STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the Matter of the Application of **Consumers Power Company** for Authority to Recover Implementation costs, for approval of stranded cost true-up methodology, and for other relief	))))))	Case No. U-11955
In the Matter of the Application of **The Detroit Edison Company** for authority to recover retail access program implementation costs and for approval of a true-up mechanism in connection with the recovery of stranded costs	))))))))	Case No. U-11956

INITIAL BRIEF OF ENERGY MICHIGAN

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I. INTRODUCTION AND SUMMARY OF POSITION

A. Introduction

In Case U-11290 the Michigan Public Service Commission (Commission) directed Consumers Energy Company (Consumers Energy) and Detroit Edison Company (Detroit Edison or Edison) to file cases which would initiate a process to determine various issues related to the true-up process ordered by the Commission in U-11454, October 29, 1997. Consumers Energy and Detroit Edison filed their cases on June 4, 1999 regarding open access implementation costs and on September 17, 1999 regarding stranded cost true-up and metering/billing issues. Staff and Intervenors filed their direct testimony October 25, 1999 and rebuttal was filed November 19, 1999. Cross-examination of all the parties occurred December 14-15, 1999.

B. Summary of Energy Michigan Position

1. Metering issues

Customers should be able to choose their own meter providers or meter providers should be selected through a bid process which would choose the least expensive provider for the entire utility system. In the alternative, metering systems installed by utilities should allow unrestricted dial-in or Internet access at no charge to customers or their marketing providers as is currently provided by Consumers Energy. Finally, an advisory group should be established consisting of utilities, customers, marketers and MPSC Staff to develop new standards to ensure utilization of uniform data and equipment standards.

2. Retail access implementation costs

Open access implementation costs incurred through 2001 (even though deferred) should be offset by utility earnings through 2001 which are above levels authorized by the Commission. A utility should not be able to collect implementation costs incurred during a period that the utility experienced excess earnings.

3. There is no stranded cost until 2002 unless a utility is earning less than its authorized return

Both Consumers Energy and Detroit Edison are short of capacity and will be buying extra power at least until 2002 despite the modest phase-in of open access capacity. Given the full use of utility generating assets and demonstrated excess return on investment, there can be no showing of true stranded cost by Edison and Consumers until 2002, if then, when more than 12.5% of utility peak load is available to competition. If a utility earns below its authorized return, stranded cost recovery could be considered.

4. The MPSC true-up plan

The MPSC true-up plan process develops an adjusted Transition Charge (A yr) by calculating an estimated amount of stranded cost/kWh as a Estimated Transition Charge (E) (1.2 ¢ /kWh for Consumers and 1.25 ¢ /kWh for Edison) based on the estimate that the 1998 Base Market Price of power (MCPB) was 2.9 ¢ escalated at 3% per year (MCPB yr). If, in the future, the yearly Actual Market Clearing Prices of power (MCPA yr) differs from the 2.9 ¢ estimate (e.g. 3.4 ¢ instead of 2.9 ¢) the difference between estimated MCPB yr and MCPA yr (3.4 ¢ - 2.9 ¢ = .5 ¢) was to be subtracted from the Estimated Transition Charge (E) to yield an Adjusted Transition Charge (A yr) each year (e.g. for Consumers 1.2 ¢ - .5¢ =.7 ¢).

Stated as a formula the MPSC plan to adjust Consumers Energy transition charges for changes in market price is:

$$A\ yr = E - (MCPA\ yr - MCPB\ yr).$$

5. The Commission true-up plan does not work

The MPSC true-up process always produces a total competitive power cost (combination of market rate capacity and transition charge) which starts at 4.1 ¢ /kWh in 1998 and increases at a rate of about 3% per year (1998 = 4.1 ¢, 2000 = 4.3 ¢ , 2002 = 4.5 ¢, etc.). This is because under the PSC plan any increases or decreases in the Actual Market Clearing Price (MCPA) of power are offset automatically and equally by increases or decreases in the transition charge. Also, steadily increasing the estimated Base Market Clearing Price (MCPB yr)at 3% per year produces a total cost of power and transition charge which always increases at 3% per year.

The MPSC true-up system also fails to recognize that the utility power production costs which compete with open access are declining due to mitigation efforts by utilities. Thus, while the MPSC formula literally mandates an increasing total cost of open access power, competing utility power production costs are declining.

6. The MPSC true-up plan can work if it incorporates mitigation

The MPSC true-up process can be made to work while also recognizing utility mitigation measures by reducing the Base Market Clearing Price (MCPB) to reflect actual production cost reductions achieved by Edison and Consumers during 1998 and assuming a 1% annual reduction in production costs in the future, a level of mitigation far less than the historical cost reductions achieved by these utilities. This mitigation adjustment would incorporate proven 1998 mitigation of .4 ¢ /kWh for Detroit Edison and .09 ¢ /kWh for Consumers Energy which was not considered by the Commission restructuring Orders which were issued in January and February of 1998 and thus merely estimated 1998 transition charges and costs. The new 1998 MCPB yr values would be 2.81 ¢ /kWh for Consumers and 2.5 ¢ /kWh for Edison, declining at 1% per year.

The Energy Michigan revised true-up process in effect changes the MPSC 1998 Base Market Clearing Price estimate from an escalating number that was used in January 1998 to estimate total future stranded costs given current market conditions to a number which is used in future years. This new use of the Base Market Clearing Price will allow the Commission to annually calculate the future impact of declining utility costs of production on the total stranded cost each year.

7. Summary of the Energy Michigan true-up plan

Energy Michigan proposes the following true-up plan incorporating all the basic concepts approved by the Commission plus the mitigation concept described above.

a. Approved annual stranded costs (S yr): Stranded costs would be limited to the five buckets of cost approved by the Commission in 1997 and 1998 U-11290 Orders. Seven hundred to eight hundred million dollars of new stranded costs proposed by Edison in this case are excluded. The initial estimates of Consumers Energy stranded cost at $1.76 billion NPV 1997 are reduced to $1.55 billion NPV 1997 because Consumers' over stated above market costs of PURPA contracts by excluding the market value of at least 4 million Mwh of available QF capacity per year and failed to escalate the cost of that capacity for inflation.

b. <u>Sales volumes used to recover stranded costs:</u> Stranded cost as adjusted per (a) above should be spread over total retail, open access <u>and wholesale</u> sales. The potential dissolution of MECS at the end of 2000 is just one factor indicating that interutility transactions will increasingly be priced at market rates and constitute a growing source of revenue to recover utility fixed costs.

c. <u>Cap on sales volumes used to recover stranded costs:</u> The true-up formula used by the PSC does not set a level of total retail and wholesale sales above which a utility does not have stranded costs. The PSC should establish a base level of sales above which there are no stranded costs. The base level of sales should be determined in an amount and time frame when the utility had little or no open access capacity, earned its authorized rate of return and thus experienced no stranded costs.

Total 1998 retail and wholesale sales should be used for this base sales level (kWh 98). Starting 2002, approved stranded costs determined each year (S yr) should be divided by the 1998 base total retail and wholesale sales (kWh 98) to establish stranded cost per kWh to be recovered. <u>Actual</u> annual retail and wholesale sales each year (kWh yr) would then be multiplied by the stranded costs to be recovered per kWh of retail and wholesale sales. This process would yield the stranded costs recovered each year through wholesale and retail sales. <u>To the extent that there is a short fall between total stranded cost and stranded cost recovered from retail and</u>

wholesale sales, the shortfall of stranded cost should be divided by actual annual Retail Open Access sales (kWh OA yr) to establish the unadjusted annual transition charge (U yr) applicable to open access sales.

This theory recognizes the idea, implicit in Mr. Celio's testimony, that when a utility has total retail and wholesale sales that exceed a predetermined level, there is no stranded cost.

Adjusting U yr For Changes in Market Price

d. Actual Market Clearing Price (MCPA): The Actual Market Clearing Price (MCPA) should be calculated per Staff proposals by totaling actual Retail Open Access contract prices and adjusting for load loss and load factor. This open access contract cost per kWh should be added to mandatory ancillary service costs to establish the total actual Market Clearing Price (MCPA) paid by open access customers each year.

e. Base Market Clearing Price (MCPB): The Estimated Base 2.9 ¢ /kWh market price used by the PSC would be changed from a concept which was used to estimate market prices in January 1998 to a concept which shows that declining utility costs of production reduce stranded cost because declining production costs are making utility power more competitive with the Actual Market Clearing Price of Power (MCPA). This revised role for the Base Market Clearing Price can be achieved, as discussed in I.B.6. above, if the (MCPB) price used to compare with actual market price (MCPA) is reduced from 2.9 ¢ /kWh to show actual mitigation achieved by utilities in 1998 (.09¢ /kWh for Consumers and .4 ¢ /kWh for Edison) and then is assumed to decline at a rate of 1% per year. The 1998 Base Market Clearing Price (MCPB) now becomes 2.81 ¢ for Consumers and 2.5 ¢ for Edison and both Base prices decline at 1% per year.

f. Adjusted Transition Charge (A yr): The unadjusted transition charge U yr is adjusted for changes in market price by subtracting the difference between Actual Market Clearing Price (MCPA) and Base Market Clearing Price (MCPB) from the unadjusted transition charge (U yr).

Illustration

The Energy Michigan true-up concept can be illustrated as a formula which operates in two steps to develop an adjusted annual transition charge (A yr) by utilizing the actual values and concepts approved by the Commission in its U-11290 Orders and incorporating demonstrable mitigation at levels actually achieved by utilities.

Let:

A yr	= Adjusted Transition Charge
U yr	= Unadjusted Transition Charge
yr	= Current Year
S	= Approved Stranded Costs
MCPA	= Actual Market Clearing Price
MCPB	= Base Market Clearing Price
kWh	= Total Energy Sales to Retail and Wholesale Customers
kWh OA	= Total Energy Sales to Open Access Customers
98	= 1998

1. $$U\ yr = \left(\frac{S\ yr}{kWh\ 98 \times kWh\ OA\ yr}\right) \times (kWh\ 98 - kWh\ yr)$$

2. $$A\ yr = U\ yr - (MCPA\ yr - MCPB\ yr)$$

DETAILED DISCUSSION OF ISSUES

II. CUSTOMERS SHOULD BE ALLOWED TO SUPPLY THEIR OWN METERING SERVICES

A. The Commission Ordered development of a record which would allow determination of the appropriate entity (utility, customer or marketer) to supply metering and billing services.

In Case U-11290 the Commission Ordered that the true-up proceeding include consideration of whether metering and billing services should be provided as a utility monopoly or whether marketers should have the option to provide these services. *U-11290, March 8, 1999, p. 44.*

B. Energy Michigan Position

Energy Michigan Witness Richard Polich testified that customers should be allowed to choose the provider of their metering service and that such services could be provided through a bid process which would ensure that the metering costs charged to customers are minimal. The metering systems installed by customers or low cost bidders should utilize industry standard equipment and installations which are compatible with utility data systems to minimize expense. Proprietary technologies such as those used by Detroit Edison which restrict free customer use of electric data are totally unacceptable. *5 T 796*.

As a second best alternative, Mr. Polich stated that customers and their agents must have unrestricted access to meter data at all times at no additional cost. Data supplied to customers should include the billing determinants needed by and acceptable to the customer or their agent. *Id*.

Finally, standard business operating rules for the competitive electric industry are currently under development and should be adopted by Detroit Edison and Consumers Energy. Creation of an open access metering and billing advisory group to the Commission consisting of representatives of the utilities, marketers and customers would facilitate this action. *5 T 799-800*.

C. Support for the Energy Michigan Position

Mr. Polich explained that his proposals were necessitated by Detroit Edison's use of meters with call out functions that can only dial one number which has to be Detroit Edison's own data collection system. The Edison approach restricts the access of customers or their agents to metered electric data. Data based on the wholesale, on-peak and off-peak hours used by Detroit Edison is not available and customer hourly data is available only if the customer agrees to buy the data at a cost of $180 per meter per year for hard copy or $240 in the e-mail or disk version. *5 T 796-97*. The Edison type of meter installation literally forces marketers or their customers to incur typically up to $1000 of hardware or installation cost to install the equipment and data transmission devices necessary to obtain real time data. *5 T 669-70 (Edison's Witness Gessner)*.

Consumers witness Gilzow concurred with Mr. Polich's conclusion that utilities should provide no cost customer access to meter data on a dial in or e-mail accessible version. *4 T 529*. Edison' own witness Gessner confirmed that Edison meters do not allow customer direct access to real time data and force subscription to Detroit Edison services to obtain such data. *5 T 657-8*. Mr. Gessner admitted that this lack of data availability forces open access customers to duplicate Edison meter investment if they wish to obtain real time data. *5 T 663-65*.

D. Conclusion

The current utility monopoly on providing metering and billing services is being abused by Detroit Edison to produce anti-competitive results. Edison's plan to install demand meters which do not provide access to real time data by an open access customer or their marketer without incurring substantial expenses to duplicate utility meter hardware plus monthly data line costs effectively gives Detroit Edison a cost advantage over its competitors. Only Edison can obtain real time meter data without incurring extra costs.

The testimony of Energy Michigan Witness Polich Consumers Energy witness Gilzow, and Edison's own Witness Gessner, prove that customers should be allowed to install their own metering so long as the metering equipment is compatible with the utility billing systems and software. As a second best alternative, a utility should be ordered to install meter equipment which will provide no cost dial in or Internet available real time consumption data to open access customers or their agents.

III. DETROIT EDISON AND CONSUMERS ENERGY OPEN ACCESS IMPLEMENTATION COSTS SHOULD BE COLLECTED FROM ALL CUSTOMERS AND OFFSET BY EXCESS EARNINGS THROUGH 2001

A. Open Access Implementation Costs Should Be Offset by Earnings Through 2001

Energy Michigan Witness Kuhn testified that both Consumers Energy and Detroit Edison appear to have had earnings well above authorized levels through spring 1999. *4 T 96-97*. To the extent that these excess earnings are greater than the actual incurred and deferred cost of open access implementation no customer should pay for such implementation costs. Mr. Kuhn explained that it would be unreasonable to allow to a utility to recover excess earnings and then recover additional implementation costs from customers for the same time frame. *Id.* Only to the extent that the utilities experience earnings deficiencies through 2001 after paying for implementation costs should rate increases in the form of implementation charges be allowed.

Note that Mr. Kuhn's fears about excess utility earnings have been confirmed by the fact that the Michigan State Tax Tribunal has approved what are estimated to be up to $100 million per year of tax reductions for Michigan utilities. Exhibit 1. Unless excess earnings produced by these new cost reductions are used to offset implementation costs, utility profits will soar in the very same time frame that customers are being forced to pay a new utility implementation charge.

B. Implementation Costs Should Be Billed To All Customers

Energy Michigan concurs with Consumers witness Rasmussen that open access implementation costs should be charged to all customers. *4 T 565-66.*

IV. THE SHORTAGE OF ELECTRIC CAPACITY IN MICHIGAN ENSURES THAT DETROIT EDISON AND CONSUMERS ENERGY WILL HAVE NO STRANDED COST THROUGH 2001

A. Energy Michigan Position

Energy Michigan Witness Theodore Kuhn testified that since both Edison and Consumers had earnings above authorized levels during 1998 and since the projected phase-in of 12 ½ % open access capacity through 2001 will be offset by utility load growth through 2001, no stranded cost will be incurred through 2001 at the modest levels of open access capacity ordered by the Commission. *4 T 99*.

