STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of INDIANA MICHIGAN POWER COMPANY, D/B/A AMERICAN ELECTRIC POWER, for certain approvals in connection with 2000 PA 141 Section 10v	)	Case No. U-12780
In the matter of the application of INTERNATIONAL TRANSMISSION COMPANY, CONSUMERS ENERGY COMPANY, and GREAT LAKES ENERGY COOPERATIVE	)	Case No. U-12781

DIRECT TESTIMONY

OF

DAVID A. BLECKER, P.E.

ON BEHALF OF

ENERGY MICHIGAN, INC.

APRIL 25, 2001

Q. Please state your name, business address and for whom you appear.

A. My name is David A. Blecker. My address is 7295 E. Cate Road, Belleville, WI 53508. I am appearing on behalf of Energy Michigan, Inc.

Q. Please state your occupation?

A. I am the co-founder of Earth Energy Systems, Ltd. (Earth Energy) and have served as its President and Managing Director since August 1, 2000. Earth Energy is a non-profit organization that, among other things, specializes in the development and application of natural resource and energy planning practices that promote sustainable economic development, safeguard consumers, and protect the environment.

Q. Are you appearing on behalf of Earth Energy Systems, Ltd?

A. No.

Q. Please describe your educational background and work experience.

A. I am a licensed Professional Engineer in the State of Wisconsin. I hold a Bachelor's degree in Electrical Engineering from Rensselaer Polytechnic Institute and I am in the process of completing the requirements for a Master of Science in Energy Analysis and Policy from the University of Wisconsin at Madison. Prior to joining Earth Energy, I served from 1992 through 2000, as the Senior Engineering Associate at MSB Energy Associates in Middleton, Wisconsin. My work experience has focused on the technical and economic analysis and modeling of energy use and production systems. Prior to working for MSB, I worked 3 years for General Electric where I designed power control and monitoring equipment for the U.S. Navy Trident II nuclear submarine program and I served four years onboard ballistic missile submarines in the U.S. Navy as a nuclear weapon system supervisor.

Q. Are you a member of any professional societies?

A. Yes. I am a member of the Institute of Electrical and Electronic Engineers, the National Wind Coordinating Committee Transmission Working Group, the American Solar Energy Society and the American Wind Energy Association. I also co-chair the Energy Center of Wisconsin Technology Systems Transfer Committee and I am the Vice-President of the Midwest Renewable Energy Association.

Q. Are you experienced with utility transmission planning issues?

A. Yes. I have provided technical and policy assistance to a number of clients on transmission planning and policy issues since 1994.

Q. Would you summarize your relevant transmission experience.

A. From 1994 through 1997, I provided expert assistance to the Alliance for Clean Energy Systems, a not-for profit energy advocacy organization, for its participation in the Wisconsin Targeted Area Planning (TAP) Collaborative. The TAP Collaborative was convened by the Wisconsin Public Service Commission, and was comprised of the five large Wisconsin investor-owned utilities, Public Service Commission of Wisconsin (PSCW) Staff and public intervenors. The Collaborative was convened to develop new transmission and planning methods to ensure that the least-cost solution to energy delivery problems is properly identified. The PSCW required that all utility transmission lines be screened for TAP as part of the Commission's biennial Advance Plan (AP) 7 and Advance Plan 8.

In 1996 and 1997, I directed preparation of a report for the U.S. Department of Energy entitled, "Integrated Targeted Area Resource Planning (ITARP): A Transmission and Distribution Planning Model for the Restructured Utility." ITARP builds on the TAP model and establishes a procedural and analytical framework to characterize problems on the transmission and distribution system for their amenability to alternative solutions, and to identify the most economical solution to those problems in a deregulated utility industry.

I have provided assistance to several independent power producers to assess the adequacy, capability, pricing and availability of transmission in various regions across the United States and I have analyzed the strategic implication of existing transmission contracts and access options to support market generation acquisition decisions.

