Founded in 1852
by Sidney Davy Miller

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January 30, 2017

Ms. Kavita Kale
Executive Secretary
Michigan Public Service Commission
7109 W. Saginaw Highway
Lansing MI 48917

Re: Upper Michigan Energy Resources Corporation
MPSC Case No. U-18224

Dear Ms. Kale:

Enclosed for filing in the above case is an Application, supported by the Direct Testimony and Exhibits of Terrence W. Carroll, Joel R. Gaughan, Joann Henry, Laura M. Jarmuz, Daniel P. Krueger, Russell T. Laursen, Susan M. Schumacher, James O. Sherman, Jr., Jeff Knitter, James A. Schubilske and Andrew W. Sutherland on behalf of Upper Michigan Energy Resources Corporation ("UMERC").

Also enclosed for filing is Upper Michigan Energy Resources Corporation's Motion for Protective Order and Notice of Hearing.

Finally, enclosed are the Appearances of Michael C. Rampe, Theresa A.G. Staley and Ronald W. Bloomberg.

Additionally, a draft proposed Notice of Hearing is being e-mailed to Angela McGuire at mcguirea@michigan.gov.

Very truly yours,

Miller, Canfield, Paddock and Stone, P.L.C.

By: Michael C. Rampe

Digitally signed by: Michael C. Rampe
DN: CN = Michael C. Rampe C = US O = Miller Canfield
Date: 2017.01.30 13:40:36 -04'00'

Michael C. Rampe

cc: Robert Garvin
Theodore Eidukas
Dennis Derricks
Doug Wetjen
Catherine Phillips
Rick Stasik
Amy Winkler
Colleen Siporski

S T A T E O F M I C H I G A N
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

NOTICE OF HEARING
UPPER MICHIGAN ENERGY RESOURCES CORPORATION
CASE NO. U-18224

- Upper Michigan Energy Resources Corporation has filed an application requesting that the Michigan Public Service Commission: (1) issue a Certificate of Necessity pursuant to MCL 460.6s, for the construction of two reciprocating internal combustion engine electric generation facilities in Baraga Township, Baraga County, Michigan, and Negaunee Township, Marquette County, Michigan; (2) issue certificates of public convenience and necessity pursuant to MCL 460.502, for the construction, ownership and operation of the two reciprocating internal combustion engine electric generation facilities in Baraga Township, Baraga County, Michigan, and Negaunee Township, Marquette County, Michigan; (3) approve a Special Contract with Tilden Mining Company, L.C.; and (4) approve the accounting and ratemaking treatment of financing costs incurred during the construction period.

- The information below describes how a person may participate in this case.

- You may call or write Upper Michigan Energy Resources Corporation, at its Michigan service centers at 800 Industrial Park Drive, Iron Mountain, Michigan, (800) 242-9137, or 1717 Tenth Avenue, Menominee, MI 49858, (800) 450-7260, for a free copy of its application. Any person may review the application at the offices of Upper Michigan Energy Resources Corporation.

- A public hearing in this docket will be held:

DATE/TIME: This hearing will be a prehearing conference to set future hearing dates and decide other procedural matters.

BEFORE: Administrative Law Judge _____

LOCATION: Michigan Public Service Commission
7109 West Saginaw Highway
Lansing, Michigan

PARTICIPATION: Any interested person may attend and participate. The hearing site is accessible, including handicapped parking. Persons needing any accommodation to participate should contact the Commission's Executive Secretary at (517) 284-8090 in advance to request mobility, visual, hearing or other assistance.

The Michigan Public Service Commission (Commission) will hold a public hearing in this docket to consider the Application as filed by Upper Michigan Energy Resources Corporation (UMERC) on January 30, 2017.

All documents filed in this case shall be submitted electronically through the Commission's E-Dockets website at: michigan.gov/mpscedockets. Requirements and instructions for filing can be found in the User Manual on the E-Dockets help page. Documents may also be submitted, in Word or PDF format, as an attachment to an email sent to mpscedockets@michigan.gov. If you require assistance prior to e-filing, contact Commission staff at (517) 284-8090 or by email at mpscedockets@michigan.gov.

Any person wishing to intervene and become a party to the case shall electronically file a petition to intervene with this Commission by _____, 2017. (Interested persons may elect to file using the traditional paper format.) The proof of service shall indicate service upon Upper Michigan Energy Resource Corporation's attorneys, Michael C. Rampe, Miller, Canfield, Paddock, and Stone, P.L.C., One Michigan Avenue, Suite 900, Lansing, Michigan 48933.

Any person wishing to appear at the hearing to make a statement of position without becoming a party to the case may participate by filing an appearance. To file an appearance, the individual must attend the hearing and advise the presiding administrative law judge of his or her wish to make a statement of position. All information submitted to the Commission in this matter becomes public information, thus available on the Michigan Public Service Commission's website, and subject to disclosure. Please do not include information you wish to remain private.

Requests for adjournment must be made pursuant to the Michigan Administrative Hearing System's Administrative Hearing Rules R 792.10422 and R 792.10432. Requests for further information on adjournment should be directed to (517) 284-8130.

A copy of Upper Michigan Energy Resources Corporation's application may be reviewed on the Commission's website at: michigan.gov/mpscedockets, and at the office of Upper Michigan Energy Resources Corporation. For more information on how to participate in a case, you may contact the Commission at the above address or by telephone at (517) 284-8090.

Jurisdiction is pursuant to 1909 PA 106, as amended, MCL 460.551 et seq.; 1919 PA 419, as amended, MCL 460.54 et seq.; 1939 PA 3, as amended, MCL 460.1 et seq.; 1969 PA 306, as amended, MCL 24.201 et seq.; 1982 PA 304, as amended, MCL 460.6s et seq.; 1929 PA 69, as amended, MCL 460.501 et seq; and the Michigan Administrative Hearing System's Administrative Hearing Rules, 2015 AC, R 792.10401 et seq.

The Utility Consumer Representation Fund has been created for the purpose of aiding in the representation of residential utility customers in 1982 P.A. 304 proceedings. Contact the Chairperson, Utility Consumer Participation Board, Department of Licensing and Regulatory Affairs, P.O. Box 30004, Lansing, Michigan 48909, for more information.

_____, 2017

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the Matter of the Application of Upper Michigan Energy Resources Corporation for approval of a Certificate of Necessity pursuant to MCL 460.6s for Two Reciprocating Internal Combustion Engine Electric Generation Facilities Located in the Upper Peninsula of Michigan, Approval of Certificate(s) of Public Convenience And Necessity, approval of a Special Contract with Tilden Mining Company L.C. and related accounting and ratemaking authorizations.	))))))))))))	Case No. U-18224

APPLICATION

Upper Michigan Energy Resources Corporation ("UMERC" or "the Company") respectfully requests that the Michigan Public Service Commission ("Commission" or "MPSC") issue a certificate of necessity ("CON") pursuant to § 6s of 2008 PA 286, MCL 460.6s ("§ 6s"), and the Commission's "Filing Requirements and Instructions for Certificate of Public Convenience and Necessity Application" ("CON Filing Requirements"), issue Certificates of Public Convenience and Necessity ("CPCN"), and grant other approvals (as specified herein and in supporting testimony and exhibits) in connection with the construction of two Reciprocating Internal Combustion Engine ("RICE") electric generation facilities in the Upper Peninsula of Michigan ("UP"). UMERC also requests that the Commission approve the Retail Large Curtailable Special Contract between WEC Energy Group, Inc. ("WEC") and Tilden Mining Company, L.C. ("Tilden") dated August 12, 2016 ("Tilden Special Contract").

UMERC specifically requests the following in this Application:

A. A CON that the power to be supplied as a result of the proposed construction of the RICE electric generation facilities is needed;

B. A CON that the size, fuel type, and other design characteristics of the RICE electric generation facilities represent the most reasonable and prudent means of meeting that power need;

C. A CON that the estimated purchase or capital costs of and the financing plan for the RICE electric generation facilities, including, but not limited to, the costs of siting and licensing the RICE electric generation facilities and the estimated cost of power from the RICE electric generation facilities, will be recoverable in rates from UMERC's customers (as described in the testimony in support of this Application);

D. A CPCN pursuant to MCL 460.500 et seq., authorizing UMERC to construct, own and operate a RICE electric generation facility (but not to serve or transact a local business) in the Township of Baraga;

E. A CPCN pursuant to MCL 460.500 et seq., authorizing UMERC to construct, own and operate a RICE electric generation facility (but not to serve or transact a local business) in the Township of Negaunee;

F. Approval of the Tilden Special Contract;

G. Accounting authorizations requested in Section V, herein;

H. Such other and further relief as is just and reasonable; and

I. Granting of all approvals requested herein within 270 days of the filing of this Application.

This Application is supported by the pre-filed testimony and exhibits submitted in this case. The testimony and exhibits, which are incorporated in this Application by reference, provide more detail on the specific investments and activities for the CONs and other requests for relief in this Application. UMERC expressly reserves the right to revise, amend, or otherwise change the relief it is requesting in any way appropriate depending upon the duration and progress of hearings in this proceeding, the issuance of orders that have an impact upon this case, or the occurrence of other material events.

In support of this Application, UMERC states as follows:

I. Introduction

1. Pursuant to the Commission's December 9, 2016 approval of the settlement agreement signed by all the parties in Case No. U-18061, on January 1, 2017, UMERC was established as a Michigan jurisdictional regulated utility providing service only to electric and natural gas customers in Michigan. UMERC is engaged as a public utility in the business of generating, purchasing, distributing, and selling electric energy to approximately 36,500 full requirements customers, as well as any distribution-only customers who qualify for retail access service ("RAS"). UMERC also provides retail natural gas service to approximately 5,300 full requirements customers, and natural gas transportation service to approximately 17 transportation customers.

2. UMERC was established pursuant to commitments made by WEC (formerly known as Wisconsin Energy Corporation) and Wisconsin Electric Power Company ("WEPCo") in the Amended and Restated Settlement Agreement approved in Case No. U-17682 ("ARSA"). Paragraph 6.g. of the ARSA provides:

> WEC further agrees to the creation of a Michigan-only jurisdictional utility to facilitate this long term solution, if reasonable and prudent, with timing to be determined by the MPSC.

3. The "long term solution" discussed in the ARSA provision quoted in the preceding paragraph refers to new, clean generation to be built in the UP, which is referenced throughout the ARSA. Paragraph 6.g. of the ARSA also contains various commitments for WEC and WEPCo ranging from purchasing output of the new generation, to having an ownership interest in the new generation. Consistent with WEC and WEPCo's commitments under ¶ 6.g. of the ARSA, UMERC will construct and own the two new RICE electric generation facilities that are the subject of this Application. WEC has also entered into the Tilden Special Contract for which approval is requested in Section IV of this Application, and pursuant to which UMERC will provide service to Tilden after the RICE electric generation facilities achieve commercial operation. WEC has assigned the Tilden Special Contact to UMERC.

4. UMERC's retail electric business is subject to the Commission's jurisdiction pursuant to various provisions of 1909 PA 106, as amended, MCL 460.551 et seq., 1919 PA 419, as amended, MCL 460.54 et seq., 1939 PA 3, as amended, MCL 460.1, et seq., including 2008 PA 286 and 1929 PA 69, as amended, MCL 460.501, et seq. Pursuant to these and other statutory provisions, the Commission has the power and jurisdiction to regulate UMERC's retail electric rates and issue the requested CONs and CPCNs, approve the Tilden Special Contract, and grant the other relief requested in this Application.

5. UMERC's address for purposes of this Application is: 231 W. Michigan Street, Milwaukee, Wisconsin, 53203.

6. The name, title and business address of the person to whom correspondence should be directed is set forth below:

Susan H. Martin
Executive Vice President, General Counsel
and Corporate Secretary
WEC Energy Group, Inc.
231 W. Michigan Street, P 444
Milwaukee, Wisconsin 53203
Telephone: (414) 221-2712
Fax (414) 221-2185
E-mail: Susan.Martin@wecenergygroup.com

with a copy to:

Michael C. Rampe (P58189)
Theresa A.G. Staley (P56998)
Ronald W. Bloomberg (P30011)
Miller Canfield Paddock and Stone, PLC
One Michigan Avenue, Suite 900
Lansing, Michigan 48933
Telephone: (517) 487-2070
Fax: (517) 374-6304

7. Confidential information filed in support of this Application has been specifically identified and marked as confidential to preserve its confidential nature. Along with this Application, UMERC is submitting a motion and proposed Protective Order to provide for the use and protection of the confidential information.

8. As fully discussed in the pre-filed direct testimony and exhibits in support of this Application, UMERC would construct two RICE electric generation facilities in the UP. This technology utilizes modular RICE-driven electric generators fueled by natural gas, and are more fully described in the testimony filed in support of this Application. The RICE electric generation facilities will permit UMERC to provide service to its retail full requirements customers using its own generation, sell its energy into the Midcontinent Independent System Operator, Inc. ("MISO") market, and terminate its power purchase agreements ("PPA") with

WEPCo and Wisconsin Public Service Corporation ("WPS Corp"). UMERC anticipates the commencement of commercial operation of the RICE electric generation facilities as soon as Summer 2019, at which time Tilden would transfer as a customer of UMERC and would commence receiving electric service from UMERC pursuant to the Tilden Special Contract. Finally, commercial operation of the RICE electric generation facilities will put WEPCo in a position to request required approvals to retire the Presque Isle Power Plant ("PIPP").

9. Consistent with § 6s(4), the testimony and exhibits in support of this Application establish the following:

a. a need for the power that the RICE electric generation facilities would supply;

b. the RICE electric generation facilities will comply with all applicable state and federal environmental standards, laws, and rules;

c. the estimated cost of power from the RICE electric generation facilities is reasonable;

d. the RICE electric generation facilities represent the most reasonable and prudent means of meeting the power need relative to other resource options for meeting power demand, including energy efficiency programs and electric transmission efficiencies; and

e. the construction of the RICE electric generation facilities will be completed using a workforce composed of residents of Michigan to the extent practicable.

The CON requests therefore meet all the requirements of § 6s and should be granted.

II. Request for Certificates of Necessity

10. Section 6s of 2008 PA 286, MCL 460.6s, permits a utility that seeks to construct an electric generation facility to request one or more CONs. Pursuant to ¶ 6.g. of the ARSA,

UMERC requests the following CONs from the Commission in connection with the Company's proposal to build the two RICE electric generation facilities, pursuant to MCL 460.6s(3):

> (a) A certificate of necessity that the power to be supplied as a result of the proposed construction, … is needed.
>
> (b) A certificate of necessity that the size, fuel type, and other design characteristics of the… proposed electric generation facility … represent the most reasonable and prudent means of meeting that power need.
>
> (d) A certificate of necessity that the estimated purchase or capital costs of and the financing plan for the …proposed electric generation facility, including, but not limited to, the costs of siting and licensing a new facility and the estimated cost of power from the new or proposed electric generation facility, will be recoverable in rates from the electric utility's customers subject to subsection (4)(c).

11. MCL 460.6s(11) provides:

> The commission shall establish standards for an integrated resource plan that shall be filed by an electric utility requesting a certificate of necessity under this section. An integrated resource plan shall include all of the following:
>
> (a) A long-term forecast of the electric utility's load growth under various reasonable scenarios.
>
> (b) The type of generation technology proposed for the generation facility and the proposed capacity of the generation facility, including projected fuel and regulatory costs under various reasonable scenarios.
>
> (c) Projected energy and capacity purchased or produced by the electric utility pursuant to any renewable portfolio standard.
>
> (d) Projected energy efficiency program savings under any energy efficiency program requirements and the projected costs for that program.
>
> (e) Projected load management and demand response savings for the electric utility and the projected costs for those programs.
>
> (f) An analysis of the availability and costs of other electric resources that could defer, displace, or partially displace the proposed generation facility or purchased power agreement, including additional renewable energy, energy efficiency programs, load management, and demand response, beyond those amounts contained in subdivisions (c) to (e).
>
> (g) Electric transmission options for the electric utility.

In compliance with the provisions of § 6s(11), the Commission issued an Order adopting the CON Filing Requirements, which set forth requirements, instructions, and guidelines for utilities seeking relief pursuant to MCL 460.6s.

12. As required by the CON Filing Requirements, UMERC representatives had pre-application consultation meetings with the MPSC Staff on October 27, 2016 and January 10, 2017.

13. Accompanying this Application is UMERC's Integrated Resource Plan ("IRP") and supporting testimony and exhibits which comply with § 6s and the CON Filing Requirements. The IRP represents the results of extensive analysis of UMERC's capacity and energy needs, and evaluation of the most cost-effective resources to meet those needs under an array of future scenarios and sensitivities. The IRP concludes, along with the testimony and exhibits in support of this Application, that the power to be supplied from the proposed new RICE electric generation facilities is needed, and that the size, fuel type, and other design characteristics of the RICE electric generation facilities, is the most reasonable and prudent alternative under the alternate scenarios analyzed. The IRP and other testimony and exhibits address the choice of supply alternatives including new combined cycle electric generation facilities, new transmission lines, continued operation of PIPP, and renewable generation. The IRP also addresses the use of energy efficiency and other customer side alternatives to building new generation. The new RICE electric generation facilities represent the most reasonable and prudent means of meeting current and future power needs relative to other resource options, including energy efficiency programs and electric transmission efficiencies. The RICE electric generation facilities are a proven technology that will provide a fast-acting power, voltage, and regulation resource. The RICE electric generation facilities will enhance electric reliability by providing a new large block of capacity and energy production in MISO Zone 2.

14. UMERC's estimates of the cost of the RICE electric generation facilities is provided in the testimony and exhibits in support of this Application. UMERC's supporting

testimony and exhibits provide additional detail about the new RICE electric generation facilities and schedule for the project. UMERC reserves the right to update its cost estimates pursuant to § 6s(4)(c). UMERC requests a CON that the estimated purchase or capital costs of and the financing plan for the RICE electric generation facilities, including, but not limited to, the costs of siting and licensing the RICE electric generation facilities and the estimated cost of power from the RICE electric generation facilities, will be recoverable in rates from UMERC's customers, as described in the testimony in support of this Application.

15. The RICE electric generation facilities will provide additional tax revenues to the local communities in which they are located. UMERC expects a peak of approximately 100 construction workers at the smaller of the two RICE electric generation facilities, and approximately 200 at the larger RICE electric generation facility. It is anticipated that 60% to 80% of the construction workforce will be drawn from local unions and be residents of Michigan. Local contractors will be used whenever possible.

III. Request for Certificates of Public Convenience and Necessity

16. UMERC has identified the following two sites for the two new RICE electric generation facilities:

A. Negaunee Township Site: UMERC will construct, own and operate one of the RICE electric generation facilities at a location in Negaunee Township, as more fully described in the testimony of Terrence W. Carroll.

B. Baraga Township Site: UMERC will construct, own and operate one of the RICE electric generation facilities at a location in Baraga Township as more fully described in the testimony of Mr. Carroll.

17. Upper Peninsula Power Company ("UPPCO") is a public utility organized under the laws of the state of Michigan. UPPCO owns and operates an electric utility system and is engaged in the generation, distribution, and sale of electric energy in certain service areas in the UP. Such service areas encompass both the Negaunee Township Site and the Baraga Township Site.

18. Pursuant to MCL 460.502:

> No public utility shall hereafter begin the construction or operation of any public utility plant or system thereof nor shall it render any service for the purpose of transacting or carrying on local business either directly, or indirectly, by serving any other utility or agency so engaged in such local business, in any municipality in this state where any other utility or agency is then engaged in such local business and rendering the same sort of service, or where such municipality is receiving service of the same sort, until such public utility shall first obtain from the commission a certificate that public convenience and necessity requires or will require such construction, operation, service, or extension.

19. With respect to the Baraga Township Site and the Negaunee Township Site, the statutory language of MCL 460.502 is not clear whether UMERC needs a CPCN to construct, own and operate its RICE electric generation facilities in UPPCO's service territory in a municipality in which UMERC will not provide any electric service directly to the public, although the Commission's December 8, 1987 in Case No. U-8941 granted a CPCN under similar circumstances. In Case No. U-8941, the Commission granted the following CPCN in connection with WEPCo's ownership of PIPP and related facilities located in areas served by another utility, even though WEPCo would not provide electric service directly to the public ("PIPP CPCN") in the municipalities in which the facilities were located:

> THEREFORE, IT IS ORDERED that Wisconsin Electric Power Company is granted a Certificate of Public Convenience and Necessity:
>
> 1. To own and operate electric utility plant and facilities, but not to serve or transact a local business in the city of Marquette, the city of Ishpeming, and the townships of Forsyth, Ishpeming, Marquette, Negaunee and Wells,

all located in Marquette County, Michigan;

20. Based on the Commission's granting of the PIPP CPCN, UMERC requests that the Commission grant UMERC a CPCN for Baraga Township and Negaunee Township that is similar to the PIPP CPCN. Specifically, UMERC requests a CPCN to construct, own and operate electric utility plant and facilities, but not to serve or transact a local business, in Baraga Township, located in the County of Baraga. UMERC further requests a CPCN to construct, own and operate electric utility plant and facilities, but not to serve or transact a local business, in Negaunee Township, located in the County of Marquette. As UMERC does not plan to provide any electric service to the public in the Township of Baraga or the Township of Negaunee, it has not obtained a franchise from either township authorizing it to transact a local business as described in MCL 460.503(2). UMERC will obtain all required local permits and other approvals before commencing construction of a new RICE electric generation facilities in both townships.

21. The standard for granting a CPCN is set forth in MCL 460.505, which provides:

> In determining the question of public convenience and necessity the commission shall take into consideration the service being rendered by the utility then serving such territory, the investment in such utility, the benefit, if any, to the public in the matter of rates and such other matters as shall be proper and equitable in determining whether or not public convenience and necessity requires the applying utility to serve the territory. Every certificate of public convenience and necessity issued by the commission, under the authority hereby granted, shall describe in detail the territory in which said applicant shall operate and it shall not operate in or serve any other territory under the authority of said certificate.

22. As set forth in the testimony and exhibits in support of this Application, the requests for CPCNs for Baraga Township, and for Negaunee Township, meet the MCL 460.505 standard. Construction of the new RICE electric generation facilities will not result in any wasteful duplication of facilities, as the facilities are needed to serve UMERC's customers.

Moreover, UMERC will not provide any service to UPPCO retail customers in Baraga Township or Negaunee Township, and so granting the CPCN will not result in duplication of services. The new RICE electric generation facilities are expected to enable the eventual retirement of PIPP pursuant to MISO procedures.

23. The sites were chosen because of their reasonably close proximity to gas fuel supply, electric transmission, and existing roadways. Both sites are in rural locations away from dense residential areas and subdivisions, and have land available for purchase. The site topography and environmental factors make both sites favorable for facility construction. UMERC customers will benefit from just and reasonable rates once the new RICE electric generation facilities are constructed and operational, and new UMERC base rates are set in a general rate case. Locating the new RICE electric generation facilities is not expected to have any negative impact on UPPCO's customers.

24. Construction and operation of the RICE electric generation facilities will be in accordance with all applicable standards and regulations, including those of the MPSC.

25. Based on the foregoing, UMERC represents that the proposed construction of the RICE electric generation facilities at the Baraga Township Site and the Negaunee Township Site, are required by the public convenience and necessity.

IV. Request for Approval of Tilden Special Contract

26. Pursuant to Article 5.1.1 of the Tilden Special Contract,

> Upon the incorporation of UMERC and the transfer of Wisconsin Electric's electric distribution assets in Michigan and retail electric business in Michigan (other than assets and contracts used to provide service to Buyer [Tilden]), Seller [WEC] shall assign its rights, obligations and interests in this Agreement to UMERC.

UMERC, as an assignee of WEC, requests approval of the Tilden Special Contract pursuant to Rule 31 of the Commission's Filing Procedures for Electric, Wastewater, Steam, and Gas Utilities, Mich Admin Code, R 460.2031(1) ("Rule 31").

27. As of the date of this Application, WEPCo, a subsidiary of WEC, provides full requirements electric service to Tilden pursuant to a special contract approved in Case No. U-17862.

28. WEC and Tilden engaged in good faith negotiations, including for the assignment of WEC's interest to UMERC, and have executed the Tilden Special Contract which is sponsored by UMERC's witness Mr. James O. Sherman, Jr. UMERC would provide full requirements electric service to Tilden once the Tilden Special Contract becomes effective.

29. Rule 31(1) provides that when "a utility enters into a special contract to provide service in a manner or at a rate not specifically covered by its filed rate schedules or rules and regulations, the utility shall file an application for approval of the special contract with the commission." UMERC requests approval of the Tilden Special Contract appended as Attachment A pursuant to Rule 31(1).

30. The Tilden Special Contract sets forth what will be UMERC's charges to Tilden for electric services provided thereunder. As UMERC considers the pricing and other terms to be highly sensitive commercial information, in order to maintain the confidentiality of this information, the Tilden Special Contract has been redacted in a similar fashion as Tilden's current special contract in Case No. U-17862. *See also In Re Application of Detroit Thermal, LLC for Approval of a Steam Sales Agreement*, Case No. U-17753 (application filed December 19, 2014), approved by the Commission order dated February 12, 2015. The original un-redacted Tilden Special Contract will be made available pursuant to a protective order. The

Tilden Special Contract, as set forth in the paragraph labeled "term," starts "upon the signing by both Parties . . ." and "continues through the conclusion of the Delivery Period and payment by Buyer [Tilden Mine] of all amounts due under this Agreement. . . unless early terminated in accordance with this Agreement." The Delivery Period is defined as "Twenty (20) years beginning with the HE01 EST of the first day of the first month following the Commercial Operations Date ("COD") subject to this Agreement."

31. UMERC represents that the terms and conditions in the Tilden Special Contract are reasonable and in the public interest, and in support thereof states that:

A. UMERC's electric generation system will be capable of meeting the electric requirements of Tilden as provided for in the Tilden Special Contract without jeopardizing electric reliability and service to its other customers.

B. The Tilden Special Contract will not impede the development of competition in UMERC's service territory. Tilden had adequate opportunity to explore competitive alternatives to the Tilden Special Contract and has previously received service from an alternative electric supplier, and other customers are actively participating in UMERC's RAS.

C. During negotiations leading to the Tilden Special Contract, the parties protected their own interests, and both were represented by counsel.

D. There will be clear benefits in the Tilden Special Contract for UMERC and its customers, as the Tilden Special Contract paves the way for the construction of new, clean generation in the UP (*i.e.*, the RICE electric generation facilities), consistent with the ARSA and the eventual retirement of PIPP.

E. Additional benefits of the Tilden Special Contract are discussed in the testimony in support of this Application.

32. UMERC's system will be capable of meeting the electric requirements of Tilden as provided for in the Tilden Special Contract without jeopardizing electric reliability and service to its other customers.

33. The Tilden Special Contract provisions will not violate any statutes or Commission rules, orders or clearly established policies.

34. The Tilden Special Contract will not harm other customers or otherwise detract from the public interest.

V. Accounting Approvals

35. In addition to other relief requested in this Application, UMERC requests approval for the accounting and ratemaking treatment of financing costs incurred during the construction period as set forth in the Commission's March 14, 1980 Order in Case No. U-5281 ("U-5281 Order"). The U-5281 Order specifies the computation of an Allowance for Funds Used During Construction ("AFUDC") offset to Construction Work In Progress ("CWIP") with a corresponding adjustment to operating income. The computation of AFUDC will be on each monthly CWIP balance with the AFUDC offset rate being UMERC's overall authorized rate of return. As required by the U-5281 Order, the capitalized AFUDC amounts will not be compounded. The capitalization of AFUDC will result in an increase in the total capitalized cost of the new RICE electric generation facilities and will increase the revenue requirements of the RICE electric generation facilities after they are placed in service. UMERC reserves the right under MCL 460.6s(12) to seek recovery of financing cost during construction if it files a general

rate case based upon a test-year occurring before the RICE electric generation facilities achieve commercial operation.

VI. Request for Relief

WHEREFORE, Upper Michigan Energy Resources Corporation requests that the Michigan Public Service Commission:

A. Grant a CON that the power to be supplied as a result of the proposed construction of the RICE electric generation facilities is needed;

B. Grant a CON that the size, fuel type, and other design characteristics of the RICE electric generation facilities represent the most reasonable and prudent means of meeting that power need;

C. Grant a CON that the estimated purchase or capital costs of and the financing plan for the RICE electric generation facilities, including, but not limited to, the costs of siting and licensing the RICE electric generation units and the estimated cost of power from the RICE Plans, will be recoverable in rates from UMERC's customers;

D. Grant a CPCN pursuant to MCL 460.500 et seq., authorizing UMERC to construct, own and operate a RICE electric generation facility (but not to serve or transact a local business) in the Township of Baraga;

E. Grant a CPCN pursuant to MCL 460.500 et seq., authorizing UMERC to construct, own and operate a RICE electric generation facility (but not to serve or transact a local business) in the Township of Negaunee;

F. Approve the Tilden Special Contract, Attachment A to this Application;

G. Grant the requested accounting approvals;

H. Grant UMERC such other and further relief as is just and reasonable; and

I. Grant all approvals requested herein within 270 days of the filing of this Application.

Respectfully submitted,

UPPER MICHIGAN ENERGY RESOURCES CORPORATION

Michael C. Rampe

Digitally signed by: Michael C. Rampe
DN: CN = Michael C. Rampe C = US O = Miller Canfield
Date: 2017.01.30 13:41:12 -04'00'

Dated: January 30, 2017

One of its Attorneys
Michael C. Rampe (P58189)
Theresa A.G. Staley (P56998)
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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*** * * * ***

In the Matter of the Application of	)	
Upper Michigan Energy Resources Corporation	)	
for approval of a Certificate of Necessity	)	
pursuant to MCL 460.6s for	)	Case No. U-18224
Two Reciprocating Internal Combustion Engine	)	
Electric Generation Facilities Located in the	)	
Upper Peninsula of Michigan,	)	
Approval of Certificate(s) of Public Convenience	)	
And Necessity, approval of a Special Contract with	)	
Tilden Mining Company L.C.	)	
and related accounting and ratemaking	)	
authorizations.	)	

DIRECT TESTIMONY AND EXHIBIT

OF

DANIEL P. KRUEGER

ON BEHALF OF

UPPER MICHIGAN ENERGY RESOURCES CORPORATION

I. Introduction

Q. Please state your name and business address.

A. My name is Daniel P. Krueger. My business address is 231 West Michigan Street, Milwaukee, Wisconsin, 53203.

Q. By whom are you employed and what is your position?

A. I am employed by WEC Energy Group, Inc. ("WEC Energy Group") as Senior Vice President – Wholesale Energy and Fuels.

Q. Please describe your educational and business experience.

A. In my current position, I lead the development and implementation of market resource strategies to minimize the net cost of serving the energy needs of the customers of the WEC Energy Group subsidiaries. In this capacity, I oversee market activities for both electric and natural gas assets. This includes interactions with the Midcontinent Independent System Operator ("MISO"), an integrated regional nonprofit entity that operates the bulk power transmission system and associated energy market. For power plant operations, I oversee the annual purchase and delivery of coal, natural gas, and related commodities. I am also responsible for gas supply planning, storage, and operations for all of the WEC Energy Group local distribution companies. I am responsible for developing generation expansion plans, long-term wholesale marketing activities, and maintaining relationships with WEC Energy Group's largest commercial and industrial customers.

I joined the WEC Energy Group family of companies in 2014 as vice president of Wisconsin Electric Power Company ("WEPCo"). My responsibilities included long-term strategy for performance of WEPCo's electric generating assets and fuel handling capabilities. I also served a key role in completing the Integrys Energy Group, Inc. ("TEG") acquisition, and in planning for integration of the TEG companies. I was promoted to my current position in July 2015.

Prior to joining WEPCo, I worked for Accenture from 1987-2014, leading the successful development of that company's global advisory business in power generation, fuels and power markets.

I hold a Bachelor of Science degree in Engineering degree from the University of Illinois at Urbana-Champaign, which I received in 1987.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support Upper Michigan Energy Resources Corporation's ("UMERC" or the "Company") Application in this docket, which requests a Certificate of Necessity ("CON") from the Michigan Public Service Commission ("Commission") in connection with the construction of two natural gas-fired Reciprocating Internal Combustion Engine ("RICE") electric generation facilities in the Upper Peninsula of Michigan ("UP"). UMERC also requests that the Commission issue a certificate of public convenience and necessity ("CPCN") to authorize UMERC to construct, own and operate the RICE electric generation facilities within the electric service territory of Upper Peninsula Power Company ("UPPCO"). UMERC also requests approval of the Retail Large Curtailable Special Contract between WEC Energy Group and Tilden Mining Company, L.C. ("Tilden"), dated August 12, 2016 ("Tilden Special Contract"), as well as certain accounting authorizations and other relief set forth in its Application filed in this case.

My testimony provides an overall introduction and background to the Application, including the specific approvals sought, and provides background on the establishment of UMERC and the decision to construct, own and operate the two RICE

electric generation facilities. I also introduce the witnesses and the subject matter of their testimonies.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring Exhibit A-__ (DPK-1), which consists of Michigan Governor Rick Snyder's Special Message, dated March 13, 2015.

Q. How is the remainder of your testimony organized?

A. Following this Introduction, my testimony is organized into these remaining sections:

II. Background;

III. Summary of Relief Requested; and

IV. Identification of Witnesses and the Subject Matter of Their Testimony

II. Background

Q. Please describe UMERC.

A. The Commission's Order dated April 23, 2015, in the TEG acquisition, Case No. U-17682, approved an Amended and Restated Settlement Agreement ("ARSA"). The ARSA, in ¶ 6.g., contained the following provision:

> WEC further agrees to the creation of a Michigan-only jurisdictional utility to facilitate this long term solution, if reasonable and prudent, with timing to be determined by the MPSC.

Consistent with this provision, WEPCo and Wisconsin Public Service Corporation filed a Joint Application in Case No. U-17682 requesting to form UMERC as a Michigan-only jurisdictional electric and gas utility. The Commission approved the formation of UMERC with its Order dated December 9, 2016.

Q. Has UMERC been formed?

A. Yes. Following a series of steps outlined in the Joint Application and testimony in Case No. U-18061, UMERC was established as a Michigan-only utility and commenced providing electric and natural gas service effective January 1, 2017.

Q. How many customers does UMERC have?

A. UMERC is engaged as a public utility in the business of purchasing, distributing, and selling electric energy to approximately 36,500 full requirements customers, as well as any distribution-only customers who qualify for retail access service ("RAS"). UMERC also provides retail natural gas service to approximately 5,300 full requirements customers, and natural gas transportation service to 17 transportation customers. UMERC will also generate electric energy with the RICE units, as proposed in the Application filed in this case.

Q. What circumstances led to UMERC's decision to construct, own and operate two new RICE electric generation facilities?

A. The "long term solution" in the earlier-quoted portion of the ARSA, ¶ 6.g., refers to new, clean generation to be built in the UP, which is discussed in various provisions of the ARSA. Paragraph 6.g. of the ARSA also contained various commitments by WEC Energy Group, then known as Wisconsin Energy Corporation, and WEPCo, ranging from purchasing output of the new generation, to having an ownership interest in, and constructing, the new generation.

Consistent with WEC Energy Group and WEPCo's commitments under ¶ 6.g. of the ARSA, WEC negotiated and entered into the Tilden Special Contract for which approval is requested in Section IV of the Application, and pursuant to which UMERC

will provide service to Tilden after the RICE electric generation facilities achieve commercial operation. To serve its customers, including Tilden under the Tilden Special Contract, UMERC will construct and own the two new RICE electric generation facilities that are the subject of its Application.

The proposed RICE electric generation technology is particularly well-suited to provide a long-term generation solution for the UP. Pre-existing natural gas delivery infrastructure ensures an adequate supply of natural gas to support a clean generation alternative to the continued operation of the Presque Isle Power Plant ("PIPP"). The RICE technology has matured and can now support large, utility-scale electric generation applications that are as reliable and efficient as other natural gas-fired electric generating technologies. The advantage of RICE over other technologies is its scalability. With unit sizes of 9-10 MW and 18-20 MW, a RICE electric generation facility can be sized to fit the load to be served more precisely, especially when the load is relatively small as it is in the UP. This scalability reduces the up-front capital cost of the UP generation solution, while providing UMERC customers with the same level of efficiency and reliability as they would receive from a larger facility.

Q. Will approval of the CON and other relief requested in the Application enable the retirement of PIPP owned by WEPCo?

A. WEPCo plans to run PIPP to serve customers until such time as PIPP is authorized for retirement by the MISO. Approval of the new RICE electric generation facilities will permit WEPCo to pursue retirement of PIPP through MISO procedures.

Q. Will retirement of PIPP result in lower emissions?

A. Yes, if PIPP is replaced by the RICE electric generation facilities. Reliance solely on a transmission solution would not reduce emissions because the energy would be generated from Wisconsin and elsewhere, which is predominantly coal-based generation. Retiring PIPP and replacing it with transmission in this fashion does not reduce total emissions – only the RICE electric generation facilities can do that.

III. Summary of Relief Requested

Q. Please describe the CONs that UMERC is requesting in this case.

A. UMERC requests the following CONs:

- A CON that the power to be supplied as a result of the proposed construction of the RICE electric generation facilities is needed;
- A CON that the size, fuel type, and other design characteristics of the RICE electric generation facilities represent the most reasonable and prudent means of meeting that power need;
- A CON that the estimated purchase or capital costs of and the financing plan for the RICE electric generation facilities, including, but not limited to, the costs of siting and licensing the RICE electric generation facilities and the estimated cost of power from the RICE electric generation facilities allocated to UMERC's non-Tilden customers, will be recoverable in rates from UMERC's non-Tilden customers.

Q. Has the Company conducted a formal review of its future capacity needs?

A. Yes. In compliance with the Commission's CON application filing requirements, the Company has developed an Integrated Resource Plan ("IRP"), which is sponsored by witness Jeff Knitter.

Q. Why should the Commission grant the requested CONs?

A. As I discussed earlier in this testimony, the ARSA contemplates a "long term solution" for electric generation in the UP. The CONs, the CPCN requests, and other requested relief in connection with the new RICE electric generation facilities are necessary to the realization of the long term generation solution.

UMERC's IRP, along with a report entitled "Northern Michigan Power Generation Technology Comparison", which was prepared by HDR Engineering, Inc. ("HDR Report") and sponsored by Andrew W. Sutherland, indicates that the RICE electric generation facilities are the most reasonable and prudent means to satisfy future customer electric capacity and energy needs. The RICE electric generation facilities also fulfill Michigan Governor Rick Snyder's goal of ensuring affordable, reliable, adaptable, and environmentally protective energy, as stated in his Special Message, dated March 13, 2015, which is my Exhibit A-__ (DPK-1). As fully set forth in the IRP, and the other testimony and exhibits in support of this case, the RICE electric generation facilities will provide affordable and long term electric reliability for UMERC customers and in the MISO UP footprint. The RICE electric generation facilities are also adaptable in that they are modular, giving UMERC flexibility to adjust to changing conditions. The RICE electric generation facilities also provide for Michigan jobs, new tax base, power when it is needed, electric capacity and energy through lower emitting technology than the PIPP

coal units that WEPCo intends to retire. The new RICE electric generation facilities will provide a long term solution for the White Pine system support resource, and will eliminate the need for major transmission network upgrade projects.

Tilden is a critical stakeholder in any long term UP generation solution, and has agreed to receive service from UMERC under the Tilden Special Contract for a period of 20 years. Governor Snyder's March 13, 2015 Special Message, on page 9, stated:

> . . . . However, WE Energies has now agreed to provide service without seeking extra system support revenues, and Cliffs has agreed to remain with WE Energies until the new plant can be built. Just as before, the new plant to replace PIPP will be constructed no later than 2020, and will be supported by a series of business agreements. We look forward to working with legislative partners and the utilities to further cement Michigan's energy independence, by enabling the creation of Michigan-only utilities when that is in the ratepayers' best interest.
>
> - Call to action: Finalize the transactions that will solve the U.P. power crisis

WEC and Tilden have responded to the "call to action" by entering into the Tilden Special Contract. Approval of the Tilden Special Contract and the other requests for relief in the Application are required steps in the retirement of PIPP.

Q. You stated earlier that UMERC is requesting a CPCN. In what municipalities would UMERC's requested CPCN rulings apply?

A. UMERC has identified the following two sites for the two new RICE electric generation facilities:

A. Negaunee Township Site: UMERC will construct, own and operate one of the RICE electric generation facilities at a location in Negaunee Township that is described in the testimony of Terrence W. Carroll and other witnesses.

B. Baraga Township Site: UMERC will construct, own and operate one of the RICE electric generation facilities at a location in Baraga Township, also described in Mr. Carroll's testimony and the testimony of other witnesses.

Q. Would either site fall within another public utility's service territory?

A. Yes. UPPCO's service territory encompasses both proposed sites.

Q. Is UMERC requesting a CPCN for Baraga Township?

A. Yes. UMERC requests that the Commission grant UMERC a CPCN to construct, own and operate electric utility plant and facilities, but not to serve or transact a local business in the Township of Baraga, located in the County of Baraga.

Q. Is UMERC requesting a CPCN for Negaunee Township?

A. Yes. UMERC requests that the Commission grant UMERC a CPCN to construct, own and operate electric utility plant and facilities, but not to serve or transact a local business in the Township of Negaunee, located in the County of Marquette.

Q. Will UMERC provide service to the public in Baraga Township or in Negaunee Township?

A. No. UMERC would construct, own and operate the RICE electric generation facilities in Baraga Township and in Negaunee Township, but would not provide service to the public in either township. UMERC will obtain all required local permits and other approvals from the townships before commencing construction of a new RICE electric generation facilities in the townships.

Q. Will approval of the requested relief for CPCN's result in wasteful duplication of facilities?

A. No. The testimony of Mr. Carroll explains why these sites were chosen. The new RICE electric generation facilities will not result in any wasteful duplication of facilities. The new RICE electric generation facilities are not duplicative because they are needed to serve UMERC's customers, including to provide service to the Tilden Mine pursuant to the Tilden Special Contract. If the RICE electric generation facilities were not constructed at the proposed sites, they would still need to be constructed somewhere else. As I stated earlier in this testimony, the new RICE electric generation facilities are expected to enable WEPCo to seek retirement of the PIPP pursuant to MISO procedures. As shown in Mr. Knitter's testimony and IRP, the RICE electric generation facilities will benefit UMERC's customer rates.

Q. By what date does UMERC request the Commission to approve all the requested relief in the Application?

A. UMERC respectfully requests that the Commission grant all requests in the Application within 270 days of its filing date. Receipt of all requested relief will enable UMERC to commence construction as soon as possible.

IV. Identification of Witnesses and the Subject Matter of Their Testimony

Q. Please identify the other witnesses in this case, as well as the subject matter of their testimony.

UMERC's witnesses in this case, and the subject of their testimony, are as follows:

- Terrence W. Carroll: Provides an overview of the project; describes the proposed sites and factors considered in site selection; describes and discusses the planned generating technology, including reliability, efficiency, major support systems

and expected output; discusses required permits; discusses infrastructure required, including gas infrastructure for plant construction and operation, transportation systems, and water and sewer infrastructure; discusses and describes the basic schedule for development and construction and workforce required; and discusses the capital costs and operation and maintenance costs expected for the proposed RICE electric generation facilities.

- Joann Henry: Addresses interconnection requests to MISO; discusses the basis for UMERC's determination of location and amount of generation at each proposed location, including a discussion of studies conducted by MISO and ATC; and discusses network upgrades under the MISO tariff and funding for those upgrades.
- Laura M. Jarmuz: Addresses the air quality regulations, the cost impacts of complying with air quality regulations, the proposed schedule for obtaining the requisite air permits, and reduction in regional air emissions.
- Russell T. Laursen: Addresses the supply of natural gas to the RICE electric generation facilities and the need to construct additional pipeline facilities to support the project; addresses natural gas transportation capacity and how those will apply to UMERC; addresses contracting for capacity, and terms of proposed transportation agreement with the pipeline; addresses necessary gas laterals and estimated costs; and addresses natural gas procurement.
- Susan M. Schumacher: Addresses the environmental site assessments, including environmental factors investigated and the environmental factors considered in the selection of sites; addresses required environmental permits, including state

and federal wetland permits, and state air quality permits; and addresses federal environmental regulations that apply to the sites.

- James O. Sherman, Jr.: Sponsors and explains the Tilden Special Contract, its relevance to the CON application, and Tilden's future relationship with UMERC; discusses key provisions of the Tilden Special Contract; discusses Tilden's load requirements; and sponsors and discusses UMERC's current power purchase agreements.
- Joel R. Gaughan: Describes WPSC Rate Zone and WEPCo Rate Zone energy and demand forecasting methodologies employed by UMERC and discusses the annual energy and firm peak demand requirements for the UMERC system.
- Jeff Knitter: Sponsors and addresses the IRP and the results which support the proposed project, and related matters.
- James A. Schubilske: Addresses plans for financing the capital costs of the proposed RICE generating facilities; describes the regulatory treatment of costs and revenues associated with the project with the Tilden Special Contract, and UMERC's other customers; and supports the request for accounting approvals.
- Andrew W. Sutherland: Sponsors and supports the HDR Report, which evaluates the most feasible options for UMERC to generate power in the Marquette and Keweenaw Peninsula area to serve its customers.

Q. Does this conclude your direct testimony?

A. Yes.

STATE OF MICHIGAN
EXECUTIVE OFFICE
LANSING

RICK SNYDER
GOVERNOR

BRIAN CALLEY
LT. GOVERNOR

March 13, 2015

A Special Message from Gov. Rick Snyder
Ensuring Affordable, Reliable, and Environmentally Protective Energy for Michigan's Future

To Michiganders and the Michigan Legislature

Introduction

Michigan needs to take aggressive steps to avoid a future of spiking energy prices and widespread power outages.

In the last two years, we have laid the groundwork for a bright energy future for Michigan. We have gathered key information and met with residents all over the state to learn about our options. We set clear goals for Michigan's energy future.

We knew our energy must be affordable for our homes and businesses – for instance, residential bills for heat and electricity should not be higher than the national average. We looked to ensure that people could rest easily, knowing there would be dependable heat and electricity to power their homes. Specifically, we said that we should not have widespread outages due to a lack of supply, and that our residents should endure less than one outage a year on average, and that our outages should averages less than two hours and 15 minutes. We sought to make sure we had options so our state could draw energy from a variety of sources, able to adapt as technology developed reliable and efficient alternatives. We said that the newest technological advances that will be right for Michigan are in natural gas and renewable generation. And we made it a priority to protect our environment for the generations to come, reducing mercury, acid rain, and particles in the air

We've made real progress since 2012. We met the 11th most aggressive renewable portfolio standard in the nation, and we did so under budget – in some cases, at no additional cost compared to other energy sources. We were able to do that for a lot of reasons. Our standard encouraged collaboration, so we had access to people familiar with the newest technologies. We saw huge price reductions in even the last five years as we took advantage of those new technologies – better towers, better blades, and better electronics all meant better prices for Michiganders in the wind space, which has

been our least expensive resource to date. In another success story, we established both utility and non-utility programs to reduce energy waste that are delivering measureable and very cost-effective results. In fact, our energy waste elimination is coming in at about a third the cost of what we would pay to generate that power. There is an awful lot of coal and natural gas we never had to burn, and that is only one way we managed to save so much money. We have proposed an energy code that will reduce new building energy usage by at least 25 percent.

I could keep listing good things that have happened, but we are here today because we have a lot more to do.

Our mission is to build a foundation of adaptability – that means that regardless of what the future holds, our energy system will be able to support all our needs at a reasonable price. Our efforts should be focused on ensuring our energy infrastructure can keep up with the demands of a growing economy. We need to ensure Michigan's future energy decisions are made in Michigan. We need to make sure that when we make those decisions, we have the right process to ensure the decisions focus on the pillars of a strong energy future: affordability, reliability, and protection of the environment.

Now it is time to propose a plan that will see Michigan through at least the next 10 years of energy decision-making. During those next 10 years, Michigan will have to solve a shortage of electric generation. It will likely have to do that while complying with new federal regulations on carbon emissions. Our economy is expected to grow, and our infrastructure and natural assets will become even more important to our future. Ten years is near enough to have a good idea of the challenges we will face, and long enough to take concrete steps to secure our energy future.

Affordability

Eliminating waste – investing in our homes and businesses – is vital to meeting our affordability goals.

Michiganders pay more than the national average for the energy that powers, warms and cools their homes right now. That needs to change. The first and best thing we must do to change that is to help our homes and businesses eliminate waste. When you can get the same result for less money by upgrading your home or business, that's a win-win-win solution for Michigan.

In 2009, Michiganders used 38 percent more energy -- heating plus electricity -- than the national average. Our average bills were 6 percent above national average. We can lower those bills.

There is a lot going on in those numbers. Our climate requires us to use more energy heating our homes than we do cooling them, unlike other parts of the country.

Our natural gas price is one of the 10 lowest in the country, and that is used to heat the vast majority of homes in Michigan. That is why we use so much more energy than average, but our overall spending is a lot closer to average.

But people in their homes and businesses can do better just by eliminating energy waste, and we have reason to think we have some big opportunities there. First, Michigan homes tend to be smaller and older than the national average, which means they should take less energy to heat and cool if they are properly insulated and have heating and air conditioning systems that are reasonably up to date. That means we have a big opportunity to hold down our costs by helping our neighbors do the same. When we need to build a plant or burn some coal, that shows up on all our bills. Our current program that utilities use to reduce waste has been so successful that we have spent about a third of the money we would have otherwise on coal, gas, or facilities. In other words, we saved two-thirds of our dollars, and did so while making Michiganders homes and businesses more comfortable and their bills lower. Why wouldn't we do more of that?

- Call to action: We should meet at least 15 percent more of Michigan's energy needs in the next decade by eliminating energy waste.

We know that an energy shortage will come if we do nothing. The more energy we need, the more we have to build, and building gets expensive. The best way to avoid those large expenses is to reduce that demand when it makes good economic sense. We know it does make a lot of economic sense for Michigan to reduce energy waste. The 15 percent goal comes from the reports that were prepared by the Michigan Public Service Commission and the Michigan Economic Development Corporation. That figure is actually conservative, as it represents carrying out <u>only half</u> of the projects that already pay for themselves.

Here are some examples of ways Michiganders are already reducing energy waste in these programs:

- Insulating or caulking windows to keep drafts from stealing away our heat.
- Replacing old furnaces and water heaters so that we can be just as comfortable for a lot less money.
- Getting newer seals on the big freezers and refrigerators in convenience and grocery stores.
- Replacing older industrial equipment with newer technologies that create a better price-per-piece.

We do have a lot of variation in the amount of waste that can be eliminated across the state. Some utilities cover a large number of vacation homes that are unoccupied during the winter. Insulating them won't produce much energy savings. Other utilities serve large areas with thousands of mercury street lights that are twice as expensive to operate as newer, brighter LED technologies, older homes that are occupied year-round and could be much more comfortable if they were better insulated,

and a large number of industrial operations that could become much more competitive if they had access to the expertise and capital necessary to capture those savings. Those are opportunities for save we can't pass up.

Michigan needs to change its attitude from seeing waste elimination as a nice-to-have add-on and see it as the cornerstone for Michigan's next energy policy.

- Call to action: We need to eliminate artificial limits to the amount of waste reduction that utilities do. Right now, our law prevents utilities from spending more than 2 percent of their budget on waste reductions, even if that forces them to buy more expensive equipment instead.

- Call to action: We need to make sure our Public Service Commission can weigh the benefits of energy waste reductions in the same way it can weigh other kinds of expenses.

- Call to action: We need to break out of the thinking that says the only compensation for waste reduction programs is to offset a loss, and instead make our smartest option a place where utilities want to invest. Capital invested in stopping energy waste should not be less valuable than capital invested in a new plant.

Working families and seniors on a fixed income might want to insulate or install a better furnace, but don't have the up-front money to do it. Or, someone might be a renter that pays utilities and would benefit from the lower bill, but doesn't own the house. On-bill financing can be a key tool to address these kinds of situations – and 30 other states are taking advantage of it. Such plans would allow utility payers to take measures that reduce their waste, and pay for them over time as part of their electric bill. In other words, someone could essentially borrow the money to improve the furnace, and pay it back out of their monthly bill. Their bill doesn't go up, because of the energy savings. When they are done paying it off, their bill drops.

This can be a great tool for lots of Michiganders. Renters who want to make an investment to keep their utilities bill down have a way to do it. A senior citizen who knows their home could be more comfortable but doesn't know how long they will be in the home can make the change and know they will only pay for as much as they use. Last year the Legislature and I worked as partners to allow municipal utilities to offer these programs.

- Call to action: We should continue our good work on this issue, and repeal the on-bill financing ban for other utilities.

There is one more big reason Michigan should be a leader in this area. Michigan has companies that design more efficient building materials, appliances, and machinery. We build many of these items here, too. Other Michiganders install these technologies and materials in Michigan homes and businesses. This is a perfect example of an

opportunity to build on existing leadership the state has in connecting Michigan businesses to each other. It is the right thing to do for energy costs, and the right thing to do for Michigan businesses and Michigan jobs. We cannot let this opportunity pass us by.

In every possible scenario, the elimination of energy waste is the right answer for Michigan. It enhances our reliability, as the only kind of energy that never strains the grid is the energy you don't use. It is the best thing we can do for affordability; the cheapest energy is the energy you don't use. It is the best thing we can do for environmental protection; the cleanest energy is the energy you don't use. And it allows our businesses and residents to save money by supporting each other.

Eliminating energy waste is only the place to start.

- Call to action: When utilities propose big-dollar investments, we need to make sure those investments will keep down costs, provide reliability, and protect our environment.

Utilities make a lot of investments – sometimes in new plants, sometimes in big upgrades to existing plants, and sometimes in operation, maintenance, and long-term purchase contracts. In 2008, we took a big step forward by saying investing new plants should have to be compared to other possible alternatives before pre-approval would be given. We need to expand that to all large investments.

We can protect our affordability by making decisions that take into account many possible futures. That includes making sure that Michigan's Public Service Commission has the power to require the cost of all alternatives be determined for the short and long term. Those alternatives also should be put through tests to determine the impact on reliability, our environment, and long-term regulatory compliance, and only the best alternative should be funded.

That is why we must get the right expertise asking the right questions. Michigan has the opportunity to be a nationwide leader in designing such a process; we should do that now.

We know that for some businesses, energy costs are not just one of many important costs, but one of their biggest expenses. Larger industrial customers that shaping metal in some way – like a steel-maker or a metal melter – are examples. On the agricultural side, some greenhouse operations also spend a large percentage of their budget on energy. We need to make sure that such businesses are able to choose Michigan, because they are a crucial part of our economic future. These are job creators that have a choice of where to locate. In order for the rest of our economy to build on a strong base of advanced manufacturing, we must be able to make sure such businesses can locate in Michigan and be competitive.

We need to adhere to our cost-of-service principles for all classes, meaning no one should be subsidizing others. Under legislation passed last year, the Public Service Commission is already looking at ensuring that rates properly reflect cost-of-service in most of lower Michigan.

But there is more we can do. These are many users that are motivated to work to control their own costs and destinies -- if given the tools to do so. For instance, we have seen a lot of success through the metal melting rate that Consumers Energy offers, which has as a major component pricing to encourage use during off-peak hours. We also need to encourage other voluntary "peak shaving" activities by energy users. Even small changes at the right time may have outsize benefits.

- Call to action: Some energy users, especially energy intensive industries, may be able to manage their energy use to go down when the grid starts to get strained, which will hold down costs and lower risks for everyone. We should make sure that we both create an opportunity and a reward for them to partner with our utilities to capture that savings.

Reliability

Michigan needs to do more to keep providing reliable electric and gas service.

Michigan residents and businesses need to know that when they flick the switch or twist the dial, they will have electricity and heat.

Just a few days after I announced my reliability goals in 2012, many Michiganders endured the hardship of spending several days without electric power. We have had a lot of extreme weather in the last two years that was hard on our electrical system – ice storms, heavy winds – and that has made us look at all the steps we need to take to make sure that we get better about protecting ourselves from outages.

People can't get things done when the power goes out. Many of our businesses can't function without power. Our schools close and parents must leave work to pick up their children. There also is a human element to outages that we can't forget. Dialysis centers have to find somewhere else that can provide lifesaving treatment. A lack of air conditioning on a hot day is life-threatening to our seniors.

Michigan set goals last year of being leaders in reliability – meaning ensuring that both we don't have as many outages, and they don't last as long. The goals we set would mean that Michiganders would experience less than one outage a year, and that it would be over in about the time of a competitive college basketball game – less than two and half hours. For instance, in 2011, the average number of outages a year per customer was 1.13 (a little more than one a year). Today, it is 0.8 – meaning most Michiganders won't experience a sustained outage this year. But we still have more to do.

I commend the Public Service Commission for setting aggressive goals in this area and working to encourage more measures that are already bearing fruit, and for our utilities and grid owners for responding.

Taking advantage of new technologies can also give us opportunities to prevent and fix outages much more easily than in the past. Until very recently, if your power went out, the utility did not know it until you called. Our utilities had to figure out what likely broke by how many people called, and where they were located. Now, with newer technologies, utilities can immediately see a problem and know what needs to be sent to the site to fix it.

- Call to action: Michigan needs to complete plans to deploy smart meters that help utilities locate outages and restore power more quickly.

The deployment of smart meters might be the best thing we ever do for reliability. That deployment should be complete in our two largest utilities in the next three years, and I know the commission has been working with utilities to accelerate the effort.

- Call to action: Michigan needs to continue investing in infrastructure and maintenance to keep our power grid and pipeline system working smoothly and safely.

The PSC has taken other steps to ensure reliability as well. It has pushed for more investment in tree trimming and challenged our utilities to step up their game on other infrastructure and maintenance activities that help keep our grid reliable. It's working. The average number of power interruptions has been declining in Michigan since 2011.

On the natural gas side, the commission took advantage of record-low gas prices to encourage utilities to replace our aging natural gas pipelines – especially those that are made of cast iron. For too long, we neglected our pipelines and recently, we have seen a quadrupling of leaks for some of our largest gas utilities compared to a decade ago. These programs are the right thing to do and must be continued, and accelerated as much as is economically feasible.

- Call to action: We must change our electric market structure to ensure all electric providers are protecting their customers from massive outages due to lack of supply.

An electric grid is a unique, gigantic machine that makes the market for electricity unlike all other economic markets. In most markets, if there is a shortage, some customers get the materials and some don't. But with electricity, if you can't get the electrons to the last light switch that flips "on," then the grid fails and no one gets power. We've seen this happen in Michigan before. In 2003, much of lower Michigan

experienced a massive outage and the Upper Peninsula remembers a similar problem when the Presque Isle Power Plant flooded out.

The Midcontinent Independent Systems Operator – MISO –is charged with making the interstate electric grid operate smoothly. MISO says the majority of lower Michigan is facing a 3 gigawatt shortfall of generation that can be called on to keep the grid from failing. That is about the size of our two largest nuclear plants – Cook and Fermi – put together. And that doesn't count the needs of the UP, which needs another plant built in the next five years. We've already taken some actions to fill that gap – but we aren't done yet addressing that gap, and we will need to do more almost every year for the next decade to fill that gap.

Michigan's risk of devasting outages is serious and growing. No large-scale grid operator in the country has a more serious risk than MISO, and no place in MISO has a shortage nearly as big as Michigan's.

If we don't solve that problem, Washington D.C. will solve it for us – and we will not like its solutions. We know this from what we are dealing with in the Upper Peninsula right now.

- Call to action: We need to act now to make sure we have the tools to solve our own problems and keep decision-making in Michigan, not in Washington D.C.

It is pretty clear that we have to make a lot of decisions – expensive decisions – in the coming years. And we have recently learned how important it is to take action in order to protect our ability to make those decisions here in Michigan. We know that if we don't get plants built in Michigan that we need, the federal government will essentially take over setting our electric rates and planning our energy future. And we know from experience that the "solution" imposed on us will not feature adaptability, affordability, reliability, or protection of the environment.

Consider what happened to the Upper Peninsula in the last year.

When the utility that owned a coal plant announced it didn't need it anymore, the people who run our interstate electrical grid for most of Michigan, a group called MISO, said the plant had to be kept operating for reliability. MISO doesn't normally get into the economics of running actual plants; that is usually done at the state level. But when there is a potential for the grid to collapse and leave everyone without electricity, it can step in. MISO entered into a private agreement with the utility that meant Michigan ratepayers were now going to have to pay almost $100 million a year until new electric lines could be built – something that takes at least 5 years, even if done expediently.

Michigan's Public Service Commission said that amount was way too high – it meant as much as an overnight 20 percent increase in some bills. That's approximately $120 a year extra for the hardest-hit residential customers, many of whom are on fixed incomes. That's the kind of rate hike businesses can't plan for and absorb. The Federal

Energy Regulatory Commission imposed the rate hike it anyway, saying that even though those rates might be unjust and unreasonable, it would be sorted out later.

Let's think about the "solution" we were buying for all that money – keeping an old coal plant limping along while we spent more than a half a billion dollars on upgrading the system to bring out-of-state energy -- mostly coal-generated -- into Michigan. It would leave our reliability in a worse position than building a plant, it would be less affordable than building a plant, and it would be worse for the environment than building a new, natural gas plant that is designed to reduce energy waste by selling steam.

That's just not what Michiganders call a solution. So in January, we were able to announce a series of likely transactions that would provide for an orderly retirement – without millions of additional dollars in MISO-imposed payments -- of the Presque Isle Power Plant (PIPP) and construction of a combined heat and power plant.

Today, I am announcing that the transactions have changed slightly, but overall, the outcome is still very positive for U.P. residents. Despite the best efforts of the Upper Peninsula Power Company and Cliffs Natural Resources, they were unable to come to terms on a contract for service. However, WE Energies has now agreed to provide service without seeking extra system support revenues, and Cliffs has agreed to remain with WE Energies until the new plant can be built. Just as before, the new plant to replace PIPP will be constructed no later than 2020, and will be supported by a series of business agreements. We look forward to working with legislative partners and the utilities to further cement Michigan's energy independence, by enabling the creation of Michigan-only utilities when that is in the ratepayers' best interest.

- Call to action: Finalize the transactions that will solve the U.P. power crisis.

I am proud to say that we still believe a long-term solution for the U.P.'s current energy crisis will be in place this year. We solved the problem, because that is what Michiganders hired us do. But it is not going to be a way we can keep solving this problem, and this problem is set to hit the Lower Peninsula in a big way.

The same day FERC issued orders that imposed unreasonable costs in the Upper Peninsula; it issued another order to one of Michigan's biggest utilities, Consumers Energy. Consumers Energy plans to retire at least seven coal plants next year. It doesn't just plan to – it has a court order requiring it to do so for environmental compliance. But when Consumers Energy asked the FERC for permission to retire those plants, FERC didn't simply approve their request. Instead, FERC demanded more information on the impact those closings would have on others, suggesting the company could be placed in an impossible position: conflicting federal orders both to keep the plants running and to close them.

This time, after a lot of additional information, the FERC agreed the plants could be closed. But what happens next time, when the Lower Peninsula has a plant that the

grid needs but the utility wants to close because it doesn't make economic sense to run it?

If we don't have the ability to make some good decisions now, our future will be decided in years of Washington bureaucratic wrangling and court cases.

- Call to action: Prevent the Lower Peninsula from developing the same crisis the U.P. is living through by reforming our electrical market to require every electric provider to protect its customers.

We are facing a crisis because of a shortage of plants once coal plants begin retiring next year. These plants are being retired for two main reasons. First, our coal fleet is on average more than 50 years old, so many of the facilities just aren't efficient to run anymore. Second, there are some EPA regulations that are going to come into effect in the near future that will mean at least nine coal plants in lower Michigan, plus PIPP, will need to retire because they are too expensive to upgrade to meet the new standards.

This projected shortfall does not take into account any additional federal requirements that are currently proposed; it is the result of regulations that have already survived years of court challenges and are undoubtedly coming. We know at least 10 plants in Michigan will retire in the coming years. It could be more.

We cannot fix this without changing the way we structure our market. We need to give our regulators the power to determine when we may face a shortage, and tools to address it when we do. Without that, we cannot be adaptable. We also need to make sure that every company that sells energy in Michigan is protecting its customers from unpredictable price spikes due to a lack of generation or import ability. We can fix our electric capacity problem without forcing customers to change electric providers. But we can't fix our electric capacity problem until every electric provider has an equal responsibility to ensure that the plants or transmission lines their customers rely on will be there. Right now, we know we have a problem coming on that front. We need to require everyone selling power in Michigan to be part of solving that problem.

We can solve this problem without getting rid of retail open access – sometimes called choice -- for those businesses that have already made plans and commitments to get their power from an alternative electric supplier. But we can only solve this problem if that choice is a fair choice. In Michigan, any company that sells you life insurance has to show the state that they have enough reserves to make good on the policy they are selling. It's only fair to make sure that everyone who sells power is also required to buy the insurance policy that protects us all from big risks if there is not enough power available.

Right now, our incumbent utilities are required to be ready to take 100 percent of customers back – but those utilities will not receive approval to build plants their current customers don't need. When there were plenty of plants, that system worked without

causing a reliability problem. But that is not going to be the case in the coming years. Instead, we face the question of how to pay for plants that may only need to run a few weeks a year, if no utility can be authorized to build them, and no investor thinks they can make their money back.

In Michigan, we believe in the principle of cost of service – users should not be subsidizing each other. That principle needs to apply to our market design too, and make sure everyone is fairly sharing in the costs of those plants we may only need a few times a year, or the lines we need to bring in the power that keeps our grid running. This must be a top priority.

While we need to change our market structure, we need to recognize the fact that in much of Michigan, 10 percent of businesses have relationships with other electric providers. When we change our system, we can respect those business decisions and allow those relationships to continue, if those providers can be part of the solution to our current problems. Reorganizing and redesigning electric markets, and giving our electric companies and their customers time to respond to those changes, is crucial. We also need to have a defined universe of megawatts we are addressing, so we need to keep the 10 percent limit.

It takes 3-5 years to build a new generating plant, including all regulatory approvals and permit requirements. So we need to know electric customers are protected now and 5 years into the future. That will give us time to construct a new, efficient plant if needed. All electric companies should be required to show the MPSC they have the capacity to serve their customers for the next five years in order to do business in Michigan. I am calling on the legislature to help us reform this system before the summer break, so that we can give ourselves as much time as possible to make a smooth transition.

Adaptability

Michigan must set a reasonable, achievable and efficient goal for 2025 : a minimum of 30 percent clean energy – and potentially much more.

2025 is 10 years away. And in those 10 years, Michigan is going to need to build new plants for electric generation and make sure our natural gas infrastructure is able to handle increased demand. We need to make sure our decisions keep Michigan adaptable, while making sure our energy is reliable, affordable, and protective of the environment. We’ve been talking about energy for some time, and that time has given us clarity on some key challenges facing Michigan.

Michigan has historically been one of the top 10 states most dependent on coal. We will have fewer coal plants in the near future. Now is the time when we will make energy decisions that shape our future and our children’s energy future. That energy future can be one where our system is adaptable, reliable, affordable, and protects our

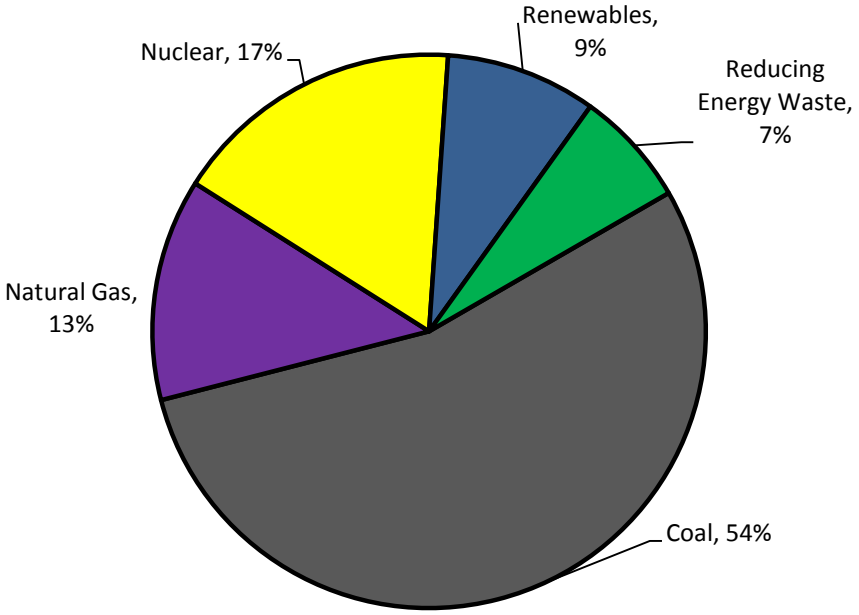
environment – but only if we are smart about how we make those decisions and take advantage of our strengths.

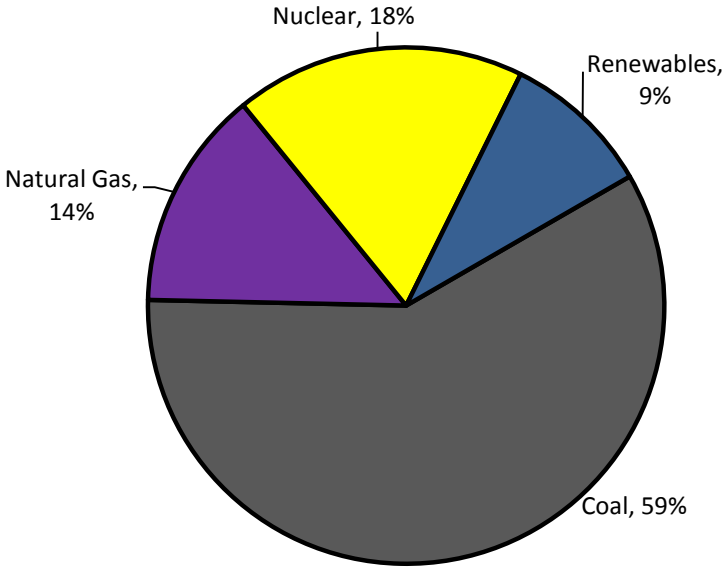
Michigan is well-positioned to make those decisions. We've been working during the last few years and have a pretty good idea of the range of the best solutions for Michigan**.**

First, we know that Michigan will benefit most by eliminating energy waste as our first priority. Then we can look at what plants will be shutting down and what will be replacing those to determine what our future mix of electric plants will look like. We will have less coal and more natural gas and renewables. We will have more natural gas plants for baseload generation as well as for intermittent generation when power from renewables may not be available -- and more renewable energy to help us contain costs. And reducing energy waste will be an increasingly important part of our portfolio.

If you look at where Michigan gets its electricity today, we are still pretty reliant on coal. But we are seeing a contribution from our newer investments – reducing waste and renewables – that is almost as large as the contribution from our nuclear plants. Below are charts showing what our mix looks like when you add in the energy waste reductions, or if you look only at our generation.

Michigan's 2015 Electricity Mix





Now, when we look at the future, what do we know? First off, we know Michigan is growing again. While we should look at all scenarios, we should plan for at least a moderate amount of growth in electric demand.

We know that renewable energy has dropped significantly in cost, making it cost-competitive or close to cost-competitive. We are now hearing firm 20-year price quotes for wind that are less expensive than coal or natural gas. These least-expensive renewables can't provide baseload power – because they only work when the sun is shining or the wind is blowing. That said, we have a unique asset that helps us store power in Ludington, Mich. so we can get more benefit from intermittent power than most states do.

We know that our nuclear production is likely to hold steady until the federal government figures out what do to with the waste, and until we figure out a way to make sure nuclear plant construction can be done cost-effectively.

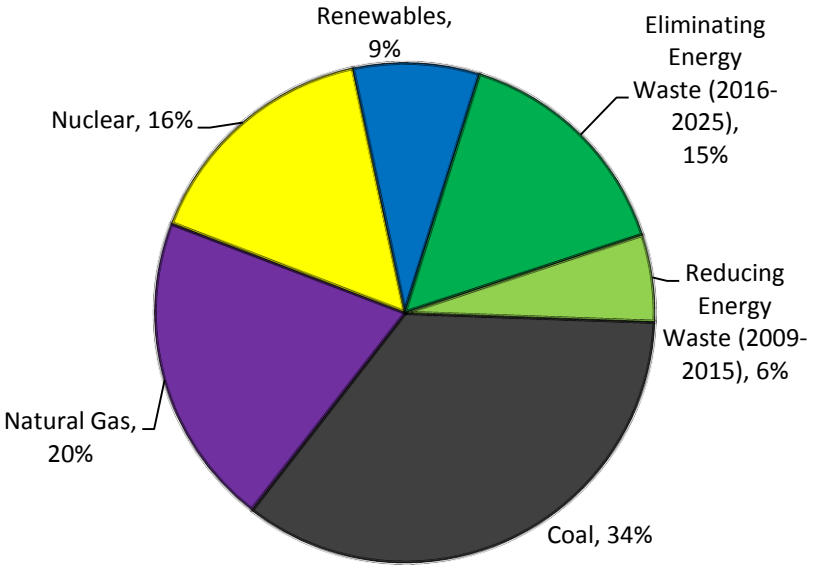
Our new source of baseload power will likely come from natural gas. We know that natural gas prices at more stable lows than we have seen for decades. We know Michigan has the best natural gas storage in the country. We know Michigan has the ability to produce natural gas – with a safety record to be proud of. And we know natural gas prices are very competitive in Michigan – the eighth-lowest in the country. With that said, natural gas also has a history of very volatile fuel pricing – lots of spikes as well as valleys. To protect Michigan residents and business from big price swings, we will need to offset that risk of natural gas prices with power that doesn't need us to pay for fuel – renewables.

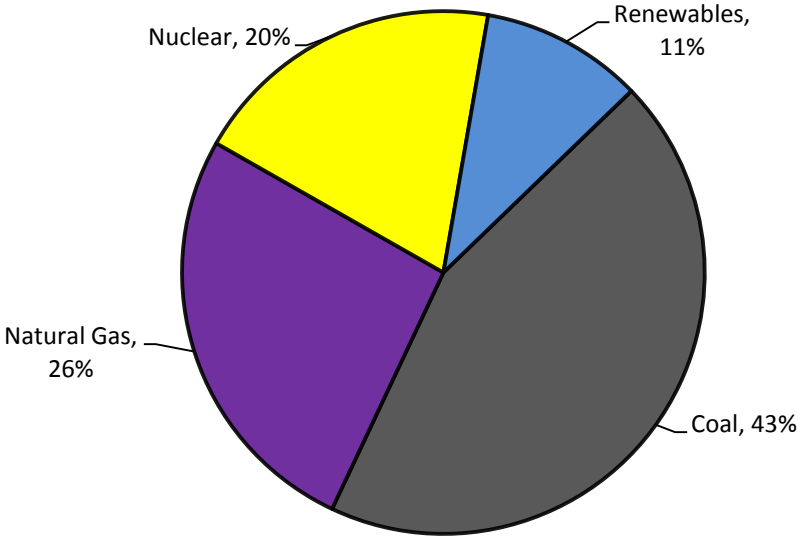
Now, let's get to what we don't know. We don't know if exactly what natural gas will cost – if it will beat renewables, or vice-versa. So starting with what we know, we can try out some possible futures and see what our mix would be if we just built as

much of the cheapest thing as possible to fill our gap. To make it simple, these scenarios do not try to include any new federal regulations change the mix, or hedge our risks, or technological changes.

If natural gas generation is generally less expensive than renewables (onshore wind), then here would be the state's energy mix in 2025 with energy waste elimination shown (top), or the resource mix of only our generation assets (below).

Michigan's Potential 2025 Electricity Mix
(natural gas less expensive than renewables per kWh)

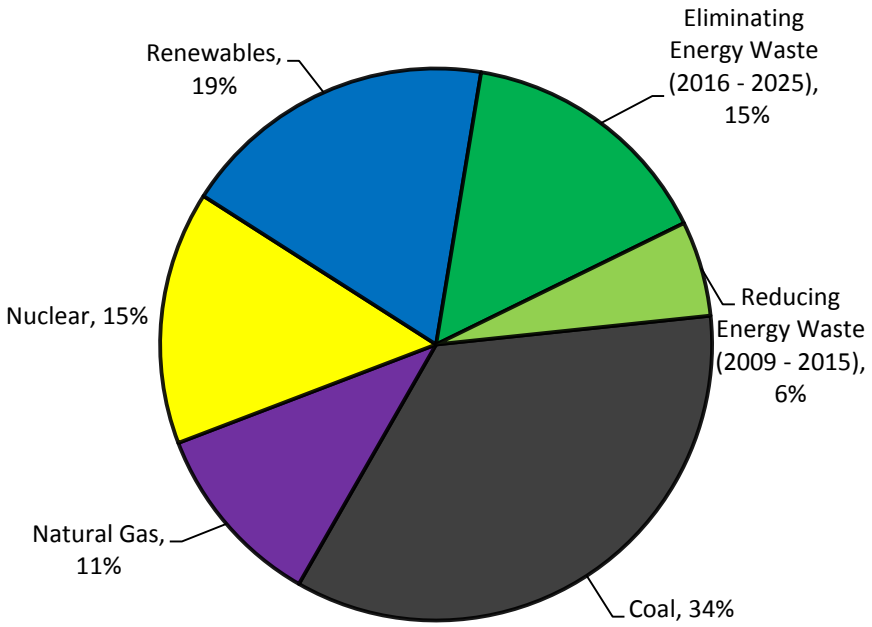


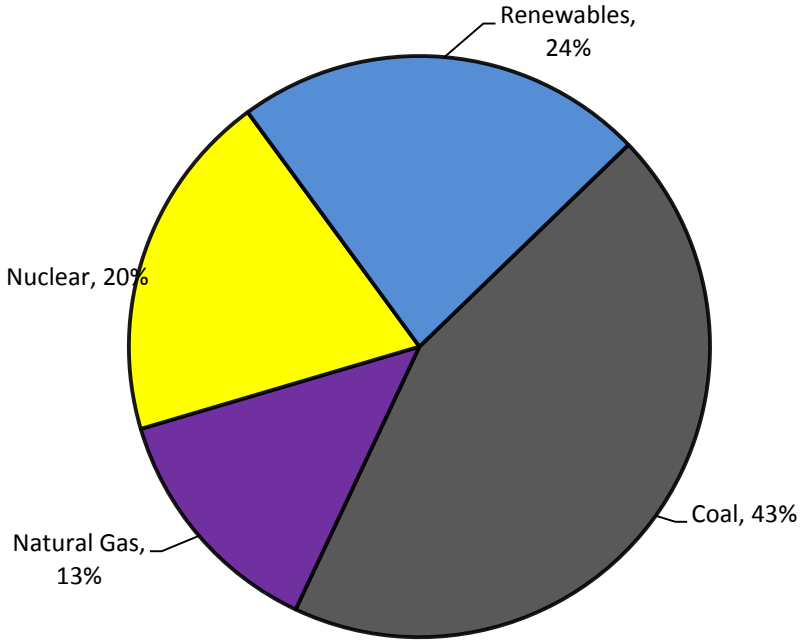


Now let's look at another scenario, where onshore wind is less expensive than natural gas.

Michigan's Potential 2025 Electricity Mix

(natural gas more expensive than renewables per kWh)





If we look at nothing but cost -- and renewables don't beat natural gas on cost -- Michigan would want to get **30 percent of our energy needs in 2025** from our cleanest sources (eliminating waste and renewable energy).

If we look at nothing but cost, and renewables beat natural gas on cost, Michigan would want to get **40 percent of our energy needs by 2025** from our cleanest sources (eliminating waste and renewable energy).

Once you start looking at possible futures, you can see why Michigan's energy goals include the elimination of energy waste and moving to a mix of natural gas and renewables. No matter what the future holds, there is no scenario in which we should not more than double our efforts to reduce energy waste. There are reasonably likely situations in which for financial reasons alone, Michigan would want to more than double our current renewable generation. And you also see why we need to be adaptable, since we don't know which future we will actually come to see.

When other factors are taken into account, including the likelihood of increased regulation on coal and the expected upward pressure on natural gas prices, it is clear that this range – 30 percent to 40 percent renewables plus waste reduction -- represents the <u>least</u> amount of waste reduction and renewable energy that would make sense for Michigan to invest in during the next ten years.

Protecting the Environment

Michigan's energy generation needs to be part of a healthier future by reducing mercury emissions, pollution that creates acid rain, and particles in the air for the health of Michigan.

In Michigan, pregnant women and children can't eat a lot of fish we catch in our lakes and rivers because the mercury in the fish would cause serious health and developmental problems. There also are studies dating back decades that show particulate matter in the air is linked to asthma attacks and hospitalization, especially in children. And as the home of the Great Lakes, Michiganders care about acid rain creation, which is why we showed a lot of early leadership in controlling the pollutants that cause this.

We should not lose sight of the fact that there are other reasons beyond cost and portfolio diversity that these technologies are better for Michigan than what we have today.

Pure Michigan has been such a powerful brand for our state because it promotes the reality of our state. People should come here to enjoy the kind of experiences that make treasured memories.

One nearly-perfect Pure Michigan moment that comes to mind is a kid pulling a huge fish out of a picture-perfect lake. You know how to make that perfect? Having the kid be able to eat that fish that night. That's a part of no-regrets energy decision making.

We need to continue to take environmental priorities into account when making energy decisions. We must work to ensure our energy portfolio should continue to get better over time in controlling pollutants. When you replace a coal plant with a natural gas plant, you have essentially eliminated mercury as a pollutant from that plant. Chemicals that lead to acid rain-- SOx and NOx -- also drop enormously when you replace coal with natural gas. Particulate matter, which is linked to heart and lung diseases – like asthma – is reduced through natural gas use instead of coal, but large reductions come when you rely more on our cleanest sources, like waste elimination and wind or solar power.

Of course, we can't just look at power plants when we discuss energy and the environment.

In charting out Michigan's energy future, we should also explore ways to promote the adoption of advanced transportation fuels such as natural gas, biofuels, hydrogen, and electricity. Passenger cars and trucks, transit buses, fleet delivery vans, refuse and utility trucks, and even heavy duty rigs are now being powered by alternative energy sources and we must continue to examine how smart policies can help encourage their growth as part of Michigan's energy future. We also need to look at emerging technologies that may be able to do more to limit pollution from traditional vehicles.

Michigan has been a leader in developing and testing autonomous and connected vehicles, which would not only help reduce crashes, but can reduce emissions too.

In another arena, yesterday new rules went into place that continue Michigan's tradition of protective and effective regulation of drilling for natural gas and oil, and help us adapt to technological change.

We are pleased at the level of thoughtful interest and exchange this issue is receiving outside of government. The rules that took effect this week regarding high volume hydraulic fracturing were developed while key decision-makers from the state were participating in the first phase of an integrated assessment by the University of Michigan's Graham Institute. That helped us see an opportunity to strengthen our protection of water and give the public more information.

Specifically, we took some steps to require more preparatory work and monitoring of water levels. Baseline water quality samples will also have to be collected, so we will be able to know what the water quality was in the area before the operation started. DEQ will also have to be notified at least 48 hours before the operation starts.

The public will also have more information about when and where high volume hydraulic fracturing is used – permits will now have to contain this information, even if the producer is using the technique on an old well. The pressures and volumes being used will be reported, and operators must post information about the chemical additives used on the FracFocus Chemical Disclosure Registry – which is on the web and anyone can access.

The Graham Institute is now well into the second phase of its integrated assessment and the State will be among the many entities giving public comment to the researchers. The State looks forward to reading the final assessment and considering whether further rule changes or other improvements should be proposed.

Conclusion

Now is the time for Michigan to take charge of its energy future.

We have an agenda before us with great challenges. We have set ambitious goals and there is much to do if we are to meet them.

But one thing we know for sure is that Michiganders do not back away from challenges. Our reinvention is proof that we know how to pull together, innovate and find solutions. We can lead the nation. That's the only way we should approach our energy needs.