Mr. Kuhn's assumptions can be confirmed by tracking future utility earnings during the period 1998-2001. If utility earnings stay at or above authorized levels, it confirms that there are no stranded cost being incurred. If returns fall below authorized levels, the revenue deficiencies could be made up through transition charges. *4 T 99-100*. Mr. Kuhn supported his position by testifying that current and projected retail customer demand is greater than the current capability of Edison and Consumers to provide power. *Id.* The Statewide power shortage in Michigan provides a huge excess of demand over supply of electric capacity. Both Detroit Edison and Consumers Energy have an advantage over out-State suppliers in meeting this demand because out-State suppliers must incur the cost of bringing power into Michigan through out-State transmission systems. *4 T 100.*

B. Data Confirms that Michigan Utilities Are Huge Purchasers, Not Exporters of Power

Exhibit I-52 taken from the Detroit Edison 1999 PSCR filing projects purchases by Edison of thousands of MW of power each year for the next five years through 2004. *Case U-12121, September 30, 1999, Brief Exhibit 2*. Thus, Edison has a substantial net generating capacity deficiency which effectively creates a market for excess Consumers power energy supplies. <u>In that same filing, Edison Witness Byron at page 24 confirms that the MECS agreement will expire at the end of 2000 thus potentially allowing MECS members to charge each other a market rate price for excess power that was previously shared by Edison and Consumers at below market rates.</u> If Edison and Consumers reach a new agreement on interutility sharing of power at below market rates, open access customers should not be penalized for this retail customer "subsidy". All wholesale and interutility transactions within MECs should be assumed to contribute to stranded costs at the same rate as retail sales.

Detroit Edison filing U-12266 and Consumers Energy filing U-11954 plus recent announcements of the conversion of the Consumers Cobb 1-3 units to natural gas confirm that Michigan's utilities are scrambling to build or buy additional generating sources. Mr. Kuhn testified that the compound growth rate of Consumers 1995-98 was 3.8% and that of Detroit Edison was 3.9%. *4 T 99*. Given this growth rate, even with open access implementation at the 2 ½ % annual rate scheduled by the Commission, <u>utility retail sales load will grow rather than decline through 2001.</u>

Mr. Kuhn calculated a peak load short fall for Consumers and Detroit Edison of about 3,650 MW by 2001. *4 T 101*. While these calculations are based on peak conditions, the magnitude of the short fall means that more than just peak time periods will be affected. Mr. Kuhn testified that the size of the capacity shortage is of such an extent that a prudent utility would need to have or purchase substantial blocks of power for more than just on-peak periods to maintain acceptable coverage of demand. *4 T 101*. This assumption is borne out by the capacity purchase plans described by Edison in its year 2000 PSCR filing September 30, 1999. *See Brief Exhibit 2*. The duration of the acquired capacity is longer than just peak periods and is at such a high cost that the price paid could cover year-round requirements with very little additional cost. Clearly, migration of open access capacity off the Edison and Consumers systems is likely to reduce, not increase, utility cost per kWh through 2001.

C. Summary

There is no doubt that Detroit Edison and Consumers Energy retail load is growing faster than the 12 ½ % of open access capacity authorized by the Commission through 2001 much less the amount of open access capacity that will actually be served. Given this circumstance and the fact that Edison and Consumers are earning well above their authorized return on equity, no stranded cost will be experienced by these utilities at least through 2001. Based on this record, the Commission should disallow any claim for stranded cost or transition charges during the phase-in period through 2001 unless utility load growth from 1998-2001 is proven to be less than increases in open access load. Any transition charges collected from customers through 2002 should be refunded or credited to future transition charges.

V. CALCULATION OF STRANDED COSTS

A. The MPSC True-Up Plan Must Incorporate Mitigation to Function Properly

1. How the MPSC plan was supposed to work

The Commission envisioned that its stranded cost true-up methodology would function as follows:

> 1) To the extent that actual open access [sales] volumes varied from those used in estimates to calculate stranded costs, the stranded cost would be recalculated using the actual volumes.
>
> 2) To the extent that actual market price varies from the 2.9 ¢ assumption, stranded cost would be adjusted up or down by the product of multiplying the actual open access volumes for that year by the difference between estimated market price and the actual market price. *U-11290, January 14, 1998, p. 18*.

The MPSC true-up plan process develops an annual adjusted transition charge (A yr) by calculating an Estimated Transition Charge (E) /kWh (1.2 ¢ /kWh for Consumers and 1.25 ¢ /kWh for Edison) based on the Estimated Base Market Clearing Price (MCPB) for 1998 of 2.9 ¢ escalated at 3% per year. If the Actual Market Clearing Price of power each year (MCPA yr) differed from the escalated MCPB 2.9 ¢ estimate (e.g. 3.4 ¢ instead of 2.9 ¢) the difference (.5 ¢) was to be subtracted from the Estimated Transition Charge (E), (e.g. for Consumers 1.2 ¢ - .5¢ =.7 ¢).

Note that the Commission recognized the need to consider and potentially incorporate mitigation of utility production costs as an offset to claimed stranded costs. *U-11290, February 11, 1998, p.6.*

Expression of MPSC Process as a Formula

Let:

A yr	= Yearly Adjusted Transition Charge
E	= MPSC Unadjusted Estimated Transition Charge (1.2 ¢ /kWh for Consumers, 1.25 ¢ /kWh in 1998 escalated at 3% yr)
MCPA	= Actual Market Clearing Price
MCPB	= Base Market Clearing Price

Stated as a formula the MPSC plan is:

$$A\ yr = E - (MCPA\ yr - MCPB\ yr).$$

2. Problems with the MPSC true-up process

As explained by Energy Michigan Witness Kuhn, the MPSC stranded cost calculation and true-up process attempts to adjust for changes in the market clearing price of power but is flawed because it always produces the same total cost of market power and transition charge to the customer which starts at 4.1 ¢ in 1998 and rises at the rate of 3% per year regardless of changes in the market price of power. *4 T 103-4*.

As shown in Exhibit I-1, the total price paid by open access customers in the year 2002 would be the same even though the market price of power varied by .3 ¢ /kWh since the transition charge is automatically adjusted to offset this change. *Id*, *Exhibit I-1, Brief Exhibit 3*. Under the Commission Order, the total price paid by the open access customer increases 3% per year throughout 2007 regardless of the fact that the cost of competing power provided by regulated utilities such as Detroit Edison and Consumers Energy has declined. It is clear that when and if Detroit Edison and Consumers Energy can produce power at a rate equal to or lower than the total 4.1 ¢ escalated at 3% market rate, the entire open access program will cease to function. The cause for this failure of open access will be the MPSC adjustment mechanism which produces continually increasing total costs of open access power regardless of changes in the market prices of non-utility power or the declining cost of utility power.

3. The Energy Michigan proposal to use mitigation to assure a functional true-up process

The root cause of the problems associated with the Commission true-up plan can be found in the failure to incorporate mitigation. The Commission methodology calculated stranded cost using a fairly accurate assumption that Market Clearing Prices at the beginning of 1998 were roughly 2.9 ¢ /kWh, a figure substantially below utility production costs which were roughly 1.2 ¢ /kWh higher. In early 1998 these assumptions produced the total stranded cost numbers estimated by the Commission at that time. While the Commission recognized that actual Market Clearing Prices might increase faster or slower than its assumed 2.9 ¢ escalated by 3% per year, the Commission did not introduce a mechanism to recognize the potential effects of utility cost mitigation which might reduce overall utility costs of production, making utility power more competitive with market power, thereby also reducing potential stranded cost under the Commission program. *4 T 105*.

In Exhibits I-2 a. and b., Mr. Kuhn documented this trend of declining utility costs of production which equals approximately 5% per year for Detroit Edison and 6% per year for Consumers Energy from the period 1995-1998. *Id.* The Kuhn data supporting utility cost reductions is restated in Exhibit 4 a. and 4 b. to this Brief to address the concerns raised by Consumers which are discussed below. However, Mr. Kuhn's fundamental point has not changed! Utility non-fuel costs of production declined dramatically from 1995-1998 at a rate of 5% of more. Large reductions in utility costs of production occurred by the end of 1998 which were not known by the MPSC when it formulated its January 1998, U-11290 plan.

A large part of the reduced utility costs of production was due to greatly increased wholesale transactions reflecting the ability to spread fixed costs over increased production. Regardless of the reason, however, declining utility costs of production will shrink stranded costs just as much as increased market prices. The Commission must take this phenomenon of changing production costs into account to formulate an accurate true-up process which incorporates mitigation.

Changes in non-fuel power costs were used by Mr. Kuhn to adjust the Commission 1998 market price base because these costs are controllable by utilities to some degree and are impacted by depreciation. Variable costs like fuel are not considered because they impact both utilities and non-utilities alike. *4 T 105.*

The reality of declining utility costs of production and their impact on stranded cost and hence transition charges can be incorporated as the type of mitigation measure, encouraged by the Commission in its orders. *U-11290, February 11, 1998, p. 6.*

The mitigation method recommended by Mr. Kuhn would be to revise the Base Market Clearing Price (MCPB) used in the Commission formula from the 2.9 ¢ /kWh estimated in 1998 and assumed to increase by 3% to a value used in the future true-up proceedings that incorporated the actual reductions achieved in utility production costs during 1998 (since those reductions could not be shown in the MPSC case U-11290 issued on January 14 of 1998) and then assume a rate of cost reduction thereafter of 1% per year. The 1% future annual mitigation factor is significantly below actual achieved rates of cost reduction by Edison and Consumers but it could produce an incentive system whereby utilities kept reductions in excess of the assumed rate. *4 T 105-6.*

The method described above to incorporate mitigation would accomplish the desirable end of recognizing that utilities have mitigated their stranded cost problems by reducing their cost of production which will either make them more competitive against open access service or produce revenues higher than assumed by the Commission in 1998 if they sell their excess power on the open market.

4. Reply to Consumers cross examination questions

a. Mr. Kuhn's mislabeling of Nuclear Decommissioning Revenues.

During cross examination, counsel for Consumers Energy raised questions about the figures shown on Mr. Kuhn's Exhibit I-2 for the line marked "Plus Nuclear Decomm.Rsrv." *4 T 123-131.* Consumers counsel correctly pointed out that the figures currently contained in Exhibit I-2 refer to the accumulated provision for the amortization of nuclear fuel. <u>We agree that the entry was mislabeled</u>.

We do not believe that Consumers Energy or Detroit Edison should earn a return on the accumulated provision for nuclear decommissioning. These funds accrue interest separately from the utility, to be used for the purpose of funding the eventual nuclear decommissioning requirements. However, in the interest of removing a source of dispute, replacing the Nuclear Decommissioning Revenue figures shown in Exhibit I-2 with the appropriate accumulated provisions for nuclear decommissioning has no material impact on the conclusions drawn from this exhibit, which prove to the declining overall cost of providing power from Consumers Energy and Detroit Edison. Table 1 below provides the compound annual growth rates for the period 1995-1998 before and after changing the figures referenced by Consumers Energy's counsel. Both sets of figures support the contention that Consumers Energy and Detroit Edison have substantially lower costs of providing power today than they did four years ago. The complete modified exhibits are attached as Exhibits 4a and 4b to this Brief.

Table 1

	Consumers Energy Costs 1995-98		**Detroit Edison Costs 1995-98**	
	Total Decline in Cost per kWh	Non-Fuel/purchased power Cost Decline per kWh	Total Cost Decline per kWh	Non-fuel/purchased power Cost per kWh
Original Exhibit	-0.8 ¢	-.32 ¢	-.38 ¢	-.48 ¢
Modified Exhibit	-0.4 ¢	-.25 ¢	-.38 ¢	-.48 ¢

Whether the accumulated provisions for the amortization of nuclear fuel remain in the calculations or are removed has no impact on the conclusions, since the values are constant throughout the period examined for both utilities.

b. Rate of Return on Deferred Taxes

Counsel questioned if Mr. Kuhn had treated deferred taxes as zero cost capital. *4 T 131-132.*

Whether deferred taxes are included (as at the FERC) or treated as zero-cost capital (as at the MPSC) has no material impact on Mr. Kuhn's conclusions because the values for deferred taxes are relatively constant throughout the period examined for both utilities. *Id.*

c. Issues Raised on Cross by Detroit Edison

Consumers counsel for Detroit Edison questioned whether Exhibit I-2 correctly incorporated Fermi 2 costs. *4 T 140-141.* The values shown in Exhibit I-2 were taken directly from the reports filed by Consumers Energy and Detroit Edison with the FERC. No changes or alterations were made to the data prior to their use in the exhibit.

In regards to the values shown for Detroit Edison (Exhibit I-2, page 2 of 2) (Exhibit 4b to this Brief), a question was raised by counsel for Detroit Edison regarding the inclusion or exclusion of Fermi nuclear plant. As stated by Edison in their report to the FERC in 1998 (FERC Form 1), "Fermi 2 was determined to be an impaired asset and was written off at 12/31/98 and was restablished (sic) a regulatory asset in account 186." This is apparently a primary reason for the large decline in Total Production Plant (Gross), <u>as well as the large offsetting reduction in Accumulated Depreciation.</u> *Emphasis supplied.*

<u>Regardless of the treatment of Fermi or its retirement, the fact remains that these changes in gross plant and depreciation had no significant impact on the resulting calculation of the cost per kWh.</u> This can be seen most clearly by examining the line in Exhibit I-2 labeled Pre-Tax Return, which calculates the dollar value to be included in annual cost related to Rate Base (also shown in the exhibit). The reduction in this amount is relatively consistent on a year-to-year basis over the entire period shown:

1995-96	$18,014,000
1996-97	$14,573,000
1997-98	$21,270,000

Furthermore, the magnitude of these changes in relationship to the total costs involved and their impact on the annual change in overall cost per kWh is very small. Changes in production plant (from 1997-1998) account for less than ½ mill of the reduction in total cost per kWh shown in the exhibit.

d. Would Use of a Lower Base Market Clearing Price Have Increased Utility Stranded Costs?

Cross exam of Mr. Kuhn by counsel for Consumers Energy confused the impact of Mr. Kuhn's proposals. *4 T 135.* Consumers attempted to show that Mr. Kuhn's recognition of utility production cost reductions achieved by the end of 1998 would reduce the Base Market Clearing Price from the 2.9 ¢ assumed by the Commission (which is true) and that a reduced Base Market Clearing Price would produce larger, not smaller, stranded costs (which is not true).

Consumers counsel apparently did not understand the Kuhn proposal.

Mr. Kuhn recognizes that the Commission 2.9 ¢ /kWh 1998 Base Market Clearing Price, escalated at 3% was used for the purpose of producing estimates of stranded costs and an Estimated Transition Charge (1.2 ¢ for Consumers, 1.25 ¢ for Edison).