In 2001, I served as engineering director of intervenor participation in technical hearings held before the Public Service Commission of Wisconsin regarding Wisconsin Public Service Corporation's application for approval of a 250 mile 345 kV power line.

Q. Have you testified in other transmission cases?

A. Yes. In 1996, I testified before the Ohio Public Utility Commission (Case No. 95-600-EL-BTX) on behalf of a citizens group that opposed construction of a Centerior Energy 11-mile 138kV transmission line.

In 1998, I testified before the Arkansas Public Service Commission on behalf of a citizen's group (Docket Number 98-141-U) as to the adequacy of a $25 million, 24-mile, 161 kV transmission line Application submitted by Entergy Corporation.

Also in 1998, I testified before the Minnesota Environmental Quality Board (MEQB) on behalf of Concerned River Valley Citizens (MEQB Docket Number NSP-TR-4) for Northern States Power Company's proposed Chisago 230 kV Electric Transmission Line Project.

In May of 2000, I testified before the Virginia State Corporation Commission on behalf of the Bland County Board of Supervisors (Case No. PUE-970766) in the matter of American Electric Power Company's application for approval to construct a 100-mile long 765 kV power line.

In September 2000, I testified before the MEQB (MEQB Docket Number MP-HVTL-EA-1-99, OAH Docket Number 9-2901-12620-2) on behalf of Save Our Unique Lands in the matter of the application of Minnesota Power Company's Application for exemption for high voltage transmission lines.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to bring several issues to the MPSC's attention regarding the consideration and approval of a Joint Plan to expand the capability of the Michigan transmission system as required by Section 10v of 2000 PA 141 and to comment on the filings of American Electric Power (AEP) in Case U-12781 and the joint filings of Consumers Energy Company, International Transmission Company and Great Lakes Energy Cooperative in Case U-12781 (Consumers et al).

Q. Are you familiar with the requirements of Section 10v of 2000 PA 141?

A. Yes. My understanding of Michigan Section 10v of PA 141 is that it requires, in part that electric utilities serving more than 100,000 retail customers in Michigan are to file a joint plan with the MPSC detailing measures to permanently expand, by June 5, 2002, the available transmission capability by at least 2,000 megawatts (MW) over the available transmission capability in place as of January 1, 2000. Furthermore, 2000 PA 141 Section 10v provides that the Commission shall authorize recovery from benefiting customers of all reasonable and prudent costs incurred by transmission owners for authorized actions taken and facilities installed pursuant to the requirements of Section 10v that are not recovered through Federal Energy Regulatory Commission tariffs.

Q. Please summarize the relevant issues and your recommendations.

A. My concerns can be summarized as follows:

1. The filings submitted by the utility parties to this case do not assure that Michigan energy consumers will directly benefit as intended by 2000 PA 141 in that the utilities

will not guarantee the availability of 2,000 MW increased transmission capability to support Michigan import market transactions. I recommend that all 2,000 MW of new incremental Available Transfer Capability (ATC) or as an alternative, a combination of new ATC and in-state generation, be made available only to, or as a first-priority to alternate energy suppliers licensed in Michigan. I also recommend requiring transmission owners to make their transmission reserve margin, capacity benefit margin and native load transmission transaction requirements publicly available to ensure accountability of posted ATC values.

2. It is not clear if a consumer surcharge or other mechanism is an appropriate or required means of cost recovery for the planned transmission system improvements. I recommend that the ability of the utility system to support increased power transfers due to the proposed Section 10v improvements, and the impact of Independent Power Producer (IPP) interconnection fees be considered prior to approving any cost recovery mechanisms. I further recommend withholding any cost recovery mechanism until the transmission owners make public, on a regular basis, their transmission reserve margin, capacity benefit margin and native load transmission transaction requirements.

3. The proposed transmission system improvements for the Michigan Electric Coordinated System (MECS)-Ontario Hydro (OH) interface will not necessarily support a more competitive energy market for Michigan energy consumers. I recommend that these improvements not be counted towards the legislative mandate

unless the improvements can be used by alternate energy suppliers or unless the improvements result in a one-for-one decrease in firm transmission reservations on the MECS southern interface.