I announced in the State of the State address that I plan to create a state agency focused entirely on meeting our energy needs now and long into the future. Later this

month, I will sign an executive order creating that agency so that we can start improving our energy decision-making. We will do that not by replacing the skilled decision-making by our Public Service Commission and Department of Environmental Quality, but by having a single agency dedicated to getting all of our departments and commissions the information and context they need to support our energy priorities. We will be ready to put into place the changes that come about through work with our legislative partners as well as stakeholders. And most of all, we will be ready to adapt and make sure Michigan – and Michiganders -- make the best energy decisions for our future.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the Matter of the Application of	)	
Upper Michigan Energy Resources Corporation	)	
for approval of a Certificate of Necessity	)	
pursuant to MCL 460.6s for	)	Case No. U-18224
Two Reciprocating Internal Combustion Engine	)	
Electric Generation Facilities Located in the	)	
Upper Peninsula of Michigan,	)	
Approval of Certificate(s) of Public Convenience	)	
And Necessity, approval of a Special Contract with	)	
Tilden Mining Company L.C.	)	
and for related accounting and ratemaking	)	
authorizations.	)	

DIRECT TESTIMONY AND EXHIBITS

OF

TERRENCE W. CARROLL

ON BEHALF OF

UPPER MICHIGAN ENERGY RESOURCES CORPORATION

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Terrence W. Carroll. My business address is 231 West Michigan Street, Milwaukee, Wisconsin 53203.

Q. By whom are you employed and what is your position?

A. I am employed by WEC Energy Group Inc. ("WEC") as Major Projects Manager in the Generation Projects Group.

Q. Please describe your educational and business experience.

A. I received a Bachelor of Science Degree in Electrical Engineering from the University of Wisconsin-Madison in 1984. I joined Wisconsin Electric Power Company in 1984, and worked in various capacities, including distribution engineer, customer service engineer, and account manager. From 1996 to 2006, I worked for an affiliate of Wisconsin Electric (Minergy Corp) as regional manager of its biomass energy projects, and plant manager of the Minergy biomass plant in Neenah, Wisconsin. From 2006 until 2011, I was a project development manager in Wisconsin Electric's generation projects group, primarily focused on wind projects. From 2011 to March 31, 2016, I was manager at Rothschild Biomass Co-Generation Facility ("RBCF"). I assumed my current position in April, 2016.

Q. Do you hold a professional license or belong to any professional organizations?

A. Yes, I am a registered Professional Engineer in the state of Wisconsin.

Q. Please describe your responsibilities in your current position.

A. I am currently the Major Projects Manager in Power Generation, overseeing the engineering of the proposed Reciprocating Internal Combustion Engine ("RICE") electric generation facilities.

Q. Have you ever testified in other cases?

A. Yes. I have filed testimony with the Michigan Public Service Commission ("Commission" or "MPSC") in Wisconsin Electric Power Company's ("WEPCo") 2015 power supply cost recovery reconciliation proceeding (Case Number U-17674-R), and with the Public Service Commission of Wisconsin ("PSCW") for construction and operation of the RBCF (Case Number 6630-CE-305) and the Glacier Hills Wind Park

(Case Number 6630-CE-302).

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to support Upper Michigan Energy Resources Corporation's ("UMERC" or the "Company") Application filed in this docket. My testimony will address a number of the filing requirements for a Certificate of Necessity ("CON") as set forth in the Commission's December 23, 2008 Order in Case No. U-15896, as well as other matters relevant to the Application in connection with the construction of and investment in two RICE electric generation facilities in the Upper Peninsula of Michigan ("UP") (together, the "UP Generation Project" or the "Project"). My testimony will:

- Generally describe the proposed sites for the RICE electric generation facilities, including identification of the municipalities in which the facilities will be constructed, and the current use of those sites;
- Describe the RICE electric generation facility technology and major support systems;
- Describe the nameplate capacity, expected availability factor, operating heat rate, expected life, and other significant operational characteristics of the RICE electric generation facilities;
- Describe the resolutions obtained from the two municipalities in which the RICE electric generation facilities will be located;
- Describe all major state, federal, and local permits required to construct and operate the RICE generation facilities;
- Describe the modifications to existing road, rail, or water way transportation facilities not located on the proposed sites, but required for construction and operation of the

RICE electric generation facilities;

- Confirm that there will be no water and sewer infrastructure required for construction and operation other than that located on the proposed sites;
- Describe the basic schedule for development and construction of the RICE electric generating facilities;
- Provide an estimate of the proportion of the construction workforce that will be composed of residents of the State of Michigan;
- Provide an estimate of the capital costs and contracting strategy for the Project; and
- Provide an estimate of the Operation and Maintenance ("O&M") costs for the Project.

Q. Are you sponsoring any exhibits to accompany your testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-__ (TWC-1) – Project Location Map;

Exhibit A-__ (TWC-2) – Negaunee Township Site (Marquette County) Facility Location Map;

Exhibit A-__ (TWC-3) – Baraga Township Site (Baraga County) Facility Location Map;

Confidential Exhibit A-__ (TWC-4) – General Arrangement Drawing –Marquette County facility including potential expansion area;

Confidential Exhibit A-__ (TWC-5) – General Arrangement Drawing –Baraga County facility including potential expansion area;

Exhibit A-__ (TWC-6) – Photos of similar RICE electric generation facilities;

Exhibit A-__ (TWC-7) – RICE Generation Facilities Map;

Exhibit A-__ (TWC-8) – Township of Negaunee Resolution;

Exhibit A-__ (TWC-9) – Township of Baraga Resolution; and

Exhibit A-__ (TWC-10) – Project Milestone Schedule.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

Q. How is the remainder of your testimony organized?

A. The remainder of my testimony is organized in sections as follows:

II. Project and Site Description

III. Electric Generating Technology

IV. Required Permits

V. Required Infrastructure

VI. Construction Schedule and Workforce

VII. Capital Costs and Operation and Maintenance Costs for the Proposed Project Electric Generation facilities

II. PROJECT AND SITE DESCRIPTION

Q. Please generally describe the Project.

A. The Project includes two separate electric generation facilities strategically located in the UP. Each of the facilities will be comprised of multiple, modular RICE electric generating units.

Q. Please describe the proposed sites, including identification of the municipalities in which the facilities will be constructed and the current use of those sites.

A. The proposed RICE electric generation facilities will be located at two sites in the UP; one site in Negaunee Township, Marquette County ("Negaunee Township Site"), and the other site in Baraga Township, Baraga County ("Baraga Township Site"). The general location of these two sites is shown on my Exhibit A-__ (TWC-1), Exhibit A-__ (TWC-

2) and Exhibit A-__ (TWC-3). The Negaunee Township Site will be located on one or more parcels of land located near Eagle Mills Road, southeast of the Lake Superior & Ishpeming Railroad yard. The nearest addressed business to the Negaunee Township Site is the North Country Disposal Transfer Station, located at 83 Eagle Mills Road, Negaunee, Michigan. The Baraga Township Site will be located on one or more parcels of land near the American Transmission Company ("ATC") M38 substation which is located at 16431 Schwalm Road, Pelkie, MI. The current uses of the Negaunee Township Site and Baraga Township Site are described in the testimony and exhibits of Susan M. Schumacher. UMERC has obtained options to purchase parcels of land to locate the generation facility for the Negaunee Township Site and the Baraga Township Site. The parcels in both locations are sufficient to locate the generation facility. Additional parcels have been acquired to provide additional space (i.e., buffer land) between the generation facilities' sites and adjacent properties with different land uses. The company is also working with ATC to obtain easements and options to purchase land for the transmission interconnection facilities.

Q. You mention that UMERC has selected two sites for the RICE electric generation facilities. Why two sites?

A. As further explained in the testimony of Joann Henry, UMERC is proposing two geographically separate sites for transmission stability and reliability reasons. I provide additional reasons for the selection of these sites later in this testimony.

Q. Please summarize your site selection process.

A. In considering potential sites for the generation facilities, primary considerations were: 1) proximity to a transmission interconnection, 2) ability to satisfy the need to support the

UP grid reliability, and 3) proximity to natural gas fuel source. Further, several other factors came into play.

Q. What other factors were considered in the site selection process?

A. First, to facilitate construction, a relatively flat terrain is needed that can accommodate the size of the generation facilities and support systems. The site should also provide space for construction laydown and temporary parking for the construction work force. Additionally, the local roads should be suitable for equipment deliveries and the commuting work force.

Environmental impacts during construction and operation are also important considerations. Finally, a location away from dense residential areas and subdivisions is desirable.

Q. Are there any other factors that you would consider important?

A. It is desirable that the selected site have some space for possible future expansion.

Q. Please describe the electric generation facilities that would be constructed at the Negaunee Township Site, and why the site was selected.

A. The Negaunee Township Site was selected for construction of a 120 to 150 MW RICE electric generation facility. The Negaunee Township Site was selected for the following reasons:

- <u>Close proximity to transmission</u>: The Negaunee Township Site is within 1 mile of two 138 kV transmission line corridors each with multiple transmission lines. It is expected that transmission line and substation interconnection facilities will be constructed to connect the generation facility to the transmission lines located about 1 mile east of the generation facility.

- Local region grid impacts: As indicated in the testimony of witness Joann Henry, ongoing and scheduled MISO studies are expected to confirm that locating the proposed amount of generation at this location will not require significant transmission network upgrades, eliminate the need for ATC's planned Plains/National 138 kV line, and allow for the retirement of the Presque Isle Power Plant.
- Reasonable proximity to natural gas fuel supply: The Northern Natural Gas ("NNG") gas pipeline is located adjacent to the parcel for which UMERC has an option to purchase to locate the generation facilities. Although a final route has not yet been decided, it is likely that most or all of the gas lateral necessary to connect the power station to the gas pipeline will be on Company-owned property.
- Site topography: The site topography is relatively flat and is favorable for facility construction.
- Environmental factors: As described in the testimony of Susan M. Schumacher, minimal environmental impacts are expected from the project.
- Location: This is an industrial park location away from dense residential areas and subdivisions.
- Existing Roadways: Existing roadways in the area to accommodate the construction and operation of the generation facilities.
- Availability of Land: Availability of the land necessary for siting the facility, accommodating construction laydown and parking, and to provide space for possible future expansion.

Q. Please describe the electric generation facilities that would be constructed at the Baraga Township Site, and why the site was selected.

A. The Baraga Township Site was selected for construction of a 35 to 55 MW RICE electric generation facility. The Baraga Township Site was selected for the following reasons:

- Close proximity to transmission: The facility will be located within ½ mile of the ATC 138 kV M38 Substation. Although interconnection studies are in process and have not yet been completed, minimal off-site transmission work is expected to connect the Baraga facility to the transmission system.
- Local region grid impacts: As indicated in the testimony of witness Joann Henry, ongoing and scheduled MISO studies are expected to confirm that locating the proposed amount of generation at this location will not require significant network upgrades and will eliminate the need for the planned Lakota to Winona line rebuild from 69 kV to 138 kV.
- Reasonable proximity to natural gas fuel supply: Less than four miles east of the Baraga Township Site is the NNG gas transmission pipeline. Although a final route has not yet been decided, it is possible that the majority of the gas lateral necessary to connect the power station to the gas transmission pipeline will be in or adjacent to existing road right-of-way.
- Site topography: The site topography is relatively flat and is favorable for facility construction.
- Environmental factors: As described in the testimony of Susan M. Schumacher, minimal environmental impacts are expected from the project.
- Location: This is a rural location away from dense residential areas and

subdivisions.

- Existing roadways: The Baraga Township Site is located adjacent to Michigan State Highway M38 which will provide efficient access to the site during construction and operation.
- Availability of Land: Availability of the land necessary for siting the plant, accommodating construction laydown and parking, and to provide space for possible future expansion.

III. ELECTRIC GENERATING TECHNOLOGY

Q. Can you describe the electric generating technology?

A. Yes. The planned generating technology uses modular RICE-driven electric generators fueled by natural gas. The RICE operates on a four-stroke cycle for the conversion of pressure into rotational energy. Spark ignition of the natural gas fuel in the engine cylinders ignites the natural gas fuel which produces the pressure in the engine cylinders, similar to an automobile engine. The engine's drive shaft turns the attached electric generator which produces electricity. These are heavy duty, medium speed engines that can be started and stopped (or "cycled") quickly and can easily adapt to grid-load variations. Engines operate at constant speeds ranging from about 500 to 900 revolutions per minute ("RPM") depending on the manufacturer's model. The model selected will operate at an RPM level that allows the generator to produce electricity at a frequency of 60 Hz.

Q. Is the RICE electric generation a new technology?

A. No. The internal combustion engine is a mature technology that has been operating in mobile and stationary applications since the 1800s. RICE generators have been used for

backup power for decades due to their fast starting and ramping capabilities, but they are increasingly being favored in utility-scale power generation and distributed power generation applications. The use of large, stationary RICE engines to generate electricity for load following, peaking, and even baseload applications has developed in response to increased supplies of natural gas around the world. As the market has grown, increased competition has driven engine manufacturers to develop models with increased electrical output, higher efficiency, greater operational flexibility, and improved reliability. Utility-scale RICE models include the 9-10 MW and 18-20 MW unit classes. While the largest engine classes are relatively recent developments, they are typically engineered as scaled versions of successfully deployed engine designs. Today, worldwide, there is over 60 GW of installed RICE generation in operation in at least 176 countries. In the United States, 25 utility-scale RICE generation facilities are either in operation or under construction representing over 200 engine units totaling over 1,400 MW in generating capacity. Exhibit A-__ (TWC-7), RICE Generation Facilities Map, prepared by UMERC's engineering contractor, Burns & McDonnell, shows a map of the United States and location of those facilities.

Q, Are there any RICE electric generation facilities in operation in colder Northern climates?

A. Yes, as shown in my Exhibit A-__ (TWC-7), including Alaska, Minnesota and North Dakota.

Q. Is utility-scale RICE electric generation a reliable technology?

A. Yes. Modern utility-scale RICE generators represent a mature, reliable technology. In comparison to gas turbine technologies (including simple-cycle and combined-cycle

configurations), RICE units commonly exhibit more favorable availability and startup reliability statistics. Availability generally refers to the percentage of time a unit is available for operation. When operated and maintained according to manufacturer recommendations, RICE units typically exhibit availability factors of 95% or better, with approximately 99% start reliability. In addition, it is important to consider the advantage of multi-shaft reliability. Since there are often multiple engines at a given location, maintenance outages can be staggered to avoid taking the entire plant offline. Similarly, an unplanned outage event for a single unit will not force the entire plant offline.

Q. How efficient is utility-scale RICE electric generation and how does it compare with other forms of electric generation?

A. Modern utility-scale RICE generators have better full-load heat rates than gas turbines operating in simple cycle configurations, as well as traditional fossil-fueled steam generating plants. This benefit is even more pronounced at part-load operation. There are two ways for a multi-unit RICE plant to achieve 50% plant load. First, half the plant can be operated at full load, which will essentially maintain the full-load heat rate, depending on the auxiliary loads still running. Second, if all reciprocating engines are ramped down to 50% load simultaneously, the resultant net heat rate is still competitive with the full-load heat rate of a gas turbine.

Reciprocating engines can start up and ramp load more quickly than most gas turbines, and can be designed to accommodate start times under 10 minutes. In addition, reciprocating engines are generally more tolerant of altitude and ambient temperature than gas turbines. With site conditions below 3,000 feet and 95°F, altitude and ambient temperature have minimal impact on the electrical output of reciprocating engines,

though the efficiency may be slightly affected.

Q. Are there any similar facilities in the State of Michigan?

A. Yes. A RICE facility is currently under construction by the Marquette Board of Light & Power located at 2200 Wright Street, Marquette, Michigan (the "Marquette Energy Center"). The Marquette Energy Center will utilize 3 RICE engines from Wärtsilä, totaling approximately 50 MW. The Marquette Energy Center is planned to be a dual-fueled facility, capable of using either natural gas or fuel oil.

Q. Are there other similar facilities in places with winter weather like the UP?

A. Yes. There are three facilities in Minnesota, and one in North Dakota, Montana, and Alaska. The North Dakota, Montana, and Alaska facilities are in commercial operation; the Minnesota facilities are currently under construction.

Q. Please describe the physical appearance of the proposed RICE electric generating facilities.

A. All engines will be housed indoors in a building with an exterior view that resembles that of a warehouse. The exhaust system will be located outside the building. After passing through the emission control system and silencer (muffler), the engine exhaust is ducted to the exhaust stack. See my Exhibit A-__ (TWC-6) for photos of similar RICE facilities.

Q. What are the major support systems?

A. The major support systems include the engine cooling system, engine exhaust and emission control system, fuel supply system, and compressed air systems.

Q. Please describe the engine cooling system.

A. Engine cooling is provided by a closed loop system. The system circulates coolant through the engine, then through a forced air cooled radiator bank, then back to the

engine to complete the cycle. The closed loop cooling system consumes a minimum amount of water, typically 2 gallons per engine per week. Each site's radiator bank is sized to accommodate all of each facility's RICE generator sets operating at design conditions. Please refer to the site layout drawings, Confidential Exhibit A-__ (TWC-4) – General Arrangement Drawing – Negaunee Township Site Generation Facility including potential expansion area and Confidential Exhibit A-__ (TWC-5) – General Arrangement Drawing – Baraga Township Site Generation Facility including potential expansion area.

Q. Please describe the engine exhaust and emission control system.

A. The engine exhaust system includes emissions control system components, silencers, and exhaust stacks. The configuration and height of the stacks will be determined based on air dispersion models. Air emission control systems are comprised of selective catalytic reduction ("SCR") using urea to control nitrogen oxide ("NOx") emissions, and an oxidation catalyst to control carbon monoxide ("CO"), volatile organic compounds ("VOCs"), and hazardous air pollutants ("HAPs"). The CO catalyst is installed downstream of the SCR catalyst within the catalytic converter assembly. The chemical reaction in the CO catalyst combines atmospheric oxygen molecules present in the engine exhaust with the CO molecules to yield carbon dioxide ("CO_2"). The presence of a catalyst lowers the activation energy required for the reaction. The catalyst is a series of metal plates such as platinum, palladium, and rhodium, which can be replaced if necessary to ensure good reaction efficiency. The catalytic converter in an automobile uses a similar technology. Particulate matter ("PM") and CO_2 emissions are controlled by good combustion practices. Sulfur dioxide emission controls are not needed as there is

essentially no sulfur in the natural gas fuel.

Q. Please describe the fuel supply system.

A. Natural gas fuel will be supplied to the site via the off-site gas lateral connection to the NNG gas transportation pipeline. The on-site fuel gas supply and conditioning equipment includes overpressure protection, coalescing filters to remove any particulate matter and water droplets from the fuel, and dew point heater(s); all to maintain the desired fuel requirements of the engine.

Q. Will the plant operate on fuel oil?

A. No. The amount of firm gas under contract, as described in the testimony of Russell T. Laursen, will result in sufficient generation capacity to meet UMERCs uncurtailable load so dual fuel is unnecessary.

Q. Please describe the compressed air systems.

A. Compressed air systems are used for engine startup and instrument air. The engines are started by injecting compressed air into the engine cylinders to initiate rotation (essentially being used like a starter motor in an automobile). Once sufficient engine rotation is achieved, the natural gas fuel/air mixture is introduced, spark ignites the mixture, and the engine accelerates to operating speed. A separate instrument air system is made up of air compressors and receivers to provide service to various control and protection devices.

Q. Can you briefly describe additional facility support systems?

A. Yes. There are a number of facility support systems, including:

- The fresh water makeup system, which consists of a fresh water storage tank and associated pumps, piping, valves, and controls to supply makeup water to the engine

cooling system;

- The waste water system, which consists of a holding tank and associated pumps, piping, valves, and controls to provide for equipment drain and process waste water storage;
- The new lubrication oil system, which consists of oil tanks and associated pumps, piping, valves, and controls to provide fresh oil for periodic oil changes;
- The used oil system, which consists of an oil storage tank and associated pumps, piping, valves, and controls to provide for collecting and holding used oil from periodic oil changes;
- The facility fire detection and suppression system, which consists of a dedicated fire water storage tank, pumps, piping, valves, and controls covering all facility areas where combustible materials could be located;
- Generator step up transformers ("GSU") and associated breakers, disconnects and conductors for connection to ATC's substation. GSUs convert the RICE generator's output of 13.8 kV to match voltage required to connect to the ATC transmission substation; and
- The generation facility auxiliary power system, which provides house loads via 13.8 kV transformers supplied by the RICE generators' output, an auxiliary generator or ATC-supplied off site power.

Q. Do you have any information on the expected nameplate capacity, availability, heat rates, and expected life?

A. Yes. We expect to use multiple RICE generating units available in the range of approximately 7 to 20 MW gross output at each generation facility. Combined, both

facilities are expected to have a nameplate capacity of approximately 183 MW. The amount of capacity installed at each site will be determined as transmission studies progress. The full-load heat rate of a single RICE unit is approximately 8,400 Btu/kWh (HHV). With the operational flexibility afforded by multiple modular units, the nominal full-load heat rate for each generation facility is expected to be approximately 8,400 Btu/kWh (HHV) for the majority of power demand scenarios.

Regarding the expected life of the generation facilities, with regular maintenance of the facilities, the useful life of 30 years is expected.

IV. REQUIRED PERMITS AND MUNICIPAL CONSENT

Q. Can you provide information on the permits or permissions required to construct and operate the proposed electric generation facilities?

A. Yes. I will address the major construction and operation permits. Environmental permits are addressed in the testimonies of Laura M. Jarmuz and Susan M. Schumacher. The major construction and operation permits/ permissions within my area of responsibility are;

- Permits required by local units of government;
- County Soil Erosion and Sedimentation Control Permits;
- Local and/or Michigan Department of Transportation ("MDOT") Access to existing road permits;
- Local Site Plan Approvals;
- MDOT permits for oversize/weight loads, i.e. RICE generator set transport (150-300 ton);

In addition, other local permits and permissions may be required, and we will work with

local units of government to comply with those requirements.

Q. In addition to reaching out to local government, have you done any public outreach?

A. Yes, we have made personal contacts with many of the area landowners to give them an overview of the Project. For those landowners that are interested in selling their property to host the RICE generating station, we are discussing a voluntary option to acquire their property as previously mentioned in my testimony.

Q. As part of its approval to construct the RICE generation facilities, has UMERC approached the Township of Negaunee and the Township of Baraga to obtain a resolution from each of the communities to support the construction and operation of the RICE generation facilities?

A. Yes. We have an approved resolution with each of the townships consenting to the construction and operation of the RICE generation facilities. Attached as Exhibit A-___(TWC-8) – Township of Negaunee Resolution and Exhibit A-___(TWC-9) – Township of Baraga Resolution.

V. REQUIRED INFRASTRUCTURE

Q. What is the current status of transmission interconnection studies and expected or required transmission system modifications?

A. Joann Henry's testimony provides information on the status of the transmission studies and system modifications.

Q. What natural gas infrastructure is required for plant construction and operation not located on the proposed site but required for plant construction and operation?

A. The Baraga Township site will require approximately 3.5 miles of natural gas lateral to

be constructed in order to connect the facility to the Northern Natural Gas pipeline. The Negaunee Township site will require less than ¼ mile of a lateral to the Northern Natural Gas pipeline. Witness Russell Larsen will address the specifics of the natural gas lateral.

Q. In your previous discussion of favorable site attributes, you mentioned a favorable characteristic of a desirable site would be the presence of existing roadways. Do you anticipate modifications to existing road, rail, or water way transportation facilities not located on the proposed site but required for plant construction and operation?

A. According to our contractors and suppliers, temporary modifications to roads during construction may be needed due to the weight of the engines. The engines can be shipped either assembled or disassembled, depending on the size of the engines and the requirements of the site and/or transportation logistics. It is anticipated that the engines will ship to a nearby Great Lakes shoreline via barge, and then be unloaded for rail and/or road transport to the project site. Heavy haul transports can distribute the shipping weight so that the maximum load per axle is similar to common over-the-road trucks. Accommodations for heavy haul may include escorts and night transport. A transportation study will be performed to determine probable routes and possible modifications that may be required for existing roads, bridges, tunnels, etc. It is understood that some roads required for site access may be seasonally unavailable. Even if engine deliveries are scheduled around those limitations, those roads may still require upgrades to accommodate occasional shipments of lubricating oil and SCR reagent to support normal plant operation.

MDOT and appropriate local agencies will, therefore, be consulted during the transportation planning process. No permanent modifications to rail or waterway

transportation infrastructure are anticipated.

Q. Who will pay for any transportation system improvements needed for construction and operation?

A. UMERC would pay for such improvements not covered by public funding.

Q. Will there be any water and sewer infrastructure required for construction and operation not located on the proposed site but required for plant construction and operation?

A. No. Water required for the construction and operation of both project sites will be supplied by municipal supplies, new onsite wells, or trucked in by local water supplier. Process wastewater (i.e., water that could contain small quantities of antifreeze, oil, etc.) will be captured by the facility drain system, routed to an underground holding tank, transferred to a tanker truck, and transported to an off-site treatment facility. Sanitary wastewater is expected to be discharged to new on-site septic fields.

VI. CONSTRUCTION SCHEDULE AND WORKFORCE

Q. Please describe the basic schedule for development and construction which include an estimated time between the start of construction and commercial operation of the facility.

A. Upon receipt of final regulatory approvals, full notice to proceed will be given to the equipment suppliers and construction contractors for the generation facilities and to the parties responsible for constructing the electric and gas interconnection facilities. The current plan is to construct both generating facilities in a staggered manner, by two to three months, to allow the construction workforce to transfer between the two sites. The base schedule assumes receipt of MPSC approval by the end of 2017, start of

construction in the spring of 2018, and achieving commercial operation of both generating facilities in the staggered manner, generally mid-year 2019. Electric and gas interconnection facilities are expected to be in service by late 2018. Gas transportation pipeline improvements necessary to provide uninterruptible gas service are expected to be completed before the winter of 2019. Receipt of MPSC approvals earlier in 2017 might result in earlier generating facility commercial operation dates, especially if there is sufficient time to complete meaningful construction work prior to the winter of 2017/2018. Please refer to my Exhibit A-__ (TWC-10) – Project Milestone Schedule.

Q. What are your expectations for the proportion of the construction workforce that will be composed of residents of the State of Michigan?

A. We expect a peak of approximately 100 construction workers at the Baraga Township Site, and approximately 200 at the Negaunee Township Site. We will use a work force composed of residents of Michigan whenever possible and economic. We anticipate that 60% to 80% of the construction workforce will be drawn from local unions and be residents of Michigan.

VII. CAPITAL COSTS AND OPERATION AND MAINTENANCE COSTS FOR THE PROPOSED RICE ELECTRIC GENERATION FACILITIES

Q. How were the capital costs estimated for the Project?

A. Burns & McDonnell has been selected as the Project's engineering contractor. Burns & McDonnell is a leading engineering, procurement and construction ("EPC") contractor in the US for many types of electric generation facilities, including RICE electric generating facilities. They have developed a significant base of expertise having developed many similar projects in the U.S. Using this expertise, they have provided a total installed cost estimate for EPC costs for the generating facility. We prepared the Electric and Gas

Interconnection costs using our experience constructing these types of facilities. We prepared the Owners costs, which includes internal labor, permitting, licensing, and land acquisition costs, based on our experience with other energy projects.

Estimated construction costs consider 183MW of capacity installed at two separate sites. The project cost estimate in 2016 dollars is as follows:

EPC	$225,700,000
Electric & Gas Interconnection	18,000,000
Owners	22,000,000
Total	$265,700,000

The estimated Allowance for Funds Used During Construction ("AFUDC") amount of $11,500,000 results in a total project cost, including AFUDC, of approximately $277,200,000.

Q. How much of the project cost is for air quality control system equipment?

A. The project cost of $277.2 million includes an estimated $15.0 million for air quality control system equipment.

Q. What is UMERC's contract strategy?

A. As previously stated, Burns & McDonnell has been selected as the Project's engineering contractor based on their extensive U.S. experience in the design and installations of RICE electric generation facilities. The engines will be competitively bid and purchased by UMERC. The balance of plant equipment will be competitively bid and purchased by either the Burns & McDonnell or UMERC. Construction and start-up services are also expected to be competitively bid. Equipment procurement, construction and testing and

startup services contracts will be bid and awarded within timeframes to support the planned in-service date of mid-2019.

Q. On the topic of operation and maintenance, please describe how the facilities will be staffed and operated.

A. UMERC has not fully completed the design of the work design for the facilities, but total employment is expected to be fewer than 12 individuals. The RICE technology utilizes a significant level of automation. A central computer receives instrumentation readings from hundreds of sensors that track temperatures, vibration, air and fuel flow, energy production, and other similar metrics. The central computer will perform automatic control and record keeping functions, and provide for a human-machine interface for operator input and monitoring. The facility will be tied, via telecommunications circuitry, to the utility's system control center. Each engine will be capable of being started remotely without local operator input, and will be configured to modulate energy production on a real-time basis in response to electric system requirements. There will be a number of security cameras along the fence line and in key operational areas (e.g., truck unloading, entrances, etc.) with video displayed in the control room.

Q. How will maintenance functions be accomplished at the facilities?

A. Although the final work design has not been completed, it is possible that UMERC will employ a system that is commonly found in RICE facilities in the U.S. This system utilizes an approach where operations personnel perform some regular maintenance duties, in addition to their normal operating duties. A partial list of the operational duties is as follows: conduct system surveillance and inspections, perform manual system monitoring and control actions as needed, coordinate with the utility system control

center, report outages and trouble, facilitate the delivery of parts and supplies, troubleshoot problem equipment, and implement the facilities' safety programs (e.g., lockout/tag out, fall protection, hot work, confined space entry, etc.). Extended maintenance and overhauls are expected to be performed mainly by outside contractors or representatives of the original equipment manufacturers, supplemented by the facilities' operating personnel.

Q. What are the scheduled maintenance requirements of RICE generation facilities?

A. There are several levels of maintenance and service frequency. The list varies by engine manufacturer, but in general, activities can be summarized as follows:

1. Regular maintenance is typically required approximately every 2,000 hours. This might consist of service related to inspections, valve clearances, air filters, oil filters, gas leak checks, spark plugs, ignition coils, and crank shaft alignment.
2. Extended maintenance cycles may range from 4,000 - 6,000 hour intervals. These activities might include the regular maintenance (as listed above), plus more in-depth services that might address charge air cooling, fuel filters, flex connections, turbocharger, and the exhaust system.
3. Overhauls are typically required at long intervals of operation, such as 15,000 - 24,000 hour cycles. In addition to the lists above for regular and extended maintenance, overhauls might address pistons, piston rings, gear box, bearings, cooling water pumps, cylinder linings, crankshafts, cam shafts, fuel/gas system, turbochargers, SCR catalyst, and the electrical system.

Q. Were these scheduled maintenance activities included in your estimate of the RICE generation facilities availability factor?

A. Yes. The availability performance of a typical RICE facility is enhanced by the utilization of the multiple-unit design being proposed. By installing several generating units at each location, maintenance can be performed in a sequence that only impacts one or two generators at a time. As compared to a large solid-fuel fired facility, whose maintenance requires the entire unit's output to be offline for several weeks, a RICE plant can maintain the majority of its output as available even during times of a single unit's service outage.

Q. What are the expected typical annual costs associated with operating the facility including fuel, O&M, and environmental compliance?

A. Burns & McDonnell has provided the non-fuel O&M cost estimate factors based on industry typical dollars-per-kWh costs for Operations and Maintenance, inclusive of labor, consumables, and environmental compliance. These factors were applied to the expected power production of the proposed RICE electric generating facilities. Gas lateral O&M costs were obtained from SEMCO. These annual O&M costs total about $5,300,000 per year.

Property taxes are estimated to total around $5,900,000 per year. The basis for the property tax estimate is discussed in the testimony of James A. Schubilske.

Major maintenance costs, including major engine overhauls and catalyst replacement costs, are expected to be capitalized. These cost estimates were provided by Burns & McDonnell and were based on their industry experience and projected plant operation.

Firm natural gas transportation fees were negotiated with the gas transportation pipeline and are provided in the testimony of Russell T. Laursen.

Estimated annual fuel cost estimates are provided in the testimony and exhibits of Jeff

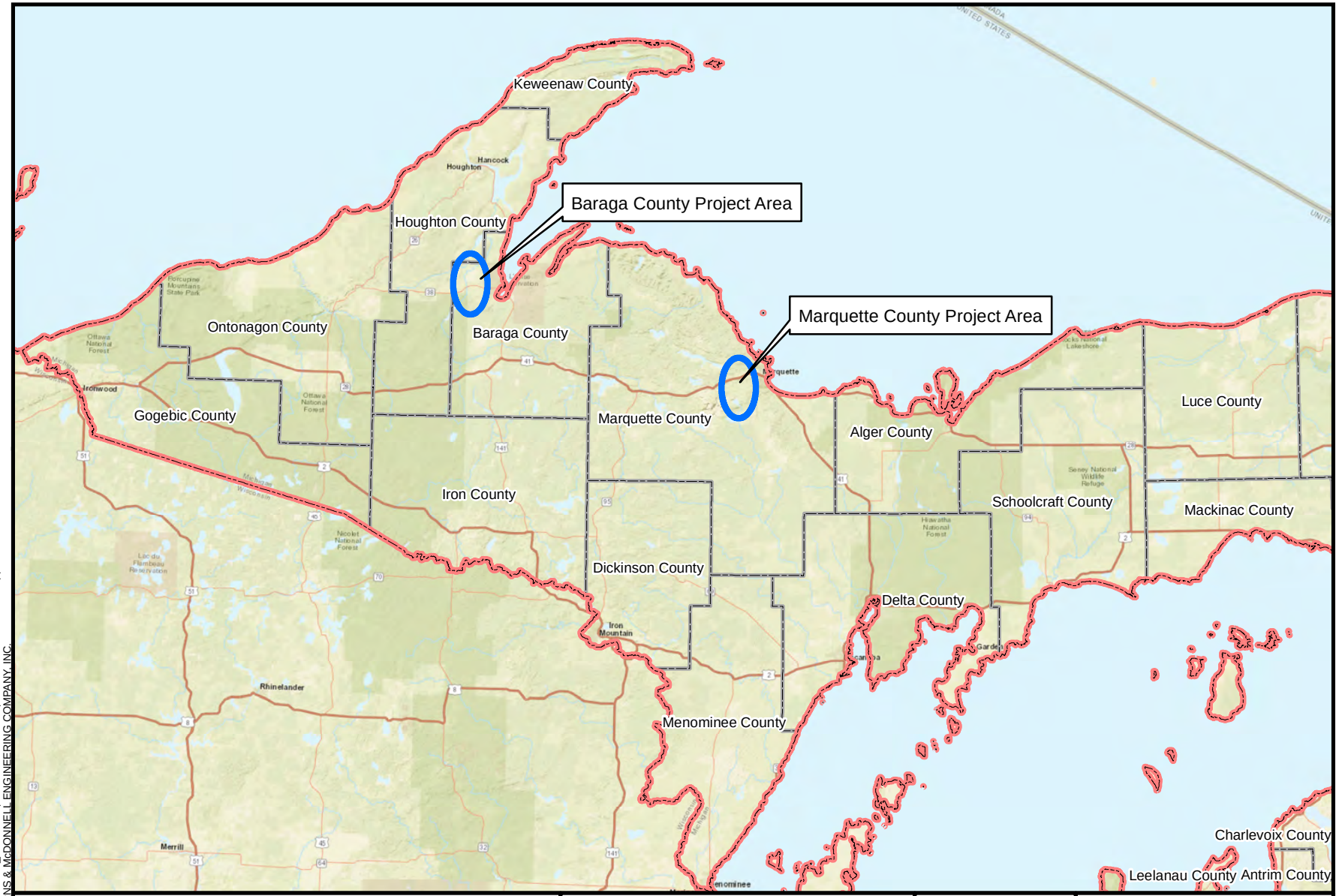
Knitter.

Q. Does UMERC plan to update its cost estimates in this case pursuant to MCL 460.6s(4)(c)?

A. Yes, our present intention is to do so.

Q. Does this conclude your testimony?

A. Yes.



Legend

Approximate Project Locations

0 10 20 40 Miles

N

Source: ABB, ESRI and Burns & McDonnell Engineering.

WEC Energy Group

BURNS McDONNELL

Approximate Project Locations

Upper Peninsula, MI

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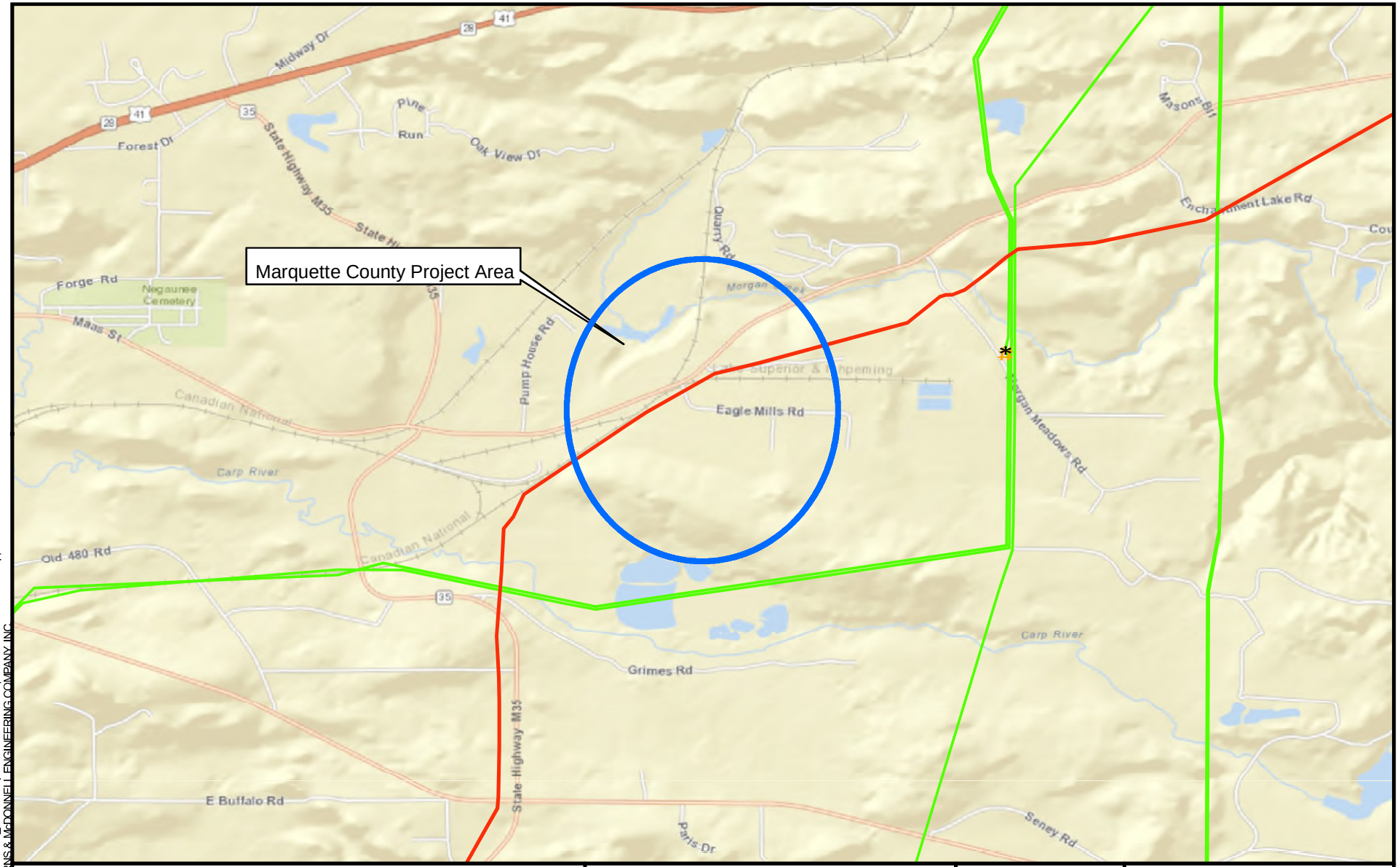
Issued: November, 17 2016



Legend

- Approximate Project Locations
- Substation
- Natural Gas Pipeline
- Transmission Line

0 1,000 2,000 4,000 Feet

Source: ABB, ESRI and Burns & McDonnell Engineering.

WEC Energy Group

BURNS McDONNELL

Approximate Project Locations

Upper Peninsula, MI

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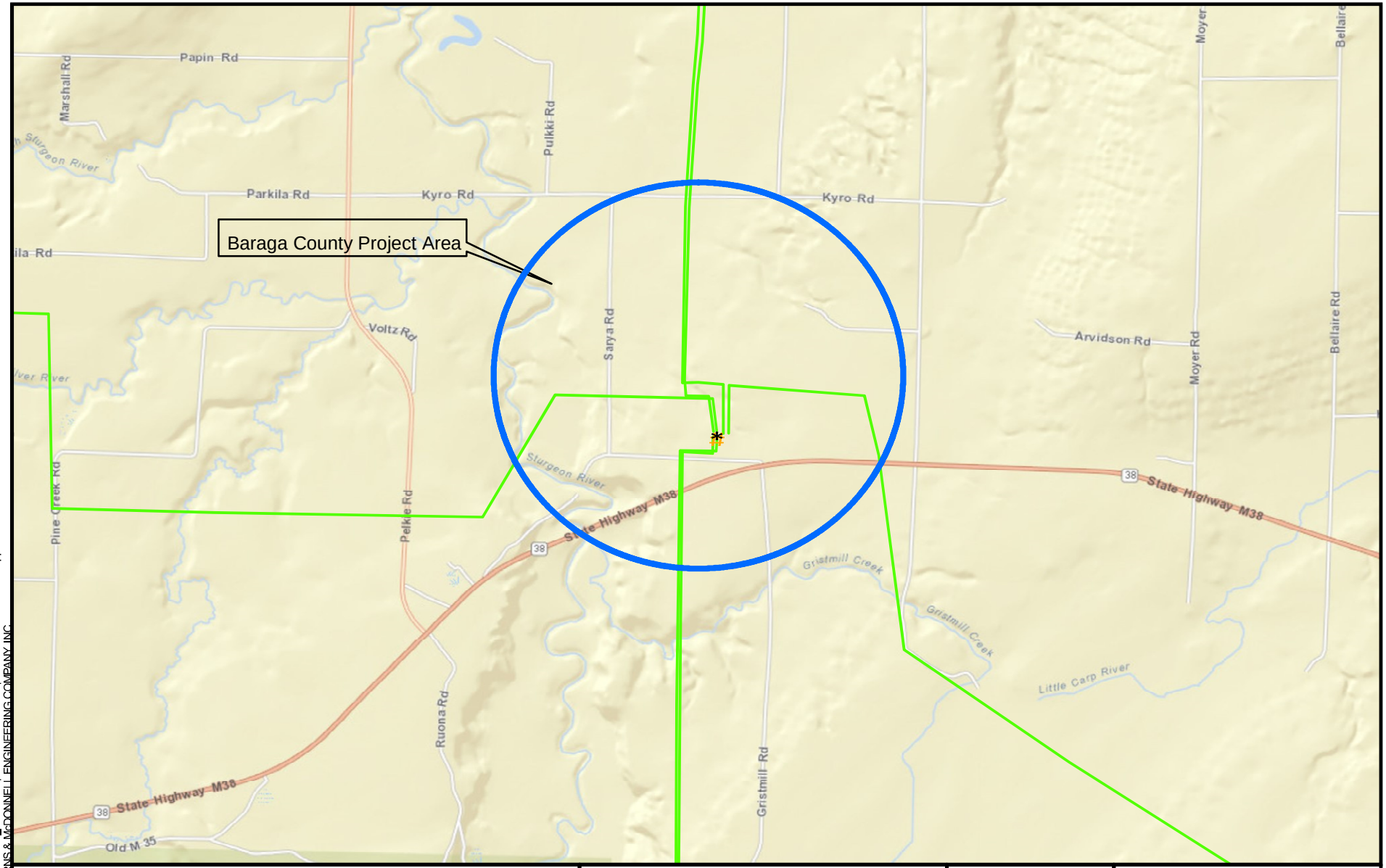

Legend

- Approximate Project Locations
- Substation
- Natural Gas Pipeline
- Transmission Line

0 1,000 2,000 4,000 Feet

Source: ABB, ESRI and Burns & McDonnell Engineering.

WEC Energy Group

BURNS McDONNELL

Approximate Project Locations

Upper Peninsula, MI

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Issued: October, 13 2016

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*** * * * ***

In the Matter of the Application of	)	
Upper Michigan Energy Resources Corporation	)	
for approval of a Certificate of Necessity	)	
pursuant to MCL 460.6s for	)	Case No. U-18224
Two Reciprocating Internal Combustion Engine	)	
Electric Generation Facilities Located in the	)	
Upper Peninsula of Michigan,	)	
Approval of Certificate(s) of Public Convenience	)	
And Necessity, approval of a Special Contract with	)	
Tilden Mining Company L.C.	)	
and related accounting and ratemaking	)	
authorizations.	)	

CONFIDENTIAL

EXHIBIT A-__ (TWC-4)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*** * * * ***

In the Matter of the Application of	)	
Upper Michigan Energy Resources Corporation	)	
for approval of a Certificate of Necessity	)	
pursuant to MCL 460.6s for	)	Case No. U-18224
Two Reciprocating Internal Combustion Engine	)	
Electric Generation Facilities Located in the	)	
Upper Peninsula of Michigan,	)	
Approval of Certificate(s) of Public Convenience	)	
And Necessity, approval of a Special Contract with	)	
Tilden Mining Company L.C.	)	
and related accounting and ratemaking	)	
authorizations.	)	

CONFIDENTIAL

EXHIBIT A-__ (TWC-5)

Tom Darte Energy Center – 25 MW (3 Units)

Pioneer Generation Station – 110 MW (12 Units)

Reciprocating Engine Power Plant Experience

Utility Plants 25MW or Greater

- Over 50% of these facilities were designed by Burns & McDonnell
- Over 1400 MW operating or in construction

BURNS McDONNELL

Negaunee Township
"A Community on the Grow"
42 East M-35elieves
Negaunee, Michigan 49866
Phone: (906) 475-7869
Fax: (906) 475-5071

Township of Negaunee
County of Marquette, State of Michigan

RESOLUTION

At the regular meeting of the Township of Negaunee, County of Marquette, Michigan, held in the Township offices on December 8, 2016, at 6 p.m., prevailing Eastern Time.

PRESENT: William Carlson
Kathleen Carlson
Patrick Moyle
Rachel Sertich
Gary Wommer

ABSENT: None

The following preamble and resolution were offered by Kathleen Carlson and supported by Gary Wommer:

WHEREAS, the Township of Negaunee (the "Township"), a township located in the County of Marquette, Michigan (the "County") has been requested to consent to: (i) the construction and operation by WEC Energy Group, Inc., a Wisconsin corporation, or any of its subsidiaries or affiliates, of an electric generating facility ("Facility") to be located within the Township of Negaunee; and (ii) the construction, location and operation of facilities, including any related natural gas and electric interconnection facilities, within the streets, alleys, highways, and other public places within the Township as necessary for the operation of such Facility and the transmission of energy produced by such Facility; and

NOW, THEREFORE, BE IT RESOLVED THAT:

The Township hereby consents to: (i) the construction and operation by WEC Energy Group, Inc., a Wisconsin corporation, or any of its subsidiaries or affiliates, of an electric generating facility ("Facility") to be located within the Township of Negaunee; and (ii) the construction, location and operation of facilities within the streets, alleys, highways, and other public places within the Township as necessary for the operation of such Facility and the transmission of energy produced by such Facility as described on Exhibit A which is attached hereto and made a part hereof; provided that the construction and operation of such Facilities and the construction, location and operation of facilities within the streets, alleys, highways, and other public places within the Township comply

with all applicable legal and permit requirements. This consent shall not entitle WEC Energy Group, Inc. or its subsidiaries or affiliates to transact a local business within the Township to furnish electricity for light, heat, or power.

AYES: William Carlson
Kathleen Carlson
Patrick Moyle
Rachel Sertich
Gary Wommer

NAYS: None

RESOLUTION DECLARED ADOPTED.

Rachel Sertich
Negaunee Township Clerk

I hereby certify that the attached is a true and complete copy of a resolution adopted by the Board of the Township of Negaunee, County of Marquette, State of Michigan, at a regular meeting held on December 8, 2016, and that public notice of said meeting was given pursuant to and in full compliance with the Open Meetings Act, Act No. 267, Public Acts of Michigan, 1976, and that minutes of the meeting were kept and will be or have been made available as required by said Open Meetings Act.

Rachel Sertich
Negaunee Township Clerk

Exhibit A: Facility Description

WEC Energy Group and its subsidiaries and affiliates (collectively, "WEC Energy Group") has proposed to construct two power stations which will provide a clean source of new generation, allow for the retirement of Presque Isle Power Plant, and eliminate the need for two major electric transmission projects. WEC Energy Group plans to locate one of the generating stations in Negaunee Township.

The Negaunee Township generating station will consist of multiple, natural gas fueled reciprocating internal combustion engine (RICE) driven electric generators. It is currently estimated that seven or eigbt engines will be installed as part of the initial installation, but the final quantity may vary depending on area energy infrastructure needs and the engine manufacturer and size selected. The ideal site will have space to accommodate some future expansion if needed.

The major support systems include the engine cooling system, exhaust and emission control system, fuel supply and compressed air systems.

Several ancillary support systems include auxiliary power generators, fresh water makeup, waste water retention, fresh lubrication oil, waste oil storage and facility fire protection system.

All engines will be housed indoors in a building whose exterior view resembles that of a warehouse. Some systems, such as the engine exhaust is ducted to the exhaust stack. A fan-cooled radiator bank will be located outside.

The engine closed loop cooling system consumes a minimal amount of water, typically 2 gallons per engine per week.

The generating station will be connected to the American Transmission Company electric transmission network and to the area gas transmission pipeline.

The generating station is expected to have a minimum useful life of 30 years.

The project will require Michigan Public Service Commission and Michigan Department of Environmental Quality approvals.

Township of Baraga
County of Baraga, State of Michigan

RESOLUTION #2016-12

At the regular meeting of the Township of Baraga, County of Baraga, Michigan, held in the Township offices on 11 / 09 , 2016, at 6:00 p.m., prevailing Eastern Time.

PRESENT: Amy Isaacson, Michelle Fish, Catherine Wadaga, Jerry Dompier, Glenn Juntunen

ABSENT: None

The following preamble and resolution were offered by Wadaga and supported by Dompier:

WHEREAS, the Township of Baraga (the "Township"), a township located in the County of Baraga, Michigan (the "County") has been requested to consent to: (i) the construction and operation by WEC Energy Group, Inc., a Wisconsin corporation, or any of its subsidiaries or affiliates, of an electric generating facility ("Facility") to be located within the Township of Baraga; and (ii) the construction, location and operation of facilities, including any related natural gas and electric interconnection facilities, within the streets, alleys, highways, and other public places within the Township as necessary for the operation of such Facility and the transmission of energy produced by such Facility; and

NOW, THEREFORE, BE IT RESOLVED THAT:

The Township hereby consents to: (i) the construction and operation by WEC Energy Group, Inc., a Wisconsin corporation, or any of its subsidiaries or affiliates, of an electric generating facility ("Facility") to be located within the Township of Baraga; and (ii) the construction, location and operation of facilities within the streets, alleys, highways, and other public places within the Township as necessary for the operation of such Facility and the transmission of energy produced by such Facility as described on Exhibit A which is attached hereto and made a part hereof; provided that the construction and operation of such Facilities and the construction, location and operation of facilities within the streets, alleys, highways, and other public places within the Township comply with all applicable legal and permit requirements. This consent shall not entitle WEC Energy Group, Inc. or its subsidiaries or affiliates to transact a local business within the Township to furnish electricity for light, heat, or power.

AYES: Dompier, Fish, Isaacson, Juntunen, Wadaga

NAYS: _____

Supervisor, Isaacson declared Resolution #2016-12 adopted.
RESOLUTION DECLARED ADOPTED.

Clerk

I hereby certify that the attached is a true and complete copy of a resolution adopted by the Board of the Township of Baraga, County of Baraga, State of Michigan, at a regular meeting held on Nov. 9, 2016, and that public notice of said meeting was given pursuant to and in full compliance with the Open Meetings Act, Act No. 267, Public Acts of Michigan, 1976, and that minutes of the meeting were kept and will be or have been made available as required by said Open Meetings Act.

Michelle Fish, Township Clerk

Exhibit A: Facility Description

WEC Energy Group and its subsidiaries and affiliates (collectively, "WEC Energy Group") has proposed to construct two power stations which will provide a clean source of new generation, allow for the retirement of Presque Isle Power Plant, and eliminate the need for two major electric transmission projects. WEC Energy Group plans to locate one of the generating stations in Baraga Township.

The Baraga Township generating station will consist of multiple, natural gas fueled reciprocating internal combustion engine (RICE) driven electric generators. It is currently estimated that two or three engines will be installed as part of the initial installation, but the final quantity may vary depending on area energy infrastructure needs and the engine manufacturer and size selected. The ideal site will have space to accommodate some future expansion if needed.

The major support systems include the engine cooling system, exhaust and emission control system, fuel supply and compressed air systems.

Several ancillary support systems include auxiliary power generators, fresh water makeup, waste water retention, fresh lubrication oil, waste oil storage and facility fire protection system.

All engines will be housed indoors in a building whose exterior view resembles that of a warehouse. Some systems, such as the engine exhaust is ducted to the exhaust stack. A fan-cooled radiator bank will be located outside.

The engine closed loop cooling system consumes a minimal amount of water, typically 2 gallons per engine per week.

The generating station will be connected to the American Transmission Company electric transmission network and to the area gas transmission pipeline.

The generating station is expected to have a minimum useful life of 30 years.

The project will require Michigan Public Service Commission and Michigan Department of Environmental Quality approvals.

UMERC UP Generation Project Milestones

	2018												2019											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CON Approval	◆																							
Full Notice to Proceed	◆																							
Commence Construction			◆																					
Natural Gas Interconnection Complete							◆																	
Electric Interconnection Complete									◆															
Commercial Operation - Negaunee																		◆						
Commercial Operation - Baraga																				◆				
Firm Natural Gas Available																						◆		

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the Matter of the Application of	)	
Upper Michigan Energy Resources Corporation	)	
for approval of a Certificate of Necessity	)	
pursuant to MCL 460.6s for	)	Case No. U-18224
Two Reciprocating Internal Combustion Engine	)	
Electric Generation Facilities Located in the	)	
Upper Peninsula of Michigan	)	
Approval of Certificate(s) of Public Convenience	)	
And Necessity, approval of a Special Contract with	)	
Tilden Mining Company L.C.	)	
and for related accounting and ratemaking	)	
authorizations.	)	

DIRECT TESTIMONY OF

JOEL R. GAUGHAN

ON BEHALF OF

UPPER MICHIGAN ENERGY RESOURCES CORPORATION

Q. Please state your name and business address.

A. My name is Joel R. Gaughan. My business address is 231 W. Michigan Street, Milwaukee, Wisconsin 53203.

Q. By whom are you employed and what is your position?

A. I am a Sr. Project Specialist in the Finance department of WEC Business Services LLC ("WBS"), a wholly owned subsidiary of WEC Energy Group, Inc. ("WEC Energy Group"). Respective to this testimony I am testifying on behalf of the Applicant, Upper Michigan Energy Resources Corporation ("UMERC").

Q. Please describe your educational and business experience.

A. I have a Bachelor of Science Degree in Economics from the University of Wisconsin – Madison, and a Master of Science Degree in Economics from the University of Illinois at Urbana - Champaign. I was employed in the Information Systems Department of Wisconsin Gas from January 1986 to May 1989, specializing in statistical analysis and planning model support. In May 1989, I was hired by the Wisconsin Electric Power Company ("WEPCo") where my responsibilities have included various aspects of the development of long-term and short-term forecasts. I assumed my current position in May 2007.

Q. Have you ever testified in other cases?

A. I testified before the Michigan Public Service Commission ("Commission" or "MPSC") in WEPCo's 2015, 2016, and 2017 power supply cost recovery ("PSCR") plan cases (Case Nos. U-17674, U-17912, and U-18148, respectively). I have also testified before the Public Service Commission of Wisconsin in several rate cases and dockets to determine the need for generation capacity.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to support the forecasts used in UMERC's Application filed in this case in connection with the construction and investment of two Reciprocating Internal Combustion Engines ("RICE") electric generation facilities in the Upper Peninsula of Michigan ("UP").

Q. Please describe sales forecasting techniques.

A. Sales forecasting is the process of estimating future sales based on past and present data using a valid forecasting technique.

From least complex to more complex, time series forecasting techniques may range from arithmetic averages, to simple moving averages ("SMA"), to simple exponential smoothing ("SES") models, to trend projections, to autoregressive integrated moving average ("ARIMA") models. All of the aforementioned time series (sequence of data points over a time interval) forecasting models are essentially attempting to predict future values based on previously observed values.

An alternative quantitative modelling technique involves the use of causal or associative models, whereby the forecasted (dependent) variable is related to another (independent) explanatory variable. In this approach, linear regression is used to develop a "line" that recognizes the relationship between the variables and then forecasts the dependent variable based on values of the independent variable(s). For example, residential energy sales (dependent variable) are correlated with weather, price, and energy efficiency (independent, explanatory variables), and future higher or lower temperatures, prices, energy efficiency, etc. may be used in an associative (regression) model to project or forecast future residential energy sales.

Q. Please describe generally how a sales forecast is put together.

A. The first step in any sales forecast is to extract the source (billed or booked energy sales) data and transform this data into a series of data files that are ready for forecasting. These files will generally contain monthly (time series) data about electric, gas, and steam energy sales by forecastable customer groupings. This data is further validated with errors and anomalies "scrubbed". Once the historic energy sales data sets have been created, additional explanatory variables are identified and data collected. These data sets will contain both historical values and future values of the explanatory (weather,

price, economic, energy efficiency, etc.) variables. After transformation and merging of all of the data, the Forecaster will utilize a set of tools (SAS, Metrix ND, EXCEL, or other statistics package) that allow in-depth analysis and modelling of the data. The forecaster will investigate alternative modelling techniques and assess the results. Also, the forecaster will likely do some sensitivity analysis to see the impact of changes of the explanatory variables on the energy sales forecast. These processes are iterated to improve forecast accuracy, as measured by a variety of statistics and forecaster knowledge. Once the forecast(s) have been finalized, they are disaggregated into various forecast hierarchies for revenue projections, fuel cost estimation, and demand forecasts, as required.

Q. Please describe the different geographic areas in which UMERC will provide electric service.

A. UMERC's service territory is divided into two distinct geographic areas. The geographic areas in which UMERC will provide electric service to former Wisconsin Electric Power Company customers is known as the "WEPCo Rate Zone," and the geographic areas in which UMERC will provide electric service to former WPS Corp customers is known as the WPSC Rate Zone.

Q. How did you accommodate these electric service zones for purposes of forecasting?

A. Energy and demand forecasts were prepared for the WPSC Rate Zone and for the WEPCo Rate Zone. I then combined the forecasts and developed a UMERC Total Forecast. I then combined the forecasts and developed a UMERC Total Forecast.

Q. Please describe the UMERC – WPSC Rate Zone energy forecast methodology.

A. The monthly energy forecast is prepared by class i.e. Residential, Small C&I, Large C&I,

etc. The Residential and Small C&I forecasts are based on two models – a Use-per-Customer model and a Customer Count model. The results are multiplied together to get the respective forecasts. Transmission and distribution losses are added to produce a forecast of generation requirements. Energy associated with sales to wholesale customers and deliveries to Retail Access Service ("RAS") customers is not included in this forecast.

The models for Residential and Small C&I Use-per-Customer forecasts are Statistically Adjusted Enduse ("SAE") regression models (i.e., models where the annual energy forecast is a function of the various end-uses: water-heater, refrigerator, dryer, heating and cooling systems). This methodology and the software used, MetrixND, are from Itron. These are multiplicative models incorporating monthly weather, price, economics, and energy efficiency variables. The customer count models are OLS regression models. The Large C&I sales forecast is based on a total sales forecast model. Binary (dummy) variables, which essentially serve as statistical "on/off" switches to represent whether or not a particular condition such as "December" is present or satisfied, and autoregressive (forecast error) terms are included as necessary.

Weather is based on 20 year "normal" weather 1996-2015.

Q. Please describe the UMERC – WPSC Rate Zone demand forecast methodology.

A. The firm demand forecast for the UMERC territory is based on four to five years of monthly historical data for total demand, firm demand and interruptible demand. A monthly average was taken of the historical period. These averages were used for the forecast and the forecast was held flat for the forecast period. Historical energy and demand have been relatively flat and the forecasts reflect this. Demand associated with

sales to wholesale customers and deliveries to Retail Access Service (RAS) customers is not included in this forecast.

Q. Please describe the UMERC – WEPCo Rate Zone energy forecast methodology.

A. The monthly energy forecast is prepared by class i.e. Residential, Small C&I, Large C&I, etc. Transmission and distribution losses are added to produce a forecast of generation requirements. Energy associated with sales to wholesale customers and deliveries to RAS customers is not included in this forecast.

The methodology and software are built into the SAS Forecast Studio package. The models in this software package use a combination of methods including econometric linear regression models, ARIMA, and exponential smoothing. The models incorporate monthly weather, price, economics, and energy efficiency variables.

Weather is based on 20 year "normal" weather 1996-2015.

Q. Please describe the UMERC – WEPCo Rate Zone demand forecast methodology.

A. The total demand forecast is based on an econometric specification taking into account generation level energy, weather, customers, air conditioner saturation rates, and a number of binary (dummy) variables. Load research data relating energy sales to peak demand were used to convert the UMERC energy forecast to a corresponding peak demand forecast. Interruptible and curtailable demands are subtracted from the result to arrive at the forecast of firm demand. Demand associated with sales to wholesale customers and deliveries to RAS customers is not included in this forecast.

Q. Please describe the forecasts as combined to form the UMERC - Total forecast.

A. The energy and demand forecasts for the WEPCo Rate Zone and the WPSC Rate Zone are added together to produce the UMERC-Total forecasts. Beginning in June 2019, with

the scheduled start of commercial operation of the RICE Electric Generation Facilities, all obligations of WEPCo Rate Zone and the WPSC Rate Zone, as well as the load associated with the Tilden Mining Company ("Tilden"), are assumed to be reassigned to UMERC-Total. Since the Tilden load is fully curtailable, its assignment to UMERC adds nothing to the firm demand forecast.

Q. Please summarize the results of these efforts.

A. An annual summary of the annual energy and firm peak demand requirements for the UMERC systems is provided below.

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
UMERC-WE											
	Residential	164,258	165,115	69,423	0	0	0	0	0	0	0
	Small C&I	109,443	108,863	44,011	0	0	0	0	0	0	0
	Large C&I	86,959	86,847	36,182	0	0	0	0	0	0	0
	Street Lighting & Other Retail	2,247	2,247	945	0	0	0	0	0	0	0
	Total Retail	362,907	363,072	150,560	0	0	0	0	0	0	0
	Company Use	1,970	1,970	891	0	0	0	0	0	0	0
	Losses	22,351	22,374	9,290	0	0	0	0	0	0	0
	Total	387,228	387,416	160,740	0	0	0	0	0	0	0
UMERC-WPS											
	Residential	64,629	64,409	27,039	0	0	0	0	0	0	0
	Small C&I	27,165	27,294	11,419	0	0	0	0	0	0	0
	Large C&I	161,114	161,113	67,532	0	0	0	0	0	0	0
	Street Lighting & Other Retail	766	766	325	0	0	0	0	0	0	0
	Total Retail	253,674	253,582	106,315	0	0	0	0	0	0	0
	Losses	12,668	12,664	5,309	0	0	0	0	0	0	0
	Total	266,342	266,246	111,624	0	0	0	0	0	0	0
UMERC-Total											
	Residential	228,887	229,524	229,501	229,030	228,761	228,729	228,697	228,665	228,634	228,602
	Small C&I	136,608	136,157	136,276	136,582	136,927	137,195	137,470	137,746	138,024	138,301
	Large C&I	248,073	247,960	933,923	1,421,156	1,417,950	1,417,870	1,417,789	1,420,914	1,417,628	1,417,548
	Street Lighting & Other Retail	3,013	3,013	3,013	3,013	3,013	3,012	3,012	3,012	3,011	3,011
	Total Retail	616,581	616,654	1,302,713	1,789,781	1,786,651	1,786,806	1,786,968	1,790,338	1,787,297	1,787,462
	Company Use	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970
	Losses	35,019	35,038	51,642	63,428	63,361	63,376	63,391	63,483	63,421	63,436
	Total	653,570	653,662	1,356,325	1,855,179	1,851,983	1,852,152	1,852,329	1,855,791	1,852,689	1,852,869

		Firm Peak Demand		
		UMERC-WE	UMERC-WPS	UMERC-Total
		MW	MW	MW
2017		55	28	83
2018		55	28	83
2019		0	0	83
2020		0	0	83
2021		0	0	83
2022		0	0	83
2023		0	0	83
2024		0	0	83
2025		0	0	83
2026		0	0	83

Q. Does this conclude your testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

****

In the Matter of the Application of	)	
Upper Michigan Energy Resources Corporation	)	
for approval of a Certificate of Necessity	)	
pursuant to MCL 460.6s for	)	Case No. U-18224
Two Reciprocating Internal Combustion Engine	)	
Electric Generation Facilities Located in the	)	
Upper Peninsula of Michigan	)	
Approval of Certificate(s) of Public Convenience	)	
And Necessity, approval of a Special Contract with	)	
Tilden Mining Company L.C.	)	
and for related accounting and ratemaking	)	
authorizations.	)	

DIRECT TESTIMONY AND EXHIBITS

OF

JOANN HENRY

ON BEHALF OF

UPPER MICHIGAN ENERGY RESOURCES CORPORATION

Q. Please state your name and business address.

A. My name is Joann Henry. My business address is 333 W. Everett Street, Milwaukee, Wisconsin 53203.

Q. By whom are you employed and what is your position?

A. I am employed by WEC Energy Group Inc., ("WEC Energy Group") as a Market Strategist.

Q. Please describe your educational and business experience.

A. I received a Bachelor of Science Degree, with a major in Mechanical Engineering, from Marquette University in 1980. In 1998, I received a Master of Science Degree in Engineering Management from the Milwaukee School of Engineering.

I have been employed by WEC Energy Group and its subsidiaries for 34 years, working in a number of positions in the Customer Service and Wholesale Energy and Fuels areas. For the last six years, I worked as a Market Strategist in Wholesale Energy and Fuels supporting transmission policy.

Prior to joining WEC Energy Group, I was a design engineer for a construction equipment manufacturer in Wisconsin. In 1982, I was hired by the company as an Engineer-in-Training and moved into various engineering roles within the company. In 1990, I was promoted to Commercial Market Manager with responsibilities for developing energy management programs for specific market segments. I moved to the role of Manager for the Integrated Development Team in 1993, where my responsibilities included: electric and gas service design, mapping, business process improvement and communication, and various meter reading and service functions. In 2001, I was promoted to Director of Field Operations with responsibilities for the meter shop, meter reading, meter service, field collections in both Wisconsin and Michigan, the expansion of drive-by meter reading, and implementation of automated meter reading throughout the service territory. In 2010, I moved to Wholesale Energy and Fuels with responsibility for managing financial instruments used to hedge congestion in the Day-Ahead Market. I also represented the company on various Midcontinent Independent System Operator, Inc ("MISO") stakeholder committees. In 2011, I became a Market Strategist with primary responsibility for representing the company on MISO stakeholder committees and

American Transmission Company ("ATC") customer forums involved with transmission planning policy and proposed transmission projects.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to support the Upper Michigan Energy Resources Corporation ("UMERC") Application filed in this docket. My testimony will:

- Explain our determination of primary sites for the generation included in the MISO generator interconnection request;
- Describe the impacts of installing this electric generation on MISO approved and proposed transmission projects;
- Provide status of the interconnection request to MISO for electric generation in the Upper Peninsula of Michigan and provide information on estimates of interconnection costs to the ATC transmission system;
- Provide status of our request to MISO for an Optional Interconnection Study; and
- Explain the generator interconnection timeline.

Q. Are you sponsoring any exhibits to accompany your testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-__ (JH-1) – MISO Presque Isle Power Plant Generation Replacement Screening Study;

Exhibit A-__ (JH-2) – ATC Upper Peninsula Generation Integration Screening Study;

Exhibit A-__ (JH-3) – Executed Optional Study Agreement;

Confidential Exhibit A-__ (JH-4) – Attachment A to Appendix 5 of the Optional Interconnection Study Agreement;

Exhibit A-__ (JH-5) – MISO Generator Interconnection Feasibility Study results for

J703;

Exhibit A-__ (JH-6) – MISO Generator Interconnection Feasibility Study results for J704.

Q. Has an interconnection request been submitted to MISO for the Reciprocating Internal Combustion Engines ("RICE") electric generation facilities in the Upper Peninsula of Michigan?

A. Yes. An interconnection request was submitted to MISO on September 2, 2016 and was validated as complete on September 8, 2016.

Q. What is the current status of the MISO interconnection request?

A. MISO notified us with the assigned project numbers of J703 for the Negaunee Township Site, and J704 for the Baraga Township Site. The MISO Generator Interconnection Feasibility Study ("Feasibility Study") results for each interconnection request and associated potential points of interconnection were posted to the MISO website on October 14, 2016, and are my Exhibits A-__ (JH-5) and A-__ (JH-6). The Feasibility Study results determine milestone payments needed for entry into the MISO Definitive Planning Phase ("DPP") study cycle which is scheduled to commence in February 2017. All technical documentation and payments required for entry to the MISO February 2017 DPP study cycle were submitted to MISO on December 23, 2016. On January 3, 2017, MISO confirmed that both generation projects, J703 and J704, will be included in the February 2017 DPP.

Q. How did UMERC determine the location and amount of generation at each location?

A. Over the last several years, both MISO and ATC have performed indicative studies to

estimate the amount of generation and/or transmission upgrades needed to meet load in the Upper Peninsula of Michigan ("UP") and allow retirement of local power plants. Here is a description of those studies:

- At MISO's September 26, 2014 West Technical Studies Task Force (WTSTF) meeting, MISO presented the "Presque Isle Power Plant Generation Replacement Screening Study," which is my Exhibit A-__ (JH-1). The study resulted from an August 29, 2014 request to MISO by the Michigan Public Service Commission ("MPSC") to study various scenarios to determine the minimum amount of generation, sited at Tilden substation, needed in the UP to maintain reliability of the transmission system and, allow Presque Isle Power Plant ("PIPP") to retire. The results for the defined 'probable future scenarios' showed minimum Tilden Generating Plant capability ranging between 15 – 140 MW depending on the magnitude of a single generator contingency and the dispatch of the HVDC at Mackinaw.
- On September 9, 2016, ATC posted to their website, an Upper Peninsula Generation Integration Screening Study, my Exhibit A-__ (JH-2), that identifies potential locations and indicative amounts of generation that the transmission facilities in Michigan's UP can accommodate for steady-state, single and multiple contingencies along with other base assumptions. The preliminary results for the multiple contingency screening indicated the maximum amount of generation, or potential generation amounts, that could be placed at various locations without triggering the need for significant transmission network upgrades. We are proposing generation at a maximum of 60 MWs at the Baraga Township (M-38

substation) Site, and a maximum of 190 MWs of generation at the Negaunee Township (New 138kV substation) Site, both of which are below the potential generation amounts identified for these locations. Final amounts for the generation at each site will be determined from the Optional Interconnection study results.

The generation locations and capacities were selected to achieve the following objectives: 1) meet the requirements of the Special Contract for Tilden Mining Company; 2) eliminate the need for $373 million in major transmission network upgrade expenditures, including the MISO Board-approved transmission project "Plains to National 138 kV transmission" project, and the proposed project in the MISO project database, the "Lakota to Winona line rebuild from 69 kV to 138 kV", 3) minimize the costs to interconnect the electric generation facilities to the electrical grid, and 4) to allow for the retirement of PIPP.

Q. What was the size of the generation interconnection request to MISO?

A. The generation interconnection request is 190 MW at the Negaunee Township Site and 60 MW at the Baraga Township Site.

Q. Why did you select those sizes?

A. MISO's generator interconnection process allows the interconnection customer to only decrease the MW output of the generation facility prior to entering the DPP, so we selected generation sizes which would provide sufficient flexibility until additional studies are performed. Once the Interconnection Customer, UMERC, enters the DPP, the only modification permitted is a change in the technical parameters associated with the generating facility technology.

Q. How will you determine the specific MW output of the generation facilities?

A. The specific MW output will be based on generation needed to meet requirements of the Special Contract for Tilden Mining Company and the results of an Optional Interconnection Study that we have requested from MISO. UMERC expects the total MWs for both sites to be less than 190 MWs.

Q. What is the Optional Interconnection Study that you have requested MISO to perform?

A. The Company[1] requested MISO to perform an Optional Interconnection Study because it was necessary to determine the number of modular generators to be installed at each site. My Exhibit A-__ (JH-3) is the executed Optional Interconnection Study Agreement, and Attachment A which is the confidential attachment to the Optional Interconnection Study Agreement and labeled as my Confidential Exhibit A-__ (JH-4). In addition, the purpose of the study is to perform the necessary System Impact Study and Facilities Study, in advance, such that the timing for the DPP of the MISO generator interconnection process is significantly reduced. The general objective for the scope of the Optional Interconnection Study includes obtaining results to identify the number of modular generators that can be located at the point of interconnection for each of the two generating facility sites to minimize network upgrades associated with the generation interconnection, as well as to expedite the process.

Q. What is the status of your Optional Interconnection Study request?

A. The Optional Interconnection Study Agreement has been executed with MISO. MISO issued a Request for Proposal and awarded ATC the contract to perform the study. The

1 Because UMERC had not yet been formed at the time the interconnection request was made with MISO, the request was made by Wisconsin Electric Power Company ("WEPCo"). Per the MISO process, the request will be transferred from WEPCo to UMERC.

study agreement between MISO and ATC has ATC performing the work on the requested timeline.

Q. How does the Optional Interconnection Study fit with MISO's Generator Interconnection process?

A. The Optional Interconnection Study will be performed in parallel with the processing of our interconnection request.

The scope of the Optional Study includes the needed studies (i.e., System Impact Studies, Facilities Studies – Interconnection Facilities and Network Upgrades) required in the MISO DPP. Completing the studies prior to entering the DPP will expedite the timing in the MISO DPP and allow for any necessary adjustments that may be needed. The Optional Study will also provide planning level estimates on the interconnection and network upgrade costs for the Baraga and Negaunee Township sites.

Q. Does the Optional Interconnection Study provide other benefits?

A. Yes. Per MISO's Attachment X tariff for Generator Interconnection Procedures (GIP), the Optional Interconnection Study will identify the Transmission Owner's Interconnection Facilities, System Protection Facilities, Distribution Upgrades, Generator Upgrades, Common Use Upgrades, and the Network Upgrades, and the estimated cost required to provide transmission service or Interconnection Service.

Q. What is the timeline of MISO providing the results of the Optional Interconnection Study?

A. The results from the Optional Interconnection Study will be relayed in phases. The first phase is focused on providing information needed to determine the maximum MW output value, based on the number of modular units for each site, which is key technical data

required to enter the MISO DPP. The second phase is focused on using the results in the System Impact Studies, subject to any necessary adjustments, for the DPP. The third and final phase is focused on providing engineering quality Facilities Studies by April 2017.

Q. Will the installation of generating facilities at the Baraga Township Site eliminate the need for the Operating Guide that utilizes reconfiguration of the Western UP for planned outages?

A. The decision to eliminate the Operating Guide will ultimately be determined by MISO and ATC.

Q. What is the status of the interconnection request to MISO?

A. As indicated earlier in my testimony, MISO determined the interconnection request was complete on September 8, 2016, which establishes an initial queue position. MISO performed the Feasibility Study for each generator interconnection request based on this initial queue position. The results of the Feasibility Study are used to determine the milestone payment necessary to enter the DPP, and are my Exhibits A-__ (JH-5) and A-__ (JH-6). The company submitted the milestone payment and study deposit, as well as other technical documentation to meet the entry requirements and MISO confirmed that the interconnection projects are included in MISO's February 2017 DPP.

Q. Please provide an estimate of interconnection costs to the ATC transmission system

A. The System Impact Study (SIS) portion of the Optional Study will provide high-level planning cost estimates of the interconnection costs.

Q. How are Network Upgrades funded under the MISO tariff?

A. If identified projects are already included in the MISO Transmission Expansion Plan (MTEP), the Interconnection Customer can request that the project be expedited to meet

the in-service date for the generation facility. The Interconnection Customer is responsible for the costs associated with expediting the project. Per MISO's tariff, Section 12.2.3 of Attachment X, the Interconnection Customer is entitled to transmission credits for any expediting costs paid associated with Network Upgrades included in MTEP. If the identified Network Upgrades needed to alleviate transmission constraints are not included in MTEP, MISO will work with ATC and UMERC to identify the necessary transmission upgrades. As the Interconnection Customer, UMERC will be required to fund the entire cost of the identified transmission upgrades. If there are additional generator projects in the area and, MISO determines that all generation projects should be studied as a group, any identified Common Use Upgrades for the study group will be cost allocated based on the pro rata share of the MW impact from each project on the constraints alleviated by the Common Use Upgrade. A Common Use Upgrade is needed for the interconnection of multiple interconnection customers' generating facilities and is the shared responsibility of those interconnection customers.

Q. Will UMERC receive a refund of the amounts it pays for the network upgrades?

A. Yes. After commercial operation of the Network Resource generating facilities at the Baraga and Negaunee Township Sites in MISO, UMERC will be refunded its payments for the Network Upgrade construction costs. The costs are recovered through the ATC transmission service revenue requirement component of the MISO transmission rates for the ATC Pricing Zone.

Q. What is the timeline for the Generator Interconnection Agreement (GIA)?

A. The timeline for the GIA is as follows:

- Submitted required documentation and payments to enter the MISO February

2017 DPP on December 23, 2016;

- Start MISO February 2017 DPP process on February 2, 2017;
- Finalize System Impact Studies and Facilities Studies by July 2017;
- Work with MISO and ATC to finalize the GIA and file with FERC in the September 2017 timeframe.

Q. How will the interconnection studies incorporate PIPP retirement?

A. In the optional study scope, MISO has been asked to perform the interconnection studies with the proposed generation, at Baraga and Negaunee Township Sites, as a replacement for PIPP. The Generator Interconnection Agreements will be filed as conditional on the retirement of PIPP.

Q. Does this conclude your testimony?

A. Yes.

Presque Isle Power Plant Generator Replacement Screening Study

Objective

Prepare generic generation alternatives to address reliability issues caused by Presque Isle Power Plant opting to retire. Specifically determine the minimum amount of new (generic) generation that will maintain a reliable transmission system in the Upper Peninsula in the near-term planning horizon, according to the study scenarios requested by the Michigan PSC (MPSC) on August 29, 2014:

- Generation sited at Tilden 138 kV substation
- Evaluate for TPL Events: P1, P3 and P7 on shoulder and peak; and selected P6 during shoulder when maintenance is likely to occur (Planning events are defined in Appendix B of this report)
- 2019 System Topology with following projects modeled in-service
    - Benson Lake SVC
    - Arnold 345/138 kV Transformer
    - Holmes-Old Mead Road 138 kV Project
- Straits HVDC Flow Control: 30 MW South to North (reversed from normal, assisting UP)
- No other new generation in area

MPSC Case Definitions						
	Case 1	**Case 2**	**Case 3**	**Case 4**	**Case 5**	**Case 6**
2019 Load Profile	Summer	Shoulder	Summer	Summer	Shoulder	Summer
Tilden Mine Load	100%	100%	100%	100%	100%	20%
Empire Mine Load	20%	100%	100%	0%	0%	20%

Disclaimers

- This is an ad hoc informational study performed at the request of the Michigan PSC.
- The study results are not an indication of number of Presque Isle units needed to remain on SSR contract to maintain system reliability.
- This evaluation is for maintaining reliability only and provides no indication of the costs, economic viability, or other benefits of the addition of new generation.
- Tilden generation is sized to achieve a level of reliability comparable to the Presque Isle SSR contract. Additional generation and/or transmission upgrades would be required to mitigate reliability needs beyond the status quo.
- Ability to site generation and get adequate fuel supply have not been determined. If a generation option is to be pursued, it must go through MISO generation interconnection process. Generator interconnection related transmission upgrades may be required.

Study Results

The table below shows the generation required at Tilden substation assuming four equally sized generating units and the most limiting contingency type for the different scenarios requested by the MPSC. Plant configurations with fewer than four generating units would require greater plant capacity. Additional results for different plant configurations are available in Appendix A.

Requested Results: 2017 Topology after Holmes-Old Mead Road 138 kV Project in-service and Straits HVdc flow is assisting at 30 MW from South to North					
Case	**2019 Load Profile**	**Tilden Load % of max**	**Empire Load % of max**	**Minimum Generation at Tilden**	**Limiting Contingency Type**
Case 1	Summer	100%	20%	355	TPL Event: P3
Case 2	Shoulder	100%	100%	270	TPL Event: P6
Case 3	Summer	100%	100%	355	TPL Event: P3
Case 4	Summer	100%	0%	355	TPL Event: P3
Case 5	Shoulder	100%	0%	5	TPL Event: P6
Case 6	Summer	20%	20%	275	TPL Event: P3

The table below shows the generation required at Tilden substation assuming four equally sized generating units and the most limiting contingency type for probable future scenario (beyond 2020) – after North Appleton to Morgan Project is in service and Straits HVdc flow is 30 MW from North to South (normal). Plant configurations with fewer than four generating units would require greater plant capacity. Additional results for different plant configurations are available in Appendix A.

Probable Future scenarios: After North Appleton-Morgan 345+138 kV Project in-service and Straits HVdc flow is normal at 30 MW from North to South					
Case	**2019 Load Profile**	**Tilden Load % of max**	**Empire Load % of max**	**Minimum Generation at Tilden**	**Limiting Contingency Type**
Case 1	Summer	100%	20%	120	TPL Event: P3
Case 2	Shoulder	100%	100%	160	TPL Event: P6
Case 3	Summer	100%	100%	250	TPL Event: P3
Case 4	Summer	100%	0%	95	TPL Event: P3
Case 5	Shoulder	100%	0%	80	TPL Event: P6
Case 6	Summer	20%	20%	0	

Additional Key Assumptions used for the study

- **Modeling**
  - Models originated with MTEP14 series 2019 shoulder and summer peak models
  - Transmission
    - Submitted for recommendation in MTEP15 Plains-National 138 kV line is not modeled
    - Benson Lake SVC is packaged with the North Appleton-Morgan Project and is yet to be approved by the Public Service Commission of Wisconsin
    - North Appleton-Morgan Project was included as a MTEP Appendix A Project for the probable future scenarios. Its drivers are independent of the Presque Isle retirement.
    - Tilden 138 kV straight bus is rebuilt as a ring to accommodate generator interconnection
  - Load
    - Flat load growth: there is no allowance for load growth beyond 2019
    - 50/50 summer peak forecast: Demand on a hotter than average summer peak would exceed the modeled load
    - No additional UPMI mine development is forecasted
  - Generation
    - Tilden Generating Plant would be multiple generating units
    - Marquette Municipal Plant is online, status quo 55 MW in all models
    - Tilden Plant capacity factor: Tilden would be available and online in Shoulder and Summer Peak
    - Escanaba Steam Plant is retired
    - West Marinette Plant is offline in all models
    - No additional UPMI generator retirements
    - No additional queue generation is modeled
- **Analysis**
  - Generator outlet constraints are ignored for high generation and low mine load scenarios. Additional Generator Interconnection transmission upgrades could be required.
  - A separate project could be needed to mitigate local reliability needs in the Escanaba area independently
  - Only P1, P3, and P7 events were considered on peak, and additionally P6 events on shoulder.
  - An option to shed load for P7 events was considered to determine minimum generation required at Tilden.
  - Post-contingent loadings are calculated on the Emergency Rating.