<u>Mr. Kuhn proposes to change the way that the Base Market Clearing Price, is used in the future to determine future annual Transition Charges.</u>

Once the Commission estimated total stranded costs using the 2.9 ¢ base, its true-up process used the same (MCPB) (escalated at 3%) to compare market price with this original assumed price to see if increases or decreases in the market price produced less or more stranded costs respectively. Mr. Kuhn <u>changes</u> this concept by recognizing that <u>decreases</u> in utility production costs would tend to reduce utility stranded costs. Mr. Kuhn, therefore, proposes to reduce the 2.9 ¢ Base Market Clearing Price (MCPB) in an amount equal to 1998 utility achieved cost reductions and further reduce the Base to assume future 1% per year utility cost reductions. This adjustment has the effect of showing that utility production costs are declining while the Actual Market Clearing Prices are typically increasing. All other things being equal, Mr. Kuhn's proposal for MCPB should reduce future transition charges while the Commission's method of calculating MCPB (2.9 ¢ escalated at 3%) guarantees steadily increasing costs. This is because, all other things being equal, reduced utility costs of production tend to produce equivalent reductions in stranded cost.

5. Impact of utility mitigation of production costs on transition charge calculation

In order to correctly incorporate utility mitigation of stranded cost through reduction of cost of production, the value of Market Clearing Price Base used in the Commission formula should be reduced by .4 ¢ /kWh for Detroit Edison and .09 ¢ /kWh for Consumers Energy to incorporate 1997-98 actual reductions in non-fuel production costs with an assumption to reduce these values at 1% per year thereafter. *See Exhibit 4. a. and 4. b. to this Brief.* This would produce an initial Market Clearing Price Base value of 2.5 ¢ /kWh for Detroit Edison and 2.81 ¢ /kWh for Consumers Energy both reducing at 1% per year thereafter for use in the Commission true-up formula. Other mitigation from renegotiation of QF contracts as a result of divestiture or renegotiations of such contracts should be added as a mitigation amount with some sharing of these reductions between customer and utility.

B. Proposals To Calculate the Remaining Components of the MPSC True-Up Formula

1. Other than the Market Clearing Price Base (MCPB) rate discussed above, use of the MPSC formula requires 1) annual calculation of approved Stranded Costs (S) each year, 2) sales levels over which to spread the stranded cost, and 3) annual Actual Market Clearing Price (MCPA yr). Calculation of these elements is discussed below.

2. Calculation of Consumers Energy and Detroit Edison approved stranded cost (S)

a. Consumers Energy claimed stranded cost should be reduced

Consumers Energy's claimed stranded costs are summarized in Exhibit A-CE-20 presented by Witness Ernst. Five major disallowances are warranted:

i. Nuclear additions

Mr. Ernst testifies that nuclear asset accounts eligible for stranded cost recovery should be updated from his year end 1999 amounts if they are materially different from the estimates found in Exhibit A-CE-20 due to plant additions. *4 T 435*. On cross examination Mr. Ernst admitted that while no estimates were available of such additions for the period 2000 through 2007, the 1999 additions would be over $30 million. *4 T 449*.

Note that the Consumers and Edison proposals to pay increased nuclear stranded costs contain no proposals which would allow open access customers to benefit from increased output of these plants.

Both Energy Michigan Witness Kuhn and MPSC Witness Geml have testified that generating plant additions after 1998 should not be collected as stranded costs. *4 T 102, 5 T 834.* As succinctly stated by Mr. Geml, since 100% of nuclear plant investments are treated as stranded costs, they have no value to open access customers and if an investment in such plants is made it must be assumed that the entire value is received by retail service customers. *Id.* Open access customers would be better off if the Palisades plant were shut down entirely since they are asked to pay the entire capital cost of the plant. Making open access customers pay the cost of an increasingly more expensive plant which is being maintained purely to serve the needs of retail customers makes no sense at all.

ii. The assumed market value of capacity from Power Purchase Agreements is understated in Exhibit A-CE-20.

Mr. Ernst's Exhibit A-CE-20 assumes that the total capacity costs of Power Purchase Agreements (stated on lines 53 of A-CE-20) are offset by an assumed market value of .9 ¢ /kWh times generation output of roughly 8.6-9.4 million Mwh of output each year.

1) The output of PPA capacity is understated or the value of PPA QF capacity which is economically dispatched is understated.

Exhibit I-32 contains the work papers of Mr. Ernst related to QF output. *Brief Exhibit 5 a.-d.)* Exhibit I-32, page 1 is Mr. Ernst's work paper WP-2C which shows that QF output during 1997 was approximately 13 million Mwh with the MCV producing about 10 million of these Mwh. *4 T 448.* Total average cost of the output was about $57.34 / Mwh for the MCV and the capacity portion was about $40.00/Mwh subtracting variable cost from total costs. *I-32, p. 1.*

Mr. Ernst admitted that in A-CE-20, he projected reduced output for the MCV in 1999-2007 of between 8.6 and 9.4 million Mwh per year. He also admitted that his Exhibit A-CE-20 was based on economic dispatch, not maximum output. *4 T 449*. MCV output during 1997 was based on capacity factor of 99%. Output in Mr. Ernst's A-CE-20 assumptions of roughly 60% dispatch produces a Power Purchase Agreement <u>capacity</u> <u>only</u> <u>cost</u> of roughly $55-56/Mwh. MCV capacity in 1997 at 99% capacity factor was about $40 /Mwh total cost minus variable cost (see Brief Exhibit 5a).

<u>This differential in the cost of capacity between 60% dispatch and almost 100% dispatch is almost completely explained by the fact that the total obligation to pay for MCV capacity under a year around contract does not vary markedly regardless of the Mwh dispatched since 100% of the capacity is always assumed to be available to and paid by the purchaser</u>. Rather, it is the amount of energy that is taken which varies and causes the price per Mwh to vary because the same total capacity payment is spread over fewer Mwh. Consumers is, however, still required to pay for all MCV capacity on a year around basis since the QF project exclusively is dedicated to the need of Consumers.

In essence, Mr. Ernst's exhibit asks us to assume that the market value of MCV capacity per Mwh from a partially dispatched MCV Power Purchase Agreement will be offered to market customers for only 60% of the year <u>at the same price per Mwh as if the customer had been required to take the capacity 100% of the year</u>. This is complete nonsense as demonstrated by the disparity in the capacity cost per Mwh between the actual 1997 output at 99% load and Mr. Ernst's assumptions for 1998-2007 at 60% load .

As is shown in Exhibit 6 to this Brief, Mr. Ernst's Exhibit A-CE-20 should be revised by assuming output of at least 13 million Mwh of Power Purchases as was taken in 1997 times a value of .9 ¢ /Mwh <u>or the .9 ¢/kWh assumed market rate should be increased to 1.5 ¢ per unit of economic dispatched output by dividing .9 ¢ by .6 to spread</u>

the total cost of capacity at 100% over only 60% levels assumed by Mr. Ernst. The impact of this adjustment is to produce an extra $40 million per year of income and reduce calculated stranded cost by .08 ¢ /kWh as shown in Exhibit 6 of this Brief. Total QF stranded costs as of 1998 are reduced from the $1.883 billion claimed by Mr. Ernst on line 65 of A-CE-20 to $1.754 billion. *See line 65 of Brief Exhibit 6 attached.*

2) Mr. Ernst also failed to assume that the value of Power Purchase Agreement capacity would escalate each year (see line 82, Exhibit A-CE-20) even though he concedes that the total price of energy and capacity would increase at the rate of over 3% (see line 80).

Witness Ernst admitted that if the capacity costs in his Exhibit A-CE-20 were escalated, stranded costs would be lower. *4 T 455*. Mr. Ernst also admitted that all the escalation in his exhibit was applied to energy and not capacity. *4 T 456*.

Mr. Ernst's treatment of this subject has the effect of depriving open access customers of an increasing value of marketed excess PPA capacity as a mitigation to stranded cost. If PPA capacity is assumed to escalate at the same 3% rate as used for capacity and energy, calculated transition charges are reduced by almost .04 ¢ /kWh or about $65 million net present value in 1998. *See Brief Exhibit 7 attached, lines 82 and 71*.

The combined effect of these two adjustments is to reduce claimed stranded costs in 1998 from a net present value of $1.877 billion

<u>claimed by Mr. Ernst to $1.656 billion and transition charges are reduced from 1.2 ¢ to 1.06 ¢ .</u> *See Brief Exhibit 8, line 65.*

3) <u>PECO disallowance</u>

<u>The PECO transaction described by Mr. Ernst in A-CE-26 assumes at line 1 the same .9 ¢ /kWh above market value for MCV capacity as is developed in A-CE-22 by assuming MCV capacity output at 60% capacity factor. Thus, the PECO transaction contains excess costs which are passed on to retail and open access customers.</u> These excess costs can be reduced by requiring a higher price from PECO or reducing Consumers' claimed stranded costs based on the higher market value of MCV capacity.

4) The cost claimed by Mr. Ernst associated with FAS 106 and 109 include post 2007 cost related to <u>all</u> generation. *A-CE-20.* Collection of these costs is accelerated to the period 2007 rather than collected on a schedule which would go past that point. *4 T 456-7.* The effect is to increase stranded costs improperly. These costs should be reduced to include only costs collectible through 2007.

5) Any savings from the buyout/buy down of PPA capacity should be used wholly or partially to mitigate stranded costs.

To the extent that PPAs currently or in the future are bought out or bought down at a discounted rate, the development would produce a reduction in claimed stranded costs. At the very least, a mechanism should be set up to encourage this development by sharing such savings between company and customer.

b. Detroit Edison claimed stranded costs should be reduced.

Detroit Edison has attempted to raise its stranded costs from the 1998 level approved by the Commission at $2.483 billion (including QF costs) to $3.117 billion for all generation (Exhibit A-DE-4, line 33) plus over $128 million of QF costs (A-DE-10, line 13). Thus, Edison is trying to up an already rich ante by adding more than $.75 billion of new items. These increased costs should be rejected.

1) Additions to the Fermi nuclear plant should be removed as stranded costs.

Detroit Edison Witness VanHaerents proposed to include $180 million of capital additions to the Fermi nuclear plant as recoverable stranded cost. *Exhibit A-DE-6, line 4*. Witnesses Kuhn has opposed counting power plant additions after 1998 as stranded costs. *4 T 102*. Staff witness Mr. Geml has stated that nuclear additions cannot be justified as stranded costs and benefit only retail customers. *5 T 834.*

It makes no sense to claim that nuclear plants are unmarketable and therefore unuseable on the one hand and continue to add investment to keep the plants running on the other hand. If such additional investments are made it is clear that the nuclear plants are required to serve retail customers and it is retail customers who should pay these additional costs.

2) Costs of reacquired debt should be removed from proposed stranded costs.

Mr. VanHaerents' Exhibit A-DE-6, line 26 and Mr. Loeher's Exhibit A-DE-9 include the cost of reacquired debt on the grounds that these costs were necessary to refinance and secure a lower debt. Mr. VanHaerents also admitted that since a great many of these refinancings took place after Case U-10102 which set current retail costs, much of the benefit of the refinancings have not been received by any customers and are not reflected in lower rates. *4 T 198*. Asking any customer, much less an open access customer, to pay for a new cost while denying them the cost reduction benefits achieved through the cost is unfair, unreasonable and a double collection. The costs of reacquired debt should be denied as a stranded cost.

3) Costs of accelerating FAS 106 and 109 nuclear costs and collecting non-nuclear costs should be disallowed.

Mr. VanHaerents also admitted that acceleration of <u>all generation related (not just nuclear)</u> FAS 106 and 109 collections to the 2007 time frame was not included in MPSC Order U-11290 issued January 14, 1998. *4 T 201-202*. Edison's attempt to accelerate collection of these costs which otherwise would be collected after 2007 merely increases stranded costs which would otherwise collected at a later date. The accelerated and non-nuclear portion of these FAS 106 and 109 costs should be denied. *See A-DE-5, lines 10-15*.

4) In Summary: All Detroit Edison costs above the estimates of the Commission in January 1998 should be disallowed.

Exhibit I-7 shows Edison's own statement of Fermi 2 plant balances on a pre-tax and post-tax basis. *Brief, Exhibit 9*. It is instructive to compare these balances with the proposed total Fermi generation regulatory assets proposed by Mr. VanHaerents in Exhibit A-DE-6, line 33. For 1999 through 2007 the differences are more than $300 million per year. This difference represents the unauthorized or excessive stranded costs described above which Detroit Edison has attempted to add to its proposal. These costs should be removed and the estimated stranded cost should be recalculated consistent with previous Commission Orders in U-11290 and Exhibit 7 attached to this Brief.

3. Stranded costs must be spread over all Detroit Edison and Consumers Energy wholesale, retail and open access sales. Stranded costs should not be collected if total wholesale and retail sales exceed 1998 levels.

Energy Michigan Witness Kuhn supported use of total utility sales including wholesale sales to recover utility stranded costs. *4 T 112-13*. In contrast, both Detroit Edison and Consumers Energy have used only retail sales to spread costs. *Exhibit A-CE-20 (Consumers) and A-DE-9 (Detroit Edison)*. Note Consumers Energy Witness Ernst confirmed use of only retail sales in his Exhibit A-CE-20. *4 T 452*. Witness Loeher confirmed that only retail sales were used. *4 T 233, 238.*

Use of wholesale transactions to recover stranded costs becomes particularly critical after the year 2000. Detroit Edison Witness Byron has filed testimony in Case U-12121 stating that the current electric coordination agreement will terminate December 31, 2000. He stated that Edison and Consumers Energy are in discussions regarding potential joint merchant operations for 2001 and beyond. *Case U-12121 testimony filed September 30, 1999, p. 24.* Consumers Witness Ernst admitted that his projected sales in Exhibit A-CE-20 did not include MECS transactions, bulk power sales or other power transactions for economy purposes. *4 T 452*.

Also, utilities will sell large amounts of ancillary services to open access customers. The benefit of these sales to open access customers may not be captured if they are provided as wholesale transactions with marketers.

The magnitude of these excluded sales is not trivial. Compare Mr. Ernst's estimated sales in Exhibit A-CE-20 for 1998 of 35.48 billion Mwh with the total actual wholesale and retail sales of energy provided in 1998 for federal purposes of 39.78 billion. *Exhibit I-2, Exhibit 4 of this Brief.* In other words, Consumers' total energy delivered exceeded Mr. Ernst's retail sales estimate by more than 11%.

The issue is just as large for Detroit Edison. Compare the Edison forecast of 1999 retail sales at 50.8 million Mwh (A-DE-9) with the 1998 <u>actual</u> total retail and wholesale sales of 55.2 million of Mwh. *I-2, p. 2.*

After the year 2000 it is quite possible that Consumers Energy will sell excess capacity into the open market rather than transferring it back and forth between Edison and Consumers under arrangements which tend to produce below market prices for both utilities to the benefit of their retail customers but provide no benefit for open access customers. Other types of economy transactions also produce lower cost power for retail customers of Edison and Consumers and spread fixed costs over a larger volume of power. However, these transactions produce no corresponding benefits for open access customers unless the sales are used to recover stranded costs.

Unless the Commission recognizes the value of wholesale transactions and sales of ancillary services, etc., increased output of utility generating plants will reduce utility operating costs /kWh but will have no value to open access customers.

