003
*Insignificant at the 10% level; therefore, not used in the estimation of outage costs.
Note: Agriculture, Forestry, & Fishing (SIC 01 – 09) and Wholesale & Retail Trade (SIC 50 – 59) are included in the basis.

b) Methods of Estimation for small commercial and industrial facilities (annual consumption of less than one million kWh)

Estimates of direct costs to small commercial and industrial facilities of an outage were performed using the coefficients presented in Table 4-4 of Lawton, Sullivan, et al., 2003. Two models are presented in this table. However, upon examination of the test statistics, and the significance levels of the parameter estimates, the decision was made to use the results of Model Two. As indicated by the significance of the majority of parameters, Model Two appeared to more fully explain the variance in the estimating data set. As an added advantage, Model Two also does allow for the estimation of sector-specific outage costs as identified by two-digit Standard Industrial Classification category.

For reference purposes, the coefficients used in this effort are presented in Exhibit B-2. These coefficients (and their standard errors) were used in a simulation framework along with distributions of the number of employees at a facility and the annual kWh consumption by a facility. Following standard practice, coefficients insignificant at the 10% level or higher were not used in the estimation process; these coefficients are so indicated on Table B-2. Distributions for both the number of employees at a facility and the annual kWh consumption by a facility were truncated to those facilities estimated to use less than one million kWh per year. Data for both variables were taken from publicly available sources (see next section on data sources), and were restricted to the Midwest Census Division.

Exhibit B-2. Coefficients Used in Estimation of Small Commercial and Industrial Outage Costs

Predictor	Parameter	Standard Error
Intercept	5.92312	0.0851
Duration (hours)	0.41996	0.02622
Duration Squared	-0.02386	0.0019545
Number of employees	0.0012817	0.0002144
Annual kWh	0.000001755	1.5918E-07
Interaction Duration and kWh	7.153E-08	2.7293E-08
Morning	0.22574	0.04755
Night	0.95618	0.06147
Weekend	-0.26448*	0.39049
Winter	0.60331	0.10596
Manufacturing (SIC 20 – 39)	-0.32852	0.10082
Mining (SIC 10 – 14)	0.11212	0.12045
Construction (SIC 15 – 17)	-0.21343	0.05173
Transportation/Communications/Utilities (SIC 40-49)	-0.53278	0.1461
Finance/Insurance/Real Estate (SIC 60 – 70)	-0.32951	0.07094
Services (SIC 70 – 89)	-1.18103	0.09979
Public Administration (SIC91-97)	-0.39663*	0.06814

Taken from Table 4-4, page 31, Lawton, Sullivan, et al., 2003
*Insignificant at the 10% level; therefore, not used in the estimation of outage costs.
Note: Agriculture, Forestry, & Fishing (SIC 01 – 09) and Wholesale & Retail Trade (SIC 50 – 59) are included in the basis.

Use of the parameters in Exhibit B-2 allows the estimation of the direct costs from an interruption for small commercial and industrial facilities. As noted in the discussion (in the main body of this report) on the methods of collection of outage cost data, although estimates of direct costs encompass or include the majority of costs, they do not include the indirect costs that might occur as a result of an interruption. Further, these costs are subject to various limitations. However, as Lawton, Sullivan, et al., 2003 point out, these are the types of costs are collected the majority of the time.

The coefficients in Exhibit B-2 were estimated using a Tobit specification. This type of specification allows for a truncated dependent variable, or the possibility that a small commercial or industrial facility may report an outage cost of zero. As indicated by other analyses, as many as 20 to 30% of commercial and industrial facilities (all sizes) may report an outage cost of zero (Caves et al., 1990). Use of a Tobit allows for estimation of unbiased parameters under conditions such as these were the distribution of the dependent variable is truncated. And, for the simulations implemented for this project, the distribution of estimated outage costs was also truncated at zero. For the estimation of the original parameters, the dependent variable (e.g., outage costs) was transformed using a natural log transformation prior to estimation. This assures that the distribution of the error term is normal. Thus, the anti-log of the estimated outage cost measure was taken at the end. Since the Lawton, Sullivan, et al., 2003 effort was performed with 2002 $, our estimates were constructed in those dollars, and escalated to 2005 $ using the CPI for all urban consumers (United States Department of Labor, 2006). Other deflators could be used, but this is the method used by Lawton, Sullivan, et al., 2003.

c) Data Used for Commercial and Industrial Outage Estimates

To obtain distributions of numbers of employees and annual kWh consumption by establishment, the following sources of data were used: (1) the Commercial Buildings Energy Consumption Survey (CBECS); (2) the Manufacturing Energy Consumption Survey (MECS); (3) the Economic Census; (4) the Agriculture Resource Management Survey; and (5) data supplemental to Lawton, Sullivan, et al., 2003 provided by PRS.