MISO

APPENDIX A: Additional Plant Configuration Scenarios

Minimum Tilden Plant Sizes: NERC TPL limits under various Empire and Tilden mine demand scenarios

Timing	MPSC requested case definitions				Results with flow control assisting (30 MW South-to-North)			Results with flow control normal (30 MW North-to-South)		
	Case	2019 Season	Tilden Load % of peak	Empire Load % of peak	Minimum Tilden Generating Plant, assuming worst single generator contingency is x% of plant total 50%	33%	25%	Minimum Tilden Generating Plant, assuming worst single generator contingency is x% of plant total 50%	33%	25%
After Holmes-Old Mead Road 138 and Before North Appleton-Morgan 345+138	case 1	Summer	100%	20%	535	400	355	655	490	435
	case 2	Shoulder	100%	100%	380	285	270	500	375	335
	case 3	Summer	100%	100%	535	400	355	655	490	435
	case 4	Summer	100%	0%	535	400	355	655	490	435
	case 5	Shoulder	100%	0%	5	5	5	120	90	80
	case 6	Summer	20%	20%	410	310	275	530	400	355
					Requested study scenarios			Less likely intermediate scenario		
After North Appleton-Morgan 345+138 (2020+)	case 1	Summer	100%	20%	60	45	40	180	135	120
	case 2	Shoulder	100%	100%	100	100	100	160	160	160
	case 3	Summer	100%	100%	250	190	170	370	280	250
	case 4	Summer	100%	0%	20	15	15	140	105	95
	case 5	Shoulder	100%	0%	5	5	5	120	90	80
	case 6	Summer	20%	20%						
					Less likely future scenario			Probable future scenarios		

Multiple units at plant are required. In table above, 50% is two units, 33% is three units, and 25% is four units.

APPENDIX B: Planning Events according to NERC Standard TPL-001-4

Contingency Category and Description	Contingency Sub-category		Initial Condition	Specific Event Description	Interruption of firm service allowed?
	New TPL-001-4	Legacy TPL-001-1			
P0 no contingency	P0	A	system intact	none	
P1 single contingency		B0	system intact	loss of an element without a fault	No
	P1.1	B1		fault generator	
	P1.2	B2		fault transmission circuit	
	P1.3	B3		fault transformer	
	P1.4			fault shunt device	
	P1.5	B4		block single dc pole	
P3 multiple contingency	P3.1	C3	planned or forced outage of generator unit (< 6 months) followed by system adjustments	fault generator	No
	P3.2	C3		fault transmission circuit	
	P3.3	C3		fault transformer	
	P3.4			fault shunt device	
	P3.5	C3		block single dc pole	
P6 multiple contingency (single, adjustment, single)	P6.1	C3	planned or forced outage of non-generator facilities (< 6 months) followed by system adjustments	fault transmission circuit	Yes
	P6.2	C3		fault transformer	
	P6.3	C3		fault shunt device	
	P6.4	C3		block single dc pole	
P7 multiple contingency (common structure > 1 mi)	P7.1	C5	system intact	fault any two circuits on common structure	Yes
	P7.2	C4		block dc bipole	

Upper Peninsula Generation Integration Screening Study

September 2016

ATC voluntarily performed a high level, steady-state screening of transmission facilities in Michigan's Upper Peninsula. This was done to assist generation developers with the preliminary identification of potential locations where existing transmission facilities may be able to accommodate the addition of new and/or additional generation capacity. All potential locations were screened for single contingency steady-state limitations. Locations that could not accommodate generation for a single contingency were removed from the Tables that were produced through this effort. ATC has not performed any analysis to identify the scope or cost of work to eliminate the limit(s) that were identified for any of the contingencies that were noted. ATC may choose to perform similar screening studies of other portions of its footprint in the future, as system conditions and circumstances warrant.

Additional steady state, multiple contingency analysis was performed for locations that appeared to be capable of hosting 100 MW or more of generation under steady state, single contingency conditions. The multiple contingency analysis resulted in reduced generation capacity from the single contingency screen being indicated for some locations. Other locations could not accommodate any new generation under multiple contingency conditions and, as such, were removed from the Tables. ATC has not performed any analysis to identify the scope or cost of work to eliminate the limit(s) that were identified for any of the contingencies that were noted.

ATC's screening did not include any stability analysis. Previous studies in the UP have identified sensitivity to stability issues. Since different types of generating units may have substantially different stability performance characteristics, a stability analysis would not be generally applicable. Furthermore, this study did not consider the number or size of units necessary to be a replacement for Presque Isle Power Plant. Finally, the study analyzed only one potential generation site at a time and, as such, the results are not necessarily additive.

The Tables that follow below identify the location, screening results and the U.P. sub-zone where existing transmission facility is located. The attached map is divided into six sub zones for ease in finding the locations identified in the Tables. Tables 1 illustrates the results of the multiple contingency analysis. Table 2 provides the results of the single contingency analysis sorted by sub-zone.

Additional disclaimers: This was a high level screening study using a single steady-state model and a particular set of assumptions, as described herein. The study results listed in the Tables below may not be indicative of the results that would be produced via the MISO Tariff Attachment X Generation Interconnection process. System stability, both angular and voltage, were not considered in this screening study. ATC makes no representations, either expressed or implied, that the scope of the interconnection facilities or transmission upgrades required to connect generation at these sites would be minimal, or even feasible. Single contingency screening results do not reflect any possible reductions required for multiple contingencies. The analysis considered 69kV, 138kV and 345kV nodes in the power flow model, but did not consider actual bus configuration or the existence of buses for constructability at the locations that were studied. Corresponding interconnection facilities and transmission upgrades

will be determined by the MISO Tariff Attachment X process. This non-binding, voluntary study is presented for informational purposes only and ATC makes no guarantee or warranty that the information presented herein is accurate or complete.

Additional Steady- State Analysis Base Assumptions

Presque Isle Generating Plant Output: 0 MW

Interconnection with the City of Marquette: 0 MW interchange

Mackinac HVDC flow modeled as: 20 MW North to South

White Pine Generating Plant Output: 0 MW

Empire Mine Load: 0 MW

Preliminary Results with Multiple Contingency Screen

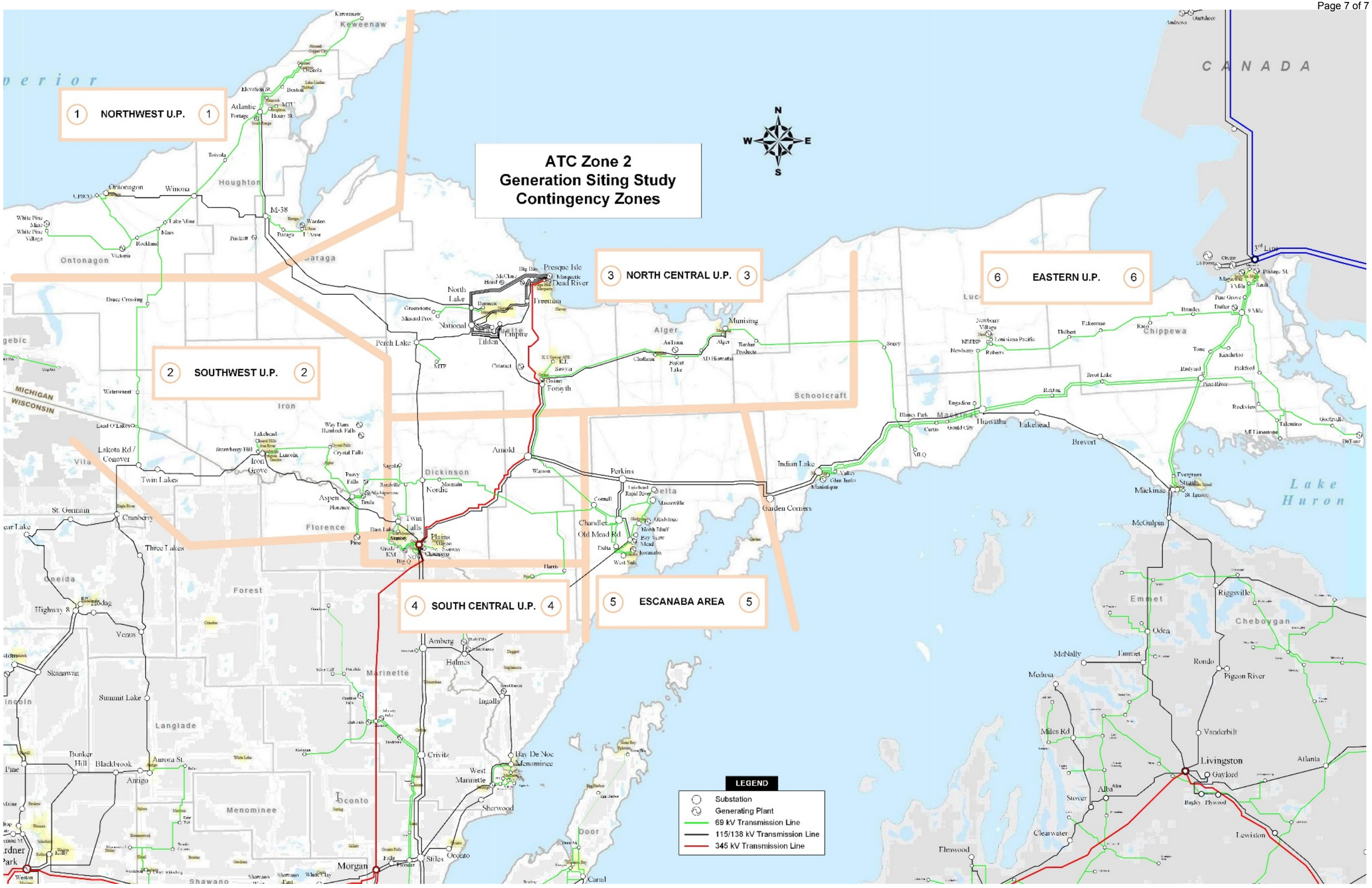
Table 1

Location	Voltage	Potential Generation Amount (MW)	Sub Zone	Contingency Screen
Atlantic	69kV	77	1	Multiple
M-38	138kV	75	1	Multiple
Presque Isle	138kV	274	3	Multiple
National	138kV	260	3	Multiple
Empire	138kV	240	3	Multiple
Freeman	138kV	149	3	Multiple
Big Bay	138kV	136	3	Multiple
Tilden	138kV	124	3	Multiple
Barnum	138kV	107	3	Multiple
North Lake	138kV	107	3	Multiple
Perch Lake	138kV	103	3	Multiple

Preliminary Results Using Single Contingency Screen				
Table 2				
Location	Voltage	Potential Generation Amount (MW)	Sub Zone	Contingency Screen
M-38	69kV	68	1	Single
Elevation St.	69kV	61	1	Single
Winona	69kV	60	1	Single
Atlantic	138kV	59	1	Single
Winona	138kV	58	1	Single
Boston	69kV	56	1	Single
Osceola	69kV	56	1	Single
Mass	69kV	50	1	Single
Henry St.	69kV	48	1	Single
MTU	69kV	48	1	Single
Lake Mine	69kV	39	1	Single
Toivola	69kV	39	1	Single
Ontonagon	69kV	37	1	Single
Ontonagan	138kV	34	1	Single
Portage	69kV	33	1	Single
White Pine Mine	69kV	33	1	Single
Rockland	69kV	32	1	Single
White Pine Village	69kV	32	1	Single
Baraga	69kV	31	1	Single
L'Anse	69kV	30	1	Single
UPSCO	69kV	27	1	Single
Victoria	69kV	26	1	Single
Keweenaw	69kV	21	1	Single
Twin Lakes	138kV	77	2	Single
Aspen	69kV	70	2	Single
Iron Grove	69kV	55	2	Single
Lakota Rd.	138kV	47	2	Single
Strawberry Hill	69kV	41	2	Single
Crystal Falls	69kV	40	2	Single
Peavy Falls	69kV	35	2	Single
Lincoln	69kV	32	2	Single
Florence	69kV	30	2	Single
Lakehead	69kV	25	2	Single
Pine	69kV	22	2	Single
Conover	69kV	20	2	Single
Lakota Rd.	69kV	20	2	Single
Michigamme	69kV	16	2	Single

Preliminary Results Using Single Contingency Screen				
Table 2 (Continued)				
Location	Voltage	Potential Generation Amount (MW)	Sub Zone	Contingency Screen
Bruce Crossing	69kV	15	2	Single
Land O Lakes	69kV	15	2	Single
Watersmeet	69kV	13	2	Single
Forsyth	69kV	93	3	Single
North Lake	69kV	60	3	Single
Barnum	69kV	52	3	Single
Alger Delta	69kV	46	3	Single
Chatham	69kV	46	3	Single
Munising	69kV	46	3	Single
Forest Lake	69kV	45	3	Single
AD Hiawatha	69kV	44	3	Single
Mineral Proc.	69kV	43	3	Single
Munising	138kV	40	3	Single
Gwinn	69kV	39	3	Single
Timber Products	69kV	29	3	Single
Greenstone	69kV	25	3	Single
Sawyer	69kV	21	3	Single
MTF	69kV	13	3	Single
Perch Lake	69kV	13	3	Single
Randville	69kV	73	4	Single
Watson	69kV	51	4	Single
Mountain	69kV	48	4	Single
Harris	69kV	36	4	Single
Sagola	69kV	34	4	Single
Old Mead Rd.	69kV	86	5	Single
Lakehead Rapid River	69kV	56	5	Single
North Bluff	69kV	53	5	Single
Masonville	69kV	52	5	Single
West Side	69kV	51	5	Single
Bay View	69kV	50	5	Single
Cornell	69kV	48	5	Single
Escanaba	69kV	45	5	Single
Gladstone	69kV	45	5	Single
Blaney Park	69kV	84	6	Single
Engadine	69kV	84	6	Single
Valley	69kV	83	6	Single
Gould City	69kV	82	6	Single
Curtis	69kV	81	6	Single
Manistique	69kV	73	6	Single

Preliminary Results Using Single Contingency Screen				
Table 2 (Continued)				
Location	Voltage	Potential Generation Amount (MW)	Sub Zone	Contingency Screen
Glen Jenks	69kV	59	6	Single
3 Mile	69kV	54	6	Single
9 Mile	69kV	54	6	Single
Newberry	69kV	49	6	Single
Sault	69kV	49	6	Single
Louisiana Pacific	69kV	48	6	Single
NBHSPL 69	69kV	48	6	Single
Newberry Village	69kV	48	6	Single
Roberts	69kV	47	6	Single
Portage St	69kV	46	6	Single
Tone	69kV	42	6	Single
Kincheloe	69kV	41	6	Single
Rudyard	69kV	41	6	Single
Eckerman	69kV	39	6	Single
Hulbert	69kV	39	6	Single
MI Limestone	69kV	37	6	Single
Raco	69kV	37	6	Single
Rexton	69kV	36	6	Single
Rockview	69kV	36	6	Single
Brimley	69kV	35	6	Single
Trout Lake	69kV	34	6	Single
Pine Grove	69kV	33	6	Single
Detour	69kV	32	6	Single
Goetzville	69kV	32	6	Single
Magazine	69kV	32	6	Single
Pickford	69kV	32	6	Single
Seney	69kV	31	6	Single
Talentino	69kV	31	6	Single
Dafter	69kV	27	6	Single
St. Ignace	69kV	26	6	Single
MLQ	69kV	25	6	Single


ATC Zone 2
Generation Siting Study
Contingency Zones
1 NORTHWEST U.P. 1
2 SOUTHWEST U.P. 2
3 NORTH CENTRAL U.P. 3
4 SOUTH CENTRAL U.P. 4
5 ESCANABA AREA 5
6 EASTERN U.P. 6
N
W
E
S
CANADA
Lake Huron
MICHIGAN
WISCONSIN
LEGEND
Substation
Generating Plant
69 kV Transmission Line
115/138 kV Transmission Line
345 kV Transmission Line

APPENDIX 5 TO GIP

OPTIONAL INTERCONNECTION STUDY AGREEMENT

THIS AGREEMENT is made and entered into this 16th day of September, 2016 by and Between Wisconsin Electric Power Company (dba) We Energies, a public utility organized and existing under the laws of the State of Wisconsin ("Interconnection Customer"), and the **Midcontinent Independent System Operator, Inc.**, a non-profit, non-stock corporation organized and existing under the laws of the State of Delaware, sometimes hereinafter referred to as the "Transmission Provider." Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties." Any capitalized term used herein but not defined herein shall have the meaning assigned to such term in the GIP and the GIA.

RECITALS

WHEREAS, Interconnection Customer is (i) proposing to develop a Generating Facility or generating capacity addition to an existing Generating Facility consistent with the Interconnection Request submitted by Interconnection Customer dated September 2, 2016 or (ii) requesting Transmission Provider to provide a non-binding independent analysis of a potential Generating Facility or generating capacity addition to an existing Generating Facility prior to an Interconnection Customer's submission of an Interconnection Request;

WHEREAS, Interconnection Customer is proposing to establish an interconnection with the Transmission System; and

WHEREAS, Interconnection Customer has submitted to Transmission Provider an Interconnection Request; and

WHEREAS, on or after the date when Interconnection Customer receives the Interconnection System Impact Study results, Interconnection Customer has further requested that Transmission Provider prepare an Optional Interconnection Study;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agree as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in the Transmission Provider's Commission-approved GIP.

2.0 Interconnection Customer elects and Transmission Provider shall cause an Optional Interconnection Study to be performed consistent with Section 10.0 of the GIP.

3.0 The scope of the Optional Interconnection Study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The Optional Interconnection Study shall be performed solely for informational purposes.

5.0 The Optional Interconnection Study report shall provide a sensitivity analysis based on the assumptions specified by Interconnection Customer in Attachment A to this Agreement. The Optional Interconnection Study will identify the Transmission Owner's Interconnection Facilities, System Protection Facilities, Distribution Upgrades, Generator Upgrades and the Network Upgrades, and the estimated cost thereof, that may be required to provide Transmission Service or Interconnection Service based upon the assumptions specified by Interconnection Customer in Attachment A.

6.0 Interconnection Customer shall provide a deposit of sixty-thousand dollars ($60,000.00) for the performance of the Optional Interconnection Study. The Transmission Provider's good faith estimate for the time of completion of the Optional Interconnection Study is [insert date].

Upon delivery of the Optional Interconnection Study report, Transmission Provider shall charge and Interconnection Customer shall pay the actual costs of the Optional Study.

Any difference between the initial payment and the actual cost of the study shall be paid by or refunded to Interconnection Customer, as appropriate.

7.0 Indemnity. To the extent permitted by law, each Party shall at all times indemnify, defend and hold the other Parties harmless from any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's performance, or non-performance of its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

8.0 Limitation of Liability. Except with respect to the duties of defense and indemnity expressly provided in this Agreement, a Party shall not be liable to another Party or to any third party or other person for any damages arising out of actions under this Agreement, including, but not limited to, any act or omission that results in an interruption, deficiency or imperfection of Interconnection Service, except as provided in the Tariff. The provisions set forth in the Tariff shall be additionally applicable to any Party acting in good faith to implement or comply with its obligations under this Agreement, regardless of whether the obligation is preceded by a specific directive.

9.0 Miscellaneous. Except as otherwise provided herein, this Agreement shall include standard miscellaneous terms including, but not limited to, indemnities, representations, disclaimers, warranties, governing law, amendment, execution, waiver, enforceability and assignment, that reflect best practices in the electric

industry, and that are consistent with regional practices, Applicable Laws and Regulations, and the organizational nature of each Party. All of these provisions, to the extent practicable, shall be consistent with the provisions of the GIP and the GIA.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

Midcontinent Independent System Operator Inc.

By: _____
Name: Paul Muney
Title: Manager Pre Queue and TSR Studies

Wisconsin Electric Power Company (dba) We Energies

By: _____
Name: Joann Henry
Title: Market Strategist

Attachment A
To Appendix5
Optional
Interconnection Study
Agreement

ASSUMPTIONS USED IN CONDUCTING THE OPTIONAL INTERCONNECTION STUDY

[To be completed by Interconnection Customer consistent with Section 10 of the GIP].
(See Attached Document)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*** * * * ***

In the Matter of the Application of	)	
Upper Michigan Energy Resources Corporation	)	
for approval of a Certificate of Necessity	)	
pursuant to MCL 460.6s for	)	Case No. U-18224
Two Reciprocating Internal Combustion Engine	)	
Electric Generation Facilities Located in the	)	
Upper Peninsula of Michigan,	)	
Approval of Certificate(s) of Public Convenience	)	
And Necessity, approval of a Special Contract with	)	
Tilden Mining Company L.C.	)	
and related accounting and ratemaking	)	
authorizations.	)	

CONFIDENTIAL

EXHIBIT A-__ (JH-4)

MISO Project Number	J703-1	County/State	Marquette, Michigan
Point of Interconnection	National 138kV Substation	Fuel Type	Natural Gas
Summer Net Output (MW)	190	Control Area	ATC

Summer Off Peak

Monitored Element	Contingency	DF(%)	Rating (MVA)	Overload (%)	Voltage (kV)
N/A	N/A	N/A	N/A	N/A	N/A

Summer Peak

Monitored Element	Contingency	DF(%)	Rating (MVA)	Overload (%)	Voltage (kV)
Empire Mine - Forsyth 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:8-1	64.17%	246	206.5%	138
Empire Mine - Forsyth 138kV Line Ckt1	P12:138:ATC:481_MT:PRESQIS:DEADRVR	62.82%	246	200.9%	138
Empire Mine - Forsyth 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:7-8	62.82%	246	182.8%	138
Forsyth - Arnold 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:8-1	59.61%	205	217.9%	138
Forsyth - Arnold 138kV Line Ckt1	P12:138:ATC:481_MT:PRESQIS:DEADRVR	58.36%	205	211.7%	138
Forsyth - Arnold 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:7-8	58.36%	205	191.5%	138
Pearch Lake - Nordic 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:8-1	31.27%	191	142.5%	138
Pearch Lake - Nordic 138kV Line Ckt1	P12:138:ATC:481_MT:PRESQIS:DEADRVR	32.54%	191	141.6%	138
Pearch Lake - Nordic 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:7-8	32.54%	191	128.1%	138
Presque Isle - Pearch Lake 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:8-1	25.56%	173	125.1%	138
Presque Isle - Pearch Lake 138kV Line Ckt1	P12:138:ATC:481_MT:PRESQIS:DEADRVR	27.22%	173	125.1%	138
Presque Isle - Pearch Lake 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:7-8	27.22%	173	112.3%	138

DPP Entry Milestone
$806,895

See Attachment A for M2 Milestone Payment Calculation

N/A indicates no constraints have been found based on the scope of the feasibility screening.

MISO Project Number	J703-2	County/State	Marquette, Michigan
Point of Interconnection	New 138kV Substatioin (Loop Tilden - Preque Isle and Freeman - Newman)	Fuel Type	Natural Gas
Summer Net Output (MW)	190	Control Area	WEC

Summer Off Peak

Monitored Element	Contingency	DF(%)	Rating (MVA)	Overload (%)	Voltage (kV)
N/A	N/A	N/A	N/A	N/A	N/A

Summer Peak

Monitored Element	Contingency	DF(%)	Rating (MVA)	Overload (%)	Voltage (kV)
Empire Mine - Forsyth 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:8-1	61.99%	246	205.70%	138
Empire Mine - Forsyth 138kV Line Ckt1	P12:138:ATC:481_MT:PRESQIS:DEADRVR	61.37%	246	201.20%	138
Empire Mine - Forsyth 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:7-8	61.37%	246	183.00%	138
Forsyth - Arnold 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:8-1	57.60%	205	217.10%	138
Forsyth - Arnold 138kV Line Ckt1	P12:138:ATC:481_MT:PRESQIS:DEADRVR	57.03%	205	212.00%	138
Forsyth - Arnold 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:7-8	57.03%	205	191.80%	138
Pearch Lake - Nordic 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:8-1	33.32%	191	145.30%	138
Pearch Lake - Nordic 138kV Line Ckt1	P12:138:ATC:481_MT:PRESQIS:DEADRVR	33.90%	191	143.10%	138
Pearch Lake - Nordic 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:7-8	33.90%	191	129.60%	138
Presque Isle - Pearch Lake 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:8-1	28.24%	173	130.40%	138
Presque Isle - Pearch Lake 138kV Line Ckt1	P12:138:ATC:481_MT:PRESQIS:DEADRVR	29.00%	173	128.60%	138
Presque Isle - Pearch Lake 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:7-8	29.00%	173	115.70%	138

DPP Entry Milestone
$806,895

See Attachment A for M2 Milestone Payment Calculation

N/A indicates no constraints have been found based on the scope of the feasibility screening.

MISO Project Number	J703-3	County/State	Marquette, Michigan
Point of Interconnection	Presque Isle 138kV Substation	Fuel Type	Natural Gas
Summer Net Output (MW)	190	Control Area	WEC

Summer Off Peak

Monitored Element	Contingency	DF(%)	Rating (MVA)	Overload (%)	Voltage (kV)
N/A	N/A	N/A	N/A	N/A	N/A

Summer Peak

Monitored Element	Contingency	DF(%)	Rating (MVA)	Overload (%)	Voltage (kV)
Empire Mine - Forsyth 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:8-1	62.99%	246	212.60%	138
Empire Mine - Forsyth 138kV Line Ckt1	P12:138:ATC:481_MT:PRESQIS:DEADRVR	62.98%	246	207.60%	138
Empire Mine - Forsyth 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:7-8	62.98%	246	188.70%	138
Forsyth - Arnold 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:8-1	58.52%	205	224.70%	138
Forsyth - Arnold 138kV Line Ckt1	P12:138:ATC:481_MT:PRESQIS:DEADRVR	58.52%	205	219.20%	138
Forsyth - Arnold 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:7-8	58.52%	205	198.10%	138
Pearch Lake - Nordic 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:8-1	33.38%	191	140.80%	138
Pearch Lake - Nordic 138kV Line Ckt1	P12:138:ATC:481_MT:PRESQIS:DEADRVR	33.38%	191	137.40%	138
Pearch Lake - Nordic 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:7-8	33.38%	191	124.50%	138
Presque Isle - Pearch Lake 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:8-1	37.01%	173	153.60%	138
Presque Isle - Pearch Lake 138kV Line Ckt1	P12:138:ATC:481_MT:PRESQIS:DEADRVR	37.01%	173	149.50%	138
Presque Isle - Pearch Lake 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:7-8	37.01%	173	133.60%	138

DPP Entry Milestone
$806,895

See Attachment A for M2 Milestone Payment Calculation

N/A indicates no constraints have been found based on the scope of the feasibility screening.

Attachment A

Voltage(kV)	Cost($)
345	350,000
230	200,000
161	130,000
138	130,000
115	130,000
69	125,000

M2 Milestone Payment = 10% x (Total for Number of Feasibility Constraints per Voltage Level x Constant Cost (see chart above) per Voltage Level + Project Size (MW) x Current Schedule 7 MISO Drive-Through and Out Yearly Maximum Cost = $10,000 per Gross MW, Minimum Cost = $2,000 per Gross MW

Schedule 7 MISO Drive-Through and Out rate = $39,731.3354

N/A indicates no constraints have been found based on the scope of the feasibility screening.

MISO Project Number	J704-1	County/State	Baraga, Michigan
Point of Interconnection	M38 138kV Substation	Fuel Type	Natural Gas
Summer Net Output (MW)	60	Control Area	UPPC

Summer Off Peak

Monitored Element	Contingency	DF(%)	Rating (MVA)	Overload (%)	Voltage (kV)
N/A	N/A	N/A	N/A	N/A	N/A

Summer Peak

Monitored Element	Contingency	DF(%)	Rating (MVA)	Overload (%)	Voltage (kV)
Empire Mine - Forsyth 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:8-1	44.73%	246	206.50%	138
Empire Mine - Forsyth 138kV Line Ckt1	P12:138:ATC:481_MT:PRESQIS:DEADRVR	44.98%	246	200.90%	138
Empire Mine - Forsyth 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:7-8	44.98%	246	182.80%	138
Forsyth - Arnold 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:8-1	41.69%	205	217.90%	138
Forsyth - Arnold 138kV Line Ckt1	P12:138:ATC:481_MT:PRESQIS:DEADRVR	41.92%	205	211.70%	138
Forsyth - Arnold 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:7-8	41.92%	205	191.50%	138
Perch Lake - Nordic 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:8-1	44.24%	191	142.50%	138
Perch Lake - Nordic 138kV Line Ckt1	P12:138:ATC:481_MT:PRESQIS:DEADRVR	44.00%	191	141.60%	138
Perch Lake - Nordic 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:7-8	44.00%	191	128.10%	138

DPP Entry Milestone
$277,388

See Attachment A for M2 Milestone Payment Calculation

N/A indicates no constraints have been found based on the scope of the feasibility screening.

MISO Project Number	J704-2	County/State	Baraga, Michigan
Point of Interconnection	M38 - Atlantic 138kV Line	Fuel Type	Natural Gas
Summer Net Output (MW)	60	Control Area	UPPC

Summer Off Peak

Monitored Element	Contingency	DF(%)	Rating (MVA)	Overload (%)	Voltage (kV)
N/A	N/A	N/A	N/A	N/A	N/A

Summer Peak

Monitored Element	Contingency	DF(%)	Rating (MVA)	Overload (%)	Voltage (kV)
Atlantic - Atlantic 138/69kV Xfr Ckt1	P24:138:ATC:M-38:BTG1-2	99.93%	59	100.80%	69
Atlantic - Atlantic 138/69kV Xfr Ckt1	J704 Tap - M-38 138kV Ckt1	99.93%	59	100.80%	69
Empire Mine - Forsyth 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:8-1	44.72%	246	205.70%	138
Empire Mine - Forsyth 138kV Line Ckt1	P12:138:ATC:481_MT:PRESQIS:DEADRVR	44.78%	246	201.20%	138
Empire Mine - Forsyth 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:7-8	44.78%	246	183.00%	138
Forsyth - Arnold 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:8-1	41.68%	205	217.10%	138
Forsyth - Arnold 138kV Line Ckt1	P12:138:ATC:481_MT:PRESQIS:DEADRVR	41.73%	205	212.00%	138
Forsyth - Arnold 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:7-8	41.73%	205	191.80%	138
Perch Lake - Nordic 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:8-1	43.83%	191	145.30%	138
Perch Lake - Nordic 138kV Line Ckt1	P12:138:ATC:481_MT:PRESQIS:DEADRVR	43.77%	191	143.10%	138
Perch Lake - Nordic 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:7-8	43.77%	191	129.60%	138

DPP Entry Milestone
$289,888

See Attachment A for M2 Milestone Payment Calculation

N/A indicates no constraints have been found based on the scope of the feasibility screening.

MISO Project Number	J704-3	County/State	Baraga, Michigan
Point of Interconnection	M38- L'Anse 69kV Line	Fuel Type	Natural Gas
Summer Net Output (MW)	60	Control Area	UPPC

Summer Off Peak

Monitored Element	Contingency	DF(%)	Rating (MVA)	Overload (%)	Voltage (kV)
N/A	N/A	N/A	N/A	N/A	N/A

Summer Peak

Monitored Element	Contingency	DF(%)	Rating (MVA)	Overload (%)	Voltage (kV)
Baraga Prison Tap - M-38 69kV Line Ckt1	Base Case	99.92%	35	161.70%	69
Baraga Prison Tap - M-38 69kV Line Ckt1	J704 Tap - L-Anse 69kV Line Ckt1	99.93%	35	153.40%	69
Baraga Prison Tap - M-38 69kV Line Ckt1	P13:14-69:ATC:WARDEN:TGSU	99.93%	35	137.10%	69
Baraga Prison Tap - M-38 69kV Line Ckt1	Warden - L-Anse 69kV Line Ckt1	99.93%	35	137.10%	69
Baraga Prison Tap - M-38 69kV Line Ckt1	ATC_B3_WARDEN-TGSU	99.92%	35	122.90%	69
Baraga Prison Tap - M-38 69kV Line Ckt1	ATC-B1_WARDEN_1-1	99.92%	35	122.90%	69
Empire Mine - Forsyth 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:8-1	29.55%	246	212.60%	138
Empire Mine - Forsyth 138kV Line Ckt1	P12:138:ATC:481_MT:PRESQIS:DEADRVR	29.54%	246	207.60%	138
Empire Mine - Forsyth 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:7-8	29.54%	246	188.70%	138
Forsyth - Arnold 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:8-1	27.69%	205	224.70%	138
Forsyth - Arnold 138kV Line Ckt1	P12:138:ATC:481_MT:PRESQIS:DEADRVR	27.69%	205	219.20%	138
Forsyth - Arnold 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:7-8	27.69%	205	198.10%	138
J704 Tap - Baraga Prison Tap 69kV Line Ckt1	Base Case	99.92%	60	102.50%	69
Perch Lake - Nordic 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:8-1	53.08%	191	140.80%	138
Perch Lake - Nordic 138kV Line Ckt1	P12:138:ATC:481_MT:PRESQIS:DEADRVR	53.07%	191	137.40%	138
Perch Lake - Nordic 138kV Line Ckt1	P23:138:ATC:PresqueIsleMT:7-8	53.07%	191	124.50%	138

DPP Entry Milestone
$302,388

See Attachment A for M2 Milestone Payment Calculation

N/A indicates no constraints have been found based on the scope of the feasibility screening.

Attachment A

Voltage(kV)	Cost($)
345	350,000
230	200,000
161	130,000
138	130,000
115	130,000
69	125,000

M2 Milestone Payment = 10% x (Total for Number of Feasibility Constraints per Voltage Level x Constant Cost (see chart above) per Voltage Level + Project Size (MW) x Current Schedule 7 MISO Drive-Through and Out Yearly Maximum Cost = $10,000 per Gross MW, Minimum Cost = $2,000 per Gross MW

Schedule 7 MISO Drive-Through and Out rate = $39,731.3354

N/A indicates no constraints have been found based on the scope of the feasibility screening.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the Matter of the Application of	)	
Upper Michigan Energy Resources Corporation	)	
for approval of a Certificate of Necessity	)	
pursuant to MCL 460.6s for	)	Case No. U-18224
Two Reciprocating Internal Combustion Engine	)	
Electric Generation Facilities Located in the	)	
Upper Peninsula of Michigan	)	
Approval of Certificate(s) of Public Convenience	)	
And Necessity, approval of a Special Contract with	)	
Tilden Mining Company L.C.	)	
and for related accounting and ratemaking	)	
authorizations.	)	

DIRECT TESTIMONY

OF

LAURA M. JARMUZ

ON BEHALF OF

UPPER MICHIGAN ENERGY RESOURCES CORPORATION

Q. Please state your name and business address.

A. My name is Laura M. Jarmuz. My business address is 333 W. Everett Street, Milwaukee, Wisconsin, 53203.

Q. By whom are you employed and what is your position?

A. I am employed by WEC Energy Group Inc., ("WEC Energy Group" or the "Company") as a Senior Engineer in the Environmental Department.

Q. Please describe your educational and business experience.

A. I received a Bachelor of Science Degree in Industrial Engineering from the University of Wisconsin – Milwaukee in 2002. In 2010, I received a Master of Science degree in Environmental Engineering from the Milwaukee School of Engineering.

I have been employed by the Company since 2012 in the Environmental Department. During this time, I have worked on air quality matters for several power generation facilities.

Prior to joining the Company, I worked as an environmental consultant for five years where I assisted clients with air quality and other environmental program compliance.

Q. Do you hold a professional license or belong to any professional organizations?

A. Yes, I am a Registered Professional Engineer in the State of Wisconsin since 2012.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to support Upper Michigan Energy Resources Corporation's ("UMERC") Application for a Certificate of Necessity ("CON") and other requests for relief in connection with the construction and investment in, two Reciprocating Internal Combustion Engines ("RICE") electric generation facilities in the Upper Peninsula of Michigan. My testimony will address:

- Air permitting requirements for the electric generation facilities,
- Air quality regulations potentially impacting the electric generation facilities, and
- Cost impacts of air quality regulation compliance for the electric generation facilities.

Q. Will the construction or operation of the two RICE electric generation facilities be required to obtain a state air permit?

A. Yes. Prior to beginning construction each of the electric generation facilities will be

required to obtain a Permit to Install ("PTI") from the Michigan Department of Environmental Quality ("MDEQ") in accordance with Michigan Administrative Rules for Air Pollution Control, Michigan Rule 336.1201. Each of the electric generation facilities will be considered a major source under the Title V program, which will require a Title V Renewable Operating Permit ("ROP") to be obtained from the MDEQ after the electric generation facilities are built.

Q. What air quality regulations will be applicable to the two RICE electric generation facilities?

A. The RICE units will be subject to the New Source Performance Standards ("NSPS") codified at 40 CFR Part 60 Subpart JJJJ and the National Emission Standards for Hazardous Air Pollutants ("NESHAP") For Stationary Reciprocating Internal Combustion Engines codified at 40 CFR Part 63 Subpart ZZZZ. Additionally, it is expected any ROP issued by MDEQ will contain various other air emission limits, monitoring requirements, and recordkeeping requirements applicable to each electric generating facility.

Q. What are the cost impacts of complying with any air quality regulations?

A. The NSPS or NESHAP do not require the installation of any additional emissions control equipment. Compliance with the NSPS and NESHAP will likely be documented by compliance emissions stack testing at each RICE unit as long as the electric generating facilities are in use on a frequency determined the applicable rule, which could be as frequently as semi-annually or up to every 3 years, depending on the pollutant. Compliance emissions stack testing is conducted by a specialized firm which will be contracted by UMERC, and costs are estimated to be $200,000 annually. This cost

estimate is based on the Company's subsidiaries' previous experience with compliance emissions stack testing.

Additionally, the Clean Air Act requires each state to develop an operating permit program that is supported by air emissions fees. This annual fee is dependent on actual emissions from the previous year, and is paid to MDEQ. Annual air emissions fees for the two RICE electric generation facilities are estimated to be $50,000. This cost estimate is based on estimated air emissions and publicly available fee information from MDEQ.

Q. What is the schedule for obtaining the air permits for the generating facilities?

A. We plan on submitting the construction air permit applications with MDEQ by the end of February. We anticipate that we will receive the permits within 6 months of filing the air permit applications.

Q. Based on your expertise, are the electric generating facilities permitable from an air permit perspective?

A. Yes. The RICE electric generating facilities will meet all the requirements in order to obtain a PTI and ROP from MDEQ.

Q. Will regional air emissions be reduced between the retirement of Presque Isle Power Plant ("PIPP") and operation of the electric generating facilities?

A. Yes. When PIPP is retired, and the electric generating facilities are in service, we anticipate emissions reductions of approximately 95% for nitrogen oxides, 50% for particulate matter, more than 99% for both sulfur dioxide and mercury, and approximately 75% for carbon dioxide.

Q. Does this conclude your prefiled direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

****

In the Matter of the Application of	)	
Upper Michigan Energy Resources Corporation	)	
for approval of a Certificate of Necessity	)	
pursuant to MCL 460.6s for	)	Case No. U-18224
Two Reciprocating Internal Combustion Engine	)	
Electric Generation Facilities Located in the	)	
Upper Peninsula of Michigan	)	
Approval of Certificate(s) of Public Convenience	)	
And Necessity, approval of a Special Contract with	)	
Tilden Mining Company L.C.	)	
and for related accounting and ratemaking	)	
authorizations.	)	

** Public Version **

DIRECT TESTIMONY AND EXHIBIT

OF

RUSSELL T. LAURSEN

ON BEHALF OF

UPPER MICHIGAN ENERGY RESOURCES CORPORATION

Q. Please state your name and business address.

A. My name is Russell T. Laursen. My business address is P.O. Box 19001, Green Bay, Wisconsin 54307-9001.

Q. By whom are you employed and what is your position?

A. I am employed by WEC Energy Group, Inc. ("WEC") as Manager of Gas Supply. In this proceeding I am testifying on behalf of Upper Michigan Energy Resources Corporation

("Company" or "UMERC").

Q. Please describe your educational and business experience.

A. I received a Bachelor of Science degree in Mechanical Engineering from the Milwaukee School of Engineering in 2004, and a Master of Business Administration degree from the University of Wisconsin – La Crosse in 2008.

In addition to my current role, I have held positions as a Natural Gas Trader (2006-2011), Manager of Upper Peninsula Power Company ("UPPCO") Power Supply (2011-2012), Manager of Retail Electric Rates (2012-2014), and Manager of Resource Planning and Policy (2014-2015).

Q. Have you ever testified in other cases?

A. Yes. I have testified before the Michigan Public Service Commission ("Commission" or "MPSC") and the Public Service Commission of Wisconsin ("PSCW") in various Power Supply Cost Recovery and rate case dockets on behalf of UPPCO and Wisconsin Public Service Corporation, including the following:

- MPSC Case No. U-17091: UPPCO's 2013 Power Supply Cost Recovery Plan;
- MPSC Case No. U-16881-R: UPPCO's 2012 Power Supply Cost Recovery Plan Reconciliation;
- MPSC Case No. U-16881: UPPCO's 2012 Power Supply Cost Recovery Plan;
- MPSC Case No. U-16421-R: UPPCO's 2011 Power Supply Cost Recovery Plan Reconciliation;
- PSCW Docket No. 6690-UR-123: Wisconsin Public Service Corporation's 2015 test year rate case; and

- PSCW Docket No. 6690-UR-122: Wisconsin Public Service Corporation's 2014 test year rate case.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to support UMERC's Application filed in this docket. My testimony will address:

- Overview of gas supply to the generation facilities;
- Interstate pipeline capacity; and
- Natural gas laterals.

Q. Are you sponsoring any exhibits to accompany your testimony?

A. Yes. I am sponsoring the following exhibit:

Confidential Exhibit A-__ (RTL-1) – Precedent Agreement for Interstate Pipeline Capacity between Northern Natural Gas ("NNG") and UMERC.

Q. Please explain the logistics of supplying natural gas to the Reciprocating Internal Combustion Engine ("RICE") electric generation facilities.

A. Delivery of the natural gas fuel to the facilities will be through a connection with the NNG, the interstate pipeline. The Negaunee and Baraga Township Sites, which are described in the testimony of Mr. Terrance W. Carroll, were chosen based, in part, on proximity to the pipeline. The Baraga Township Site is approximately 3.5 miles from NNG, while the Negaunee Township Site is less than one half mile from the pipeline. Laterals must be constructed from the pipeline to deliver gas to each site.

Q. How does UMERC move gas to the power plants?

A. The Company will purchase gas at various supply points and utilize the pipeline to move gas to the interconnect between NNG and the laterals serving each facility.

Q. Is adequate pipeline capacity available to serve each site?

A. No, because firm capacity is not available from the existing NNG pipeline. UMERC, therefore, negotiated a Precedent Agreement to provide sufficient firm capacity, which is my Confidential Exhibit A-__ (RTL-1). Confidential Exhibit A-__ (RTL-1) describes a capital project, that will be undertaken by NNG, which is required to provide sufficient firm capacity to each site. The agreed-upon solution requires the construction of a new natural gas compressor station near [begin confidential] [redacted] [end confidential]. Based on information provided by NNG, it will have [begin confidential] [redacted] [end confidential] in costs for the capital project. UMERC will pay for the [begin confidential] [redacted] [end confidential] NNG capital project in its transportation rates over the [begin confidential] [redacted] [end confidential] year term of the agreement.

Q. Will NNG have to construct additional facilities to support the project?

A. Yes. In addition to the compressor station, two Town Border Stations ("TBS") will be constructed to facilitate the movement of natural gas from the NNG pipeline into the laterals serving each RICE electric generation facility. The TBS facilities are included in the precedent agreement and cost estimate provided above.

Q. Please explain the difference between firm, secondary, and interruptible natural gas transportation capacity.

A. Firm capacity to a delivery point is contracted for with the interstate pipeline company, includes a monthly reservation charge, and gives the holder of the capacity the ability to flow gas without threat of interruption, except in cases of force majeure. Secondary capacity involves the use of reserved transportation capacity to points other than the firm,

primary contract points. Secondary capacity has a lower priority of flow than primary capacity. Interruptible capacity is paid for on an "as-used" basis so has no reservation charge. This capacity has the lowest priority of flow on the interstate pipeline system. Further information is available in the Federal Energy Regulatory Commission approved NNG Tariff.

Q. How much firm capacity did UMERC purchase?

A. UMERC has agreed to contract through the Precedent Agreement with NNG for [begin confidential] [redacted] [end confidential] dth/day of firm pipeline delivery capacity. The capacity is split between the two generation facility locations with [begin confidential] [redacted] [end confidential] dth/day at the Baraga Township Site and remaining [begin confidential] [redacted] [end confidential] dth/day at the Negaunee Township Site. The NNG capacity values represent approximately 100% firm pipeline capacity for the Baraga Township Site and approximately 56% firm capacity at the Negaunee Township Site.

Q. Why did UMERC purchase this amount of firm capacity?

A. UMERC acquired all of the incremental capacity added to the NNG system as a result of the capital projects that will be completed by NNG and paid for by UMERC. The amount of firm capacity is appropriate and reasonable.

Q. Why didn't UMERC contract for 100% firm pipeline capacity for both of the RICE electric generation facilities?

A. UMERC investigated acquiring up to 100% firm capacity at both sites. In order to acquire 100% firm capacity at both sites, an additional [begin confidential] [redacted] [end confidential] dth/day would be needed which would costs approximately [begin

confidential] [redacted] [end confidential] based on information provided by NNG. The currently contracted capacity level optimizes the firm, primary capacity received compared to the cost of the capacity. Stated another way, purchasing additional firm capacity is unnecessary and would have significantly increased costs.

Q. Does the Midcontinent Independent System Operator, Inc. ("MISO") require that natural gas-fired power plants have firm pipeline capacity?

A. No, MISO does not require natural gas power plants to have firm gas transportation capacity. However, given the unique electric and gas infrastructure circumstances of the Upper Peninsula of Michigan ("UP"), it is reasonable to purchase firm capacity to supply a significant portion of the generation.

It is equally important to consider that the UMERC facilities are near the terminus of the NNG pipeline system where the performance of interruptible capacity would sometimes be insufficient, particularly during winter months. Given the value of these assets to the integrity of the electric system in the UP, it is prudent to contract for a level of firm pipeline capacity that optimizes the risk and cost profiles of the power plants.

Q. Why is the contracted level of capacity at each RICE electric generation site reasonable?

A. The difficult electric reliability situation in the UP is well known and requires that additional attention is given to the fuel supply for the RICE electric generation sites. UMERC has carefully considered the issues at hand, and is confident that the level of firm pipeline capacity contracted for with NNG provides the electric reliability that the UP needs, while also considering the cost effectiveness of the solution. Roughly 113 MW of generation will have firm fuel supply on a 24/7 basis as a result of the agreement with

NNG.

Q. What are the terms of the proposed transportation agreement with NNG?

A. The pipeline contract with NNG will be for a [begin confidential] [redacted] [end confidential] year term beginning November 1, 2019 with an annual cost of $4.3 million [begin confidential] [redacted] [end confidential]. This cost is comprised of the NNG tariff rate of approximately [begin confidential] [redacted] [end confidential] plus the return on the [begin confidential] [redacted] [end confidential] capital investment that will be made by NNG to facilitate the capacity addition [begin confidential] [redacted] [end confidential]. The terms are shown in Exhibit A of the Precedent Agreement, which is my Confidential Exhibit A-__ (RTL-1).

Q. When will natural gas be available at each facility for testing?

A. Natural gas will be available at each site as early as August 1, 2018. This means the TBS and laterals will be constructed by this date and the Company can flow interruptible gas for testing. Firm capacity will be available as discussed above on November 1, 2019, and is dependent on the construction of the NNG compressor station near [begin confidential] [redacted] [end confidential].

Q. Can the generating facilities be placed into commercial operation before firm gas transportation capacity is available?

A. Yes. First, MISO does not require natural gas plants to have firm gas transportation capacity. Second, interruptible pipeline capacity can be used during the summer of 2019

when firm service would not be needed. Firm capacity is scheduled to be available November 1, 2019, before the winter months when it is most necessary.

Q. Please explain the purpose and status of the gas laterals at each RICE electric generation facility.

A. Laterals will be required at each site to move the gas from the interstate pipeline TBS to the electric generation facilities. The Baraga Township Site lateral will extend west 3.5 miles from approximately the point where the NNG pipeline crosses the highway to the proposed RICE electric generation facility Site. This lateral appears to be possible to build largely in existing right of way. The lateral location for the Negaunee Township Site facility will be from a pipeline which runs adjacent to the plant property. SEMCO has been selected as the party to construct, own and operate the gas laterals. SEMCO will request Commission approvals, if any, that are required to construct the gas laterals.

Q. Does UMERC have estimates on the cost of the gas laterals?

A. Yes. UMERC requested proposals for the gas laterals and have awarded the work to SEMCO. The costs from the SEMCO proposal are included in cost estimates provided in Mr. Carroll's testimony.

Q. Will UMERC procure natural gas in a similar manner to that used by Wisconsin Electric Power Company?

A. Yes, UMERC will use a similar method of procurement. The operation of the RICE electric generation facilities will vary with weather and season, so the Company will use a flexible natural gas procurement process. This process will likely include monthly commodity purchases and daily commodity purchases to serve the specific needs of the sites. Gas Traders will purchase natural gas according to the electric dispatch instructions

provided by MISO for each site.

Q. Will the portfolio used to serve the RICE electric generation sites share any assets with the portfolio used to serve UMERC retail natural gas customers?

A. No, this will be a separate portfolio and procurement method than that used by UMERC for serving its retail natural gas customers.

Q. Does this conclude your testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*** * * * ***

In the Matter of the Application of	)	
Upper Michigan Energy Resources Corporation	)	
for approval of a Certificate of Necessity	)	
pursuant to MCL 460.6s for	)	Case No. U-18224
Two Reciprocating Internal Combustion Engine	)	
Electric Generation Facilities Located in the	)	
Upper Peninsula of Michigan,	)	
Approval of Certificate(s) of Public Convenience	)	
And Necessity, approval of a Special Contract with	)	
Tilden Mining Company L.C.	)	
and related accounting and ratemaking	)	
authorizations.	)	

CONFIDENTIAL

EXHIBIT A-__ (RTL-1)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

****

In the Matter of the Application of	)	
Upper Michigan Energy Resources Corporation	)	
for approval of a Certificate of Necessity	)	
pursuant to MCL 460.6s for	)	Case No. U-18224
Two Reciprocating Internal Combustion Engine	)	
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Tilden Mining Company L.C.	)	
and for related accounting and ratemaking	)	
authorizations.	)	

DIRECT TESTIMONY AND EXHIBITS

OF

SUSAN M. SCHUMACHER

ON BEHALF OF

UPPER MICHIGAN ENERGY RESOURCES CORPORATION

Q. Please state your name and business address.

A. My name is Susan M. Schumacher. My business address is 333 W. Everett Street, Milwaukee, Wisconsin 53203.

Q. By whom are you employed and what is your position?

A. I am a Principal Ecological Scientist in the Environmental Department of WEC Business Services LLC, ("WBS"), a wholly owned subsidiary of WEC Energy Group ("WEC Energy Group" or the "Company"). I am testifying on behalf of the applicant, Upper

Michigan Energy Resources Corporation ("UMERC").

Q. Please describe your educational and business experience.

A. I received a Bachelor's Degree with a major in Zoology from the State University of New York – Oswego in 1986. In 1989, I received a Master of Science degree in Biology from the University of Wisconsin – Milwaukee.

I have been employed by the Company and/or its subsidiaries for fifteen years, working in the Environmental Department. In this position, I review projects proposed by the Company to determine if the project may have any environmental impacts, especially in the areas of wetlands, waterways, wildlife, threatened and endangered species, agriculture, and cultural artifacts. I also work with Company project managers to reconfigure project plans and schedules to avoid and minimize potential negative environmental impacts of projects, develop federal and state permit applications as necessary, and inspect construction activities to ensure compliance with permit conditions. Previously, I worked for the Wisconsin Department of Natural Resources for eleven years; as a Waterway and Wetland Management Specialist for eight years, as a Wildlife Assistant and Wetland Restoration Specialist for two years and as a Park Naturalist for one year.

Q. Have you ever testified in other cases?

A. Yes. I have testified on behalf of the Company in cases before the Public Service Commission of Wisconsin ("PSCW"), and I have testified on behalf of the Wisconsin Department of Natural Resources ("WDNR") as an employee of that department, including:

- PSCW Docket No. 663-0CE-302, construction of the Glacier Hills Wind Project;

- PSCW Docket No. 6630-CE-294, construction of the Blue Sky Green Field Wind Project;
- PSCW Docket Nos. 05-AE-109, 05-CE-130, 6650-CG-211, approval of affiliated interest transactions between W.E.Power LLC, Wisconsin Electric Power Company ("WEPCo") and WEC, application of WEPCo et. al. for construction of three large electric generation facilities and application for construction of a high pressure natural gas line;
- PSCW Docket Nos. 6650-CG-103 and 05-CG-220, proposed construction of two natural gas pipelines;
- WDNR Case No. 3-SE-96-061, application for water quality certification.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to support the UMERC's Application for a Certificate of Necessity ("CON") for the construction and operation of two Reciprocating Internal Combustion Engine ("RICE") electric generation facilities in the Upper Peninsula of Michigan ("UP") (the "Project"). My testimony will address:

- The environmental site assessments completed for the two proposed sites for the generation facilities;
- Environmental regulations and permits that may be required for construction and operation of the two proposed generation facilities;

Q. Are you sponsoring any exhibits to accompany your testimony?

A. Yes. I am sponsoring the following exhibits: Exhibit A-__ (SMS-1), an environmental assessment spreadsheet, and Confidential Exhibit A-__ (SMS-2), containing confidential endangered species information.

ENVIRONMENTAL SITE ASSESSMENTS

Q. Has the Company completed environmental surveys of the sites selected for the two new RICE electric generation station facilities?

A. Yes.

Q. Please describe the environmental factors that are investigated prior to the purchase and development of a site.

A. Properties are examined for various environmental factors including, but not limited to: wetlands; waterways; floodplains; endangered, threatened and special concern species; cultural items; publicly owned land; wells; and underground storage tanks.

Q. What data is gathered to assess these factors?

A. A desktop survey is completed for all sites initially under consideration. A desktop survey includes gathering publicly available maps and data from both federal and state websites such as U.S. National Park Service, U.S. Fish and Wildlife Service, U.S.D.A. Forest Service, the Federal Emergency Management Agency, The Michigan Natural Features Inventory, and the Michigan Department of Environmental Quality.

Q. Is any other additional data collected?

A. If the landowner grants permission to access the property, an on-site survey is completed. Biologists survey the site and delineate wetlands if present, verify whether the data collected during the desktop review stage is accurate, and determine if there are any environmental issues on site that were not listed in the desktop survey.

Q. How do you use the environmental information to assess the proposed sites?

A. I review the environmental data for the sites and provide my opinion as to whether the proposed project may cause an impact to any environmental factors present, if the impact

could be avoided or minimized, whether environmental permit(s) may be required, or if the environmental factors present are significant so as to suggest dropping the site from further consideration.

Q. Does the Company choose the sites for the proposed facilities based on the environmental review?

A. The preference is based on a number of factors, of which environmental is one. Factors such as: 1) proximity to electric transmission, 2) proximity to a natural gas supply pipeline, 3) local region grid support, 4) a preference for a rural location, and 5) accessibility and ability to purchase the land, among others, which are more fully described in the testimony of Terrence W. Carroll, are also used to determine which sites would be preferable to pursue.

Q. Have sites been selected for each of the two proposed power generation facilities?

A. Yes. One site is in Marquette County ("Negaunee Township Site"), and the second site is in Baraga County ("Baraga Township Site").

Q. What is the current use of these parcels?

A. This is described in Exhibit A-__ (SMS-1).

Q. What are the percentages of land cover present at each site?

A. This is described in Exhibit A-__ (SMS-1).

Q. Briefly describe the Negaunee Township Site location.

A. The Negaunee Township Site is approximately located near Pioneer Road, southeast of the Lake Superior & Ishpeming Railroad yard. It is located in the vicinity of 83 Eagle Mills Road, Negaunee, Michigan. The Company is currently considering two parcels for the location of the project.

Q. Please describe the known environmental factors present on those parcels in Negaunee Township.

A. Both a desk top and an on-site survey have been completed. A table indicating environmental factors known to be present on the parcels is in Exhibit A-__ (SMS-1).

Q. Are field delineated wetlands present?

A. Yes.

Q. In your opinion, will a federal or state wetland permit be required for the Negaunee Township Site?

A. Yes, permits may be necessary. It will depend, however, on the final proposed siting of the facility on the parcel. We will attempt to avoid or minimize any wetland impacts when siting the facility.

Q. In your opinion, are any listed endangered or threatened species likely to be present on the Negaunee Township Site?

A. No. One state endangered species is listed as having occurred within the same section as the Negaunee Township Site; however, it is unlikely this species is currently present. Please see Confidential Exhibit A-__ (SMS-2) for a description.

Q. Are there any other environmental issues on the Negaunee Township Site that may require a state or federal permit?

A. A state air quality permit will be required. Based on the information we have at this time for the Negaunee Township Site, no other federal permit should be required. Some additional state permits may be required, such as a construction storm water permit, and a permit for extension of water and sewer systems.

Q. Has the Company submitted applications for any of these permits?

A. No.

Q. Why not?

A. We do not yet have a site specific construction plan for the Negaunee Township Site. When we have determined where the facility would be located on the property, and the potential environmental impact, we will submit the necessary applications. When siting the facility on the parcel, the Company will attempt to avoid and minimize all impacts to environmental resources as much as reasonably possible.

Q. When will you submit applications for these permits for the Negaunee Township Site?

A. After detailed design engineering has progressed and before construction commences.

Q. Briefly describe the Baraga Township facility location.

A. The Baraga Township Site facility will be located next to the American Transmission Company M38 substation located at 16431 Schwalm Road, Pelkie, Michigan, in Baraga Township. The Company is currently considering several parcels in the vicinity of the substation. One or more parcels will be selected for the Baraga Township Site facility.

Q. Please describe the known environmental factors present on those parcels in Baraga Township.

A. A desktop survey has been completed for all the sites that have been under consideration. Some of the landowners provided permission to their parcel. If access was granted we completed an environmental survey at the site. A table indicating environmental factors known to be present on all parcels is in Exhibit A-__ (SMS-1).

Q. Are field delineated wetlands present on any of the parcels?

A. Yes.

Q. In your opinion, will a federal or state wetland permit be required for the Baraga Township Site?

A. Yes, permits may be necessary. It will depend on the final parcel or parcels chosen, and the proposed siting of the facility on the parcel. We will attempt to avoid or minimize any wetland impacts when siting the facility.

Q. In your opinion, for the parcels that have been field surveyed, are listed endangered or threatened species likely to be present on any of the parcels in Baraga Township?

A. No.

Q. Are there any other environmental issues on the site that may require a state or federal permit for the Baraga Township Site?

A. A state air quality permit will be required. Based on the information we have at this time for the Baraga Township Site, no other federal permit will be required. Some additional state permits may be required such as a construction storm water permit, and a permit for extension of water and sewer systems.

Q. Has the Company submitted applications for any of these permits for the Baraga Township Site?

A. No.

Q. Why not?

A. We have not selected a particular location or parcel(s) for the proposed facility and do not yet have a site-specific construction plan. When we have selected a final site and parcel(s), determined where the facility would be located on the parcel, and determined

the potential environmental impact, we will submit the necessary applications. When siting the facility on a parcel, the Company will attempt to avoid and minimize all impacts to environmental resources as much as reasonably possible.

Q. When will you submit applications for these permits for the Baraga Township Site?

A. After detailed design engineering has progressed and before construction commences.

<u>ENVIRONMENTAL REGULATIONS AND PERMITS THAT MAY BE REQUIRED</u>

Q. What federal environmental regulations may pertain to the two proposed project sites?

A. Permits from the U.S. Army Corps of Engineers would be required if there will be impacts to wetlands under federal jurisdiction, and from the U.S. Fish and Wildlife Service if there will be impacts to federally-listed endangered or threatened species. The federal permit process also takes into account potential impacts to objects and/or sites in the National Register of Historic Places; this process may involve the Michigan State Historic Preservation Office.

Q. What state environmental regulations may pertain to the two proposed project sites?

A. Permits from the Michigan Department of Environmental Quality ("MDEQ") would be required if there will be wetland impacts, floodplain impacts, or impacts associated with leaking underground storage tanks. Permits from the Michigan Department of Natural Resources ("MDNR") would be required for impacts to state listed endangered or threatened species. Construction storm water permits and water and sewer extension permits may also be required.

Q. Will air quality permits from MDEQ be required for the proposed Project?

A. Yes. Please refer to the testimony of Laura M. Jarmuz for information regarding those permits.

Q. Are any other state or federal permits required for the Project?

A. Two parcels have not had a field survey. It is possible that conditions at either of those locations may warrant additional permits beyond those listed above. In addition, no environmental soil sampling has been completed at either site (or parcels), so it is unknown if remediation, and permits associated with remediation, would be necessary at any location. If such conditions were found, the Company would contact the appropriate federal and state agencies.

Q. Have any of the listed agencies been contacted regarding this Project?

A. No. We will contact agencies when we have selected the final facility locations and identify which permits may be required.

Q. Are permits required if the property is in a state or federal program, such as Farmland Preservation or Commercial Forest Program?

A. No permits are required. Withdrawal of property from such a program may require repayment of fees or taxes. The Company would work with the landowner and the agency to ensure compliance with withdrawal requirements.

Q. In your opinion, will the new RICE electric generation facilities and the construction and operation of the new RICE electric generation facilities on the sites under consideration comply with all applicable state and federal environmental standards, laws, and rules?

A. Yes.

Q. Does this conclude your testimony?

A. Yes.

Exhibit A-__ (SMS-1)	Negaunee Township Site (Marquette County)		Baraga Township Site (Baraga County)						
	Parcel 1	Parcel 2	Parcel 1	Parcel 2	Parcel 3	Parcel 4	Parcel 5	Parcel 6	Parcel 7
General Site Information									
Was a Desktop map review completed?	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Was an on-site environmental survey completed?	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes	No
Wetlands									
Does the National Wetland Inventory indicate mapped wetlands present on the property?	Yes	Yes	No	No	No	No	Yes	No	Yes
Does the Baraga County Wetland Inventory (MDEQ-based) indicate potential wetlands present on the property?	N/A	N/A	No	No	No	No	Yes	No	Yes
Does the Marquette County Wetland Inventory (MDEQ-based) indicate potential wetlands present on the property?	Yes	No	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Were wetlands delineated during the field survey of the parcel?	No	Yes	Yes	Yes	Yes	Yes	N/A	No	N/A
Could a federal or state wetland permit be required[1]	No	No	Yes	Yes	Yes	Yes	Yes	No	Yes
Endangered and Threatened Species									
Is there a "documented occurrence" of a federally-listed endangered or threatened species within the section that the parcel is located?	No	No	No	No	No	No	No	No	No
Is a federal endangered species permit likely to be required for impact to a federally listed species[1]	No	No	No	No	No	No	No	No	No
Is a there a "documented occurrence" of a state-listed endangered or threatened species within the section that the parcel is located?	Yes (State Endangered animal species)	Yes (State Endangered animal species)	No	No	No	No	No	No	No
Were any federal or state-listed endangered or threatened species observed on the parcel?	No	No	No	No	No	No	Unknown	No	Unknown
Is a state permit likely to be required for impact to a state listed species[1]	No	No	No	No	No	No	No	No	No
Cultural and Historic Artifacts									
Are mapped cultural places present?	No	No	No	No	No	No	No	No	No
Are mapped historic places present?	No	No	No	No	No	No	No	No	No
Is approval through the Federal Section 106 process or State Historic Preservation Office likely to be required?	No	No	No	No	No	No	No	No	No
Publicly Owned Lands									
Is the property within a Coastal Management Zone Area?	No	No	No	No	No	No	No	No	No
Is the property within a State, Federal, County or Local Park?	No	No	No	No	No	No	No	No	No
Is a Wild or Senic River present on the property?	No	No	No	No	No	No	No	No	No
Public Programs									
Is the property within a Commercial Forest Reserve Program?	No	No	No	No	No	No	No	No	No
Is the property enrolled in a State or Federal Open Space Program (CRP, WRP, Farmland Preservation, etc)?	No	No	No	No	No	No	No	No	No
Are FIRM mapped Floodplains present on the property?	No	No	No	No	No	No	No	No	No
Wells and Underground Tanks									
Are underground tanks present (as per DEQ maps)?	No	No	No	No	No	No	No	Yes	No
Are mapped well heads present on the property?	No	No	No	No	No	No	No	No	No
Are mapped well heads present within 8,000 feet?	No	No	No	No	No	No	No	No	No
Any items of interest present on the parcel found during the field survey?	No	No	No	No	No	No	Unknown	No	Unknown
Land Cover Type (by percentage)[2]									
What is the current use of the site?	Forested	Forested	Residental/ Agricultural	Forested/ Agricultural	Forested	Forested	Agricultural/ Fallow	Agricultural/ Fallow	Residental/ Forested
Total acres reviewed for land cover type	32 acres	63 acres	42 acres	50 acres	66 acres	116 acres	44 acres	19 acres	55 acres
Residential	0%	0%	7%	4%	0%	1%	5%	10%	4%
Farmland	0%	0%	81%	15%	0%	44%	65%	89%	0%
Fallow (grassland/scrub shrub)	22%	25%	2%	8%	0%	0%	5%	0%	28%
Transmission/utility	3%	4%	5%	10%	4%	0%	0%	0%	0%
Deciduous vegetation	57%	30%	2%	24%	25%	18%	12%	0%	23%
Coniferous vegetation	18%	41%	<1%	39%	71%	37%	13%	1%	45%
Open Water	0%	0%	3%	0%	0%	0%	0%	0%	0%

1: This does not indicate that a permit is required. This indicates the possibility that a permit may be required based on the data available and the approximate footprint necessary for construction.
2: The percentage of cover is based upon several map sources and professional judgement.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*** * * * ***

In the Matter of the Application of	)	
Upper Michigan Energy Resources Corporation	)	
for approval of a Certificate of Necessity	)	
pursuant to MCL 460.6s for	)	Case No. U-18224
Two Reciprocating Internal Combustion Engine	)	
Electric Generation Facilities Located in the	)	
Upper Peninsula of Michigan,	)	
Approval of Certificate(s) of Public Convenience	)	
And Necessity, approval of a Special Contract with	)	
Tilden Mining Company L.C.	)	
and related accounting and ratemaking	)	
authorizations.	)	

CONFIDENTIAL

EXHIBIT A-__ (SMS-2)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

****

In the Matter of the Application of	)	
Upper Michigan Energy Resources Corporation	)	
for approval of a Certificate of Necessity	)	
pursuant to MCL 460.6s for	)	Case No. U-18224
Two Reciprocating Internal Combustion Engine	)	
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And Necessity, approval of a Special Contract with	)	
Tilden Mining Company L.C.	)	
and for related accounting and ratemaking	)	
authorizations.	)	

** Public Version **

DIRECT TESTIMONY AND EXHIBITS

OF

JAMES O. SHERMAN, JR.

ON BEHALF OF

UPPER MICHIGAN ENERGY RESOURCES CORPORATION

Q. Please state your name and business address.

A. My name is James O. Sherman, Jr. My business address is 231 W. Michigan Street, Milwaukee, Wisconsin 53203.

Q. By whom are you employed and what is your position?

A. I am employed by Wisconsin Electric Power Company ("WEPCo"), a subsidiary of WEC Energy Group, Inc. ("WEC Energy Group") as Director – Wholesale and Customer

Solutions and work for all of WEC Energy Group's electric utilities in this capacity.

Q. Please describe your educational and business experience.

A. My education includes a Bachelor of Science degree in Electrical Engineering from Purdue University (1990) and a Master's degree in Business Administration from Olivet Nazarene University (1996).

My work experience began in 1990 with Commonwealth Edison, where I held various retail services and retail account management positions. In 1998, I joined Cooper Power Systems, which is now a part of Eaton Corporation, where I served as their product post-shipment Service Manager and product line manager for parts sales and services. I joined WEPCo in 2008 as a Wholesale Account Manager in the Wholesale Energy Marketing group and moved into the position of Power Marketer in this same group in 2009. My responsibilities included wholesale account and contract management of wholesale customers, power marketing of available capacity and energy, and procurement of renewable energy to meet the company's renewable portfolio standard requirements in all jurisdictions. In 2015, I became Manager – Wholesale Energy Marketing and assumed the added responsibility for Wisconsin Public Service Corporation's ("WPS Corp") wholesale and renewable activities as a result of the acquisition by WEC Energy Group (then known as Wisconsin Energy Corporation) of Integrys Energy Group, Inc. in June, 2015. In 2016, I became the Director – Wholesale and Customer Solutions. In this role, I am responsible for the management of the Wholesale Energy Marketing group and the Customer Solutions group which is responsible for retail account management of the largest commercial and industrial customers for WEC Energy Group's electric utilities, including Upper Michigan Energy

Resources Corporation ("UMERC"), WEPCo and WPS Corp.

Q. Do you hold a professional license or belong to any professional organizations?

A. Yes, I am a licensed Engineer Intern in the State of Indiana and received my license in 1990 (# ET00900529).

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to sponsor the Retail Large Curtailable Special Contract between WEC Energy Group and Tilden Mining Company, L.C. ("Tilden") dated August 12, 2016 ("Tilden Special Contract"), discuss the key provisions of the contract, and request that the contract be approved. I also sponsor and discuss the power purchase agreements ("PPAs") that are the basis of Mr. Knitter's comparison of the cost of providing service to UMERC's non-Tilden customers after the RICE electric generation facilities are in service, to the cost to serve UMERC's non-Tilden customers via the WEPCo PPA and the WPS Corp PPA (his "business as usual" scenario).

Q. Are you sponsoring any exhibits to accompany your testimony?

A. Yes. I am sponsoring the following exhibit: Confidential Exhibit A-__ (JOS-1) – Retail Large Curtailable Special Contract between WEC Energy Group and Tilden. I am also sponsoring Exhibit A-__ (JOS-2) and Exhibit A-_ (JOS-3), which consist of two Purchase Power Agreements ("PPA"), one with WEPCo for the legacy WEPCo customer load in the WEPCo Rate Zone (the "WEPCo PPA"), and one with WPS Corp for the customer load in the legacy WPSC Rate Zone (the "WPS Corp PPA").

Q. Is the Tilden Special Contract relevant to UMERC's request for a Certificate of Necessity ("CON") in its Application in this case?

A. Yes. Tilden represents about 40% of the electric load in the Upper Peninsula of

Michigan ("UP") and is a key stakeholder in the "new, clean generation" solution as required under the Amended and Restated Settlement Agreement ("ARSA") that was executed on March 12, 2015 and approved by the Michigan Public Service Commission's ("Commission" or "MPSC") April 23, 2015 Order in Case No. U-17682. Tilden will be a key UMERC customer via the Tilden Special Contract when the generation achieves commercial operation. Because Tilden is a retail customer, Commission approval of the Tilden Special Contract is required.

Q. How does Tilden currently receive electric service?

A. Tilden is currently a customer of, and is served by, WEPCo under a Special Contract approved by the Commission on April 23, 2015, in Case No. U-17682.

Q. Will Tilden ever become a customer of UMERC?

A. Yes, Tilden will become a customer of UMERC when the new generation facility serving Tilden has been placed in service and Tilden begins taking service under the Tilden Special Contract.

Q. What will happen to the current Special Contract with Tilden that is in place with WEPCo?

A. When Tilden begins taking service under the Tilden Special Contract, the current Special Contract between Tilden and WEPCo will terminate and Tilden will cease being a customer of WEPCo.

Q. Let's discuss the key provisions of the Tilden Special Contract. First, why is the counterparty WEC Energy Group?

A. Because UMERC did not exist and was not approved for implementation by the Commission at the time the Tilden Special Contract was executed, WEC Energy Group

assumed responsibility as the counterparty.

Q. Will UMERC ever be the counterparty to the Tilden Special Contract?

A. Yes. Pursuant to Section 5.1.1 of the Tilden Special Contract, WEC Energy Group assigned its rights, obligations and interest in the Tilden Special Contract to UMERC effective January 1, 2017.

Q. What is the term of the Tilden Special Contract?

A. The term is 20 years.

Q. When does the term begin?

A. The 20-year term will begin on the first day of the first month following commercial operation of the new generation facility serving Tilden, as defined in the Tilden Special Contract.

Q. Will Tilden be an owner of the new generation facility serving Tilden, and, if not, will Tilden contribute capital toward the Project?

A. No, Tilden will not be an owner of the facility and, in fact, Tilden will not contribute any capital to the project. The generation project will be 100% funded by UMERC and the new generation facility serving Tilden will be 100% owned by UMERC. The recovery of some of UMERC's investment costs from Tilden will be accomplished through a monthly payment by Tilden to UMERC over the 20-year term of the Tilden Special Contract.

Q. How is the Planning Load Level (MW quantity) for Tilden determined?

A. Tilden's Planning Load level is the load level that Tilden will select pursuant to Section 2.3 of the Tilden Special Contract, and to which Tilden commits to operate at or below during any curtailments, including non-emergency curtailments requested by the

Midcontinent Independent System Operator, Inc. ("MISO"), American Transmission Company ("ATC"), or other reliability authority during the Delivery Period, which is defined in the Tilden Special Contract.

Q. Does this Planning Load level have any correlation to the amount of generation of the Reciprocating Internal Combustion Engines ("RICE") that will be installed?

A. Yes it does.

Q. Please explain.

A. Per Section 2.2.4 of the Tilden Special Contract, the total generation of the RICE units to be installed shall be sized in MW increments to achieve as close to the projected Planning Load level requested by Tilden as commercially reasonable. Final Planning Load cannot exceed the installed capacity of the RICE units.

Q. Has the final Planning Load level been determined?

A. Not at this time, but it is expected to be determined by January 31, 2017.

Q. Will Tilden be a firm load customer?

A. No, they will not.

Q. What level of firmness of load will Tilden be?

A. It is expected that Tilden will be 100% non-firm load, unless adjusted either voluntarily or involuntarily pursuant to the terms of the Tilden Special Contract.

Q. Does the fact that Tilden will be 100% non-firm load impact what Tilden is charged?

A. Yes it does.

Q. Please explain.

A. Pursuant to Section 2.1.2, a fixed Planning Load Charge Rate of [begin confidential]

[redacted] [end confidential] will be charged to Tilden on a monthly basis, for the generation installed based on the Planning Load level requested by Tilden. This is based on [begin Confidential] [redacted] [end Confidential] of installed capacity. However, because Tilden is non-firm load, it will receive a fixed Non-Firm Planning Load Credit Rate of 50% of the Planning Load Charge Rate which will be credited to Tilden on a monthly basis and is applicable to all Non-Firm Planning Load pursuant to Section 2.1.3.

Q. What is Non-Firm Planning Load?

A. Non-Firm Planning Load is the difference in MW between the Planning Load amount and the Firm Load Amount; we expect the Firm Load Amount to be zero (0) MW.

Q. Why does Tilden receive a credit for their Non-Firm Planning Load level?

A. Since Tilden will be a non-firm customer, it is subject to curtailments and will not need the MISO capacity that will be available from the generation units to cover its load. As such, it will receive a Non-Firm Planning Load Credit Rate.

Q. So based on the Planning Load Charge Rate and the Non-Firm Planning Load Credit Rate applied to Tilden, what investment recovery does UMERC effectively recover from Tilden?

A. UMERC will effectively recover 50% of the investment costs for the generation project from Tilden and will receive 100% of the capacity value of the generation project.

Q. If Tilden does not need the MISO capacity, where is it used?

A. The capacity will be used to meet the MISO Resource Adequacy requirements of UMERC, including planning reserves to serve its non-mine load.

Q. Who pays for this capacity?

A. UMERC, via the Non-Firm Planning Load Credit provided to Tilden. UMERC will also receive the benefit of all capacity sales/revenues.

Q. Earlier you stated that it was possible for Tilden's Firm Load level to be adjusted. Please explain.

A. Tilden's Firm Load can be adjusted both voluntarily and involuntarily.

Q. What do you mean by involuntarily?

A. [begin confidential] [redacted] [end confidential]

Q. Are there financial penalties on Tilden for failure to meet curtailment obligations?

A. [begin confidential] [redacted] [end confidential]

Q. What other key charges does Tilden pay for on a monthly basis and at what level?

A. Pursuant to Articles 2.1.4, 2.1.5 and 2.1.6, Tilden is responsible for 100% of the following charges on a direct pass through of actual cost basis: distribution costs, generation O&M, ATC and MISO charges applicable to Tilden's load. Administrative & General is estimated to initially be [begin confidential] [redacted] [end confidential] per month, adjusted annually.

Q. Please clarify what benefits Tilden receives from the generation?

A. Tilden will receive first rights to the value of the energy from the generation up to the quantity of their load nomination in the day-ahead market and capacity required to cover their firm load (if they were to have any).

Q. **Please clarify what direct financial benefits UMERC receives from the generation?**

A. UMERC will receive rights to the capacity from the installed generation (less Tilden's firm load requirements), will receive 100% of the value of the ancillary services (regulating reserve and contingency reserves) provided by the generation, and will receive the value of the available generation in excess of Tilden's load in any hour. In addition, UMERC will receive secondary financial benefits and reliability benefits from having locally-sourced generation.

Q. How does UMERC benefit from having locally-sourced generation?

A. The output of the generation project will tend to reduce the cost of the energy UMERC needs to serve its non-mine loads. Since the generation resources will be located relatively close to the mine load from the perspective of the bulk electric system, there will be less energy imported into the UP from Wisconsin and Lower Michigan than would otherwise be the case. This will tend to result in lower LMPs than would otherwise be seen, and UMERC will benefit from reduced costs for any energy purchases from the MISO market. UMERC will also realize reliability benefits from local reactive power capability, dynamic grid support, and decreased dependence on the reliability of the transmission grid.

Q. Is this an off-take agreement such that Tilden has committed to purchase a certain amount of energy from the generation?

A. No. Tilden will not be an off-taker under this agreement. The generating units will act as a financial hedge to the cost to serve Tilden Load. There is no minimum requirement on the amount of financial hedge provided by the generators.

Q. Will UMERC receive this same hedge protection from the generation?

A. Yes, for the portion of generation that is not utilized by Tilden and is available in the MISO market, UMERC would receive hedge protection from the generation.

Q. Regarding the construction of the generation units, does Tilden have any input?

A. No, pursuant to Section 2.2.3, Seller has sole authority and discretion for selection of the RICE vendor, generation unit sizes, and number and location of sites.

Q. Is gas supply 100% guaranteed to all generation facilities?

A. No, it is not.

Q. Could this have an impact on the availability of generation?

A. Yes, the quantity of available MW of generation could be limited.

Q. Does this mean that the UP would face an energy shortage?

A. No, since the UP is part of MISO, there is a fleet of generators that supply energy to the UP. All load serving entities procure the energy to serve their load from MISO and not specific generation units. The limiting factors would be available transmission to support the load requirements of all of the UP.

Q. Does the lack of guaranteed gas supply affect potential Tilden curtailments?

A. Yes, the lack of 100% firm gas and fuel oil backup could indirectly impact Tilden curtailments. If generation output was limited due to lack of sufficient natural gas, then less local generation would be available to MISO and they may need to curtail Tilden if there were not enough other system resources to serve the UP.

Q. Has UMERC contracted for some uninterruptible natural gas supply?

A. Yes, the uninterruptible natural gas volume purchased as described in the testimony of Russel T. Laursen, will provide sufficient natural gas to serve 100% of the Baraga Township site generation capacity and about 50-60% of the Negaunee Township site

generation capacity. These uninterrupted gas supply volumes were agreed to by Tilden as documented in Section 2.2.5 of the Tilden Special Contract.

Q. Should the generation facilities be designed with fuel oil backup?

A. No, the volume of uninterruptible natural gas supply will provide sufficient natural gas a vast majority of the time. In the rare instance that insufficient gas is available to operate the generation at full output, MISO will have other system resources available, and the ability to curtail Tilden, if necessary, to ensure reliable service to the UP.

Q. Are there termination provisions in the Tilden Special Contract?

A. Yes, Section 3.12 provides Tilden with voluntary termination rights.

Q. Are the non-mine UMERC customers held harmless, if Tilden voluntarily terminates the contract?

A. Yes, non-mine UMERC customers will be held harmless if Tilden voluntarily terminates the contract. Section 3.12 outlines the termination provisions in the in the event of a voluntary termination by Tilden. [begin confidential] [redacted]

[redacted]

[redacted] [end confidential]

Q. What happens if there is an involuntary termination of the Tilden Special Contract, and Tilden is not able to make required payments?

A. The settlement agreement approved in Case No. U-18061 provides in Paragraph 5.b.(1):

> In the event of: (i) an involuntary termination of the Retail Large Curtailable Special Contract between WEC and Tilden dated August 12, 2016 ("2016 Tilden Special Contract"), appended as Attachment A hereto; and (ii) Tilden is not able to pay, per a bankruptcy ruling, then WEC will be responsible for and protect UMERC's other ratepayers from the cost associated with Tilden's portion of the capital investment, depreciation expense, and return on investment, taxes and fixed operating costs in the new generator units that would be the subject of UMERC's planned Certificate of Necessity ("CON") proceeding, so that such costs are not passed on to UMERC's ratepayers.

Q. Both your testimony and your Exhibit A-__ (JOS-1) are redacted. Please explain why?

A. Redaction is necessary to protect both UMERC and Tilden. The Tilden Special Contract and my testimony contain pricing, terms and conditions and operational provisions that, should they be generally disclosed, would aid a competitor and would cause harm to both UMERC and Tilden. The confidential status derives actual independent economic value from not being generally known to competitors or providers in the electric power market, as well as others who could obtain economic value from the disclosure of such information. This information loses its economic value if made public. No public benefit extends from the disclosure of the information contained in the Tilden Special Contract and my testimony. Competitors, suppliers and others would benefit from economic

opportunity presented by the disclosure of this information to the potential detriment of Tilden and UMERC and its ratepayers. I understand that UMERC will be seeking a protective order in this case, pursuant to which unredacted versions of this testimony and Exhibit A-__ (JOS-1) can be provided to parties to this case.

Q. Mr. Knitter's testimony and exhibits compare the cost of providing service to UMERC's non-Tilden customers after the RICE electric generation facilities are in service, to the cost to serve UMERC's non-Tilden customers via the WEPCo PPA and the WPS Corp PPA. Are you sponsoring the WEPCo PPA and WPS Corp PPA as exhibits?

A. Yes. Exhibit A-_ (JOS-2) is the WEPCo PPA, and Exhibit A-__ (JOS-3) is the WPS Corp PPA.

Q. What are the charges in the PPAs based on?

A. Both PPAs utilize Federal Energy Regulatory Commission ("FERC") approved formula rates. The WEPCo PPA uses capacity and energy formulas contained in WEPCo's Formula Rate Wholesale Sales Tariff, FERC Electric Tariff Volume No. 9, which is included as part of my Exhibit A-_ (JOS-2). The capacity and energy formulas that are used in the WPS Corp PPA are contained in WPS Corp's FERC Rate Schedule W-1A for Full Requirements Service to Wholesale Customers, Volume 2, which is included as part of my Exhibit A-_ (JOS-3).

Q. Please provide a general description of the capacity rate.

A. The capacity rate is intended to recover the generation ownership costs and purchase capacity costs of the providing utility, *i.e.*, WEPCo and WPS Corp. Generation ownership costs include the return on and of the generation assets. The corporate

purchased capacity and generation ownership costs are divided by the summation of the system 12 monthly peaks in a year. This creates a $/kw/month charge or rate that is charged to the customer's load at the time of the company's monthly peak. Customers are billed on estimated rates that are trued-up the following year once the supplier's FERC Form 1 is filed that provides the audited actual company costs.