The Commission should recognize that because wholesale sales provide below market power sources to retail customers and provide a potential source of market revenue for surplus capacity, wholesale and interutility transactions must be taken into account when recovering so-called stranded costs.

4. There must be a mechanism which caps stranded cost recovery and reduces or

eliminates recoveries from open access customers to the extent that retail and wholesale transactions increase to a level that stranded costs are recovered.

A basic flaw in the presentations of Consumers Energy and Detroit Edison is that no matter how much power is sold, open access customers always pay stranded costs.

Perhaps the worst example of this phenomenon is the presentation of Detroit Edison Witness Charles Loeher. Mr. Loeher was asked to assume that 1999 total sales power were 50.87 million Mwh of retail and .5 million of open access. He was then asked if in the year 2007 retail sales were 60 million Mwh and 1 million Mwh of open access, would the open access customers would pay for stranded costs in the proportion of 1 to 61. He answered yes! *4 T 234.* This method of collecting costs stands logic on its head! Under Mr. Loeher's proposal Detroit Edison could purchase 50 million Mwh, generate 50 million, sell all 100 million Mwh at retail and still be collecting stranded cost if only 1 million Mwh of open access sales occurred!

The Consumers proposal is somewhat better but still contains flaws. Under Mr. Ernst's proposal there is a limitation on contributions to Power Purchase Agreement costs but open access customers would still pay a portion of nuclear and regulatory asset costs no matter how large the total retail and wholesale sales for Consumers Energy. *4 T 450-51*. Note that the proposal to "limit" PPA contributions is part of the PECO related order in U-11941. The discussion above illustrates that the assumed market value of MCV capacity, which is inherent in the PECO transaction, was significantly understated.

a. Energy Michigan proposal to incorporate retail, wholesale and open access transactions while placing a cap on contributions to stranded costs

Based upon the testimony and evidence on this record, Energy Michigan recommends the following concept to cap contributions to stranded costs and use appropriate sales levels.

1) A base level of sales must be determined which would represent a level at which the utility stranded costs may be recovered. Energy Michigan proposes using 1998 total retail and wholesale deliveries by Consumers Energy and Detroit Edison. During 1998, both utilities were earning well above their authorized rate of return. Detroit Edison had no open access sales or deliveries during that period. Consumers Energy had less than an estimated claimed 206 thousand Mwh of open access sales. These Consumers open access sales should be subtracted from the Consumers 1998 total to establish base sales levels (kWh 98). *Exhibit A-CE-20, line 3*. Witness Theodore Kuhn's exhibits show that the actual 1998 deliveries including wholesale transactions for Edison were 55.2 million Mwh (Exhibit I-2, p. 2 of 2) and for Consumers Energy were 39.8 million Mwh minus 200,000 Mwh of Open Access equals 39.6 million Mwh. *I-2, p. 1 of 2*. These 1998 sales levels should be used as a baseline for the level of retail, interutility and wholesale transactions that will recover all stranded cost.

2) A stranded cost contribution per kWh of kWh 98 Base sales deliveries should be established.

Each year the approved Stranded Costs (S) should be determined and divided by the 1998 total base sales (kWh 98). This process would yield an assumed contribution of stranded costs per kWh of 1998 deliveries.

3) A cap on stranded cost contributions would be achieved by multiplying the stranded costs contribution per kWh based on 1998 sales volumes (kWh 98) from 2) by actual yearly retail and wholesale sales (kWh yr). The product is the annual contribution to stranded costs of wholesale and retail sales in

each year.

4) The total recovery of stranded costs from retail and wholesale customers each year from 3) above would be subtracted from the total adjusted stranded cost (S) to yield unrecovered stranded costs. The unrecovered stranded costs would be divided by actual annual Retail Open Access sales (kWh OA yr) to arrive at the transition charge collectible from each kWh of open access sales (U yr).

The formula would be expressed as follows:

Let:

S yr	= Approved Stranded Costs Each Year
U yr	= Unadjusted Transition Charge Each Year
kWh 98	= Total Retail and Wholesale Sales in 1998
kWh OA yr	= Total Open Access Sales Each Year

$$\text{U yr} = \left(\frac{\text{S yr}}{\text{kWh 98 x kWh OA yr}}\right) \text{ x (kWh 98 - kWh yr)}$$

<u>Sample Calculation</u>

Assume that the 1998 total retail and wholesale sales for Consumers are 39.6 million Mwh and collectible stranded costs in 1999 were $400 million the transition charge contribution would be $400 million ÷ 39.6 Mwh = 1.01 ¢ /kWh. If 1999 actual deliveries were 39 million Mwh of wholesale and retail sales and 2 million Mwh of open access, the resulting transition charge would be 39 million x 1.01 ¢ = $394 million of revenue. $400 million of stranded costs - $394 million of revenues from retail and wholesale sales = $6.0 million to be recovered from open access customers. The unadjusted open access transition charge (U yr) would be $6 million divided by 2 million Mwh to yield an unadjusted Transition Charge (U yr) of .3 ¢ /kWh. This unadjusted Transition Charge would then be adjusted for Market Clearing Price changes, etc. as detailed below.

This methodology like that of the Staff recognizes that rapid increase in utility sales are likely to utilize virtually all utility capacity resulting in very little stranded cost. What stranded cost is leftover can fairly be apportioned to open access customers. <u>The Commission must not allow utilities to make the assumption that no matter how high their retail and wholesale sales become, nor how much money is collected that there will always be stranded costs to be paid by open access customers.</u>

5) The actual Market Clearing Price of power (MCPA) should be calculated using open access contract costs.

a . Support for use of actual open access contract prices to determine Market Clearing Price.

The MPSC itself considered the determination of Market Clearing Price and found customer retail contracts for open access service to be the best source of such data. *Case U-11454, October 29, 1997, p. 14-15*.

Energy Michigan Witness Kuhn testified that customer contracts for open access service adjusted for load factor should be used to determine Market Clearing Price. *4 T 106-107.*

Mr. Kuhn amplified on his method of adjusting contract price, under cross examination by Consumers Energy, emphasizing that it would be a fairly simple matter to adjust the contract price to match the load factor of utilities to make an accurate comparison. *4 T 136*.

A wide range of witnesses testified that use of open access contract prices are a correct proxy for Market Clearing Price because utilities are able to sell surplus power to customers at rates equal to the open access retail prices. *4 T 142 (Kuhn). Also see Witness Selecky 4 T 284-86; Phillips, 4 T 318.*

b. The use of customer open access contract data is supported by MPSC Staff testimony.

MPSC Staff Witness Stanton presented detailing the methodology by which customer open access contract data could be utilized to determine Market Clearing Price. *4 T 406-412*. Energy Michigan supports Mr. Stanton's methodology as supplemented by Mr. Stanton to address adjustments for load loss and the cost of ancillary services.

<u>Mr. Stanton also testified that the Market Clearing Price data obtained from open access contracts should be adjusted for load factor and for load loss.</u> *Id.* Mr. Stanton stated that customer open access data could be adjusted for energy loss by taking the total price that the customer paid for their energy supply for demand and energy and dividing by the kWh registered at their meter. *4 T 416*. This price would tend to reflect the fact that customers must contract for more open access kWh than actually reaches their meters because of load losses. This fact tends to drive up the price of open access energy and capacity compared to retail service prices which <u>include such losses.</u>

Finally, Mr. Stanton testified that mandatory ancillary services costs must be added to the open access contract pricing to determine the actual Market Clearing Price (MCPA) of open access service. *4 T 417*. Standby service may be included in that category. *Id.*

The need to add mandatory ancillary services to the price of open access power is not trivial. Consumers Energy charges 21 ¢ /kW for reacted supply and 17 ¢ /kW of capacity for regulation and frequency response. *See F19.00 from the Consumers open access tariff.*

5. The Base Market Clearing Price for power should be calculated using the Kuhn methodology discussed in V.A.3. above to incorporate mitigation.

The Energy Michigan proposal to incorporate mitigation in the Base Market Clearing Price (MCPB) was supported by Energy Michigan Witness Kuhn and discussed in V.A.3. above.

The resulting calculation of Base Market Clearing Price would be performed as follows:

a. Consumers Energy = 1998 base value of 2.9 ¢ - 1998 actual reduction in cost of production excluding fuel and purchase power of .09 ¢ /kWh (See revised Exhibit A-2, p. 2 which is Exhibit 4-A of the Brief) = 2.81 ¢ /kWh assumed to reduce at a rate of 1% per year after 1998 for continued mitigation.

b. Detroit Edison base value is 2.9 ¢ /kWh - 1998 actual reductions in cost of production excluding fuel and purchase power of .4 ¢ /kWh = 2.5 ¢ /kWh. *See Exhibit A-2, p. 2, which is revised Exhibit 4 B of this Brief.*

C. The Proposed Energy Michigan Formula for Calculation of Stranded Costs

The proposed two step formula for calculation of stranded costs is shown below:

Let:

A yr	= Adjusted Transition Charge
U yr	= Unadjusted Transition Charge
yr	= Current Year
S	= Approved Stranded Costs
MCPA	= Actual Market Clearing Price
MCPB	= Base Market Clearing Price
kWh	= Total Energy Sales to Retail and Wholesale Customers
kWh OA	= Total Energy Sales to Open Access Customers
98	= 1998

1. $$U\ yr = \left(\frac{S\ yr}{kWh\ 98 \times kWh\ OA\ yr}\right) \times (kWh\ 98 - kWh\ yr)$$

2. $$A\ yr = U\ yr - (MCPA\ yr - MCPB\ yr)$$

The Energy Michigan true-up process would work as follows:

1. Annual total stranded costs claimed by each utility are reduced pursuant to the Energy Michigan recommendations in V.B.2 a and b above and become approved stranded costs (S).

2. The total annual approved stranded costs established in No. 1 are divided by 1998 actual retail and wholesale sales for each utility (kWh 98) to develop a transition charge contribution to be assumed per kWh of actual retail and wholesale transactions.

3. The annual stranded cost contribution (kWh yr) per kWh from No. 2 is multiplied by actual annual wholesale and retail sales to determine the total actual contribution to stranded costs by retail and wholesale sales in that year.

4. The actual contribution to stranded costs of wholesale and retail sales from No. 3 above is subtracted from the annual stranded cost (S). The resulting unrecovered number is divided by annual open access deliveries (kWh OA yr) to obtain a current unadjusted transition charge (U yr).

5. Each year the Actual Market Clearing Price (MCPA) of power is determined pursuant to the recommendations of Energy Michigan in V.B.4. above. The Base Market Clearing Price (MCPB) calculated in V.B.5. is subtracted from the Actual Market Clearing Price (MCPA). The resulting number is then subtracted from the unadjusted Transition Charge (U yr) in No. 4. The result is the annual Transition Charge (A yr) to be assessed for the next year. Over or under collections are reconciled and credited or deducted from total charges to be collected in the next year.

Timing Issues

6. Energy Michigan recommends that the true-up process utilize projected numbers for open access sales volumes and true-up any over or under recovery in succeeding years based on actual volumes. Estimates of open access capacity should be prepared by or approved by MPSC Staff.

VI. CONCLUSION AND PRAYER FOR RELIEF

Energy Michigan requests that the Commission adopt a stranded cost true-up process and other true-up proposals as more fully discussed above.

Respectfully submitted,

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Energy Michigan Initial Brief

Exhibit 1

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REPORT NO. 245, VOLUME 38 TUESDAY, DECEMBER 21, 1999

LOCAL GOVERNMENTS CONSIDERING ACTION ON UTILITY DEPRECIATION

Worried about a change in the personal property tax depreciation schedules that they say could cost local governments millions, local officials are considering a range of options to force a change to the recently-enacted tables. The complaint centers around the new table for depreciation on the gas and electric distribution property owned by utilities, which one local official said, in effect, creates a statewide assessment on utility property.

Local officials worry that they could be forced to repay utilities as much as $300 million for retroactive tax payments, even though the new tables are only supposed to have prospective application, in addition to annual tax losses of $100 million. The utility provision is the only one in the new depreciation tables adopted last month the local governments are objecting to, and they are looking at everything from a lawsuit against the state to legislative changes to reverse the provision.

Scott Schrager of the Michigan Municipal League said officials were determined to take some action over the table, but declined to say what that action might be. And Bob Vandermark, the Oakland County equalization director, said the changes made to the utility depreciation table are unconstitutional because they effectively create a statewide assessment when assessments are to be conducted on a local basis.

Utility spokespeople said the depreciation tables more properly consider unique factors on utility property than the old tables. And if rebates are paid, then the effect on local governments will be minimal. In addition, they said that schools would be made whole from any loss of revenues by the state.

And an official with the Department of Treasury said the tables were antiquated and needed updating. While local governments might lose some revenue through the new tables, the tables address a larger issue of equitable tax collection, said Maureen McNulty-Saxton.

The issue, said Mr. Vandermark, is that the table allows utilities to depreciate the value of property from when it was first purchased instead of its current market value. In all other situations, property must be depreciated based on its current value, he said.

In effect the state depreciation table on utilities sets a statewide assessment on the property, Mr. Vandermark said. The state's constitution only permits a statewide assessment on telephone utility's property, he said.

But Charlie MacInnis of Consumers Power Company said that, unlike most corporate personal property, utility property is very similar from community to community as it tends to be in pipelines and wiring systems. The new depreciation table now sets a standard statewide for all local assessors to use, he said.

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The depreciation tables adopted by the State Tax Commission last month are supposed to take effect January 1. However, the utilities have also filed for rebates on the personal property taxes before the Tax Tribunal going back three years.

Mr. Vandermark said if the utilities are awarded the rebates, it could cost local communities $300 million plus interest. In Oakland County alone, county governments could be forced to repay some $24 million, and that does not include any future revenue losses.

Scott Simons of Detroit Edison said utilities filed thousands of personal property tax appeals in 1997 as part of an effort to draw attention to what it said was the antiquated depreciation tables the state had used since the 1960s.

Even if the utilities are awarded the rebates, local schools would get reimbursements of lost revenue from the state, he said. And the future effect on local governments would be minimal, he said, because "even though the utility may be the largest property taxpayer in a community, they still pay on average less than one-half of 1 percent of the tax paid."

And Ms. McNulty-Saxton said local governments would have to decide how to prioritize their budgets to make up for the lost revenue. That services may be affected does not hide the fact that from the state's perspective the taxes were being unjustly collected for many years, she said. One issue the state must be concerned about, she said, is the fair and just application and collection of taxes.

Mr. Vandermark said all local government groups are united in the effort to get this depreciation table overturned. Meetings are being held with legislators to look at the possibility of a statutory change to the table, he said, but the possibility of a lawsuit also exists.