4. The AEP 2000 PA 141 compliance plan does not include a second Dumont Station transformer. Yet, the Dumont substation appears to be a significant congestion point on the interconnected transmission system. I recommend that a second Dumont transformer should be ordered.

2000 PA 141 TRANSMISSION EXPANSION PLAN EFFECTIVNESS

Q. In your opinion, will the utility compliance plans satisfy the objectives of 2000 PA 141?

A. No. This is because neither Consumers et al or AEP will commit to ensure that the incremental transmission capability additions, as required by Section 10v, will be available for the use and benefit of Michigan consumers.

Q. Are you aware that Consumers et al and AEP differ in their interpretation of term "available transmission capability" as used in PA 141 Section 10v?

A. Yes I am. Consumers et al interprets "available transmission capability" to mean Available Transfer Capability (ATC) whereas AEP interprets "available transmission capability" to mean First Contingency Total Transfer Capability (FCTTC.) The difference between ATC and FCTTC is well explained by the Applicants in their testimony and plans. It is therefore sufficient to simply point out that ATC is the only measure by which market-based transmission transactions can be evaluated. FCTTC is a critical parameter to evaluate the performance and adequacy of the transmission system as a whole, but it is not a useful tool to describe how well a transmission system or transmission path will support a fully competitive energy market.

Q. Which interpretation of "available transmission capability" do you believe is proper?

A. Since the apparent intent of the legislature was to facilitate and promote a fully competitive energy market, I would interpret the legislature's language to mean Available Transfer Capability.

Q. Why are you concerned that the Applicants won't commit to make the legislative mandated capacity additions available for Michigan consumers?

A. Without this commitment, there is no guarantee that the electricity consumers of Michigan will be able to participate in the emerging retail energy market nor is there any guarantee that energy marketers will be able to secure the transmission service necessary to serve retail customers in Michigan.

Q. Do you understand that the only way to reserve transmission capacity is through the use of the Open Access Same time Information System (OASIS) as mandated by Federal Energy Regulatory Commission (FERC) orders 888 and 889 and that the transmission availability shown on OASIS is the value known as ATC?

A. Yes I do. However it is my opinion that the Commission must act to ensure that there is sufficient ATC to support a competitive environment. If no guarantees are put in place, it is possible all additional ATC will be "sold" or allocated to entities who don't serve load in Michigan, or that the transmission owners will increase their allocations of Transmission Reserve Margin (TRM) and/or Capacity Benefit Margin (CBM). In either case, the result would be to reduce the amount of new ATC that's available to support load service in Michigan by power marketers.

Q. Please explain how TRM and CBM affect ATC.

A. ATC is equal to the total transfer capability less reservations for native load less the Transmission Reserve Margin (TRM) less the Capacity Benefit Margin (CBM). Mathematically:

$$ATC = TTC - TRM - CBM - \text{Native Load}.$$

Where, TRM is the amount of transmission capacity necessary to ensure the interconnected transmission system is secure under a reasonable range of uncertainties in system condition, and where CBM is the amount of transmission transfer capability set aside to ensure access to generation over the interconnected system to meet generation reliability requirements.

Q. Can you provide an example where MECS ATC has been claimed by entities that are not serving Michigan load?

A. Yes. In MPSC Case No. 12489, Detroit Edison Witness Zakem provided rebuttal testimony that illustrated just such a situation. According to Mr. Zakem, the MECS OASIS shows firm transmission reservations totaling 783 MW for the summer 2001 period made by companies such as AEP Marketing, Constellation, Dynegy, Aquila, NIPSCO and Cinergy Marketing – none of whom are licensed alternative energy providers in Michigan.