The Commercial Buildings Energy Consumption Survey (CBECS) provides information on the physical characteristics of commercial buildings, building use and occupancy patterns (e.g., number of employees), equipment use, conservation features and practices, and types and uses of energy in buildings (EIA, 1997a, 2002, 2005). The survey also collects information on the amount of energy consumed and the costs for energy in commercial buildings. The commercial sector consists of establishments that provide services, and this definition excludes goods-producing industries such as manufacturing, agriculture, mining, forestry and fisheries, and construction. As a result, the sector does include retail and wholesale operations, hotels and motels, restaurants, and hospitals, and other facilities, such as public schools. CBECS is a national-level survey which is quadrennial (every four years).

The Manufacturing Energy Consumption Survey (MECS) provides information on energy use in the manufacturing sector (EIA, 1997b, 2000a, 2004). Manufacturing is defined as establishments classified in Standard Industrial Classifications (SIC) 20 through 39. The survey collects information from a national representative sample of US manufacturing establishments that transform input materials or substances into new products, assemble components, or perform blending operations. The survey routinely collects information from approximately 95% to 98% of such establishments. Information collected includes quantities and sources of noncombustible energy (i.e., electricity and steam), combustible energy (e.g., natural gas, oil, coal), capacity and capability for fuel switching, and consumption of fuel in end-uses such as boilers, process and non-process uses. MECS is collected every four years.

The Economic Census provides employment by establishment and other measures of economic activity in the United States. The economic census is the major economic statistical program of the United States, and it constitutes the chief source of data about the structure and functioning of the economy (US Census Bureau, 2000). Economic data are collected by this instrument at the “establishment” level. An establishment is defined as a business or industrial unit at a single-physical location that produces or distributes goods or that performs services. A firm or company may operate more than a single establishment. Data is collected for each establishment on the kind-of-business activity, physical location, form of ownership, dollar volume of business, number of employees, and various components of production costs (e.g., expenditures for labor) (US Department of Commerce, 2004). The census is performed every 5 years for years ending in “2” and “7.”

The Agricultural Resource Management Survey (ARMS) is the US Department of Agriculture’s primary source of information on production practices, financial condition, and resource use by US farmers (US Department of Agriculture, 2005). This survey instrument collects information on various production costs (including energy). However, not all of this data is easily available to the public, and for this work a special request was placed with the US Economic Research Service for cross-tabs on purchased electricity used by agricultural establishments in the Midwest. The ARMS is collected annually.

The authors of this report were also able to obtain from PRS (the firm responsible for Lawton, Sullivan, et al., 2003) additional data on the annual energy consumption values underlying the estimated parameters used for calculating energy costs. The original data from PRS is available upon request from the authors of this report.

Annual energy consumption values by establishment size (as determined by employment numbers) were extracted from CBECS, MECS, and ARMS and integrated with the data from PRS to develop the distributions of energy consumption used to obtain our reported values. Employment numbers per establishment were obtained from the Economic Census. Both of these distributions were limited to the Mid-West Census Division for the numbers presented in this report.

To obtain estimates of outage costs on a per kW basis, data on commercial and industrial annual energy consumption in the Mid-West and the system coincident peak were taken from the National Energy Modeling System (EIA, 2000b). These data are reported in the NEMS data files by state, and as such we were able to construct distributions of estimated kW required capacity during summer afternoon periods (assumed to be peak). This distribution was used as denominator for direct outage costs per kW measure reported for small commercial and industrial facilities. As a result, the outage costs per kW for small commercial and industrial facilities reported in this document could be refined if data becomes available for each utility in the MISO.

Residential Customers

a) Methods of Estimation

Estimates of willingness to pay were performed using the coefficients presented in Table 5-4 of Lawton, Sullivan, et al., 2003. For reference purposes, those coefficients are presented in Exhibit B-3. These coefficients (and their standard errors) were used in a simulation framework along with distributions of for annual household energy consumption and household income. For purposes of this work, the Mid-West is assumed to be part of the base population which is represented by observations from Northwest in the Lawton, Sullivan, et al., 2003 work. However, in our work for the MISO, the two areas were distinguished by differences in annual household energy consumption and household income. Both annual household energy consumption and household income were taken from publicly available data sources (see the next section on data sources), and were restricted to the Midwest Census Division.