Q. Please provide a general description of the energy formula rate.

A. The energy rate is intended to recover WEPCo's and WPS Corp's fuel, energy purchases, and variable generation operation and maintenance ("O&M") costs. The energy formula rate is intended to recover the fuel and energy purchases. This is accomplished by taking the corporate fuel and energy purchase costs and dividing by the system sales in megawatt hours ("MWh"), which provides a system $/MWh rate. For WPS Corp, the on peak energy rate is calculated by multiplying the system $/MWh rate by 1.2. Similarly, the off peak energy rate is calculated by multiplying the system $/MWh rate by 0.8. For WEPCo, the on peak energy rate is calculated by multiplying the system $/MWh rate by 1.14. Similarly, the off peak energy rate is calculated by multiplying the system $/MWh rate by 0.9. The customer (*i.e.*, UMERC) is billed using on peak and off peak rates determined using forecasted system costs and sales and are trued up with actual system costs and sales on a two-month lag for WPS Corp and for WEPCo on a one month lag for Energy Rate Part 1 and on an annual basis for Energy Rate Part 2.

Q. Can you provide a general description of the transmission charges?

A. The transmission charges are a pass-through to UMERC of the actual transmission, ancillary and certain market charges incurred by WPS Corp and WEPCo from MISO. This is required since the formula rates do not include transmission cost recovery

mechanisms and UMERC will not be charged directly by MISO for any applicable transmission costs since UMERC will not be a registered MISO Market Participant.

Q. The WEPCo energy rates are billed in two parts, Energy Rate Part 1 and Energy Rate Part 2. Would you please explain the difference?

A. Energy Rate Part 1 recovers fuel and energy related purchased power cost that would essentially be included in the FERC fuel clause: Fuel and Purchased Power (energy related) less Opportunity Sales Revenue (energy related). Energy Rate Part 2 recovers O&M costs defined by the FERC "Predominance Method" as energy related and are not included in the Energy Rate – Part 1 (some maintenance related accounts).

Q. Please explain the capacity charge calculation.

A. Both PPAs contain a demand charge that is derived using a formula that first derives a total system generation revenue requirement, and second divides this dollar amount by the sum of the 12 monthly system peak loads. This creates a $/kw rate that will be applied to the UMERC retail load at the time of WPSC Rate Zone (for the WPS Corp PPA) or WEPCo Rate Zone (WEPCo PPA) monthly system peak load.

Q. Please explain the energy charge calculation.

A. Both PPAs contain energy charges that are derived using a formula that first derives a total system energy related costs, and second divides this dollar amount by the monthly system energy sales. The energy charges change on a monthly basis and are initially billed using estimated rates that are trued up on either a one or two month lag once actual sales and costs are known.

Q. Please explain the transmission charge calculation.

A. The transmission charges are intended to pass-through to UMERC, the actual

transmission, ancillary and certain market charges incurred by WPS Corp and WEPCo from charges that are derived from MISO. At the time of the filing, the specific data for this calculation was not available. The rates and calculations shown for transmission costs use transmission costs reflected in the PSCR cases. This is a reasonable reflection of the cost estimates for these charges.

Q. Please explain the interruptible credit calculation.

A. Both the WEPCo and WPSC Rate Zones have retail customers that take service under a tariff that provides the company the right to interrupt load under certain conditions. This interruptible retail load reduces the firm generation capacity that is needed to satisfy resource adequacy requirements with respect to generation capacity. UMERC receives a credit for the amount of retail interruptible load that will be registered as a Load Modifying Resource ("LMR") with MISO for a planning year. For the WEPCo PPA, the interruptible credit is based on the MISO published cost of new generation capacity - Cost on New Entry ("Cone"). For the WPSC PPA, the interruptible credit is based on the interruptible credit rate as stated in the W-1A Tariff.

Q. Does this conclude your testimony?

A. Yes it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*** * * * ***

In the Matter of the Application of	)	
Upper Michigan Energy Resources Corporation	)	
for approval of a Certificate of Necessity	)	
pursuant to MCL 460.6s for	)	Case No. U-18224
Two Reciprocating Internal Combustion Engine	)	
Electric Generation Facilities Located in the	)	
Upper Peninsula of Michigan,	)	
Approval of Certificate(s) of Public Convenience	)	
And Necessity, approval of a Special Contract with	)	
Tilden Mining Company L.C.	)	
and related accounting and ratemaking	)	
authorizations.	)	

PUBLIC VERSION

EXHIBIT A-__ (JOS-1)

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RETAIL LARGE CURTAILABLE SPECIAL CONTRACT

This RETAIL LARGE CURTAILABLE SPECIAL CONTRACT, including all Exhibits (the "Agreement"), is made and entered as of this 12th day of August, 2016, by and between WEC Energy Group, Inc., a Wisconsin corporation ("WEC" or "Seller"), AND Tilden Mining Company L.C., by The Cleveland-Cliffs Iron Company, its Managing Agent ("Tilden"), a Michigan limited liability company ("Buyer"). Hereinafter, the parties hereto are sometimes referred to collectively as the "Parties," or each individually as a "Party".

WITNESSETH

WHEREAS, Seller is a public utility holding company whose electric Affiliates are engaged in the business of generating, distributing and selling electric power and energy and related services at wholesale and retail within the States of Wisconsin and Michigan;

WHEREAS, Buyer is a Michigan retail electric customer of Wisconsin Electric Power Company, an Affiliate of the Seller, and is in the business of mining within the Upper Peninsula of the State of Michigan;

WHEREAS, Buyer currently purchases its electric power needs from Wisconsin Electric Power Company on its own behalf;

WHEREAS, the Parties are signatories to an Amended and Restated Settlement Agreement (ARSA) with the State of Michigan regarding the desire for a comprehensive energy solution for the Upper Peninsula of Michigan;

WHEREAS, the Parties have jointly and mutually arrived at a solution that meets the objectives of the ARSA;

WHEREAS, each Party believes it is in its best interest and desires to enter into this Agreement as further described herein;

NOW, THEREFORE, in consideration of the recitals and mutual promises, covenants and agreements contained herein and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties, intending to be legally bound, hereby agree as follows:

ARTICLE ONE
GENERAL DEFINITIONS

1.1 As used in this Agreement, the following terms have the meanings set forth below:

ACA has the meaning given such term in the natural gas pipeline provider's tariff.

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Administrative and General Expense (A&G) means Seller's costs of staff salaries, executive wages and benefits, depreciation on office fixtures and equipment, insurance, legal counsel salaries, office supplies, accounting and tax fees, legal fees, subscriptions, etc. For purposes of the Agreement, A&G shall be equal to [redacted] per month, adjusted annually on the anniversary of the start of the Delivery Period using the Consumer Price Index - All Urban Consumers (CPI-U) U.S. City Average, All items less food and energy, not seasonally adjusted, 1982-1984=100 reference base.

Actual Generation Daily Heat Rate (AGDHR) means the daily calendar DTH actual gas consumption for Generation Resources in an Operating Day divided by the daily calendar actual MWh output, net of any unit auxiliary load, from Generation Resources.

Affiliate means any Person directly or indirectly controlling or controlled by or under direct or indirect common control of a specified Person. For purposes of this definition, "control" means the power to direct the management and policies of such Person, directly or indirectly, whether through the ownership of voting securities, by contract or otherwise. For purposes of this Agreement, it shall be assumed that the direct or indirect owner of more than 50% of the outstanding stock or other equity interest of a Person has control of such Person. The terms "controlling" and "controlled" have meanings correlative to the foregoing.

ARR/FTR Benefit Credit means credits or charges associated with Auction Revenue Rights [redacted]

ATC means American Transmission Company, LLC, or its successors.

Auction Revenue Rights (ARRs) has the meaning given in the MISO Tariff.

Billing Cycle means each calendar month during the Delivery Period and any partial calendar month at the beginning or end of the Delivery Period.

Buyer has the meaning given such term in the preamble.

Calendar Year means the twelve month period beginning on January 1 and ending on December 31.

Capacity means the capability to generate a particular amount of electrical energy at a particular time that meets the requirements for capacity established by MISO.

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Commercial Pricing Node (CP Node) has the meaning given in the MISO Tariff.

Commercial Operation Date (COD) means the date that Seller notifies Buyer that the Generation Resources are capable of sufficient deployment to meet Seller's obligations under this Agreement. [redacted]

CON means a Certificate of Necessity for a Generation Resource issued by the Michigan Public Service Commission.

Day means a 24-hour period beginning at 12:01 am EST and ending at 12:00 midnight EST.

Day-Ahead Cleared Load means the quantity [redacted] purchased in the MISO Day-Ahead Market for a given hour during an Operating Day.

Day-Ahead Cleared Generation Resource Energy means the quantity of Generation Resource Energy [redacted]

Day-Ahead Cleared Generation Resources means the quantity of Generation Resources Energy [redacted]

Day-Ahead Make Whole Payment means the Day-Ahead Revenue Sufficiency Guarantee Credit as defined in the MISO Tariff [redacted].

Day-Ahead Cleared Generation Resources Make Whole Payment Credit means the product of the Day-Ahead Make Whole Payment associated with the Day-Ahead Cleared Generation Resources [redacted]

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Day-Ahead Weighted Generation Resources LMP means the weighted average of the MISO Day-Ahead Market LMP for the Generation Resources [redacted]

Deferred Payment Agreement means the Deferred Payment Amendment to the Tilden 2015 – 2019 Large Curtailable Special Contract.

Demand Bid means a financially binding bid to purchase Energy [redacted]

Delivery Period means the period of time described in Section 2.0.4.

Distribution Facilities means the existing 138,000 to 13,800 volts transformation and associated equipment currently owned by Wisconsin Electric Power Company at the existing Tilden and Empire substations at or near Buyer's locations.

DTH means deca-therm.

Electric Infrastructure means one of each of the following to support the electrical interconnection of the generation to the electric transmission system: [redacted]

Energy has the meaning given such term in the MISO Tariff.

Environmental Credits means credits or charges resulting from existing or future environmental attributes that are associated with electricity generated from the Generation Resources including carbon emissions, carbon offsets, carbon allowances, carbon dioxide emissions, or other environmental credits or charges whether pursuant to or arising from any Governmental Authority.

EPC has the meaning given such term in the natural gas pipeline provider's tariff.

EST means Eastern Standard Time.

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Firm Load means the load level that is Buyer's level of firm service under the Agreement.

[redacted]

Force Majeure means any cause or occurrence beyond the reasonable control of and without the negligence of the Party claiming Force Majeure which causes the Party to be unable, or otherwise materially impairs its ability, to perform its obligations in whole or in part hereunder. Subject to the foregoing, such causes or occurrences may include any acts of God; acts of the public enemy; change in environmental-related Law; terrorism; wars; blockades; insurrections; riots; epidemics; landslides; lightning; earthquakes; fires; storms; floods; washouts; civil disturbances; strikes, lockouts or work stoppages; and any other cause, whether of the kind herein enumerated or otherwise, which, despite reasonable efforts of such Party to prevent or mitigate its effects, prevents or delays the performance of a Party, or prevents the obtaining of the benefits of performance by the other Party, and is not within the control of the Party claiming excuse. The following acts, events or causes shall in no event constitute an event of Force Majeure: (i) any lack of profitability to a Party or any losses incurred by a Party or any other financial consideration of a Party; or (ii) unavailability of funds or financing.

Gas Infrastructure means new laterals as required.

Generation Delivery Point means the point of delivery of Generation Resource Energy [redacted]

Generation Resource means the Reciprocating Internal Combustion Engines installed at a single location for this Agreement. [redacted]

Generation Resources means the aggregate of each Generation Resource installed for this Agreement. [redacted]

Generation Resources Capital Expense means an amount spent during the Delivery Period to acquire or improve the Generation Resources, Gas Infrastructure, or Electric Infrastructure.

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Generation Resources Energy means the sum of Energy output from each Generation Resource.

Generation Resources Operational Expense means all the operations and maintenance expense and labor expense required to maintain the Generation Resources, Gas Infrastructure, and Electric Infrastructure in good operating condition in accordance with Good Utility Practice.

[redacted]

Good Utility Practice means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision is made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather, intended to include acceptable practices, methods, or acts generally accepted in the region that is contemplated by this Agreement but not necessarily codified.

Governmental Authority means (i) the federal government of the United States, (ii) any state, county or local government, (iii) any regulatory department, body, political subdivision, commission, bureau, administration, agency, instrumentality, ministry, court, judicial or administrative body, taxing authority, (iv) any other authority of any of the foregoing (including any corporation or other entity owned or controlled by any of the foregoing), and (v) MISO, NERC, and RFC; in each case in (i) - (v) above having jurisdiction over any or all of the Parties, this Agreement or the transmission system operated by MISO, whether acting under express or delegated authority.

Law means any federal, state and local laws, statutes, regulations, rules, codes, orders, judgments, decrees or ordinances enacted, adopted, issued or promulgated by any Governmental Authority, including any authorizations issued to a Party or by which a Party may be bound (including any of the foregoing pertaining to electrical, building, zoning, environmental and occupational safety and health requirements) or any published directive, guideline, tariff, requirement or other restriction of a Governmental Authority or any determination by, or interpretation of, any of the foregoing by any Governmental Authority, binding on a given Person in a relevant jurisdiction.

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LMP means the "Locational Marginal Price" as determined by MISO.

LMR means Load Modifying Resource and has the meaning given such term in the MISO Tariff.

[redacted]

Market Participant has the meaning given such term in the MISO Tariff.

MISO means the Midcontinent Independent System Operator, Inc., or any successor organization.

MISO Administrative Charges means charges or credits assessed to a Market Participant that are based on MISO operating costs, which are (i) currently reflected in MISO Schedule 17 and Schedule 24, as may be modified or deleted and replaced from time to time; or (ii) included in any other schedule as may be applicable under MISO Tariff that is similar in nature and function to the schedules in (i) above.

MISO Day-Ahead Market means the Day-Ahead Energy and Operating Reserves Market as defined in the MISO Tariff.

MISO Real-Time Market means the Real-Time Energy and Operating Reserves Market as defined in the MISO Tariff.

MISO Tariff shall mean the document adopted by MISO, and subject to review by the Federal Energy Regulatory Commission ("FERC"), including any attachments or exhibits referenced in that document, as amended from time to time, that contains the scheduling, operating, planning, reliability, and settlement (including customer registration) policies, rules, guidelines, procedures, standards, and criteria of MISO. For the purposes of determining responsibilities and rights at a given time, the MISO Tariff, as amended in accordance with the change procedure(s) described in the MISO Tariff, in effect at the time of the performance or non-performance of an action, shall govern with respect to that action.

MISO Planning Year means the twelve month period from June 1 through May 31 of the following year, as subject to modification by MISO.

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MISO Value of Lost Load has the meaning given such term in the MISO Tariff [redacted]

MPSC means the Michigan Public Service Commission, or its successor.

MW means a megawatt.

MWh means a megawatt-hour.

NERC means the North American Electric Reliability Corporation, including in its capacity as the Electric Reliability Organization appointed by FERC, or any successor organization.

Non-Firm Planning Load means the difference in MW between the Planning Load amount and the Firm Load amount.

Operating Day has the meaning given such term in the MISO Tariff or related documents.

Party(ies) has the meaning given such term in the preamble.

Person means any natural person, corporation, limited liability company, general partnership, limited partnership, proprietorship, other business organization, trust, union, association or Governmental Authority.

Planning Load means the load level in MWs selected by Buyer and to which Buyer commits to operate at or below during any curtailments, including non-emergency curtailments requested by MISO, ATC, or other reliability authority during the Delivery Period.

Planning Reserves means the amount of generation required to be maintained pursuant to the generation resource planning reserve margin requirements approved and administered by each Governmental Authority with respect to which Seller is obligated to meet generation resource planning reserve margin requirements.

[redacted]

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[redacted]

RFC means the ReliabilityFirst Corporation, or any successor organization.

Seller has the meaning given such term in the preamble, provided however, if Seller assigns all its rights and obligations under this Agreement to a permitted assignee, it shall mean such permitted assignee.

UMERC means Upper Michigan Energy Resources Corporation.

[redacted]

[redacted]

ARTICLE TWO
CONTRACT SPECIFICS AND OPERATIONAL MECHANICS

2.0 Term of Agreement, Character of Service, and Delivery Period

2.0.1 Term: This Agreement is effective upon signing by both Parties (such date the "Effective Date") and continues through to the conclusion of the Delivery Period and payment by Buyer of all amounts due under this Agreement (the foregoing described period, the "Term"), unless earlier terminated in accordance with the terms of this Agreement.

2.0.2 During the Delivery Period, Seller will supply three-phase, 60 hertz, power service to Buyer at approximately 13,800 volts. Seller will provide such service through the Distribution Facilities; such facilities shall only be used to supply power service to Buyer or for auxiliary load of future generation facilities. Seller shall be responsible for the operation, repair and maintenance of such transformation and associated distribution facilities.

2.0.3 Metering: Seller shall install and maintain all apparatus and materials necessary for the measurement of Buyer's load. Distribution loss

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compensation, related to the Distribution Facilities, will be applied as applicable.

2.0.4 Delivery Period: Twenty (20) years beginning with the HE01 EST of the first day of the first month following the Commercial Operation Date ("COD") subject to this Agreement. For clarity, if the COD is May 10, 2019, the delivery period will be from June 1, 2019 through May 31, 2039.

2.0.5 Conditions: This Agreement shall be binding on and after the date of execution by both Parties. Notwithstanding the foregoing, the Parties' obligations under this Agreement are expressly subject to the fulfillment and satisfaction of each of the conditions identified in Exhibit C.

2.0.5.1 Except with respect to the conditions identified in Part 5 B. of Exhibit C, in each case the fulfillment of each condition shall be determined in form and substance satisfactory to Seller in Seller's sole discretion; provided that Seller may waive any such condition or may extend the date for fulfillment of any such condition by written notice to Buyer no later than the date for satisfaction of the condition. In the event that any of the conditions have not been fulfilled and satisfied by the date indicated, Seller may terminate this Agreement without further obligation by written notice to Buyer delivered no later than thirty (30) days after the date for satisfaction of the condition. If no such termination notice is delivered by Seller, this Agreement shall remain in full force and effect, and Seller shall be deemed to have waived its right to terminate this Agreement pursuant to this Section.

2.0.5.2 With respect to the condition identified in Part 5 B. of Exhibit C, the fulfillment of such condition shall be determined in form and substance satisfactory to both Buyer and Seller in their discretion; provided that they may waive such condition or may extend the date for fulfillment of such condition by mutual agreement no later than the date for satisfaction of the condition. In the event that the condition has not been fulfilled and satisfied by the date indicated, either Party may terminate this Agreement without further obligation by written notice to the other Party delivered no later than thirty (30) days after the date for satisfaction of the condition. If no such termination notice is delivered, this Agreement shall remain in full force and effect, and the Parties shall be deemed to have waived their right to terminate this Agreement pursuant to this Section.

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[redacted]

2.1 Pricing

2.1.1 The rates and charges in this Agreement apply during the Delivery Period.

2.1.2 Planning Load Charge Rate

2.1.2.1 The Planning Load Charge Rate shall be [redacted] and is applicable to all Planning Load. The Planning Load Charge Rate is based on total project costs of [redacted] of installed generation and includes construction and acquisition financing, Generation Resources, balance of plant, land, Gas Infrastructure, and Electric Infrastructure. If Seller's total actual project costs exceed [redacted], and the additional cost is due to additional environmental improvements required at the Generation Resources, the project site(s), and adjacent sites to the project site(s), then the Planning Load Charge shall be increased to include the incremental cost above [redacted] up to a maximum of [redacted]. Seller shall notify Buyer of any such cost adjustments, subject to Buyer verification, prior to the start of the Delivery Period.

2.1.2.2 If CON is not approved by December 31, 2017, then an adjustment will be applied to the project cost. The adjustment will be equal to the percentage change in the [redacted] Index between December 2017 and the month when the CON is approved.

2.1.3 Non-Firm Planning Load Credit Rate

2.1.3.1 The Non-Firm Planning Load Credit Rate shall be equal to 50% of the Planning Load Charge Rate. The Non-Firm Planning Load Credit Rate is applicable to all Non-Firm Planning Load.

2.1.4 Monthly Fixed Charges

2.1.4.1 Monthly Fixed Charges ($/month) shall be adjusted annually and consist of a direct pass through of actual costs, including:

2.1.4.1.1 Direct pass through of 100% of actual distribution costs for service to Buyer; to be determined using a direct

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assignment method that is limited to Seller's actual costs of Seller's transformation and associated distribution facilities at Buyer's location, using FERC-approved fixed charge methodology process;

2.1.4.1.2 Direct pass through of 100% of Administrative and General Expense to Buyer;

2.1.4.1.3 Generation Resources Operational Expense: Direct pass through of 100% of actual costs to Buyer; and

[redacted]

2.1.4.1.4 If Seller incurs a Generation Resources Capital Expense, Seller shall pass through [redacted] of such capital expenditures to Buyer [redacted] resulting in a monthly fixed charge. Upon notice to Buyer by Seller of the Generation Resources Capital Expense, Buyer shall pay the monthly fixed charge on a monthly basis for the remaining duration of the

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Delivery Period. [redacted]

2.1.5 ATC Charges

2.1.5.1 ATC Charges are variable charges and consist of [redacted]

2.1.6 MISO Load Charges

2.1.6.1 MISO charges related to load are variable charges determined as follows:

2.1.6.1.1 [redacted]

2.1.6.1.2 [redacted]

2.1.6.1.3 [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

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[redacted]

[redacted]

[redacted]

2.1.7.2 Energy Charge – Generation

2.1.7.2.1 The Energy Charge – Generation ($) is calculated for each hour in the Billing Cycle on an after-the-fact basis and consists of [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

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[redacted]

2.1.9 Energy Optimization and Renewable Energy Charge

2.1.9.1 The Energy Optimization Charge shall be a variable charge. The Energy Optimization charge shall consist of a direct pass through of actual MPSC-approved charges and credits for service to Buyer, if any, in accordance with Michigan law.

2.1.9.2 The Renewable Energy Charge shall be the maximum allowed by statute, currently $187.50 per meter per month, provided that Seller and its Affiliates are held harmless.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

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2.2 Generation

2.2.1 Seller has selected Reciprocating Internal Combustion Engines (RICE) technology for this application.

2.2.2 The RICE units are currently planned to be installed at two locations to approximately match Planning Load (Reference Exhibit A – Generation Installation Location Map) as follows:

2.2.2.1 West Region Site Location – Installed MW dependent on MISO analysis, and

2.2.2.2 Either a Central North Site Location or a Central South Site Location for the balance of Planning Load.

2.2.2.2.1 Buyer shall cooperate with Seller in the evaluation of site(s) for the Generation Resource. The Parties will work together to identify a site acceptable to Seller for use by Seller for the construction and operation of the Generation Resources, within 30 days of the Effective Date.

2.2.3 Seller shall have sole authority and discretion for selection of the RICE vendor, generation unit sizes, number and location of sites and shall advise Buyer of its selection.

2.2.4 The total generation shall be sized in MW increments to achieve as close to the projected Planning Load level requested by Buyer as commercially reasonable.

2.2.5 Firmness of Natural Gas Supply

2.2.5.1 Reference Exhibit A – Generation Installation Location Map

2.2.5.2 Seller expects to plan for 100% firm natural gas supply at the West Region Site Location.

2.2.5.3 Seller expects to plan for 50%-60% firm natural gas supply at the Central – North Region Site Location.

2.2.5.4 No commitment is made as to the level of firmness for natural gas supply at the Central – South Region Site Location at this time. If this site location is chosen, then the Parties will negotiate and mutually agree as to the appropriate level of firmness, expected to

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be in the range of 50%-60%, and the allocation of costs between Parties.

2.3 Capacity

2.3.1 Buyer must provide Seller with its projected Planning Load level within twenty (20) days following execution of this Agreement, such Planning Load level to be no less than 165 MW and no greater than 185 MW. Absent such notice as required, the projected Planning Load shall be deemed to be 170 MW.

2.3.2 Seller will provide Buyer written notification of Buyer's final Planning Load level options based on Buyer's projected Planning Load level and Seller's generator unit size selection when selected by Seller but in any event no later than [redacted].

2.3.3 Buyer shall notify Seller by [redacted], of its final Planning Load level option selection as presented by Seller in 2.3.2.

2.3.4 Buyer must provide Seller with its final Firm Load level at least 150 days prior to the beginning of the MISO Planning Year in which COD is expected to occur. Seller will notify Buyer of the projected COD and any changes to the projected COD. If Buyer does not provide Seller with its Firm Load level as required, then the initial Firm Load level shall be assumed to be zero (0).

[redacted]

[redacted]

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[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

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[redacted]

2.5 Operation Protocol

2.5.1 The Parties shall work together to establish an Operation Protocol required of both Parties related to implementation of this Agreement. Such Operation Protocol shall contain an effective date and shall be executed by both Parties prior to implementation.

2.5.2 Such Operation Protocol is contained in Exhibit B – Operations Protocol and may be amended as necessary in accordance with the requirements of Section 2.5.1 to effectuate the administration of this Agreement.

2.6 Buyer's Curtailment Obligations

2.6.1 Buyer shall be subject to curtailment requirements as instructed by MISO, ATC or other reliability authority. Such requirements may include load reduction to Firm Load levels and opening of transmission or distribution system circuit breakers serving Buyer's load. Such instructions will be relayed to Buyer through Seller as the MISO Market Participant as soon as commercially feasible to provide Buyer adequate time to comply with the curtailment requirement.

2.6.2 Buyer will be subject to non-curtailment charges as outlined in this Agreement.

[redacted]

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[redacted]

2.6.3.1 Buyer's Planning Load curtailment obligation survives the termination of this Agreement until the lesser of the tenth anniversary of the date of termination of the Agreement or the end of the original Delivery Period.

[redacted]

ARTICLE THREE
GENERAL TERMS AND CONDITIONS

3.0 Billing

3.0.1 Seller shall provide to Buyer the necessary billing determinants in sufficient detail for Buyer to reasonably determine the accuracy of each invoice supplied by Seller to Buyer during each Billing Cycle, [redacted]

3.1 Transmission Service and Ancillary Services

Buyer shall be responsible for the costs of all transmission and ancillary services to serve its load. Seller shall acquire transmission and ancillary services as required by any Governmental Authority for Buyer's load. In such event, Seller will bill, and Buyer shall pay Seller, for transmission and ancillary services and other costs as determined by any Governmental or Regulatory Authority during each Billing Cycle.

3.2 Audit Rights

3.2.1 Buyer has the right, at its sole expense and during normal working hours, to examine the records of the Seller to the extent reasonably necessary to verify the accuracy of any billing statement, charge or computation made pursuant to this Agreement. If requested by Buyer, Seller shall provide to

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Buyer additional detailed information in support of the billing statements for a Billing Cycle. If any such examination reveals any inaccuracy in any billing statement, the necessary adjustments in such billing statement and the payments thereof will be made promptly and shall bear interest calculated at the FERC established interest rate from the date the overpayment or underpayment was made until paid; provided, however, that no adjustment for any billing statement or payment will be made unless objection to the accuracy thereof was made prior to the lapse of twelve (12) months from the rendition thereof, and thereafter any objection shall be deemed waived.

3.3 Taxes

3.3.1 Charges are inclusive of property taxes levied on Seller.

3.4 No Requirement to Construct or Upgrade Facilities

3.4.1 Except as expressly otherwise agreed to between Buyer and Seller, Seller shall have no obligation to construct or upgrade any facilities in order to provide any electric service under this Agreement for Buyer.

[redacted]

[redacted]

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[redacted]

3.6 Compliance with Laws

3.6.1 Each Party shall at all times comply in all material respects with the MISO Tariff, all applicable Laws of any Governmental or Regulatory Authority and Good Utility Practice relating to the performance of its obligations under this Agreement. Each Party shall give all required notices, shall procure and maintain all necessary authorizations required for its performance of this Agreement and shall pay all charges and fees in connection therewith.

3.7 Change in Law

3.7.1 In the event there is a change or changes in any Law, or interpretation thereof, enacted, adopted or implemented after execution of this Agreement, or any Law (or the interpretation thereof) is applied to a new or different class of parties (a "Change in Law"), then if the Seller is affected by such Change in Law and its costs in meeting its obligations under this Agreement are increased, such increased costs shall be passed through to Buyer to the fullest extent permitted by Law; if the Seller is affected by such Change in Law and its costs in meeting its obligations under this Service Agreement are decreased, such decreased costs shall be passed through to Buyer to the fullest extent permitted by Law. In the event such increased costs cannot be passed through until approval or acceptance by a Governmental Authority, such increased costs shall be accrued and, following receipt of such approval or acceptance, applied to the earliest (and subsequent) periods permitted by Law.

3.8 Change in Circumstances

3.8.1 Change in Treatment by the MPSC: In the event that the MPSC's treatment from time to time of the revenues received or amounts charged by Seller under this Agreement or the amounts paid by Buyer under this Agreement adversely affects the Buyer or Seller (other than a change constituting a Change in Law pursuant to Section 3.7) then, upon notice by the affected Party to the other Party, the Parties shall use their

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commercially reasonable efforts to reform this Agreement in order to alleviate such adverse effect on the affected Party.

3.8.2 MISO Changes: In the event that, at any time from and after the execution of this Agreement, the MISO Tariff is changed (other than a change constituting a Change in Law pursuant to Section 3.7) or Seller withdraws from the MISO Tariff so that the benefits and burdens or the operative provisions of this Agreement are no longer consistent with the original intentions of the Parties, the Parties shall use their commercially reasonable efforts to reform this Agreement in order to give effect to the original intentions of the Parties regarding the appropriate allocation of benefits and burdens to each Party.

3.9 Seller's Rights

3.9.1 Except as otherwise specifically provided in this Agreement, Seller shall have the sole rights, authority and discretion to determine all matters in connection with the performance of its obligations under this Agreement.

[redacted]

3.11 Buyer's Participation in Customer Choice under Michigan Law

3.11.1 Buyer is prohibited from participating in Customer Choice under the provisions of Michigan Law for the Term of this Agreement.

3.12 Early Termination

3.12.1 Buyer may terminate service under this Agreement upon 60 days written notice to Seller. Such termination would be effective on the first day of the first month subsequent to [redacted] written notice ("Termination Date"). If Buyer terminates this service during the Delivery Period or if Seller terminates service for Buyer default, Buyer will pay liquidated damages to Seller determined by summing the following amounts:

[redacted]

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[redacted]

3.12.2 Payment shall be due within 30 days of the Termination Date.

3.13 MPSC Rules and Regulations

3.13.1 Except as otherwise required by law, unless terms contained herein are not consistent therewith, the provisions, all as amended from time-to-time of: (i) the Standard Rules and Regulations as contained in the Rate Book for Electric Service of Seller's Affiliate as approved by the MPSC; (ii) the applicable Administrative Rules established by the MPSC; and (iii) any applicable Michigan law shall govern the sale and distribution of electrical energy to Buyer and this Agreement.

3.14 Default and Cure

3.14.1 A party shall be in default under this Agreement if (i) that party fails to make a payment of any amount required under this Agreement and such failure continues for more than ten (10) days after such party receives written notice of such failure from the non-defaulting party; or (ii) such

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party fails to perform or comply with any other obligation, agreement, term, or provision of this Agreement applicable to it and such failure continues for more than thirty (30) days after such party receives written notice of such failure from the non-defaulting party; provided, however, that if such default of such other obligation cannot reasonably be cured within such thirty-day (30) period and if the first party is proceeding promptly and with due diligence in curing the same, the time for curing such default shall be extended for a period of time, not to exceed ninety (90) days, as may be necessary to complete such curing. If Buyer and/or Cliff Natural Resources, as guarantor, as the case may be, shall be in default under either the Deferred Payment Agreement, of even date herewith between Wisconsin Electric Power Company and Buyer, or Cliff Natural Resources' Guaranty in connection with the Deferred Payment Agreement, such default shall, without any further notice or opportunity to cure, constitute a default by Buyer under this Agreement.

3.14.2 Any event of default may be waived at the non-defaulting party's option. Upon the failure of a party to cure any such default after notice thereof from the other party and expiration of the above cure periods, then the non-defaulting party may, subject to the terms of this Agreement, do one or more of the following: withhold further performance of its obligations under this Agreement; terminate the Agreement; and/or pursue any legal remedies it may have under this Agreement (including the its rights to the cash collateral account or other security for performance), applicable law or principles of equity relating to such breach.

ARTICLE FOUR
FORCE MAJEURE

4.0 Conditions of Excuse

4.0.1 If, as a result of an event of Force Majeure, a Party is rendered unable to perform its obligations in whole or in part under this Service Agreement, the obligations of both Parties shall be excused, except as specifically provided elsewhere in this Service Agreement, from that portion of its performance that is prevented by such Force Majeure event to the extent so prevented; provided, that:

4.0.1.1 The Party claiming Force Majeure gives the other Party prompt written notice after the Party claiming Force Majeure obtains actual knowledge thereof describing the particulars of and how such event qualifies as an event of Force Majeure;

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4.0.1.2 The permitted suspension of performance is of no greater scope and of no longer duration than is required by the event of Force Majeure and the effects thereof; and

4.0.1.3 The Party claiming Force Majeure exercises commercially reasonable efforts to eliminate or mitigate the effects of the Force Majeure condition.

4.1 Burden of Proof

4.1.1 The burden of proof as to whether a Force Majeure has occurred shall be upon the Party claiming Force Majeure.

4.2 Payment and Security Obligations

4.2.1 No payment obligation arising under this Agreement, and no obligation to provide the Customer Contract Security Requirement, shall be excused by any event of Force Majeure declared by either Party.

[redacted]

ARTICLE FIVE
ASSIGNMENT; BINDING EFFECT

5.0 Binding Effect

5.0.1 This Agreement shall be binding upon and shall inure to the benefit of the Parties and their respective successors and permitted assigns.

5.0.2 The Buyer is a Party to the 2015-2019 Large Curtailable Special Contract dated March 12, 2015 (the "2015 Special Contract") with Wisconsin Electric Power Company, an Affiliate of Seller. The 2015 Special Contract terminates on December 31, 2019. In the event a COD is not achieved prior to December 31, 2019, this Agreement shall be binding upon both Parties on and after January 1, 2020 and Buyer shall not be permitted to terminate this Agreement other than pursuant to Section 2.0.5.2.

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5.1 Assignment

5.1.1 Upon the incorporation of UMERC and the transfer of Wisconsin Electric's electric distribution assets in Michigan and retail electric business in Michigan (other than assets and contracts used to provide service to Buyer), Seller shall assign its rights, obligations and interests in this Agreement to UMERC.

5.1.2 Except as provided herein, neither Party shall assign this Agreement or any portion thereof to any Person without the prior written consent of the other Party. [redacted]

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ARTICLE SIX
MISCELLANEOUS

6.0 Governing Law

6.0.1 This Agreement shall be governed by and construed in accordance with the laws of the State of Michigan as to all matters, including but not limited to matters of validity, construction, effect, performance and remedies without regard to conflict of laws rules thereof.

6.1 Cooperation; Further Assurances

6.1.1 The Parties agree to provide such reasonable cooperation to each other as necessary to give effect to the terms of this Agreement.

6.2 Amendment

6.2.1 No amendment, supplement, modification, waiver or termination of this Agreement shall be binding unless executed in writing by the Parties to be bound thereby.

6.3 Waiver

6.3.1 The failure or delay of either Party hereto to enforce at any time any of the provisions of this Agreement, or to require at any time performance of the other Party hereto of any of the provisions hereof, shall neither be construed to be a waiver of such provisions nor affect the validity of this Agreement or any part hereof or the right of such Party thereafter to enforce each and every such provision. No waiver of any of the provisions of this Agreement shall be deemed or shall constitute a waiver of any other provision of this Agreement, whether or not similar, nor shall such waiver constitute a continuing waiver unless otherwise expressly provided.

6.4 No Third-Party Beneficiaries

6.4.1 This Agreement is for the sole benefit of the Parties hereto, and except as specifically provided herein, nothing in this Agreement or any action taken hereunder shall be construed to create any duty, liability or standard of care to any Person not a party to this Agreement. Except as specifically provided herein, no Person shall have any rights or interest, direct or indirect, in this Agreement or the services to be provided hereunder, or both, except Buyer and Seller. The Parties specifically disclaim any intent

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to create any rights in any Person as a third-party beneficiary to this Agreement or the services to be provided hereunder, or both.

6.5 No Dedication of Assets

6.5.1 No undertaking by a Party hereto to the other Party hereto under any provision of this Agreement shall constitute the dedication of that Party's assets or any portion thereof to the public or to its obligations under this Agreement.

6.6 No Partnership

6.6.1 This Agreement shall not be construed to create or give rise to any partnership, joint venture, agency or other relationship between Seller and Buyer other than that of purchaser and seller. Each Party shall be solely and individually responsible for its own covenants, obligations and liabilities as herein provided, and the Parties do not intend to create any joint, several or joint and several obligations to any third party. Neither this Agreement, nor any grant, lease or license related thereto, shall create or be construed to create any new entity, such as a partnership, association or joint venture.

6.7 Forward Contract

6.7.1 The Parties acknowledge and agree that this Agreement, the transactions contemplated hereby, and any instrument(s) that may be provided by either Party hereunder (including any guaranty or Customer Contract Security Requirement) shall each, and together, constitute one and the same "forward contract" within the meaning of the United States Bankruptcy Code, and Seller and Buyer shall each constitute a "forward contract merchant" under the United States Bankruptcy Code.

6.8 Confidentiality

6.8.1 The Parties agree that neither Party shall disclose the terms or conditions of this Agreement to a third party (other than the Party's or its Affiliate's employees, lenders, counsel, accountants or advisors who have a need to know such information and have agreed to keep such terms confidential) except in order to comply with any applicable law, regulation, or any exchange, balancing area, regional reliability council, or independent system operator rule, or in connection with any court or regulatory proceeding; provided, however, each Party shall, to the extent practicable, use reasonable efforts to prevent or limit the disclosure. The Parties shall

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be entitled to all remedies available at law or in equity to enforce, or seek relief in connection with, this confidentiality obligation.

6.9 Headings

6.9.1 The headings contained in this Agreement are used solely for convenience and do not constitute a part of the Agreement between the Parties, nor should they be used to aid in any manner in the construction of this Agreement.

6.10 Counterparts

6.10.1 This Agreement may be executed simultaneously in two or more counterparts, each of which shall be deemed an original but all of which together shall constitute one and the same instrument.

6.11 All notices or other communications which may be or are required to be given by a party to the other party pursuant to this Agreement shall be in writing and shall be either (i) delivered by hand; (ii) mailed by first-class, registered or certified mail, return receipt requested, postage prepaid; or (iii) delivered by a recognized overnight or personal delivery service, addressed as and to the parties' representatives set forth below. Notices shall be effective when delivered in accordance with the foregoing provisions, whether or not accepted by, or on behalf of, the party to whom the notice is sent. Each party may designate by written notice in accordance with this Section to the other party a new address to which any notice may thereafter be given.

If to Seller, then to:	WEC Energy Group, Inc. 333 W. Everett Street, A214 Milwaukee, WI 53203 Attention: Vice President - WEAF
If to Buyer, then to:	Tilden Mining Company, L.C. 200 Public Square, Suite 3300 Cleveland, OH 44114 Attention: Chief Legal Officer

6.12 Entire Agreement

6.12.1 This Agreement constitutes the entire agreement between the Parties pertaining to the subject matter of this Agreement and supersedes and terminates any letters of intent, term sheets and all prior and

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contemporaneous agreements, understandings, negotiations and discussions between the Parties, whether oral or written, regarding said subject matter, and there are no warranties, representations or other agreements between the Parties in connection with the subject matter of this Agreement, except as specifically set forth in this Agreement.

[SIGNATURE PAGE FOLLOWS]

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IN WITNESS WHEREOF, each of the Parties has caused this Agreement to be executed by its duly authorized officer as of the date first written above.

SELLER:

WEC ENERGY GROUP, INC.

By: Allen L. Leverett

Name: Allen L. Leverett

Title: Chief Executive Officer

Date: Aug 12, 2016

BUYER:

TILDEN MINING COMPANY L.C.
BY THE CLEVELAND-CLIFFS IRON COMPANY, ITS MANAGING AGENT

By: Terry G. Fedor, II

Name: TERRY G. FEDOR, II

Title: PRESIDENT

Date: 8/12/2016

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EXHIBIT A

[redacted]

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EXHIBIT B
Operations Protocol

Dated: TBD
Supersedes the Operations Protocol dated: TBD

This Operations Protocol shall govern the responsibilities of Buyer and Seller to effectuate the implementation of the Agreement. It may be amended as necessary in accordance with the requirements of Section 2.5 of the Agreement.

Responsibilities of Buyer

1.

2.

Responsibilities of Seller

1.

2.

[SIGNATURE PAGE FOLLOWS]

IN WITNESS WHEREOF, each of the Parties has caused this Exhibit B – Operations Protocol to be executed by its duly authorized representative as of the date first written above.

SELLER:
WEC ENERGY GROUP INC.

By: _____

Name: _____

Title: _____

Date: _____

BUYER:
TILDEN MINING COMPANY L.C.
BY THE CLEVELAND-CLIFFS IRON COMPANY, ITS MANAGING AGENT

By: _____

Name: _____

Title: _____

Date: _____

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EXHIBIT C

[redacted]

WEC Energy Group

WEC Energy Group, Inc.
231 W. Michigan St.
Milwaukee, WI 53203

December 9, 2016

Mr. Tolaver Rapp
Director of Global Energy Procurement
Cliffs Natural Resources
200 Public Square, Suite 3400
Cleveland, OH 44114-2315

Re: Agreement to amend Section 2.3.2 and 2.3.3 of the Retail Large Curtailable Special Contract

Dear Tolaver,

This letter shall confirm the agreement to amend the Retail Large Curtailable Special Contract (Agreement) between WEC Energy Group, Inc. (WEC) and Tilden Mining Company L.C. (Tilden) dated August 12, 2016 as follows:

1) Section 2.3.2 is amended by deleting [redacted] and replacing the same with [redacted]; and

2) Section 2.3.3 is amended by deleting [redacted] and replacing the same with [redacted].

All other provisions of the Agreement remain unchanged and in full force and effect and this amendment shall be read together with the Agreement.

Please confirm your acknowledgement and agreement with the foregoing by executing below and returning an electronic copy to my attention.

Sincerely,

James O. Sherman, Jr.
Director – Wholesale and Customer Solutions

Acknowledgement and Agreement

Tilden acknowledges and agrees to the forgoing as of this 13th day of DECEMBER 2016.

Tilden Mining Company L.C.

By: _____

Name: TERRY G. FEDOR, II

Title: EVP-USIO

FERC ELECTRIC TARIFF
VOLUME NO. 9

FORMULA RATE WHOLESALE
SALES TARIFF

Non-Conforming
Service Agreement #XXX
Between
Wisconsin Electric Power Company
and
Upper Michigan Energy Resources Corporation

Effective: mm/dd/yyyy

NON-CONFORMING
FORMULA RATE WHOLESALE
SALES TARIFF

SERVICE AGREEMENT

This AGREEMENT (the "Agreement") is made and entered as of this ___, day of _____, 20__, by and between WISCONSIN ELECTRIC POWER COMPANY, a Wisconsin corporation ("Seller"), and UPPER MICHIGAN ENERGY RESOURCES CORPORATION, a Michigan corporation ("Buyer") and hereinafter the parties hereto are sometimes referred to collectively as the "Parties", or individually as a "Party").

WITNESSETH

WHEREAS, Seller is a public utility in the business of generating, distributing and selling electric power and energy and related services at wholesale and retail within the States of Wisconsin and Michigan;

WHEREAS, Buyer is a public utility in the business of generating, distributing and selling electric power and energy and related services at wholesale and retail within the State of Michigan;

WHEREAS, Seller and Buyer each believes it is in its best interest and desires to enter into this Agreement as further described herein;

NOW, THEREFORE, in consideration of the recitals and mutual promises, covenants and agreements contained herein and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties, intending to be legally bound, hereby agree as follows:

ARTICLE ONE
DEFINITIONS

Unless otherwise defined herein, all capitalized terms used herein shall have the same meaning as that set forth in Section 2 of the Seller's Formula Rate Wholesale Sales Tariff ("Tariff").

ARTICLE TWO
SERVICE TO BE PROVIDED

2.1 Type of Service. Buyer agrees to purchase and Seller agrees to provide the following service as set forth in the Tariff (choose one):

__X_ Load Following Service

____ Block Purchase Service

2.2 Delivery Period . The initial "Delivery Period" for the sale and purchase of Capacity and Energy under this Agreement shall commence on January 1, 2017 (HE 0100 CPT) and end on December 31, 2017 (HE 2400 CPT) and shall continue from year to year thereafter unless either party provides twelve (12) months written notice of termination to the other party or, if mutually agreeable and confirmed by written notice, a shorter termination notice shall apply. The applicable provisions of this Agreement and the Tariff shall continue in effect after termination to provide for final billings and adjustments. During the Delivery Period, each "Contract Year" shall begin on January 1 (HE 0100 CPT) and end on December 31 (HE 2400 CPT) of the succeeding calendar year.

2.3. Capacity Amount.

(a) Load Following Service. The Capacity Amount for Load Following Service is determined on a monthly basis and is equal to the Buyer's 60-minute integrated demand coincident with Seller's Monthly System Peak Load, as adjusted for any energy from the Buyer's Generation Resources identified in the Confirmation Letter.

(b) Block Purchase Service. The Capacity Amount for Block Purchase Service is the amount of Capacity nominated for a Contract Year and shall remain fixed for that Contract Year. The Capacity Amount for Block Purchase Service for each Contract Year is [____].

2.4 Rate to be Charged. Buyer agrees to pay the rates set forth in the Tariff for the applicable service specified under this Agreement, as well as any additional charges specified in the Confirmation Letter. Nothing contained herein shall be construed as affecting in any way the right of either Party to unilaterally make or challenge an application to the FERC for a change in rates under Sections 205 or 206 of the Federal Power Act and pursuant to the FERC's rules and regulations promulgated thereunder.

ARTICLE THREE
DELIVERY OF ENERGY

3.1 Market Participant. (Choose one):

Buyer is a Market Participant as defined in the Tariff _____.

Buyer is a Non-Market Participant as defined in the Tariff ___X___.

3.2 Delivery Point. For service provided under this Agreement, the Delivery Point(s) shall be those listed in the Confirmation Letter. Unless otherwise agreed to herein, Seller will not provide transmission and ancillary services to any Buyer who is a Market Participant other than those required up to the Delivery Point.

3.3. Scheduling. Buyer agrees to Schedule all Energy in accordance with the Tariff and Confirmation Letter for the service provided under this Agreement.

ARTICLE FOUR
BILLING AND PAYMENT

4.1 Billing. Seller shall bill, and Buyer shall pay, all rates and charges in accordance with Section 5 of the Tariff.

ARTICLE FIVE
PERFORMANCE ASSURANCE

5.1 Buyer shall meet the creditworthiness provisions in Section 6 of the Tariff, including any Performance Assurance requirements imposed by Seller.

ARTICLE SIX
EVENTS OF DEFAULT; REMEDIES

6.1 Events of Default. Each of the following events, unless and to the extent expressly excused under the terms of this Agreement, shall constitute an "Event of Default" of the defaulting party ("Defaulting Party"), the other Party being the non-defaulting party ("Non-Defaulting Party"):

(i) The failure of a Party to make any payment due hereunder and the continuation of such failure for three Business Days after written notice demanding such payment has been made by the Non-Defaulting Party.

(ii) Any representation or warranty made by a Party herein or in any certificate or other document delivered by such Party pursuant hereto that was false or misleading in any material respect when made, unless such false or misleading representation or warranty is capable of being cured or remedied, and such Party shall promptly commence and diligently pursue action to cause such representation or warranty to become true in all material respects and does so within 30 days after notice thereof has been given to such Party by the other Party.

(iii) A Party shall cease doing business as a going concern, shall generally not pay its debts as they become due or admit in writing its inability to pay its debts as they become due, shall file a voluntary petition in bankruptcy or shall be adjudicated a bankrupt or insolvent, or shall file any petition or answer seeking any reorganization, arrangement, composition, readjustment, liquidation, dissolution or similar relief under the present or any future federal bankruptcy code or any other present or future applicable Law relating to creditors' rights or debtors' relief, or shall seek or consent to or acquiesce in the appointment of any trustee, receiver, custodian or liquidator of such Party or of all or any substantial part of its properties, or shall make an assignment for the benefit of creditors, or such Party shall take any corporate action to authorize or that is in contemplation of the actions set forth above in this Section 6.1(iii).

(iv) Within 30 days after the commencement of any proceeding against a Party seeking any reorganization, arrangement, composition, readjustment, liquidation, dissolution or

similar relief under the present or any future federal bankruptcy code or any other statute or Law relating to creditors' rights or debtors' relief, such proceeding shall not have been dismissed, or if, within 30 days after the appointment without the consent or acquiescence of such Party of any trustee, receiver, custodian or liquidator of such Party or of all or any substantial part of its properties, such appointment shall not have been vacated.

(v) A Party fails to comply or cause compliance with the Performance Assurance requirements pursuant to Section 6 of the Tariff, or any Person furnishing any Performance Assurance on behalf of a Party pursuant to Section 6 of the Tariff fails to comply with the terms of such Performance Assurance.

(vi) A material default in performance or observance of any agreement, undertaking, covenant or other obligation (except as otherwise specified in the other provisions of this Section 6.1) contained in this Agreement by a Party unless, within 30 days after written notice has been made from the other Party specifying the nature of such material default, such Party cures such default or, if such cure cannot reasonably be completed within 30 days and if such Party within such 30-day period commences, and thereafter diligently proceeds to cure such default, said period shall be extended for such further period as shall be necessary for such Party diligently to cure such default, provided that the extended cure period shall not exceed 90 days from the date of the original notice.

6.2 Remedies. (a) If an Event of Default occurs at any time during the Delivery Period, the Non-Defaulting Party may, for so long as the Event of Default is continuing, take one or more of the following actions: (i) establish a date (which date shall be not more than 10 Business Days after the Non-Defaulting Party gives written notice of such date to the Defaulting Party, or such longer period as required by applicable Law) on which this Agreement shall terminate (the "Early Termination Date"), in which case this Agreement shall terminate on the Early Termination Date; (ii) proceed by appropriate proceedings in accordance with this Agreement; and (iii) immediately cease performance, withhold any payments, or both, due in respect of this Agreement. For avoidance of doubt, in the event the Non-Defaulting Party terminates this Agreement on the Early Termination Date as provided in (i) above and/or ceases performance or withholds payment as provided in (iii) above, the Defaulting Party shall continue to be obligated to pay damages relating to such early termination and relating to the Defaulting Party's failure to perform during such cessation or period of withholding.

6.3 Liquidated Damages. If Seller is the Non-Defaulting Party and terminates this Agreement on an Early Termination Date, then Buyer shall pay to Seller, as liquidated damages and not as a penalty, an amount calculated as follows: (i) for the first 730 days following the date of the first uncured Event of Default giving rise to the early termination (unless the Delivery Period would have ended prior to the expiration of such 730 days, in which case such liquidated damages shall be paid through the last day of such Delivery Period) equal to the Initial Daily Amount and (ii) for each subsequent day through the last day of such Delivery Period equal to the Subsequent Daily Amount. If Buyer is the Non-Defaulting Party and terminates this Agreement on an Early Termination Date, then Seller shall pay to Buyer, as liquidated damages and not as a penalty, an amount calculated as follows: (i) for the first 730 days following the date of the first uncured Event of Default giving rise to the early termination (unless the Delivery Period would have ended prior to the expiration of such 730 days, in which case such liquidated damages shall be paid through the last day of such Delivery Period) equal to the Initial Daily

Amount and (ii) for each subsequent day through the last day of such Delivery Period equal to the Subsequent Daily Amount. Calculation of liquidated damages shall be included in the written notice given by Buyer or Seller, as applicable, when declaring an Early Termination Date pursuant to Section 6.2. Liquidated damages under this Section 6.3 shall be payable no later than 30 days after the Early Termination Date.

6.4 Right to Setoff. Each Party reserves to itself all rights, setoffs, counterclaims, recoupment, combination of accounts, liens and other remedies, rights and defenses which such Party has or to which it may be entitled (whether by operation of law or in equity, under contract or otherwise).

6.5 Duty to Mitigate. Except with respect to liquidated damages, each Party has a duty to mitigate damages and covenants that it will use commercially reasonable efforts to minimize any damages it may incur as a result of the other Party's performance or non-performance hereunder.

ARTICLE SEVEN
COMPLIANCE WITH LAWS

7.1 Compliance with Laws. Each Party shall at all times comply in all material respects with all applicable Laws relating to the performance of its obligations under this Agreement. Each Party shall give all required notices, shall procure and maintain all necessary Authorizations required for its performance of this Agreement and shall pay all charges and fees in connection therewith.

7.2 Change in Law. In the event there is a change or changes in any Law, or interpretation thereof, enacted, adopted or implemented after execution of this Agreement, or any Law (or the interpretation thereof) is applied to a new or different class of parties (a "Change in Law"), then if the Seller is affected by such Change in Law and its costs in meeting its obligations under this Agreement are increased, such increased costs shall be passed through to Buyer to the fullest extent permitted by Law; if the Seller is affected by such Change in Law and its costs in meeting its obligations under this Agreement are decreased, such decreased costs shall be passed through to Buyer to the fullest extent permitted by Law. In the event such increased costs cannot be passed through until approval or acceptance by a Governmental Authority, such increased costs shall be accrued and, following receipt of such approval or acceptance, applied to the earliest (and subsequent) periods permitted by Law.

7.3 Change in Treatment by PSCW or MPSC. In the event that the PSCW's or MPSC's treatment from time to time of the revenues received or amounts charged by Seller under this Agreement or the amounts paid by Buyer under this Agreement, including any one or more components of the formulary rates set forth in Section 3.2 of the Tariff, adversely affects the Buyer or Seller (other than a change constituting a Change in Law pursuant to Section 7.2 of this Agreement or any increased cost passed through pursuant to the formula in Exhibit B) then, upon notice by the affected Party to the other Party, the Parties shall use their commercially reasonable efforts to reform this Agreement in order to alleviate such adverse effect on the affected Party; provided, however, that if the Parties are unable to reform this Agreement by a written amendment signed by both Parties within 90 days of the notification by the affected Party to the other Party of such treatment, then the affected Party shall have the right to terminate this

Agreement without default and without any further rights or obligations of either Party other than those rights and obligations of the Parties that shall have accrued prior to such termination.

7.4 MISO Changes. In the event that, at any time from and after the execution of this Agreement, the MISO Tariff is changed (other than a change constituting a Change in Law pursuant to Section 7.2) or either or both Parties withdraw from the MISO Tariff so that the benefits and burdens or the operative provisions of this Agreement are no longer consistent with the original intentions of the Parties, the Parties shall use their commercially reasonable efforts to reform this Agreement in order to give effect to the original intentions of the Parties regarding the appropriate allocation of benefits and burdens to each Party.

ARTICLE EIGHT
INDEMNIFICATION; LIMITATION OF LIABILITY

8.1 Buyer Indemnification. Buyer agrees to and shall indemnify, defend, and hold harmless Seller, its parent company and each of their respective Affiliates, and all of their respective officers, directors, shareholders, employees, servants, and agents, from and against all Claims, including Claims for personal injury, death, or damages to property, occurring at and after the Delivery Point(s), arising out of or related to the Load Following Service, Block Purchase Service and/or Buyer's performance under this Agreement.

8.2 Seller Indemnification. Seller agrees to and shall indemnify, defend, and hold harmless Buyer, and all of its Affiliates, and all of their respective officers, directors, shareholders, employees, servants, and agents, from and against all Claims, including Claims for personal injury, death, or damages to property occurring on Seller's side of the Delivery Point(s) arising out of or related to the Load Following Service, Block Purchase Service and/or Seller's performance under this Agreement.

8.3 Limitation of Remedies, Liability and Damages. BUYER AND SELLER CONFIRM THAT THE EXPRESS REMEDIES AND MEASURES OF DAMAGES PROVIDED IN THIS AGREEMENT SATISFY THE ESSENTIAL PURPOSES HEREOF FOR BREACH OF ANY PROVISION FOR WHICH AN EXPRESS REMEDY OR MEASURE OF DAMAGES IS PROVIDED. UNLESS EXPRESSLY HEREIN OTHERWISE PROVIDED, AND EXCEPT FOR THE PAYMENT OF LIQUIDATED DAMAGES SPECIFIED HEREIN, NEITHER BUYER, SELLER, NOR THEIR AFFILIATES SHALL BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT; PROVIDED, HOWEVER, THAT THIS SENTENCE SHALL NOT APPLY TO LIMIT THE LIABILITY OF BUYER OR SELLER IF ITS ACTIONS GIVING RISE TO SUCH LIABILITY CONSTITUTE GROSS NEGLIGENCE OR WILLFUL MISCONDUCT. TO THE EXTENT ANY DAMAGES REQUIRED TO BE PAID HEREUNDER ARE DENOMINATED AS LIQUIDATED DAMAGES, BUYER AND SELLER ACKNOWLEDGE AND AGREE THAT THE ACTUAL DAMAGES ARE (OR ARE EXPECTED TO BE) DIFFICULT OR IMPOSSIBLE TO DETERMINE, OTHERWISE OBTAINING AN ADEQUATE REMEDY IS (OR IS EXPECTED TO BE) INCONVENIENT AND THE LIQUIDATED DAMAGES DO NOT CONSTITUTE A PENALTY AND ARE A REASONABLE ADVANCE APPROXIMATION

OF THE HARM OR LOSS ANTICIPATED. BUYER AND SELLER ACKNOWLEDGE AND AGREE THAT THIS AGREEMENT DOES NOT PROVIDE FOR ANY TORT REMEDIES, AND BUYER AND SELLER FURTHER EXPRESSLY AGREE THAT NEITHER SHALL HAVE THE RIGHT, AND EACH WAIVES ALL RIGHTS, TO BRING AN ACTION AGAINST THE OTHER (INCLUDING AGAINST ANY AFFILIATE OF THE OTHER) IN TORT OR STRICT LIABILITY FOR ANY ACT(S) OR OMISSIONS CONSTITUTING A BREACH OR ALLEGED BREACH OF CONTRACT. BUYER AND SELLER EXPRESSLY AGREE AND UNDERSTAND THAT THE PROVISIONS OF THIS SECTION 8.3 LIMIT THE CLAIMS AND DAMAGES AVAILABLE TO THEM.

8.4 Disclaimer of Warranties. THERE ARE NO WARRANTIES UNDER THIS AGREEMENT EXCEPT TO THE EXTENT SPECIFICALLY SET FORTH IN THE TEXT HEREOF. BUYER AND SELLER HEREBY SPECIFICALLY DISCLAIM AND EXCLUDE ALL IMPLIED WARRANTIES, INCLUDING THE IMPLIED WARRANTIES OF MERCHANTABILITY AND OF FITNESS FOR A PARTICULAR PURPOSE.

ARTICLE NINE
ASSIGNMENT; BINDING EFFECT

9.1 Binding Effect. This Agreement shall be binding upon and shall inure to the benefit of the Parties and their respective successors and permitted assigns.

9.2 Assignment. Neither Party shall assign this Agreement or any portion thereof to any Person without the prior written consent of the other Party. Any consent required by this Section 9.2 shall not be unreasonably withheld, conditioned or delayed; provided, however, that neither Party shall be required to accept any limitation of its rights under this Agreement or expansion of the liability, risks or obligations imposed on it under this Agreement. It shall be a condition of any assignment, transfer or other disposition with respect to this Agreement that (a) all Performance Assurance required under Article 5 of this Agreement with respect to the assignor shall remain in place notwithstanding such assignment, transfer or other disposition, or that replacement Performance Assurance in form, substance and amount in full compliance with this Agreement or otherwise reasonably acceptable to Seller shall have been provided prior to such disposition and (b) the proposed assignee shall agree in writing to assume the assignor's obligations hereunder.

ARTICLE TEN
NOTICE

10.1 Notices. Unless otherwise specified, where notice is required by this Agreement, such notice shall be in writing and shall be deemed given: (i) upon the second Business Day after the date of such notice, when mailed by United States registered or certified mail, postage prepaid, return receipt requested; (ii) upon the next Business Day after the date of such notice, when sent by overnight delivery, using a reputable overnight delivery service; or (iii) when sent, if by facsimile transmission, or upon the next Business Day after the date of such facsimile if such facsimile transmission is sent after 5:00 P.M. CPT.

if to Seller:

Wisconsin Electric Power Company
333 West Everett Street, Room A292
Milwaukee, Wisconsin 53203
Attention: Legal Department
Telephone: 414-221-2198
Facsimile: 414-221-2139

Wisconsin Electric Power Company
333 West Everett Street, Room A516
Milwaukee, Wisconsin 53203
Attention: Federal Regulatory Affairs & Policy
Telephone: 414-221-2533
Facsimile: 414-221-4211

Wisconsin Electric Power Company
333 West Everett Street, Room A214
Milwaukee, Wisconsin 53203
Attention: Vice President, Wholesale Energy and Fuels
Telephone: 414-221-2610
Facsimile: 414-221-2350

Notices related solely to operational issues arising after the commencement of the Delivery Period are exempt from this Section 10.1 and may be given to the addressees listed below by telephone or by any other means as the Parties may from time to time agree.

Invoices, Payments and Collections:
Attn: Settlements
Phone: 414-221-4180
Facsimile: 414-221-2350
E-mail: We_Energies_Settlements_Group@we-energies.com

Scheduling:
Attn: Power Trader
Phone: 414-221-4395
Facsimile: 414-221-4210

Wire Transfer:
BNK: US Bank
ABA: 075 000 022
ACCT: 111-512-711

Credit - Performance Assurance and related documents:
231 West Michigan Street, P377
Milwaukee, WI 53203
Attn: Finance – Corporate Commodity Risk Management
Phone: 414-221-2749
Facsimile: 414-291-6937

With additional Notices of an Event of Default or Potential Event of Default to:
Attn: Donna Brophy – Finance
Phone: 414-221-2749
Facsimile: 414-291-6937

And

Attn: Legal Department
Facsimile: 414-221-2139

if to the Buyer:

Upper Michigan Energy Resources Corporation
333 West Everett Street, Room A292
Milwaukee, Wisconsin 53203
Attention: Legal Department
Telephone: 414-221-2198
Facsimile: 414-221-2139

Upper Michigan Energy Resources Corporation
333 West Everett Street, Room A516
Milwaukee, Wisconsin 53203
Attention: Federal Regulatory Affairs & Policy
Telephone: 414-221-2533
Facsimile: 414-221-4211

Upper Michigan Energy Resources Corporation
333 West Everett Street, Room A214
Milwaukee, Wisconsin 53203
Attention: Wholesale Energy and Fuels
Telephone: 414-221-2610
Facsimile: 414-221-2350

Notices related solely to operational issues arising after the commencement of the Delivery Period are exempt from this Section 10.1 and may be given to the addressees listed below by telephone or by any other means as the Parties may from time to time agree.

Invoices, Payments and Collections:
Attn: Settlements
Phone: 414-221-4180
Facsimile: 414-221-2350
E-mail: We_Energies_Settlements_Group@we-energies.com

Scheduling:
Attn: Power Trader
Phone: 414-221-4395
Facsimile: 414-221-4210

Wire Transfer:
BNK: TBD
ABA: TBD
ACCT: TBD

Credit - Performance Assurance and related documents:
231 West Michigan Street, P377
Milwaukee, WI 53203
Attn: Finance – Corporate Commodity Risk Management
Phone: 414-221-2749
Facsimile: 414-291-6937

With additional Notices of an Event of Default or Potential Event of Default to:
Attn: Donna Brophy – Finance
Phone: 414-221-2749
Facsimile: 414-291-6937

And

Attn: Legal Department
Facsimile: 414-221-2139

10.2 Change in Notice. A Party's address may be changed by written notice to the other Party.

ARTICLE ELEVEN
MISCELLANEOUS

11.1 Interpretation; Construction. In this Agreement, unless the context otherwise requires: (a) the singular shall include the plural and any pronoun shall include the corresponding masculine, feminine and neuter forms; (b) the words "hereof," "herein," "hereto" and "hereunder" and words of similar import when used in this Agreement shall, unless otherwise expressly specified, refer to this Agreement as a whole and not to any particular provision of this Agreement; (c) whenever the term "including" is used herein in connection with a listing of

items included within a prior reference, such listing shall be interpreted to be illustrative only, and shall not be interpreted as a limitation on or exclusive listing of the items included within the prior reference; (d) any reference in this Agreement to "Section," "Article," "Exhibit" or "Appendix" shall be references to this Agreement unless otherwise stated, and all such Exhibits shall be incorporated into this Agreement by reference and are intended to be a part of this Agreement; and (e) unless otherwise specified, a reference to a given agreement, document, instrument, Law, Service Schedule or tariff, including this Agreement, and all schedules, exhibits, appendices and attachments thereto, shall be a reference to that agreement, document, instrument, Law or tariff as modified, amended, supplemented and restated in accordance with its terms (if applicable) and (where applicable) subject to compliance with the requirements set forth therein, and in effect from time to time.

11.2 Governing Law. This Agreement shall be governed by and construed in accordance with the laws of the State of Wisconsin as to all matters, including but not limited to matters of validity, construction, effect, performance and remedies without regard to conflict of laws rules thereof.

11.3 Cooperation; Further Assurances. The Parties agree to provide such reasonable cooperation to each other as necessary to give effect to the terms of this Agreement.

11.4 Amendment. No amendment, supplement, modification, waiver or termination of this Agreement shall be binding unless executed in writing by the Party to be bound thereby.

11.5 Waiver. The failure or delay of any Party hereto to enforce at any time any of the provisions of this Agreement, or to require at any time performance of the other Party hereto of any of the provisions hereof, shall neither be construed to be a waiver of such provisions nor affect the validity of this Agreement or any part hereof or the right of such Party thereafter to enforce each and every such provision. No waiver of any of the provisions of this Agreement shall be deemed or shall constitute a waiver of any other provision of this Agreement, whether or not similar, nor shall such waiver constitute a continuing waiver unless otherwise expressly provided.

11.6 No Third Party Beneficiaries. This Agreement is for the sole benefit of the Parties hereto, and except as specifically provided herein, nothing in this Agreement or any action taken hereunder shall be construed to create any duty, liability or standard of care to any Person not a party to this Agreement. Except as specifically provided herein, no Person shall have any rights or interest, direct or indirect, in this Agreement or the services to be provided hereunder, or both, except Buyer and Seller. The Parties specifically disclaim any intent to create any rights in any Person as a third-party beneficiary to this Agreement or the services to be provided hereunder, or both.

11.7 No Dedication of Assets. No undertaking by a Party hereto to the other Party hereto under any provision of this Agreement shall constitute the dedication of that Party's assets or any portion thereof to the public or to its obligations under this Agreement.

11.8 No Partnership. This Agreement shall not be construed to create or give rise to any partnership, joint venture, agency or other relationship between Seller and Buyer other than that of purchaser and seller. Each Party shall be solely and individually responsible for its own

covenants, obligations and liabilities as herein provided, and the Parties do not intend to create any joint, several or joint and several obligations to any third party. Neither this Agreement, nor any grant, lease or license related thereto, shall create or be construed to create any new entity, such as a partnership, association or joint venture.

11.9 Forward Contract. The Parties acknowledge and agree that this Agreement, the transactions contemplated hereby, and any instrument(s) that may be provided by either Party hereunder (including any guaranty) shall each, and together, constitute one and the same "forward contract" within the meaning of the United Stated Bankruptcy Code, and Seller and Buyer shall each constitute a "forward contract merchant" under the United Stated Bankruptcy Code.

11.10 Severability. If any provision of this Agreement shall be determined to be unenforceable, void or otherwise contrary to any Law, such condition shall in no manner operate to render any other provision of this Agreement unenforceable, void or contrary to any Law, and this Agreement shall continue in force in accordance with the remaining terms and provisions hereof, unless such condition invalidates the purpose or intent of this Agreement. In the event that any of the provisions, or portions or applications thereof, of this Agreement are held unenforceable or invalid by any court of competent jurisdiction, Seller and Buyer shall negotiate to attempt to implement a reformation of such provision(s) with a view toward effecting the purposes of this Agreement by replacing the offending provision(s) with a valid provision the economic effect of which comes as close as possible to the original intent of the offending provision(s).

11.11 Headings. The headings contained in this Agreement are used solely for convenience and do not constitute a part of the Agreement between the Parties, nor should they be used to aid in any manner in the construction of this Agreement.

11.12 Counterparts. This Agreement may be executed simultaneously in two or more counterparts, each of which shall be deemed an original but all of which together shall constitute one and the same instrument.

11.13 Entire Agreement. This Agreement constitutes the entire agreement between the Parties pertaining to the subject matter of this Agreement and supersedes and terminates any letters of intent, term sheets and all prior and contemporaneous agreements, understandings, negotiations and discussions between the Parties, whether oral or written, regarding said subject matter, and there are no warranties, representations or other agreements between the Parties in connection with the subject matter of this Agreement, except as specifically set forth in this Agreement.

[Signature Page Follows]

IN WITNESS WHEREOF, each of the Parties has caused this Agreement to be executed by its duly authorized officer as of the date first written above.

WISCONSIN ELECTRIC POWER COMPANY

By: _____

Name: _____

Title: _____

Date: _____

UPPER MICHIGAN ENERGY RESOURCES CORPORATION

By: _____

Name: _____

Title: _____

Date: _____

APPENDIX A
CONFIRMATION LETTER

This Confirmation Letter confirms the Agreement dated _____, by and between Upper Michigan Energy Resources Corporation ("Buyer") and Wisconsin Electric Power Company ("Seller") with respect to the purchase and sale of Capacity and Energy pursuant to Seller's Formula Rate Wholesale Sales Tariff and sets forth the following information as required thereto.

1. Delivery Point(s): The delivery points shall be at UMERC's Transmission-to-Distribution interconnection points with the American Transmission Company LLC located within the MIUP Local Balancing Authority Area and the distribution level points of interconnection as adjusted for cross-border distribution usage between the Parties identified in the Wholesale Distribution Service Agreement(s) between the Parties.

2. Congestion Adjustment: Not Applicable

3. Loss Factor: The loss factor to be applied to Seller's Formula Rate Tariff shall be as stated in the Wholesale Distribution Service Agreement between Wisconsin Electric Power Company and Upper Michigan Energy Resources Corporation as may be amended from time to time. As such, the current Loss Factor to be applied to the distribution level deliveries is as follows:

   Loss Factor: 1.019

4. Interruptible Service: Buyer shall be eligible for interruptible service under this Service Agreement as stated below:

   a) Buyer's Generation Resources and Credit:
      i. Buyer's Generation Resources shall be Buyer's MISO MECT registered DR/LMR for interruptible load served by Buyer for each MISO Planning Year (June 1 to May 31 of the succeeding Contract Year) applicable to the Service Agreement.
      ii. Buyer's Generation Resource Credit: Buyer shall receive a monthly billing credit for Buyer's Generation Resources. The rate for the credit shall be based on the MISO Cost of New Entry (CONE) value ($/MW-year) assigned to MISO Local Resource Zone 2 (LRZ2) for each respective Planning Year under the Service Agreement. This rate shall be applied on a monthly basis to the respective Planning Year quantity of Buyer's Generation Resources.

   b) Reduction of Load: When notified, the Buyer shall reduce his load to the contracted firm amount or less. Failure to reduce load to firm level when notified shall result in the Buyer being penalty billed $92.40/kW of the demand difference

between the maximum load on line during the interruption and contracted firm load.

The buyer agrees to endeavor to reduce demand to a level not to exceed the firm contract demand or some higher level requested by the company, in accordance with the timetable requested by the Seller. It is understood that failure to comply with the timetable requested may result in the forced interruption of electric service to the Buyer's total demand at time of unmanageable load conditions for the Seller. Penalty billing in accordance with this clause shall occur if:

1) The Seller provided notice to interrupt one hour or more in advance and the Buyer fails to eliminate the interruptible demand, which is designated for interruption by the time requested, or,

2) The Seller provides less than a one hour notice to interrupt and the Buyer has not eliminated at least 100% of the demand, which is designated for interruption within 60 minutes after request for interruption.

5. DNRs: The Capacity amount shall be supplied from resources that meet the resource adequacy requirements of the MISO tariff.

6. Treatment of Buyer's Load in Seller's Planning Obligations: Seller shall include Buyer's load in its planning obligation and treat Buyer's load as native load and plan to serve such load with no less degree of reliability than Seller would its native load or other requirements wholesale load.

7. Financial Schedules: Not applicable, as Buyer's load will be considered part of Seller's native load requirements.

8. Scheduling: Seller shall schedule energy to meet Buyer's requirements, as necessary, with the MISO.

9. Capacity Amount: The Capacity Amount for Load Following Service shall be determined on a monthly basis and is equal to the Buyer's 60-minute integrated demand coincident with Seller's Monthly System Peak Load.

10. Metering: Section 4 of the Load Following Service - Service Schedule of the Tariff shall be modified as follows: "Buyer" shall be replaced with "Seller" and "Seller" shall be replaced with "Buyer".

11. Customer Charge: A monthly charge of $200 shall be billed for each point of delivery.

12. Performance Assurance: As required by Seller in accordance with Section 6.0 of the Tariff.

13. Transmission, Ancillary and Market Service Charges: The following shall apply to the monthly estimate, actual and true-up charges for transmission, ancillary and market services:

    a. Buyer's Load Ratio Share: The number is determined by dividing (a), the sum of the Buyer's loads (MW) at the time of the American Transmission Company's (ATC) system's monthly peak loads during the prior calendar year, divided by (b), the sum of the Seller's loads (MW) at those same times.

    b. Applicable MISO Tariff Schedules, as may be amended from time to time and/or added to or deleted from applicability:

        i. Schedule 1: Scheduling, System Control and Dispatch Service
            1. Buyer's monthly charge is the MISO rate, divided by twelve, multiplied by the Buyer's load (MW) at the time of ATC system's peak load during the Billing Cycle.

        ii. Schedule 2: Reactive Supply And Voltage Control From Generation or Other Sources Service (Network Related)
            1. Buyer's monthly charge is the MISO rate, divided by twelve, multiplied by the Buyer's load (MW) at the time of ATC system's peak load during the Billing Cycle.
            2. Buyer's monthly credit is the MISO Schedule 2 Revenue Distribution multiplied by the Buyer's Load Ratio Share.

        iii. Schedule 9: Network Integration Transmission Service
            1. Buyer's monthly charge is the MISO monthly charge to Seller, multiplied by the Buyer's Load Ratio Share.

        iv. Schedule 10: Midwest ISO Cost Adder
            1. Energy: Buyer's monthly energy charge is the MISO Schedule 10 energy rate, multiplied by the Buyer's energy usage (MWhs) for the Billing Cycle.
            2. Demand: Buyer's monthly demand charge is the MISO Schedule 10 demand rate, multiplied by the Buyer's load (MW) at the time of ATC system's peak load during the Billing Cycle multiplied by the number of hours in the month.

        v. Schedule 10: FERC – FERC Annual Charges Recovery
            1. FERC: Buyer's monthly charge will be the MISO rate multiplied by the Buyer's energy usage (MWhs) for the Billing Cycle.

        vi. Schedule 11: Wholesale Distribution Service
            1. Buyer's monthly charge is the MISO monthly charge/credit to Seller multiplied by the Buyer's Load Ratio Share.

vii. Schedule 26: Network Upgrade Charge from Transmission Expansion Plan
   1. Buyer's monthly charge is the MISO rate multiplied by the Buyer's load (MW) at the time of ATC system's peak load during the Billing Cycle, unless allocated in a different manner to Seller.

viii. Schedule 26A: Multi Value Projects
   1. Buyer's monthly charge is the Seller's Schedule 26A Rate, multiplied by the Buyer's energy usage (MWhs) for the Billing Cycle.

ix. Schedule 33 – Blackstart Service
   1. Buyer's monthly charge is the MISO rate, divided by twelve, multiplied by the Buyer's load (MW) at the time of ATC system's peak load during the Billing Cycle.

x. Schedule 43: System Support Resources (Network SSR Uplift)
   1. Buyer's monthly charge is the MISO monthly charge to Seller, multiplied by the Buyer's Load Ratio Share.

14. Wholesale Distribution Service: is provided under a separate stand-alone agreement between the Seller and Buyer.

[Signature Page Follows]

Confirmed in writing, as of the dates set forth below.

Wisconsin Electric Power Company

By: _____

Name: _____

Title: _____

Date: _____

Upper Michigan Energy Resources Corporation

By: _____

Name: _____

Title: _____

Date: _____

WISCONSIN ELECTRIC POWER COMPANY

Formula Rate Wholesale
Sales Tariff

FERC Electric Tariff Volume No. 9

1.0 Availability

Wisconsin Electric Power Company ("Seller") will provide wholesale electric service to any qualified buyer ("Buyer") at the rates and pursuant to the terms and conditions contained in this Tariff. Seller will provide such wholesale electric service in the form of Load Following Service or Block Purchase Service, as further set forth herein and as agreed to between Seller and Buyer in the Service Agreement entered into hereunder. Such service shall be available for delivery solely to entities serving load within Wisconsin and the Upper Peninsula of Michigan.

2.0 Definitions

As used in this Rate Schedule, the following terms shall have the following meanings:

"**Accept,**" "**Accepted**" or "**Acceptance**" means all of the actions of Seller or its designated representative required to be taken under MISO rules in order to accept the MISO FinSched submitted by Buyer for a relevant Operating Day during the Delivery Period pursuant to this Tariff.

"Actual Capacity Rate" is the result of the true-up of the Estimated Capacity Rate as described in Section 3.1.D.

"Actual Energy Rate Part I" has the meaning given such term in Section 3.2.H.

"Actual Energy Rate Part II" has the meaning given such term in Section 3.2.I.

"**Affiliate**" means any Person directly or indirectly controlling or controlled by or under direct or indirect common control of a specified Person. For purposes of this definition, "control" means the power to direct the management and policies of such Person, directly or indirectly, whether through the ownership of voting securities, by contract or otherwise. For purposes of this Tariff, it shall be assumed that the direct or indirect owner of more than 50% of the outstanding stock or other equity interest of a Person has control of such Person. The terms "controlling" and "controlled" have meanings correlative to the foregoing.

"ATC" means American Transmission Company, LLC, or its successors.

"Base Quantity" has the meaning given such term in Section 2(e) of the Load Following Service Schedule.

"**Billing Cycle**" means each calendar month during the Delivery Period and any partial calendar month at the beginning or end of the Delivery Period.

"Billing Dispute" has the meaning given such term in Section 5.2.

"Block Purchase Service" means service provided by Seller pursuant to the terms of the Block Purchase Service Schedule that is for the delivery of a defined amount of Capacity and Energy associated with such Capacity as identified in the Service Agreement between Buyer and Seller.

"**Business Day**" means any day other than Saturday, Sunday or any other day on which commercial banks in Milwaukee, Wisconsin are required to be closed.

"**Buyer**" means any entity that enters into a Service Agreement to take electric service from Seller under this Tariff.

"Buyer's Monthly Energy Usage" is equal to the sum of Buyer's Monthly On-Peak Energy Usage and Buyer's Off-Peak Energy Usage.

"Buyer's Monthly Off-Peak Energy Usage" has the meaning given such term in Section 3.2.F.

"Buyer's Monthly On-Peak Energy Usage" has the meaning given such term in Section 3.2.G.

"**Capacity**" means the capability to generate a particular amount of electrical energy at a particular time that meets the requirements for Capacity established by MISO.

"**Capacity Amount**" has the meaning given such term in Section 3.1.C.

"**Capacity True-Up**" has the meaning given such term in Section 3.1.D.

"**Claims**" means all claims or actions, threatened or filed and whether groundless, false, fraudulent or otherwise, that directly or indirectly relate to the subject matter of an indemnity, and the resulting losses, damages, expenses, reasonable attorneys' fees and court costs.

"Commercial Pricing Node" or **"CPNode"** has the meaning given in the MISO Tariff.

"Confirmation Letter" means a letter substantially in the form of Appendix A to the Service Agreement, as amended or superseded from time to time. Seller may confirm service pursuant to this Tariff by forwarding to Buyer a confirmation ("Confirmation") substantially in the form of Appendix A to the Service Agreement.

"**Contract Year**" shall be defined in the Service Agreement.

"**Cost of Congestion**" has the meaning given such term in the MISO Tariff.

"**Cost of Losses**" has the meaning given such term in the MISO Tariff.

"**CPT**" means Central Prevailing Time which, as of any particular time, is either Central Standard Time or Central Daylight Time, whichever is legally in effect in Milwaukee, Wisconsin.

"**Curtailment**" means any event or circumstance, including an event of Force Majeure, that causes Seller to shed, cut or otherwise curtail its Firm Load obligations.

"Day" means a 24-hour period beginning at 12:01 am CPT and ending at 12:00 am CPT.

"**Daily Energy Schedule**" has the meaning given to such term in the applicable Service Schedule.

"Deadline" has the meaning given such term in Section 9.2.

"**Delivery Point**" means the Commercial Pricing Node(s) or such other point(s) as determined by mutual consent of the Parties in the Confirmation Letter.

"Designated Network Resource" or **"DNR"** has the meaning given such term in the MISO Tariff.

"Dispute" has the meaning given such term in Section 9.

"**Energy**" has the meaning given such term in the MISO Tariff.

"Energy Rate Part I True-Up" has the meaning given such term in Section 3.2.H.

"Energy Rate Part II True-Up" has the meaning given such term in Section 3.2.I.

"**Estimated Capacity Rate**" has the meaning given such term in Section 3.1.A.

"Estimated Energy Rate Part I" has the meaning given such term in Section 3.2.C.

"Estimated Energy Rate Part II" has the meaning given such term in Section 3.2.D.

"**Federal Power Act**" means the Federal Power Act of 1935 (16 U.S.C. §§ 791 et seq.), as it may be amended or repealed from time to time.

"**FERC**" means the Federal Energy Regulatory Commission, or any successor agency.

"FERC Form 1" means the annual report filed at FERC by each public utility, as such form may be amended or superseded from time to time.

"**FERC Rate**" means the interest rate set and calculated by FERC pursuant to 18 C.F.R. § 35.19(a), as amended or superseded from time to time.

"**Force Majeure**" means any cause or occurrence beyond the reasonable control of and without the negligence of the Party claiming Force Majeure which causes the Party to be unable, or otherwise materially impairs its ability, to perform its obligations in whole or in part hereunder. Subject to the foregoing, such causes or occurrences may include any acts of God; acts of the public enemy; terrorism; wars; blockades; insurrections; riots; epidemics; landslides; lightning; earthquakes; fires; storms; floods; washouts; civil disturbances; strikes, lockouts or work stoppages; and any other cause, whether of the kind herein enumerated or otherwise, which, despite reasonable efforts of such Party to prevent or mitigate its effects, prevents or

delays the performance of a Party, or prevents the obtaining of the benefits of performance by the other Party, and is not within the control of the Party claiming excuse. The following acts, events or causes shall in no event constitute an event of Force Majeure: (i) any lack of profitability to a Party or any losses incurred by a Party or any other financial consideration of a Party; (ii) unavailability of funds or financing; or (iii) an event caused by conditions of national or local economics or markets.

"Generation Resources" means any source of Capacity and Energy associated with such Capacity that Buyer owns and which Buyer uses to serve its load. Generation Resources shall not include purchases of Capacity and/or Energy from any other sources, unless otherwise agreed to by Seller.

"**Good Utility Practice**" means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision is made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather, intended to include acceptable practices, methods, or acts generally accepted in the region, but not necessarily codified.