Q. How can the Commission prevent this situation from occurring in the future?

A. While I can not offer specific legal advice, conceptually it would make sense for the Commission to require, or work with the FERC to require, that all 2,000 MW of incremental transfer capability as required by Section 10v, be made available ONLY OR AS A FIRST PRIORITY to entities who are licensed alternate energy suppliers in Michigan. If this is not done, and if a significant portion of the incremental transmission capacity is purchased by non-licensed alternate energy suppliers, Michigan's consumers may not be able to realize the intended benefit of retail competition.

Q. Do you have concerns about how ATC is determined by the utilities?

A. Yes. As previously explained, the amount of ATC for commercial purposes is strongly dependent on how the utilities calculate TRM and CBM. These values are determined solely by the utilities without regulatory oversight or review. As well, the specific transactions and commitments required for their support of native load is not posted. Since this information is developed in the dark, we have no way of verifying the accuracy or validity of the TRM and CBM values. Hypothetically speaking, if a transmission owner wanted to limit competition in its service territory, it would only need to increase its TRM and CBM reservations that would in turn lower the ATC and limit the amount of transmission service available to outside entities.

Q. Are you aware of any situation where the Michigan utilities limited ATC as a result of their CBM or TRM requirements?

A. Yes. In 1997, I prepared a report for Enron Corporation entitled "Electric Power Transfer Adequacy in the State of Michigan: Transmission Issues in a Competitive Market." At the time, my study found that there was no ATC for the summer peak months due to MECS CBM requirements. The report stated, in part:

"The value of importance is the total simultaneous transfer capability into MECS. This is 3,500 MW for ATC planning purposes. This does not mean that 3,500 MW of capacity is available to support direct access. In fact, CE reports that the Capacity Benefit Margin (CBM) required to meet a one day in ten year loss of load probability is 3,500 MW on-peak. From the equation for ATC, a 3,500 MW CBM leaves 0 MW available for use by other market participants.

Consumers Energy and Detroit Edison may be trying to limit competitive access to the Michigan electric grid, through manipulation and control of the transmission system. It would seem to be more than a coincidence that the transfer capacity reserved by the utilities is equal to the amount of available capacity. By claiming to require all 3,500 MW of transfer capability, the utilities may be attempting to exclude competitors from being able to offer firm transmission service. The possibility also exists that the methods used to calculate transfer capability are flawed."

Q. What can be done to ensure that utility native load transmission reservations as well as TRM and CBM requirements are fair and accurate?

A. The Commission should require the utilities to identify the contract paths and amount of transmission capacity reserved to serve native load and to make this information publicly available. Similarly, the Commission should order the utilities to identify the affected contract paths and amounts of transmission reserved for TRM and CBM and to make this information publicly available. We recognize that OASIS business practices and regulation are a FERC issue. However, the MPSC could require that this information be posted on the MPSC web site, or similar venue, to avoid jurisdictional problems.

Q. If the Applicant can not or will not guarantee 2,000 MW of incremental ATC available for Michigan consumers, what can be done?

A. It is my understanding that the Michigan Legislature required a 2,000 MW increase in available transmission capability to mitigate the adverse effects of transmission constraints on the emerging competitive market. If the transmission-owning entities that serve Michigan can not or will not guarantee the availability of all 2,000 MW for Michigan consumers, then it is my opinion that the legislative mandate will remain unfulfilled. In this situation, the utilities should be required to make 2,000 MW of new capacity available to licensed alternative energy suppliers through any combination of available transfer capability and generation provided from in-state sources.

This transmission – generation hybrid capacity approach would allow for the orderly operation and function of the OASIS transmission reservation system, would provide additional encouragement for the construction of in-state generation, and would guarantee consumers retail choice options as promised to them through restructuring.

COST RECOVERY ISSUES

Q. Are the cost recovery mechanisms proposed by the utilities appropriate?

A. They may or may not be appropriate. There are several factors the MPSC should evaluate with respect to any cost recovery authorization. These factors are the role of the FERC authorized Open Access Transmission Tariffs and the impact of new generation interconnection fees.