Exhibit B-3. Coefficients Used in the Estimation of Residential Outage Costs

Predictor	Parameter	Estimated Standard Error*
Intercept	0.2503	0.238323
Duration	0.2211	0.059451
Duration sq	-0.0098	0.002635
Morning	-0.0928	0.037027
Night	-0.1943	0.052245
Winter	0.1275	0.039365
Annual MWh (kWh/1000)	0.0065	0.001748
Log of Household Income	0.0681	0.018311

Taken from Table 5-4, page 40, Lawton, Sullivan, et al., 2003
*Lawton, Sullivan, et al., 2003 did not provide estimates of standard errors for these parameters. Therefore, we used a well established method for estimating these parameters (Greene, 1997).

Use of the parameters in Exhibit B-3 allows the estimation of willingness to pay (WTP) to avoid an interruption. As noted in the discussion (in the main body of this report) of the methods of collection of the outage cost data, willingness to pay is a more robust value, and less subject to change than willingness to accept measures. Thus, willingness to pay is considered to be a more accurate measure of residential outage costs. Further, as Lawton, Sullivan, et al., 2003 noted in their report, WTP is collected across more studies, thus providing for a better set of data for estimation.

The coefficients in Exhibit B-3 were estimated using a Tobit specification. This type of specification allows for a truncated dependent variable, or the possibility that residential consumers may report an outage cost of zero. Past analyses have shown that as many as 60 to 80% of residential consumers will report such an observation. Use of a Tobit allows for estimation of unbiased parameters under these conditions. And, for the simulations implemented for this project, the distribution of estimated outage costs was also truncated at zero. For the estimation of the original parameters, the dependent variable (e.g., WTP) was transformed using a natural log transformation prior to estimation. This assures that the distribution of the error term is normal. Also, annual household income was transformed using a natural log transformation due to the skewed nature of that variable. For the simulations, annual household income was also transformed. And, the anti-log of the estimated WTP measure was taken at the end. Since the Lawton, Sullivan, et al., 2003 work was performed with 2002 $, our estimates were constructed in those dollars, and escalated to 2005 $ using the CPI for all urban consumers. (United States Department of Labor, 2006). Other deflators could be used, but this is the method used by Lawton, Sullivan, et al., 2003.

b) Data

To obtain distributions of income and annual electricity consumption for estimates of residential outage costs (WTP), household level data from the Department of Labor's Consumer Expenditure Survey (CES) was utilized. The Consumer Expenditure Survey (CES) provides a continuous and comprehensive flow of data on family expenditures for goods and services used in day to day living, the amount and source of family income, changes in savings and debts, and major demographic and economic characteristics of family members. For this analysis, data was extracted for the period from 1988 through 2004 for the Mid-West Census Division.

The CES is a stratified national sample of consumer units which are selected to participate in the survey based on their proportional representation in the entire non-institutionalized population of the USA (United States Department of Labor, 1997). Survey data are collected on a consumer unit basis, where a consumer unit is a group of related individuals living in the same residence or a group of individuals who pool resources to make joint expenditure decisions. The interview survey obtains the expenditures of consumers for major purchases or regularly recurring expenses such as utilities in five consecutive quarterly interviews. This survey is a rotating panel, and as a result, a sample unit is dropped from the survey after the fifth interview and replaced by a new consumer unit. For the survey as a whole 20% of the sample is dropped and a new group added each quarter. Within the sample, at any given time, consumer units are selected to participate based on their proportional representation in the entire population of the US.

For this work, two variables were extracted from the published tables of the CES. Those variables included the total household income before taxes, and the expenditure for electricity (United States Department of Labor, 1988-2004). All values are presented in current dollars. To obtain constant values for the year 2002, the income variable was normalized using the Consumer Price Index for all urban consumers (United States Department of Labor, 2006). After calculations estimating the VOLL were completed, the CPI was used to escalate $2002 to $2005. Quantities of electricity consumed by households were calculated using the expenditure for electricity and census region level delivered prices for residential electricity provided by the EIA (EIA, 2006).

To obtain estimates of WTP on a per kW basis, data on household annual energy consumption in the Mid-West and the system coincident peak were taken from the National Energy Modeling System (EIA, 2000b). These data are reported in the NEMS data files by state, and as such we were able to construct distributions of estimated kW required capacity during summer afternoon periods (assumed to be peak). This distribution was used as denominator for WTP per kW measure reported under residential results. As a result, the WTP per kW estimates reported in this document could be refined if data becomes available for each utility in the MISO.