"**Governmental Authority**" means (i) the federal government of the United States, (ii) any state, county or local government, (iii) any regulatory department, body, political subdivision, commission, bureau, administration, agency, instrumentality, ministry, court, judicial or administrative body, taxing authority, (iv) any other authority of any of the foregoing (including any corporation or other entity owned or controlled by any of the foregoing), and (v) MISO, NERC, MRO and RFC; in each case in (i) - (v) above having jurisdiction over any or all of the Parties, this Tariff or the transmission system operated by MISO, whether acting under express or delegated authority.

"**HE**" means hour ending.

"Initial Daily Amount" means a dollar amount equal to:

[the Monthly Capacity Charge multiplied by the Capacity Amount (in kilowatts) multiplied by 12] divided by 365.

"**Law**" means any federal, state and local laws, statutes, regulations, rules, codes, orders, judgments, decrees or ordinances enacted, adopted, issued or promulgated by any Governmental Authority, including any Authorizations issued to a Party or by which a Party may be bound (including any of the foregoing pertaining to electrical, building, zoning, environmental and occupational safety and health requirements) or any published directive, guideline, tariff, requirement or other restriction of a Governmental Authority or any determination by, or interpretation of, any of the foregoing by any Governmental Authority, binding on a given Person in a relevant jurisdiction.

"Limitations Date" has the meaning given such term in Section 4.7.

"**LMP**" means the Locational Marginal Price as determined by MISO.

"Load Following Service" shall mean the delivery of Capacity and/or Energy as described and agreed to in the Service Agreement between Buyer and Seller.

"Loss Factor" has the meaning given such term in Sections 3.1.B and 3.2.E.

"Market Participant" has the meaning given such term in the MISO Tariff.

"**MISO**" means the Midwest Independent Transmission System Operator, Inc., or any successor organization.

"**MISO Auction Revenue Right" or "MISO ARR**" has the meaning given such term in the MISO Tariff and includes any financial transmission rights or other rights arising from or associated with such MISO Auction Revenue Right.

"**MISO Day-Ahead Market**" means the Day-Ahead Market as defined in the MISO Tariff.

"**MISO FinSched**" means an Energy schedule as such term is defined in the MISO Tariff.

"MISO Module E" has the meaning given such term in the MISO Tariff.

"**MISO Tariff**" means the Open Access Transmission and Energy Market Tariff for the Midwest Independent Transmission System Operator, Inc., as amended from time to time, or any tariff of a successor to the MISO.

"**Monthly Capacity Charge**" has the meaning given such term in Section 3.1.

"**Monthly Energy Charge**" has the meaning given such term in Section 3.2.

"**Monthly Energy Rate**" means the energy rate for On-Peak periods or for Off-Peak periods, as applicable, for any particular month in question, calculated pursuant to Exhibit B.

"Monthly System Peak Load" shall mean Seller's maximum 60 minute integrated demand during a month.

"MPSC" means the Michigan Public Service Commission, or its successor.

"**MRO**" means the Midwest Reliability Organization, or any successor organization.

"**MW**" means a megawatt.

"**MWh**" means a megawatt-hour.

"**NAESB**" means the North American Energy Standards Board, or any successor organization.

"**NERC**" means the North American Electric Reliability Corporation, including in its capacity as the Electric Reliability Organization appointed by FERC, or any successor organization.

"Non-Market Participant" means any entity that is not a Market Participant.

"Off-Peak" means all times that are not On-Peak.

"Off-Peak Multiplier" has the meaning given such term in Section 3.2.A.

"**On-Peak**" means HE 0900 CPT to and including HE 2000 CPT, Monday through Friday, excluding any day designated as a holiday by NERC until such time the NAESB is responsible for such designations, whereupon NAESB designations will control as to holidays.

"On-Peak Multiplier" has the meaning given such term in Section 3.2.B.

"**Operating Day**" has the meaning given such term in the MISO Tariff or related documents.

"Party(ies)" means Buyer and/or Seller, as applicable.

"Performance Assurance" means security or credit support in the form of cash, letter(s) of credit, or other collateral acceptable to Seller.

"**Person**" means any natural person, corporation, limited liability company, general partnership, limited partnership, proprietorship, other business organization, trust, union, association or Governmental Authority.

"**Planning Reserves**" means the amount of generation required to be maintained pursuant to the generation resource planning reserve margin requirements approved and administered by each Governmental Authority with respect to which Seller is obligated to meet generation resource planning reserve margin requirements.

"Power the Future" means Seller's generation expansion project approved by the PSCW in Docket Nos. 05-CE-117 and 05-CE-130 designed to meet Wisconsin's needs for reliable and reasonably priced energy now and in the future as such project may be revised and amended from time to time.

"**PSCW**" means the Public Service Commission of Wisconsin, or its successor.

"**Renewable Attributes**" means any and all renewable resource credits, emissions credits and any other credits granted by a Governmental Authority and attributed to the production of Energy from renewable power resources and included in the formulaic power production cost(s).

"Revised Limitations Date" the meaning given such term in Section 4.8.

"**RFC**" means the ReliabilityFirst Corporation, or any successor organization.

"**Schedule,**" "**Scheduled**" or "**Scheduling**" means all of the actions of Buyer or its designated representatives and/or Seller required to be taken under MISO rules in order to submit to MISO a MISO FinSched for a relevant Operating Day during the Delivery Period pursuant to this Tariff.

"Service Agreement" means an agreement for service signed by the Buyer that does not materially deviate from the Form of Service Agreement contained in Exhibit A.

"Service Year" is the calendar year in which electric service is provided.

"**Seller**" means Wisconsin Electric Power Company and its successors.

"Senior Executives" means the individuals within Buyer's organization and Seller's organization with sufficient decision-making authority to bind their respective organization to the terms of an agreement.

"Subsequent Daily Amount" means a dollar amount equal to the Initial Daily Amount multiplied by the return on equity specified in Exhibit B, Attachment A.

"Tariff" means the Seller's "Formula Rate Wholesale Sales Tariff" as on file with the FERC, as revised or superseded from time to time.

"Total Actual Annual Capacity Charge" has the meaning given such term in Section 3.1.D.

"Trued-Up Year" has the meaning given such term in Section 4.1.

3.0 Rate.

Buyer shall make monthly payments to Seller for electric service taken under this Tariff, as described below.

3.1 Monthly Capacity Charge. Buyer's Monthly Capacity Charge during a Service Year is determined in accordance with the formula below:

Monthly Capacity Charge = (Estimated Capacity Rate x Loss Factor x Capacity Amount) + Capacity True-Up

The terms in the formula are described below.

A. Estimated Capacity Rate. The Estimated Capacity Rate during the Service Year shall be determined in accordance with the formula in Exhibit B, Attachment A. The Estimated Capacity Rate used during the months of January through April of the Service Year shall be based upon FERC Form 1 information for the year that is two years prior to the Service Year. The Estimated Capacity Rate used during the months of May through December of the Service Year shall be based upon FERC Form 1 information for the year preceding the Service Year. To minimize

true-ups, the Estimated Capacity Rate will be based upon calendar year-end rate base balances instead of average balances. In addition, the Estimated Capacity Rate will include Seller's best estimate of Power the Future costs for the Service Year rather than the actual Power the Future costs from prior years.

B. Loss Factor. The Loss Factor accounts for losses, incurred or avoided, by delivering power to the Delivery Point as specified in the Service Agreement between Buyer and Seller. The Loss Factor shall be 1.0 for a Delivery Point consisting of 90% of the WEC.S Commercial Pricing Node and 10% of the WEC.N Commercial Pricing Node. For Buyers that are interconnected at a distribution level, losses on the distribution system will be addressed in an appropriate wholesale distribution service agreement.

C. Capacity Amount. The Capacity Amount for any particular month is determined in accordance with the Service Agreement between Buyer and Seller.

D. Capacity True-Up. Prior to rendering a bill in June, for services provided in May, in the year following the Service Year, Seller shall calculate its actual costs for the Service Year based upon cost and load information reported in the FERC Form 1 for the Service Year. The calculation will use average rate base balances and actual Power the Future costs for the Service Year. From this actual cost, Seller shall develop an Actual Capacity Rate. Seller shall multiply the Actual Capacity Rate x Loss Factor x the sum of the monthly Capacity Amounts for the Service Year to calculate the Total Actual Annual Capacity Charge that should have been collected during the Service Year.

(i) Any difference between the sum of the Monthly Capacity Charges for the Service Year based upon the Estimated Capacity Rates and the Total Actual Annual Capacity Charges for the Service Year based upon the Actual Capacity Rate shall be refunded to or collected from Buyer in equal amounts in the monthly bills rendered in June through December of the calendar year following the Service Year. The refund or collection may be paid in one lump sum at the payer's option. Any such refund by Seller or payment by Buyer shall be increased by interest at the FERC Rate.

(ii) Major Assets - If Seller purchases or sells a major electric production asset with a gross plant-in-service value of $100,000,000 or more during a Service Year, the Actual Capacity Rate formula for the Service Year shall employ a 13-month average balance for such an asset for the specified items instead of an average of beginning and end-of-calendar year balances. The specified items shall consist of plant-in-service, depreciation reserve, deferred taxes and CWIP in rate base.

3.2 Monthly Energy Charge. Buyer's Monthly Energy Charge during a Service Year is determined in accordance with the formula below:

[(On-Peak Multiplier x Estimated Energy Rate Part I) + Estimated Energy Rate Part II] x Loss Factor x Buyer's Monthly On-Peak Energy Usage

plus

[(Off-Peak Multiplier x Estimated Energy Rate Part I) + Estimated Energy Rate Part II] x Loss Factor x Buyer's Monthly Off-Peak Energy Usage

plus

Energy Rate Part I True-up + Energy Rate Part II True-up.

The terms in the formula are described below:

A. Off-Peak Multiplier. The Off-Peak Multiplier converts the Energy Rate Part I to an Off-Peak rate based on the relationship of Off-Peak energy costs to average energy costs. The Off-Peak Multiplier is 0.90.

B. On-Peak Multiplier. The On-Peak Multiplier converts the Energy Rate Part I to an On-Peak rate based on the relationship of On-Peak energy costs to average energy costs. The On-Peak Multiplier is 1.14.

C. Estimated Energy Rate Part I. The Estimated Energy Rate Part I to be applied with respect to a particular calendar month shall be determined in such calendar month by inputting estimated cost and energy data into Energy Rate Part I Formula in Exhibit B, Attachment B.

D. Estimated Energy Rate Part II. The Estimated Energy Rate Part II for each month shall be determined in accordance with the Energy Rate Part II Formula in Exhibit B, Attachment B. The Estimated Energy Rate Part II for energy used during the months of January through April of the Service Year shall be based upon FERC Form 1 information for the year that is two years prior to the Service Year. The Estimated Energy Rate Part II for energy used during the months of May through December of the Service Year shall be based upon FERC Form 1 information for the year preceding the Service Year.

E. Loss Factor. The Loss Factor accounts for losses, incurred or avoided, by delivering power to the Delivery Point as specified in the Service Agreement between Buyer and Seller. The Loss Factor shall be 1.0 for a Delivery Point consisting of 90% of the WEC.S Commercial Pricing Node and 10% of the WEC.N Commercial Pricing Node. For Buyers that are interconnected at a distribution level, losses on the distribution system will be addressed in an appropriate wholesale distribution service agreement.

F. Buyer's Monthly Off-Peak Energy Usage. Buyer's Monthly Off-Peak Energy Usage is the amount of energy, in kilowatt-hours, delivered to Buyer during the month in the Off-Peak hours.

G. Buyer's Monthly On-Peak Energy Usage. Buyer's Monthly On-Peak Energy Usage is the amount of energy, in kilowatt-hours, delivered to Buyer during the month in the On-Peak hours.

H. Energy Rate Part I True-up. Any true-up of the Estimated Energy Rate Part I for each calendar month shall be made at the time of a billing of the subsequent calendar month. The Actual Energy Rate Part I for the prior calendar month shall be determined using the Energy Rate Part I Formula in Exhibit B, Attachment B and actual costs and energy for that month.

The Energy Rate Part I True-up =

[On-Peak Multiplier x (Actual Energy Rate Part I for the previous calendar month less the Estimated Energy Rate Part I for the previous calendar month) x Loss Factor x Buyer's Monthly On-Peak Energy Usage for the previous calendar month] plus

[Off-Peak Multiplier x (Actual Energy Rate Part I for the previous calendar month less the Estimated Energy Rate Part I for the previous calendar month) x Loss Factor x Buyer's Monthly Off-Peak Energy Usage for the previous calendar month] plus

interest at the FERC Rate.

I. Energy Rate Part II True-up. Prior to rendering a bill in June, for services provided in May, in the year following the Service Year, Seller shall calculate the Actual Energy Rate Part II for the Service Year based upon cost and load information reported in the FERC Form 1 for the Service Year.

The Energy Rate Part II True-Up =

(Actual Energy Rate Part II x Loss Factor x sum of the twelve months of Buyer's Monthly Energy Usage during the Service Year) minus

[the sum over the twelve months of the Service Year of (Estimated Energy Rate Part II for each month x Loss Factor x Buyer's Monthly Energy Usage for the month)].

The Energy Rate Part II True-Up shall be refunded or collected in equal amounts in the monthly bills rendered in June through December of the calendar year following the Service Year. The refund or collection may be paid in one lump sum at the

payer's option. Any such refund by Seller or payment by Buyer shall be increased by interest at the FERC Rate.

3.3 Taxes.

3.3.1 Seller's Taxes. Seller is liable for and shall pay, or cause to be paid, or reimburse Buyer if Buyer has paid, all taxes applicable to any transaction arising out of this Tariff prior to the Delivery Point. Seller shall indemnify, defend and hold harmless Buyer from any Claims for such taxes applicable prior to the Delivery Point. Notwithstanding the foregoing, Buyer shall be liable for all gross receipts taxes related to service provided under this Tariff.

3.3.2 Buyer's Taxes. Buyer is liable for and shall pay, or cause to be paid, or reimburse Seller if Seller has paid, all taxes applicable to (a) any transaction arising out of this Tariff at or after the Delivery Point and (b) any and all Renewable Attributes transferred from Seller to Buyer, if applicable. Buyer shall indemnify, defend and hold harmless Seller from any Claims for such taxes.

3.3.3 Certificate of Tax Exemption. A Party that is exempt from any taxes shall, upon written request of the other Party, provide a certificate of exemption or other reasonably satisfactory evidence of exemption.

3.4 Transmission Service and Ancillary Services.

Buyer shall be responsible for the costs of all transmission, distribution and ancillary services.

3.4.1 Market Participant. If Buyer is a Market Participant, Buyer shall be responsible for all transmission and ancillary services and costs as required by any Governmental Authority for Buyer's load designated in the Service Agreement between Buyer and Seller. If Buyer ceases to be a Market Participant at any time during the term of its Service Agreement between Buyer and Seller, Buyer shall inform Seller 90 days prior to this change and amend such Service Agreement as necessary.

3.4.2 Non-Market Participant. If Buyer is a Non-Market Participant, Seller may, if necessary, acquire transmission and ancillary services as required by any Governmental Authority for Buyer's load. In such event, Seller will bill, and Buyer shall pay, Seller for transmission and ancillary services and other costs as determined by any Governmental Authority during each Billing Cycle.

3.5 Congestion and Losses. Seller shall be responsible for Cost of Congestion and Cost of Losses up to the Delivery Point. Buyer shall be responsible for Cost of Congestion and Cost of Losses from and after the Delivery Point. To the extent Seller is charged for the Cost of Congestion and/or the Cost of Losses after the Delivery Point, Seller will bill, and Buyer shall pay, Seller for such costs during each Billing Cycle.

3.6 Title. Title to and risk of loss of all Energy sold and purchased hereunder shall transfer from Seller to Buyer at the Delivery Point. Seller warrants that it will deliver to Buyer such Energy free and clear of all liens and encumbrances.

3.7 Planning Reserves. Seller will use commercially reasonable efforts to plan its system to provide Planning Reserves associated with the Capacity purchased hereunder. The purchase of Capacity and Energy under this Tariff shall not give Buyer any entitlement to any Capacity or Energy beyond the Capacity Amount for the applicable Contract Year(s).

3.8 Formula Rate Adjustments. To the extent that Buyer is paying or receiving credit for the MISO energy market charge types identified in Exhibit C as a result of being a Market Participant or as a result of some other contractual arrangement, the charges or credits associated with the charge types identified in Exhibit C shall be removed from the formula in Exhibit B.

4.0 Buyer's Audit Rights

4.1 Audit. On or about May 31 of each year, Seller shall meet, at its offices in Milwaukee, Wisconsin, with Buyer and provide to Buyer its formula rate true-up for the prior calendar year Trued-Up Year. The purpose of the meeting will be to (a) review the formula calculations and the resulting actual rates for the Trued-up Year; and (b) review the formula calculations and the resulting estimated rates, subject to true-up and finalized true-up, that will apply for the remainder of the current calendar year (*i.e.*, from May through December of the current year) and for January through April of the next calendar year.

4.2 Information. At the true-up meeting, Seller will:

a. provide sufficient information[1] to enable Buyer to replicate the calculation of formula results from Form 1 or other applicable accounting inputs and to compare that calculation to that of prior years; items to be provided include the following:

i. a live electronic spreadsheet of the calculations;

ii. a copy of the Seller's FERC Form 1 for the Trued-Up Year, if it is not otherwise readily available;

iii. identification of any changes in the formula's references to the FERC Form 1 from the previous year;

iv. identification of all adjustments made to FERC Form 1 data in determining formula inputs, including relevant footnotes to the FERC Form 1 and any adjustments not shown in a FERC Form 1 footnote;

v. identification of all instances in which differences between state commission (PSCW or MPSC) and FERC ratemaking affected the Seller's FERC Form 1 accounting and thereby affected formula inputs;

[1] As appropriate, competitively sensitive information may be provided only pursuant to a confidentiality agreement.

vi. breakdowns of the monthly peak demands shown on page 401b of the Form 1 and of the monthly peak demands used in the denominator of the capacity formula, sufficiently detailed to enable transparent reconciliation of these two demand measures, and including the following:

- Generation under the Seller's control in the Seller's balancing area, control area, or sub-area, if the Seller operates one;
- Firm purchased power by the Seller;
- Aggregated tie-line information;
- Actual interruptible/curtailable load available at the time of the Seller's monthly system peak as reported in the FERC Form 1; and
- Actual interruptible/curtailable load included in the Seller's monthly system peak as reported in the FERC Form 1.

vii. an itemization for each of the following accounts (including sub-accounts) of the Uniform System of Accounts. (This listing does not prevent Buyer from obtaining itemization of other accounts, or other relevant information, as part of the audit process.):

- a/c 105 Property Held for Future Use (Production)
- a/c 107 Pollution Control CWIP
- a/c 190 Accumulated Deferred Income Tax
- a/c 282 Accumulated Deferred Income Tax – Other Property
- a/c 283 Accumulated Deferred Income Tax – Other
- a/c 404 Amortization of Limited Term Electric Plant
- a/c 407 Amortization of Property Losses, Unrecovered Plant and Regulatory Study Costs
- a/c 454 Rent From Electric Property
- a/c 456 Other Electric Revenue

b. identify any respects in which the formula rate's application to the Trued-Up Year materially differed from its application in the preceding year (*e.g.*, due to changes in accounting procedures, the purchase or sale of major assets, or other such significant changes) and describe how such altered application has affected the formula output;

c. identify the major reason(s) for the differences, if any, between (1) the trued-up rate and the estimated rate for the Trued-up Year and (2) the trued-up rate and the preceding year's trued-up rate;

d. provide the average monthly coal inventory for Seller's coal plant(s) and for Seller in the aggregate for the prior year and projections for the next year (the inventory to be expressed as a multiple of the average daily burn - *i.e.*, in days of burn at the applicable average burn rate).

4.3 Estimated Rates. The results of the true-up will establish the estimated rates that will apply as the basis for initial bills, subject to Sections 4.5 through 4.11 below and absent contrary agreement, for the remainder of the current calendar year (*i.e.*, from May 1 through December 31 of the current year) and for January 1 through April 30 of the next calendar year. However, the Seller and Buyer may, by mutual agreement, modify the estimated rates so as to more closely approximate the expected trued-up rate(s) and thereby minimize future true-up adjustment(s).

4.4 Final Rates. Subject to the provisions of this Section 4, the results of the true-up will establish the final rates for the Trued-Up Year.

4.5 Audit of Trued-Up Year. Buyer shall have the right to audit the actual Trued-Up Year data to verify the formula inputs, calculations, and resulting rates, and to verify that all formula inputs have been adjusted as appropriate so that the formula output reflects the fully allocated average embedded cost. Buyer shall be entitled to request Seller to adjust the true-up rates. Seller shall issue a refund or a surcharge bill to account for any differences in the event (i) there is a discrepancy between the data employed by Seller in performing the true-up and the actual data for the Trued-Up Year, (ii) Seller developed the true-up in a manner inconsistent with this rate schedule, (iii) Seller has not reasonably applied the terms of the formula rate and the applicable procedures (*e.g.*, has made a discretionary accounting decision that is neither precluded nor mandated by the Uniform System of Accounts and its instructions, but which results in the formula output not reflecting the fully allocated average embedded cost), or (iv) Seller has addressed issues that were or should have been identified pursuant to Section 4.2.b or 4.2.c above in a manner that does not yield the fully allocated average embedded cost. Seller will provide such information as Buyer may reasonably request in order to understand Seller's true-up calculations.

4.6 Timing. The audit period of any audit conducted pursuant to the provisions of this Section, with respect to billings for a particular Trued-Up Year, shall be completed by the second October 31 that follows the end of the Trued-Up Year, unless extended by written mutual agreement. During such audit, Seller shall make a good faith effort to respond to information requests within 15 business days of receipt of such requests. Each Trued-Up Year shall be subject to audit only once.

4.7 Limitations Date. Buyer shall submit all concerns to Seller, in writing, by the Limitations Date, which shall be the second December 30th that follows the end of the Trued-up Year. If Buyer does not object to the true-up to the Seller by the Limitations Date, the Seller's costs for the Trued-Up Year shall be deemed final, shall not be subject to further dispute or challenge as to that Buyer, and shall not be subject to refund.

4.8 Exception to Limitations Date. For good cause and before the Limitations Date, the Seller may inform Buyer that the true-up as billed (a) was more or less than it should have been for consistency with this rate schedule and its procedures and (b) should be adjusted. Any such notice must be in writing, and accompanied by an explanation of the adjustment. Buyer shall have full rights to audit any such adjustment. Issuance of such a notice will open a new 17-

month audit period (and a Revised Limitations Date, which shall be 60 days following the end of such 17-month audit period) as to any such adjustment. As to each Buyer to which the Seller does not submit such a notice by the Revised Limitations Date, the Seller's charges for the Trued-Up Year shall not be subject to upwards adjustment.

4.9 Complaint. If any objection made pursuant to Section 4.7 or notice provided pursuant to Section 4.8 is not resolved within 60 days of being submitted, the aggrieved party may then file with FERC pursuant to Federal Power Act ("FPA") Sections 205 or 206. Any such filing shall specify the portion(s) of the actual or sought revenue collection that is subject to dispute. Such filings may be made earlier than such date if attempts at informal resolution are at an impasse. In any such proceeding, Seller shall bear the burden of proving that it has reasonably applied the terms of the formula rate; that the resultant rate is just, reasonable, and not unduly discriminatory; and that it followed the applicable procedures herein. In the event a party other than Seller seeks to modify the formula rate in any respect, that party shall bear the burden of proving that the formula rate is no longer just and reasonable without such modification and that the proposed modification is just, reasonable, and consistent with the original intent of the formula rate.

4.10 The following example illustrates the timeline contemplated by the preceding provisions. Pursuant to the preceding provisions, dates and estimated rate levels used for pre-true-up billing may be subject to change by mutual agreement.

i. Service Year: January 1, 2008 through December 31, 2008.

ii. Basis for estimated-rate billing, prior to true-up:

(a) January 1, 2008 through April 30, 2008, formula applied to calendar 2006 Form 1 data; and

(b) May 1, 2008 through December 31, 2008, formula applied to calendar 2007 Form 1 data.

iii. Basis for trued-up billing: Formula applied to calendar 2008 Form 1 data.

iv. Filing of Form 1 that will be used as basis for trued-up billing: April 2009.

v. True-up provided by the Seller, subject to audit: On or before May 31, 2009.

vi. End of audit period: October 31, 2010.

vii. Limitations Date: December 30, 2010.

viii. Any ensuing filing pursuant to FPA Sections 205 or 206: Upon impasse, but not later than March 1, 2011, or reasonable period thereafter.

4.11 If the Buyer disputes the true-up rates, the Buyer shall continue to pay its total bill on a monthly basis. If a refund is determined to be due to the Buyer, it shall be paid to the Buyer with interest at the FERC Rate.

4.12 Filings to Change the Formula. The formula rate is intended to yield practicably administrable unit rates that, as trued-up, will reflect the fully allocated embedded cost in a manner that is just, reasonable, and not unduly discriminatory. The following provisions are intended to support formula results that accord with that intent while also providing for FERC review of any changes to the filed rate formula.

a. Seller or Buyer may file under FPA Section 205 or 206, as applicable, in order to change the formula rate so that it reflects the fully allocated embedded cost in a manner that is just, reasonable, and not unduly discriminatory. If such a filing is made before the affected Service Year(s) or Trued-Up Year(s) becomes final under Sections 4.7 or 4.8 above, and a change to the formula, made to achieve that intent, is found by the FERC to be appropriate, the effective date for such a change will be retroactive so as to encompass the entirety of the affected, non-finalized year(s). To qualify for such retroactivity pursuant to this provision, the filing must (a) address material changes in the formula rate application that were (or, in the case of a filing by Buyer, were or should have been) identified pursuant to Sections 4.2.b-c above for a True-Up Year; (b) fit within Section 4.5(i.), (ii), (iii), or (iv) above; (c) be directed to ensuring that the formula rate as applied to those issues yields a result that reflects fully allocated average embedded cost; (d) be made before the end of the third calendar month following the month that includes the Limitations Date for that True-Up Year; and, (e) result in a final determination to change the formula rate.

b. No changes may be made to the formula absent a FPA Section 205 or 206 filing with FERC. If the formula must be changed to conform with changes in the format of FERC Form 1, the format of the Uniform System of Accounts, or other reasons of a similar ministerial nature, Seller shall, absent extraordinary circumstances, provide Buyer(s) with 30 days notice of the Seller's intent to file to change the formula and a full explanation of the changes. If such notice is given and no Buyer(s) presents a good faith, written objection in response, the Buyer(s) will be deemed to have consented to the filing and the effective date necessary, including a retroactive effective date, to implement the formula as originally intended.

5.0 Billing and Payment

5.1 General. Seller shall send a billing statement to Buyer on or before the 10th day after the end of each Billing Cycle stating the Monthly Capacity Payment and the Monthly Energy Payment. Buyer shall pay such amount to Seller within 20 days after the date of the billing statement in immediately available funds through wire transfer to an account designated by Seller. Any amounts due and payable and not paid by the due date will be deemed delinquent and will accrue interest at the FERC Rate, such interest to be calculated from and including the due date but excluding the date the delinquent amount is paid in full.

5.2 Billing Disputes. In the event that either Party disagrees with the amount of any bill, such disagreement shall be deemed a Billing Dispute, but only to the extent that the disputing Party notifies the other Party of the amount in dispute. In any event, Buyer shall pay

to Seller the full amount of such bill on or prior to the applicable due date, as identified in Section 5.1, notwithstanding such Dispute. Upon resolution of such Billing Dispute, in the event a refund is owed by Seller to Buyer, Seller shall pay, with interest computed at the FERC Rate, from and including the date the disputed payment was made, but excluding the date the refund payment is made, any refund amount ultimately found to be due to Buyer. Upon resolution of such Billing Dispute, in the event an additional payment is owed by Buyer to Seller, Buyer shall pay, with an interest charge computed at the FERC Rate from and including the date the disputed payment was made, but excluding the date the additional payment is made, any additional payment ultimately found to be due to Seller.

5.3 Netting. Netting means the process of offsetting, as of a particular day, all amounts owed by Seller to Buyer and *vice versa*, so that only the excess of Buyer's and Seller's mutual and offsetting debts and obligations remains owing from one to the other. Buyer and Seller shall discharge any mutual debts and payment obligations that are due and owing to each other under this Tariff by means of Netting. Seller or Buyer, whichever is owed a debt as a result of Netting, shall issue a bill to the other for payment in accordance with the provisions of this Section 5.3.

5.4 Finality. Neither the Buyer nor Seller shall have the right to challenge any billing statement rendered or received hereunder after 180 days from the date such billing statement was rendered for the last Operating Day included in the billing statement. In the event that any such billing statement depends in whole or in part upon estimated data, the 180-day limitation period in the preceding sentence shall be deemed to begin on the first day of the Billing Cycle in which such estimated data is adjusted to actual. This 180-day limitation shall not apply if Buyer has invoked its audit rights pursuant to Section 4 hereunder, in which case Section 4 shall apply.

6.0 Creditworthiness.

6.1 Creditworthiness. Seller, in order to satisfy itself of the ability of Buyer to meet its obligations under any Service Agreement entered into pursuant to this Tariff, may in accordance with standard commercial practices, conduct reasonable credit reviews. Seller will require Buyer to provide the information and meet the requirements determined by Seller. Buyer's failure to provide adequate credit support shall be grounds for Seller to deny a request for service or to terminate service. Seller may require Buyer, or Buyer's guarantor, to provide and maintain in effect during the term of any Service Agreement, or any transaction hereunder, an unconditional and irrevocable letter of credit, a parental guaranty, or an alternative form of security acceptable to Seller and consistent with commercial practices ("Performance Assurance"). Seller reserves the right, on a non-discriminatory basis, to require Buyer, or Buyer's guarantor, to submit to Seller updated financial information to permit Seller to evaluate creditworthiness of the Buyer, or Buyer's guarantor, on an on-going basis, and if necessary, to require future Performance Assurance. Upon receipt of such notice Buyer, or Buyer's guarantor, shall have three (3) Business Days to remedy the situation by providing such Performance Assurance to Seller. In the event that Buyer or Buyer's guarantor fails to provide such Performance Assurance acceptable to Seller within three (3) Business Days of receipt of notice, then an Event of Default will be deemed to have occurred.

7.0 No Requirement to Construct or Upgrade Facilities.

Except as expressly otherwise agreed to between Buyer and Seller, Seller shall have no obligation to construct or upgrade any facilities in order to provide any electric service under this Tariff for a potential Buyer.

8.0 Force Majeure.

8.1 Conditions of Excuse. If, as a result of an event of Force Majeure, a Party is rendered unable to perform its obligations in whole or in part under this Tariff, such Party shall be excused, except as specifically provided elsewhere in this Tariff, from that portion of its performance that is prevented by such Force Majeure event to the extent so prevented; provided, that:

8.1.1 The Party claiming Force Majeure gives the other Party prompt written notice after the Party claiming Force Majeure obtains actual knowledge thereof describing the particulars of and how such event qualifies as an event of Force Majeure;

8.1.2 The permitted suspension of performance is of no greater scope and of no longer duration than is required by the event of Force Majeure and the effects thereof; and

8.1.3 The Party claiming Force Majeure exercises commercially reasonable efforts to eliminate or mitigate the effects of the Force Majeure condition.

8.2 Burden of Proof. The burden of proof as to whether a Force Majeure has occurred shall be upon the Party claiming Force Majeure.

8.3 Payment and Security Obligations. Notwithstanding anything in this Tariff to the contrary, no payment obligation arising under this Tariff, including any Monthly Capacity Payment or Monthly Energy Payment, and no obligation to provide Performance Assurance shall be excused by any event of Force Majeure declared by either Party.

9.0 Dispute Resolution.

9.1 Dispute Resolution Procedures. Every dispute between the Parties arising out of or in connection with this Tariff (a "Dispute"), other than a Billing Dispute in Section 5.2, shall be resolved in accordance with this Section 9 (the "Dispute Resolution Procedures"), to the extent permitted by law.

9.2 Negotiation. In the event of a Dispute, the Parties shall attempt to resolve such Dispute by negotiations through their representative responsible for the performance of service under this Tariff. Either representative may request the other to meet within seven days at a

mutually agreed upon time and place. Such request must be in the form of a written notice that sets forth the nature of the controversy or claim. If the Dispute that gave rise to such controversy or claim is not resolved within 30 days from the date of the first meeting of such representatives or if such representatives fail to meet within such seven-day period (in either case, the "Deadline"), such representatives shall refer the Dispute to senior executives, who shall have authority to settle the Dispute (the "Senior Executives"). Thereupon, each such representative shall, no later than 15 days following the Deadline, prepare and deliver to the Senior Executives and the other such representative a memorandum stating the issues in dispute and their positions, summarizing any negotiations which have taken place and attaching relevant documents. The Senior Executives shall meet for negotiations within 30 days following the Deadline at a mutually agreed time and place. If the Dispute is not resolved within 10 days of the first meeting of the Senior Executives, then, in accordance with this Tariff, either Party may pursue any remedy it may have at law or in equity. After the resolution of any Dispute pursuant to this Section 9, each of the Parties and their Senior Executives shall give effect to and be bound by such resolution.

9.3 Disputes Subject to FERC Jurisdiction. All Disputes hereunder subject to FERC jurisdiction shall be resolved by appropriate filings and proceedings with FERC.

9.4 Continued Performance. Subject to the provisions of this Section, notwithstanding any Dispute between the Parties and pending the final decision of a Dispute, each Party shall continue to perform its respective obligations under any Service Agreement entered into under this Tariff.

10.0 Standard of Review.

Nothing contained herein shall be construed as affecting in any way the right of Seller under this Tariff to unilaterally make application to the FERC for a change in rates under Section 205 of the Federal Power Act and pursuant to the FERC's Rules and Regulations promulgated thereunder.

WISCONSIN ELECTRIC POWER COMPANY
FORMULA RATE WHOLESALE SALES TARIFF

LOAD FOLLOWING SERVICE
SERVICE SCHEDULE

LOAD FOLLOWING SERVICE
SERVICE SCHEDULE

1. AVAILABILITY

This Service Schedule is available to any Buyer for the purchase of Load Following Service; provided that:

(a) Seller has sufficient Capacity and Energy to provide to Buyer without diminishing service to existing customers;

(b) Buyer meets the creditworthiness requirements in Section 6 of the Tariff and the Performance Assurance provisions set forth in Article 5 of the Service Agreement;

(c) Buyer and Seller have executed a Service Agreement in the form included in this Tariff; and

(d) Buyer complies with all other applicable provisions of this Tariff.

2. APPLICABILITY AND CHARACTER OF SERVICE

Buyer agrees that Load Following Service shall include all the Capacity and Energy required to serve Buyer's full Energy and Capacity requirements; provided, however, that Buyer may utilize Generation Resources identified in the Confirmation Letter to meet a portion of Buyer's Energy and Capacity requirements. Capacity shall be measured in MW and Energy shall be measured in MWh. Seller and Buyer shall comply with the MISO Tariff, all applicable Laws of any Governmental Authority and Good Utility Practice.

(a) Planning Reserves. For purposes of establishing and maintaining Planning Reserves, Buyer and Seller agree to cooperate with one another and use commercially reasonable efforts to account for any Service Agreement entered into hereunder in their respective annual MISO Module E filings and other required regulatory filings as provided hereafter. In its MISO Module E filings and other required regulatory filings related to Planning Reserves, Seller shall not be required to designate specific DNRs as Capacity resources, but instead will represent its obligations under any Service Agreement entered into hereunder as an increase in its load obligations, and Buyer will represent its obligations under any Service Agreement entered into hereunder as an identical decrease in its load obligations.

(b) DNRs. If Parties are required to designate specific network resources in order for Buyer to obtain DNR accreditation pursuant to the MISO Tariff, Buyer and Seller shall reasonably cooperate with one another to identify and designate Seller's generation resources that best reflect the characteristics of the Delivery Point(s) applicable under any Service Agreement entered into pursuant to the Tariff. Any such DNRs shall be set forth in the Confirmation Letter.

(c) MISO ARRs. As necessary, Buyer and Seller shall reasonably cooperate with one another to allow Buyer to request MISO ARRs associated with the DNRs provided for in Section 2(b) above. In no event will Seller be required to provide any MISO ARRs, or any equivalent value, to Buyer pursuant to this Tariff.

(d) Curtailment. Load Following Service shall be provided with the same degree of reliability and quality of service as Seller's service to its firm load. In the event of any Curtailment, Seller will apply the effect of any Curtailment to Buyer on a pro rata basis, or as otherwise directed by any Governmental Authority. If any event or circumstance causing or contributing to a Curtailment also constitutes a Force Majeure as to Seller, then the Parties' rights and obligations with respect to such Force Majeure shall be governed by Section 7 of the Tariff to the extent and for so long as such Force Majeure persists. Otherwise, the Parties' rights and obligations with respect to such Curtailment shall be governed by this Section 2(d).

(e) Planning. Buyer shall provide Seller with a written five-year forecast reflecting its anticipated Capacity Amount on a monthly basis for each of the 5 years of its forecast. Buyer shall be entitled to an additional Capacity Amount beyond its forecast Capacity Amount in the first year that Seller provides Load Following Service ("Base Quantity"). After the first year that Seller provides Load Following Service, in no event will the total increased Base Quantity for Load Following Service exceed the previous year's Base Quantity multiplied by 1.1, or 5 MW, whichever is greater. ("Maximum Load Growth Rights"). To the extent Seller can provide Capacity and associated Energy from such Capacity that exceeds Maximum Load Growth Rights, Seller, at its sole discretion, may elect to do so.

3. SCHEDULING

(a) Energy Scheduling. The amount of Energy that Buyer will purchase for each hour of the Operating Day shall be equal to the Buyer's actual hourly load, as adjusted for Energy from Buyer's Generation Resources identified in the Confirmation Letter, if applicable (the "Daily Energy Schedule"). Other scheduling requirements shall be as indicated in the Confirmation Letter.

(b) Financial Schedules. Unless otherwise agreed to by the Parties, Buyer shall Schedule each MISO FinSched in the MISO Day-Ahead Market related to the delivery of Energy in accordance with the Daily Energy Schedule, and Seller shall Accept such MISO FinSched no later than the deadline established by MISO for Acceptance, with each using the appropriate MISO electronic scheduling system and protocols. If Seller fails to Accept a MISO FinSched Scheduled by Buyer in accordance with this Section 3(b) and the other provisions of this Tariff, and such failure is not excused under the terms of this Tariff, then Seller shall pay to Buyer, within five (5) Business Days of the date of an invoice therefore, an amount equal to the difference between (a) the sum of the amounts for each hour of the MISO FinSched determined by multiplying (i) the MISO Day-Ahead Market LMP for each hour of such MISO FinSched by (ii) the Energy that Seller failed to Accept in such hour, and (b) the amount of the Monthly Energy Payment that Buyer would have incurred under any Service Agreement entered hereunder had the Energy been Accepted. Any invoice submitted by Buyer to Seller pursuant to

this Section 3(b) shall include a written statement explaining in reasonable detail the calculation of the amount due from Seller.

4. METERING

(a) Buyer shall arrange for metering service that meets ATC's and/or MISO's requirements for load serving entities.

(b) Buyer shall arrange for and pay cost of transmitting meter data on a real time basis.

(c) Buyer shall arrange for Seller to receive copies of all metering calibrations and tests.

(d) Seller may request a special test of metering equipment. If the meter(s) fall within ATC and MISO specifications, Seller shall pay for testing; if the results are outside of the specifications, Buyer shall pay for testing.

5. RATE

All charges for Load Following Service provided under this Service Schedule shall be set forth in the Tariff and/or Service Agreement, as applicable.

6. TARIFF

Unless otherwise stated herein, all the provisions of the Tariff are applicable to this Service Schedule.

WISCONSIN ELECTRIC POWER COMPANY
FORMULA RATE WHOLESALE SALES TARIFF

BLOCK PURCHASE SERVICE
SERVICE SCHEDULE

BLOCK PURCHASE SERVICE
SERVICE SCHEDULE

1. AVAILABILITY

This Service Schedule is available to any Buyer for the purchase of Block Purchase Service; provided that:

(a) Seller has sufficient Capacity and Energy to provide to Buyer without diminishing service to existing customers;

(b) Buyer meets the creditworthiness requirements in Section 6 of the Tariff and the Performance Assurance provision of Article 5 of the Service Agreement;

(c) Buyer and Seller have executed a Service Agreement in the form included in this Tariff; and

(d) Buyer complies with all other applicable provisions of this Tariff.

2. APPLICABILITY AND CHARACTER OF SERVICE

Block Purchase Service shall include a stated amount of Capacity in the Service Agreement between Buyer and Seller. Buyer shall pay for the amount of Energy scheduled and the amount of Capacity agreed to under the Service Agreement, even if no Energy is scheduled. Capacity shall be measured in MW and Energy shall be measured in MWh. Seller and Buyer shall comply with the MISO Tariff, all applicable Laws of any Governmental Authority and Good Utility Practice.

(a) Planning Reserves. For purposes of establishing and maintaining Planning Reserves, Buyer and Seller agree to cooperate with one another and use commercially reasonable efforts to account for any Service Agreement entered into hereunder in their respective annual MISO Module E filings and other required regulatory filings as provided hereafter. In its MISO Module E filings and other required regulatory filings related to Planning Reserves, Seller shall not be required to designate specific DNRs as Capacity resources, but instead will represent its obligations under any Service Agreement entered into hereunder as an increase in its load obligations, and Buyer will represent its obligations under any Service Agreement entered into hereunder as an identical decrease in its load obligations.

(b) DNRs. If Parties are required to designate specific network resources in order for Buyer to obtain DNR accreditation pursuant to the MISO Tariff, Buyer and Seller shall reasonably cooperate with one another to identify and designate Seller's generation resources that best reflect the characteristics of the Delivery Point(s) applicable under any Service Agreement entered into pursuant to the Tariff. Any such DNRs shall be set forth in the Confirmation Letter.

(c) MISO ARRs. As necessary, Buyer and Seller shall reasonably cooperate with one another to allow Buyer to request MISO ARRs associated with the DNRs provided for in Section 2(b) above. In no event will Seller be required to provide any MISO ARRs, or any equivalent value, to Buyer pursuant to this Tariff.

(d) Curtailment. Block Purchase Service shall be provided with the same degree of reliability and quality of service as Seller's service to its firm load. In the event of any Curtailment, Seller will apply the effect of any Curtailment to Buyer on a pro rata basis, or as otherwise directed by any Governmental Authority. If any event or circumstance causing or contributing to a Curtailment also constitutes a Force Majeure as to Seller, then the Parties' rights and obligations with respect to such Force Majeure shall be governed by Section 8 of the Tariff to the extent and for so long as such Force Majeure persists. Otherwise, the Parties' rights and obligations with respect to such Curtailment shall be governed by this Section 2(d).

(e) Planning. Buyer shall provide Seller with a written nomination of its Capacity Amount for each Contract Year under this Block Purchase Service Schedule.

3. SCHEDULING

(a) Energy Scheduling. Buyer shall submit to Seller an Energy schedule which indicates the amount of Energy that Buyer will purchase for each hour of the following Operating Day (the "Daily Energy Schedule"). The Daily Energy Schedule must be submitted to Seller no later than two hours prior to the scheduled close of the MISO Day-Ahead Energy Market for such following Operating Day. Additional Scheduling requirements shall be as indicated in the Confirmation Letter. Subject to the above limits, the hourly Energy values of the Daily Energy Schedule may range between zero and the quantity of Energy produced during a time period of one hour by the nominated Capacity Amount for the applicable Contract Year. If Buyer fails to submit a Daily Energy Schedule, such Daily Energy Schedule shall be deemed to be zero MW for all applicable hours.

(b) Financial Schedules. Unless otherwise agreed by the Parties, Buyer shall Schedule each MISO FinSched in the MISO Day-Ahead Market related to the delivery of Energy in accordance with the Daily Energy Schedule, and Seller shall Accept such MISO FinSched no later than the deadline established by MISO for Acceptance, with each using the appropriate MISO electronic scheduling system and protocols. If Seller fails to Accept a MISO FinSched Scheduled by Buyer in accordance with this Section 3(b) and the other provisions of this Tariff, and such failure is not excused under the terms of this Tariff, then Seller shall pay to Buyer, within five (5) Business Days of the date of an invoice therefore, an amount equal to the difference between (a) the sum of the amounts for each hour of the MISO FinSched determined by multiplying (i) the MISO Day-Ahead Market LMP for each hour of such MISO FinSched by (ii) the Energy that Seller failed to Accept in such hour, and (b) the amount of the Monthly Energy Payment that Buyer would have incurred under its Service Agreement had the Energy been Accepted. Any invoice submitted by Buyer to Seller pursuant to this Section 3(b) shall include a written statement explaining in reasonable detail the calculation of the amount due from Seller.

(c) Minimum On-Peak Energy Schedule. With respect to the On-Peak periods of each month, Buyer shall Schedule a minimum of 50% of the total maximum Energy that Buyer is permitted to Schedule with respect to the On-Peak periods of such month pursuant to its Service Agreement. An example of the minimum amount of Energy required to be Scheduled in accordance with this Section 3(c) is set forth on Attachment A to this Service Schedule.

(d) Minimum Off-Peak Energy Schedule. With respect to the Off-Peak periods of each month, Buyer shall Schedule a minimum of 50% of the total maximum Energy that Buyer is permitted to Schedule with respect to the Off-Peak periods of such month pursuant to its Service Agreement. An example of the minimum amount of Energy required to be Scheduled in accordance with this Section 3(d) is set forth on Attachment A to this Service Schedule.

(e) Minimum On-Peak Scheduling. For each month that Buyer fails to Schedule the minimum On-Peak Energy in accordance with Section 3(c) of this Service Schedule, and such failure is not excused under the terms of this Tariff, then Buyer shall pay to Seller, as liquidated damages and not as a penalty, within five (5) Business Days of the date of an invoice therefor, an amount equal to (i) the Monthly Energy Rate for the On-Peak periods during such month, multiplied by (ii) the difference between (A) the minimum quantity of On-Peak Energy required to be Scheduled by Buyer with respect to such month, and (B) the quantity of On-Peak Energy Scheduled by Buyer with respect to such month.

(f) Minimum Off-Peak Scheduling. For each month that Buyer fails to Schedule the minimum Off-Peak Energy in accordance with Section 3(d) of this Service Schedule, and such failure is not excused under the terms of this Tariff, then Buyer shall pay to Seller, as liquidated damages and not as a penalty, within five (5) Business Days of the date of an invoice therefor, an amount equal to (i) the Monthly Energy Rate for the Off-Peak periods during such month, multiplied by (ii) the difference between (A) the minimum quantity of Off-Peak Energy required to be Scheduled by Buyer with respect to such month, and (B) the quantity of Off-Peak Energy Scheduled by Buyer with respect to such month.

(g) In the event any calculation under Section 3(e) or 3(f) of this Service Schedule produces a negative number, no payment shall be required.

(h) Any invoice submitted by Seller to Buyer pursuant to Sections 3(e) and 3(f) of this Service Schedule shall include a written statement explaining in reasonable detail the calculation of the amount due from Buyer.

4. RATE

All charges for Block Purchase Service provided under this Service Schedule shall be set forth in the Tariff and/or Service Agreement, as applicable.

5. TARIFF

Unless otherwise stated herein, all the provisions of the Tariff are applicable to this Service Schedule.

Wisconsin Electric Power Company
Formula Rate Wholesale Sales Tariff

Block Purchase Service Schedule

Attachment A
Minimum Scheduling Examples

With respect to Section 3(c) of this Service Schedule, in a given month in a Contract Year having a Capacity Amount nomination of 100 MW and 21 On-Peak days, the maximum On-Peak Energy that can be Scheduled is equal to 100 MW*12 hours*21 days = 25,200 MWh. The minimum amount of energy that must be Scheduled by Buyer during the On-Peak periods of such month is equal to 25,200*.50 = 12,600 MWh.

With respect to Section 3(d) of this Service Schedule, in a given 30-day month in a Contract Year having a Capacity Amount nomination of 100 MW and 21 On-Peak days, the maximum Off-Peak Energy that can be Scheduled is equal to (100 MW*12 hours*21 days) + (100MW*24 hours * 9 days) = 46,800 MWh. The minimum amount of Off-Peak Energy that must be Scheduled by Buyer during the Off-Peak periods of such month is equal to 46,800*.50 = 23,400 MWh.

WISCONSIN ELECTRIC POWER COMPANY
FORMULA RATE WHOLESALE SALES TARIFF

EXHIBIT A

FORM OF SERVICE AGREEMENT

FORMULA RATE WHOLESALE
SALES TARIFF

SERVICE AGREEMENT

This AGREEMENT (the "Agreement") is made and entered as of this ___, day of _____, 20__, by and between WISCONSIN ELECTRIC POWER COMPANY, a Wisconsin corporation ("Seller"), and [_____], a [_____] ("Buyer") and hereinafter the parties hereto are sometimes referred to collectively as the "Parties", or individually as a "Party").

WITNESSETH

WHEREAS, Seller is a public utility in the business of generating, distributing and selling electric power and energy and related services at wholesale and retail within the States of Wisconsin and Michigan;

WHEREAS, Buyer is a [_____];

WHEREAS, Seller and Buyer each believes it is in its best interest and desires to enter into this Agreement as further described herein;

NOW, THEREFORE, in consideration of the recitals and mutual promises, covenants and agreements contained herein and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties, intending to be legally bound, hereby agree as follows:

ARTICLE ONE
DEFINITIONS

Unless otherwise defined herein, all capitalized terms used herein shall have the same meaning as that set forth in Section 2 of the Seller's Formula Rate Wholesale Sales Tariff ("Tariff").

ARTICLE TWO
SERVICE TO BE PROVIDED

2.1 Type of Service. Buyer agrees to purchase and Seller agrees to provide the following service as set forth in the Tariff (choose one):

____ Load Following Service

____ Block Purchase Service

2.2 Delivery Period . The "Delivery Period" for the sale and purchase of Capacity and Energy under this Agreement shall commence on [_____] (HE 0100 CPT) and end on

[_____] (HE 2400 CPT). During the Delivery Period, each "Contract Year" shall begin on [_____] (HE 0100 CPT) and end on [_____] (HE 2400 CPT) of the succeeding calendar year.

2.3. Capacity Amount.

(a) Load Following Service. The Capacity Amount for Load Following Service is determined on a monthly basis and is equal to the Buyer's 60-minute integrated demand coincident with Seller's Monthly System Peak Load, as adjusted for any energy from the Buyer's Generation Resources identified in the Confirmation Letter.

(b) Block Purchase Service. The Capacity Amount for Block Purchase Service is the amount of Capacity nominated for a Contract Year and shall remain fixed for that Contract Year. The Capacity Amount for Block Purchase Service for each Contract Year is [____].

2.4 Rate to be Charged. Buyer agrees to pay the rates set forth in the Tariff for the applicable service specified under this Agreement, as well as any additional charges specified in the Confirmation Letter. Nothing contained herein shall be construed as affecting in any way the right of either Party to unilaterally make or challenge an application to the FERC for a change in rates under Sections 205 or 206 of the Federal Power Act and pursuant to the FERC's rules and regulations promulgated thereunder.

ARTICLE THREE
DELIVERY OF ENERGY

3.1 Market Participant. (Choose one):

Buyer is a Market Participant as defined in the Tariff _____.

Buyer is a Non-Market Participant as defined in the Tariff _____.

3.2 Delivery Point. For service provided under this Agreement, the Delivery Point(s) shall be those listed in the Confirmation Letter. Unless otherwise agreed to herein, Seller will not provide transmission and ancillary services to any Buyer who is a Market Participant other than those required up to the Delivery Point.

3.3. Scheduling. Buyer agrees to Schedule all Energy in accordance with the Tariff and Confirmation Letter for the service provided under this Agreement.

ARTICLE FOUR
BILLING AND PAYMENT

4.1 Billing. Seller shall bill, and Buyer shall pay, all rates and charges in accordance with Section 5 of the Tariff.

ARTICLE FIVE
PERFORMANCE ASSURANCE

5.1 Buyer shall meet the creditworthiness provisions in Section 6 of the Tariff, including any Performance Assurance requirements imposed by Seller.

ARTICLE SIX
EVENTS OF DEFAULT; REMEDIES

6.1 Events of Default. Each of the following events, unless and to the extent expressly excused under the terms of this Agreement, shall constitute an "Event of Default" of the defaulting party ("Defaulting Party"), the other Party being the non-defaulting party ("Non-Defaulting Party"):

(i) The failure of a Party to make any payment due hereunder and the continuation of such failure for three Business Days after written notice demanding such payment has been made by the Non-Defaulting Party.

(ii) Any representation or warranty made by a Party herein or in any certificate or other document delivered by such Party pursuant hereto that was false or misleading in any material respect when made, unless such false or misleading representation or warranty is capable of being cured or remedied, and such Party shall promptly commence and diligently pursue action to cause such representation or warranty to become true in all material respects and does so within 30 days after notice thereof has been given to such Party by the other Party.

(iii) A Party shall cease doing business as a going concern, shall generally not pay its debts as they become due or admit in writing its inability to pay its debts as they become due, shall file a voluntary petition in bankruptcy or shall be adjudicated a bankrupt or insolvent, or shall file any petition or answer seeking any reorganization, arrangement, composition, readjustment, liquidation, dissolution or similar relief under the present or any future federal bankruptcy code or any other present or future applicable Law relating to creditors' rights or debtors' relief, or shall seek or consent to or acquiesce in the appointment of any trustee, receiver, custodian or liquidator of such Party or of all or any substantial part of its properties, or shall make an assignment for the benefit of creditors, or such Party shall take any corporate action to authorize or that is in contemplation of the actions set forth above in this Section 6.1(iii).

(iv) Within 30 days after the commencement of any proceeding against a Party seeking any reorganization, arrangement, composition, readjustment, liquidation, dissolution or similar relief under the present or any future federal bankruptcy code or any other statute or Law relating to creditors' rights or debtors' relief, such proceeding shall not have been dismissed, or if, within 30 days after the appointment without the consent or acquiescence of such Party of any trustee, receiver, custodian or liquidator of such Party or of all or any substantial part of its properties, such appointment shall not have been vacated.

(v) A Party fails to comply or cause compliance with the Performance Assurance requirements pursuant to Section 6 of the Tariff, or any Person furnishing any Performance Assurance on behalf of a Party pursuant to Section 6 of the Tariff fails to comply with the terms of such Performance Assurance.

(vi) A material default in performance or observance of any agreement, undertaking, covenant or other obligation (except as otherwise specified in the other provisions of this Section 6.1) contained in this Agreement by a Party unless, within 30 days after written notice has been made from the other Party specifying the nature of such material default, such Party cures such default or, if such cure cannot reasonably be completed within 30 days and if such Party within such 30-day period commences, and thereafter diligently proceeds to cure such default, said period shall be extended for such further period as shall be necessary for such Party diligently to cure such default, provided that the extended cure period shall not exceed 90 days from the date of the original notice.

6.2 Remedies. (a) If an Event of Default occurs at any time during the Delivery Period, the Non-Defaulting Party may, for so long as the Event of Default is continuing, take one or more of the following actions: (i) establish a date (which date shall be not more than 10 Business Days after the Non-Defaulting Party gives written notice of such date to the Defaulting Party, or such longer period as required by applicable Law) on which this Agreement shall terminate (the "Early Termination Date"), in which case this Agreement shall terminate on the Early Termination Date; (ii) proceed by appropriate proceedings in accordance with this Agreement; and (iii) immediately cease performance, withhold any payments, or both, due in respect of this Agreement. For avoidance of doubt, in the event the Non-Defaulting Party terminates this Agreement on the Early Termination Date as provided in (i) above and/or ceases performance or withholds payment as provided in (iii) above, the Defaulting Party shall continue to be obligated to pay damages relating to such early termination and relating to the Defaulting Party's failure to perform during such cessation or period of withholding.

6.3 Liquidated Damages. If Seller is the Non-Defaulting Party and terminates this Agreement on an Early Termination Date, then Buyer shall pay to Seller, as liquidated damages and not as a penalty, an amount calculated as follows: (i) for the first 730 days following the date of the first uncured Event of Default giving rise to the early termination (unless the Delivery Period would have ended prior to the expiration of such 730 days, in which case such liquidated damages shall be paid through the last day of such Delivery Period) equal to the Initial Daily Amount and (ii) for each subsequent day through the last day of such Delivery Period equal to the Subsequent Daily Amount. If Buyer is the Non-Defaulting Party and terminates this Agreement on an Early Termination Date, then Seller shall pay to Buyer, as liquidated damages and not as a penalty, an amount calculated as follows: (i) for the first 730 days following the date of the first uncured Event of Default giving rise to the early termination (unless the Delivery Period would have ended prior to the expiration of such 730 days, in which case such liquidated damages shall be paid through the last day of such Delivery Period) equal to the Initial Daily Amount and (ii) for each subsequent day through the last day of such Delivery Period equal to the Subsequent Daily Amount. Calculation of liquidated damages shall be included in the written notice given by Buyer or Seller, as applicable, when declaring an Early Termination Date pursuant to Section 6.2. Liquidated damages under this Section 6.3 shall be payable no later than 30 days after the Early Termination Date.

6.4 Right to Setoff. Each Party reserves to itself all rights, setoffs, counterclaims, recoupment, combination of accounts, liens and other remedies, rights and defenses which such Party has or to which it may be entitled (whether by operation of law or in equity, under contract or otherwise).

6.5 Duty to Mitigate. Except with respect to liquidated damages, each Party has a duty to mitigate damages and covenants that it will use commercially reasonable efforts to minimize any damages it may incur as a result of the other Party's performance or non-performance hereunder.

ARTICLE SEVEN
COMPLIANCE WITH LAWS

7.1 Compliance with Laws. Each Party shall at all times comply in all material respects with all applicable Laws relating to the performance of its obligations under this Agreement. Each Party shall give all required notices, shall procure and maintain all necessary Authorizations required for its performance of this Agreement and shall pay all charges and fees in connection therewith.

7.2 Change in Law. In the event there is a change or changes in any Law, or interpretation thereof, enacted, adopted or implemented after execution of this Agreement, or any Law (or the interpretation thereof) is applied to a new or different class of parties (a "Change in Law"), then if the Seller is affected by such Change in Law and its costs in meeting its obligations under this Agreement are increased, such increased costs shall be passed through to Buyer to the fullest extent permitted by Law; if the Seller is affected by such Change in Law and its costs in meeting its obligations under this Agreement are decreased, such decreased costs shall be passed through to Buyer to the fullest extent permitted by Law. In the event such increased costs cannot be passed through until approval or acceptance by a Governmental Authority, such increased costs shall be accrued and, following receipt of such approval or acceptance, applied to the earliest (and subsequent) periods permitted by Law.

7.3 Change in Treatment by PSCW or MPSC. In the event that the PSCW's or MPSC's treatment from time to time of the revenues received or amounts charged by Seller under this Agreement or the amounts paid by Buyer under this Agreement, including any one or more components of the formulary rates set forth in Section 3.2 of the Tariff, adversely affects the Buyer or Seller (other than a change constituting a Change in Law pursuant to Section 7.2 of this Agreement or any increased cost passed through pursuant to the formula in Exhibit B) then, upon notice by the affected Party to the other Party, the Parties shall use their commercially reasonable efforts to reform this Agreement in order to alleviate such adverse effect on the affected Party; provided, however, that if the Parties are unable to reform this Agreement by a written amendment signed by both Parties within 90 days of the notification by the affected Party to the other Party of such treatment, then the affected Party shall have the right to terminate this Agreement without default and without any further rights or obligations of either Party other than those rights and obligations of the Parties that shall have accrued prior to such termination.

7.4 MISO Changes. In the event that, at any time from and after the execution of this Agreement, the MISO Tariff is changed (other than a change constituting a Change in Law pursuant to Section 7.2) or either or both Parties withdraw from the MISO Tariff so that the benefits and burdens or the operative provisions of this Agreement are no longer consistent with the original intentions of the Parties, the Parties shall use their commercially reasonable efforts to reform this Agreement in order to give effect to the original intentions of the Parties regarding the appropriate allocation of benefits and burdens to each Party.

ARTICLE EIGHT
INDEMNIFICATION; LIMITATION OF LIABILITY

8.1 Buyer Indemnification. Buyer agrees to and shall indemnify, defend, and hold harmless Seller, its parent company and each of their respective Affiliates, and all of their respective officers, directors, shareholders, employees, servants, and agents, from and against all Claims, including Claims for personal injury, death, or damages to property, occurring at and after the Delivery Point(s), arising out of or related to the Load Following Service, Block Purchase Service and/or Buyer's performance under this Agreement.

8.2 Seller Indemnification. Seller agrees to and shall indemnify, defend, and hold harmless Buyer, and all of its Affiliates, and all of their respective officers, directors, shareholders, employees, servants, and agents, from and against all Claims, including Claims for personal injury, death, or damages to property occurring on Seller's side of the Delivery Point(s) arising out of or related to the Load Following Service, Block Purchase Service and/or Seller's performance under this Agreement.

8.3 Limitation of Remedies, Liability and Damages. BUYER AND SELLER CONFIRM THAT THE EXPRESS REMEDIES AND MEASURES OF DAMAGES PROVIDED IN THIS AGREEMENT SATISFY THE ESSENTIAL PURPOSES HEREOF FOR BREACH OF ANY PROVISION FOR WHICH AN EXPRESS REMEDY OR MEASURE OF DAMAGES IS PROVIDED. UNLESS EXPRESSLY HEREIN OTHERWISE PROVIDED, AND EXCEPT FOR THE PAYMENT OF LIQUIDATED DAMAGES SPECIFIED HEREIN, NEITHER BUYER, SELLER, NOR THEIR AFFILIATES SHALL BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT; PROVIDED, HOWEVER, THAT THIS SENTENCE SHALL NOT APPLY TO LIMIT THE LIABILITY OF BUYER OR SELLER IF ITS ACTIONS GIVING RISE TO SUCH LIABILITY CONSTITUTE GROSS NEGLIGENCE OR WILLFUL MISCONDUCT. TO THE EXTENT ANY DAMAGES REQUIRED TO BE PAID HEREUNDER ARE DENOMINATED AS LIQUIDATED DAMAGES, BUYER AND SELLER ACKNOWLEDGE AND AGREE THAT THE ACTUAL DAMAGES ARE (OR ARE EXPECTED TO BE) DIFFICULT OR IMPOSSIBLE TO DETERMINE, OTHERWISE OBTAINING AN ADEQUATE REMEDY IS (OR IS EXPECTED TO BE) INCONVENIENT AND THE LIQUIDATED DAMAGES DO NOT CONSTITUTE A PENALTY AND ARE A REASONABLE ADVANCE APPROXIMATION OF THE HARM OR LOSS ANTICIPATED. BUYER AND SELLER ACKNOWLEDGE AND AGREE THAT THIS AGREEMENT DOES NOT PROVIDE FOR ANY TORT REMEDIES, AND BUYER AND SELLER FURTHER EXPRESSLY AGREE THAT

NEITHER SHALL HAVE THE RIGHT, AND EACH WAIVES ALL RIGHTS, TO BRING AN ACTION AGAINST THE OTHER (INCLUDING AGAINST ANY AFFILIATE OF THE OTHER) IN TORT OR STRICT LIABILITY FOR ANY ACT(S) OR OMISSIONS CONSTITUTING A BREACH OR ALLEGED BREACH OF CONTRACT. BUYER AND SELLER EXPRESSLY AGREE AND UNDERSTAND THAT THE PROVISIONS OF THIS SECTION 8.3 LIMIT THE CLAIMS AND DAMAGES AVAILABLE TO THEM.

8.4 Disclaimer of Warranties. THERE ARE NO WARRANTIES UNDER THIS AGREEMENT EXCEPT TO THE EXTENT SPECIFICALLY SET FORTH IN THE TEXT HEREOF. BUYER AND SELLER HEREBY SPECIFICALLY DISCLAIM AND EXCLUDE ALL IMPLIED WARRANTIES, INCLUDING THE IMPLIED WARRANTIES OF MERCHANTABILITY AND OF FITNESS FOR A PARTICULAR PURPOSE.

ARTICLE NINE
ASSIGNMENT; BINDING EFFECT

9.1 Binding Effect. This Agreement shall be binding upon and shall inure to the benefit of the Parties and their respective successors and permitted assigns.

9.2 Assignment. Neither Party shall assign this Agreement or any portion thereof to any Person without the prior written consent of the other Party. Any consent required by this Section 9.2 shall not be unreasonably withheld, conditioned or delayed; provided, however, that neither Party shall be required to accept any limitation of its rights under this Agreement or expansion of the liability, risks or obligations imposed on it under this Agreement. It shall be a condition of any assignment, transfer or other disposition with respect to this Agreement that (a) all Performance Assurance required under Article 5 of this Agreement with respect to the assignor shall remain in place notwithstanding such assignment, transfer or other disposition, or that replacement Performance Assurance in form, substance and amount in full compliance with this Agreement or otherwise reasonably acceptable to Seller shall have been provided prior to such disposition and (b) the proposed assignee shall agree in writing to assume the assignor's obligations hereunder.

ARTICLE TEN
NOTICE

10.1 Notices. Unless otherwise specified, where notice is required by this Agreement, such notice shall be in writing and shall be deemed given: (i) upon the second Business Day after the date of such notice, when mailed by United States registered or certified mail, postage prepaid, return receipt requested; (ii) upon the next Business Day after the date of such notice, when sent by overnight delivery, using a reputable overnight delivery service; or (iii) when sent, if by facsimile transmission, or upon the next Business Day after the date of such facsimile if such facsimile transmission is sent after 5:00 P.M. CPT.

if to Seller:

Wisconsin Electric Power Company
333 West Everett Street, Room A292

Milwaukee, Wisconsin 53203
Attention: Legal Department
Telephone: 414-221-2198
Facsimile: 414-221-2139

Wisconsin Electric Power Company
333 West Everett Street, Room A459
Milwaukee, Wisconsin 53203
Attention: Federal Regulatory Affairs & Policy
Telephone: 414-221-2533
Facsimile: 414-221-4211

Notices related solely to operational issues arising after the commencement of the Delivery Period are exempt from this Section 10.1 and may be given to the addressees listed below by telephone or by any other means as the Parties may from time to time agree.

Wisconsin Electric Power Company
333 West Everett Street, Room A214
Milwaukee, Wisconsin 53203
Attention: Vice President, Wholesale Energy and Fuels

Telephone: 414-221-2537
Facsimile: 414-221-2250

Wisconsin Electric System Operator/Trader:
Phone: 414-221-4505
Fax: 414-221-4210

if to the Buyer:

_____
_____
_____

With a copy to:

_____
_____
_____

10.2 Change in Notice. A Party's address may be changed by written notice to the other Party.

ARTICLE ELEVEN
MISCELLANEOUS

11.1 Interpretation; Construction. In this Agreement, unless the context otherwise requires: (a) the singular shall include the plural and any pronoun shall include the corresponding masculine, feminine and neuter forms; (b) the words "hereof," "herein," "hereto" and "hereunder" and words of similar import when used in this Agreement shall, unless otherwise expressly specified, refer to this Agreement as a whole and not to any particular provision of this Agreement; (c) whenever the term "including" is used herein in connection with a listing of items included within a prior reference, such listing shall be interpreted to be illustrative only, and shall not be interpreted as a limitation on or exclusive listing of the items included within the prior reference; (d) any reference in this Agreement to "Section," "Article," "Exhibit" or "Appendix" shall be references to this Agreement unless otherwise stated, and all such Exhibits shall be incorporated into this Agreement by reference and are intended to be a part of this Agreement; and (e) unless otherwise specified, a reference to a given agreement, document, instrument, Law, Service Schedule or tariff, including this Agreement, and all schedules, exhibits, appendices and attachments thereto, shall be a reference to that agreement, document, instrument, Law or tariff as modified, amended, supplemented and restated in accordance with its terms (if applicable) and (where applicable) subject to compliance with the requirements set forth therein, and in effect from time to time.

11.2 Governing Law. This Agreement shall be governed by and construed in accordance with the laws of the State of Wisconsin as to all matters, including but not limited to matters of validity, construction, effect, performance and remedies without regard to conflict of laws rules thereof.

11.3 Cooperation; Further Assurances. The Parties agree to provide such reasonable cooperation to each other as necessary to give effect to the terms of this Agreement.

11.4 Amendment. No amendment, supplement, modification, waiver or termination of this Agreement shall be binding unless executed in writing by the Party to be bound thereby.

11.5 Waiver. The failure or delay of any Party hereto to enforce at any time any of the provisions of this Agreement, or to require at any time performance of the other Party hereto of any of the provisions hereof, shall neither be construed to be a waiver of such provisions nor affect the validity of this Agreement or any part hereof or the right of such Party thereafter to enforce each and every such provision. No waiver of any of the provisions of this Agreement shall be deemed or shall constitute a waiver of any other provision of this Agreement, whether or not similar, nor shall such waiver constitute a continuing waiver unless otherwise expressly provided.

11.6 No Third Party Beneficiaries. This Agreement is for the sole benefit of the Parties hereto, and except as specifically provided herein, nothing in this Agreement or any action taken hereunder shall be construed to create any duty, liability or standard of care to any Person not a party to this Agreement. Except as specifically provided herein, no Person shall have any rights or interest, direct or indirect, in this Agreement or the services to be provided hereunder, or both, except Buyer and Seller. The Parties specifically disclaim any intent to

create any rights in any Person as a third-party beneficiary to this Agreement or the services to be provided hereunder, or both.

11.7 No Dedication of Assets. No undertaking by a Party hereto to the other Party hereto under any provision of this Agreement shall constitute the dedication of that Party's assets or any portion thereof to the public or to its obligations under this Agreement.

11.8 No Partnership. This Agreement shall not be construed to create or give rise to any partnership, joint venture, agency or other relationship between Seller and Buyer other than that of purchaser and seller. Each Party shall be solely and individually responsible for its own covenants, obligations and liabilities as herein provided, and the Parties do not intend to create any joint, several or joint and several obligations to any third party. Neither this Agreement, nor any grant, lease or license related thereto, shall create or be construed to create any new entity, such as a partnership, association or joint venture.

11.9 Forward Contract. The Parties acknowledge and agree that this Agreement, the transactions contemplated hereby, and any instrument(s) that may be provided by either Party hereunder (including any guaranty) shall each, and together, constitute one and the same "forward contract" within the meaning of the United Stated Bankruptcy Code, and Seller and Buyer shall each constitute a "forward contract merchant" under the United Stated Bankruptcy Code.

11.10 Severability. If any provision of this Agreement shall be determined to be unenforceable, void or otherwise contrary to any Law, such condition shall in no manner operate to render any other provision of this Agreement unenforceable, void or contrary to any Law, and this Agreement shall continue in force in accordance with the remaining terms and provisions hereof, unless such condition invalidates the purpose or intent of this Agreement. In the event that any of the provisions, or portions or applications thereof, of this Agreement are held unenforceable or invalid by any court of competent jurisdiction, Seller and Buyer shall negotiate to attempt to implement a reformation of such provision(s) with a view toward effecting the purposes of this Agreement by replacing the offending provision(s) with a valid provision the economic effect of which comes as close as possible to the original intent of the offending provision(s).

11.11 Headings. The headings contained in this Agreement are used solely for convenience and do not constitute a part of the Agreement between the Parties, nor should they be used to aid in any manner in the construction of this Agreement.

11.12 Counterparts. This Agreement may be executed simultaneously in two or more counterparts, each of which shall be deemed an original but all of which together shall constitute one and the same instrument.

11.13 Entire Agreement. This Agreement constitutes the entire agreement between the Parties pertaining to the subject matter of this Agreement and supersedes and terminates any letters of intent, term sheets and all prior and contemporaneous agreements, understandings, negotiations and discussions between the Parties, whether oral or written, regarding said subject matter, and there are no warranties, representations or other agreements between the Parties in

connection with the subject matter of this Agreement, except as specifically set forth in this Agreement.

IN WITNESS WHEREOF, each of the Parties has caused this Agreement to be executed by its duly authorized officer as of the date first written above.

WISCONSIN ELECTRIC POWER COMPANY

By: _____

Name: _____

Title: _____

[_____]

By: _____

Name: _____

Title: _____

APPENDIX A
CONFIRMATION LETTER

This Confirmation Letter confirms the Agreement dated _____, by and between _____ ("Buyer") and Wisconsin Electric Power Company ("Seller") with respect to the purchase and sale of Capacity and Energy pursuant to Seller's Formula Rate Wholesale Sales Tariff and sets forth the following information as required thereto.

1. Delivery Point(s): _____

2. Congestion and/or Losses Adjustment:
_____

3. Transmission: _____

4. Ancillary Services: _____

5. Buyer's Generation Resources: _____

6. DNRs: _____

7. Scheduling: _____

8. Performance Assurance: _____

9. Wire Transfer Instructions: _____

Confirmed in writing this ___ day of _____.