Energy Michigan Initial Brief

Exhibit 2

I-52

Case No.	U-12121
Exhibit No.	(JHB3)
Witness:	J.H. Byron
Page No.	1 of 2

ANNUAL PURCHASED AND NET INTERCHANGE FOR 2001 - 2004

Line No.	Sales		2000	2001	2002	2003	2004
1	Wholesale						
2		- GWh	336	2,232	2,232	2,232	2,232
3		- $1,000	15,642	47,358	48,778	50,242	51.749
4							
5							
6							
7	Satellites						
8		- GWh	360	360	360	360	360
9		- $1,000	10,984	11,313	11,652	12,002	12,362
10							
11							
12	Consumers Energy						
13		- GWh	1,896	0	0	0	0
14		- $1,000	30,336	0	0	0	0
15							
16	OH Sale						
17		- GWh	1,250	1,250	0	0	0
18		- $1,000	10,129	10,421	0	0	0
19							
20	Ludington Lease - $1,000		14,928	15,345	6,467		
21							
22							
23							
24	TOTAL SALES -						
25		- GWh	3,842	3,842	2,592	2,592	2,592
26		- $1,000	82,019	84,437	66,898	62,244	64,111
27							
28							
29							
30							
31							
32	SALES. PURCHASES AND NET INTERCHANGE						
33							
34							
35		- GWh	2,367	1,829	1,303	2,786	2,314
36		- $1,000	300,280	308,831	318,517	395.493	422,957

M. SHIELDS
A. COLANDREA
D. HICKS
T. HSIEH
K. O'NEILL

Case No.	U-12121
Exhibit No.	(JHB-3)
Witness:	J.H. Byron
Page No.	2 of 2

ANNUAL PURCHASED AND NET INTERCHANGE FOR 2001 - 2004

Line No.	Purchases		2000	2001	2002	2003	2004
1	Wholesale						
2		- GWh	2,538	2,748	1,630	2,991	2,333
3		- $1,000	60,108	70,532	41,377	76,973	60,452
4			23.69	25.67	25.38	25.73	25.92
5							
6		R-10 Capacity	21,894	22,551	23,228	23,925	24,642
7							
8	Summer Contracts (5x16)						
9							
10		- GWh	819	882	945	1,009	1,135
11		cost - $1,000	74,610	82,760	91,331	100,343	116,272
12							
13	Summer Calls						
14							
15		- GWh	407	427	455	514	572
16		Energy - $1,000	48,160	49,880	53,320	60,200	67,080
17		Premium - $1,000	72,102	76,918	84,689	98,485	113,033
18		Total - $1,000	120,262	126,798	138,009	158,685	180,113
19							
20	Ontario Hydro LTP						
21		- GWh	750	750			
22		Capacity - $1,000	3,100	4,030			
23							
24	Transmission		$36,121	$38,876	$42,316	$47,184	653,442
25							
26	Beacon						
27		- GWh	43	43	43	43	43
28		$1,000	4,343	4,473	4,607	4,746	4,888
29							
30	Consumers Energy						
31							
32		- GWh	828	0	0	0	0
33		- $1,000	19,872	0	0	0	0
34	Purpa Qualifying Facility						
35							
36		- GWh	823	821	821	821	823
37		- $1,000	41,988	43,248	44,545	45,882	47,258
38							
39	TOTAL PURCHASES						
40							
41		- GWh	6,209	5,671	3,895	5,378	4,906
		-1000	382,299	393,268	385,415	457,737	487,067

Energy Michigan Initial Brief

Exhibit 3

CURRENT MPSC PROCEDURE FOR THE CALCULATION OF TRANSITION CHARGES

Year	(A)	(B)	(C)	(D)	(E)	(F)
	Market Price		Transition Charge			Total Paid by Open Access (Market) Customers (6)
	Actual (1)	Base (2)	Base (3)	Market Price Adjustment (4)	Net (5)	
1998	3.5	2.9	1.2	0.6	0.6	4.1
2002 ①	3.8	3.3	1.2	0.5	0.7	4.5
2002 ②	3.5	3.3	1.2	0.2	1.0	4.5

Notes:
All values expressed as cents per kWh.
(1) Assumed here for illustrative purposes.
(2) Approximate; based on 2.9¢ per kWh escalated at 3% per year.
(3) Consumers Energy value used for illustration.
(4) Column (A) – Column (B)
(5) Column(C) – Column@)
(6) Column (A) + Column (E)

Energy Michigan Initial Brief

Exhibit 4

Consumers Power Company FERC Form 1 data	1995	1996	1997	1998
	Value ($000)			
Total Production Plant (Gross)	$ 2,409,562	$ 2,490,062	$ 2,484,318	$ 2,460,519
Less Accumulated Depreciation	(1,380,922)	(1522,646)	(1,649,585)	(1,753,372)
Plus Nuclear Decomm. Rsrv	261,079	347,137	434,832	517,377
Gen/Com/Intngbl Plant	75,119	75,902	118,905	96,195
Plant held for future use	118	118	118	118
Net Production Plant	$ 1,364,956	$ 1,390,573	$ 1,388,587	$ 1,320,837
Less Deferred Tax Adjustment	(270,043)	(259,369)	(246,973)	(236,875)
Plus Materials & Supplies	79,767	74,763	71,920	77,121
Rate Base (I)	$ 1,174,180	$ 1,205,966	$ 1,213,534	$ 1,161,083
DOE SpentNuc (Acct.224)	45,218	53,300	64,191	69,877
Rate Base (II)	$ 1,219,398	$ 1,259,266	$ 1,277,725	$ 1,230,960
Rate of Return on Rate Base	10.6%	10.6%	10.6%	10.6%
Pre-Tax Return	129,256	133,482	135,439	130,482
Income & Other Taxes	103,745	109,064	116,015	114,599
Depreciation Expense	106,503	108,597	108,055	106,615
Prod. Operations & Maintenance	1,179,426	1,304,658	1,324,101	1,356,902
A&G Alloc. Share	126,470	128,939	116,360	116,969
TOTAL Production Costs	1,645,399	1,784,741	1,799,969	1,825,567
Fuel & Purchased Power Costs	978,103	1,095,949	1,146,574	1,178,577
Non-Fuel/PP Costs	667,296	688,792	653,395	646,990
Energy Provided (excl. losses)	35,521	37,066	37,896	39,782
Cost per MWh (mills/kWh)	46.3	46.2	47.5	45.9
Cost per **MWh (mills/kWh)** EXCL **Fuel/PP**	18.8	18.6	17.2	16.3

Detroit Edison Company
FERC Form 1 data

	1995	1996	1997	1998
		Value ($000)		
Total Production Plant (Gross)	$ 8,644,659	$ 8,697,949	$ 8,768,930	$ 6,865,728
Less Accumulated Depreciation	(3,176,007)	(3,454,631)	(3,755,140)	(2,324,353)
Plus Nuclear Decomm. Rsrv	78,396	124,306	178,940	105,029
Gen/Com/Intngbl Plant	432,301	481,580	527,730	557,563
Plant held for future use	9,623	9,623	9,623	9,623
Net Production Plant	$ 5,988,972	$ 5,858,827	$ 5,730,082	$ 5,213,589
Less Deferred Tax Adjustment	(1,378,761)	(1,361,817)	(1,319,253)	(1,122,379)
Plus Materials & Supplies	231.773	218745	705.835	238.837
Rate Base (I)	$ 4,841,983	$ 4,707,754	$ 4,616,664	$ 4,330,046
DOE SpentNuc (Acct.224)				
Rate Base (II)	$ 4,841,983	$ 4,707,754	$ 4,616,664	$ 4,330,046
Rate of Return on Rate Base	10.0%	10.0%	10.0%	10.0%
Pre-Tax Return	484,198	470,775	461,666	433,005
Income & Other Taxes	333,606	330,238	372,885	314,184
Depreciation Expense	320,948	322,798	324,068	290,049
Prod. Operations & Maintenance	1,111,180	1,111,614	1,076,917	1,311,166
A&G Alloc. Share	257,285	256,303	274,067	256,313
TOTAL Production Costs	2,507,218	2,491,729	2,509,603	2,604,717
Fuel & Purchased Power Costs	828,957	810,792	813,193	988,157
Non-Fuel/PP Costs	1,678,261	1,680,937	1,696,410	1,616,560
Energy Provided (excl. losses)	49,207	48,723	50,898	55,204
Cost per MWh (mills/kWh)	51.0	51.1	49.3	47.2
Cost **per MWh (mills/kWh)** EXCL **Fuel/PP**	34.1	34.5	33.3	29.3

Energy Michigan Initial Brief

Exhibit 5

WP-2C

CONSUMERS P... ER COMPANY

Exhibit: A-___(WCK-2)
Witness: WC Keyser
Date: February 1998
Page: 13 of 13

Ex. 5.a.

Purchase Power and Cogeneration - Energy and Expense
For the 12 Months Ending December 1997

= ENERGY = $550 305 556

= $344,442 677

Line	Company Name (a)	MWH (b)	Variable Energy	Admin Fees	Net Energy $ (c)	Fixed Energy $ (d)	Capacity $ (e)	Total $ (f)	Variable Energy Cost $/Mwh (g)	Total Cost $/Mwh (h)
1	Michigan St University	571	11.917	(659)	11,258	0	0	11,258	19.72	19.72
2	Commonwealth - Hubbardston	698	14,474	(697)	13,777	0	22,191	38,558	10.79	52.53
3	Black River Power	3,931	80,173	(4,923)	61,250	0	104,904	166,154	20.64	47.28
4	S D Warren	5,870	83,487	(5,117)	58,350	0	0	58,350	9.84	8.84
5	Dow Corning	0	0	0	0	0	0	0	000	0.00
6	STS - Fallasberg	5,531	116,293	(3,532)	110,761	0	156,770	267,531	20.03	48.37
7	Catalyst Beaverton Hydro	1,895	39.898	(1,895)	31,501	0	55.353	86,154	19.95	50.74
8	Whites Bridge	3.324	69.052	(3,321)	65,731	0	114,490	160.221	19.77	54.22
9	Thornapple Associates	5,833	122.729	(5,833)	118,598	0	119.245	299.141	20.04	50.77
10	Michiana Hydro	225	4,135	(225)	4,510	0	7,688	121209	20.04	54.26
11	Great Laker Tissue	24	325	(24)	301	0	0	301	12.54	12.54
12	Commonwealth - Labarge	3,989	83.017	(3,988)	79,029	0	130.515	209.544	19.81	52.53
13	Cameron- Mix Hydro	559	10,697	(697)	10,000	0	13,835	23,835	17.89	42.28
14	STS - Morrow	4,378	91.887	(4,377)	87,490	0	159,011	246,501	19.98	56.30
15	STS - Cascade	7,419	156,087	(7,419)	148,668	0	289.139	437,807	20.04	59.01
16	Grenfell Hydro	1.997	41.480	(1,996)	39.484	0	73.495	112,979	18.77	56.57
17	Neshkoro	0	0	0	0	0	0	0	0.00	0.00
18	Commonwealth Mng	1,914	38,872	(1,914)	36,958	0	55,056	92,014	19.31	4b u/
19	Commonwealth Middleville	1,807	28,393	(1,377)	27,018	0	48,816	75,834	14.95	41.66
20	Grengar - Seymour	6,925	116,832	(6,923)	109.809	27328	292,411	429,612	15.87	62.04
21	County of Jackson	2,932	44,143	(2,934)	41,809	0	0	41,809	14.26	14.26
22	Resid & Comm Aux Power	88	2,390	0	2,390	0	0	2,390	27.16	27.16
23	MCV	9,783,684	165,173,771	(24,000)	165,149,771	38,637,300	344,024,250	547,811,321	16.66	55.84
24	MCV Above Caps Economic	83,690	1,413,552	0	1,413,552	0	418,427	1,831,979	16.89	21.89
25	MCV Unit Constraints	29.824	410,440	0	410.440	0	0	416.440	13.96	13.96
26	MCV Residual Energy	14.600	245,816	0	245,816	0	0	245,816	16.95	16.95
27	Alternate Power	22,562	381,755	(22,141)	359,014	87,288	1,002,547	1,449,430	15.92	64.19
28	Wolverine Power Company	39,208	585.3411	0	888,346	0	328,321	1,214,669	22.66	30.98
29	Granger - Ottawa	40,070	675,798	(30,325)	645,473	157,631	1,699,511	2,502,615	16.11	62.46
30	Granger - Grand Blanc	21.410	381.349	(21.406)	338.941	83,391	897,512	1,320,844	15.68	81.68
31	Adrian Energy	11,847	366,762	(17,643)	350.838	0	744.765	1,095,727	19.66	81.40
32	North American Resources	22,680	382.123	(22,681)	360,044	69,671	978,532	1,426,247	15.07	62.89
33	Bio Energy Partners	12,226	196,816	(12,247)	184,569	11.801	538.874	778.344	15.09	63.49
34	Cadillac Renewable Energy, LLC	248,939	4,784,449	(25,999)	4,758,450	610,230	12,936,537	18,205,217	19.11	73.13
35	Ada Cogeneration	191,068	3,179,602	(24,000)	3,155,602	929,940	9,609,245	13,694,787	16.51	71.67
36	Michigan Power Limited	1,061,735	22,089,734	(24,000)	22,065,734		31,107,546	53,173,280	20.78	50.09
37	Granger Renewal Res Landfill (2A)	23,369	382,438	(23,459)	355,919	109.46':	1,109,619	1,576,285	15.36	6754
38	Hillman Limited	148,649	3,040,238	(146,649)	2,893,369	0	5,168,468	8,061,857	19.10	54.90
39	Viking - McBain	135,852	2,822,286	(135,654)	2,686,632	0	5,341,899	8,028,531	19.81	58.18
40	Kent County	91,323	1,895,298	(24,000)	1,871,298	0	4,467,271	6,338,567	20.49	69.41
41	Viking - Lincoln	140,686	2,924,487	(140,686)	2,783,801	0	5,535,439	8,319,240	18.19	59.13
42	Filer City	403,031	9,849,600	(24,000)	9,825,600	0	22,886,579	32,714,379	20.34	87.73
43	Granger Renewal Res Landfill (1A)	19,721	318.474	(19,720)	298.754	76,598	840.573	1.215.825	15.09	61.66
44	Grayling Gen Sta Ltd Ptt (A)	179,694	3,041,435	(30,267)	3,011,168	1,320,686	13,517,874	17,849,730	16.74	89.22
45	Genessee Power Station	140,854	2,442,758	(26,000)	2,416,758	1,074,089	11,087,237	14,578,084	11.15	103.42
46	St. Joseph	0	0	0	0	0	0	0	0.00	000
47	Grayling Gen Sta Ltd Ptt (B)	0	0	0	0	0	0	0	0.00	
48	Venice Resources Inc (B)	0	0	0	0	0	0	0	0.00	0.00
49	White River Peoples	0	0	0	0	0	0	0	0.00	0.00
50	Venice Resources Inc (C)	0	0	0	0	0	0	0	0.00	0.00
	TOTAL	13,020,869	228,417,388	(855,130)	227,562,258	43,157,421	475,948,437	746,668,117	17.48	57.34