Q. Please explain.

A. Any improvements to the transmission system that will result in increased available transmission capability into and out of Michigan may also increase the ability of the regional transmission system to be used for bulk power and market-based transactions. Furthermore, some of the identified upgrades were part of the company's transmission enhancement plans before the requirements of 2000 PA 141 took effect.

For example, in 1998, AEP began implementing system improvements such as the addition of shunt capacitors in its service territory (Pasternack, Page 11 lines 10-23.) We don't know the location of all of these improvements, but we do know that some capacitor additions were made in Ohio. As a result, it is reasonable to assume these improvements provide benefits to the larger AEP system, not just in Michigan, that increase the AEP system's ability to accommodate firm transmission service requests.

If these or any other projects identified by AEP as part of its 2000 PA 141 compliance plan allow for increased transmission service and sales, the revenue from those sales may be sufficient to allow the Company to fully recover its investment without the need for external recovery mechanisms. In fact, current trends suggest transmission-owning utilities have experienced unprecedented growth in revenue from wheeling since FERC Order 888 was implemented. Furthermore, the revenue increases occurred without commensurate increases in transmission investment. This suggests that additional transfer capacity investments may well be quickly recovered through existing Open Access Transmission Tariffs (OATTs). AEP is a good example of this. According to the company's FERC Form 1 filings, wheeling revenue for the AEP system increased from $68.4 million in 1996 to $178.9 million in 1998 – a 161% increase.

Therefore, we caution the Commission to explicitly consider the impact of any Section 10v approved transmission improvements on the ability of the larger system to support increased market transfers and the amount of revenue that would be collected under the existing OATTs.

Q. Do these concerns exist for the MECS utilities as well?

A. Yes. These concerns exist to the degree that any of the Section 10v improvements planned for, or implemented, by the Michigan utilities that allow an increase in the number or magnitude of wheeling transactions but that do not directly serve Michigan consumers will mitigate or lessen the need for Commission authorized cost recovery.

Q. Do you believe the proposed customer surcharge as presented by Consumer Energy Witness Ruhl is appropriate?

A. The purpose of this testimony is not to decide whether the amount of the requested surcharge is appropriate, but rather to offer a perspective on the issue of cost recovery. Consumers et al states that its costs will be incurred to expand the import capability of the transmission system which will benefit all customers, therefore Consumers et al believe the surcharge should be collected on a kilowatt-hour basis from all retail customers.

As discussed above, while the improvements may be intended for the benefit of Michigan consumers, there may be collateral transmission benefits such as increasing the ability of the Michigan transmission system to support firm wheeling transactions that do NOT benefit or affect Michigan customers, but that provide wheeling revenue to the utilities.

Perhaps most importantly, it seems inconsistent to allow the utilities to assign a fixed cost recovery rate to all customers when they will not guarantee that the proposed system improvements can be exclusively dedicated to Michigan customers.

Q. Are there other cost recovery issues the Commission should be aware of?

A. Yes. Another factor to consider is potential impact of IPP interconnection charges assessed by transmission-owning entities. As provided by the FERC, transmission owners have the right to charge the full cost of transmission facility upgrades required to support interconnection of new generation to the IPP that request interconnection.

Consumers et al and AEP both discuss the nature and magnitude of new generation interconnections in their joint plan filings with the Commission. (Consumers: Sparks Exhibit A-_____(TJS-1) page 11; AEP: Pasternack Exhibit _____(BMP-1) page 7.) According to the Applicants, there are approximately 14,000 MW of new generation under study in Lower Michigan with 1,000 MW of this capacity having signed interconnection agreements. AEP has over 3,000 MW of interconnection study requests and 640 MW of this has been formalized with a signed Interconnection Agreement.

Transmission owners can charge interconnection costs ranging from tens of thousands of dollars to tens of millions of dollars depending on the size, location and impact of a proposed IPP power plant. If the transmission owners decide to charge IPPs the full cost of interconnection, and if the upgrades or connections result in increased MECS import transfer capability as specified by PA 141, or if the interconnection projects are the same as those identified in the Applicants' plans, then the transmission owners should not be allowed to recover the same costs multiple times. Under the worst case, they would be compensated three times for the same investment–through wheeling revenue, interconnection fees, and a consumer based surcharge (or other Commission approved means).