Wisconsin Electric Power Company	[Buyer]
_____	_____
_____	_____

WISCONSIN ELECTRIC POWER COMPANY
FORMULA RATE WHOLESALE SALES TARIFF

EXHIBIT B

Wisconsin Electric Power Company
Formula Rate Wholesale Sales Tariff, FERC Electric Tariff Volume No. 9

FERC Electric Tariff						Attachment A
						page 1 of 7
Formula Rate - Non-Levelized		**Capacity Rate Formula Template Utilizing FERC Form 1 Data**				For the 12 months ended 12/31/2013
		Wisconsin Electric Power Company				
Line		**Form No. 1**				**Allocated**
No.		**Page, Line, Col.**				**Amount**
1	**GROSS REVENUE REQUIREMENT**	(page 3, line 37, col 5)				$0
1a	Non-firm Load Cost	401.29.d footnote (non-firm load (kW) times cost of CT ($/kW-year))				0
	REVENUE CREDITS		Total		Allocator	
2	Acct 447	(page 4, line 33, col 5)	0	PP	0	0
3	Acct 454	(page 4, line 34d, col 5)	0	PP	0	0
4	Acct 456	(page 4, line 37, col 5)	0	PP	0	0
5	Acct 254	(page 4, line 37a, col 5)	0	PP	0	0
6	TOTAL REVENUE CREDITS	(sum lines 2-5)				0
7	**NET REVENUE REQUIREMENT**	(line 1 + line 1a minus line 6)				0
	DIVISOR					
8	Average of 12 coincident system peaks for requirements (RQ) service	401b.d				0
9a	Plus: Average of 12 month Nonfirm Load Demands that were interrupted	401.29.d footnote				0
9b	Less: Average of WPPIs monthly actual demands coincident with WE's peak	401.29.d footnote				0
9c	Plus: Average of WPPI's actual monthly demand nominations	401.29.d footnote				0
10	**Divisor**	(sum lines 8-9)				0
11	Annual Rate ($/kW/Yr)	(line 7 / line 10)	0			
12	**Monthly Capacity Rate ($/kW-Month) - At Generation Bus**	(line 11 / 12 months)	0			
13	Transmission loss rate	401.27.b footnote for transmission losses	0			
14	**Monthly Capacity Rate ($/kW-Month) - At Transmission to Distribution Interface**	(Line 12 x Line 13)	**0**			
	NET REVENUE REQUIREMENT SUMMARY					
15	O&M Expense	(page 3, line 16, col 5)				0
16	Depreciation Expense	(page 3, line 21, col 5)				0
17	Taxes Other Than Income Taxes	(page 3, line 28, col 5)				0
18	Income Taxes	(page 3, line 35, col 5)				0
19	Return	(page 3, line 36, col 5)				0
20	GROSS REVENUE REQUIREMENT	(lines 15-19)				0

Wisconsin Electric Power Company
Formula Rate Wholesale Sales Tariff, FERC Electric Tariff Volume No. 9

20a	Non-firm Load Cost	(line 1a)				0
21	less: Revenue Credits	(line 6)				0
22	**NET REVENUE REQUIREMENT**	(line 20 plus line 20a minus line 21)				0

FERC Electric Tariff						Attachment A
						page 2 of 7
Formula Rate - Non-Levelized		**Capacity Rate Formula Template Utilizing FERC Form 1 Data**				For the 12 months ended 12/31/2013
		Wisconsin Electric Power Company				
	(1)	(2)	(3)		(4)	(5)
Line	**RATE BASE:**	**Form No. 1**	**Co. Total**		**Allocator**	**Electric Prod**
No.		**Page, Line, Col.**	**Average**			(3) * (4)
	GROSS PLANT IN SERVICE					
1	Production	Page 7, line 1, col 6	0	PP	0	0
2	Transmission	Page 7, line 2, col 6	0	NA		0
3	Distribution	Page 7, line 3, col 6	0	NA		0
4	General & Intangible	Page 7, line 4, col 6	0	W/S	0	0
5	Common (Electric)	Page 7, line 5, col 6	0	W/S	0	0
6	**TOTAL GROSS PLANT**	(sum lines 1-5)	0	GP=	0	0
	ACCUMULATED DEPRECIATION					
7	Production	Page 7, line 6, col 6	0	PP	0	0
7a	Less NU Decommissioning	Page 7, line 6a, col 6	0	PP	0	0
7b	AROs (Subtract AROs included in Accum Dep & Add AROs excluded from Accum Dep)	Page 7, line 6b, col 6	0	PP	0	0
8	Transmission	Page 7, line 7, col 6	0	NA		0
9	Distribution Add AROs (Subtract AROs included in Accum Dep & Add AROs excluded from Accum Dep)	Page 7, line 8, col 6	0	NA		0
10	General & Intangible	Page 7, line 9, col 6	0	W/S	0	0
11	Common (Electric)	Page 7, line 10, col 6	0	W/S	0	0
11a	Common	Page 7,line 10a,col 6	0	W/S	0	0
12	**TOTAL ACCUM. DEP**	(sum lines 7-11a)	0			0
	NET PLANT IN SERVICE		0			
13	Production	(line 1-(line 7-7a+7b))	0			0
14	Transmission	(line 2- line 8)	0			0
15	Distribution	(line 3 - line 9)	0			0
16	General & Intangible	(line 4 - line 10)	0			0
17	Common (Electric)	(line 5 - lines 11, 11a)	0			0
18	**TOTAL NET PLANT**	(sum lines 13-17)	0	NP=	0	0
	ADJUSTMENTS TO RATE BASE (Note A)					
19	Acct 281 (enter negative)	Page 7, line 11, col 6	0	zero	0	0
20	Acct 282 (enter negative)	Page 7, line 12, col 6	0	GP	0	0
21	Acct 283 - Prod (enter credit bal. as negative /debit bal. as positive)	Page 7, line 13, col 6	0	PP	0	0
21a	Acct 283 - Gen (enter credit balances as negative /debit balances as positive)	Page 7,line 13a,col 6	0	W/S	0	0
22	Acct 190 - Production	Page 7, line 14, col 6	0	PP	0	0
22a	Acct 190 - General	Page 7, line 14a,col 6	0	W/S	0	0
23	**TOTAL ADJUSTMENTS**	(sum lines 19-22a)	0			0

Wisconsin Electric Power Company
Formula Rate Wholesale Sales Tariff, FERC Electric Tariff Volume No. 9

	WORKING CAPITAL					0
24	CWC Demand Related O&M	1/8 page 3, line 16b, col 3	0			0
24a	CWC Other Energy O&M	1/8 Page 3,Line 8,col 3	0	PE	0	0
25	Materials & Supplies (prod)	Page 7, line 15, col 6	0	PE	0	0
26	Fossil Fuel Stock	Page 6 line 20, col 3	0	PE	0	0
27	Prepayments (Acct 165)	Page 7, line 16, col 6	0	CGP	0	0
28	**TOTAL WORKING CAPITAL**	(sum lines 24-27)	0			0
29	Pollution Control CWIP	Page 7, line 17, col 6	0	PE	0	0
30	Prop Held For Future Use (prod)	Page 7, line 18, col 6	0	PE	0	0
31	**RATE BASE**	(lines 18,23,28,29,30)	0			0

FERC Electric Tariff						Attachment A
						page 3 of 7
Formula Rate – Non-Levelized		**Capacity Rate Formula Template Utilizing FERC Form 1 Data**				For the 12 months ended 12/31/2013
		Wisconsin Electric Power Company				
	(1)	(2)	(3)		(4)	(5)
Line		**Form No. 1**	**Company**		**Allocator**	**Electric Prod**
No.		**Page, Line, Col.**	**Total**			(3) * (4)
	O&M					
1	Total Power Prod Expenses	321.80.b	0	PE	0	0
2	Plus Non-FERC Deferrals / Amortizations - Demand Related	320.11.b footnote PTF lease payments removing special WI Reg treatment, less 327.12.L, 327.13.L, 327.14.L	0	PE	0	0
3	Plus - Transmission non FNS	332.4.h plus 320.88.b footnote Balancing Authority Costs and MISO Schedule 24 Distribution Amount	0	PE	0	0
4	Less Acct 501	320.5.b	0	PE	0	0
4a	Less Acct 503	320.7.b	0	PE	0	0
4b	Less Acct 504 (enter negative)	320.8.b	0	PE	0	0
4c	Less Acct 509	320.12.b	0	PE	0	0
5	Less Acct 518	320.25.b	0	PE	0	0
6	Less Acct 547	321.63.b	0	PE	0	0
7	Less Purchased Power Eng Related	327.Total.k less 65% of NextEra Energy Point Beach 327.11.k	0	PE	0	0
8	Less Other Energy Related O&M, Accts 510, 512, 513, 528, 530, 531, 544)	320.15.b, 320.17.b, 320.18.b, 320.35.b, 320.37.b, 320.38.b, 320.56.b	0	PE	0	0
8a	Less NERC Fees Acct 556	321.77.b footnote	0	PE	0	0
8b	Less Non-FERC Jurisdiction Renewable Attribute Purchases	(327.1).4.l	0	PE	0	0
9	A&G	323.197.b	0	W/S	0	0
10	Less General Advertising Exp	323.191.b	0	W/S	0	0
11						
12	Less EPRI Dues	353.12.d	0	W/S	0	0
13	Less Industry Assoc Dues	335.1.b	0	W/S	0	0
14	Less Retail Regulatory Exp	350.6.d,350.9.d,350.23.d	0	W/S	0	0
15						
16	**TOTAL O&M**	(sum lines 1-3, 9,15, less	0			0

Wisconsin Electric Power Company
Formula Rate Wholesale Sales Tariff, FERC Electric Tariff Volume No. 9

		lines 4-8b, 10-14)				
16a	Less Demand Related Purchased Power	327.Total.j plus 65% of NextEra Energy Point Beach 327.11.k	0	PE	0	0
16b	**O&M for Working Capital Purposes**		0			0

Wisconsin Electric Power Company
Formula Rate Wholesale Sales Tariff, FERC Electric Tariff Volume No. 9

FERC Electric Tariff						Attachment A
						page 3 of 7, continued
Formula Rate - Non-Levelized		**Capacity Rate Formula Template Utilizing FERC Form 1 Data**				For the 12 months ended 12/31/2013
		Wisconsin Electric Power Company				
	(1)	(2)	(3)		(4)	(5)
Line		**Form No. 1**	**Company**		**Allocator**	**Electric Prod**
No.		**Page, Line, Col.**	**Total**			(3) * (4)
	DEPRECIATION EXPENSE					
17	Production Plant	336.2.f, 336.3.f, 336.4.f, 336.6.f, 115.9.g 115.10.g less 219.8.c footnote steam transfer depreciation exp	0	PP	0	0
18	Transmission Plant	336.7.f	0	PP	0	0
19	General & Intangible	336.10.f, 336.1.f	0	W/S	0	0
20	Common (Electric)	336.11.f	0	W/S	0	0
21	**TOTAL DEPRECIATION**	(sum lines 17-20)	0			0
	TAXES OTHER THAN INCOME TAXES (Note B)					
22	Payroll	263.2.i., 263.3.i, 263.7.i, 263.21.i, 263.29.i	0	W/S	0	0
23	Car Line	263.15.i, 263.16.i, 263.17.i, 263.18.i, 263.19.i	0	PP	0	0
24	Production Property	263.23.i	0	PP	0	0
25	Insurance	263.10.i	0	PP	0	0
25a	MI Single Business Tax	263.22.i	0	GP	0	0
26	Use Taxes	263.38.i, 263.39.i	0	GP	0	0
27	Non FERC or Non Production	263.9.i, 263.20.i, 263.27.i, 263.31.i	0		0	0
28	**TOTAL OTHER TAXES**	(sum lines 22-27)	0			0
	INCOME TAXES (Note C)					
29	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		0			
30	CIT=(T/1-T) * (1-(WCLTD/R)) =		0			
	where WCLTD=(page 4, line 27) and R=(page 4, line 30) and FIT, SIT & p are as given in Note C.					
31	1 / (1 - T) = (from line 29)		0			
32	Amortized Investment Tax Credit (266.8.f) (enter neg)		0			
33	Income Tax Calculation	(line 30 * line 36)	0		NA	
34	ITC Adjustment	(line 31 * line 32)	0		GP	
35	**Total Income Taxes**	(line 33 plus line 34)	0			
36	**RETURN**	[Rate Base (page 2, line 31)*Rate of Return (page 4, line 30)]	0		NA	
37	**GROSS REVENUE REQUIREMENT**	(sum lines 16,21,28,35,36)	0			

Wisconsin Electric Power Company
Formula Rate Wholesale Sales Tariff, FERC Electric Tariff Volume No. 9

FERC Electric Tariff						Attachment A
						page 4 of 7
Formula Rate - Non-Levelized		**Capacity Rate Formula Template Utilizing FERC Form 1 Data**				For the 12 months ended 12/31/2013
		Wisconsin Electric Power Company				
Line		**SUPPORTING CALCULATIONS AND NOTES**				
No.	(1)	(2)	(3)	(4)		(5)
	PRODUCTION PLANT INCLUDED IN CAPACITY RATES					
1	Total Production Plant	(page 2,line 1,col 3)				0
2	Less plant excluded from rates (Note D)					0
3	Less plant included in other rates (Note E)					0
4	Production plant included in Capacity rate	(line 1 - lines 2,3)				0
5	Percentage of plant included in Rates	(line 4 divided by line 1)			PP=	0
	PRODUCTION EXPENSES					
6	Total Production expenses	(page 3,line 14,column 3)				0
7	Less expenses included in other Rates (Note F)					0
8	Included Prod. expenses	(line 6 less line 7)				0
9	Percentage of Production expenses after adjustment	(line 8 divided by line 6)				0
10	Percentage of plant included in other rates	(line 5)			PP=	0
11	Percentage of Prod. expenses included in Capacity rate	(line 9 times line 10)			PE=	0
	WAGES & SALARY ALLOCATOR (W&S)					
12	Production	354.20.b	0	0		
13	Transmission	354.21.b	0	0		
14	Distribution	354.23.b	0	0		W&S Allocator (WS)
15	Other	354.24.b, 354.25.b, 354.26.b	0	0		($/Allocation)
16	Total	(sum lines 12-15)	0	0	=	0
	COMMON PLANT ALLOCATOR (CE)					
		Form 1 Reference	**$**	% Electric		W&S Allocator (WS)
17	Electric	356 (average current and previous year)	0	(line 17 / line 20)		(line 16)
18	Gas	356 (average current and previous year)	0	0	*	0
19	Steam	356 (average current and previous year)	0			
20	Total	(sum lines 17-19)	0		CE=	0
	RETURN (R)					
21	Long Term Interest	117.62.c,117.63.c,117.64.c				0
22	Preferred Dividends	118.29.c (enter positive)				0

Wisconsin Electric Power Company
Formula Rate Wholesale Sales Tariff, FERC Electric Tariff Volume No. 9

	DEVELOPMENT OF COMMON STOCK						
23	Proprietary Capital	average (112.16.c,d)					
24	Less Preferred Stock	(line 28)					0
25	Less Account 216.1	average (112.12.c,d) (enter negative)					0
26	Common Stock	(sum lines 23-25)					0
			$	%	Cost (Note G)		Weighted
27	Long Term Debt	page 6,line 39,column 4	0	0	0	WCLTD=	
28	Preferred Stock	average (112.3.c,d)	0	0	0		
29	Common Stock	(line 26)	0	0	0		
30	Total	(sum lines 27-29)	0			R=	

FERC Electric Tariff						Attachment A
						page 4 of 7, continued
Formula Rate - Non-Levelized		**Capacity Rate Formula Template Utilizing FERC Form 1 Data**				For the 12 months ended 12/31/2013
		Wisconsin Electric Power Company				
Line		**SUPPORTING CALCULATIONS AND NOTES**				
No.	(1)	(2)	(3)	(4)		(5)
	REVENUE CREDITS					
	ACCT 447 (SALES FOR RESALE) (Note H)					Load
31	a. Capacity revenues for Resale	311.Subtotal non-RQ.h plus 311.Subtotal non RQ.j less 311.h&j lines 5,9,11,13 less (311.1).h&j lines 1,3,5				0
32	b. Capacity revenues included in Divisor on page 1					0
33	Total of (a)-(b)					0
34	**ACCT 454 (RENT FROM ELECTRIC PROPERTY)**		Co. Total	Allocator		Electric Prod (3) * (4)
34a	a. Rent from production property	300.19.b footnote Detail Lines 8, 14	0	PP	0	0
34b	b. Rent from distribution property	300.19.b footnote Detail Lines 1-7, 9-13, 16-20, 22	0	NA	0	0
34c	c. Rent from general property	300.19.b footnote Detail Lines 15, 21	0	W/S	0	0
34d	d. Total	(sum lines 34a-34c)	0			0
	ACCT 456 (OTHER ELECTRIC REVENUES)					
35	a. Production charges in Acct 456	300.21.b footnote Detail: Lines 2, 4, 5, 8, 9, 11, 12, 13, 21				0
35a	b. Revenue from Allowance Sales	229a.33.m, 229a.44.m				0
36	c. Production charges for all production transactions included in Divisor on Page 1					0
37	Total of (a) + (b) - (c)					0
	ACCT 254 (OTHER REGULATORY LIABILITIES)					
37a	Non-FERC Deferrals	278.25.d				0
	COMPANY GROSS PLANT ALLOCATOR (CGP)					
38	Electric Production Plant In Service	(page 2, line 6, col 5)	0			0

39	Total Company Gross Plant less AROs	Average [110.2.c - (205.15.g, 205.24.g, 205.34.g, 207.74.g)] and [110.2.d - (204.15.b, 204.24.b, 204.34.b, 206.74.b)]	0			0
40	Company Gross Plant Allocator (CGP)	Line 38/Line 39	0			

Wisconsin Electric Power Company
Formula Rate Wholesale Sales Tariff, FERC Electric Tariff Volume No. 9

FERC Electric Tariff				Attachment A
				page 5 of 7
Formula Rate - Non-Levelized		**Capacity Rate Formula Template**		For the 12 months ended 12/31/2013
		Utilizing FERC Form 1 Data		
		Wisconsin Electric Power Company		
General Note:	References to pages in this formulary rate are indicated as: (page#, line#, col.#)			
	References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)			
A	The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note C. Account 281 is not allocated.			
B	Includes FICA, unemployment, property, and other assessments charged in the current year. Gross receipts taxes are not included in this section since they are included elsewhere.			
C	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 29).			
	Inputs Required:	FIT =	0%	(Federal Income Tax Rate 262.1.a footnote)
		SIT=	0%	(Composite State Income Tax Rate 262.5.a footnote)
		p =	0%	(percent of federal income tax deductible for state purposes)
	Source: Page 262 footnote Federal and State income tax rate			
D	Removes any production plant determined by commission order to be non-jurisdictional.			
E	Removes any production plant recovered through mechanisms other than this capacity charge.			
F	Removes any production expenses recovered through mechanisms other than this capacity charge.			
G	Debt cost rate = long-term interest (line 21) / long term debt (line 27). Preferred cost rate = preferred dividends (line 22) / preferred outstanding (line 28). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.			
H	Applicable only to explicit capacity revenues from wholesale sales not subject to this capacity charge if not included in capacity charge denominator			

Wisconsin Electric Power Company
Formula Rate Wholesale Sales Tariff, FERC Electric Tariff Volume No. 9

FERC Electric Tariff					Attachment A
		Capacity Rate Formula Template			page 6 of 7
		Utilizing FERC Form 1 Data **Wisconsin Electric Power Company**			For the 12 months ended 12/31/2013
Formula Rate - Non-Levelized					
Line					
No.					
1	Hold for Future Use				
2	Hold for Future Use				
3	Hold for Future Use				
4	Hold for Future Use				
5	Hold for Future Use				
6	Hold for Future Use				
	Monthly Fossil Fuel Inventory Balances		End of Month Balance		
7	December	227.1.c footnote	0		
8	January	227.1.c footnote	0		
9	February	227.1.c footnote	0		
10	March	227.1.c footnote	0		
11	April	227.1.c footnote	0		
12	May	227.1.c footnote	0		
13	June	227.1.c footnote	0		
14	July	227.1.c footnote	0		
15	August	227.1.c footnote	0		
16	September	227.1.c footnote	0		
17	October	227.1.c footnote	0		
18	November	227.1.c footnote	0		
19	December	227.1.c footnote	0		
20	13 Month Average		0		
	Rate Base Adjustments for Sale / Purchase of Major Asset				
	To Reflect 13 Month Average Rather Than 2 Point Average				
	Item		**13 Month Average**	**2 Point Average**	**Adjustment to Formula**
21	Plant In Service	200.15.c footnote	0		
22	Depreciation Reserve	200.15.c footnote	0		
23	Deferred Taxes - Acct 190	NA	0		
24	Deferred Taxes - Acct 282	275.2.k footnote	0		
25	Pollution Control CWIP	NA	0		
	Calculation of 13 Month Average Long Term Debt Balance		Change	Balance	

Wisconsin Electric Power Company
Formula Rate Wholesale Sales Tariff, FERC Electric Tariff Volume No. 9

26	December	(257.1).28.h footnote			
27	January	(257.1).28.h footnote			
28	February	(257.1).28.h footnote			
29	March	(257.1).28.h footnote			
30	April	(257.1).28.h footnote			
31	May	(257.1).28.h footnote			
32	June	(257.1).28.h footnote			
33	July	(257.1).28.h footnote			
34	August	(257.1).28.h footnote			
35	September	(257.1).28.h footnote			
36	October	(257.1).28.h footnote			
37	November	(257.1).28.h footnote			
38	December	(257.1).28.h footnote			
39	13 Month Average				

FERC Electric Tariff						Attachment A
						page 7 of 7
Formula Rate - Non-Levelized		**Capacity Rate Formula Template**			For the 12 months ended 12/31/2013	
		Utilizing FERC Form 1 Data				
		Wisconsin Electric Power Company				
	(1)	(2)	(3)	(4)	(5)	(6)
		Form No. 1	**BOY**	**EOY**		**Average**
		Page, Line, Col.	Prior Year	Current Year	**Adjustment for Purchase/**	
Line No.	RATE BASE: Beginning and End of Year Detail	**Average**	Form 1	Form 1	**Sale of Major Asset**	(((3)+(4))/2)+(5)
	GROSS PLANT IN SERVICE					
1	Production	200.12.c plus 205.46.g less (205.15.g, 205.24.g, 205.34.g, 205.44.g) less 204.16.c footnote plant in service related to steam heating	0	0	0	$0
2	Transmission	207.58.g less 207.57.g	0	0		0
3	Distribution	207.75.g less 207.74.g	0	0		0
4	General & Intangible	205.5.g, 207.99.g less 207.98.g	0	0		0
5	Common (Electric)	356 Total Common Plant - Electric	0	0		0
	ACCUMULATED PROVISIONS FOR DEPRECIATION & AMORTIZATIONS					
6	Production	200.32.c, 219.20.c, 219.21.c, 219.22.c, 219.23.c, 219.24.c less page 219.8.c footnote accumulated depreciation related to steam heating	0	0	0	0
6a	Less (Nuclear Decommissioning)	Already excluded from above	0	0		0
6b	Add Asset Retirement Obligations (Subtract	219.19.c footnote accumulated depreciation	0	0		0

	AROs included in Accum Depr and Add AROs excluded from Accum Depr).	related to Prod. asset retirement obligations				
7	Transmission	219.25.c	0	0		0
8	Distribution Add Asset Retirement Obligations (Subtract AROs included in Accum Depr and Add AROs excluded from Accum Depr).	219.26.c plus 219.19.c footnote accumulated depreciation related to distribution asset retirement obligations	0	0		0
9	General & Intangible	219.28.c plus 200.14.c footnote intangible depreciation reserve	0	0		0
10	Common (Electric)	356.1 Accumulated Provision for Depreciation - Electric Utility	0	0		0
10a	Common	356.2	0	0		0

Wisconsin Electric Power Company
Formula Rate Wholesale Sales Tariff, FERC Electric Tariff Volume No. 9

FERC Electric Tariff						Attachment A
						page 7 of 7, continued
Formula Rate - Non-Levelized		**Capacity Rate Formula Template**			For the 12 months ended 12/31/2013	
		Utilizing FERC Form 1 Data				
		Wisconsin Electric Power Company				
	(1)	(2)	(3)	(4)	(5)	(6)
		Form No. 1	**BOY**	**EOY**		**Average**
Line		**Page, Line, Col.**	Prior Year	Current Year	**Adjustment for Purchase/**	
No.	RATE BASE: Beginning and End of Year Detail	**Average**	Form 1	Form 1	**Sale of Major Asset**	(((3)+(4))/2)+(5)
	ADJUSTMENTS TO RATE BASE					
11	Acct 281 (enter negative)	273.8.k	0	0		0
12	Acct 282 (enter negative)	275.2.k	0	0	0	0
13	Acct 283 - Production (enter credit balances as negative and debit balances as positive)	276.8.a footnote accumulated deferred income taxes account 283-Production	0	0		0
13a	Acct 283 - General (enter credit balances as negative and debit balances as positive)	276.8.a footnote accumulated deferred income taxes account 283-General	0	0		0
14	Acct 190 - Production	234 accumulated deferred taxes account 190 - Production	0	0	0	0
14a	Acct 190 - General	(234.1) accumulated deferred taxes account 190 -General	0	0		0
	WORKING CAPITAL					
15	Materials & Supplies (production)	227.7.c	0	0		0
16	Prepayments (Acct 165)	111.57.c plus 263.41.h	0	0		0
17	Pollution Control CWIP	(216.1).13.a footnote pollution control CWIP	0	0	0	0
18	Property Held For Future Use (production)	214.9.a footnote plant held for future use - production	0	0		0

Wisconsin Electric Power Company
Formula Rate Wholesale Sales Tariff, FERC Electric Tariff Volume No. 9

				Attachment B
		Energy Rate Part I Formula Template		Page 1 of 1
The Energy Rate Part I shall be computed by using WE's estimated monthly costs and energy accounting data, and trued up the following month using actual monthly costs and energy accounting data.				
Line			Form No. 1	
No.			Page, Line, Col.	Actual 2013
	Energy Rate Part I Equals:			
1		Monthly Fuel and Purchased Power Costs		$0
2	Divided by	Monthly System MWHs		0
3	Equals	Energy Rate Part I ($/MWh)		0
4		**Energy Rate Part I ($/kWh) (Transmission Level)**		**0**
	Where Monthly Fuel and Purchased Power Costs Equal:			
5		Fuel: Steam (Acct 501)	320.5.b	0
6	Plus	Fuel: Nuclear (Acct 518)	320.25.b	0
7	Plus	Fuel: Other (Acct 547)	321.63.b	0
8	Plus	Purchased Power - Energy Related	327.Total.k less 65% of NextEra PPA	0
8a	Plus	Market Facilitation, Monitoring and Compliance Services (Acct 575.7)	320.121.b footnote Market Facilitation amounts	0
9	Plus	Non-FERC Deferrals / Amortizations: Energy Related less Carrying Charges	232.xx.c less carrying charges in footnote (if any)	0
10	Plus	Steam from Other Sources (Acct 503)	320.7.b	0
11	Less	Steam Transferred - Credit (Acct 504)	320.8.b	0
12	Plus	Allowances (Acct 509)	320.12.b	0
13	Equals	Subtotal 1		0
14	Less	Opportunity Sales Revenues - Energy Charges (Acct 447)	311.Subtotal non-RQ.i less 311.i lines 5,9,11,13 less (311.1).i lines 1,3,5	0
15	Equals	**Monthly Fuel and Purchased Power Costs**		0
	Where Monthly System MWHs Equal:			
15a		System Generation	401a.9.b	0
16	Plus	Purchased power	401a.10.b	0
17	Plus	Net Exchange	401a.14.b	0
18	Less	Opportunity Sales	401a.24.b	0
19	Less	MWhs of Marginally Priced Sales to retail customers	326.8.g footnote	0
20	Less	Company Use	401a.26.b	0
21	Equals	Monthly System MWhs	320.5.b	0
Energy Rate Part II Formula Template				
	Energy Rate Part II Equals:			
22		Other Energy Related O&M (Accts 510,512,513,528,530, 531, 544)	320.15.b,320.17.b,320.18.b, 320.35.b, 320.37.b, 320.38.b, 320.56.b	$0
23	Plus	Schedule 24 Allocation Amount	320.88.b footnote Allocation Amt	0
24	Plus	Wind Production Tax Credit Generated	261.28.b footnote	0
25	Less	Fuel Costs recovered through Marginally Priced Sales to retail customers	326.8.k footnote	0
25a	Less	Renewable Energy Program (EFT) Premiums	(304.1).30.a footnote	0
26		Net Energy Rate Part II Costs		0
27	Divided by	Annual System MWH's		0
28		Other Energy Related O&M Rate ($ per MWH)		0
29		**Energy Rate Part II ($/kWH) (Transmission Level)**		**0**
	Where Annual System MWH's Equal:			

Wisconsin Electric Power Company
Formula Rate Wholesale Sales Tariff, FERC Electric Tariff Volume No. 9

30		System Generation	401a.9.b	0
31	Plus	Purchased Power	401a.10.b	0
32	Plus	Net Exchange	401a.14.b	0
33	Less	Opportunity Sales	401a.24.b	0
34	Less	MWhs of Marginally Priced Sales to retail customers	326.8.g footnote	0
35	Less	Company Use	401a.26.b	0
36	Equals	Annual System MWH's		0

WISCONSIN ELECTRIC POWER COMPANY
FORMULA RATE WHOLESALE SALES TARIFF

EXHIBIT C

EXHIBIT C

Energy and capacity charge adjustments

A. Adjustments For MISO Market Participants and MISO Asset Owners:

The charges calculated pursuant to Exhibit B shall be reduced to account for Buyer's membership in MISO or to reflect other contractual arrangements. The adjustments pertain to the MISO charges for Day Ahead Revenue Sufficiency Guarantee Distribution Amount, Real Time Revenue Neutrality Uplift Amount, Ancillary Service Charges, MISO Schedule 16 – FTR Administrative fee, MISO Schedule 17 – Market Administration fee and MISO Schedule 24—Balancing Authority costs. These adjustments are calculated as follows:

1. Day Ahead Revenue Sufficiency Guarantee Distribution Amount Adjustment:

The monthly booked dollar value, which includes all settlements and adjustments for prior months, for the Day Ahead Revenue Sufficiency Guarantee Distribution Amount will be divided by the monthly kWh reported on Line 21 of the Energy Rate Part I Formula Template contained in Exhibit B, Attachment B, to determine the adjustment to the Energy Rate Part I.

2. Real Time Revenue Neutrality Uplift Amount Adjustment:

The monthly booked dollar value, which includes all settlements and adjustments for prior months, for the Real Time Revenue Neutrality Amount will be divided by the monthly kWh reported on Line 21 of the Energy Rate Part I Formula Template contained in Exhibit B, Attachment B, to determine the adjustment to the Energy Rate Part I.

3. MISO Schedule 16 – FTR Administrative Fee:

The monthly booked dollar value for MISO Schedule 16 – FTR Administrative fee will be divided by the monthly kWh reported on Line 21 of the Energy Rate Part I Formula

Template contained in Exhibit B, Attachment B, to determine the adjustment to the Energy Rate Part I.

4. MISO Schedule 17 – Market Administration Fee:

The monthly booked dollar value for MISO Schedule 17 – Market Administration fee will be divided by the monthly kWh reported on Line 21 of the Energy Rate Part I Formula Template contained in Exhibit B, Attachment B, to determine the adjustment to the Energy Rate Part I.

5. MISO Ancillary Service Market Charges:

The sum of the monthly booked dollar value for the Ancillary Service Market Charges of the Regulation Cost Distribution Amount, Spinning Reserve Cost Distribution Amount and Supplemental Reserve Cost Distribution Amount will be divided by the monthly kWh reported on Line 21 of the Energy Rate Part I Formula Template contained in Exhibit B, Attachment B, to determine the adjustment for Energy Rate Part I.

6. MISO Schedule 24 – Balancing Authority Costs:

The sum of monthly booked dollar value for the Day Ahead Schedule 24 Allocation Amount and the Real Time Schedule 24 Allocation Amount will be divided by the monthly kWh reported on Line 21 of the Energy Rate Part I Formula Template contained in Exhibit B, Attachment B, to determine the adjustment for Energy Rate Part I.

The adjustment on Buyer's bill will be determined by summing the adjustments 1-6 set forth above in Part A of this Exhibit C and then multiplying that sum by Buyer's energy purchases under the Tariff during the Billing Period.

B.1 MISO Schedule 17 – Related Charge:

Seller will apply the MISO Schedule 17 related charge to Buyer's total MWh purchases under this Tariff, as applicable. This charge will be identified as a separate line item on Buyer's bill.

B.2 MISO Schedule 24—Related Charge:

Seller will apply the MISO Schedule 24 related charge to Buyer's total MWh purchases under this Tariff, as applicable. This charge will be identified as a separate line item on Buyer's bill.

WISCONSIN PUBLIC SERVICE CORPORATION
RATE SCHEDULE W-1A
FOR FULL REQUIREMENTS SERVICE
TO WHOLESALE CUSTOMERS

VOLUME NO. 2

Non-Conforming
Service Agreement #XXX
For
Full Requirements With Interruptible Service
Between
Wisconsin Public Service Corporation
and
Upper Michigan Energy Resources Corporation

Effective: mm/dd/yyyy

EXHIBIT A

NON-CONFORMING
RATE SCHEDULE W-1A

SERVICE AGREEMENT
FOR
FULL REQUIREMENTS WITH INTERRUPTIBLE SERVICE

THIS AGREEMENT, made this ____ day of _____, 20__, by and between WISCONSIN PUBLIC SERVICE CORPORATION, a Wisconsin corporation, (hereinafter called "the company"), and UPPER MICHIGAN ENERGY RESOURCES CORPORATION, a Michigan corporation, (hereinafter called "the customer");

W I T N E S S E T H:

That in consideration of the mutual covenants and agreements herein contained, the parties hereto agree as follows:

1. The company agrees to sell and deliver to the customer, and the customer agrees to purchase and receive from the company, full requirements interruptible electric service as specified in Exhibit 1, attached hereto and made a part hereof, or in any successor exhibit.

2. All electric service furnished hereunder shall be paid for by the customer under Rate Schedule W-1A for Full Requirements with Interruptible Service to Wholesale Customers. This Agreement in all respects shall be subject to the provisions of such rate schedule as in effect from time to time. Nothing contained herein shall be construed as affecting in any way the company's right to unilaterally make application to the Federal Energy Regulatory Commission, or other regulatory agency having jurisdiction, for a change in said rate schedule under Section 205 of the Federal Power Act or other applicable statute and any rules and regulations promulgated thereunder.

3. The term of this Agreement shall commence on January 1, 2017 (HE 0100 CPT), when the rate schedule to which it is an exhibit becomes effective as to the customer, and shall continue through December 31, 2017 (HE 2400 CPT) and shall continue from year to year thereafter unless either party provides a twelve (12) months written notice of termination to the other party or, if mutually agreeable and confirmed by written notice, a shorter termination notice shall apply. The applicable provisions of this Agreement and Rate Schedule W-1A shall continue in effect after termination to provide for final billings and adjustments.

4. This Agreement, as of the effective date hereof, supersedes and cancels any previous power supply agreement between the parties.

5. Neither party may assign its rights and obligations under this Agreement without the prior written consent of the other party, which consent shall not be unreasonably withheld. It shall be unreasonable to withhold consent to a successor to all, or substantially all, of the properties and business of a party used for supplying service in the territory in which the energy purchased or sold hereunder is delivered.

WISCONSIN PUBLIC SERVICE CORPORATION
("The Company")

By _____
President

Attest _____
Secretary

UPPER MICHIGAN ENERGY RESOURCES CORPORATION
("The Customer")

By _____
President

Attest _____
Secretary

EXHIBIT 1

1. **Customer:** Upper Michigan Energy Resources Corporation in accordance with the Agreement dated [month dd, yyyy]

2. **Delivery Point(s):** The delivery points shall be at UMERC's Transmission-to-Distribution interconnection points with the American Transmission Company LLC located within the WPS Local Balancing Authority Area and the distribution level points of interconnection as adjusted for cross-border distribution usage between the Parties identified in the Wholesale Distribution Service Agreement(s) between the Parties.

3. **Loss Factor:** The loss factor to be applied to the company's Rate Schedule W-1A shall be as stated in the Wholesale Distribution Service Agreement between Wisconsin Public Service Corporation and Upper Michigan Energy Resources Corporation as may be amended from time to time. As such, the current Loss Factor to be applied to the distribution level deliveries is as follows:

   Loss Factor: 1.0127

4. **Interruptible Service:** Interruptible service shall be applicable to the customer in accordance with Rate Schedule W-1A, unless modified below:

   (a) **Term and Termination of Interruptible Service:**
   The term and termination provisions for interruptible service shall be the same provision as Section 3 of this Agreement

   (b) **The Customer's Generation Resources and Credit:**
   i. Customer's Generation Resources shall be the customer's MISO MECT registered DR/LMR for interruptible load served by the customer for each MISO Planning Year (June 1 to May 31 of the following year) applicable to the Agreement.
   ii. Customer's Generation Resource Credit: The customer shall receive a monthly billing credit for the customer's Generation Resources. The rate for the credit shall be in accordance with Rate Schedule W-1A for each respective Planning Year under this Agreement. This rate shall be applied on a monthly basis to the respective Planning Year quantity of the customer's Generation Resources.

5. **Designated Network Resources ("DNRs"):** The Capacity amount shall be supplied from resources that meet the resource adequacy requirements of the MISO tariff.

6. **Treatment of the Customer's Load in the Company's Planning Obligations:** The company shall include the customer's load in its planning obligation and treat the customer's load as native load and plan to serve such load with no less degree of reliability than the company would its native load or other requirements wholesale load.

7. **Planning Reserves:** The company shall schedule planning reserves to meet the customer's requirements as part of the company's native load forecast schedule with the MISO.

8. **Financial Schedules:** Not applicable, as the customer's load will be considered part of the company's native load requirements.

9. **Scheduling:** The company shall schedule energy to meet the customer's requirements, as necessary, with the MISO.

10. **Capacity Amount:** As required by the company in accordance with Rate Schedule W-1A.

11. **Metering:** As required by the company in accordance with Rate Schedule W-1A.

12. **Fixed Charge:** A monthly charge in accordance with Rate Schedule W-1A shall be billed for each point of delivery.

13. **Performance Assurance:** The company, in order to satisfy itself of the ability of the customer to meet its obligations under this Agreement, may in accordance with standard commercial practices conduct reasonable credit reviews. The company will require the customer to provide the information and meet the requirements determined by the company. The customer's failure to provide adequate credit support shall be grounds for the company to deny a request for service or to terminate service. The company may require the customer to provide and maintain in effect during the term of this Agreement, an unconditional and irrevocable letter of credit, a parental guaranty, or an alternative form of security acceptable to the company and consistent with commercial practices ("Performance Assurance"). The company reserves the right, on a non-discriminatory basis, to require the customer to submit to the company updated financial information to permit the company to evaluate the customer's creditworthiness on an on-going basis, and if necessary, to require future Performance Assurance. Upon receipt of such notice the customer shall have three (3) Business Days to remedy the situation by providing such Performance Assurance to the company. In the event the customer fails to provide such Performance Assurance acceptable to the company within three (3) Business Days of receipt of notice, then an event of default will be deemed to have occurred.

14. **Capacity and Energy Charges:** The monthly and annual estimated and actual true-up charges for capacity and energy shall be determined in accordance with the company's Rate Schedule W-1A, unless stated differently in the Agreement.

15. **Transmission Demand Charge:** The customer's full requirements load shall be subject to the Transmission Demand Charge in accordance with Article B Rates and Charges, Section 4 of the company's Rate Schedule W-1A for Full Requirements Service to Wholesale Customers.

16. **Wholesale Distribution Service**: is provided under a separate stand-alone agreement between the company and the customer.

Wisconsin Public Service Corporation as of 9/16/2013
Electric TCS and MBR
WPSC Tariff Database
Effective Date: 07/23/2010 Status: Effective
FERC Docket: ER10-01894-001 29
FERC Order: DLO Order Date: 01/19/2011
Rate Schedule W-1A, Rate Schedule W-1A, Volume No. 2, 0.0.0 A

WISCONSIN PUBLIC SERVICE CORPORATION

RATE SCHEDULE W-1A

FOR FULL REQUIREMENTS SERVICE

TO WHOLESALE CUSTOMERS

Volume No. 2

RATE SCHEDULE W-1A
FOR FULL REQUIREMENTS SERVICE
TO WHOLESALE CUSTOMERS

Article A
General Terms and Conditions

1. **AVAILABILITY**

a. Wholesale electric service is available under this rate schedule from Wisconsin Public Service Corporation (hereinafter called "the company") to any municipality, municipal electric company, rural electric cooperative, or investor-owned utility (hereinafter called "the customer") at existing delivery points and at such other delivery points as may be agreed to by the company and the customer. The service available under this rate schedule shall consist of three-phase, sixty-hertz, power and energy.

b. This rate schedule shall be available for:

1) Full requirements firm electric service upon execution of a Service Agreement in the form provided in Exhibit A hereof,

2) Full requirements interruptible service upon execution of a Service

Agreement conforming with paragraph 7 of Article B hereof, and,

3) Firm or interruptible service where the customer has installed peak shaving facilities upon execution of a Service Agreement conforming with paragraph 8 of Article B hereof.

The Service Agreement between the company and each customer shall be appended to this rate schedule and shall be considered an integral part thereof.

c. All transmission service (including any required distribution and/or non-generation supplied ancillary services) in connection with service agreements providing for the commencement of service on or after July 9, 1996 shall be provided pursuant to currently applicable tariff(s) except as provided in Section 4 of Article B.

2. NEW LOAD

The company may decline a request for service under this rate schedule, which would require it to meet end use loads which it is not presently serving:

a. If it lacks adequate capacity so that it is unable to provide the service either at retail or at wholesale, or,
b. If the load is located outside the service areas of the company or its W-1A or W-2A customers.

Any utility seeking service under this rate schedule for end use load not already served by the company shall describe to the company in writing the service sought and shall furnish such information as the company may require for its power supply and planning purposes. The company shall notify the utility within 60 days of receiving the customer's request of whether it will provide the requested service.

3. CONVERSION FROM FULL TO PARTIAL REQUIREMENTS SERVICE

A customer taking service under this rate schedule shall have the right to interconnect in a manner such that it can take any of its requirements from another supplier or deliver to other buyers. In the event that the customer desires to purchase less than its full requirements from the company, the customer will provide the company with at least five years' prior written notice specifying the date of the conversion; provided, however, only two years' prior notice of a conversion shall be required if the nominated annual contract Period A summer and winter demands, respectively, under the company's then applicable partial requirements rate schedule of the converted delivery points for the first two years following conversion are at least 75% of the Period A summer and winter demands, respectively, of such delivery points in the calendar year immediately preceding the conversion.

In the event that the customer desires to purchase less than its full requirements, the company and the customer shall enter into an amended or new contract for partial requirements service, pursuant to the company's then applicable partial requirements rate schedule. The notice period may be shortened by mutual agreement of the company and the customer. If the customer fails to make the conversion on the date specified, the

company shall use its best efforts to continue to supply the customer's full requirements but may file a rate for the continued service to recover any higher than average incremental costs incurred in rendering the service.

4. **CONVERSION OF CUSTOMER FROM PARTIAL TO FULL REQUIREMENTS SERVICE**

The company may decline a request by a wholesale customer taking partial requirements service for conversion to full requirements service under this rate schedule if the company lacks the adequate generating or transmission capacity to provide the full requirements service.

Any utility seeking conversion from partial requirements service to full requirements service under this rate schedule shall so notify the company and shall provide the date of conversion and such other information as the company may require for its power supply and planning purposes. The company shall notify the utility within 60 days of receiving the customer's request of whether it will provide the requested service. If the company notifies the customer that it will provide the requested service but the customer then does not convert on the date specified, the company will bill the customer, and the customer will pay on the basis of the billing determinants that would have pertained if the conversion had been accomplished as specified.

5. **OBLIGATIONS OF COMPANY AND CUSTOMER**

a. Acceptance of service under this rate schedule by the customer binds the customer to all of its provisions as they may be modified from time to time by the company by notifying the customer and filing changes with the Federal Energy Regulatory Commission, or other regulatory agency having jurisdiction, in accordance with section 205 of the Federal Power Act.

b. All obligations of the company and the customer are subject to action of the Federal Energy Regulatory Commission or other regulatory agency or government authority having jurisdiction.

c. This rate schedule and the appended Service Agreements are not intended to and shall not create rights of any character whatsoever in favor of any person, corporation, association, or entity other than the parties to such agreements, and the obligations herein assumed are solely for the use and benefit of said parties.

d. The obligations of the company and the customer are subject to and conditioned upon their securing and retaining all permits and licenses and other rights and approvals necessary for service to be rendered.

6. **INFORMATION TO BE FURNISHED BY CUSTOMER**

The customer shall furnish the company forecasts of its summer and winter peak demands and energy purchases and such other information as the company may request to assist the company in planning to meet the customer's loads. The customer shall promptly inform the company of any probable major changes in the customer's power supply plans.

7. FACILITIES TO BE INSTALLED BY COMPANY AND CUSTOMER

a. The company agrees to own, operate, and maintain in good condition the necessary equipment for supplying the customer with electrical energy at the delivery point(s) to the customer, unless other provisions are made in the Service Agreement.

b. The customer agrees to furnish and maintain, at its own expense, all necessary wiring, fixtures and appliances required to connect up with the facilities of the company for the receiving and making use of electric energy, unless other provisions are made in the Service Agreement. It is further agreed that the company's undertaking is completed by the delivery of electricity to the delivery point(s), and that beyond such point, all safety devices, equipment, and appliances required to control, regulate, or utilize the energy are to be furnished and maintained by the customer.

c. Where no step-down substation facilities are required by the company, the resale customer shall provide a support for the company to terminate the primary conductors and install other required equipment. All substation equipment shall be owned, operated, and maintained by the resale customer. The support and substation equipment is subject to the company inspection and approval.

8. ACCESS TO CUSTOMER'S PROPERTY

The customer agrees to provide, free of charge, proper and sufficient space on its premises for necessary poles, wires, switches, enclosures, and appurtenances, and grants to the company a free right-of-way over its premises for the construction, maintenance, removal, and repair of such of the company's facilities as shall be placed thereon; provided, however, that the company will place on the customer's property only such of its facilities as are usual and customary for the service to be provided.

9. METERING

a. The electric power and energy delivered by the company to the customer shall be metered by suitable metering equipment provided and maintained by the company at the delivery point(s) to the customer.

b. Metering equipment shall be tested by the company at suitable intervals not to exceed 12 months. The accuracy of registration shall be maintained in accordance with good practice. On the request of the customer, special tests shall be made. If any special meter test discloses the metering devices to be registering within acceptable limits of accuracy as specified hereinafter, then the customer shall bear the expenses thereof. Otherwise, the expense of such test shall be borne by the company. Representatives of customer shall be afforded opportunity to be present at all routine or special tests and upon occasions when any readings for purposes of settlements hereunder are taken. At the time of any test, meters shall be adjusted to as close to 100% accurate as practical.

c. If, as a result of any test, any meter shall be found to be registering more than two percent above or below one hundred percent of accuracy, the account between

the parties hereto shall be corrected for a period equal to one-half of the elapsed time since the last prior test, according to the percentage of inaccuracy so found, except that if the meter shall have become defective or inaccurate at a reasonably ascertainable time since the last prior test of such meter, the correction shall extend back to such time. Should metering equipment at any time fail to register, the energy delivered shall be determined from the best available data. All meters shall be kept under seal, such seals to be broken only when the meters are to be tested or adjusted.

10. **CONTINUITY OF SERVICE**

The company shall exercise due diligence and reasonable care and foresight to maintain continuity of service in the delivery of power and energy but shall not be considered to be in default with respect to any obligation hereunder and shall not be liable in damages to the customer if prevented from fulfilling such obligation by fire, strikes, labor disputes, casualties, civil, judicial, or military authority, wars, riots, civil disturbance, or insurrection, the action of the elements or by any other similar or dissimilar cause beyond the company's reasonable control; the company shall not be liable for any reduction in voltage or interruption of service resulting from operation in accordance with good utility practice of an emergency load reduction program. In the event that the company is unable to fulfill any obligations hereunder by reason of such cause or causes, it shall use due diligence to remove such inability with reasonable dispatch, provided that the settlement of strikes or labor disturbances shall be entirely within the discretion of the company and the above requirements, that any difficulty shall be removed with reasonable dispatch, shall not require the settlement of strikes or labor disputes by acceding to the demands of the opposition in such strikes or labor disturbances when such course is inadvisable in the discretion of the company.

11. **LIABILITY**

The customer and the company each expressly agrees to indemnify, hold harmless, and defend the other against all claims, liability, costs, or expense for loss, damage, or injury to persons or property in any manner directly or indirectly connected with or growing out of the generation, transmission, or distribution of electric energy on its side of the delivery point(s).

12. **WAIVER**

Any waiver at any time, by either the company or the customer, of its rights with respect to any matter arising in connection with this rate schedule shall not be deemed a waiver with respect to any subsequent default or matter. Any delay, short of the statutory period of limitation, in asserting or enforcing any right under this rate schedule shall not be deemed a waiver of such right.

13. **PAYMENT OF BILLS**

Bills for service shall be due within 15 days of the date of the bill. If transmittal of payment is not received by the due date, the customer shall pay an interest charge computed daily from the due date at an annual rate equal to 18%. The daily rate shall be determined by dividing the annual rate by the number of days in the current calendar year. The daily

rate shall be applied to any unpaid balance due, including any interest charges previously accrued, compounded monthly.

14. **CHANGES IN TERMS AND CONDITIONS**

Nothing contained herein shall be construed as affecting in any way the company's right to unilaterally make application to the Federal Energy Regulatory Commission or other regulatory agency having jurisdiction for a change in this Article A of this rate schedule, pursuant to section 205 of the Federal Power Act or other applicable statute and any rules and regulations promulgated thereunder.

15. **TERMINATION OF SERVICE**

Service under this rate schedule shall commence on the date that the rate schedule is permitted to become effective under the Federal Power Act as to the customer and shall continue for a period of five years and from year to year thereafter unless the company or the customer shall, at least 60 months before the end of any one-year period thereafter, serve upon the other party a written notice of election to terminate service under this rate schedule at the end of such designated period, when it shall terminate accordingly. Notwithstanding the above, service may be terminated by the company upon 60 days' written notice to the customer for nonpayment of a bill.

16. **CONFLICT WITH SERVICE AGREEMENT**

In the event of any conflict between this tariff and the service agreement executed by the customer, the service agreement shall control.

Article B

Rates and Charges

The customer shall make monthly payments, on a totalized basis, to the company for electric service under this rate schedule by summing the following charges:

1. FIXED CHARGE :
$113.02/Month/Delivery Point

2. MONTHLY CAPACITY CHARGE

a. Estimated Monthly Capacity Rate/KW

1) The customer's monthly bill for service during a Service Year is to be based on the estimated Monthly Capacity Rate times the Customer's Monthly Billing Demand. The "Service Year" is the calendar year in which service is provided.
2) The estimated Monthly Capacity Rate for each month during which service is received during the Service Year shall be determined in accordance with the formula in Attachment A using (i) a forecast of the Service Year construction work in progress ("CWIP") included in rate base, (ii) FERC Form 1 information for the year that is two years prior to the Service Year for the months of January through March of the Service Year; and (iii) FERC Form 1 information for the year preceding the Service Year for the months of April through

December of the Service Year.

3) The CWIP forecast used for billing for the months of April through December of the Service Year and for January through March of the following Service Year shall be based on the company's best CWIP estimate for the Service Year that is available as of April 1st of each Service Year.

b. True Up

1) At the time of the April Billing for the year following the Service Year, the company shall perform a true up by recalculation of its costs for the Service Year based on actual cost and load information (including actual CWIP information) as reported in the FERC Form 1 for the Service Year and shall develop thereby a preliminary actual Monthly Capacity Rate which shall be multiplied by the Customer's Monthly Billing Demand for the Service Year to calculate the preliminary actual Capacity Charge.

2) The preliminary actual Capacity Charge shall also be adjusted to the extent necessary and subject to Article B, Section 15(a)(iii) to reflect the Rate Ceiling Procedure ("RCP") in Attachment D. If the RCP does not require an adjustment to the preliminary actual Capacity Charge, that charge shall become the final actual Capacity Charge. If an adjustment is warranted, the preliminary actual Capacity Charge, as adjusted, shall become the final actual Capacity Charge.

3) If the amount paid by the customer based on the estimated Capacity Charge exceeds the amount based on the final actual Capacity Charge, the company shall refund to the customer the difference between the two amounts. If the amount paid by the customer based on the estimated Capacity Charge is less than the amount based on the final actual Capacity Charge, the customer shall pay to the company the difference between the two amounts.

4) Any difference between the estimated Capacity Charge and the final actual Capacity Charge to be refunded to or collected from the customer shall be so refunded or collected in equal amounts in the monthly bills rendered in April through December of the calendar year following the Service Year. Any such refund by the company or payment by the customer shall be increased by interest calculated in accordance with Section 35.19a of FERC's regulations from the dates of the customer's excess payment or underpayment to the date of refund or payment to the company.

c. Capacity Rate Formula (See Attachment A)

1) The capacity rate formula will include CWIP costs in rate base for the company's production plant accounts, including those for the Weston 4 project, to the same extent as included in the company's Wisconsin retail rates. The said Weston 4 CWIP allowance shall include 100% of CWIP only if, only as of the date or dates, and only to the extent Weston 4 CWIP is allowed in the company's Wisconsin retail rate base. The said 100% shall be equal to 100% of the company's expected ownership share of the Weston 4 plant as that expected share may vary from time to time. Any CWIP included in rate base for any project, other than the Weston 4 project, exceeding 50% shall be the subject of a filing by the company pursuant to the provisions of Section 205 of the Federal Power Act for that portion exceeding 50% and the customer shall not object to such filing. CWIP will be included in rate base

pursuant to this Section 2.c.1) with respect to service provided as of July 1, 2004.

2) The capital and operating costs of the company's power plants placed in service will also be included in the Annual Production Capacity Revenue Requirement after the plant-in-service date of each such plant.

3) Customer's Monthly Billing Demand

a) Each customer's monthly billing demand, adjusted for losses, will be determined for each calendar month by 1/12 of the sum of the customer's load coincident with the hour of company's twelve monthly firm system peak loads during the Service Year that corresponds to the FERC Form 1 information used in calculating the estimated or true up Capacity Charge.
b) Each coincident customer load will be adjusted for a pre-defined distribution loss factor for customers taking service from the company's distribution system.
c) The distribution loss factor will be defined in the customer's wholesale distribution service agreement with the company.

4) Major Assets

If the Company purchases or sells a major electric production asset with a gross plant-in-service value of $100,000,000 or more during a Service Year, the capacity rate formula for the Service Year shall employ a 13-month average balance for such an asset for the specified items instead of an average of beginning and end of year balances. The specified items shall consist of plant-in-service, depreciation reserve, deferred taxes and CWIP in rate base.

d. Customer's Audit Rights

1) The customer shall have the right to conduct an audit of the actual data for Service Year and shall be entitled to request the company to adjust the final true up rates, and any refunds it received or payments it made, pursuant to those rates in the event of a discrepancy between the data employed by the company in performing the true up and the actual data for the Service Year or in the event the company developed the true up in a manner that is inconsistent with this rate schedule. The company will provide such information as the customer may request in order to understand the company's true up calculations.
2) Any refund received by a customer by virtue of these audit provisions shall be net of any prior RCP rate adjustment.
3) The audit with respect to billings for a Service Year conducted pursuant to the provisions of Section d.1) shall be completed by September 30th of the calendar year following the Service Year; provided that the company and the customer may jointly agree to an extension of an audit period and provided further the customer may allege in a complaint unilaterally filed with the Commission prior to November 30th that the period through September 30th for conducting the audit was insufficient due to company caused delays in the

customer's review of the audit data.

4) If a customer fails to object to the true up by November 30th of the calendar year following the Service Year or by the end of any extension of the audit period as provided for in Section d.3), the company's costs for the Service Year shall be deemed final, shall not be subject to further dispute or challenge as to that customer, and shall not be subject to refund. If the customer does file a complaint, the customer shall specify the portion of the revenue collection subject to dispute. The November 30th deadline does not apply to the extent that (i) the company makes a later change in its FERC Form 1 numbers for a Service Year either on its own or as a result of a Commission audit that effects a modification of prior rates; (ii) the Commission prior to December 31st of the calendar year following the Service Year institutes its own investigation under Section 206 of the Federal Power Act of the company's Service Year costs; or (iii) the Commission's policies with respect to fuel costs and purchased power costs would allow a challenge to those costs at a later date than December 31st of the calendar year following the Service Year.

3. <u>ENERGY CHARGE</u>

a. An estimated On-Peak Charge and Off-Peak Charge shall be billed each month and applied to the customer's On-Peak and Off-Peak Period energy consumption, adjusted for losses, during the calendar month.

1) The estimated On-Peak Charge and Off-Peak Charge shall be based on an estimated Monthly Energy Rate.
2) The estimated Monthly Energy Rate shall be determined each calendar month in accordance with the energy rate formula in Attachment B.
3) The customer's On-Peak and Off-Peak energy consumption will be adjusted for a pre-defined distribution loss factor for customers taking service from the WPSC distribution system.
4) The distribution loss factor will be defined in the customer's wholesale distribution service agreement with the company.

On-Peak Charge: (Monthly Energy Rate) x 1.2

Off-Peak Charge: (Monthly Energy Rate) x 0.8

b. <u>True Up</u>

1) A true up of the estimated On-Peak Charge and Off-Peak Charge for each calendar month shall be made at the time of the billing of the second subsequent billing month (in other words, on a two month lagging basis) with the exception of the "variable operations and maintenance" and the "interruptible revenue credit" components of the Monthly Energy Rate, which shall be trued-up annually for each calendar year at the time of the April billing of the following calendar year.
2) The true up shall use the actual costs for the trued up calendar month in

determining the actual Monthly Energy Rate with the exception of the "variable operations and maintenance" and the "interruptible revenue credit" components of the Monthly Energy Rate, which shall be calculated using actual costs from the FERC Form 1 information for the calendar year.

3) Any difference between the estimated Energy Charge and the actual Energy Charge will be refunded or collected from the customer to include interest calculated in accordance with Section 35.19a of FERC's regulations from the dates of the customer's excess payments or underpayments to the date of refund by or payment to the company.

4) The true up for the "variable operations and maintenance" and the "interruptible revenue credit" shall be paid by or to the company pursuant to the schedule set forth in Section 2.b.4.

c. On-Peak Period

1) Winter (Billing Months Oct-May):
6:00 AM to 10:00 PM; Monday through Friday (except holidays).

2) Summer (Billing Months Jun-Sep):
7:00 AM to 11:00 PM; Monday through Friday (except holidays).

d. Off-Peak Period

1) Winter (Billing Months Oct-May):
10:00 PM to 6:00 AM; Monday through Friday, all day Saturday, Sunday, and holidays.

2) Summer (Billing Months Jun-Sep):
11:00 PM to 7:00 AM; Monday through Friday, all day Saturday, Sunday, and holidays.

4. TRANSMISSION DEMAND CHARGE

a. Alger Delta Electric Association, City of Stephenson and Village of Daggett shall pay the Attachment C transmission charges as of May 11, 2003. On the request of any other customer whose total load is 5 MW or less, the company shall file a revised service agreement with the FERC making the customer subject to the Transmission Demand Charge set forth in Attachment C. For such customers, the company shall obtain transmission service from the Midwest ISO (or successor transmission provider) as if that customer's load were part of the company's retail native load. In the event the company provides such transmission service to a customer, the company shall be entitled to the financial transmission rights ("FTRs") associated with service to that customer unless and until the customer determines to unbundle its service, at which point the customer is entitled to full use of the FTRs available for its load. The company will not discriminate in the application of FTRs to such a customer as compared to the company's retail native load.

b. The Transmission Demand Charge shall be billed by multiplying the Transmission Rate determined by Attachment C by the total average monthly customer transmission load coincident with the American Transmission Company, or its successor, zone's monthly peak for each month during the prior calendar year. The denominator for the transmission rate formula will be the actual average monthly company transmission sub-zone load coincident with the American Transmission Company zone's monthly peak for each month during the prior calendar year, which is used by the Transmission Provider for determining annual load ratio shares for purposes of billing network transmission service. Since the actual cost of network transmission service is to be recovered through this Transmission Demand Charge, the Transmission Rate determined in Attachment C will be billed to the customer on a one month lagging basis after the monthly bill for transmission service is received by WPSC.

5. MINIMUM CHARGE

Unless otherwise provided by contract, the monthly minimum charge shall be the Fixed Charge and Monthly Capacity Charge.

6. INTERRUPTIBLE CLAUSE

Customers desiring interruptible service shall be required to sign individual service agreements. All interruptible service will be subject to the following provisions:

a. Customer shall contract for a given amount of firm demand which shall be billed as the generation component at the appropriate Period A demand charge. Any excess monthly demands above this firm demand shall be considered as interruptible demand. Firm demand nomination shall be revised at least annually prior to the first day of June. Said revision shall delete data for expired demand nominations and add additional nominations to cover a complete 60 month period. On any revision the renomination of any demands for any year shown in a previous nomination or revision of a previous nomination is permitted; provided however, that said revision cannot include 1) a decrease in firm demand or 2) a decrease in interruptible demand in conjunction with a comparable increase in firm demand, approved otherwise by the service company. The company shall approve all requests for increases in firm demand, subject to the conditions of Paragraph m.

b. The maximum interruptible demand shall be billed monthly at the Monthly Capacity Rate less an interruptible credit of $7.00/kW.

c. Normal size of interruptible load shall be at least 200 kW.

d. The company shall provide a regional energy update at the annual spring interruptible meeting. This meeting will be held prior to May 1st of each year and shall include an update of the regional generation and transmission systems as well as any proposed interruptible clause changes. Written copies of presentations shall be made available to all interruptible customers.

e. Firm demand nominations approved by the company shall be supplied by the company in the same manner as other firm load of the company.

f. The company shall endeavor to provide notice of interruption with as much lead time as possible. Notice to interrupt will be by telephone or other verbal means to designated representatives of the customer and will later be confirmed by the company in writing. Under normal circumstances, at least one hour's notice will be given before each interruption with normal interruption ranging from one to six hours. This is subject to change due to unmanageable capacity situations which could require interruption of loads to maintain system standards of operations.

g. When notified, the customer shall reduce his load to the contracted firm amount or less. Failure to reduce load to firm level when notified shall result in the customer being penalty billed $92.40/kW of the demand difference between the maximum load on line during the interruption and contracted firm load.

The customer agrees to endeavor to reduce demand to a level not to exceed the firm contract demand or some higher level requested by the company, in accordance with the timetable requested by the company. It is understood that failure to comply with the timetable requested may result in the forced interruption of electric service to the customer's total demand at time of unmanageable load conditions for the company. Penalty billing in accordance with this clause shall occur if:

1) The company provided notice to interrupt one hour or more in advance and the customer fails to eliminate the interruptible demand, which is designated for interruption by the time requested, or,

2) The company provides less than a one hour notice to interrupt and the customer has not eliminated at least 100% of the demand, which is designated for interruption within 60 minutes after request for interruption.

h. Normal company procedures for implementation of interruption are most likely to occur when the native system demand (firm plus interruptible), required operating reserves (including regulating margin), and firm transaction sales cannot be supplied by available generating capacity plus purchased energy. Said unplanned condition could occur due to forced outages of generating or transmission equipment or cancellation by others of one or more of our purchased power transactions or greater than expected load. Prior to interruption, the company will generally implement available generating capacity, purchase energy to the extent reasonably possible, and curtail nonfirm sales of interchange energy by the company to other utilities, except for nonfirm sales necessary to maintain the reliability of the bulk power system. Except for audit purposes, this interruptible service shall normally have a degree of firmness second only to the native system firm demand, contractual firm sales, emergency nonfirm sales, and regulating margin.

i. There shall be no guarantee by the company as to the length or number of interruptions. However, the company will endeavor to keep the length and number to a minimum and will equalize the hours of interruption on an annual basis for all customers taking service under the interruptible clause to the extent reasonably practical. It is agreed that if the cumulative total hours of interruption exceed 300 hours of interruption during any calendar year, the customer’s

interruptible load will have the same firmness as the company's other firm load for the balance of the calendar year.

j. If the differential between the interruptible demand charge and the Period A demand charges of this rate schedule are reduced to an annual monthly average of $3.00 or less, the customer has the right within 60 days of said change to immediately terminate interruptible service, subject to the conditions of Paragraph M.

k. An interruptibility audit shall not be performed by the company if the customer experienced an actual interruption that was successfully implemented and recorded within the last six (6) months. The interruptibility audits shall normally not be required more often than once a year during summer months and once at or near each winter peak load period. The necessity of an actual interruption or acceptance of other means of verifying ability to interrupt shall be under the sole control of the company. It is the intent of the company that the duration of interruptions for audit purposes will not be extended beyond the time necessary to satisfy the conditions of the audit.

l. The total amount of load contracted as interruptible by all customers shall not exceed 10% of the company system peak demand.

m. Upon notice of cancellation of interruptible service, the company will endeavor to supply the interruptible load on a firm basis at that date or as soon thereafter as reasonably possible. A notice of cancellation shall be treated as a request for firm service, unless specified otherwise by the customer, as of the date of cancellation. Requests for increases in firm demand shall be treated as requests for firm service as of the requested date. Such requests shall take precedence over any subsequent request for firm service by any customer or potential customer that is not specifically reflected in the most current revision of the company's long range capacity plan. It is further agreed that any portion of the interruptible demand that cannot be served as firm demand, and is still desired by the customer, shall continue to be considered and billed as interruptible demand in accordance with this clause until that load obtains firm status.

n. In addition to these specifications, interruptible customers shall be responsible for all applicable charges and clauses of this rate schedule.

o. Service agreements shall have a minimum term of five years with a five year cancellation notice.

7. <u>CUSTOMER PEAKING FACILITIES</u>

Customers desiring to install peaking facilities for the purpose of shaving their billing demands shall be required to sign new individual customer contracts. All such contracts shall include provisions for the following:

a. Peaking facilities shall be operated in a manner which will not adversely affect the company's system, and appropriate protective devices shall be installed to prevent the flow of any energy from the customer's system into the company's system.

b. Scheduled maintenance of the peaking facilities shall be coordinated with the company's maintenance schedule.

c. Contracts shall have a minimum term of 5 years with a 3-year cancellation notice.

d. The customer shall be responsible for all applicable charges and clauses of the W-1 tariff.

7A. PEAK SHAVING BY OTHER MEANS

In addition to the procedures set forth in Section 7 and subject to the conditions hereinafter set forth, peak shaving may be accomplished by purchasing peaking capacity or by means of generation not located on the customer's side of the company's delivery points for service to the customer.

a. In this Section 7A, "peaking capacity" means the facilities or portions thereof which a customer designates to shave its demand from the company; "peaking demand" means the portion of the customer's system demand which is supplied through its peaking capacity; "peaking energy" means the energy associated with the peaking demand; "service period" means a period of two calendar years during which peak shaving service is provided, except that the initial service period will extend from the month in which peak shaving begins through the completion of two full calendar years; and "system demand" means the total firm demand delivered to the customer's delivery points including the customer's demand which is supplied by peaking capacity and energy under this Section 7A.

b. Customers shall sign new customer contracts having a minimum term of 5 years commencing with the date peak shaving begins and a 3 year cancellation notice and shall be responsible for all applicable charges and clauses of this tariff. Subject to the requirements of the Federal Power Act and the regulations thereunder promulgated, peak shaving may be terminated by the company upon 60 days' written notice to the customer for nonpayment of a bill.

c. The customer shall be responsible for delivery of the peaking demand and energy to the transmission provider’s transmission system, and the party responsible for transmission service shall arrange for the delivery of that power over the transmission provider’s transmission system to the customer's delivery points.

d. Peaking energy shall be supplied in a manner which will not adversely affect the company's system. The required procedures shall be subject to good utility practice and shall be coordinated informally between the company and the customer. The customer shall schedule all deliveries to the company's system in advance in accordance with the company's standard procedures for scheduling power transactions. All scheduled deliveries to the company's system shall be in units of whole megawatts and the accounting for the associated energy for such deliveries to the company's system will be in units of whole megawatts.

e. In any month, the peak shaving demand deliveries shall not exceed the lesser of the peaking capacity designated by the customer under subparagraph (g) or 10% of the average of the customer's 12 preceding monthly peak system demands. If a

customer serves multiple distribution systems under a totalized rate, the said average will be based on the totalized monthly system demands of only those distribution systems which continue to be served on an all requirements basis with company power. Peaking energy shall not be scheduled by the customer to be delivered in more than 10% of the hours in any calendar year.

f. Notwithstanding any other provision of this tariff or any contract between the company and the customer, peak shaving shall terminate if and when the customer converts from all requirements service. For purposes of converting from all requirements service, the amount of load which may be withdrawn shall be determined on the basis of the customer's billing demand.

g. The following additional provisions shall also apply:

1) The customer shall give the company at least two years written notice prior to commencement of peak shaving. That notice shall specify the customer's expected monthly peaking demands during the initial service period following the commencement of peak shaving, and shall include documents, contracts or other materials demonstrating to the satisfaction of the company that the customer will be able to acquire the peaking capacity required to meet the expected peaking demand.

2) No later than 3 months prior to the beginning of a service period, the customer shall have (i) entered into contracts establishing the customer's right at all times, subject to emergencies, including emergencies on the system where the peaking capacity is located, to utilize peak shaving capacity to provide for its peaking demand and energy during that service period, or purchased or constructed peaking capacity for that purpose and (ii) designated the peaking capacity on which it proposes to rely for peak shaving and given the company notice of its peak shaving plans during that service period. That notice shall consist of copies of the said contracts, a specification of the customer's expected peaking demands and peaking energy by month during the service period, and such other information as the company may reasonably require.

3) Once a service period has begun, a customer may designate new peaking capacity to replace peaking capacity specified in its subparagraph 2) notice by arranging for alternative peaking capacity in the manner specified in clause (i) of subparagraph 2); provided that a copy of any new contract or evidence of ownership of a peaking facility shall be promptly furnished to the company; and provided further that the customer maintains under contract for the entire service period the level of peaking capacity reported in its subparagraph 2) notice for that service period. In addition, within 90 days of the effective date of a rate change filed by the company which reduces by 5% or more the demand charge in the rate paid by the customer, the customer may be tendering the appropriate documentation to the company designate a reduced level of peaking capacity for that service period.

4) Capacity designated as peaking capacity pursuant to subparagraph 2) or 3) must be dedicated to peak shaving on the company's system and while so designated, may not be assigned or committed by the customer for any other purpose or use, except emergencies as specified in subparagraph 2) and

except that nothing herein is intended to prevent or restrict the sale of energy from such peaking capacity when not used for peak shaving. In addition, peaking energy need not be supplied from the peaking capacity.

5) At the beginning of each service year, the customer shall provide the company with its best estimate of the monthly amounts of peak shaving which will be undertaken by the customer during the succeeding two years. The customer shall keep the company informed on a regular basis of any changes which occur in those plans. From time to time, the company may require the customer to provide an updated or new peak shaving forecast which shall encompass such period as the company may specify. The purpose of such coordination will be to facilitate the company's planning and operational activities.

6) The use of peaking capacity for peak shaving hereunder shall be subject to the company's approval. The company shall not withhold such approval unless it determines that either the said capacity or the terms of the customer's contract or contracts for such capacity are unsuitable for peak shaving purposes.

7) Notwithstanding any other provision of this tariff or any contract between the company and the customer, a failure to be in compliance with any provision of this Section 7A., shall terminate the peak shaving hereunder. Such peak shaving may not be renewed unless and until the customer gives the two year advance notice as required by subparagraph 1) hereof.

h. The crediting procedure to compensate the customer for the peaking demand and energy deliveries shall be as follows:

1) The customer shall be billed for the total demand and energy delivered to the customer's delivery points during the monthly billing cycle excluding any adjustment for peak shaving under this Section 7A.

2) The peaking demand and energy delivered to the company's system for peak shaving under this Section 7A, shall be adjusted for losses so that in the calculation of the credit hereunder the losses associated with the peaking demand and the peaking energy shall equal the transmission level demand and energy losses incorporated in the all requirements rate demand and energy allocation factors. The credit shall also be adjusted for the transformation losses incorporated in the all requirements rate.

3) The customer's monthly billing shall be adjusted in the second succeeding monthly bill (e.g., the credit for January shall be reflected in the bill rendered in April) for a peak shaving off system demand and energy credit which shall be calculated on the basis of the peaking demand, the peaking energy and the rates figuring in the paragraph h.1) computation and in accordance with the following procedures:

a) The peaking demand delivered to the company's system at the time of the company's period A firm calendar month system peak after adjustment for losses as described in paragraph h.2) shall be increased

by a factor of 1.08 to adjust for the difference in diversity between demand at the time of the company's period A system peak and billing units which are based on the customer's maximum demand on the company. The resulting demand shall be multiplied by the system demand generation component demand charge.

b) The peaking energy delivered to company delivery points after adjustment for losses as described in paragraph h.2) above, shall be multiplied by the appropriate energy charges including fuel clause adjustment.

c) The sum of a) and b) above equals the off system demand and energy credit. Said credit shall be increased for any applicable primary discount provisions.

d) For purposes of the above calculation a billing month and calendar month shall be considered as the same time span.

7B. PEAK SHAVING BY OTHER MEANS (Alternate Scheduling and Crediting Procedure)

Upon mutual agreement between the customer and the company, as evidenced by an executed individual customer contract, the scheduling and crediting procedures of Section 7A. PEAK SHAVING BY OTHER MEANS shall be modified as follows:

a. The company shall schedule all deliveries of the customer's peak shaving capacity and peaking energy to meet the needs of the company's system. Said scheduling by the company shall be in accordance with standard scheduling procedures.

b. The company shall not schedule such deliveries for more than six hours in any one day or more than 100 hours in any one calendar month.

c. The customer shall receive the billing credits calculated under Section 7A.h. as if the peaking demand and energy was delivered to the transmission provider’s system at the time of the company's highest period A firm calendar month system peak, unless the customer fails to deliver the peak shaving capacity and peaking energy when requested by the company in accordance with standard scheduling procedures, unless such failure by the customer is the result of an emergency on the company's system that restricts the company from receiving the scheduled deliver.

Said assumed delivery of peaking demand at the time of the company's highest period A firm calendar month system peak, subject to the same failure to deliver provision specified above, shall also be assumed by the company for cost allocation of demand - related production costs in future rate filings with the FERC for firm service to the customer which are to be effective for periods coincident with periods under which the customer is peak shaving pursuant to this Section 7B.

Prior to the beginning of each service year, the company shall provide customer with its best estimate of the monthly amounts of peak shaving which will be scheduled from the customer during the following year. The company shall keep the customer informed on a

regular basis of any changes which occur in those plans. The purpose of such coordination will be to facilitate the customer's planning and operational activities. The provisions of paragraph g.5 of Section 7A shall not apply to peak shaving under this Section 7B.

8. REACTIVE LOAD

The customer shall keep his lagging reactive load at each delivery point at a level that does not exceed his kW demand at that delivery point and shall not operate with a leading reactive load at any delivery point.

9. VARIATION OF DEMAND

Variation of customer load at each delivery point shall be limited to time changing demand levels which are within system standards of operation as established by the company.

10. DETERMINATION OF DEMAND

The system Billing Demand, as defined above, in kilowatts shall be based on the hourly integrated load observed or recorded for the total of all delivery points. The beginning and ending times of the energy periods shall be as shown in the rate schedule, plus or minus ten minutes.

The beginning and ending times of the hourly integrated load shall start and end at the hour, plus or minus ten minutes.

11. HOLIDAYS

The days of the year which are considered holidays are: New Year's Day, Good Friday, Memorial Day, Fourth of July, Labor Day, Thanksgiving Day, Friday After Thanksgiving, Day Before Christmas, Christmas Day, Day Before New Year's Day.

12. ESTIMATION PROCEDURE

In the event of loss of data for calculation of one or more billing parameters, the Company shall forecast on the basis of historic billing parameters to obtain an estimate of current month's billing parameters. This estimate shall be subject to modification or replacement based on known and quantifiable operating conditions of the current month.

13. SPECIAL RULES

The current per phase of the customer's load at each delivery point shall not be unbalanced greater than 10%. Other special rules and conditions provided in special contracts with each customer.

14. CHANGES IN RATES AND CHARGES

a. Except as noted in Section 14.b., nothing contained herein shall be construed as affecting in any way the company's right to unilaterally make application to the Federal Energy Regulatory Commission or other regulatory agency having jurisdiction for a change in this Article B of this rate schedule, pursuant to Section

205 of the Federal Power Act or other applicable statute and any rules and regulations promulgated thereunder. However, with notice to the customer, the company shall have the right to modify the FERC Form 1 references in Attachments A and B to reflect changes in the format of FERC Form 1 without filing for and obtaining FERC acceptance; provided that, at least once every three years the company shall make a filing pursuant to Section 205 of the Federal Power Act with the Commission so that the Attachment A-B formula rates reflect the correct FERC Form 1 format.

b. Subject to the just and reasonable standard and through Section 205 subject to refund filings in the case of the company and Section 206 filings with refund effective dates by the customer, the company and the customer are each entitled to propose changes in Sections 2 through 4 of this Article B and in Attachments A, B and C to include but not be limited to the following items:

1) Increases in CWIP in rate base to correspond to Public Service Commission of Wisconsin ("PSCW") allowances for post-Weston 4 projects as described in Section 2.c.1) and reductions in the CWIP allowance to correspond to reductions ordered by the PSCW with such reductions to be effective as of the dates and to the extent such PSCW ordered reductions are effective in the company's retail rates;
2) Regulatory assets and regulatory liabilities in addition to those listed in Attachment E;
3) Changes in common equity return and allowances for depreciation, decommissioning and post-employment benefits and post-retirement benefits other than pensions;
4) Changes in accounting affecting Attachments A, B or C; or
5) Addition of new taxes to Attachment A, B or C.

Changes to the formula rates for the following items shall be limited to the Mobile-Sierra standard of review, which shall apply whether the changes are proposed by the company or the customer: (i) reductions in the CWIP allowance as set forth in Section 2.c.1) except for those reductions referred to in clause b.1) above; (ii) elimination of the RCP while formula rates for capacity, energy, and transmission charges, as now set forth in Attachments A, B, and C and as subject to change pursuant to this Article B, are in effect; (iii) inclusion of deferred credits (Account 253) and deferred debits (Account 186); and (iv) termination of the said formula rates prior to May 11, 2015 if there is no material change in FERC or PSCW ratemaking policies as described in subparagraph (c).

c. The company will charge and the customer will pay for requirements electric service pursuant to the provisions of the formula rates in Attachments A, B and C through May 11, 2015, and neither the company nor a customer may unilaterally file to replace the formula rates with fixed rates with an effective date prior to May 11, 2015; provided that either the company or the customer may unilaterally make such a filing pursuant to the provisions of and the just and reasonable standards of Section 205 or Section 206 of the Federal Power Act in the event of a material change in rate regulation by the FERC or the PSCW.

d. On or before December 31, 2014, a customer or the company may, by notice to the other, terminate the Attachment A-C formula rates as of the end of May 11, 2015.

If no such notice is given, the said formula rate shall remain in effect on an annual basis thereafter unless and until a customer or the company, by notice to the other on or before December 31 of any succeeding year, terminates the said formula rates as of the next May 11.

e. During the period the formula rates in Attachments A, B and C are effective, a customer shall not participate either directly or indirectly through financial support or otherwise in litigation before the Public Service Commission of Wisconsin concerning the company's electric retail rates as to issues of common equity return, capital structure, allocated cost of service, rate design, and issues related to transmission and distribution service. The Algoma Group may intervene on any other matters, including but not limited to generation related revenue requirement issues.

15. COMPANY COST DEFERRALS AND RECOVERY

In addition to the cost recovery specified above, the company has the right to bill the customer for the recovery of any company production related costs that have been deferred and are identified in Attachment E provided that the costs have not already been passed on to the customer through the cost recovery mechanisms above. The company has the additional right to bill the customer for the recovery of such additional deferred costs which must be the subject of future Section 205 filings with FERC to be recoverable. The recovery of such additional costs shall be in accordance with the method accepted by the FERC and modified only to the extent necessary in order to properly coordinate with the billing mechanisms and terms of this tariff.

a. Notwithstanding any other terms in this Tariff, including the RCP, the following terms concerning the treatment of future deferrals and amortizations, hereinafter referred to as "Ditem" in the singular or "Ditems" in the plural, to be included in the wholesale formula rates are adopted pursuant to the November 2006 settlement for the customers that are parties to that settlement and pursuant to the November 2006 offer of settlement for the company's remaining customers in Docket Nos. ER05-1089-000, *et al.* ("Docket No. ER05-1089 Settlement"). The capitalized term "Ditem" or "Ditems" refers to a cost or a credit which is treated as a deferred asset as currently recorded in Account 182 or a deferred liability as currently recorded in Account 254 respectively.

i. Generally, a wholesale Ditem will be deferred and amortized consistent with PSCW treatment of the retail Ditem. The deferral and amortization will be effective for wholesale as and when the PSCW authorizes deferral and amortization of the retail Ditem to become effective. Customers agree to not dispute the act of deferral or the length of the amortization period of a Ditem either at the PSCW or at the FERC.

ii. Consistent treatment of deferral and amortization of wholesale and retail Ditems shall be effective only on a prospective basis. Deferrals and amortizations that are currently reflected in Attachment E of the formula rates will not be changed. If a portion of the wholesale Ditem has been passed through the formula rates to wholesale customers prior to the effective date of the authorized retail deferral, the portion of that Ditem already passed through may not be subsequently credited back through the formula rates. Only

unrecovered wholesale Ditems may be deferred and amortized. (*e.g.,* wholesale Ditems to be deferred will not include that portion of the Ditem that has previously been passed through to wholesale customers). Notwithstanding the provisions of clause (i), wholesale customers may by written request to the company have the right, after the effective date of a PSCW authorized retail deferral, to have a Ditem pass through the wholesale formula rates on a current basis.

iii. In regard to both clauses (i) and (ii) above, the customers and company agree to eliminate from the calculation of the RCP disparities between wholesale and retail rates that are created by the timing differences of cost recovery caused by differing wholesale and retail deferrals and amortizations of Ditems. These timing differences of cost recovery are created by differing retail and wholesale amortization periods, or, on the one hand, by the deferral and amortization of a retail Ditem and the concurrent wholesale pass through of the cost related to the retail Ditem through the formula rates, and on the other hand, by a deferral and amortization of a wholesale Ditem, and the immediate pass through of the retail Ditem through the retail rates.

iv. Customers have the right to dispute before the FERC the justness and reasonableness of Ditems, both with respect to their amount and appropriateness for inclusion in rates.

v. In order to provide the customers with an appropriate basis for making the election in clause (ii) above, the company agrees to provide the customers with reasonable notice of proposed retail deferrals.

vi. Notwithstanding anything to the contrary in clauses (a) (i) and (ii) above, the Commission is not bound by a PSCW amortization period if the Commission determines that the PSCW amortization period violates Commission policy.

16. NERCO COAL SALES COMPANY AND SOO LINE BUYOUT COSTS:

a. During each billing period in the period January, 1993 through December, 2005, there shall be added to the charge otherwise paid by each customer the Customer's Share of the sum of the Monthly Principal Payment associated with the costs the company incurred in buying out of a Coal Supply Agreement with Nerco Coal Sales Company ("Nerco") dated September 20, 1985, as amended, and a Coal Transportation Agreement with the Chicago, Milwaukee, St. Paul and Pacific Railroad Company dated June 1, 1984, as amended; and carrying charges on the portion of the total of all Monthly Principal Payments that has not been included in calculating charges in prior billing periods. The Customer's Share shall be a percentage derived from a fraction the numerator of which shall be the kilowatt hours sold to the customer under this tariff in that month and the denominator of which shall be the Company's total system Generation, Purchases and Interchange-in, less Intersystem Sales and less Total System Losses for that month.

b. The Monthly Principal Payments are as follows:

1993	$331,913
1994	345,746
1995	350,246
1996	148,536

1997	149,952
1998	142,702
1999	142,286
2000	141,536
2001	132,036
2002	125,702
2003	55,000
2004	45,833
2005	43,250

The said Monthly Principal Payments shall be increased or reduced if, whenever and to the extent that the composite (Federal and State) income tax rate applicable to the Company increases above or decreases below 40.14%. The increased or decreased payment shall be calculated by multiplying the applicable Monthly Principal Payment by a factor determined by the following formula: (1 - 0.4014) ÷ (1 - X) in which "X" is the new composite corporate income tax rate.

c. The carrying charge on the portion of the total of all Monthly Principal Payments that has not yet been included in calculating charges in prior billing periods shall be calculated at a net-of-tax at current rates overall rate of return that is based on an 11.00% common equity return and the company's cost of debt, exclusive of short term debt, and preferred stock and capital structure as of December 31st of the preceding year. The said overall return will be increased to the gross-of-tax level that is effective at the time of recovery. The return on equity component of the overall rate of return shall be 11.00%, but shall be subject to prospective change from time-to-time pursuant to the provisions of Sections 205 and 206 of the Federal Power Act.

EXHIBIT A

Form of Service Agreement

THIS AGREEMENT, made this ____ day of _____, 20__, by and between WISCONSIN PUBLIC SERVICE CORPORATION, a Wisconsin corporation, (hereinafter called "the company"), and _____, a _____, (hereinafter called "the customer");

W I T N E S S E T H:

That in consideration of the mutual covenants and agreements herein contained, the parties hereto agree as follows:

1. The company agrees to sell and deliver to the customer, and the customer agrees to purchase and receive from the company, firm full requirements electric service as specified in Exhibit 1, attached hereto and made a part hereof, or in any successor exhibit.

2. All electric service furnished hereunder shall be paid for by the customer under Rate Schedule W-1A for Full Requirements Service to Wholesale Customers. This Agreement in all respects shall be subject to the provisions of such rate schedule as in effect from time to time. Nothing contained herein shall be construed as affecting in any

way the company's right to unilaterally make application to the Federal Energy Regulatory Commission, or other regulatory agency having jurisdiction, for a change in said rate schedule under Section 205 of the Federal Power Act or other applicable statute and any rules and regulations promulgated thereunder.

3. The term of this Agreement shall commence on _____, when the rate schedule to which it is an exhibit becomes effective as to the customer, and shall continue until service is terminated in accordance with paragraph 15 of Article A of the rate schedule. The applicable provisions of this Agreement and Rate Schedule W-1A shall continue in effect after termination to provide for final billings and adjustments.

4. This Agreement, as of the effective date hereof, supersedes and cancels any previous power supply agreement between the parties.

5. Neither party may assign its rights and obligations under this Agreement without the prior written consent of the other party, which consent shall not be unreasonably withheld. It shall be unreasonable to withhold consent to a successor to all, or substantial all, of the properties and business of a party used for supplying service in the territory in which the energy purchased or sold hereunder is delivered.

WISCONSIN PUBLIC SERVICE CORPORATION
("The Company")

By _____
President

Attest _____
Secretary

_____
("The Customer")

By _____
President

Attest _____
Secretary

EXHIBIT 1

1. Name of customer: _____

2. Location of point(s) of delivery: _____

3. Metering: _____

4. Facilities to be provided by the company: _____

5. Facilities to be provided by customer: _____

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

****

In the Matter of the Application of	)	
Upper Michigan Energy Resources Corporation	)	
for approval of a Certificate of Necessity	)	
pursuant to MCL 460.6s for	)	Case No. U-18224
Two Reciprocating Internal Combustion Engine	)	
Electric Generation Facilities Located in the	)	
Upper Peninsula of Michigan,	)	
Approval of Certificate(s) of Public Convenience	)	
And Necessity, approval of a Special Contract with	)	
Tilden Mining Company L.C.	)	
and for related accounting and ratemaking	)	
authorizations.	)	

** Public Version **

DIRECT TESTIMONY AND EXHIBIT

OF

JEFF KNITTER

ON BEHALF OF

UPPER MICHIGAN ENERGY RESOURCES CORPORATION

Q. Please state your name and title.

A. My name is Jeff Knitter. My title is Director of Planning in the Wholesale Energy and Fuels Department representing Wisconsin Electric Power Company ("WEPCo"), Wisconsin Public Service Corporation ("WPS Corp"), and Upper Michigan Energy Resource Corporation ("UMERC" or "the Company").

Q. Please describe your educational and business experience.

A. I graduated from the University of Wisconsin – Madison in 1982 with a degree in Mechanical Engineering. Since that time, I have been employed by WEC Energy Group and/or its subsidiaries in various capacities. From 1995 to 2000, I was the Manager of Resource Planning in the Business Planning Department, where I was responsible for generation planning. From 2000 to 2004, I was Manager – Special Projects in the Legal department, and was active in the planning and development of the Power The Future project since its inception. Among my responsibilities were the development and evaluation of WEPCo's long-range supply plans and their economic analysis for which I provided testimony in the Port Washington and Elm Road dockets. Since 2004, I have worked in the Wholesale Energy and Fuels department focusing on the Midcontinent Independent System Operator, Inc. ("MISO") energy market, MISO ancillary services market, financial transmission rights, and longer range planning. Since June 1, 2009, I have also managed the planning staff with responsibility for the annual fuel cost recovery plans in Wisconsin and Michigan.

Q. Have you ever testified in other cases?

A. Yes. In addition to the Power The Future dockets in Wisconsin, I have testified in the following construction dockets in Wisconsin:

- Valley Power Plant Conversion to Gas
- Rothschild Biomass Energy Project
- WPL Riverside

I also testified in WEPCo's 2010 power supply cost recovery ("PSCR") reconciliation (Case No. U-15664-R) and 2011 PSCR plan case (Case No. U-16424)

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to support UMERC's Application filed in this case. My testimony will provide:

- An overview of the Integrated Resource Plan ("IRP") and its results, which support the proposed construction of two Reciprocating Internal Combustion Engine ("RICE") electric generation facilities in the Upper Peninsula of Michigan ("UP"), to which I refer in this testimony as the "UP Gen Project";
- An overview of various assumptions contained in the IRP, including the following:
    - The Company's available generation resources, including operating parameters and costs, and future changes to capacity;
    - The Company's existing Power Purchase Agreements ("PPAs"), including purchases from renewable resources, as well as spot market purchases and off system sales;
    - The Company's assumptions regarding the amount of service to be provided to electric retail access service ("RAS") customers;
    - The Company's assumption regarding future requirements to supply a portion of its retail sales with renewable resources, and how these resources will receive credit under the Michigan Renewable Portfolio Standard ("RPS");
    - Evaluations of potential RPS policy changes;
    - The Company's assumptions regarding the Planning Reserve Margins expected to be maintained; and
    - The provision of Ancillary Services.
- An overview of the results of the IRP analysis including a summary of results;
- Supply alternatives to the proposed generating facility, including:

- The Company's evaluation of opportunities to purchase existing generating facilities from others, including technology, fuel, operating characteristics, environmental compliance and expected costs;
- The Company's evaluation of opportunities to contract for supply;
- Economic impact of imports and exports of electricity from and to other electric systems;
- A "no-build" option as well as the ability of Energy Optimization ("EO") and renewable energy to meet the projected capacity need; and
- The Company's evaluation of natural gas fueled combined cycle and other supply alternatives.

- The proposed course of action identified as the most reasonable and prudent means of meeting the project capacity need;
- The rationale for the proposed facility, including technology, fuel, capacity, and other significant design characteristics; and
- The effect of the proposed facility on wholesale market competition.

Q. Are you sponsoring any exhibits to accompany your testimony?

A. Yes. I am sponsoring Exhibit A-__ (JEK-1) – "2016 Integrated Resource Plan for UMERC beginning in 2019." This is the IRP to which I referred earlier in this testimony.

Q. Was this exhibit prepared by you or at your direction?

A. Yes.

Q. Can you provide an overview of how UMERC currently provides service?

A. Yes. UMERC is a gas and electric utility that was formed on January 1, 2017, as approved by the Commission on December 9, 2016, in Case No. U-18061. On January 1,

2017, the electric and gas distribution facilities of WEPCo and WPS Corp that are located in the UP were transferred to UMERC. UMERC now provides service to approximately 36,500 electric customers in the UP. All but one Michigan customer, the Tilden Mining Company LC ("Tilden") was transferred to UMERC effective January 1, 2017. Tilden remains a WEPCo customer and will be served under the special contract approved by the MPSC in Case No. U-17862. This contract will remain in place and WEPCo will continue to serve Tilden until UMERC places new generation in service, which is expected in 2019.

Until new generation is placed in service in the UP, UMERC obtains its power supply from both WEPCo and WPS Corp via full requirements PPAs pursuant to FERC-approved tariffs. There is one PPA between WEPCo and UMERC to supply the legacy WEPCo Rate Zone load, and another PPA between WPS Corp and UMERC to supply the legacy WPSC Rate Zone load. These PPAs provide UMERC with the full slice of system costs and benefits of both the WEPCo and WPS Corp generation portfolios, similar to what the WEPCo and WPS Corp customers in the UP had prior to the formation of UMERC.

Q. Does the IRP you are sponsoring meet all of the requirements set forth in the MPSC's IRP Filing Guidelines, Attachment B to the Commission's December 23, 2008 Order in Case No. U-15896?

A. Yes. The Guidelines specify the information to be provided in an IRP for a generating project such as the proposed UP Gen Project, and the IRP I am sponsoring includes all of the information required. The IRP concludes that there are no viable alternatives to the proposed UP Gen Project other than "business as usual," where the Presque Isle Power

Plant ("PIPP") does not retire until MISO and American Transmission Company ("ATC") build expensive new transmission infrastructure. The reasoning for why various alternatives are not viable is a significant portion of the IRP.

Q. Does the IRP demonstrate that the power that would be supplied by the RICE electric generation facilities is needed?

A. Yes, UMERC needs power from the UP Gen Project to supply its customers commencing in 2019 and beyond.

Q. Does the IRP show that the size, fuel type, and other design characteristics of the RICE electric generation facilities represent the most reasonable and prudent means of meeting that power need?

A. Yes, the IRP concludes that the UP Gen Project uses the right technology and fuel to provide energy to UMERC and is the most reasonable and prudent means available to meet UMERC's non-Tilden customers' power need.