TOTAL PURCH PWR CAPACITY COST

TOTAL PURCHASED POWER COST, CAPACITY AND ENERGY

COMPANY	MW CAPACITY	CAPACITY COSTS ($1000S) 1999	2000	2001	2002	2003	2004	2005	2006	2007
1 ADA COGENERATION LTD	29.40	11.299	12.000	12.660	13.328	14.026	14,734	15,387	16.081	16.748
2 ADRIAN ENERGY	2.50	845	847	845	845	645	650	876	a76	a76
3 ALTERNATIVE PWR LTD PTN	2.75	944	946	944	944	944	946	944	944	944
4 BEAVER-MICHIGAN ASSOC. / 5 BIO-ENERGY PARTNERS	34.00 / 1.50	10,787	10,817	10.787	10.787	10.787	10,817	10,787	10,787	10,707
		527	528	527	527	527	528	527	527	527
6 BLACK RIVER POWER INC	0.84	a5	a5	85	a5	85	a5	85	a5	85
7 CAMERON G&E CO - MIX HYDRO	0.14	15	15	15	15	15	15	15	15	15
a CITY OF BEAVERTON	0.52	07	07	87	a7	a7	a7	07	07	a7
9 COMMONWEALTH PWR - HUBBSTN	0.22	24	24	24	26	27	27	28	28	28
10 COMMONWEALTH PWR - LABARGE / 11 DOW CORNING CORP	0.70 / 0.00	117	118	118	130	134	135	136	137	138
		0	0	0	0	0	0	0	0	0
12 GENESEE PWR STA LMT PTN / 13 GRANGER RENEWABLE-GRAND BLANC	35.00 / 2.31	12,488	12,522	12,488	12,488	12,488	12.522	12.468	12,408	12.488
14 GRANGER RENEWABLE-LANDFILL 1	3.04	793	795	793	793	793	795	793	793	793
15 GRANGER RENEWABLE-LANDFILL 2	3.04	1,012	1,014	1,012	1,012	1,012	1,014	1,012	1,012	1,012
16 GRANGER - RENEWABLE-OTTAWA	4.57	1,022	1,025	1,022	1,022	1,022	1,025	1,022		1,022
17 GRAYLING GEN STN LTD PTNR	36.17	12,097	1,569	1.584	1,564	1,564	1.569	1,564	1,564	1,564
18 GREAT LAKES TISSUE CO.	0.26	0	12,130	12,097	12,097	12,097	12.130	12,097	12,097	12,097
			0	0	0	0	0	0	0	0
19 GRENFELL HYDRO INC	0.30	68	69	68	68	68	69	68	68	68
20 HILLMAN LIMITED PTNR / 21 IRVING - COMMONWEALTH	16.00 / 0.24	4,422	4,435	4,422	4,422	4,422	4,435	4,422	4,422	4,422
22 JACKSON COUNTY	0.29	n	32		32	32	32	33	33	33
		-	-	0	0	0	0	0	0	n
23 KENT COUNTY	15.60	4,793	4,802	4,793	4,793	4,793	4,802	4,793	4,793	4.793
24 MCV - ALBION REPLACEMENT	43.56	12,254	12.267	12,254	12.254	12,254	12.287	12,254	12,254	12.254
25 MCV - MICHIGAN COGEN PTNR	65.36	18,386	18,436	18,386	18,386	[illegible]	[illegible]	18,386	16,386	18,386
26 MCV - MIDLAND COGEN VENTURE	915.00	257,377	258.082	257,377	257,377	257,377	258.082	257.377	257,377	257,377
27 MCV-216	216.08	52,555	54,216	55,746	57,425	59,104	60,949	60,783	60,763	60.783
28 MICHIANA HYDRO ELECT CO	0.08	a	a	a	8	11	11	11	11	11
29 MICHIGAN POWER LTD PTN	123.00	33.127	36,912	40.499	44,182	47,867	51,689	49.838	36,563	36,563
30 MICHIGAN STATE	0.60	0	0	0	0	0	0	0	0	0
31 MIDDLEVILE - COMMONWEALTH	0.20	26	26	26	26	26	26	27	27	27
32 NESHKORO PWR - MORLEY	0.23	23	23	23	23	23	23	23	32	33
33 NORTH AMERICAN NATURAL RESOURC	3.06	954	957	954	954	954	957	954	954	954
34 SD. WARREN CO	0.60	0	0	0	0	0	0	0	0	n
35 STS HYDRO LTD - CASCADE	1.40	322	323	322	322	322	323	322	322	32;
36 STS HYDRO LTD - FALLSBG / 37 STS HYDRO LTD - MORROW	0.85 / 1.60	148	148	148	148	148	148	148	148	148
		167	167	167	167	167	167	167	167	167
38 T.E.S. FILER CITY / 39 THORNAPPLE ASSOC INC	60.00 / 1.40	26,869	26,949	26,869	26,069	26.869	26,949	26.869	26.869	26,869
		196	196	196	196	196	196	196	196	196
40 VIKING - LINCOLN & MCBAIN / 41 WHITE PINE BRENT RUN	36.00 / 1.87	10,241	10,269	10,241	10.241	10,241	10.269	10.241	10,241	10,241
42 WHITE PINE SEYMOUR	1.50	469	476	475	475	475	476	475	475	475
			471	469	469	469	471	469	469	469
43 WHITES BRIDGE HYDRO CO	0.02	132	132	132	132	132	132	132	132	132
44 WOLVERINE POWER'CORP	11.00	285	286	285	285	285	286	285	285	285
45 TOTAL	1,672.58	$477,035	$484,223	$488,960	$495,004	5501.074	$508,494	$506,121	$493,550	$494,219
46 MCV Total (Sum of Lines 24 thru 27)	1240.00,	5340.572	$343,020	$343,763	$345,442	$347,121	5349,754	5348,000	$348,800	$346.600
47 Other NUG Total	432.58	$136.463	$141,203	$145.197	$149.562	$153.953	$158.740	$157.321	$144.750	$145.419
48 Total	1,672.58	$477,035	$484,223	$488,960	$495.004	$501,074	$508,494	$506,121	$493,550	$494.219

Ex. 5 c.

WPl-2of3

COMPANY	MW CAPACITY	MWHRs 1999	2000	2001	2002	2003	2004	2005	2006	2007
49 ADA COGENERATION LTD	29.40	213.270	220.199	225.923	226.671	226.930	230,112	231,245	232,116	235,603
50 ADRIAN ENERGY	2.50	20,126	20,161	20.126	20,126	20,126	20,181	20,126	20,126	20,126
51 ALTERNATIVE PWR LTD PTN	2.75	22,136	22.199	22,136	22.136	22.138	22.199	22.136	22,130	22.138
52 BEAVER MICHIGAN ASSOC.	34.00	256.737	257,441	256,737	256,731	256,737	257,441	256,737	256.737	256,737
53 BIO-ENERGY PARTNERS	1.50	9,650	10,373	10 937	11,009	11,033	11,304	11,439	11,521	11,849 11849
54 BLACK RIVER POWER INC	0.84	3.296	3,296	3,296	3,296	3,296	3,296	3,296	3.296	3.296
55 CAMERON G&E CO - MIX HYDRO	0.14	650	650	650	650	650	650	650	650	650
56 CITY OF BEAVERTON	0.52	2,029	2,637	2,629	2,629	2,029	2,637	2,629	2,629	2.829
57 COMMONWEALTH PWR - HUBBSTN	0.22	721	723	721	721	721	723	721	721	721
58 COMMONWEALTH PWR - LABARGE	0.70	3,556	3, 3560	3,556	3,556	3550	3 ,566	3 ,556	3,556	3,556
59 DOW CORNING CORP		10.361	10.381	10.301	10.301	10,381	10,301	10.301	10,381	10.301
60 GENESSEE PWR STA LMT PTN	35.00	225,622	236,586	244,920	246,001	246,359	250,677	252.510	253,770	258,732
61 GRANGER RENEWABLE-GRAND BLANC	2.31	10.590	18,647	10,596	16,596	16.596	10.647	10,596	10,596	10,596
62 GRANGER RENEWABLE-LANDFILL 1	3.04	19.052	20,103	20,906	21,011	21,027	21,452	21,637	21.760	22,236
63 GRANGER RENEWABLE-LANDFILL 2	3.04	19,837	21,022	21,025	22,054	22,072	22,549	22,362	22,002	22,441
64 GRANGER RENEWABLE-OTTAWA	4.57	36,790	36,690	36,790	36,790	36,790	36,690	36.790	36,790	36.790
65 GRAYLING GEN STN LTD PTNR	36.17	236.516	249,501	259,707	261,022	261,223	266,560	266,900	270.436	276.419
66 GREAT LAKES TISSUE CO.	0.26	1,718	1,710	1,710	1,716	1.716	1,710	1,716	1,710	1.718
67 GRENFELL HYDRO INC	0.30	1,061	1,061	1,861	1,061	1,861	1,061	1,861	1,061	1,861
68 HILLMAN LIMITED PTNR	16.00	125,874	125,874	125,874	125,874	125,874	125,874	125,874	125,874	125,874
69 IRVING - COMMONWEALTH	0.24	041	043	841	041	041	043	041	041	041
70 JACKSON COUNTY	0.29	121	121	121	121	121	121	1 2 1	121	121
71 KENT COUNTY	15.66	96,215	96,215	96,215	96,215	96.215	96,215	96,215	98,215	98,215
72 MCV - ALBION REPLACEMENT	43.56	150.760	161.107	169,691	168,917	162.367	172.057	167,454	174.043	165.427
73 MCV - MICHIGAN COGEN PTNR	65.36	230,016	244,126	256,912	256,675	240,564	260,909	284,534	265,107	261,173
74 MCV - MIDLAND COGEN VENTURE	815.00	4,312,337	4,548,440	4,684,927	4,635,308	4,541,024	4,723,922	4,651.945	4,715,501	4,865,376
75 MCV - 216	216.06	714,037	777,505	820,757	812,111	781,264	829,781	900,441	843,357	895,823
76 MICHIANA HYDRO ELECT CO	0.06	226	227	226	226	226	227	226	226	226
77 MICHIGAN POWER LTD PTN	123.00	969.731	972,366	969.731	969.731	969.731	972.306	969,731	969.731	969.731
78 MICHIGAN STATE	0.60	11354	1,354	1,354	1,354	1,354	1,354	1,364	1,354	1,354
79 MIDDLEVILE - COMMONWEALTH	0.20	701	703	701	701	701	703	701	701	701
80 NESHKORO PWR - MORLEY	0.23	665	667	665	665	665	667	665	665	665
61 NORTH AMERICAN NATURAL RESOURC	3.06	22,460	22,522	22,460	22.460	22.460	22,522	22,460	22,460	22.460
62 S.D. WARREN CO	0.60	3,796	3,796	3.796	3.796	3,796	3,796	3.796	3,796	3,795
83 STS HYDRO LTD - CASCADE	1.40	6,278	8,300 276	6,276	6,276	6,270	6 ,300	6,276	6,270	6,270
84 STS HYDRO LTD - FALLSBG	0.85	5,220	5,234	5.220	5,220	5,220	5,234	5,220	5,220	5,220
85 STS HYDRO LTD - MORROW	1.00	4,590	4,602	4,590	4,590	4,590	4,602	4.590	4.590	4,590
86 T.E.S. FILER CITY	60.00	452.750	452,750	452,750	452,750	452,750	452,750	452,750	452,750	452,750
87 THORNAPPLE ASSOC INC	1.40	6,377	6,394	6,377	6,377	6.377	6,394	6,377	6,377	6.377
88 VIKING - LINCOLN & MCBAIN	36.00	260,014	260,726	260,014	260 , 014	260,014	260 , 726	260,014	260,014	260,011
69 WHITE PINE BRENT RUN	1.37	11,029	11,059	11,029	11,029	11,029	11,059	11,029	11,029	11.029
90 WHITE PINE SEYMOUR	1.50	11,029	11,059	11,029	11,029	11,029	11,059	11,029	11.029	11.029
91 WHITES BRIDGE HYDRO CO	0.62	3.627	3,627	3,627	3,627	3,627	3,627	3.627	3,627	3.627
92 WOLVERINE POWER'CORP	11.00	34,433	34,433	34,433	34,433 34	, 433 34,433	34,43	34 433	34,433	34433
93 TOTAL	1,672.58	8,532,053	8,894,520	9,117,545	9,061,709	8,920,813	9,194,815	9,433,798	9,212,246	9.457.009
94 MCV Total (Sum of Lines 72 thru 75)	1240.00	5,407,160	5,731,172	5,932,287	5,873,011	5,731,239	5,986,669	6,224,374	5,998,808	6.227.799
95 Other NUG Total	432.58	3,124,893	3,163,348	3,185,258	3,188,698	3,189,574	3,208,146	3,209,424	3,213,438	3,229,210
96 Total	1,672.58	8,532,053	8,894,520	9,117,545	9,061,709	8,920,813	9,194,815	9,433,798	9,212,246	9.457.009

	1999	2000	2001	2002	2003	2004	2005	2006	2007
07 **Estimate** Market **Price** of Capadty **(c/kwh)**	0.900	0.900	0.900	0.900	0.900	0.900	0.900	0.900	0.900
Estimated Market Value of Capacity ($1000s)									
98 MCV **(Line** 07 x LIne 04)	$48,664	$51,561	$53,301	$52,657	$51,561	$53,660	$56,010	$53,060	$56,050
00 Other NUGS (LIne 07 x Une 05)	$28.124	$28.470	$28.667	$28.698	$28.706	$28.873	$28.885	$28.921	$29.063
100 Total	$70,766	$60,051	$62,056	$61,555	$60,267	$62,753	$64,004	$62.010	$85,113
Potential Transition Costs (1000s)									
101 MCV (LIne 46 - LIne 06)	$291,908	$201,430	$290,372	$292,585	$295,540	$205,674	$202,761	$204,611	$292,750
102 **Other** NUGS (LIne 47 - Line 00)	$108.339	$112.733	$116.530	$120.864	$125.247	$129.867	$128.436	$115.829	$116.356
103 Total	$400,247	$404,172	$406,902	$413,449	$420,767	$425,741	$421,217	$410,640	$400,106

Energy Michigan Initial Brief

Exhibit 6

Modifications t0
Exhibit A-___(FAE-1)