Q. In your opinion, is there a relationship between 2000 PA 141 Section 10v cost recovery issues and your recommendations for full and public disclosure of utility transmission reservations for native load, TRM and CBM?

A. Yes. I recommend that the Commission not approve any Section 10v cost recovery mechanism until an agreement can reached with the utilities to provide native load, TRM and CBM transmission contract path and capacity information discussed in the previous section of my testimony.

Q. Are you aware that AEP did not request a specified cost recovery amount?

A. Yes. However AEP has reserved its right to evaluate the need for, and request cost recovery, from "benefiting customers" at a later date.

MECS - ONTARIO HYDRO INTERFACE

Q. Will transfer capability improvements between MECS and Ontario Hydro (OH) benefit Michigan consumers?

A. The question cannot be answered definitively. However we do know that OH does not have an OATT that would prescribe the terms and conditions of transmission service on the OH transmission system. Furthermore, we know that OH does not maintain an active OASIS node. Therefore, it would appear that the MECS-OH transmission interface continues to operate in a monopoly fashion. That is, no other parties can equitably compete for transmission service over that interface as they can on FERC jurisdictional OASIS transmission nodes.

Q. Why is this a concern?

A. If alternative energy suppliers cannot obtain transmission service using the MECS-OH interface through established processes, then any improvements to the MECS-OH interface will not increase the ability of Michigan consumers to choose alternative energy providers.

Q. Are there any exceptions to that statement?

A. Yes. If the utilities will agree that increased transfer capability on the MECS-OH interface will result in a one-for-one decrease of firm ATC reservations on the MECS southern transmission interface, then the concern raised above is lessened, but not eliminated. For example, if 820 MW of new transfer capacity is added to the MECS-OH interface, then MECS should cancel or release 820 MW of firm transmission reservations on its southern interface.

Q. Do any of the Applicant's plans increase the MECS-OH interface?

A. Yes. International Transmission Company (ITC) predicts its planned system improvements will increase the Hydro One to MECS firm commercial capability by 820 MW. To put this in perspective, 820 MW is more than 40% of the PA 141 requirement. It would be inconsistent with the intent of PA 141 to allow this much transmission capacity to be developed, yet remain unavailable to power marketers, and hence the electric consumers of Michigan.

DUMONT STATION TRANSFORMER

Q. Are you aware that AEP and the other utility parties disagree that a new Dumont Station transformer is required to meet the requirements of 2000 PA 141?

A. Yes I am.

Q. Do you have an opinion as to whether or not the Commission should require the construction of a second Dumont Station transformer?

A. Yes. Although I have not performed any load flow analysis for this testimony, available evidence suggests that Dumont is a significant transmission constraint on the ECAR system in general and for MECS imports in particular. This evidence is well-cited in the testimony of Consumer Energy Witness Sparks on pages 6-8 and in Mr. Sparks' Exhibit A-______(TJS-2). Mr. Sparks refers to several ECAR Transmission System Performance Reports that identify Dumont as a limiting facility. Dumont limitations are also identified by ECAR in its August 2000 report entitled "2003 Summer Multiple Contingency Assessment of ECAR Transmission System Conformance to ECAR Document No. 1 (00-TSPP-55)" and its May 2000 "Facility Outage Notification Table - Summer 2000 (00-TSPP-2)."

AEP reports that "new generation locating near the Cook or Dumont Stations would have the largest beneficial impact on the AEP System's ability to deliver power into MECS." (Pasternack 15:11-13). Furthermore, AEP is processing an interconnection request for an 560 MW IPP facility at the Dumont site (Pasternack Exhibit 1.)

Given these factors, the addition of a second Dumont Station transformer seems appropriate.

Q. Does this conclude your testimony?

A. Yes it does.