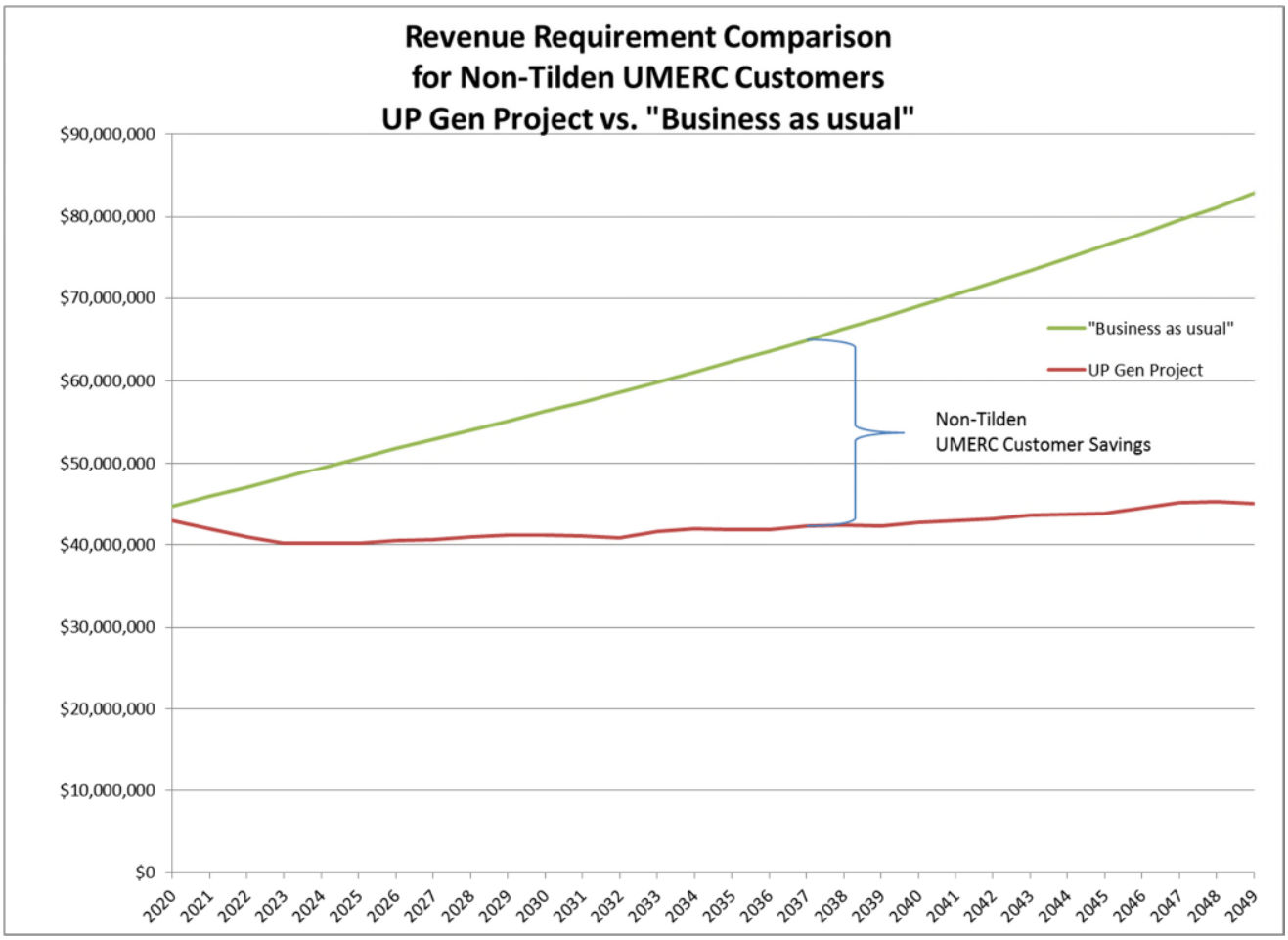
Q. Does the IRP show that the estimated cost of power from the RICE electric generation facilities is reasonable?

A. Yes, the IRP concludes that the UP Gen Project is the least cost plan, saving UMERC's non-Tilden customers $161 million in net present value over 30 years compared to the next best alternative.

Q. Can you summarize the results of the comparison between business as usual (using existing purchase power contracts) and the RICE units for the non-Tilden customers?

A. Yes. The RICE units provide a lower net present value of $161 million over a 30-year period for non-Tilden customers. Starting with the first full year in service (2020), and

each year going forward, the projected revenue requirement for the RICE units is lower cost than the forecasted revenue requirement for the PPAs. See the graph below for a comparison of these forecasted annual costs.

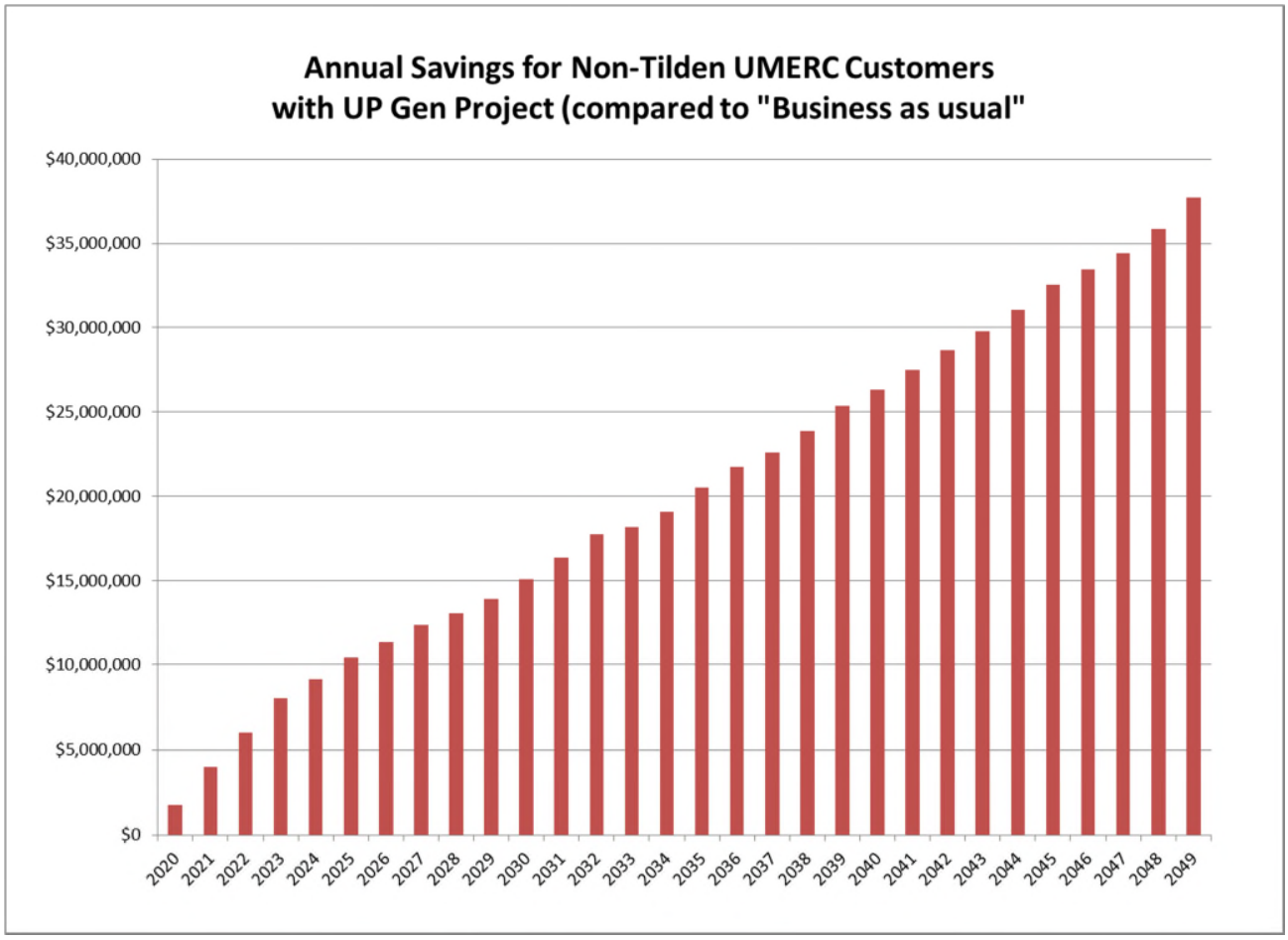


Graph 1

Q. What are the annual customer savings?

A. In the first full year of service, the savings is forecasted to be $1.8 million. This would represent an approximate savings for non-Tilden customers of 3.3% of the power supply costs (not including transmission) in business as usual scenario. See the graph below for the annual cost savings. These annual savings for non-Tilden customers significantly

increase over time as the revenue requirement of the RICE units is generally flat over this time period as the plant-in-service depreciates.



Graph 2

Q. Can you provide some background on the calculation of the forecasted PPA costs?

A. Yes. First, the forecasted demand and energy consumption for each rate zone was determined. These demand and energy values were then applied to the forecasted capacity and energy rates for the WEPCo and WPS Corp PPAs.

Q. Can you provide similar background on the derivation of the RICE units' revenue requirement for the non-Tilden customers?

A. Yes. The revenue requirement of the RICE units for the non-Tilden reflects the cost

allocations described in the testimony of Mr. James O. Sherman, Jr. The revenue requirement includes forecasted energy sales and purchases for the non-Tilden load, and the purchase of renewable energy credits to meet the Michigan RPS. The revenue requirement also includes a credit for forecasted sale of excess capacity, as well as ancillary services.

Q. Does the IRP show that the RICE electric generation facilities represent the most reasonable and prudent means of meeting the power need relative to other resource options for meeting power demand, including energy efficiency programs and electric transmission efficiencies?

A. Yes, the IRP considers all of the other options of meeting UMERC's energy needs, including energy efficiency programs and electric transmission efficiencies, and concludes that the UP Gen Project is the most reasonable and prudent means of meeting the power need.

Q. Was this IRP prepared prior to the development and negotiation of the Retail Large Curtailable Special Contract between WEC Energy Group, Inc. ("WEC Energy Group") and Tilden ("Tilden Special Contract"), which included the selection of RICE for the UP Gen Project?

A. No. The IRP was prepared after the Tilden Special Contract was signed in August 2016. As I will explain elsewhere in my testimony, the generation technology selected for inclusion into the Tilden Special Contract was driven by the reliability needs of the UP as well as costs and contract terms.

Q. In a traditional IRP, the projected need for capacity and energy can be met in a wide variety of ways with new generation or demand reductions added in a five-to-

ten-year time frame over a broad geographical area. Is the situation in the UP different and, if so, how do the differences affect the IRP?

A. There are several specific limitations to a UP generation solution. First, a UP generation solution must include a long-term arrangement with Tilden. Second, the UP is a "load pocket" unless or until transmission infrastructure is built to allow imports to fully serve the UP load including Tilden. Without new transmission, local loads must be supplied to a large extent from local generation. Because it is a load pocket, the UP load requires highly redundant and reliable generators. Third, the main base load plant located in the UP is PIPP, which WEPCo plans to retire when a new plant is built. Finally, the options for new generation in the UP are becoming limited because many UP solutions have been proposed in the last five years, but none have survived or been implemented. If the UP Gen Project is not built, it is likely that new transmission lines will be built.

Q. Why must a UP generation solution include a long-term arrangement with Tilden?

A. The UP electrical demand is dominated by the needs of the Cliffs' mining operations. When both Tilden and Empire iron ore mines (collectively, the "Mines") were in operation, they accounted for more than half of the annual electricity used in the entire UP. In 2016, the Empire mine closed. For the foreseeable future, the remaining Tilden mine will account for about 40% of the UP load. Tilden was supplied by an Alternative Energy Supplier from 2013 until returning to WEPCo in 2015.

Q. What is a load pocket?

A. A load pocket is an area where the local load must be served, at least in part, by local generation. They are usually associated with geographic isolation, such as with islands or peninsulas or huge cities with limited transmission import capability, like Manhattan. If

enough transmission import capability can be added, a load pocket can be eliminated. If not, the area must depend on local generation to maintain reliability.

Q. Why is the UP a load pocket?

A. As a peninsula, the UP has historically had to rely on local generation. It is interconnected to Wisconsin and, more recently, the lower peninsula of Michigan, but the transmission import capability from these interconnections remains limited.

Q. What kinds of local generation have served UP load?

A. The UP has a long history of "customer owned" generation. Numerous paper mills, mines, and municipalities in the UP have their own "behind the meter" generation including Mead, City of Marquette, Verso Corporation, and White Pine Mine, to name a few. More than 70% of UP generation was originally built by companies to self-serve their own energy needs, and there was limited coordination among customer-owned generation and the surrounding transmission system. Cliffs built and operated the PIPP units from 1955 until 1987, adding new units to match the growth of the mining operations. In the 1980s, iron ore mining in the UP nearly ended due to high inflation, high interest rates, low-cost imported ore, and Cliffs customer and partner bankruptcies. The sale of PIPP to WEPCo provided Cliffs with cash and lower energy costs while allowing WEPCo to meet growing electric demand at a reasonable cost.

Q. Please review the events in the UP which have shaped the current need for generation or transmission.

A. The Mines, WEPCo, and PIPP have been the focus of the following events in the last five years:

November 2012 WEPCo - PIPP: Joint venture with Wolverine Power Supply

	Cooperative announced, would have added $140 million in environmental controls to PIPP
September 2013	Mines chose Alternate Energy Supplier (announced in July 2013)
September 2013	WEPCo filed to suspend PIPP operations for 16 months
April 2014	WEPCo filed to retire PIPP, effective October 2015
January 2015	WEPCo announced proposal to sell WEPCo and future WPS Corp Michigan assets to Upper Peninsula Power Company ("UPPCO")
March 2015	Amended and Restated Settlement Agreement ("ARSA") in Case No. U-17682 signed
June 2016	Approvals requesting to establish UMERC filed
August 2016	WEC Energy Group signed special contract with Tilden for a 20-year agreement that includes building the UP Gen Project
December 2016	UMERC approved

Q. What customers are you planning for in this IRP?

A. The IRP is for UMERC customers, including Tilden. Tilden will become UMERC's customer after the UP Gen Project goes into operation on or about June 1, 2019. So specifically, this IRP is for UMERC customers after June 2019.

Q. What is the planning period covered by this IRP?

A. The planning period for the IRP is 30 years starting in 2019.

Load Forecasts

Q. Please describe the load forecast used to establish the amount of energy and demand to be served by UMERC.

A. Load and peak demand for UMERC is forecast to be flat – not growing or shrinking – from 2017 through 2026. For planning purposes, the growth rate in the latter years of the forecast is used to extrapolate energy and peak demand out 30 years. Since the forecast is flat, the extrapolation is flat. The details of the load forecast including the methodology and data used are described in Mr. Joel R. Gaughan's testimony.

Q. What reserve margin is assumed for UMERC?

A. A reserve margin is used to ensure adequate generation is available at peak demand. The MISO reserve margin requirement averaged 15.6% for the years 2017 – 2026 in the MISO's 2017 Loss of Load Expectation Study. This reserve margin was used throughout the planning period.

Project Timing and Need

Q. What is driving the timing of a UP solution?

A. The UP Gen Project is needed in about 2019 for these reasons:

- [begin confidential] [redacted] [end confidential].
- PIPP cannot retire until the UP Gen Project is on-line (since there are significant cost savings associated with PIPP retirement, the sooner PIPP can retire, the better)

If the UP Gen Project is not approved, the path to a UP solution becomes unclear, much like it was before the ARSA. The default or "business as usual" solution is to postpone retiring PIPP until sufficient transmission infrastructure is built, which is significantly more expensive to UMERC customers. New transmission infrastructure will cost $373 million with costs spread over all ATC customers in Michigan and Wisconsin. Thus,

generation solution is preferred by Michigan's Governor and agencies over the transmission solution.

Q. Does PIPP retirement eliminate the possibility of a PIPP SSR?

A. Yes, I expect MISO will approve the 2019 retirement of PIPP so long as the UP Gen Project begins operation before PIPP retires. Under current circumstances, we are not aware of a scenario where the UP Gen Project would need an SSR.

Demand Reduction Resources

Q. Are demand reduction resources a viable alternative to the proposed project?

A. No. As described in the IRP, load management and energy efficiency are not practical alternatives to fill 100-200 MW gaps in the supply portfolio of the UP by 2019. Tilden is effectively a very large load management customer since its entire load is non-firm. There are only 19 MW of other non-firm UMERC load. Energy efficiency cannot replace the UP Gen Project proposed in this proceeding because of the magnitude of the need (at least 95 MW in 2019) and the reliability and grid support required.

Q. Do the load forecasts in the IRP include existing and projected energy efficiency savings?

A. Yes.

Supply Resources - Renewables

Q. Are renewable resources viable supply alternatives to the UP Gen Project?

A. No. As described in the IRP, wind, solar, and solar with battery storage are not able to provide reliable energy in the amounts required during every hour of the year. If wind or solar generation were used to supply a significant portion of the 183 MW UP Gen

Project, the UP Gen Project would still be needed, in its entirety, to meet the reliability requirements of the UP.

Supply Resources – Gas Combined Cycle

Q. Are gas combined cycle units a viable supply alternative to the UP Gen Project?

A. HDR Engineering, Inc. ("HDR"), a Michigan engineering firm, has produced the "Northern Michigan Power Generation Technology Comparison" report ("HDR Report") which compares combined cycle and RICE technology choices in detail. The report also includes simple cycle technology and PIPP options. The study concludes that the proposed UP Gen Project, using RICE technology, is over 25% lower in Total Cost of Generation (sometimes referred to as "all-in" cost) than a pair of 2x1 combined cycle units. The HDR Report is described and supported by HDR witness Andrew W. Sutherland and the report is an exhibit to his testimony.

Q. What are some of the key assumptions made in the HDR Report?

A. The HDR Report is based on HDR's extensive experience and independent expertise. In the HDR Report, the generation technology costs are normalized for capacity and energy to make the project cost ($/kW) and cost of generation ($/MWh) comparable across the generation technologies. Specifically, the minimum capacity is 140 MW with two generating units out of service ("N-2" capacity in the report), which roughly corresponds to the UP Gen Project "N-2" capacity (183 MW minus 2@18MW = 147 MW). The energy output for each generation technology was set at about 0.9 million MWh to correspond to the UP Gen Project running at 55% capacity factor, which is within the range of the UP Gen Project capacity factors expected for the UP Gen Project (expected

range is 50 or higher).

Q. Does the HDR Report address the qualitative advantages of a RICE-based UP solution?

A. No. The HDR Report does not take into account the qualitative advantages of a RICE-based solution over combined cycle. First, the redundancy provided with ten RICE units is far greater than with a pair of 2x1 combined cycle units. One could argue that the pair of combined cycle units does not pass the "N-2" requirement since a planned outage of one unit and a subsequent outage of the remaining unit results in zero generation from the new plant. Second, the RICE technology is specified in the Tilden Special Contract. Third, a RICE plant is scalable since the engine modules come in 18 (or less) MW unit sizes. This makes "right sizing" the plant easier in the design phase. If more generation were required later, adding more RICE units is relatively straightforward and comes in smaller chunks than the 140 MW combined cycle units. Fourth, the right sized RICE plant will require less transmission infrastructure to interconnect the new plant to the grid.

Q. How does the HDR Report address MISO energy and capacity market revenues?

A. The HDR Report is based on estimated costs; it does not take into account estimated revenues from the sale of capacity or energy from each technology option. The capacity of the combined cycle option discussed by HDR is about 89 MW larger than the RICE option. Estimating the future value of an additional 89 MW of capacity is difficult because there is no index or futures market for MISO capacity, only a once-per-year auction for the next year's capacity. There is also a wide range of historical and possible future prices. UMERC has used a capacity value of about $60,000 per MW per year in

the Economic Analysis of Alternatives section in the IRP. Selling the additional 89 MW of combined cycle capacity at $60,000/MW/yr results in $5.3 million in annual capacity revenue.

Energy revenue can be estimated from the expected generation and the approximate net margin on energy sales. The HDR Report assumed 0.9 million MWh of energy generation. From WEC Energy Group's experience operating several large combined cycle units, UMERC estimates the net margin for combined cycle will be $5-7/MWh which accounts for the lower heat rate of the smaller combined cycle units, but a higher expected Locational Marginal Pricing ("LMP") in the UP compared to Wisconsin. Using these estimates, the net energy revenue for the combined cycle units of 0.9 million MWh times $6/MWh is about $5.4 million in net energy revenue per year. The RICE units' net margin is expected to be about half of the combined cycle unit net margin, so the difference in combined cycle versus RICE net revenues is about $2.7 million. The capacity and energy revenue advantages for combined cycle total about $8 million or $9/MWh. HDR's Options Comparison Table 1.0-1 has a Total Cost of Generation ($/MWh) of $73.78/MWh for the RICE option and $98.04/MWh for the combined cycle option. Subtracting $9/MWh from the combined cycle option to account for capacity and energy revenue differences results lowers the combined cycle $/MWh to $89/MWh. With these estimates, the expected Total Cost of Generation advantage of the RICE option over the combined cycle option becomes $16/MWh.

Q. How does the HDR Report address the cost of the Lakota-Winona 69-to-138 kV upgrade project?

A. The HDR Report includes the $100 million cost of the Lakota-Winona 69-to-138 kV upgrade project for all of the technology options that require the Lakota-Winona project to be built, namely, all of the options other than the UP Gen Project option. The $100 million cost will be paid for by all ATC customers in Michigan and Wisconsin. Its inclusion in the HDR Report is appropriate since the technology selection and, specifically, the UP Gen Project siting option has significant cost ramifications to a broad range of electric customers. In the IRP economic analysis, the focus is on UMERC costs, so only UMERC's small (about 1%) share of the $100 million costs is included. For comparison purposes, using the HDR Report methodologies, the $100 million total cost is about a $10.5 million annual cost or about $12/MWh.

Q. Please summarize your interpretation of the HDR Report.

A. To summarize, various adjustments and caveats could be applied to the HDR Report. Even if one was to assume that the RICE and combined cycle technologies had approximately equal cost to UMERC, the RICE technology remains the superior choice for two primary reasons. First, the proposed combined cycle configuration is inadequate to maintain reliability in the UP. Second, the Tilden Special Contract, which is a prerequisite to any UP generation solution, specifies RICE technology.

Supply Resources – Existing Resources (PIPP)

Q. Is PIPP a viable supply alternative to the UP Gen Project?

A. Yes, at least until planned transmission infrastructure goes into service in the mid-2020s or until new environmental regulations require costly investments. The PIPP units were built in 1974 to 1979, have high O&M costs, and may require additional capital

investments to address equipment condition problems as they arise and to comply with environmental regulations. If needed, PIPP could be run until 2025 and then retire. "PIPP then transmission" is the default "business as usual" or "do nothing" alternative in the IRP.

Q. Why do you assume PIPP runs until 2025?

A. WEPCo would like to retire PIPP as soon as an alternative is available. If the UP Gen Project is not built, the next opportunity to retire PIPP will come when the Plains-National plus Morgan-Thunder-Plains project goes into service.

Q. Are there any other existing supply resources to consider?

A. No. There are no other generating units over 20 MW anywhere near Tilden or PIPP.

Supply Resources – Transmission

Q. Is new or existing transmission infrastructure a viable alternative to the UP Gen Project?

A. Yes, in combination with postponing PIPP retirement until 2025.

Q. Please describe the history of new transmission infrastructure construction in the UP.

A. Building new transmission infrastructure (transmission lines, substations, and associated equipment) has been considered as an alternative to new and existing generation, in and around the UP, for decades. Many new transmission facilities have been built in the last 20 years, including Central UP project, Northern Umbrella project (transmission lines around Green Bay), HVDC lines at the Straits of Mackinac, and some of the Bay-Lake projects. Nonetheless, the UP is still not able to fully rely on energy imports to meet UP

load. This has led to a preference, both historically and currently, for generation installed in the UP to meet reliability rather than more transmission projects.

Q. Despite considerable transmission infrastructure additions to the UP, have there been large blackouts in the UP?

A. Yes, there have been three significant events affecting the UP in November 2001, December 2003, and May 2011.[1] These events also support the preference for generation solutions.

Q. What transmission projects has MISO proposed that would allow PIPP to retire?

A. MISO has received internal approval to proceed with the Plains-National 138kV line project estimated at $273 million, with a projected in-service date of December 2023 (but modeled as January 2025). The Plains-National project is designed to allow PIPP to retire, while maintaining reliability in the UP through energy imports and the existing small generators in the UP. The Plains-National project is currently on hold at MISO pending approval of the UP Gen Project. If the UP Gen Project is approved, the Plains-National project will be suspended or cancelled.

Q. What other transmission project would be affected by the UP Gen Project?

A. The need for the Lakota-Winona 69-to-138 kV upgrade project is directly affected by the UP Gen Project. The Lakota-Winona project consists of one 69kV refurbishment project and a 69-to-138 kV upgrade project. By locating a portion of the UP Gen Project near the M-38 substation, the 69-to-138 kV upgrade estimated at $100 million will be

[1] November 14, 2001 event: An unknown cause tripped a 138 kV line north of Green Bay, Wisconsin, causing 900-1000 MW of load to be islanded, with 100 MW of industrial load being lost, and causing a trip in another line, affecting 60 MW in distribution load.

December 4, 2003 event: a system blackout resulted in a loss of 650 MW of load.

May 10, 2011 event: a lightning strike took out a 138 kV transmission line resulting in a blackout affecting two-thirds of the UP for 12 to 16 hours.

unnecessary.

Supply Resources – Other Supply Resource Options

Q. Are there other supply resource options?

A. Yes, everything from new nuclear power plants and new coal units to offshore wind and solar thermal power plants are on the long list of possible options.

Q. Are any of the other supply options viable alternatives to the UP Gen Project?

A. No, the practical alternatives have already been addressed in my testimony and in the IRP and represent the mainstream supply planning alternatives. The HDR Report also considers the most reasonable supply alternatives.

Fuel Prices

Q. What fuel prices are used in the IRP?

A. Fuel price forecasts affect both the cost of energy produced from the gas-fueled supply options but also the price of energy (Locational Marginal Prices or LMP) in MISO and the UP. Gas prices in the IRP are based on the November 9, 2016, NYMEX Henry Hub futures prices for the next three years and then assumed to grow at general inflation. Coal prices are based on ABB PROMOD data. WEPCo and WPS Corp plant-specific fuel prices are based on contracts in hand and near-term forecasts. Coal prices are escalated at the same general inflation rate as gas prices. The IRP uses the same fuel price forecast methodology as used in WEPCo and WPS Corp PSCR cases filed with the MPSC in September 2016.

Base case: Gas: $3.04/mmBtu (average annual price); Coal: $1.80 to $2.80/mmBtu (varies by plant).

Environmental Regulations, Costs and Constraints

Q. How does the IRP address current and future environmental costs and constraints?

A. The IRP focuses on the environmental costs and constraints associated with continued PIPP operation beyond 2019, the effect of the CSAPR Update (CSAPR 2) and the Clean Power Plan. Other environmental issues affecting existing plants outside of the UP will have only minor effects on the comparison of alternatives and, more importantly, will have the same effect on all UP alternatives. The environmental permits necessary to construct and operate the UP Gen Project are described in Laura M. Jarmuz's and Susan M. Schumacher's testimony. The annual environment costs for the UP Gen Project are included in the IRP Economic Analysis of Alternatives section.

Legislation

Q. Are there any likely or expected legislative or administrative changes that may impact the IRP?

A. The Michigan Legislature recently passed 2016 PA 341 and 342, and some of its new provisions are addressed in the IRP. I am not aware of any other likely or expected legislative or administrative changes that may impact the IRP.

Planning Process and Modeling

Q. Please describe the planning process and the models used in the IRP.

A. As stated elsewhere in my testimony, the IRP was developed after the Tilden Special Contract was signed in August 2016. The modeling methodology used in this IRP is to combine PROMOD fuel cost and energy price results with all other annual cost and revenue calculations, and then combine with one-time investment costs into a revenue requirements spreadsheet, which calculates and compares the net present value of revenue requirements (NPVRR) for UMERC for the proposed project and the "business as usual" alternative.

PROMOD is a widely-used hourly production cost model which accounts for transmission system operating limits, generating unit fuel costs and operating profiles and customer load in calculating hourly prices (LMP). WEPCo and WPS Corp use PROMOD for their annual fuel cost filings in Michigan and Wisconsin. Typically, and in this IRP, PROMOD is configured to model the load, generation, and transmission in MISO and PJM. The PROMOD runs capture the annual dispatch costs and revenues for the two alternatives, including generator and load LMPs and energy production or consumption in MWh on an hourly basis. PROMOD is also used to evaluate the gas price and CO2 scenarios and their relative effect on UMERC for each alternative.

Other variables such as financing costs (depreciation, return, taxes, etc.), fixed O&M, and capacity market prices are incorporated into the NPVRR spreadsheet.

Q. Why did you choose PROMOD and an NPV approach instead of EGEAS or other general purpose IRP tools?

A. The general purpose IRP tools sometimes used to perform IRP analyses, including EGEAS, Strategist and MIDAS (all of which have been used by WEPCo or WPS Corp in the past), have serious drawbacks when applied to UMERC and the UP compared to the PROMOD plus NPVRR model approach. General purpose IRP tools do not capture the workings of the MISO energy market because they are not hourly, nodal or transmission aware which are important in general but especially in the UP where location and transmission are very important. General purpose IRP tools are also intended to sort through thousands of generation option combinations in reasonable time so they use analytical shortcuts which speed up each iteration. Since there are relatively few options and no combinations of alternatives, we have time to use PROMOD and get a more accurate result and comparison of alternatives.

Q. How does the use of the NPVRR analysis work?

A. The financing and other costs associated with the construction and operation of the UP Gen Project that would be allocated to the non-Tilden UMERC customers in accordance with the Tilden Special Contract were evaluated to determine the annual base revenue requirements for the non-Tilden UMERC customers over a 30-year period. The cost of purchasing energy from the MISO energy market, and the revenue associated with selling capacity, energy, and ancillary services from the UP Gen Project into the MISO energy market that benefits the non-Tilden UMERC customers, was then evaluated to determine the net energy costs associated with serving the non-Tilden customers over a 30-year period. The total annual base revenue requirement cost and energy cost was then compared to the total projected cost associated with serving the non-Tilden UMERC

customers under the two full requirements PPAs. The difference in costs represents the difference in the Power Supply Charges that the non-Tilden UMERC customers would expect when the UP Gen Project replaces the two PPAs.

Q. Does this analysis account for transmission costs?

A. Yes. The base network transmission charge that will apply to the non-Tilden UMERC customers would be the same whether the customers were served by the UP Gen Project or the PPAs; however, the avoided transmission infrastructure costs of $373 million, less the UP Gen Project transmission interconnection costs, represent incremental savings to the non-Tilden UMERC customers. In the NPVRR, a net avoided transmission infrastructure investment of $300 million was used.

Q. Were any other costs included in the NPVRR analysis?

A. Yes. The analysis includes the impact of the 6.595% allocation of the PIPP retirement costs to UMERC as agreed to in the Settlement Agreement for Case No. U-18061.

Results

Q. What are the results of the Economic Analysis?

A. The Economic Analysis concludes that the UP Gen Project is $161 million lower in cost (net present value over 30 years) than the "business as usual" case. The key drivers in the economic analysis are the costs of the PPAs with WEPCo and WPS Corp which in the "business as usual" case continue through the 30-year forecast period and the net cost to the non-Tilden UMERC customers of building, operating and maintaining the UP Gen Project and buying or selling energy to meet customer's energy requirements in accordance with the cost allocations as contemplated in the Tilden Special Contract. The

cost of energy from the UP Gen Project is significantly lower than the cost of energy from PIPP.

Uncertainty and Sensitivity Analysis

Q. What sensitivities are analyzed in the IRP?

A. The purpose of sensitivity analyses is to check the robustness of the least cost plan if key assumptions turn out to be wrong. The two primary sensitivities performed in this IRP are higher gas prices and CO2 emission limits from the CPP.

Q. What are the results of the Sensitivity Analysis?

A. The "Gas + $1" scenario shows the effect of increased gas prices on both the "business as usual" and UP Gen Project cases. In both cases, the energy price (LMP) increases due to higher gas costs. In the "business as usual" case, the PPAs are more expensive than the base case. In the UP Gen Project case, the RICE units run less and energy purchases from the MISO energy market increase at the higher LMP, which increases costs compared to the base case. With higher gas prices, the UP Gen Project is still $118 million lower in NPV costs than the "business as usual" alternative.

Proposed Course of Action

Q. What is the proposed course of action?

A. The proposed and least cost course of action is to build the UP Gen Project.

Q. Describe the effect of the proposed project on wholesale market competition.

A. The proposed project will have no effect on wholesale market competition. The proposed project is located in the MISO energy market which includes over 140,000

MW of generation. The proposed project is 183 MW. With the formation of UMERC, the addition of the UP Gen Project, in combination with the retirement of PIPP, reduces the amount of UP generation owned by WEC Energy Group utilities.

Q. Does that conclude your testimony?

A. Yes.

2016 Integrated Resource Plan for Upper Michigan Energy Resources Corporation Beginning in 2019

1. Introduction/Overview

An integrated resource plan ("IRP") is a utility plan for meeting forecasted annual peak and energy demand, plus some established reserve margin, through a combination of supply-side and demand-side resources over a specific future period[1]. This IRP is prepared in accordance with the Michigan Public Service Commission's "Filing Requirements and Instructions for Certificate of Public Convenience and Necessity Application" ("CON Filing Requirements"). This IRP is focused on the newly formed Upper Michigan Energy Resources Corporation ("UMERC") utility and the resource options available in the Upper Peninsula of Michigan ("UP") over the next 20-30 years.

As explained in detail in this IRP, the unique generator reliability situation in the UP results in a significant narrowing of the IRP options available to serve UMERC and its customers in the UP. This results in a "situational IRP" which demonstrates that the most reasonable and prudent solution is also a least cost solution that provides economic benefits, improved reliability and a reduced environmental footprint for UMERC and the UP.

This IRP concludes that gas-fueled reciprocating internal combustion engine ("RICE") electric generation facilities in multiples of up to 18 megawatts ("MW") each, referred to herein as the "UP Gen Project" or "the Project", is $161 million lower in cost (net present value) than the next lowest cost alternative, the "business as usual" approach (*i.e.*, run the Presque Isle Power Plant ("PIPP") until transmission can be built to replace PIPP). The key drivers in the economic analysis are the costs of UMERC's power purchase agreements ("PPAs") with Wisconsin Electric Power Company ("WEPCo") and Wisconsin Public Service Corporation ("WPS Corp"), which in the business as usual case continue through the 30-year forecast period and the net cost to UMERC of building, operating and maintaining the UP Gen Project and buying or selling energy to meet its customers' energy requirements.

The UP electrical demand is dominated by the needs of the Tilden Mining Company L.C.'s ("Tilden") mining operations. The UP also has a long tradition of industries self-supplying their electrical needs – Cliffs and Upper Peninsula Power Company ("UPPCO") formed a partnership (Upper Peninsula Generation) which built and operated the PIPP units from 1955 through 1987. At the time the units were sold to WEPCo on January 1, 1988, Cliffs owned approximately 83% of the PIPP generating assets and UPPCO owned approximately 7%. Numerous paper mills, mines and towns in the UP have their own "behind the meter" power plants including Mead, City of Marquette, Verso Corporation, and White Pine Mine, to name a few.

[1] From "Best Practices in Electric Utility Integrated Resource Planning", Synapse Energy Economics, June 2013.

When both the Tilden and Empire iron ore mines were in operation, they accounted for more than half of the annual electricity used in the entire UP. In 2016, the Empire Mine closed. For the foreseeable future, Tilden will account for about 40% of the entire UP load. Tilden is an energy-only customer – its entire load is curtailable to zero in an emergency. Tilden is also a very steady load – it has a high load factor – and does not vary seasonally.

Tilden changed energy suppliers in 2013, and then returned to WEPCo full requirements service in 2015. Any long-term generation solution in the UP must include an agreement with Tilden to be viable. On August 12, 2016, WEC Energy Group, Inc. ("WEC") signed a Retail Large Curtailable Special Contract with Tilden ("Tilden Special Contract"), which is a long-term agreement that is predicated on the UP Gen Project being built. The Tilden Special Contract has been assigned to UMERC and UMERC will service Tilden pursuant to the Tilden Special Contract.

UMERC is located in the middle part of the UP with UPPCO, Cloverland Electric Cooperative, and other smaller municipal utilities as neighbors. While there is some hydro generation, the UP does not have any large base load type generation other than PIPP (344 MW). Tilden and PIPP are in a load pocket, which means the local load is served with local generation. Load pockets are rare in the United States and are usually associated with geographic isolation, such as islands or peninsulas, or huge cities with limited transmission import capability, like Manhattan. Load pockets need local generation to maintain reliability. New transmission import capability can eliminate a load pocket.

Transmission is also a key part of serving load in the UP. The amount of new and upgraded transmission needed to maintain reliability in the UP is either: A) two large new transmission projects with an estimated cost of $373 million if the UP Gen Project is not built; or B) the UP Gen Project without this new transmission.

The proposed UP Gen Project uses gas-fueled RICE electric generation facilities in multiples of up to 18 MW each. The original interest in the RICE technology was to offer an alternative to transmission projects by locating RICE machines at various weak points in the transmission system. RICE unit efficiency improvements make the machines attractive to the regional energy market at current and expected gas prices.

PIPP is currently needed for reliability. WEPCo, the owner and operator of PIPP, will request to retire PIPP as soon as the proposed UP Gen Project goes into service. Retiring PIPP will result in both cost savings and environmental benefits.

New generation can be built to avoid transmission, but the new generation must be highly reliable since it will be the only generation in the UP available to serve Tilden and the UP most of the hours of the year. The retiring PIPP has five units which provide the needed redundancy to ensure reliability in the UP. Reliability planners want sufficient resources to serve load even if there is one unit planned to be out of service (for an annual maintenance outage, for instance)

and another unit forced out of service due to equipment failure or other breakdown. In the past, the five-unit PIPP would have three units available even if one unit was on planned outage and one unit was forced out of service. The ten-unit UP Gen Project also easily meets this reliability criterion – with eight units available even if one unit is on planned outage and one unit is forced out of service.

The primary technology alternative to gas RICE units is gas combined cycle units. Modern combined cycle units are typically about 700 MW and have two combustion turbines and one steam turbine generator (a 2x1 configuration[2]). Clearly, 700 MW is much more than is required to meet a 100-200 MW need. Also, the redundancy requirement in the UP does not allow such a plant configuration since a planned or forced outage of the lone steam turbine would leave the UP short of generation to serve load. A report entitled "Northern Michigan Power Generation Technology Comparison" from HDR Engineering, Inc. ("HDR") concludes that the proposed UP Gen Project using RICE technology is over 25% lower in Total Cost of Generation (sometimes referred to as "all-in" cost) than a pair of 2x1 combined cycle units.

The size of the UP Gen Project (183 MW) works well for several reasons. The Tilden Special Contract requires approximately this amount of capacity. UP reliability benefits from a few extra RICE units. Recent MISO studies have required about 95 MW to serve the UP without PIPP. UMERC believes that 183 MW will be sufficient in MISO's current reliability studies. UMERC has about 96 MW of load responsibility (including reserves) which is covered by the UP Gen Project with some allowance for future load growth.

2. Summary

The IRP economic analysis concludes that the UP Gen Project is significantly lower in costs (about $161 million net present value ("NPV") over 30 years) than the "business as usual" alternative (continued WEPCo and WPS Corp PPAs, delayed retirement of PIPP, expensive transmission in about 2025). The UP Gen Project is $123 million lower in NPV cost even if gas prices are $1.00/mmBtu (33%) higher than current projections. The UP Gen Project is also lower in cost than "business as usual" if CO2 is monetized in the future.

3. Load Forecast

The load forecast for UMERC is flat for both energy (MWh) and peak demand (MW, firm) (Table IRP-1). In Table IRP-1, the energy and demand forecasts for 2017 and 2018 are divided into the two rate zones, the WEPCo Rate Zone ("UMERC-WE") and WPSC Rate Zone ("UMERC-WPS"). In 2019, the load forecasts assume the UP Gen Project goes into service on June 1, 2019, at which time Tilden becomes a UMERC customer and the two rate zones are merged. The first full year of combined UMERC load (Tilden, UMERC-WE and UMERC-

[2] For combined cycle plants, 2x1 refers to 2 combustion turbine (CT) with 1 steam turbine. 3x1 is three CTs with one steam turbine, and so forth.

WPS) is 2020. This load forecast extends through 2026. For planning purposes, the load is assumed to continue to be flat for the rest of the planning period.

Table IRP-1: Load and Peak Demand Forecast

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
UMERC-WE											
	Residential	164,258	165,115	69,423	0	0	0	0	0	0	0
	Small C&I	109,443	108,863	44,011	0	0	0	0	0	0	0
	Large C&I	86,959	86,847	36,182	0	0	0	0	0	0	0
	Street Lighting & Other Retail	2,247	2,247	945	0	0	0	0	0	0	0
	Total Retail	362,907	363,072	150,560	0	0	0	0	0	0	0
	Company Use	1,970	1,970	891	0	0	0	0	0	0	0
	Losses	22,351	22,374	9,290	0	0	0	0	0	0	0
	Total	387,228	387,416	160,740	0	0	0	0	0	0	0
UMERC-WPS											
	Residential	64,629	64,409	27,039	0	0	0	0	0	0	0
	Small C&I	27,165	27,294	11,419	0	0	0	0	0	0	0
	Large C&I	161,114	161,113	67,532	0	0	0	0	0	0	0
	Street Lighting & Other Retail	766	766	325	0	0	0	0	0	0	0
	Total Retail	253,674	253,582	106,315	0	0	0	0	0	0	0
	Losses	12,668	12,664	5,309	0	0	0	0	0	0	0
	Total	266,342	266,246	111,624	0	0	0	0	0	0	0
UMERC-Total											
	Residential	228,887	229,524	229,501	229,030	228,761	228,729	228,697	228,665	228,634	228,602
	Small C&I	136,608	136,157	136,276	136,582	136,927	137,195	137,470	137,746	138,024	138,301
	Large C&I	248,073	247,960	933,923	1,421,156	1,417,950	1,417,870	1,417,789	1,420,914	1,417,628	1,417,548
	Street Lighting & Other Retail	3,013	3,013	3,013	3,013	3,013	3,012	3,012	3,012	3,011	3,011
	Total Retail	616,581	616,654	1,302,713	1,789,781	1,786,651	1,786,806	1,786,968	1,790,338	1,787,297	1,787,462
	Company Use	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970
	Losses	35,019	35,038	51,642	63,428	63,361	63,376	63,391	63,483	63,421	63,436
	Total	653,570	653,662	1,356,325	1,855,179	1,851,983	1,852,152	1,852,329	1,855,791	1,852,689	1,852,869

		Firm Peak Demand		
		UMERC-WE	UMERC-WPS	UMERC-Total
		MW	MW	MW
2017		55	28	83
2018		55	28	83
2019		0	0	83
2020		0	0	83
2021		0	0	83
2022		0	0	83
2023		0	0	83
2024		0	0	83
2025		0	0	83
2026		0	0	83

Note 1: 2019 load and demand assume Tilden becomes UMERC customer on June 1, 2019 when the UP Gen Project goes into service.

UMERC inherited the WEPCo and WPS Corp RAS customers and is now well over 10% its average load. Existing RAS customers are allowed to remain RAS customers. UMERC has sufficient resources with or without the UP Gen Project to accommodate any RAS customers which return to UMERC.

4. Reserves and Reliability

The reserve margin assumed for this IRP is 15.6% based on the most recent MISO capacity reserve margin projections. The peak demand plus reserves is 96 MW (83 MW times 1.156) throughout the planning period. In a more typical IRP, the resource requirement would be 96 MW. In the UP, the resource requirement is driven by reliability and redundancy requirements and is dependent on the technology selection. For the proposed RICE-based UP Gen Project, the resource requirement is also driven by the Tilden Special Contract which specifies 183 MW of RICE-based generation.

When PIPP retires, new generation will be required to serve UMERC demand and energy needs. The new generation must be configured to provide redundancy to maintain reliability. Prior to Empire closing, PIPP satisfied this redundancy requirement by having five units of either 55 or 78 MW. This allowed three units to be available even with one unit planned to be out of service (for an annual maintenance outage, for instance) and another unit forced out of service due to equipment failure or other breakdown.

In 2014, MISO studied the minimum amount of generation that would be required if Empire closed and the North Appleton-Morgan 345 kV and 138 kV lines were installed[3]. The study concluded that 95 MW would be required to maintain reliability assuming no other new transmission lines were built. The Empire Mine closed in 2016. The North Appleton-Morgan lines are expected to be in-service in late 2018. Completion of North Appleton-Morgan provides the opportunity to retire PIPP and replace it with a smaller, more cost effective and more environmentally-friendly alternative.

MISO will study the reliability of the UP Gen Project combined with PIPP retirement with the expected 2019 transmission infrastructure as part of the UP Gen Project interconnection study. For IRP purposes, it is assumed that the MISO interconnection study will conclude that the UP Gen Project combined with PIPP retirement meets the reliability requirements in the UP.

5. Demand-Side Management: Load Management and Energy Efficiency

a. Load Management

Load management refers to curtailable and interruptible customer load and is also referred to as non-firm load. Tilden will be the biggest, but not the only, non-firm customer of UMERC. The

[3] MISO's Presque Isle Power Plant Generator Replacement Screening Study, published September 26, 2014.

entirety of the Tilden load is non-firm because it can be curtailed to zero MW in an emergency and certain non-emergency circumstances[4]. Other UMERC customer non-firm load totals 19 MW. UMERC customers have had the opportunity to become curtailable or interruptible customers under WE and WPS rate tariffs for many years. For planning purposes, the IRP assumes no change in non-firm load.

b. Energy Efficiency

On October 6, 2008, Governor Jennifer Granholm signed into law Public Acts 286 and 295. Subpart "B" of Part 2 of Act 295 concerns energy optimization ("EO"), and requires, among other things, the filing with the Commission of EO plans by each electric provider. With the passage of Public Act 342 of 2016, EO plans are now referred to as "waste reduction plans".

The overall goal of a waste reduction plan is to reduce the future costs of provider service to customers. Waste reduction plans are to be "designed to delay the need for constructing new electric generating facilities and thereby protect consumers from incurring the costs of such construction." 2016 PA 342, § 71(2).

Section 91 of PA 295, as amended, created an option for electric and natural gas providers to offer EO/waste reduction services through a program Administrator selected by the Commission. To fund the program, which is administered by Efficiency United, the Administrator is paid directly by the participating providers using funds collected from customers via a Commission-approved surcharges on utility bills. Both WEPCo and WPS Corp have met their Act 295 obligation by utilizing the independent EO Administrator option since 2009.

WPS Corp has filed and received approval from the MPSC for four EO plan cases. The most recent filing, Case No. U-17776, was approved by the MPSC on September 10, 2015 for plan years 2016 and 2017. The surcharges currently in place for WPS Corp customers are intended to annually collect an amount equal to 2% of 2015 WPS Corp retail electric revenues in Michigan that is to be paid to the EO Administrator.

WEPCo has filed and received approval from the MPSC for four EO plan cases. The most recent filing, in Case No. U-17777, was approved by the MPSC on October 27, 2015 for plan years 2016 and 2017. The surcharges currently in place for WEPCo customers are intended to annually collect an amount equal to 2% of 2015 WEPCo retail electric revenues in Michigan that is to be paid to the Administrator. UMERC expects to continue to make payments to the Administrator, based on 2% of utility sales revenues for the foreseeable future.

Efficiency United reports that it has saved 151,000 MWh for the combined WPS Corp and WEPCo legacy Michigan electric service territories for the time period of 2009-2015. The EO plans for WPS Corp and WEPCo have been adopted by UMERC for 2017. Energy efficiency

[4] Curtailment is to contracted Planning Load level which is currently zero MW.

will continue to be provided by Efficiency United in the UMERC service territory and similar continued energy savings are expected.

The load forecasts in this IRP include the energy savings from the on-going EO/waste reduction plans.

Energy efficiency cannot replace the UP Gen Project because of the magnitude of the need (at least 96 MW in 2019) and the reliability and grid support required.

6. Supply Options

While a full range of supply options are considered in an IRP, the situation in the UP and for UMERC limits the viable options. To be considered a reasonable supply option, the generation must be able to provide reliable energy and capacity to UMERC after PIPP retires. This will require at least 96 MW of capacity starting in 2019 with consistent energy production throughout the year with two generating units out of service.

a. Solar

New solar construction is able to provide energy and capacity only during the day. To make up for this limitation, a new plant like the UP Gen Project would be required to back up the solar generation. Since the UP Gen Project is needed in addition to solar, the least cost plan is to build the UP Gen Project without new solar.

While not part of the least cost plan, solar is a complementary generation source with the UP Gen Project plant since RICE machines are able to start, stop and change load quickly to offset changes in solar generation.

b. Solar with battery backup

Theoretically, if enough batteries were installed to store solar energy during the day and discharge it at night during or during cloud cover, the combination of solar plus batteries could be an option. Practically, even without considering cost, a rough estimate of the amount of energy storage required would include weeks, if not months, of at least 50 MW per hour to cover the winter months when solar generation is limited due to cloud cover and fewer daylight hours. Storing 50 MW around the clock for just two weeks is 17,000 MWh which is far greater than the largest US battery installation. Solar with battery storage is therefore not a viable alternative.

c. Wind

Wind generation could provide energy for roughly 30-40% of the hours in the years. Wind would be expected to contribute only 10-20% of its rated capacity towards meeting peak demand, particularly in the summer when hot weather tends to be associated with low wind speeds. To make up for this limitation, a new plant like UP Gen Project would be required to

back up the wind generation. Since a new plant like the UP Gen Project is needed in addition to wind, the least cost plan is to build the UP Gen Project without wind generation.

While not part of the least cost plan, wind is a complementary generation source with the UP Gen Project since RICE machines are able to start, stop and change load quickly to offset changes in wind generation.

d. Distributed Generation

Distributed generation refers to small, modular generators that are distributed as needed across a utility service area or at individual customer locations. Distributed generation can be used to defer or eliminate new transmission projects if the generation is located in the right locations. Wind and solar are often considered distributed generation. RICE machines are also considered distributed generation. The UP Gen Project is a utility-scale distributed generation project. The UP Gen Project is located in the right locations to eliminate the need to build $373 million of new transmission infrastructure. Smaller scale distributed generation or customer-owned and sited distributed generation would reduce the non-mine load somewhat but would do nothing to offset the mine load. While distributed generation cannot replace the UP Gen Project, RICE machines are a complimentary resource to smaller distributed generation. In any event, UMERC is not aware of any planned distributed generation that would reduce projected load.

e. New Transmission Infrastructure with Market Energy and Capacity Purchases

Building new transmission infrastructure (transmission lines, substations and associated equipment) has been considered as an alternative to new and existing generation in and around the UP for decades. Many new transmission facilities have been built in the last 20 years, including the Central UP project, Northern Umbrella project (several transmission line projects around Green Bay), HVDC lines at the Straits of Mackinac, and some of the Bay-Lake projects. Nonetheless, the UP is still not able to fully rely on energy imports to meet UP load. This has led to a preference, both historically and currently, for generation installed in the UP to meet reliability rather than more transmission projects.

MISO has proposed and received internal approval to proceed with a package of projects which includes a new Plains-National 138kV line and a new Morgan-Thunder-Plains 345 kV line, as well as related substation upgrades[5]. The package of projects is estimated to cost $273 million

[5] The package of projects consists of:

- MISO Project ID 8071 (New Plains – National 138kV, $124.6M, In-service 12/2023)
- MISO Project ID 8073 (Plains – Marquette Area Reinforcement Project - Plains – Arnold 138kV uprate, Install 2nd 345/138 transformer at Plains, Upgrade existing 345/138 transformer, $43.7M, In-service 12/2023)
- MISO Project ID 8076 (New 138kV line from Morgan – Thunder, Convert High Falls - Crivitz from 69kV to create Thunder-Crivitz 138kV, Create new Thunder – Plains 345kV line, Create new Morgan – Thunder 345kV line, Install new 138/69 kV transformer, Install new 345/138 kV transformer, $105M, In-service 12/2023)

with a projected in-service date of December 2023. In the Economic Analysis, the new transmission lines are assumed to be a year late (in service in 2025) since the projects will likely be on hold for another year due UP Gen Project licensing. The Plains-National plus Morgan-Thunder-Plains project is designed to allow PIPP to retire while maintaining reliability in the UP with power imported from outside of the UP and the existing small generators in the UP. The Plains-National plus Morgan-Thunder-Plains project is currently on hold at MISO pending UP Gen Project approvals. If the UP Gen Project is approved, the Plains-National plus Morgan-Thunder-Plains project will be cancelled.

While not a supply alternative to the UP Gen Project, the need for the Lakota-Winona 69-to-138 kV upgrade project[6] is directly affected by the Project. By locating a portion of the UP Gen Project near the M-38 substation, the Lakota-Winona upgrade estimated at $100 million will be unnecessary.

For this IRP, new transmission estimated at $373 million is both a supply alternative if the UP Gen Project is not built and an avoided cost if the UP Gen Project is built. The life cycle cost comparison of transmission versus the UP Gen Project is described and quantified in the Economic Analysis of Alternatives section.

f. Purchased Power (without new transmission)

Load pockets such as the PIPP-mines area need local generation to serve local load. Power purchased from outside of the PIPP-mines area cannot reach the PIPP-mines area due to transmission import limits. MISO's 2014 study concluded that at least 95 MW of generation must be located near the Tilden and Empire mines if PIPP is retired. Purchased power is therefore not a viable option.

g. Combined Cycle Units

In many locations, big efficient combined cycle units would be the technology competing with RICE units, but the UP presents a different situation. Modern combined cycle units are typically about 700 MW and have two combustion turbines and one steam turbine generator (a 2x1 configuration[7]). Clearly, 700 MW is much more than is required to meet a 100-200 MW need in the UP. The redundancy requirement in the UP is the big obstacle to combined cycle technology competing directly with RICE units. As described earlier in this IRP, a single 2x1 combined cycle plant configuration does not meet the reliability and redundancy requirement since a planned or forced outage of the lone steam turbine would leave the UP short of generation to serve load.

[6] MISO Project ID 8089 (Lakota – Winona convert from 69kV to 138kV, $100M, in-service 12/2021)
[7] For combined cycle plants, 2x1 refers to 2 combustion turbine (CT) with 1 steam turbine. 3x1 is three CTs with one steam turbine and so forth.

HDR, a Michigan engineering firm, has produced a "Northern Michigan Power Generation Technology Comparison" ("HDR Report") which compares combined cycle and RICE technology choices in detail. The report also includes simple cycle technology and PIPP options. The study concludes that the proposed UP Gen Project using RICE technology is over 25% lower in Total Cost of Generation (sometimes referred to as "all-in" cost) than a pair of 2x1 combined cycle units.

h. Continue to operate PIPP (See "Existing Resources" section)

Continuing to operate PIPP until new transmission goes into service in 2025 is a supply option and is described in the Existing Resources section, and is analyzed in the Economic Analysis of Alternatives section.

i. Energy purchased or produced pursuant to a Renewable Portfolio Standard

As discussed above, renewable energy is not a viable alternative to the UP Gen Project. As the UP Gen Project will meet UMERC's customers' requirements, UMERC does not contemplate purchasing any renewable energy or capacity. UMERC will likely meet its renewable portfolio requirements under 2008 PA 295, as amended by 2016 PA 342, by purchasing renewable energy credits ("RECs"). UMERC expects RECs to be available for less than $5/MWh, much lower in cost than new wind, solar, biomass, hydro or other renewable energy projects.

j. The proposed UP Gen Project

The proposed UP Gen Project is the least cost supply alternative. The Project is described in detail in several other sections including:

- Relevant costs and project parameters such as heat rate and unit capacity are detailed in the Economic Analysis of Alternatives section.
- Full description of the Project is found in the testimony and exhibits of Mr. Carroll.

The UP Gen Project meets the redundancy requirement for generation in the UP. The Project consists of ten generating units. If there are two UPGen RICE units out of service, the Project can still supply 80% of its rated generation or 146 MW. The Project is located at two separate locations which adds geographic separation, which increases reliability and eliminates the need for multiple new transmission projects.

7. <u>Fuel Prices</u>

Fuel price forecasts affect both the cost of energy produced from the gas-fueled supply options, but also the price of energy (Locational Marginal Prices or "LMP") in MISO and the UP. Gas prices in this IRP are based on the November 9, 2016 NYMEX Henry Hub futures prices for the next 3-4 years, and then are assumed to grow at general inflation. Non-WEPCo/WPS Corp coal prices are based on ABB PROMOD data while WEPCo and WPS Corp plant-specific fuel prices

are based on contracts in hand and near-term forecasts. The coal prices are escalated at the same general inflation rate as gas prices. The IRP uses the same fuel price forecast methodology as was used in the WE and WPS Corp Power Supply Cost Recovery ("PSCR") cases filed with the MPSC in September 2016.

Base case: Gas: $3.04/mmBtu (average annual price), Coal: $1.80 to $2.80/mmBtu (varies by plant).

In the Michigan UMERC formation docket (Case No. U-18061), the Commission approved a Settlement Agreement containing the following commitment:

> (5) Commit to have UMERC submit, for MPSC consideration as part of the CON application case, fuel and/or energy cost hedging options regarding the UMERC non-Mines load.

The following discussion addresses this commitment.

Four fuel and/or energy cost hedging options would be available to the UMERC non-Tilden load customers. These are 1) electric energy futures at a trading hub; 2) electric energy purchases for delivery to the UMERC load zone; 3) gas futures or options for the UP Gen Project units; and 4) gas futures or options as a cross commodity hedge to electric energy prices.

1) Purchase electric energy futures or options for electric energy delivered at a MISO market trading hub, such as the Michigan Hub. By purchasing electric energy futures or options at a liquid market trading hub, the future price for electricity can be either locked in or capped at a reasonable transaction cost; however, the UMERC non-Mines customers would still be exposed to the basis risk (difference in market prices) between the trading hub and the UMERC load zone.

2) Purchase electric energy under a bilateral agreement for delivery to the UMERC load zone. By purchasing electric energy for delivery to the UMERC load zone, the basis risk associated with a market trading hub is eliminated; however, the transaction costs are likely to be higher due to the transfer of the basis risk to the counter party and the limited number of these types of market transactions. One potential method of executing this option would be to hold a "reverse Dutch Auction," with a company such as EnerNoc, where pre-approved bidders participate.

3) Purchase natural gas futures or options for the projected energy output of the UP Gen Project units that is expected to be used to serve the non-Mine customers. Given the current expected installed capacity of the UP Gen Project units relative to the projected Mine load, a portion of the economically dispatched energy from the UP Gen units will be used to meet the requirements of the UMERC non-Mines customers. This output will serve as a natural hedge to energy market purchases for a portion of the UMERC non-Mines customer load. To provide a further hedge, the projected natural gas usage for the portion of the UP Gen Project units projected to serve the

UMERC non-Mines customers could be hedged through the purchase of natural gas futures or options.

4) Purchase natural gas futures or options as a cross commodity hedge to electric energy prices. There is a correlation between natural gas prices and electric market prices (e.g. as natural gas prices increase, electric prices increase and as natural gas prices decrease, electric prices decrease). The purchase of natural gas futures or options based upon the expected UMERC non-Mines customer load can provide a hedge to electric market prices based upon the correlation; however, UMERC non-Mines customers would still be exposed to changes in the correlation between electric and natural gas prices.

The approximate timing for executing any of these hedge strategies is about a year before commercial operation date of the UP Gen Project. There needs to be some certainty in the quantities of either electric generation or gas consumption before hedging is worthwhile. These types of hedges are routinely evaluated and the best hedging options are executed regularly by both WEPCo and WPS Corp every year with review and oversight from the Michigan and Wisconsin Commissions. The hedging process for UMERC will be added to the WEPCo and WPS Corp hedging processes about a year before UP Gen Project commercial operation.

8. Environmental Costs and Constraints

This IRP focuses on the environmental costs and constraints associated with continued PIPP operation beyond 2019, the effect of the Cross State Air Pollution Rule Update ("CSAPR 2") and the Clean Power Plan ("CPP"). Other environmental issues affecting existing plants outside of the UP will have only minor effects on the comparison of alternatives and, more importantly, will have the same effect on all alternatives. The environmental permits necessary to construct and operate the UP Gen Project are described in Ms. Jarmuz's and Ms. Schumacher's testimony. The annual environmental costs for the UP Gen Project are included in the Economic Analysis of Alternatives section.

a. Continued PIPP Operation

If PIPP must operate past 2019, and perhaps until 2025, it will need to comply with the EPA water intake rules (referred to as the 316b rules) and that would require an estimated one-time cost of about $2 million (assumed variable frequency drive circulating water pumps for seasonal flow reductions). The PIPP units also will need to be retrofit with new dry bottom ash handling systems to meet the EPA Effluent Limitation Guidelines at a one-time cost of about $35 million.

CSAPR 2 will have a modest effect on ozone season energy prices beginning in 2017. The ozone season is May 1 to September 30. The price for Ozone Season NOx allowances are estimated to be about $1,500/ton. This translates into a $0.05 or $0.50/MWh increase in energy prices for gas combined cycle or coal units without SCR, respectively. The PROMOD energy

model uses the Ozone Season NOx allowance price to calculate a dispatch price adder for each unit based on the unit's NOx emission rate.

b. Clean Power Plan

The future of the CPP is currently uncertain due to ongoing legal challenges and the change in federal administrations. This IRP assumes CPP or its successor will become effective no sooner than 2025, a three year delay from the CPP's original timeline. The primary effect of greenhouse gas regulation is captured by modeling a $20/ton of CO2 for all affected units. There are many possible complications and nuances which are simplified into a single $/ton assumption. There is consensus that CO2 allowance trading likely will exist under the CPP or its successor. Many other analyses use a CO2 allowance price assumption between $10 and $30/ton of CO2. The IRP uses $0 and $20/ton of CO2 since the effect of other prices can be roughly extrapolated from these two cases. The PROMOD model used in this IRP uses a CO2 allowance cost to calculate the additional cost to run all affected units based on a unit's heat rate and calculated CO2 emissions per MWh.

The CPP listed all existing units which are affected units and all new unit types which will be subject to CO2 limitations. RICE machines were not included in the CPP, and therefore currently have no costs associated with their CO2 emissions.

9. Existing Resources

The Presque Isle Power Plant is the only existing base load resource in the UP. There are other smaller peaking units or smaller dedicated power plants (e.g., Shiras and the new Marquette RICE units are or will be used to support Marquette, Michigan load), but no coal- or gas-fueled base or intermediate load type plants anywhere near Tilden or PIPP. Tilden and PIPP are in a load pocket, which means the local load must be served with local generation. Load pockets are rare in the US and are usually associated with geographic isolation such as islands or peninsulas or huge cities with limited transmission import capability, like Manhattan. Load pockets need either local generation or new transmission import capability to eliminate the load pocket.

WEPCo is planning to retire PIPP when the UP Gen Project goes into service on June 1, 2019 (an approximate date used throughout this IRP). The reasons to retire PIPP include above-market energy generation costs, high O&M costs, age of the units, future capital expenditures required to comply with environmental rules and capital required to maintain reliable operation.

a. PIPP has above-market generation costs

If PIPP units were not needed for reliability, they would run much less than they do now. In 2015, PIPP units had a 58% capacity factor, but were running out of economic dispatch order 70% of the hours they were on-line.

b. PIPP has high O&M costs

PIPP O&M costs were about $40 million in 2015 based on FERC Form 1 data. This is high for a 344 MW plant ($120,000/MW/yr). For comparison, WEPCo's OC5-8 has similar O&M costs for 900 MW, $40,000/MW/yr, despite being built more than a decade before PIPP.

c. PIPP units are near the end of their normal useful life

PIPP units 5-9 were built in 1974 to 1979 and are 37 to 42 years old. Over 80% of units of this vintage in the US have been retired.

d. PIPP will have additional capital costs if not retired in 2019

As noted in the Environmental Costs and Constraints section, if PIPP must operate past 2019, and perhaps until 2025, it will incur one-time costs of $2 million for 316b rules compliance, and $25 million to meet the EPA Effluent Limitation Guidelines. The HDR Report estimates ongoing capital expenditures to be about $25 million per year.

WEPCo is committed to retiring PIPP as part of the UP Gen Project. WEPCo expects the MISO Interconnection Agreement, which allows the UP Gen Project to put power on the grid, will be conditioned on PIPP retiring at about the same time as the UP Gen Project begins commercial operation. A brief transition period where both PIPP and UP Gen Project are available may be required for testing.

10. Modeling Approach

The modeling methodology used in this IRP is to combine PROMOD[8] fuel cost and energy price results with all other annual cost and revenue calculations and then combine these with one-time investment costs into a revenue requirements spreadsheet which calculates and compares the net present value of revenue requirements ("NPVRR") for UMERC for the proposed project and the "business as usual" alternative.

The PROMOD runs capture the annual dispatch costs and revenues for the two generation alternatives (UP Gen Project and "business as usual") including generator and load LMPs and energy production or consumption in MWh on an hourly basis. PROMOD is also used to evaluate the gas price and CO2 scenarios and their relative effect on UMERC for each alternative.

Other variables such as financing costs (depreciation, return, taxes, etc.), fixed O&M and capacity market prices are incorporated into the NPVRR spreadsheet.

[8] PROMOD is a widely-used hourly production cost model which accounts for transmission system operating limits, generating unit fuel costs and operating profiles and customer load in calculating hourly prices (LMP). WEPCo and WPS Corp use PROMOD for their annual fuel cost filings in Michigan and Wisconsin. Typically, and in this IRP, PROMOD is configured to model the load, generation and transmission in MISO and PJM.

11. Time Frame

The time frame for this IRP and economic analysis is 30 years based on the estimated life of the UP Gen Project. The Tilden Special Contract extends 20 years from the in-service of the UP Gen Project. Using a 30 year time frame allows the IRP to capture the economic changes after the Tilden Special Contract ends. The economic analysis assumes the UP Gen Project continues to run and that the terms of the Tilden Special Contract are renewed for ten years except for the capital payments since Tilden will have already paid their half of the UP Gen Project during the current 20-year Tilden Special Contract.

12. Uncertainty and Sensitivity Analysis

The purpose of sensitivity analyses is to check the robustness of the least cost plan if key assumptions turn out to be wrong. The two sensitivities performed in this IRP are higher gas prices and CO2 emission limits from the CPP.

a. Gas Price Sensitivity

The UP Gen Project is gas-fueled so the cost of producing electricity depends on the price of natural gas. Gas price forecasts have generally been unreliable in the past. However, recent estimates of shale gas reserves have significantly lowered the gas price in "high gas price" scenarios. For this IRP, the high gas price scenario uses current gas prices plus $1/mmBtu.

b. CO2 Sensitivity

The base IRP analysis was run without CO2 limits. The CO2 sensitivity assumes a $20/ton of CO2 allowance price beginning in 2024. The Environmental Costs and Constraints section describes the assumptions and basis for this sensitivity.

13. Economic Analysis of Alternatives

The Economic Analysis concludes that the UP Gen Project is $161 million lower in cost (net present value over 30 years) than the "business as usual" case. The key drivers in the economic analysis are the costs of the PPAs with WEPCo and WPS Corp, which in the "business as usual" case continue through the 30-year forecast period, and the net cost to UMERC of building, operating and maintaining the UP Gen Project plant and buying or selling energy to meet its customer's energy requirements. The cost of energy from the UP Gen Project is significantly lower than the cost of energy from PIPP.

The NPV analysis is in IRP Attachment A.

Overview of UMERC Changes

a. UMERC - Before UP Gen Project

UMERC became a utility on January 1, 2017, and started without any generation assets. Energy and capacity to serve UMERC customers is supplied through full requirements PPAs with WEPCo and WPS Corp. These PPAs will continue until the UP Gen Project goes into service on or about June 1, 2019.

b. UP Gen Project

When the UP Gen Project goes into service on or about June 1, 2019, the following events occur roughly concurrently:

- Tilden becomes a UMERC customer under the Tilden Contract
- The PPAs between UMERC and WEPCo/WPS Corp end
- UMERC owns and operates the UP Gen Project
- UMERC becomes a MISO Market Participant (this may happen any time between 2017 and 2019)
- PIPP will retire (subject to MISO approval)

As a result, the basis for calculating the cost of power supply to UMERC customers changes significantly. As described fully in the "Results" section, the UP Gen Project lowers the cost of power supply to UMERC customers.

c. "Business as Usual"

If the UP Gen project is not built, UMERC will continue as a full requirements customer of WEPCo and WPS Corp through the PPAs. PIPP will continue to operate until the Plains-National plus Morgan-Thunder-Plains project goes into service (assumed to be 2025). PIPP will then retire. The IRP assumes UMERC will buy market capacity and energy after PIPP retires.

UP Gen Project Costs

Capital Cost: $265.7 million before AFUDC. UP Gen Project receives benefit of 30% bonus depreciation in 2019 (only).

On-going CapEx: varies by year and by need

Forced outage rate: 5%

Planned maintenance outages: 1-3 weeks per unit per year, depending on hours of operation per year

Expected capacity factor: 50% or greater at expected gas prices.

Operating and Maintenance Costs: $5.3 million/yr

Annual A&G Costs: $2.1 million/yr

Annual Gas Pipeline Charge: $4.3 million/yr

Property Tax: $5.9 million/yr

UMERC Forecasts and Assumptions

Peak Demand (coincident with MISO peak demand): 94 MW

Annual Non-Mine Energy: WEPCo Zone: 380,000 MWh; WPS Corp Zone: 260,000 MWh; Total: 641,000 MWh/yr

Average LMP: $26.12/MWh in 2019 from PROMOD.

General Assumptions

Value of Capacity: $26,250/MW/yr (PY2016 MISO Auction value) rising to $61,250/MW/yr in 2023, then flat thereafter.

Inflation and Escalation: All escalation is at general inflation rate of 2%/yr

UMERC "Business as Usual" Forecasts and Assumptions

WEPCo and WPS Corp PPA Price: May 2016 Formula Rate Tariff ("FRT") Forecasts (shared with FRT customers in May 2016)

Transmission Costs:

> Avoided Investment: $300 million, assumes new ATC projects ($373 million) less interconnection costs for UP Gen Project (not yet known but projected at $73 million).
>
> Allocation of ATC Costs: WEPCO = 42.3%, WPS = 18.5%, UMERC = 1.0%
>
> Note: UMERC share of ATC transmission costs is only $0.5 million/yr due to small (1%) allocation percentage

PIPP Retirement in 2025:

> Michigan portion of PIPP net book value: 6.595%

Assumed removal and salvage costs: $30 million

Energy Cost: $6-8 million/yr higher cost for "business as usual" compared to UP Gen Project

PROMOD Energy Cost Analysis Assumptions

PROMOD is the production cost model used by WEPCo and WPS Corp fuel filings in Wisconsin and Michigan. WEPCo has been using PROMOD for over a decade. PROMOD simulates the hourly energy market across MISO and PJM based on input generator performance data, monthly fuel cost forecasts, expected transmission topology, additions or retirements of generators, demand and energy forecasts and other WEPCo/WPS Corp-specific energy market components (FTRs, make whole payments, ancillary services, etc.).

For this IRP, PROMOD was used to simulate the first year of UP Gen Project operation (2019) for the "business as usual" and UP Gen Project cases. For the "business as usual" case, two PROMOD runs were used: one with PIPP running and another with PIPP retired and new transmission added.

The PROMOD assumptions in this IRP are essentially the 2017 Fuel Plan and PSCR run assumptions with any known generation or transmission changes in (or before) 2019. PROMOD simulates the energy market to predict generator energy and locational prices (LMPs). The high level results are included in IRP Attachments A, B and C. The full results are available in very large databases and spreadsheets. PROMOD input data other than WEPCo and WPS Crop (and UP Gen Project) data are available to individuals who have signed a confidentiality agreement with MISO and PROMOD and can demonstrate critical energy infrastructure information ("CEII") certification.

Sensitivity: Gas Prices plus $1/mmBtu

The "Gas + $1" scenario shows the effect of increased gas prices on both the "business as usual" and UP Gen Project cases. In both cases the energy price (LMP) increases due to higher gas costs. In the "business as usual" case, the FRT-based PPAs are more expensive than the base case. In the UP Gen Project case the RICE units run less and energy purchases from the MISO energy market increase at the higher LMP which increases costs compared to the base case. Even with higher gas prices, the UP Gen Project is $123 million lower in NPV costs than the "business as usual" alternative with higher gas prices.

The NPV analysis for the Gas plus $1 scenario is in IRP Attachment B.

Sensitivity: CO2 at $20/ton

The CO2 scenario shows the effect of $20/ton of CO2 on both the "business as usual" and UP Gen Project cases. The cost of market energy increases in both cases due to the $20/ton allowance cost (or opportunity cost) being passed through coal and gas generation offers.

WEPCo has a PPA with Next Era for power from the Point Beach Nuclear Plant which effectively shields a portion of WEPCo's PPA costs from the CO2 cost. The UP Gen Project is $67 million lower in NPV costs than the "business as usual" alternative with $20/ton CO2.

The NPV analysis for the CO2 scenario is in IRP Attachment B.

14. Results

The results of the IRP are summarized in this table:

Comparison of Alternatives (NPVRevReq)

	UP Gen Proj	Business As Usual
No CO2	base	+$161 million
CO2	base	+$67 million
Gas + $1 (No CO2)	base	+$123 million

15. Estimated Calculation of Impact On Average Customer Rates:

	UMERC 2020 PPA Forecast	2020 UP Gen	Difference
Generation Resource Supply ($):	44,757,919	42,977,757	(1,780,162)
Transmission ($):	9,733,901	9,733,901	-
Total Power Supply Cost ($):	54,491,820	52,711,658	(1,780,162)
Total Power Supply ($/kWH):	0.085	0.082	(0.003)
		Rate Reduction:	**3.3%**

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*** * * * ***

In the Matter of the Application of	)	
Upper Michigan Energy Resources Corporation	)	
for approval of a Certificate of Necessity	)	
pursuant to MCL 460.6s for	)	Case No. U-18224
Two Reciprocating Internal Combustion Engine	)	
Electric Generation Facilities Located in the	)	
Upper Peninsula of Michigan,	)	
Approval of Certificate(s) of Public Convenience	)	
And Necessity, approval of a Special Contract with	)	
Tilden Mining Company L.C.	)	
and related accounting and ratemaking	)	
authorizations.	)	

2016 Integrated Resource Plan for
Upper Michigan Energy Resources Corporation Beginning in 2019

Attachment A

UP Gen Project (U-18224) -- IRP

Spreadsheet Name: IRP Attachment A - UP Gen UMERC Allocation Impact (MPSC Filing).xlsx
Sheet Name: NPV Analysis

General Assumptions:

RICE In-service Date of 6/30/19

	50% 2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
UMERC																
(+) Reduced PPA Cost[1]	21,851,582	44,757,919	45,897,133	47,017,326	48,169,554	49,394,559	50,638,255	51,864,627	52,937,306	54,031,439	55,147,455	56,285,791	57,446,894	58,631,219	59,839,231	61,071,402
(+) Avoided Transmission ($300M)[2]							403,048	394,093	386,486	381,215	375,897	370,538	365,139	359,704	354,070	348,221
(-) Return Of PIPP Net Plant[3]		(950,529)	(892,716)	(838,406)	(794,683)	(749,694)	(703,704)	(656,273)	(607,043)	(557,004)	(506,976)	(165)				
(-) UP Gen Cost[4]	(22,364,252)	(42,977,757)	(41,914,799)	(41,028,800)	(40,162,763)	(40,261,129)	(40,223,591)	(40,529,176)	(40,629,946)	(40,934,692)	(41,241,508)	(41,209,623)	(41,062,628)	(40,901,517)	(41,644,533)	(41,976,206)
Total	(512,670)	829,633	3,089,618	5,150,120	7,212,109	8,383,736	10,114,009	11,073,270	12,086,803	12,920,958	13,774,869	15,446,541	16,749,405	18,089,406	18,548,767	19,443,417

	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	50% 2049
UMERC															
(+) Reduced PPA Cost[1]	62,328,217	63,610,169	64,917,759	66,251,501	67,611,918	68,999,544	70,414,922	71,858,607	73,331,166	74,833,177	76,365,227	77,927,919	79,521,864	81,147,689	41,403,015
(+) Avoided Transmission ($300M)[2]	342,337	336,453	330,568	324,684	318,799	312,915	307,031	301,146	295,262	289,377	284,806	281,546	276,975	271,090	132,603
(-) Return Of PIPP Net Plant[3]															
(-) UP Gen Cost[4]	(41,831,819)	(41,892,078)	(42,310,762)	(42,392,889)	(42,250,168)	(42,680,982)	(42,945,698)	(43,203,343)	(43,568,103)	(43,741,159)	(43,782,456)	(44,443,847)	(45,100,002)	(45,274,721)	(22,535,359)
Total	20,838,735	22,054,543	22,937,565	24,183,296	25,680,550	26,631,477	27,776,254	28,956,410	30,058,325	31,381,395	32,867,577	33,765,618	34,698,837	36,144,058	19,000,259

Discount Rate	7.22%
20 Year NPV	82,288,346
30 Year NPV	82,288,346

[1]The total projected cost of the WE and WPS Power Purchase Agreements

[2]The avoided ATC LLC transmission cost allocation of the projected $300 million avoided net transmission cost associated with the installation of the UP Gen units

[3]Cost associated with the recovery of the 6.595% of the PIPP costs allocated to Michigan with recovery over 10-years.