CONSUMERSENERGY
TRANSITION COSTANALYSIS

Line #			12/31/97	Units	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
1	Load Forecast														
2	Total Load			MWh		35,481,334	36,369,901	37.395233	39,110,651	39559,442	40,456,794	41,416,230	42,425,980	43,377,467	43,830,059
3	Load @ Choice			MWh		206,539	1,180,224	1,770,336	2,360,448	39,559,442	40,456,794	41,416,230	42,425,980	43,377,467	43,830,059
4	% of Load@Choice			%		0 662%	3.246%	4.734%	6035%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%
5															
6	Discount Rate		7.00%												
7															
6	Net Nuclear Plant on 12/31/97 and Annual Revenue Requirements														
9			12/31/97												
IO	Palisades	Gross Plant	$ 735,856	$1000s		$ 735,856	$ 735,856	$ 735,856	$ 735,656	5 735.856	$ 735,856	5 735,856	$ 735,856	5 735,856	5 735,856
11		CWIP	$ 32,111	$1000s		5 32,111	5 32111	$ 32,111	$ 32,111	$ 32,111	$ 32,111	$ 32,111	$ 32,111	$ 32,111	$ 32,111
12		Inventory	$ 17,823	$1000s		$ 17,823	5 17,823	5 17,823	$ 17,823	$ 17,823	$ 17,623	$ 17,623	$ 17,823	$ 17.623	$ 17,623
13		I'	########	$1000s		$ (305,718)	$ (369,930)	$ (434,141)	$ (498,353)	$ (544,565)	$ (590,777)	$ (636,988)	$ (683,200)	$ (729,412)	$ (785,790)
14		Net Investment	$637,297	$1000s		5 480,072	$ 415,860	$ 361,649	$ 287,437	5 241,225	5 195,013	5 148,802	$ 102,590	5 56,378	5 0
15		Depredation Rate	6.280%												
16															
17	Big Rock Point	Gross Plant	$ 65262	$1000s		5 65.262									
16		CWIP	5 2	$1000s		5 2									
19		Inventory	5 2,338	$1000s		$ 2,339									
20		I'	$ (52,397)	$1000s		5 (67,593)									
21		Net Investment	5 15,196	$1000s		5 -									
22		Depreciation Rate	12.580%												
23															
24	Total Net Plant Investment		$552.493	$1000s		$ 480,072	$ 415,860	$ 351,649	$ 281.437	5 241,225	5 195,013	5 148,802	$ 102,593	5 66,376	5 0
25															
26	Pretax Return on Average Net Plant Balance	Rate =	10.63%	$1000s		5 54,881	$ 47.619	$ 40,793	$ 33,967	5 28,098	$ 23,166	$ 18,274	5 13,361	5 8,449	$ 2,997
27	Depreciation			$1000s		5 46,212	5 46212	$ 46212	$ 46,212	$ 46,212	$ 46,212	$ 46,212	$ 46,212	$ 46,212	$ 56,378
28				$1000s		$ 11,013	$ 18,000	$ 18,000	$ 18,000	$ -	5 -	5 -	$ 5	5	-
29				$1000s		$8.2095	-	5 -	5 -	$ -	$ -	$ -	5 -	5 -	$ -
30				$1000s		$ 6,987	$ 5	-	5 -	$ -	$ -	5 -	5 -	5 -	5 -
31	Total Revenue Requirements			$1000s		5 127,301	$ Ill.831	$ 105,005	$ 98.179	$ 74,310	5 69,398	5 64,486	5 59,573	$ 54,661	$ 59,375
32															
33	Choice Load's Portion (Line 4 x Line 31)			$1000s		$ 741	$ 3,629	$ 4,971	$ 5,925	5 74,310	$ 69,393	$ 64,466	5 59,573	$ 54,661	5 59,375
34	Net Present Value (NPV) Nuclear (line 33*)			$1000s	$ 230,290	$ 246,411	$ 263,660								
35															
36															

Modifications to
Exhibit A-_(FAE-1)

CONSUMERS ENERGY [illegible]
TRANSITION COST ANALYSIS

Line #			Units	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
37	Production Regulatory Assets on 12/31/97 and Annual Revenue Requirements													
38		12/31/97												
39	Abandoned Midland Facility -3B	5 86,626	$1000s		$ 36,121	$ 36.121	$ 36,121	5 12,040	5 -	5 -	5	5 -	5 -	5 -
40	Previously Incurred Other Post-Emptmnt Benefits (OPEB)*	5 97.187	$1000s		$ 6,942	5 6,642	5 6.942	5 6,912	5 6,942	5 6,942	5 6.942	5 6,942	5 6,942	5 6,942
41	Demand-Side Management Investment (DSM)	$ 42621	$1000s		$ 18,687	5 17,726	$ 14,363	5 3,093	5 3,093	5 3,093	5 3,093	5 -	5	5 -
42	Decommissioning Cost for DOE Enrichment Facilities	5 19,509	$1000s		$ 2,168	5 2,168	5 2,168	5 2,168	5 2,168	5 2,168	5 2,168	5 2,168	5 2,168	5 -
43	Previously Flowed Thru Income Tax Benefits (SFAS 109)"	$ 48,947	$1000s		$ 9,415	5 9,415	$ 9,415	$ 3,961	5 1,234	5 1,234	5 1,234	5 1,234	5 1,234	5 1,234
44	Refunded Debt **	$ 4,506	$1000s		$ 347	5 347	5 347	5 347	5 347	5 347	5 347	5 347	5 347	5 347
45	Ludington Plant Costs for Land and Fishery Settlement	$ 12256	$1000s		$ 2,753	5 2,591	5 2,428	5 2,265	5 2,102	5 1,939	5 1,776	5 1,613	5 -	5 -
46	Total	$311,652	$1000s		$ 76.432	5 75,308	5 71,783	5 30.816	5 15,886	5 15,723	5 15,560	5 12,304	5 10,691	5 8,523
47														
48	Choice Load's Portion (Line 4 x Line 46)		$1000s		5 4465	2,444	5 3,398	5 1,860	5 15,886	5 15,723	5 15,560	5 12,304	5 10,691	5 8,523
49	Net Present Value (NPV) Nuclear (line 48")		$1000s	$ 67,335	$ 72,049	$ 77,092								
50														
51														
62	Power Purchase Agreements (PPA)													
53	Capacity Costs		$1000s		5 471,070	5 477.035	5 484,223	5 488,960	5 495,004	5 501.074	5 508,494	5 506,121	5 493,550	5 494,219
54														
55	Generation		MWh		13,000,000	13,000,000	13,000,000	13,000,000	13,000,000	13,000,000	13,000,000	13,000,000	13,000,000	13,000,000
66	Assumed Market Capacity Charge		¢/kWh		0.9000	0.9000	0.9000	0.9000	0.9000	0.9000	0.9000	0.9000	0.9000	0.9000
57	Assumed Market Capacity Cost (Line 55 x Line 56/100)		$1000s		5 117,000	5 117,000	5 117,000	5 117,000	5 117,000	5 117,000	5 117,000	5 117,000	$ 117,000	5 117,000
58														
69	Total Potential Transition (Line 53 - Line 57)		$1000s		5 354,070	5 360,035	5 367,223	5 371,960	5 378,004	5 384,074	$ 391,494	5 383,121	5 376,550	5 377,219
60	Choice Loads Portion (Line 4 x Line 59)		$1000s		5 2,061	5 11,683	5 17.385	5 22449	$ 378,004	$ 384,074	5 391,494	5 389,121	5 376,550	$ 377,219
61	*NW* PPA Transition (Line 60)		$1000s	51341.810	$1,435,737	$1,536,238								
62														
63	Total Transition Cost fro Load @Choice													
64	Total Nuclear, Reg Assets. & PPAs (Lines 33, 48, 60)		$1000s		5 3247	5 17,756	5 25,764	5 30,234	5 468,200	5 469,195	5 471,540	5 460,998	5 441,902	5 446,117
65	*N W* PPA Transition (Line 64)		$1000s	$1,639,436	$1,754,196	$1,876,990								
66														
67	Contributions													
68	100 MW Dir&Access (721 GWh)	Rate (¢/kWh)= 0.275	$1000s		5 (1.953)	5 (1,983)	5 (1,983)							
69	*NW* Contributions (Line 68)		$1000s	5 (4,865)	5 (5,205)	5 (5,570)								
70														
71	Present Value of Costs to be Recovered (Line 65 + Line 69)		$1000s	$1,634,571	$1,748,991	$1,871,420								
72														
73	Average Transition Surcharge													
74	Load to be Surcharged (Line 3)		MWh		206,539	1,180,224	1,770,336	2,360,448	39.558.442	40,456,794	41,416,230	42,425,980	43.377467	43,830,059
75	Surcharge (Line 71 (1998) / NPV (1998) of Line 74*100)		¢/kWh		1.1212	11212	1.1212	11212	1 1212	1.1212	1.1212	1.1212	1.1212	1.1212
76	Surcharge Revenue (Line 74 x Line 75)		$1000s		5 2,316	5 13,233	5 19,849	5 26,465	5 443,640	5 453,601	5 464,358	5 475,681	5 486,348	5 491,422
77	*NW* Surcharge Revenue (Line 76)		$1000s	$1,634,571	$1,748,991	$1,871,420								
78														
79	Escalation Rate		%		3.060%	3.060%	3.060%	3.060%	3.060%	3.060%	3.060%	3.060%	3.740%	3.740%
80	Market Clearing Price		¢/kWh		2.9000	29887	3.0802	3.1744	3.2716	3.3717	3.4749	35812	37151	3.8541
81	Energy		¢/kWh		2.0000	2.0887	2.1802	2.2744	23716	24717	2.5749	2.6812	2.8151	2.9541
82	Capacity		¢/kWh		0.9000	0.9000	0.9000	0.9000	0.9000	0.9000	0.9000	0.9000	0.9000	0.9000

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Exhibit 7

Modifications to
Exhibit A-_(FAE-1)

CONSUMERS ENERGY [illegible]
TRANSITION COST ANALYSIS

Line #				Units	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
1	Load Forecast														
2	Total Load			MWh		35,481,334	36,369,901	37,395,238	39,110,651	39.5X9.442	40,456,794	41,416,230	42,425,980	43,377,467	43,830,059
3	Load @ Choice			MWh		206,539	1,180,224	1,770,336	2,360,448	39,559,442	40,456,794	41,416,230	42,425,980	43.377467	43,830,059
4	% of Load@Choice			%		0.582%	3 246%	4.734%	6.035%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%
5															
6	Discount Rate		7.00%												
7															
8	Net Nuclear Plant on 12/31/97 and Annual Revenue Requirements														
9			12/31/97												
10	Palisades	Gross Plant	$ 735,856	$1000s		5 735,856	$ 735.856	5 735.856	5 735,856	5 735,856	$ 735.856	$ 735.656	5 735,856	5 735,856	$ 735,856
11		CWIP	5 32,111	$1000s		$ 32,111	5 32111	5 32,111	5 32,111	$ 32111	5 32,111	$ 32,111	$ 32,111	$ 32,111	$ 32,111
12		Inventory	5 17.823	$1000s		5 17,823	$ 17,823	5 17,823	5 17,823	5 17.623	$ 17,823	$ 17,823	$ 17,623	5 17,823	5 17,823
13		[illegible]	########	$1000s		$ (305,718)	$ (369,930)	5 (434,141)	$ (498,353)	$ (544,565)	5 (590,777)	$ (636,988)	$ (683,200)	$ (729,412)	$ (785,790)
14		Net Investment	$ 537,297	$1000s		5 480,072	5 415,860	$ 351,649	5 287.437	$ 241.225	$ 195,013	$ 148,802	$ 102,590	$ 56,378	$ 0
15		Depreciation Rate	6 260%												
16															
17	Big Rock Point	Gross Plant	$ 65,252	$1000s		5 65,252									
18		CWIP	5 2	$1000s		5 2									
19		Inventory	5 2,339	$1000s		$ 2,339									
20		[illegible]	$ (62.397)	$1000s		5 (67,593)									
21		Net Investment	5 15,196	$1000s		5 -									
22		Depreciation Rate	12.580%												
23															
24	Total Net Plant Investment		$ 552,493	$1000s		5 480,072	5 415,860	5 351,649	5 281,437	$ 241,225	5 195,013	5 148,802	5 102,590	5 56,378	$ 0
25															
26	Pretax Return cm Average Net Plant Balance	Pate =	10.63%	$1000s		5 54,881	5 47.619	$ 40,793	5 33,967	5 28,098	$ 23.186	$ 18,274	$ 13,361	$ 8,449	$ 2,997
27	Depreciation			$1000s		5 46212	5 46,212	$ 46.212	$ 46,212	$ 46,212	$ 46212	$ 46212	$ 46,212	$ 46,212	$ 56,378
28				$1000s		5 11,013	5 18,000	5 18,000	5 18,000	$ -	$ -	$	$ -	$ -	$ -
29				$1000s		$ 8,209	$ -	5 -	5 -	5 -	5 -	5 -	5 -	$ -	$ -
30				$1000s		$ 6,987	$ 5	-	5 -	5 -	5 -	$ -	$ -	$ -	$ -
31	Total Revenue Requirements			$1000s		5 127,301	5 111,831	5 105,005	5 93,179	5 74,310	5 69,398	5 64,466	$ 69,573	5 54,661	$ 59,375
32															
33	Choice Load's Portion (tine 4 x Line 31)			$1000s		$ 741	5 3,629	5 4,971	$ 5.925	$ 74,310	$ 69,398	5 64,486	5 58,573	$ 54,661	$ 59,375
34	Net Present Value (NPV) Nuclear (line 33*)			$1000s	$ 230,290	$ 246,411	$ 263,660								
35															
36															

Modifications to
Exhibit A-_(FAE-1)

CONSUMERSENERGY
TRANSITION COST ANALYSIS

Line #			Units	1997	1998	1999	2000						2006	2007
37	production Regulatory Assets on 12/31/97 and Annual Revenue Requirements													
38		12/31/97												
39	Abandoned Midland Facility -3B	$ 86.626	$1000s		$ 36.121	$ 36,121	$ 36,121	$ 12040	$ -	$ -	$ -	$ -	$ -	$ -
40	Previously Incurred Other Post-Emplmnt Benefits (OPEB)*	5 97,167	$1000s		$ 6,942	$ 6,942	$ 6,942	$ 6,942	$ 6,942	$ 6,942	$ 6.942	$ 6,942	5 6,942	$ 6,942
41	Demand-Side Management Investment (DSM)	$ 42521	$1000s		$ 18.687	$ 17.726	$ 14,363	$ 3,093	$ 3,093	$ 3,093	$ 3,093	5 5	-	$ -
42	Decommissioning Cost for DOE Enrichment Facilities	$ 19.509	$1000s		$ 2,168	$ 2,168	$ 2,163	$ 2,168	5 2,168	5 2,168	5 2,168	$ 2,168	5 2,168	$ -
43	Previously Flowed Thru Income Tax Benefits (SFAS 109)"	$ 48.947	$1000s		$ 9,415	$ 9,415	$ 9,415	$ 3,961	$ 1,234	$ 1,234	5 1,234	$ 1,234	5 1,234	$ 1,234
44	Refunded Debt **	$ 4,506	$1000s		$ 347	$ 347	$ 347	$ 347	$ 347	$ 347	$ 347	5 347	5 347	$ 347
45	Ludington Plant Costs for Land and Fishery Settlement	$ 12256	$1000s		$ 2,753	$ 2,591	$ 2,428	$ 2,265	$ 2,102	$ 1,939	5 1.776	$ 1,613	5 -	$
46	Total	$311,552	$1000s		$ 76,432	$ 75,308	$ 71,783	$ 30,816	$ 15,886	$ 15,723	$ 15,560	$ 12304	$ 10,691	5 8,523
47														
48	Choice Load's Portion (Line 4 x Line 46)		$1000s		$ 445	$ 2,444	$ 3.393	5 1,860	$ 15,886	$ 15,723	$ 15,560	5 12304	$ 10,691	5 8,523
49	Net Present Value (NPV) Nuclear (line 48**)		$1000s	$ 67,335	$ 72,049	$ 77,092								
50														
51														
52	Power Purchase Agreements (PPA)													
53	Capacity costs		$1000s		$ 471,070	$ 477.035	$ 484,223	$ 488,960	$ 495,004	$ 501,074	$ 508,494	$ 506,121	$ 493,550	$ 494219
54														
55	Generation		MWh		8,677,560	8,532,053	8,894,520	9.117.545	9,061,709	8,920,813	9,194,815	9,433,798	9212,246	9,457,009
56	Assumed Market Capacity Charge		¢/kWh		0.9000	0 9275	0.9559	0.9852	10153	1.0464	1.0764	11114	1.1530	1.1931
57	Assumed Market Capacity Cost (Line 55 x Line 56/100)		$1000s		$ 78,098	$ 79,138	5 85,025	$ 89,624	$ 92,005	$ 93,346	$ 99,158	5 104.848	$ 106,215	$ 113,115
58														
59	Total Potential Transition (Line 53 - Line 57)		$1000s		$ 392,972	$ 397,897	5 399,198	$ 399,136	$ 402,999	$ 407.728	5 409,336	$ 401,273	5 387,335	$ 381,104
60	Choice Loads Portion (Line 4 x Line 59)		$1000s		5 2,288	5 12,912	$ 18,699	$ 24,089	5 402,999	$ 407.728	$ 409,336	$ 401,273	$ 3S7.335	$ 381,104
61	NPV PPA Transition (Line60)		$1000s	$1,401,043	$1,499,116	$1,604,054								
62														
63	Total Transition Cost fro Load @Choice													
64	Total Nuclear, Reg Assets. & PPAs (Lines 33, 48, 60)		$1000s		$ 3,473	$ 18,985	$ 27,268	$ 31,874	$ 493.195	$ 492,646	$ 489,382	$ 473.150	$ 452,687	$ 449,002
65	NPV PPA Transition (Line 64)		$1000s	$1,698,669	$1,817,575	$1,944,806								
66														
67	Contributions													
68	100 MW Direct Access (721 GWh) Rate (¢/kWh)=	$1000s).275			$ (1,983)	5 (1,963)	$ (1,983)							
69	NPV Contributions (Line 68)		$1000s	5 (4,865)	$ (5,205)	5 (5,570)								
70														
71	Present Value of Costs to be Recovered (Line 65 + Line 69)		$1000s	$1,693,804	$1,812,370	$1,939,236								
72														
73	Average Transition Surcharge													
74	Load to be Surcharged (Line 3)		MWh		206,539	1,180,224	1,770,336	2,360,448	39,559,442	40,456,794	41.416230	42,425,980	43,377,467	43,830,059
75	Surcharge (Line 71 (1998) / NPV (1998) of Line 74'100)		¢/kWh		1.1818	1.1818	11618	1.1618	11618	1.1618	1.1818	1.1818	1.1818	1 1618
76	Surcharge Revenue (Line 74 x Line 75)		$1000s		$ 2,400	$ 13,712	$ 20,568	$ 27,424	5 459,613	$ 470,039	$ 461,186	$ a.917	$ 503,972	$ 509,230
77	N W Surcharge Revenue (Line 76)		$1000s	$1,693,804	$1,812,370	$1,939,236								
78														
79	Escalation Rate		%		3.060%	3 060%	3.060%	3.060%	3.060%	3.060%	3.060%	3 060%	3.740%	3 740%
80	Market Clearing Price		¢/kWh		2.9000	2.9887	3.0802	3.1744	3.2716	3.3717	3.4749	3.5812	3.7151	3.6541
81	Energy		¢/kWh		2.0000	2.0612	2 1243	2.1893	2.2563	2.3253	2.3965	2.4698	2.5622	2.6580
82	Capacity		¢/kWh		0.9000	0.9275	0.9559	0.9852	1.0153	1.0464	1.0784	1.1114	1.1530	1.1961

Energy Michigan Initial Brief

Exhibit 8

Modifications to
Exhibit A-_(FAE-1)

CONSUMERS ENERGY [illegible]
TRANSITION COST ANALYSIS

Line #				Units	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
1	Load Forecast														
2	Total Load			MWh		35,481,334	36,369,901	37.395236	39,110,651	39,559,442	40,456,794	41,416,230	42,425,980	43,377,467	43,830,059
3	Load @ Choice			MWh		206,539	1,180,224	1,770,336	2,360,448	39,559,442	40,456,794	41,416,230	42,425,980	43,377,467	43,830,059
4	% of Load@Choice			%		0.582%	3.245%	4.734%	6.035%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%
5															
6	Discount Rate		7.00%												
6	Net Nuclear Plant on 12/31/97 and Annual Revenue Requirements														
9			12/31/97												
10	**Palisades**	Gross Plant	$ 735,856	$1000s		$ 735,856	5 735.856	5 735,856	5 735,856	5 735.856	5 735,856	5 735,856	$ 735,856	5 735,856	5 735,856
11		CWIP	$ 32,111	$1000s		$ 32,111	5 32111	$ 32,111	$ 32,111	$ 32111	$ 32,111	$ 32,111	5 32,111	$ 32,111	5 32,111
12		Inventory	$ 17,823	$1000s		5 17,823	5 17,823	5 17,823	5 17,623	5 17,623	5 17,823	5 17,823	$ 17,823	5 17,823	5 17,823
13		[illegible]	########	$1000s		$ (305,718)	$ (369,930)	$ (434,141)	$ (498,353)	$ (544,565)	$ (590,777)	$ (636,988)	$ (683,200)	$ (729,412)	$ (785,790)
14		Net Investment	$537,297	$1000s		5 480,072	5 415,860	5 361,649	5 267,437	5 241,225	5 195,013	$ 148,802	5 102,590	5 66,378	5 0
15		Depreciation Rate	6.260%												
16															
17	**Big Rock Point**	Gross Plant	$ 65,252	$1000s		5 65,252									
18		CWIP	$ 2	$1000s		5 2									
19		Inventory	$ 2.339	$1000s		5 2,339									
20		[illegible]	$ (52,397)	$1000s		5 (67.593)									
21		Net Investment	$ 15,196	$1000s		5 -									
22		Depreciation Rate	12580%												
23															
24	Total Net Plant Investment		$ 552,493	$1000s		5 480,072	5 415,860	5 351,649	$ 287,437	5 241,225	5 195,013	5 146.602	5 102,590	5 66.378	5 0
25															
26	Pretax Return on Average Net Plant Balance	Pate =	10 63%	$1000s		5 54,881	5 47,619	5 40,793	5 33,967	5 28,098	5 23,186	5 18,274	5 13,361	5 8,449	5 2,937
27	Depreciation			$1000s		5 46212	5 46212	5 46,212	5 46,212	$ 46,212	5 46,212	5 46,212	5 46,212	5 46.212	5 56,378
28				$1000s		5 11.013	5 18,000	5 18,000	$ 18,000	5	5 -	5 -	5 -	5 -	5 -
29				$1000s		$ 8,209	$ -	5 -	5 -	5 -	5 -	5	5 -	5 -	5 -
30				$1000s		5 6,987	$ -	5 -	5	5 -	5 -	5	5	5 -	5 -
31	Total Revenue Requirements			$1000s		5 127,301	5 111,631	5 105,005	5 93,179	5 74,310	5 69,398	$ 64,486	5 59,573	5 54,661	5 59,375
32															
33	Choice Load's Portion (Line 4 x Line 31)			$1000s		5 741	5 3,629	5 4,971	5 5,925	5 74.310	5 69,398	$ 64,486	5 59,573	5 54,661	5 59,375
34	Net Present Value (NPV) Nuclear (line 33')			$1000s	$ 230,290	$ 246.41115	263,660								
35															
36															

Modifications to
Exhibit A-_(FAE-1)

CONSUMERS ENERGY [illegible]
TRANSITION COST ANALYSIS

Line #		12/31/97	Units	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
37	Production Regulatory Assets on 12/31/97 and Annual Revenue Requirements													
38		12/31/97												
39	Abandoned Midland Facility -3B	$ 86,626	$1000s		$ 36,121	$ 36,121	$ 36,121	5 12,040	5	5 -	5 -	5	5 -	5 -
40	Previously Incurred Other Post-Emplmnt Benefits (OPEB)*	$ 97,167	$1000s		$ 6,942	$ 6,942	5 6,942	5 6.942	5 6.942	5 6,942	5 6.942	5 6,942	5 6.942	5 6,942
41	Demand-Side Management Investment (DSM)	5 42,521	$1000s		$ 18,687	$ 17.726	5 14,363	$ 3,093	5 3,093	5 3,093	5 3,093	$ -	5 -	5 -
42	Decommissioning Cost for DOE Enrichment Facilities	$ 19,509	$1000s		$ 2,168	$ 2,168	$ 2.168	$ 2,168	5 2,168	5 2,168	5 2,168	5 2,168	5 2,168	5 -
43	Previously Flowed Thru Income Tax Benefits (SFAS 109)**	5 48,947	$1000s		$ 9,415	$ 9,415	5 9,415	$ 3,961	5 1,234	5 I.234	$ 1,234	5 1,234	5 1.234	5 1,234
44	Refunded Debt **	5 4,506	$1000s		$ 347	$ 347	$ 347	5 347	5 347	5 347	$ 17765 347	5 1,613 347	5 347	5 347
45	Ludington Plant Costs for Land and Fishery Settlement	5 12256	$1000s		$ 2,753	$ 2,581	5 2,428	5 2,265	$ 2,102	$ 1,939	.,. . -		5 -	5
46	Total	$311,552	$1000s		$ 76,432	$ 75,308	$ 71,763	5 30,816	5 15,886	5 15,723	5 15,560	5 12,304	5 10,691	5 6,523
47														
46	Choice Load's Portion (Line 4 x Line 46)		$1000s		5 445	5 2,444	5 3,388	5 1,860	5 15,886	$ 15,723	5 15,560	5 12,304	$ 10.691	5 6,623
49	Net Present Value (NPV) Nuclear (line 46")		$1000s	$ 67,335	$ 72,049	$ 77,092								
50														
51														
52	Power Purchase Agreements (PPA)													
53	Capacity Costs		$1000s		5 471,070	5 477,035	5 484,223	5 488,960	5 495,004	5 501,074	5 508,494	506,121	5 493,550	5 494,219
54														
55	Generation		MWh		13.000.000	13.000.000	13,000,000	13,000,000	13,000,000	13,000,000	13,000,000	13,000,000	13,000,000	13,000,000
56	Assumed Market Capacity Charge		¢/kWh		0.9000	09275	0.9559	0.9852	1.0153	1.0464	1.0764	1.1114	1.1530	1.1931
57	Assumed Market Capacity Cost (Line 55 x Line 56/100)		$1000s		5 117,000	$ 120,580	5 124,270	5 128,073	5 131,992	5 135,031	5 140,193	$ 144,483	5 149,667	5 155,492
58														
59	Total Potential Transition (Line 53 - Line 57)		$1000s		5 354.070	5 356,455	5 359,953	5 360,887	5 363,012	5 365,043	$ 368,301	5 361,638	5 343,663	5 338,727
60	Choice Load's Portion (Line 4 x Line 59)		$1000s		5 2,061	$ 11,567	$ 17,041	5 21.761	5 363,012	5 365,043	5 368,301	5 361,638	5 343.663	5 338,727
61	NPV PPA Transition (Line 60)		$1000s	$1,255,682	$1,343,580	$1,437,631								
62														
63	Total Transition Cost fro Load @Choice													
64	Total Nuclear, Reg Assets. & PPAs (Lines 33, 48, 60)		$1000s		5 3247	5 17,640	$ 25,410	5 29,566	5 453,209	5 450,164	5 446,346	5 433.515	5 409,015	5 406,624
65	*N W* PPA Transition (Line 64)		$1000s	$1,553,308	$1,662,040	$1,778,382								
66														
67	Contributions													
68	100 MW Direct Access (721 GWh) Rate (¢/kWh)=	0.275	$1000s		5 (1,983)	5 (1,983)	5 (1,983)							
69	*NW* Contributions (Line 68)		$1000s	5 (4,865)	5 (5,205)	5 (5,570)								
70														
71	Present Value of Costs to be Recovered (Line 65 + Line 69)		$1000s	$1,548,443	$1,656,834	$1,772,813								
72														
73	Average Transition Surcharge													
74	Load to be Surcharged (Line 3)		MWh		206,539	1,180,224	1,770,336	2,360,448	39559.442	40,456,794	41.416230	42,425,980	43,377,467	43,830,059
75	Surcharge (Line 71 (1998) / NPV (1998) of Line 74*100)		¢/kWh		1.0621	1.0621	1.0621	1.0621	1.0621	1.0621	1.0621	1.0621	1.0621	1.0621
76	*Surcharge Revenue (Lime 74* x Line 75)		$1000s		5 2,194	5 12,535	5 18,803	5 25,071	5 420,169	5 429,700	5 439,891	5 450,616	5 460,722	5 465,529
77	*NW* Surcharge Revenue (Line *76)*		$1000s	$1,548,443	$1,656,834	$1,772,813								
78														
79	Escalation Rate		%		3.060%	3.060%	3.060%	3.060%	3060%	3 060%	3.060%	3060%	3.740%	3.7443%
80	Market Clearing Price		¢/kWh		2.9000	2.9887	3.0802	3.1744	32716	3.3717	3.4749	3.5812	3.7151	3.8541
81	Energy		¢/kWh		2.0000	2.0612	2.1243	2.1693	2.2563	2.3263	2.3965	2.4698	2.562	2.6580
82	Capacity		¢/kWh		0.9000	0.9275	0.9559	0.9652	10163	1.0464	1.0764	1.1114	1.1530	I.1961

Energy Michigan Initial Brief

Exhibit 9

Exhibit I-7

MPSC Case No.: U-I 1956
Respondent: M. G. VanHaerents
Requestor: Energy Michigan
Question No.: EMDE3.33/72
Page: 1 of1

Question: What are Fermi 2 plant balances under your proposal each year 1998 through 2007 net of all relevant investment tax credits and deferred taxes?

Answer: As of December 31, 1998, Detroit Edison wrote off its Fermi 2 net plant balance of $2.508 billion as shown on WP (MGV-2) Line 1, Page No. 2 of 4 due to an impairment as a result of ceasing application of SFAS No. 71. The Commission in Case No. U-11726 provided the Company an opportunity for regulatory recovery of Fermi 2 through 2007. As a result of this order, the Company recorded a regulatory asset of $2.808 billion as displayed on WP (MGV-2) Line 1, Page No. 3 of 4, which includes the Fermi plant investment as of 12/31/98 and the related Wolverine regulatory asset, regulatory tax asset and investment tax credit. The after-tax amounts of the regulatory asset by year are shown below.

Year End Balance	Pre-tax Regulatory Asset Balance (Billions)	After-tax Regulatory Asset Balance (Billions)
1998	$2.808	$1.825
1999	2.554	1.660
2000	2.288	1.487
2001	2.009	1.306
2002	1.716	1.115
2003	1.408	0.915
2004	1.084	0.705
2005	0.742	0.483
2006	0.381	0.248
2007	0.000	0.000

In addition the Company has assumed $20 million of investment additions for Fermi as shown in WP (MGV-2) Line 3 & 4, Page No. 1 of 1. The after-tax amounts of the regulatory asset by year are shown below.

MPSC Case No.: U-I 1956
Respondent: M. G. VanHaerents
Requestor: Enerav Michiqan
Question No.: EMDE3.33/72

Year End Balance	Pre-tax Regulatory Asset Balance (Millions)	After-tax Regulatory Asset Balance /Millions)
1999	$17.778	$11.556
2000	33.056	21.486
2001	45.476	29.559
2002	54.563	35.466
2003	59.651	38.773
2004	59.738	38.830
2005	53.159	34.553
2006	36.579	23.776
2007	0.000	0.000