[4]Cost associated with the UP Gen solution

UP Gen Project (U-18224) -- IRP

Spreadsheet Name: IRP Attachment A - UP Gen UMERC Allocation Impact (MPSC Filing).xlsx
Sheet Name: Avoided Transmission

= Input Field

Avoided Transmission Cost Estimation

ASSUMPTIONS:

Avoided Investment	##########			UMERC Allocation:	0.94%
Useful Life (for return of)	50	years			
Tax Rate	40.00%				
Bonus Depreciation	0.00%				
O&M Rate	2.00%				
Weighted Average Cost of Capital					
	%	Cost	Weighted		
Debt	50.00%	4.20%	2.100%		
Equity	50.00%	10.00%	5.000%		
	100%		7.100%		

CALCULATION:

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
Accumulated Depreciation	6,000,000	12,000,000	18,000,000	24,000,000	30,000,000	36,000,000	42,000,000	48,000,000	54,000,000	60,000,000	66,000,000	72,000,000	78,000,000	84,000,000	90,000,000	96,000,000	102,000,000	108,000,000	114,000,000	120,000,000	126,000,000	132,000,000	138,000,000	144,000,000	150,000,000	156,000,000	162,000,000	168,000,000	174,000,000	180,000,000	183,000,000
Net Plant	294,000,000	288,000,000	282,000,000	276,000,000	270,000,000	264,000,000	258,000,000	252,000,000	246,000,000	240,000,000	234,000,000	228,000,000	222,000,000	216,000,000	210,000,000	204,000,000	198,000,000	192,000,000	186,000,000	180,000,000	174,000,000	168,000,000	162,000,000	156,000,000	150,000,000	144,000,000	138,000,000	132,000,000	126,000,000	120,000,000	117,000,000
Depreciation Expense (Return of)	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**3,000,000**
20 Year Macrs	3.75%	7.22%	6.68%	6.18%	5.71%	5.29%	4.89%	4.52%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	2.23%										
Tax Depreciation	11,250,000	21,657,000	20,031,000	18,531,000	17,139,000	15,855,000	14,664,000	13,566,000	13,386,000	13,383,000	13,386,000	13,383,000	13,386,000	13,383,000	13,386,000	13,383,000	13,386,000	13,383,000	13,386,000	13,383,000	6,693,000	-	-	-	-	-	-	-	-	-	-
Deferred Taxes	(2,100,000)	(6,262,800)	(5,612,400)	(5,012,400)	(4,455,600)	(3,942,000)	(3,465,600)	(3,026,400)	(2,954,400)	(2,953,200)	(2,954,400)	(2,953,200)	(2,954,400)	(2,953,200)	(2,954,400)	(2,953,200)	(2,954,400)	(2,953,200)	(2,954,400)	(2,953,200)	(277,200)	2,400,000	2,400,000	2,400,000	2,400,000	2,400,000	2,400,000	2,400,000	2,400,000	2,400,000	1,200,000
Beginning Rate Base	300,000,000	291,900,000	281,737,200	276,387,600	270,987,600	265,544,400	260,058,000	254,534,400	248,973,600	243,045,600	237,046,800	231,045,600	225,046,800	219,045,600	213,046,800	207,045,600	201,046,800	195,045,600	189,046,800	183,045,600	177,046,800	173,722,800	170,400,000	164,400,000	158,400,000	152,400,000	146,400,000	140,400,000	134,400,000	128,400,000	122,400,000
Ending Rate Base	291,900,000	281,737,200	276,387,600	270,987,600	265,544,400	260,058,000	254,534,400	248,973,600	243,045,600	237,046,800	231,045,600	225,046,800	219,045,600	213,046,800	207,045,600	201,046,800	195,045,600	189,046,800	183,045,600	177,046,800	173,722,800	170,400,000	164,400,000	158,400,000	152,400,000	146,400,000	140,400,000	134,400,000	128,400,000	122,400,000	118,200,000
Average Rate Base	295,950,000	286,818,600	279,062,400	273,687,600	268,266,000	262,801,200	257,296,200	251,754,000	246,009,600	240,046,200	234,046,200	228,046,200	222,046,200	216,046,200	210,046,200	204,046,200	198,046,200	192,046,200	186,046,200	180,046,200	175,384,800	172,061,400	167,400,000	161,400,000	155,400,000	149,400,000	143,400,000	137,400,000	131,400,000	125,400,000	120,300,000
Revenue Requirement (Return On)	**30,877,450**	**29,924,741**	**29,115,510**	**28,554,740**	**27,989,086**	**27,418,925**	**26,844,570**	**26,266,334**	**25,667,002**	**25,044,820**	**24,418,820**	**23,792,820**	**23,166,820**	**22,540,820**	**21,914,820**	**21,288,820**	**20,662,820**	**20,036,820**	**19,410,820**	**18,784,820**	**18,298,481**	**17,951,739**	**17,465,400**	**16,839,400**	**16,213,400**	**15,587,400**	**14,961,400**	**14,335,400**	**13,709,400**	**13,083,400**	**12,551,300**
O&M Expense (Return Of)	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**
System Avoided Cost of $300M Investment	**42,877,450**	**41,924,741**	**41,115,510**	**40,554,740**	**39,989,086**	**39,418,925**	**38,844,570**	**38,266,334**	**37,667,002**	**37,044,820**	**36,418,820**	**35,792,820**	**35,166,820**	**34,540,820**	**33,914,820**	**33,288,820**	**32,662,820**	**32,036,820**	**31,410,820**	**30,784,820**	**30,298,481**	**29,951,739**	**29,465,400**	**28,839,400**	**28,213,400**	**27,587,400**	**26,961,400**	**26,335,400**	**25,709,400**	**25,083,400**	**21,551,300**

UP Gen Project (U-18224) -- IRP

Spreadsheet Name: IRP Attachment A - UP Gen UMERC Allocation Impact (MPSC Filing).xlsx
Sheet Name: PIPP Retirement Cost

= Input Field

PIPP Retirement Cost Recovery Estimation

ASSUMPTIONS:

Projected PIPP Book Value:	**175,895,000**
Projected Decommissioning Cost:	**30,000,000**
Total PIPP Recovery:	205,895,000
Michigan PIPP Allocation (%):	**6.595%**
Michigan PIPP Allocation:	13,578,775
Non-Mine UMERC Allocation (%):	**35%**
Non-Mine UMERC Allocation:	4,752,571
Recovery Period (years):	**10**
Tax Rate:	38.9%

Weighted Average Cost of Capital

	%	Cost	Weighted
Debt	**48.00%**	**4.20%**	2.016%
Equity	**52.00%**	**10.00%**	5.200%
	100%		7.216%

Tax Rate	
Federal	**35.00%**
State-MI	**6.00%**
Effective Rate	38.9%

CALCULATION:

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Accumulated Depreciation	475,257	950,514	1,425,771	1,901,029	2,376,286	2,851,543	3,326,800	3,802,057	4,277,314	4,752,571	4,752,571
Net Plant	4,277,314	3,802,057	3,326,800	2,851,543	2,376,286	1,901,029	1,425,771	950,514	475,257	-	-
Depreciation Expense (Return of)	**475,257**	**475,257**	**475,257**	**475,257**	**475,257**	**475,257**	**475,257**	**475,257**	**475,257**	**475,257**	**-**
10 Year Macrs	10.00%	18.00%	14.40%	11.52%	9.22%	7.37%	6.55%	6.55%	6.56%	6.55%	3.28%
Tax Depreciation	475,257	855,463	684,370	547,496	438,187	350,265	311,293	311,293	311,769	311,293	155,884
Deferred Taxes	(0)	(147,900)	(81,345)	(28,101)	14,420	48,622	63,782	63,782	63,597	63,782	(60,639)
Beginning Rate Base	4,752,571	4,277,314	3,654,157	3,245,455	2,823,442	2,390,706	1,949,651	1,489,553	1,014,296	538,854	63,782
Ending Rate Base	4,277,314	3,654,157	3,245,455	2,823,442	2,390,706	1,949,651	1,489,553	1,014,296	538,854	63,782	(60,639)
Average Rate Base	4,514,943	3,965,736	3,449,806	3,034,448	2,607,074	2,170,178	1,719,602	1,251,925	776,575	301,318	1,571
Revenue Requirement (Return On)	**475,272**	**417,459**	**363,149**	**319,425**	**274,437**	**228,447**	**181,016**	**131,786**	**81,747**	**31,719**	**165**
PIPP Retirement Cost	**950,529**	**892,716**	**838,406**	**794,683**	**749,694**	**703,704**	**656,273**	**607,043**	**557,004**	**506,976**	**165**

UP Gen Project (U-18224) -- IRP

Spreadsheet Name: IRP Attachment A - UP Gen UMERC Allocation Impact (MPSC Filing).xlsx
Sheet Name: UP Gen Rate Base

= Input Field

	Equity	Debt	Total
Capital Structure	52.00%	48.00%	100.00%
Cost of Capital	10.00%	4.20%	
Wtd Cost of Capital (discount rate)	5.20%	2.02%	**7.22%**
Tax Gross-up	1.637		
Economic Cost of Capital	8.51%	2.02%	**10.53%**

Tax Rate	
Federal	35.00%
State-MI	6.00%
Effective Rate	**38.9%**

	Yrs In-Service Year	2017	2018	2019	1 2020	2 2021	3 2022	4 2023	5 2024	6 2025	7 2026	8 2027	9 2028	10 2029	11 2030	12 2031	13 2032	14 2033	15 2034	16 2035	17 2036	18 2037	19 2038	20 2039	21 2040	22 2041	23 2042	24 2043	25 2044	26 2045	27 2046	28 2047	29 2048	30 2049	Total
Total CAPEX																																			
Initial Construction		10,700,000	178,465,744	76,524,040																															265,689,783
Capital Improvements					-	-	3,325,000	1,425,000	5,780,000	-	10,530,000	-	10,530,000	4,750,000	700,000	330,000	-	20,030,000	-	1,030,000	4,750,000	10,530,000	-	-	10,530,000	-	5,780,000	4,750,000	1,030,000	-	14,000,000	6,030,000	-	-	115,830,000
AFUDC																																			
Debt		45,768	1,646,083	1,704,577																															3,396,427
Equity		108,853	3,915,008	4,054,129																															8,077,990
Book Basis		10,854,621	194,881,455	277,164,200	277,164,200	277,164,200	280,489,200	281,914,200	287,694,200	287,694,200	298,224,200	298,224,200	308,754,200	313,504,200	314,204,200	314,534,200	314,534,200	334,564,200	334,564,200	335,594,200	340,344,200	350,874,200	350,874,200	350,874,200	361,404,200	361,404,200	367,184,200	371,934,200	372,964,200	372,964,200	386,964,200	392,994,200	392,994,200	392,994,200	-
Tax Basis		10,745,768	190,857,594	269,086,211	269,086,211	269,086,211	272,411,211	273,836,211	279,616,211	279,616,211	290,146,211	290,146,211	300,676,211	305,426,211	306,126,211	306,456,211	306,456,211	326,486,211	326,486,211	327,516,211	332,266,211	342,796,211	342,796,211	342,796,211	353,326,211	353,326,211	359,106,211	363,856,211	364,886,211	364,886,211	378,886,211	384,916,211	384,916,211	384,916,211	-
Months In-Service				6	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	6	360
Book Depreciation	3.94%			5,463,858	10,927,715	10,927,715	11,058,809	11,114,993	11,342,880	11,342,880	11,758,045	11,758,045	12,173,210	12,360,487	12,388,086	12,401,097	12,401,097	13,190,817	13,190,817	13,231,427	13,418,704	13,833,869	13,833,869	13,833,869	14,249,034	14,249,034	14,476,921	14,664,199	14,704,809	14,704,809	15,256,785	15,494,529	15,494,529	7,747,264	392,994,200
AFUDC Equity Amort included in book depr				*134,633*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*134,633*	*8,077,990*
Bonus %		50%	40%	30%																															
Tax Depreciation		-	-	87,789,376	13,597,733	12,576,820	11,759,706	11,054,496	10,496,475	9,924,844	9,576,440	9,778,967	10,068,767	10,518,846	10,571,901	10,464,936	10,352,844	10,994,839	11,614,523	11,484,362	11,568,472	12,024,477	12,269,868	7,903,866	3,944,257	4,224,003	4,241,847	4,402,041	4,323,137	4,123,881	4,315,899	4,702,498	4,546,294	39,699,795	384,916,211
Rate Base (Total)																																			
PP&E - Gross		10,854,621	194,881,455	277,164,200	277,164,200	277,164,200	280,489,200	281,914,200	287,694,200	287,694,200	298,224,200	298,224,200	308,754,200	313,504,200	314,204,200	314,534,200	314,534,200	334,564,200	334,564,200	335,594,200	340,344,200	350,874,200	350,874,200	350,874,200	361,404,200	361,404,200	367,184,200	371,934,200	372,964,200	372,964,200	386,964,200	392,994,200	392,994,200	392,994,200	
Accum Depreciation				(5,463,858)	(16,391,573)	(27,319,288)	(38,378,097)	(49,493,090)	(60,835,970)	(72,178,850)	(83,936,894)	(95,694,939)	(107,868,149)	(120,228,636)	(132,616,722)	(145,017,819)	(157,418,916)	(170,609,733)	(183,800,550)	(197,031,977)	(210,450,681)	(224,284,550)	(238,118,419)	(251,952,288)	(266,201,322)	(280,450,356)	(294,927,278)	(309,591,477)	(324,296,285)	(339,001,094)	(354,257,878)	(369,752,407)	(385,246,936)	(392,994,200)	
Accum Deferred Income Tax				(32,076,999)	(33,220,381)	(33,966,627)	(34,344,021)	(34,425,232)	(34,200,725)	(33,753,854)	(33,009,955)	(32,344,838)	(31,630,954)	(31,019,300)	(30,417,549)	(29,769,127)	(29,077,101)	(28,327,610)	(27,819,176)	(27,244,313)	(26,629,317)	(26,030,208)	(25,526,556)	(23,324,529)	(19,420,716)	(15,625,723)	(11,749,024)	(7,861,789)	(3,928,063)	83,173	4,234,433	8,327,788	12,481,907	(0)	
Working Capital				3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	
Net Rate Base-EOY		10,854,621	194,881,455	242,623,344	230,552,247	218,878,285	210,767,082	200,995,878	195,657,505	184,761,497	184,277,351	173,184,423	172,255,097	165,256,264	154,169,929	142,747,254	131,038,183	138,626,857	125,944,474	114,317,911	106,264,202	103,559,442	90,229,225	78,597,383	78,782,162	68,328,121	63,507,899	57,480,935	47,739,852	37,046,280	39,940,755	34,569,581	23,229,171	3,000,000	
Net Rate Base-Avg				130,696,886	236,587,795	224,715,266	214,822,684	205,881,480	198,326,692	190,209,501	184,519,424	178,730,887	172,719,760	168,755,681	159,713,097	148,458,592	136,892,719	134,832,520	132,285,666	120,131,192	110,291,057	104,911,822	96,894,334	84,413,304	78,689,772	73,555,141	65,918,010	60,494,417	52,610,393	42,393,066	38,493,517	37,255,168	28,899,376	6,557,293	

UP Gen Project (U-18224) -- IRP

Spreadsheet Name: IRP Attachment A - UP Gen UMERC Allocation Impact (MPSC Filing).xlsx
Sheet Name: UP Gen (Base Rev Rqrmnt Calc)

= Input Field

O&M and A&G Inflation Rate: 2.00%

Capital Cost Allocation: 50.00%

						(A) * (B)						(C+D+E+F+G+H)
				(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	Year	Months In-Serv	Asset Life	Average Rate Base	Economic Cost of Capital	"Return On" Rate Base	Tax Impact AFUDC Amoritization	Depreciation Expense	Allocated A&G Expense	NNG Pipeline Cost	Property Tax	Total Base Revenue Requirement
In-Service 6/30/2019	2019	6	30	$65,348,443	10.53%	$6,878,994	$42,858	$2,731,929	$867,249	$2,155,836	$2,927,782	$15,604,647
	2020	12	30	$118,293,898	10.53%	$12,452,371	$85,716	$5,463,858	$1,769,187	$4,311,672	$5,855,563	$29,938,366
	2021	12	30	$112,357,633	10.53%	$11,827,482	$85,716	$5,463,858	$1,804,571	$4,311,672	$5,855,563	$29,348,861
	2022	12	30	$107,411,342	10.53%	$11,306,803	$85,716	$5,529,405	$1,840,662	$4,311,672	$5,855,563	$28,929,821
	2023	12	30	$102,940,740	10.53%	$10,836,199	$85,716	$5,557,496	$1,877,475	$4,311,672	$5,855,563	$28,524,122
	2024	12	30	$99,163,346	10.53%	$10,438,567	$85,716	$5,671,440	$1,915,025	$4,311,672	$5,855,563	$28,277,982
	2025	12	30	$95,104,750	10.53%	$10,011,333	$85,716	$5,671,440	$1,953,325	$4,311,672	$5,855,563	$27,889,049
	2026	12	30	$92,259,712	10.53%	$9,711,846	$85,716	$5,879,022	$1,992,392	$4,311,672	$5,855,563	$27,836,211
	2027	12	30	$89,365,444	10.53%	$9,407,177	$85,716	$5,879,022	$2,032,240	$4,311,672	$5,855,563	$27,571,390
	2028	12	30	$86,359,880	10.53%	$9,090,792	$85,716	$6,086,605	$2,072,884	$4,311,672	$5,855,563	$27,503,232
	2029	12	30	$84,377,840	10.53%	$8,882,150	$85,716	$6,180,244	$2,114,342	$4,311,672	$5,855,563	$27,429,687
	2030	12	30	$79,856,548	10.53%	$8,406,210	$85,716	$6,194,043	$2,156,629	$4,311,672	$5,855,563	$27,009,833
	2031	12	30	$74,229,296	10.53%	$7,813,849	$85,716	$6,200,548	$2,199,762	$4,311,672	$5,855,563	$26,467,110
	2032	12	30	$68,446,359	10.53%	$7,205,101	$85,716	$6,200,548	$2,243,757	$4,311,672	$5,855,563	$25,902,357
	2033	12	30	$67,416,260	10.53%	$7,096,666	$85,716	$6,595,409	$2,288,632	$4,311,672	$5,855,563	$26,233,657
	2034	12	30	$66,142,833	10.53%	$6,962,617	$85,716	$6,595,409	$2,334,405	$4,311,672	$5,855,563	$26,145,381
	2035	12	30	$60,065,596	10.53%	$6,322,888	$85,716	$6,615,713	$2,381,093	$4,311,672	$5,855,563	$25,572,645
	2036	12	30	$55,145,528	10.53%	$5,804,970	$85,716	$6,709,352	$2,428,715	$4,311,672	$5,855,563	$25,195,988
	2037	12	30	$52,455,911	10.53%	$5,521,844	$85,716	$6,916,935	$2,477,289	$4,311,672	$5,855,563	$25,169,018
	2038	12	30	$48,447,167	10.53%	$5,099,858	$85,716	$6,916,935	$2,526,835	$4,311,672	$5,855,563	$24,796,578
	2039	12	30	$42,206,652	10.53%	$4,442,942	$85,716	$6,916,935	$2,577,371	$4,311,672	$5,855,563	$24,190,198
	2040	12	30	$39,344,886	10.53%	$4,141,694	$85,716	$7,124,517	$2,628,919	$4,311,672	$5,855,563	$24,148,080
	2041	12	30	$36,777,571	10.53%	$3,871,442	$85,716	$7,124,517	$2,681,497	$4,311,672	$5,855,563	$23,930,407
	2042	12	30	$32,959,005	10.53%	$3,469,475	$85,716	$7,238,461	$2,735,127	$4,311,672	$5,855,563	$23,696,014
	2043	12	30	$30,247,208	10.53%	$3,184,014	$85,716	$7,332,099	$2,789,830	$4,311,672	$5,855,563	$23,558,894
	2044	12	30	$26,305,197	10.53%	$2,769,053	$85,716	$7,352,404	$2,845,626	$4,311,672	$5,855,563	$23,220,034
	2045	12	30	$21,196,533	10.53%	$2,231,282	$85,716	$7,352,404	$2,902,539	$4,311,672	$5,855,563	$22,739,176
	2046	12	30	$19,246,759	10.53%	$2,026,037	$85,716	$7,628,392	$2,960,589	$4,311,672	$5,855,563	$22,867,969
	2047	12	30	$18,627,584	10.53%	$1,960,858	$85,716	$7,747,264	$3,019,801	$4,311,672	$5,855,563	$22,980,875
	2048	12	30	$14,449,688	10.53%	$1,521,066	$85,716	$7,747,264	$3,080,197	$4,311,672	$5,855,563	$22,601,479
	2049	6	30	$3,278,646	10.53%	$345,131	$42,858	$3,873,632	$1,570,901	$2,155,836	$2,927,782	$10,916,139

UP Gen Project (U-18224) -- IRP

Spreadsheet Name: IRP Attachment A - UP Gen UMERC Allocation Impact (MPSC Filing).xlsx
Sheet Name: UP Gen Cost

= Input Field

Energy/LMP Inflation Rate: **2.00%**

				(A * C)					0.1 * (G * H)	(G * B)	(I + J) - (D + E + F)		(H + I)
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(H)	(I)	(J)
Year	**Market Capacity Value ($/MW-Year)**	**UP Gen Estimated LMP ($/MWh)**	**UP Gen Excess Capacity (MW)**	**UP Gen Excess Capacity Value**	**UP Gen Energy Sales Value**	**UP Gen Ancillary Sales Value**	**UP Gen Total UMERC Load (MWh)**	**UP Gen REC Cost ($/REC)**	**UP Gen Renewables Cost**	**UP Gen Load Purchase Cost**	**Annualized UP Gen Total Energy Costs**	**Annualized UP Gen Base Rev Req Costs**	**Annualized Up Gen Total Costs**
2017													
2018													
2019	**$26,250**	**$26.12**	**91.2**	$2,394,263	**$488,539**	**$525,600**	**640,712**	**$3.00**	$192,214	$16,735,397	$13,519,210	$31,209,294	$44,728,503
2020	**$35,000**	$26.64	91.2	$3,192,350	$498,310	$536,112	640,712	$3.06	$196,058	$17,070,105	$13,039,391	$29,938,366	$42,977,757
2021	**$43,750**	$27.18	91.2	$3,990,438	$508,276	$546,834	640,712	$3.12	$199,979	$17,411,507	$12,565,939	$29,348,861	$41,914,799
2022	**$52,500**	$27.72	91.2	$4,788,525	$518,441	$557,771	640,712	$3.18	$203,979	$17,759,738	$12,098,979	$28,929,821	$41,028,800
2023	**$61,250**	$28.27	91.2	$5,586,613	$528,810	$568,926	640,712	$3.25	$208,058	$18,114,932	$11,638,641	$28,524,122	$40,162,763
2024	**$61,250**	$28.84	91.2	$5,586,613	$539,387	$580,305	640,712	$3.31	$212,219	$18,477,231	$11,983,146	$28,277,982	$40,261,129
2025	**$61,250**	$29.42	91.2	$5,586,613	$550,174	$591,911	640,712	$3.38	$216,464	$18,846,776	$12,334,542	$27,889,049	$40,223,591
2026	**$61,250**	$30.00	91.2	$5,586,613	$561,178	$603,749	640,712	$3.45	$220,793	$19,223,711	$12,692,965	$27,836,211	$40,529,176
2027	**$61,250**	$30.60	91.2	$5,586,613	$572,401	$615,824	640,712	$3.51	$225,209	$19,608,185	$13,058,556	$27,571,390	$40,629,946
2028	**$61,250**	$31.22	91.2	$5,586,613	$583,849	$628,141	640,712	$3.59	$229,713	$20,000,349	$13,431,460	$27,503,232	$40,934,692
2029	**$61,250**	$31.84	91.2	$5,586,613	$595,526	$640,703	640,712	$3.66	$234,307	$20,400,356	$13,811,821	$27,429,687	$41,241,508
2030	**$61,250**	$32.48	91.2	$5,586,613	$607,437	$653,518	640,712	$3.73	$238,993	$20,808,363	$14,199,790	$27,009,833	$41,209,623
2031	**$61,250**	$33.13	91.2	$5,586,613	$619,586	$666,588	640,712	$3.80	$243,773	$21,224,530	$14,595,518	$26,467,110	$41,062,628
2032	**$61,250**	$33.79	91.2	$5,586,613	$631,977	$679,920	640,712	$3.88	$248,649	$21,649,021	$14,999,160	$25,902,357	$40,901,517
2033	**$61,250**	$34.46	91.2	$5,586,613	$644,617	$693,518	640,712	$3.96	$253,622	$22,082,002	$15,410,876	$26,233,657	$41,644,533
2034	**$61,250**	$35.15	91.2	$5,586,613	$657,509	$707,388	640,712	$4.04	$258,694	$22,523,642	$15,830,826	$26,145,381	$41,976,206
2035	**$61,250**	$35.86	91.2	$5,586,613	$670,659	$721,536	640,712	$4.12	$263,868	$22,974,114	$16,259,174	$25,572,645	$41,831,819
2036	**$61,250**	$36.57	91.2	$5,586,613	$684,073	$735,967	640,712	$4.20	$269,145	$23,433,597	$16,696,090	$25,195,988	$41,892,078
2037	**$61,250**	$37.31	91.2	$5,586,613	$697,754	$750,686	640,712	$4.28	$274,528	$23,902,269	$17,141,744	$25,169,018	$42,310,762
2038	**$61,250**	$38.05	91.2	$5,586,613	$711,709	$765,700	640,712	$4.37	$280,019	$24,380,314	$17,596,311	$24,796,578	$42,392,889
2039	**$61,250**	$38.81	91.2	$5,586,613	$725,943	$781,014	640,712	$4.46	$285,619	$24,867,920	$18,059,970	$24,190,198	$42,250,168
2040	**$61,250**	$39.59	91.2	$5,586,613	$740,462	$796,634	640,712	$4.55	$291,332	$25,365,279	$18,532,901	$24,148,080	$42,680,982
2041	**$61,250**	$40.38	91.2	$5,586,613	$755,271	$812,567	640,712	$4.64	$297,158	$25,872,584	$19,015,292	$23,930,407	$42,945,698
2042	**$61,250**	$41.19	91.2	$5,586,613	$770,377	$828,818	640,712	$4.73	$303,101	$26,390,036	$19,507,330	$23,696,014	$43,203,343
2043	**$61,250**	$42.01	91.2	$5,586,613	$785,784	$845,395	640,712	$4.83	$309,164	$26,917,837	$20,009,209	$23,558,894	$43,568,103
2044	**$61,250**	$42.85	91.2	$5,586,613	$801,500	$862,303	640,712	$4.92	$315,347	$27,456,193	$20,521,125	$23,220,034	$43,741,159
2045	**$61,250**	$43.71	91.2	$5,586,613	$817,530	$879,549	640,712	$5.02	$321,654	$28,005,317	$21,043,280	$22,739,176	$43,782,456
2046	**$61,250**	$44.58	91.2	$5,586,613	$833,881	$897,140	640,712	$5.12	$328,087	$28,565,424	$21,575,878	$22,867,969	$44,443,847
2047	**$61,250**	$45.48	91.2	$5,586,613	$850,558	$915,082	640,712	$5.22	$334,649	$29,136,732	$22,119,128	$22,980,875	$45,100,002
2048	**$61,250**	$46.39	91.2	$5,586,613	$867,569	$933,384	640,712	$5.33	$341,342	$29,719,467	$22,673,242	$22,601,479	$45,274,721
2049	**$61,250**	$47.31	91.2	$5,586,613	$884,921	$952,052	640,712	$5.43	$348,168	$30,313,856	$23,238,439	$21,832,279	$45,070,718

NOTE: Above calculation excludes transmission costs which will be the same regardless of scenario

UP Gen Project (U-18224) -- IRP

Spreadsheet Name: IRP Attachment A - UP Gen UMERC Allocation Impact (MPSC Filing).xlsx
Sheet Name: PPA Costs

= Input Field

Energy/LMP Inflation Rate: **2.00%**

							(A*C)+(B*D)-(E*F)							(H*J)+(I*K)-(L*M)	(G + N)
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
Year	**WE Zone Capacity Rate ($/kW-Month)**	**WE Zone Energy Rate ($/MWh)**	**WE Zone Average Demand (MW/Month)**	**WE Zone Annual Energy (MWh)**	**WE Zone Non-Firm Load (MW/Month)**	**WE Zone Non-Firm Credit ($/kW-Month)**	**WE Zone PPA Costs**	**WPS Zone Capacity Rate ($/kW-Month)**	**WPS Zone Energy Rate ($/MWh)**	**WPS Zone Average Demand (MW/Month)**	**WPS Zone Average Energy (MWh)**	**WPS Zone Non-Firm Load (MW/Month)**	**WPS Zone Non-Firm Credit ($/kW-Month)**	**WPS Zone PPA Costs**	**UMERC PPA Total Costs**
2017	**$27.25**	**$24.35**	**55.67**	**380,412**	**6.00**	**7.926**	$26,896,450	**$18.60**	**$30.05**	**36.20**	**260,300**	**14.27**	**7.000**	$14,703,175	$41,599,625
2018	**$27.90**	**$24.90**	55.67	380,412	6.00	7.926	$27,539,903	**$19.00**	**$30.95**	36.20	260,300	14.27	7.000	$15,111,205	$42,651,108
2019	**$28.45**	**$25.65**	55.67	380,412	6.00	7.926	$28,192,634	**$19.35**	**$31.90**	36.20	260,300	14.27	7.000	$15,510,530	$43,703,164
2020	**$29.00**	**$26.35**	55.67	380,412	6.00	7.926	$28,826,344	**$19.75**	**$32.85**	36.20	260,300	14.27	7.000	$15,931,575	$44,757,919
2021	**$29.60**	**$27.15**	55.67	380,412	6.00	7.926	$29,531,498	**$20.15**	**$33.85**	36.20	260,300	14.27	7.000	$16,365,635	$45,897,133
2022	**$30.20**	**$27.90**	55.67	380,412	6.00	7.926	$30,217,631	**$20.55**	**$34.85**	36.20	260,300	14.27	7.000	$16,799,695	$47,017,326
2023	**$30.80**	**$28.70**	55.67	380,412	6.00	7.926	$30,922,784	**$20.95**	**$35.90**	36.20	260,300	14.27	7.000	$17,246,770	$48,169,554
2024	**$31.40**	**$29.60**	55.67	380,412	6.00	7.926	$31,665,979	**$21.40**	**$37.00**	36.20	260,300	14.27	7.000	$17,728,580	$49,394,559
2025	**$32.05**	**$30.45**	55.67	380,412	6.00	7.926	$32,423,555	**$21.80**	**$38.20**	36.20	260,300	14.27	7.000	$18,214,700	$50,638,255
2026	**$32.70**	**$31.30**	55.67	380,412	6.00	7.926	$33,181,132	**$22.25**	**$39.25**	36.20	260,300	14.27	7.000	$18,683,495	$51,864,627
2027	$33.35	$31.93	55.67	380,412	6.00	7.926	$33,856,168	$22.70	$40.04	36.20	260,300	14.27	7.000	$19,081,139	$52,937,306
2028	$34.02	$32.56	55.67	380,412	6.00	7.926	$34,544,704	$23.15	$40.84	36.20	260,300	14.27	7.000	$19,486,735	$54,031,439
2029	$34.70	$33.22	55.67	380,412	6.00	7.926	$35,247,012	$23.61	$41.65	36.20	260,300	14.27	7.000	$19,900,443	$55,147,455
2030	$35.40	$33.88	55.67	380,412	6.00	7.926	$35,963,366	$24.08	$42.49	36.20	260,300	14.27	7.000	$20,322,426	$56,285,791
2031	$36.10	$34.56	55.67	380,412	6.00	7.926	$36,694,046	$24.57	$43.34	36.20	260,300	14.27	7.000	$20,752,848	$57,446,894
2032	$36.83	$35.25	55.67	380,412	6.00	7.926	$37,439,341	$25.06	$44.20	36.20	260,300	14.27	7.000	$21,191,878	$58,631,219
2033	$37.56	$35.95	55.67	380,412	6.00	7.926	$38,199,541	$25.56	$45.09	36.20	260,300	14.27	7.000	$21,639,689	$59,839,231
2034	$38.31	$36.67	55.67	380,412	6.00	7.926	$38,974,945	$26.07	$45.99	36.20	260,300	14.27	7.000	$22,096,457	$61,071,402
2035	$39.08	$37.41	55.67	380,412	6.00	7.926	$39,765,858	$26.59	$46.91	36.20	260,300	14.27	7.000	$22,562,360	$62,328,217
2036	$39.86	$38.15	55.67	380,412	6.00	7.926	$40,572,588	$27.12	$47.85	36.20	260,300	14.27	7.000	$23,037,580	$63,610,169
2037	$40.66	$38.92	55.67	380,412	6.00	7.926	$41,395,453	$27.67	$48.80	36.20	260,300	14.27	7.000	$23,522,306	$64,917,759
2038	$41.47	$39.70	55.67	380,412	6.00	7.926	$42,234,776	$28.22	$49.78	36.20	260,300	14.27	7.000	$24,016,725	$66,251,501
2039	$42.30	$40.49	55.67	380,412	6.00	7.926	$43,090,885	$28.78	$50.77	36.20	260,300	14.27	7.000	$24,521,033	$67,611,918
2040	$43.15	$41.30	55.67	380,412	6.00	7.926	$43,964,116	$29.36	$51.79	36.20	260,300	14.27	7.000	$25,035,428	$68,999,544
2041	$44.01	$42.13	55.67	380,412	6.00	7.926	$44,854,812	$29.95	$52.83	36.20	260,300	14.27	7.000	$25,560,110	$70,414,922
2042	$44.89	$42.97	55.67	380,412	6.00	7.926	$45,763,322	$30.54	$53.88	36.20	260,300	14.27	7.000	$26,095,286	$71,858,607
2043	$45.79	$43.83	55.67	380,412	6.00	7.926	$46,690,001	$31.16	$54.96	36.20	260,300	14.27	7.000	$26,641,165	$73,331,166
2044	$46.70	$44.70	55.67	380,412	6.00	7.926	$47,635,215	$31.78	$56.06	36.20	260,300	14.27	7.000	$27,197,962	$74,833,177
2045	$47.64	$45.60	55.67	380,412	6.00	7.926	$48,599,333	$32.41	$57.18	36.20	260,300	14.27	7.000	$27,765,895	$76,365,227
2046	$48.59	$46.51	55.67	380,412	6.00	7.926	$49,582,733	$33.06	$58.32	36.20	260,300	14.27	7.000	$28,345,186	$77,927,919
2047	$49.56	$47.44	55.67	380,412	6.00	7.926	$50,585,801	$33.72	$59.49	36.20	260,300	14.27	7.000	$28,936,063	$79,521,864
2048	$50.55	$48.39	55.67	380,412	6.00	7.926	$51,608,930	$34.40	$60.68	36.20	260,300	14.27	7.000	$29,538,758	$81,147,689
2049	$51.56	$49.36	55.67	380,412	6.00	7.926	$52,652,522	$35.09	$61.89	36.20	260,300	14.27	7.000	$30,153,507	$82,806,029

NOTE: Above calculation excludes transmission costs which will be the same regardless of scenario

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*** * * * ***

In the Matter of the Application of	)	
Upper Michigan Energy Resources Corporation	)	
for approval of a Certificate of Necessity	)	
pursuant to MCL 460.6s for	)	Case No. U-18224
Two Reciprocating Internal Combustion Engine	)	
Electric Generation Facilities Located in the	)	
Upper Peninsula of Michigan,	)	
Approval of Certificate(s) of Public Convenience	)	
And Necessity, approval of a Special Contract with	)	
Tilden Mining Company L.C.	)	
and related accounting and ratemaking	)	
authorizations.	)	

2016 Integrated Resource Plan for
Upper Michigan Energy Resources Corporation Beginning in 2019

Attachment B

UP Gen Project (U-18224) -- IRP

Spreadsheet Name: IRP Attachment B - UP Gen UMERC Allocation Impact (MPSC Filing-Gas +$1).xlsx
Sheet Name: NPV Analysis

General Assumptions:
RICE In-service Date of 6/30/19

	50% 2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
UMERC																	
(+) Reduced PPA Cost[1]	22,134,703	45,324,162	46,463,375	47,583,568	48,735,797	49,960,802	51,204,498	52,430,869	53,514,874	54,620,558	55,748,356	56,898,710	58,072,072	59,268,900	60,489,665	61,734,846	63,004,930
(+) Avoided Transmission ($300M)[2]							403,048	394,093	386,486	381,215	375,897	370,538	365,139	359,704	354,070	348,221	342,337
(-) Return Of PIPP Net Plant[3]		(950,529)	(892,716)	(838,406)	(794,683)	(749,694)	(703,704)	(656,273)	(607,043)	(557,004)	(506,976)	(165)					
(-) UP Gen Cost[4]	(23,952,604)	(46,217,996)	(45,219,843)	(44,399,944)	(43,601,330)	(43,768,467)	(43,801,076)	(44,178,211)	(44,351,962)	(44,731,148)	(45,113,893)	(45,159,455)	(45,091,457)	(45,010,923)	(45,836,127)	(46,251,632)	(46,192,754)
Total	(1,817,901)	(1,844,363)	350,817	2,345,219	4,339,784	5,442,640	7,102,766	7,990,478	8,942,355	9,713,621	10,503,385	12,109,628	13,345,753	14,617,681	15,007,608	15,831,435	17,154,513

	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	50% 2049
UMERC														
(+) Reduced PPA Cost[1]	64,300,415	65,621,810	66,969,634	68,344,413	69,746,689	71,177,010	72,635,937	74,124,043	75,641,910	77,190,136	78,769,325	80,380,099	82,023,088	41,849,468
(+) Avoided Transmission ($300M)[2]	336,453	330,568	324,684	318,799	312,915	307,031	301,146	295,262	289,377	284,806	281,546	276,975	271,090	132,603
(-) Return Of PIPP Net Plant[3]														
(-) UP Gen Cost[4]	(46,340,231)	(46,847,878)	(47,020,748)	(46,970,584)	(47,495,806)	(47,856,819)	(48,212,686)	(48,677,632)	(48,952,879)	(49,098,411)	(49,866,121)	(50,630,721)	(50,916,055)	(25,412,439)
Total	18,296,637	19,104,500	20,273,570	21,692,629	22,563,798	23,627,221	24,724,397	25,741,672	26,978,408	28,376,531	29,184,751	30,026,352	31,378,124	16,569,632

Discount Rate	7.22%
20 Year NPV	60,711,027
30 Year NPV	60,711,027

[1]The total projected cost of the WE and WPS Power Purchase Agreements
[2]The avoided ATC LLC transmission cost allocation of the projected $300 million avoided net transmission cost associated with the installation of the UP Gen units
[3]Cost associated with the recovery of the 6.595% of the PIPP costs allocated to Michigan with recovery over 10-years.
[4]Cost associated with the UP Gen solution

UP Gen Project (U-18224) -- IRP

Spreadsheet Name: IRP Attachment B - UP Gen UMERC Allocation Impact (MPSC Filing-Gas +$1).xlsx
Sheet Name: Avoided Transmission

= Input Field

Avoided Transmission Cost Estimation

ASSUMPTIONS:

Avoided Investment	##########			UMERC Allocation:	0.94%
Useful Life (for return of)	50	years			
Tax Rate	40.00%				
Bonus Depreciation	0.00%				
O&M Rate	2.00%				
Weighted Average Cost of Capital					
	%	Cost	Weighted		
Debt	50.00%	4.20%	2.100%		
Equity	50.00%	10.00%	5.000%		
	100%		7.100%		

CALCULATION:

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
Accumulated Depreciation	6,000,000	12,000,000	18,000,000	24,000,000	30,000,000	36,000,000	42,000,000	48,000,000	54,000,000	60,000,000	66,000,000	72,000,000	78,000,000	84,000,000	90,000,000	96,000,000	102,000,000	108,000,000	114,000,000	120,000,000	126,000,000	132,000,000	138,000,000	144,000,000	150,000,000	156,000,000	162,000,000	168,000,000	174,000,000	180,000,000	183,000,000
Net Plant	294,000,000	288,000,000	282,000,000	276,000,000	270,000,000	264,000,000	258,000,000	252,000,000	246,000,000	240,000,000	234,000,000	228,000,000	222,000,000	216,000,000	210,000,000	204,000,000	198,000,000	192,000,000	186,000,000	180,000,000	174,000,000	168,000,000	162,000,000	156,000,000	150,000,000	144,000,000	138,000,000	132,000,000	126,000,000	120,000,000	117,000,000
Depreciation Expense (Return of)	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**3,000,000**
20 Year Macrs	3.75%	7.22%	6.68%	6.18%	5.71%	5.29%	4.89%	4.52%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	2.23%										
Tax Depreciation	11,250,000	21,657,000	20,031,000	18,531,000	17,139,000	15,855,000	14,664,000	13,566,000	13,386,000	13,383,000	13,386,000	13,383,000	13,386,000	13,383,000	13,386,000	13,383,000	13,386,000	13,383,000	13,386,000	13,383,000	6,693,000	-	-	-	-	-	-	-	-	-	-
Deferred Taxes	(2,100,000)	(6,262,800)	(5,612,400)	(5,012,400)	(4,455,600)	(3,942,000)	(3,465,600)	(3,026,400)	(2,954,400)	(2,953,200)	(2,954,400)	(2,953,200)	(2,954,400)	(2,953,200)	(2,954,400)	(2,953,200)	(2,954,400)	(2,953,200)	(2,954,400)	(2,953,200)	(277,200)	2,400,000	2,400,000	2,400,000	2,400,000	2,400,000	2,400,000	2,400,000	2,400,000	2,400,000	1,200,000
Beginning Rate Base	300,000,000	291,900,000	281,737,200	276,387,600	270,987,600	265,544,400	260,058,000	254,534,400	248,973,600	243,045,600	237,046,800	231,045,600	225,046,800	219,045,600	213,046,800	207,045,600	201,046,800	195,045,600	189,046,800	183,045,600	177,046,800	173,722,800	170,400,000	164,400,000	158,400,000	152,400,000	146,400,000	140,400,000	134,400,000	128,400,000	122,400,000
Ending Rate Base	291,900,000	281,737,200	276,387,600	270,987,600	265,544,400	260,058,000	254,534,400	248,973,600	243,045,600	237,046,800	231,045,600	225,046,800	219,045,600	213,046,800	207,045,600	201,046,800	195,045,600	189,046,800	183,045,600	177,046,800	173,722,800	170,400,000	164,400,000	158,400,000	152,400,000	146,400,000	140,400,000	134,400,000	128,400,000	122,400,000	118,200,000
Average Rate Base	295,950,000	286,818,600	279,062,400	273,687,600	268,266,000	262,801,200	257,296,200	251,754,000	246,009,600	240,046,200	234,046,200	228,046,200	222,046,200	216,046,200	210,046,200	204,046,200	198,046,200	192,046,200	186,046,200	180,046,200	175,384,800	172,061,400	167,400,000	161,400,000	155,400,000	149,400,000	143,400,000	137,400,000	131,400,000	125,400,000	120,300,000
Revenue Requirement (Return On)	**30,877,450**	**29,924,741**	**29,115,510**	**28,554,740**	**27,989,086**	**27,418,925**	**26,844,570**	**26,266,334**	**25,667,002**	**25,044,820**	**24,418,820**	**23,792,820**	**23,166,820**	**22,540,820**	**21,914,820**	**21,288,820**	**20,662,820**	**20,036,820**	**19,410,820**	**18,784,820**	**18,298,481**	**17,951,739**	**17,465,400**	**16,839,400**	**16,213,400**	**15,587,400**	**14,961,400**	**14,335,400**	**13,709,400**	**13,083,400**	**12,551,300**
O&M Expense (Return Of)	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**
System Avoided Cost of $300M Investment	**42,877,450**	**41,924,741**	**41,115,510**	**40,554,740**	**39,989,086**	**39,418,925**	**38,844,570**	**38,266,334**	**37,667,002**	**37,044,820**	**36,418,820**	**35,792,820**	**35,166,820**	**34,540,820**	**33,914,820**	**33,288,820**	**32,662,820**	**32,036,820**	**31,410,820**	**30,784,820**	**30,298,481**	**29,951,739**	**29,465,400**	**28,839,400**	**28,213,400**	**27,587,400**	**26,961,400**	**26,335,400**	**25,709,400**	**25,083,400**	**21,551,300**

UP Gen Project (U-18224) -- IRP

Spreadsheet Name: IRP Attachment B - UP Gen UMERC Allocation Impact (MPSC Filing-Gas +$1).xlsx
Sheet Name: PIPP Retirement Cost

= Input Field

PIPP Retirement Cost Recovery Estimation

ASSUMPTIONS:

Projected PIPP Book Value:	**175,895,000**
Projected Decommissioning Cost:	**30,000,000**
Total PIPP Recovery:	205,895,000
Michigan PIPP Allocation (%):	**6.595%**
Michigan PIPP Allocation:	13,578,775
Non-Mine UMERC Allocation (%):	**35%**
Non-Mine UMERC Allocation:	4,752,571
Recovery Period (years):	**10**
Tax Rate:	38.9%

Weighted Average Cost of Capital

	%	Cost	Weighted	**Tax Rate**	
Debt	**48.00%**	**4.20%**	2.016%	Federal	**35.00%**
Equity	**52.00%**	**10.00%**	5.200%	State-MI	**6.00%**
	100%		7.216%	Effective Rate	38.9%

CALCULATION:

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Accumulated Depreciation	475,257	950,514	1,425,771	1,901,029	2,376,286	2,851,543	3,326,800	3,802,057	4,277,314	4,752,571	4,752,571
Net Plant	4,277,314	3,802,057	3,326,800	2,851,543	2,376,286	1,901,029	1,425,771	950,514	475,257	-	-
Depreciation Expense (Return of)	**475,257**	**475,257**	**475,257**	**475,257**	**475,257**	**475,257**	**475,257**	**475,257**	**475,257**	**475,257**	**-**
10 Year Macrs	10.00%	18.00%	14.40%	11.52%	9.22%	7.37%	6.55%	6.55%	6.56%	6.55%	3.28%
Tax Depreciation	475,257	855,463	684,370	547,496	438,187	350,265	311,293	311,293	311,769	311,293	155,884
Deferred Taxes	(0)	(147,900)	(81,345)	(28,101)	14,420	48,622	63,782	63,782	63,597	63,782	(60,639)
Beginning Rate Base	4,752,571	4,277,314	3,654,157	3,245,455	2,823,442	2,390,706	1,949,651	1,489,553	1,014,296	538,854	63,782
Ending Rate Base	4,277,314	3,654,157	3,245,455	2,823,442	2,390,706	1,949,651	1,489,553	1,014,296	538,854	63,782	(60,639)
Average Rate Base	4,514,943	3,965,736	3,449,806	3,034,448	2,607,074	2,170,178	1,719,602	1,251,925	776,575	301,318	1,571
Revenue Requirement (Return On)	**475,272**	**417,459**	**363,149**	**319,425**	**274,437**	**228,447**	**181,016**	**131,786**	**81,747**	**31,719**	**165**
PIPP Retirement Cost	**950,529**	**892,716**	**838,406**	**794,683**	**749,694**	**703,704**	**656,273**	**607,043**	**557,004**	**506,976**	**165**

UP Gen Project (U-18224) -- IRP

Spreadsheet Name: IRP Attachment B - UP Gen UMERC Allocation Impact (MPSC Filing-Gas +$1).xlsx
Sheet Name: UP Gen Rate Base

= Input Field

	Equity	Debt	Total
Capital Structure	52.00%	48.00%	100.00%
Cost of Capital	10.00%	4.20%	
Wtd Cost of Capital (discount rate)	5.20%	2.02%	**7.22%**
Tax Gross-up	1.637		
Economic Cost of Capital	8.51%	2.02%	**10.53%**

Tax Rate	
Federal	35.00%
State-MI	6.00%
Effective Rate	**38.9%**

Yrs In-Service				1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Year	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Total CAPEX																		
Initial Construction	10,700,000	178,465,744	76,524,040															
Capital Improvements				-	-	3,325,000	1,425,000	5,780,000	-	10,530,000	-	10,530,000	4,750,000	700,000	330,000	-	20,030,000	-
AFUDC																		
Debt	45,768	1,646,083	1,704,577															
Equity	108,853	3,915,008	4,054,129															
Book Basis	10,854,621	194,881,455	277,164,200	277,164,200	277,164,200	280,489,200	281,914,200	287,694,200	287,694,200	298,224,200	298,224,200	308,754,200	313,504,200	314,204,200	314,534,200	314,534,200	334,564,200	334,564,200
Tax Basis	10,745,768	190,857,594	269,086,211	269,086,211	269,086,211	272,411,211	273,836,211	279,616,211	279,616,211	290,146,211	290,146,211	300,676,211	305,426,211	306,126,211	306,456,211	306,456,211	326,486,211	326,486,211
Months In-Service			6	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
Book Depreciation 3.94%			5,463,858	10,927,715	10,927,715	11,058,809	11,114,993	11,342,880	11,342,880	11,758,045	11,758,045	12,173,210	12,360,487	12,388,086	12,401,097	12,401,097	13,190,817	13,190,817
AFUDC Equity Amort included in book depr			*134,633*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*
Bonus %	50%	40%	30%															
Tax Depreciation	-	-	87,789,376	13,597,733	12,576,820	11,759,706	11,054,496	10,496,475	9,924,844	9,576,440	9,778,967	10,068,767	10,518,846	10,571,901	10,464,936	10,352,844	10,994,839	11,614,523
Rate Base (Total)																		
PP&E - Gross	10,854,621	194,881,455	277,164,200	277,164,200	277,164,200	280,489,200	281,914,200	287,694,200	287,694,200	298,224,200	298,224,200	308,754,200	313,504,200	314,204,200	314,534,200	314,534,200	334,564,200	334,564,200
Accum Depreciation			(5,463,858)	(16,391,573)	(27,319,288)	(38,378,097)	(49,493,090)	(60,835,970)	(72,178,850)	(83,936,894)	(95,694,939)	(107,868,149)	(120,228,636)	(132,616,722)	(145,017,819)	(157,418,916)	(170,609,733)	(183,800,550)
Accum Deferred Income Tax			(32,076,999)	(33,220,381)	(33,966,627)	(34,344,021)	(34,425,232)	(34,200,725)	(33,753,854)	(33,009,955)	(32,344,838)	(31,630,954)	(31,019,300)	(30,417,549)	(29,769,127)	(29,077,101)	(28,327,610)	(27,819,176)
Working Capital			3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000
Net Rate Base-EOY	10,854,621	194,881,455	242,623,344	230,552,247	218,878,285	210,767,082	200,995,878	195,657,505	184,761,497	184,277,351	173,184,423	172,255,097	165,256,264	154,169,929	142,747,254	131,038,183	138,626,857	125,944,474
Net Rate Base-Avg			130,696,886	236,587,795	224,715,266	214,822,684	205,881,480	198,326,692	190,209,501	184,519,424	178,730,887	172,719,760	168,755,681	159,713,097	148,458,592	136,892,719	134,832,520	132,285,666

Yrs In-Service	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	
Year	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**Total**
Total CAPEX																
Initial Construction																265,689,783
Capital Improvements	1,030,000	4,750,000	10,530,000	-	-	10,530,000	-	5,780,000	4,750,000	1,030,000	-	14,000,000	6,030,000	-	-	115,830,000
AFUDC																
Debt																3,396,427
Equity																8,077,990
Book Basis	335,594,200	340,344,200	350,874,200	350,874,200	350,874,200	361,404,200	361,404,200	367,184,200	371,934,200	372,964,200	372,964,200	386,964,200	392,994,200	392,994,200	392,994,200	-
Tax Basis	327,516,211	332,266,211	342,796,211	342,796,211	342,796,211	353,326,211	353,326,211	359,106,211	363,856,211	364,886,211	364,886,211	378,886,211	384,916,211	384,916,211	384,916,211	-
Months In-Service	12	12	12	12	12	12	12	12	12	12	12	12	12	12	6	360
Book Depreciation	13,231,427	13,418,704	13,833,869	13,833,869	13,833,869	14,249,034	14,249,034	14,476,921	14,664,199	14,704,809	14,704,809	15,256,785	15,494,529	15,494,529	7,747,264	392,994,200
AFUDC Equity Amort included in book depr	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*134,633*	*8,077,990*
Bonus %																
Tax Depreciation	11,484,362	11,568,472	12,024,477	12,269,868	7,903,866	3,944,257	4,224,003	4,241,847	4,402,041	4,323,137	4,123,881	4,315,899	4,702,498	4,546,294	39,699,795	384,916,211
Rate Base (Total)																
PP&E - Gross	335,594,200	340,344,200	350,874,200	350,874,200	350,874,200	361,404,200	361,404,200	367,184,200	371,934,200	372,964,200	372,964,200	386,964,200	392,994,200	392,994,200	392,994,200	
Accum Depreciation	(197,031,977)	(210,450,681)	(224,284,550)	(238,118,419)	(251,952,288)	(266,201,322)	(280,450,356)	(294,927,278)	(309,591,477)	(324,296,285)	(339,001,094)	(354,257,878)	(369,752,407)	(385,246,936)	(392,994,200)	
Accum Deferred Income Tax	(27,244,313)	(26,629,317)	(26,030,208)	(25,526,556)	(23,324,529)	(19,420,716)	(15,625,723)	(11,749,024)	(7,861,789)	(9,928,063)	83,173	4,234,433	8,327,788	12,481,907	(0)	
Working Capital	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	
Net Rate Base-EOY	114,317,911	106,264,202	103,559,442	90,229,225	78,597,383	78,782,162	68,328,121	63,507,899	57,480,935	47,739,852	37,046,280	39,940,755	34,569,581	23,229,171	3,000,000	
Net Rate Base-Avg	120,131,192	110,291,057	104,911,822	96,894,334	84,413,304	78,689,772	73,555,141	65,918,010	60,494,417	52,610,393	42,393,066	38,493,517	37,255,168	28,899,376	6,557,293	

UP Gen Project (U-18224) -- IRP

Spreadsheet Name: IRP Attachment B - UP Gen UMERC Allocation Impact (MPSC Filing-Gas +$1).xlsx
Sheet Name: UP Gen (Base Rev Rqrmnt Calc)

= Input Field

O&M and A&G Inflation Rate: **2.00%**

Capital Cost Allocation: **50.00%**

						(A) * (B)						(C+D+E+F+G+H)
				(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	Year	Months In-Serv	Asset Life	Average Rate Base	Economic Cost of Capital	"Return On" Rate Base	Tax Impact AFUDC Amoritization	Depreciation Expense	Allocated A&G Expense	NNG Pipeline Cost	Property Tax	Total Base Revenue Requirement
In-Service 6/30/2019	2019	**6**	**30**	$65,348,443	**10.53%**	$6,878,994	$42,858	$2,731,929	**$867,249**	**$2,155,836**	**$2,927,782**	$15,604,647
	2020	12	30	$118,293,898	10.53%	$12,452,371	$85,716	$5,463,858	$1,769,187	$4,311,672	$5,855,563	$29,938,366
	2021	12	30	$112,357,633	10.53%	$11,827,482	$85,716	$5,463,858	$1,804,571	$4,311,672	$5,855,563	$29,348,861
	2022	12	30	$107,411,342	10.53%	$11,306,803	$85,716	$5,529,405	$1,840,662	$4,311,672	$5,855,563	$28,929,821
	2023	12	30	$102,940,740	10.53%	$10,836,199	$85,716	$5,557,496	$1,877,475	$4,311,672	$5,855,563	$28,524,122
	2024	12	30	$99,163,346	10.53%	$10,438,567	$85,716	$5,671,440	$1,915,025	$4,311,672	$5,855,563	$28,277,982
	2025	12	30	$95,104,750	10.53%	$10,011,333	$85,716	$5,671,440	$1,953,325	$4,311,672	$5,855,563	$27,889,049
	2026	12	30	$92,259,712	10.53%	$9,711,846	$85,716	$5,879,022	$1,992,392	$4,311,672	$5,855,563	$27,836,211
	2027	12	30	$89,365,444	10.53%	$9,407,177	$85,716	$5,879,022	$2,032,240	$4,311,672	$5,855,563	$27,571,390
	2028	12	30	$86,359,880	10.53%	$9,090,792	$85,716	$6,086,605	$2,072,884	$4,311,672	$5,855,563	$27,503,232
	2029	12	30	$84,377,840	10.53%	$8,882,150	$85,716	$6,180,244	$2,114,342	$4,311,672	$5,855,563	$27,429,687
	2030	12	30	$79,856,548	10.53%	$8,406,210	$85,716	$6,194,043	$2,156,629	$4,311,672	$5,855,563	$27,009,833
	2031	12	30	$74,229,296	10.53%	$7,813,849	$85,716	$6,200,548	$2,199,762	$4,311,672	$5,855,563	$26,467,110
	2032	12	30	$68,446,359	10.53%	$7,205,101	$85,716	$6,200,548	$2,243,757	$4,311,672	$5,855,563	$25,902,357
	2033	12	30	$67,416,260	10.53%	$7,096,666	$85,716	$6,595,409	$2,288,632	$4,311,672	$5,855,563	$26,233,657
	2034	12	30	$66,142,833	10.53%	$6,962,617	$85,716	$6,595,409	$2,334,405	$4,311,672	$5,855,563	$26,145,381
	2035	12	30	$60,065,596	10.53%	$6,322,888	$85,716	$6,615,713	$2,381,093	$4,311,672	$5,855,563	$25,572,645
	2036	12	30	$55,145,528	10.53%	$5,804,970	$85,716	$6,709,352	$2,428,715	$4,311,672	$5,855,563	$25,195,988
	2037	12	30	$52,455,911	10.53%	$5,521,844	$85,716	$6,916,935	$2,477,289	$4,311,672	$5,855,563	$25,169,018
	2038	12	30	$48,447,167	10.53%	$5,099,858	$85,716	$6,916,935	$2,526,835	$4,311,672	$5,855,563	$24,796,578
	2039	12	30	$42,206,652	10.53%	$4,442,942	$85,716	$6,916,935	$2,577,371	$4,311,672	$5,855,563	$24,190,198
	2040	12	30	$39,344,886	10.53%	$4,141,694	$85,716	$7,124,517	$2,628,919	$4,311,672	$5,855,563	$24,148,080
	2041	12	30	$36,777,571	10.53%	$3,871,442	$85,716	$7,124,517	$2,681,497	$4,311,672	$5,855,563	$23,930,407
	2042	12	30	$32,959,005	10.53%	$3,469,475	$85,716	$7,238,461	$2,735,127	$4,311,672	$5,855,563	$23,696,014
	2043	12	30	$30,247,208	10.53%	$3,184,014	$85,716	$7,332,099	$2,789,830	$4,311,672	$5,855,563	$23,558,894
	2044	12	30	$26,305,197	10.53%	$2,769,053	$85,716	$7,352,404	$2,845,626	$4,311,672	$5,855,563	$23,220,034
	2045	12	30	$21,196,533	10.53%	$2,231,282	$85,716	$7,352,404	$2,902,539	$4,311,672	$5,855,563	$22,739,176
	2046	12	30	$19,246,759	10.53%	$2,026,037	$85,716	$7,628,392	$2,960,589	$4,311,672	$5,855,563	$22,867,969
	2047	12	30	$18,627,584	10.53%	$1,960,858	$85,716	$7,747,264	$3,019,801	$4,311,672	$5,855,563	$22,980,875
	2048	12	30	$14,449,688	10.53%	$1,521,066	$85,716	$7,747,264	$3,080,197	$4,311,672	$5,855,563	$22,601,479
	2049	6	30	$3,278,646	10.53%	$345,131	$42,858	$3,873,632	$1,570,901	$2,155,836	$2,927,782	$10,916,139

UP Gen Project (U-18224) -- IRP

Spreadsheet Name: IRP Attachment B - UP Gen UMERC Allocation Impact (MPSC Filing-Gas +$1).xlsx
Sheet Name: UP Gen Cost

= Input Field

Energy/LMP Inflation Rate: **2.00%**

				(A * C)					0.1 * (G * H)	(G * B)	(I + J) - (D + E + F)		(H + I)
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(H)	(I)	(J)
Year	**Market Capacity Value ($/MW-Year)**	**UP Gen Estimated LMP ($/MWh)**	**UP Gen Excess Capacity (MW)**	**UP Gen Excess Capacity Value**	**UP Gen Energy Sales Value**	**UP Gen Ancillary Sales Value**	**UP Gen Total UMERC Load (MWh)**	**UP Gen REC Cost ($/REC)**	**UP Gen Renewables Cost**	**UP Gen Load Purchase Cost**	**Annualized UP Gen Total Energy Costs**	**Annualized UP Gen Base Rev Req Costs**	**Annualized Up Gen Total Costs**
2017													
2018													
2019	**$26,250**	**$30.90**	**91.2**	$2,394,263	**$374,438**	**$525,600**	**640,712**	**$3.00**	$192,214	$19,798,001	$16,695,914	$31,209,294	$47,905,208
2020	**$35,000**	$31.52	91.2	$3,192,350	$381,927	$536,112	640,712	$3.06	$196,058	$20,193,961	$16,279,630	$29,938,366	$46,217,996
2021	**$43,750**	$32.15	91.2	$3,990,438	$389,565	$546,834	640,712	$3.12	$199,979	$20,597,840	$15,870,982	$29,348,861	$45,219,843
2022	**$52,500**	$32.79	91.2	$4,788,525	$397,357	$557,771	640,712	$3.18	$203,979	$21,009,797	$15,470,123	$28,929,821	$44,399,944
2023	**$61,250**	$33.45	91.2	$5,586,613	$405,304	$568,926	640,712	$3.25	$208,058	$21,429,993	$15,077,208	$28,524,122	$43,601,330
2024	**$61,250**	$34.12	91.2	$5,586,613	$413,410	$580,305	640,712	$3.31	$212,219	$21,858,593	$15,490,485	$28,277,982	$43,768,467
2025	**$61,250**	$34.80	91.2	$5,586,613	$421,678	$591,911	640,712	$3.38	$216,464	$22,295,764	$15,912,027	$27,889,049	$43,801,076
2026	**$61,250**	$35.49	91.2	$5,586,613	$430,112	$603,749	640,712	$3.45	$220,793	$22,741,680	$16,342,000	$27,836,211	$44,178,211
2027	**$61,250**	$36.20	91.2	$5,586,613	$438,714	$615,824	640,712	$3.51	$225,209	$23,196,513	$16,780,572	$27,571,390	$44,351,962
2028	**$61,250**	$36.93	91.2	$5,586,613	$447,488	$628,141	640,712	$3.59	$229,713	$23,660,444	$17,227,915	$27,503,232	$44,731,148
2029	**$61,250**	$37.67	91.2	$5,586,613	$456,438	$640,703	640,712	$3.66	$234,307	$24,133,653	$17,684,206	$27,429,687	$45,113,893
2030	**$61,250**	$38.42	91.2	$5,586,613	$465,567	$653,518	640,712	$3.73	$238,993	$24,616,326	$18,149,622	$27,009,833	$45,159,455
2031	**$61,250**	$39.19	91.2	$5,586,613	$474,878	$666,588	640,712	$3.80	$243,773	$25,108,652	$18,624,347	$26,467,110	$45,091,457
2032	**$61,250**	$39.97	91.2	$5,586,613	$484,375	$679,920	640,712	$3.88	$248,649	$25,610,825	$19,108,566	$25,902,357	$45,010,923
2033	**$61,250**	$40.77	91.2	$5,586,613	$494,063	$693,518	640,712	$3.96	$253,622	$26,123,042	$19,602,470	$26,233,657	$45,836,127
2034	**$61,250**	$41.59	91.2	$5,586,613	$503,944	$707,388	640,712	$4.04	$258,694	$26,645,502	$20,106,251	$26,145,381	$46,251,632
2035	**$61,250**	$42.42	91.2	$5,586,613	$514,023	$721,536	640,712	$4.12	$263,868	$27,178,412	$20,620,109	$25,572,645	$46,192,754
2036	**$61,250**	$43.27	91.2	$5,586,613	$524,304	$735,967	640,712	$4.20	$269,145	$27,721,981	$21,144,243	$25,195,988	$46,340,231
2037	**$61,250**	$44.13	91.2	$5,586,613	$534,790	$750,686	640,712	$4.28	$274,528	$28,276,420	$21,678,860	$25,169,018	$46,847,878
2038	**$61,250**	$45.02	91.2	$5,586,613	$545,485	$765,700	640,712	$4.37	$280,019	$28,841,949	$22,224,170	$24,796,578	$47,020,748
2039	**$61,250**	$45.92	91.2	$5,586,613	$556,395	$781,014	640,712	$4.46	$285,619	$29,418,788	$22,780,385	$24,190,198	$46,970,584
2040	**$61,250**	$46.83	91.2	$5,586,613	$567,523	$796,634	640,712	$4.55	$291,332	$30,007,163	$23,347,725	$24,148,080	$47,495,806
2041	**$61,250**	$47.77	91.2	$5,586,613	$578,874	$812,567	640,712	$4.64	$297,158	$30,607,307	$23,926,412	$23,930,407	$47,856,819
2042	**$61,250**	$48.73	91.2	$5,586,613	$590,451	$828,818	640,712	$4.73	$303,101	$31,219,453	$24,516,673	$23,696,014	$48,212,686
2043	**$61,250**	$49.70	91.2	$5,586,613	$602,260	$845,395	640,712	$4.83	$309,164	$31,843,842	$25,118,738	$23,558,894	$48,677,632
2044	**$61,250**	$50.69	91.2	$5,586,613	$614,305	$862,303	640,712	$4.92	$315,347	$32,480,719	$25,732,845	$23,220,034	$48,952,879
2045	**$61,250**	$51.71	91.2	$5,586,613	$626,591	$879,549	640,712	$5.02	$321,654	$33,130,333	$26,359,234	$22,739,176	$49,098,411
2046	**$61,250**	$52.74	91.2	$5,586,613	$639,123	$897,140	640,712	$5.12	$328,087	$33,792,940	$26,998,151	$22,867,969	$49,866,121
2047	**$61,250**	$53.80	91.2	$5,586,613	$651,906	$915,082	640,712	$5.22	$334,649	$34,468,799	$27,649,847	$22,980,875	$50,630,721
2048	**$61,250**	$54.87	91.2	$5,586,613	$664,944	$933,384	640,712	$5.33	$341,342	$35,158,175	$28,314,576	$22,601,479	$50,916,055
2049	**$61,250**	$55.97	91.2	$5,586,613	$678,243	$952,052	640,712	$5.43	$348,168	$35,861,338	$28,992,600	$21,832,279	$50,824,878

NOTE: Above calculation excludes transmission costs which will be the same regardless of scenario

UP Gen Project (U-18224) -- IRP

Spreadsheet Name: IRP Attachment B - UP Gen UMERC Allocation Impact (MPSC Filing-Gas +$1).xlsx
Sheet Name: PPA Costs

= Input Field

Energy/LMP Inflation Rate: **2.00%**

							(A*C)+(B*D)-(E*F)							(H*J)+(I*K)-(L*M)	(G + N)
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
Year	**WE Zone Capacity Rate ($/kW-Month)**	**WE Zone Energy Rate ($/MWh)**	**WE Zone Average Demand (MW/Month)**	**WE Zone Annual Energy (MWh)**	**WE Zone Non-Firm Load (MW/Month)**	**WE Zone Non-Firm Credit ($/kW-Month)**	**WE Zone PPA Costs**	**WPS Zone Capacity Rate ($/kW-Month)**	**WPS Zone Energy Rate ($/MWh)**	**WPS Zone Average Demand (MW/Month)**	**WPS Zone Average Energy (MWh)**	**WPS Zone Non-Firm Load (MW/Month)**	**WPS Zone Non-Firm Credit ($/kW-Month)**	**WPS Zone PPA Costs**	**UMERC PPA Total Costs**
2017	**$27.25**	**$24.73**	**55.67**	**380,412**	**6.00**	**7.926**	$27,041,007	**$18.60**	**$31.67**	**36.20**	**260,300**	**14.27**	**7.000**	$15,124,861	$42,165,868
2018	**$27.90**	**$25.28**	55.67	380,412	6.00	7.926	$27,684,459	**$19.00**	**$32.57**	36.20	260,300	14.27	7.000	$15,532,891	$43,217,350
2019	**$28.45**	**$26.03**	55.67	380,412	6.00	7.926	$28,337,190	**$19.35**	**$33.52**	36.20	260,300	14.27	7.000	$15,932,216	$44,269,406
2020	**$29.00**	**$26.73**	55.67	380,412	6.00	7.926	$28,970,901	**$19.75**	**$34.47**	36.20	260,300	14.27	7.000	$16,353,261	$45,324,162
2021	**$29.60**	**$27.53**	55.67	380,412	6.00	7.926	$29,676,054	**$20.15**	**$35.47**	36.20	260,300	14.27	7.000	$16,787,321	$46,463,375
2022	**$30.20**	**$28.28**	55.67	380,412	6.00	7.926	$30,362,187	**$20.55**	**$36.47**	36.20	260,300	14.27	7.000	$17,221,381	$47,583,568
2023	**$30.80**	**$29.08**	55.67	380,412	6.00	7.926	$31,067,341	**$20.95**	**$37.52**	36.20	260,300	14.27	7.000	$17,668,456	$48,735,797
2024	**$31.40**	**$29.98**	55.67	380,412	6.00	7.926	$31,810,536	**$21.40**	**$38.62**	36.20	260,300	14.27	7.000	$18,150,266	$49,960,802
2025	**$32.05**	**$30.83**	55.67	380,412	6.00	7.926	$32,568,112	**$21.80**	**$39.82**	36.20	260,300	14.27	7.000	$18,636,386	$51,204,498
2026	**$32.70**	**$31.68**	55.67	380,412	6.00	7.926	$33,325,688	**$22.25**	**$40.87**	36.20	260,300	14.27	7.000	$19,105,181	$52,430,869
2027	$33.35	$32.31	55.67	380,412	6.00	7.926	$34,003,615	$22.70	$41.69	36.20	260,300	14.27	7.000	$19,511,258	$53,514,874
2028	$34.02	$32.96	55.67	380,412	6.00	7.926	$34,695,101	$23.15	$42.52	36.20	260,300	14.27	7.000	$19,925,457	$54,620,558
2029	$34.70	$33.62	55.67	380,412	6.00	7.926	$35,400,417	$23.61	$43.37	36.20	260,300	14.27	7.000	$20,347,940	$55,748,356
2030	$35.40	$34.29	55.67	380,412	6.00	7.926	$36,119,838	$24.08	$44.24	36.20	260,300	14.27	7.000	$20,778,872	$56,898,710
2031	$36.10	$34.98	55.67	380,412	6.00	7.926	$36,853,649	$24.57	$45.12	36.20	260,300	14.27	7.000	$21,218,423	$58,072,072
2032	$36.83	$35.68	55.67	380,412	6.00	7.926	$37,602,135	$25.06	$46.03	36.20	260,300	14.27	7.000	$21,666,765	$59,268,900
2033	$37.56	$36.39	55.67	380,412	6.00	7.926	$38,365,591	$25.56	$46.95	36.20	260,300	14.27	7.000	$22,124,074	$60,489,665
2034	$38.31	$37.12	55.67	380,412	6.00	7.926	$39,144,316	$26.07	$47.89	36.20	260,300	14.27	7.000	$22,590,529	$61,734,846
2035	$39.08	$37.86	55.67	380,412	6.00	7.926	$39,938,616	$26.59	$48.84	36.20	260,300	14.27	7.000	$23,066,313	$63,004,930
2036	$39.86	$38.62	55.67	380,412	6.00	7.926	$40,748,802	$27.12	$49.82	36.20	260,300	14.27	7.000	$23,551,613	$64,300,415
2037	$40.66	$39.39	55.67	380,412	6.00	7.926	$41,575,191	$27.67	$50.82	36.20	260,300	14.27	7.000	$24,046,619	$65,621,810
2038	$41.47	$40.18	55.67	380,412	6.00	7.926	$42,418,109	$28.22	$51.83	36.20	260,300	14.27	7.000	$24,551,525	$66,969,634
2039	$42.30	$40.98	55.67	380,412	6.00	7.926	$43,277,884	$28.78	$52.87	36.20	260,300	14.27	7.000	$25,066,529	$68,344,413
2040	$43.15	$41.80	55.67	380,412	6.00	7.926	$44,154,855	$29.36	$53.93	36.20	260,300	14.27	7.000	$25,591,833	$69,746,689
2041	$44.01	$42.64	55.67	380,412	6.00	7.926	$45,049,366	$29.95	$55.01	36.20	260,300	14.27	7.000	$26,127,644	$71,177,010
2042	$44.89	$43.49	55.67	380,412	6.00	7.926	$45,961,767	$30.54	$56.11	36.20	260,300	14.27	7.000	$26,674,170	$72,635,937
2043	$45.79	$44.36	55.67	380,412	6.00	7.926	$46,892,415	$31.16	$57.23	36.20	260,300	14.27	7.000	$27,231,627	$74,124,043
2044	$46.70	$45.25	55.67	380,412	6.00	7.926	$47,841,677	$31.78	$58.37	36.20	260,300	14.27	7.000	$27,800,233	$75,641,910
2045	$47.64	$46.15	55.67	380,412	6.00	7.926	$48,809,924	$32.41	$59.54	36.20	260,300	14.27	7.000	$28,380,212	$77,190,136
2046	$48.59	$47.07	55.67	380,412	6.00	7.926	$49,797,536	$33.06	$60.73	36.20	260,300	14.27	7.000	$28,971,789	$78,769,325
2047	$49.56	$48.02	55.67	380,412	6.00	7.926	$50,804,900	$33.72	$61.95	36.20	260,300	14.27	7.000	$29,575,199	$80,380,099
2048	$50.55	$48.98	55.67	380,412	6.00	7.926	$51,832,412	$34.40	$63.18	36.20	260,300	14.27	7.000	$30,190,676	$82,023,088
2049	$51.56	$49.96	55.67	380,412	6.00	7.926	$52,880,473	$35.09	$64.45	36.20	260,300	14.27	7.000	$30,818,463	$83,698,937

NOTE: Above calculation excludes transmission costs which will be the same regardless of scenario

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*** * * * ***

In the Matter of the Application of	)	
Upper Michigan Energy Resources Corporation	)	
for approval of a Certificate of Necessity	)	
pursuant to MCL 460.6s for	)	Case No. U-18224
Two Reciprocating Internal Combustion Engine	)	
Electric Generation Facilities Located in the	)	
Upper Peninsula of Michigan,	)	
Approval of Certificate(s) of Public Convenience	)	
And Necessity, approval of a Special Contract with	)	
Tilden Mining Company L.C.	)	
and related accounting and ratemaking	)	
authorizations.	)	

2016 Integrated Resource Plan for
Upper Michigan Energy Resources Corporation Beginning in 2019

Attachment C

UP Gen Project (U-18224) -- IRP

Spreadsheet Name: IRP Attachment C - UP Gen UMERC Allocation Impact (MPSC Filing-CO2).xlsx
Sheet Name: NPV Analysis

General Assumptions:
RICE In-service Date of 6/30/19

	50% 2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
UMERC																	
(+) Reduced PPA Cost[1]	21,411,972	43,878,700	45,017,914	46,138,107	47,290,335	48,515,340	49,759,036	50,985,407	52,040,503	53,116,700	54,214,421	55,334,096	56,476,165	57,641,075	58,829,284	60,041,257	61,277,469
(+) Avoided Transmission ($300M)[2]							403,048	394,093	386,486	381,215	375,897	370,538	365,139	359,704	354,070	348,221	342,337
(-) Return Of PIPP Net Plant[3]		(950,529)	(892,716)	(838,406)	(794,683)	(749,694)	(703,704)	(656,273)	(607,043)	(557,004)	(506,976)	(165)					
(-) UP Gen Cost[4]	(25,204,206)	(48,771,265)	(47,824,177)	(47,056,365)	(46,310,880)	(46,532,208)	(46,620,091)	(47,053,607)	(47,284,865)	(47,722,710)	(48,165,286)	(48,271,876)	(48,266,127)	(48,249,086)	(49,139,053)	(49,620,617)	(49,629,118)
Total	(3,792,234)	(5,843,094)	(3,698,979)	(1,756,664)	184,773	1,233,438	2,838,289	3,669,620	4,535,080	5,218,200	5,918,057	7,432,593	8,575,177	9,751,693	10,044,301	10,768,861	11,990,688

	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	50% 2049
UMERC														
(+) Reduced PPA Cost[1]	62,538,405	63,824,560	65,136,439	66,474,555	67,839,433	69,231,608	70,651,628	72,100,047	73,577,435	75,084,371	76,621,445	78,189,261	79,788,434	40,709,795
(+) Avoided Transmission ($300M)[2]	336,453	330,568	324,684	318,799	312,915	307,031	301,146	295,262	289,377	284,806	281,546	276,975	271,090	132,603
(-) Return Of PIPP Net Plant[3]														
(-) UP Gen Cost[4]	(49,845,322)	(50,423,072)	(50,667,445)	(50,690,215)	(51,289,829)	(51,726,723)	(52,159,989)	(52,703,881)	(53,059,653)	(53,287,319)	(54,138,808)	(54,988,862)	(55,361,358)	(27,679,544)
Total	13,029,535	13,732,057	14,793,677	16,103,139	16,862,518	17,811,916	18,792,785	19,691,428	20,807,160	22,081,857	22,764,184	23,477,374	24,698,166	13,162,854

Discount Rate	7.22%
20 Year NPV	20,704,328
30 Year NPV	20,704,328

[1]The total projected cost of the WE and WPS Power Purchase Agreements
[2]The avoided ATC LLC transmission cost allocation of the projected $300 million avoided net transmission cost associated with the installation of the UP Gen units
[3]Cost associated with the recovery of the 6.595% of the PIPP costs allocated to Michigan with recovery over 10-years.
[4]Cost associated with the UP Gen solution

UP Gen Project (U-18224) -- IRP

Spreadsheet Name: IRP Attachment C - UP Gen UMERC Allocation Impact (MPSC Filing-CO2).xlsx
Sheet Name: Avoided Transmission

= Input Field

Avoided Transmission Cost Estimation

ASSUMPTIONS:

Avoided Investment	##########			UMERC Allocation:	0.94%
Useful Life (for return of)	50	years			
Tax Rate	40.00%				
Bonus Depreciation	0.00%				
O&M Rate	2.00%				
Weighted Average Cost of Capital					
	%	Cost	Weighted		
Debt	50.00%	4.20%	2.100%		
Equity	50.00%	10.00%	5.000%		
	100%		7.100%		

CALCULATION:

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
Accumulated Depreciation	6,000,000	12,000,000	18,000,000	24,000,000	30,000,000	36,000,000	42,000,000	48,000,000	54,000,000	60,000,000	66,000,000	72,000,000	78,000,000	84,000,000	90,000,000	96,000,000	102,000,000	108,000,000	114,000,000	120,000,000	126,000,000	132,000,000	138,000,000	144,000,000	150,000,000	156,000,000	162,000,000	168,000,000	174,000,000	180,000,000	183,000,000
Net Plant	294,000,000	288,000,000	282,000,000	276,000,000	270,000,000	264,000,000	258,000,000	252,000,000	246,000,000	240,000,000	234,000,000	228,000,000	222,000,000	216,000,000	210,000,000	204,000,000	198,000,000	192,000,000	186,000,000	180,000,000	174,000,000	168,000,000	162,000,000	156,000,000	150,000,000	144,000,000	138,000,000	132,000,000	126,000,000	120,000,000	117,000,000
Depreciation Expense (Return of)	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**3,000,000**
20 Year Macrs	3.75%	7.22%	6.68%	6.18%	5.71%	5.29%	4.89%	4.52%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	2.23%										
Tax Depreciation	11,250,000	21,657,000	20,031,000	18,531,000	17,139,000	15,855,000	14,664,000	13,566,000	13,386,000	13,383,000	13,386,000	13,383,000	13,386,000	13,383,000	13,386,000	13,383,000	13,386,000	13,383,000	13,386,000	13,383,000	6,693,000	-	-	-	-	-	-	-	-	-	-
Deferred Taxes	(2,100,000)	(6,262,800)	(5,612,400)	(5,012,400)	(4,455,600)	(3,942,000)	(3,465,600)	(3,026,400)	(2,954,400)	(2,953,200)	(2,954,400)	(2,953,200)	(2,954,400)	(2,953,200)	(2,954,400)	(2,953,200)	(2,954,400)	(2,953,200)	(2,954,400)	(2,953,200)	(277,200)	2,400,000	2,400,000	2,400,000	2,400,000	2,400,000	2,400,000	2,400,000	2,400,000	2,400,000	1,200,000
Beginning Rate Base	300,000,000	291,900,000	281,737,200	276,387,600	270,987,600	265,544,400	260,058,000	254,534,400	248,973,600	243,045,600	237,046,800	231,045,600	225,046,800	219,045,600	213,046,800	207,045,600	201,046,800	195,045,600	189,046,800	183,045,600	177,046,800	173,722,800	170,400,000	164,400,000	158,400,000	152,400,000	146,400,000	140,400,000	134,400,000	128,400,000	122,400,000
Ending Rate Base	291,900,000	281,737,200	276,387,600	270,987,600	265,544,400	260,058,000	254,534,400	248,973,600	243,045,600	237,046,800	231,045,600	225,046,800	219,045,600	213,046,800	207,045,600	201,046,800	195,045,600	189,046,800	183,045,600	177,046,800	173,722,800	170,400,000	164,400,000	158,400,000	152,400,000	146,400,000	140,400,000	134,400,000	128,400,000	122,400,000	118,200,000
Average Rate Base	295,950,000	286,818,600	279,062,400	273,687,600	268,266,000	262,801,200	257,296,200	251,754,000	246,009,600	240,046,200	234,046,200	228,046,200	222,046,200	216,046,200	210,046,200	204,046,200	198,046,200	192,046,200	186,046,200	180,046,200	175,384,800	172,061,400	167,400,000	161,400,000	155,400,000	149,400,000	143,400,000	137,400,000	131,400,000	125,400,000	120,300,000
Revenue Requirement (Return On)	**30,877,450**	**29,924,741**	**29,115,510**	**28,554,740**	**27,989,086**	**27,418,925**	**26,844,570**	**26,266,334**	**25,667,002**	**25,044,820**	**24,418,820**	**23,792,820**	**23,166,820**	**22,540,820**	**21,914,820**	**21,288,820**	**20,662,820**	**20,036,820**	**19,410,820**	**18,784,820**	**18,298,481**	**17,951,739**	**17,465,400**	**16,839,400**	**16,213,400**	**15,587,400**	**14,961,400**	**14,335,400**	**13,709,400**	**13,083,400**	**12,551,300**
O&M Expense (Return Of)	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**	**6,000,000**
System Avoided Cost of $300M Investment	**42,877,450**	**41,924,741**	**41,115,510**	**40,554,740**	**39,989,086**	**39,418,925**	**38,844,570**	**38,266,334**	**37,667,002**	**37,044,820**	**36,418,820**	**35,792,820**	**35,166,820**	**34,540,820**	**33,914,820**	**33,288,820**	**32,662,820**	**32,036,820**	**31,410,820**	**30,784,820**	**30,298,481**	**29,951,739**	**29,465,400**	**28,839,400**	**28,213,400**	**27,587,400**	**26,961,400**	**26,335,400**	**25,709,400**	**25,083,400**	**21,551,300**

UP Gen Project (U-18224) -- IRP

Spreadsheet Name: IRP Attachment C - UP Gen UMERC Allocation Impact (MPSC Filing-CO2).xlsx
Sheet Name: PIPP Retirement Cost

= Input Field

PIPP Retirement Cost Recovery Estimation

ASSUMPTIONS:

Projected PIPP Book Value:	**175,895,000**
Projected Decommissioning Cost:	**30,000,000**
Total PIPP Recovery:	205,895,000
Michigan PIPP Allocation (%):	**6.595%**
Michigan PIPP Allocation:	13,578,775
Non-Mine UMERC Allocation (%):	**35%**
Non-Mine UMERC Allocation:	4,752,571
Recovery Period (years):	**10**
Tax Rate:	38.9%

Weighted Average Cost of Capital

	%	Cost	Weighted	**Tax Rate**	
Debt	**48.00%**	**4.20%**	2.016%	Federal	**35.00%**
Equity	**52.00%**	**10.00%**	5.200%	State-MI	**6.00%**
	100%		7.216%	Effective Rate	38.9%

CALCULATION:

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Accumulated Depreciation	475,257	950,514	1,425,771	1,901,029	2,376,286	2,851,543	3,326,800	3,802,057	4,277,314	4,752,571	4,752,571
Net Plant	4,277,314	3,802,057	3,326,800	2,851,543	2,376,286	1,901,029	1,425,771	950,514	475,257	-	-
Depreciation Expense (Return of)	**475,257**	**475,257**	**475,257**	**475,257**	**475,257**	**475,257**	**475,257**	**475,257**	**475,257**	**475,257**	**-**
10 Year Macrs	10.00%	18.00%	14.40%	11.52%	9.22%	7.37%	6.55%	6.55%	6.56%	6.55%	3.28%
Tax Depreciation	475,257	855,463	684,370	547,496	438,187	350,265	311,293	311,293	311,769	311,293	155,884
Deferred Taxes	(0)	(147,900)	(81,345)	(28,101)	14,420	48,622	63,782	63,782	63,597	63,782	(60,639)
Beginning Rate Base	4,752,571	4,277,314	3,654,157	3,245,455	2,823,442	2,390,706	1,949,651	1,489,553	1,014,296	538,854	63,782
Ending Rate Base	4,277,314	3,654,157	3,245,455	2,823,442	2,390,706	1,949,651	1,489,553	1,014,296	538,854	63,782	(60,639)
Average Rate Base	4,514,943	3,965,736	3,449,806	3,034,448	2,607,074	2,170,178	1,719,602	1,251,925	776,575	301,318	1,571
Revenue Requirement (Return On)	**475,272**	**417,459**	**363,149**	**319,425**	**274,437**	**228,447**	**181,016**	**131,786**	**81,747**	**31,719**	**165**
PIPP Retirement Cost	**950,529**	**892,716**	**838,406**	**794,683**	**749,694**	**703,704**	**656,273**	**607,043**	**557,004**	**506,976**	**165**

UP Gen Project (U-18224) -- IRP

Spreadsheet Name: IRP Attachment C - UP Gen UMERC Allocation Impact (MPSC Filing-CO2).xlsx
Sheet Name: UP Gen Rate Base

= Input Field

	Equity	Debt	Total
Capital Structure	52.00%	48.00%	100.00%
Cost of Capital	10.00%	4.20%	
Wtd Cost of Capital (discount rate)	5.20%	2.02%	**7.22%**
Tax Gross-up	1.637		
Economic Cost of Capital	8.51%	2.02%	**10.53%**

Tax Rate	
Federal	35.00%
State-MI	6.00%
Effective Rate	**38.9%**

	Yrs In-Service Year	2017	2018	2019	1 2020	2 2021	3 2022	4 2023	5 2024	6 2025	7 2026	8 2027	9 2028	10 2029	11 2030	12 2031	13 2032	14 2033	15 2034	16 2035	17 2036	18 2037	19 2038	20 2039	21 2040	22 2041	23 2042	24 2043	25 2044	26 2045	27 2046	28 2047	29 2048	30 2049	Total
Total CAPEX																																			
Initial Construction		10,700,000	178,465,744	76,524,040																															265,689,783
Capital Improvements					-	-	3,325,000	1,425,000	5,780,000	-	10,530,000	-	10,530,000	4,750,000	700,000	330,000	-	20,030,000	-	1,030,000	4,750,000	10,530,000	-	-	10,530,000	-	5,780,000	4,750,000	1,030,000	-	14,000,000	6,030,000	-	-	115,830,000
AFUDC																																			
Debt		45,768	1,646,083	1,704,577																															3,396,427
Equity		108,853	3,915,008	4,054,129																															8,077,990
Book Basis		10,854,621	194,881,455	277,164,200	277,164,200	277,164,200	280,489,200	281,914,200	287,694,200	287,694,200	298,224,200	298,224,200	308,754,200	313,504,200	314,204,200	314,534,200	314,534,200	334,564,200	334,564,200	335,594,200	340,344,200	350,874,200	350,874,200	350,874,200	361,404,200	361,404,200	367,184,200	371,934,200	372,964,200	372,964,200	386,964,200	392,994,200	392,994,200	392,994,200	-
Tax Basis		10,745,768	190,857,594	269,086,211	269,086,211	269,086,211	272,411,211	273,836,211	279,616,211	279,616,211	290,146,211	290,146,211	300,676,211	305,426,211	306,126,211	306,456,211	306,456,211	326,486,211	326,486,211	327,516,211	332,266,211	342,796,211	342,796,211	342,796,211	353,326,211	353,326,211	359,106,211	363,856,211	364,886,211	364,886,211	378,886,211	384,916,211	384,916,211	384,916,211	-
Months In-Service				6	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	6	360
Book Depreciation	3.94%			5,463,858	10,927,715	10,927,715	11,058,809	11,114,993	11,342,880	11,342,880	11,758,045	11,758,045	12,173,210	12,360,487	12,388,086	12,401,097	12,401,097	13,190,817	13,190,817	13,231,427	13,418,704	13,833,869	13,833,869	13,833,869	14,249,034	14,249,034	14,476,921	14,664,199	14,704,809	14,704,809	15,256,785	15,494,529	15,494,529	7,747,264	392,994,200
AFUDC Equity Amort included in book depr				*134,633*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*269,266*	*134,633*	*8,077,990*
Bonus %		50%	40%	30%																															
Tax Depreciation		-	-	87,789,376	13,597,733	12,576,820	11,759,706	11,054,496	10,496,475	9,924,844	9,576,440	9,778,967	10,068,767	10,518,846	10,571,901	10,464,936	10,352,844	10,994,839	11,614,523	11,484,362	11,568,472	12,024,477	12,269,868	7,903,866	3,944,257	4,224,003	4,241,847	4,402,041	4,323,137	4,123,881	4,315,899	4,702,498	4,546,294	39,699,795	384,916,211
Rate Base (Total)																																			
PP&E - Gross		10,854,621	194,881,455	277,164,200	277,164,200	277,164,200	280,489,200	281,914,200	287,694,200	287,694,200	298,224,200	298,224,200	308,754,200	313,504,200	314,204,200	314,534,200	314,534,200	334,564,200	334,564,200	335,594,200	340,344,200	350,874,200	350,874,200	350,874,200	361,404,200	361,404,200	367,184,200	371,934,200	372,964,200	372,964,200	386,964,200	392,994,200	392,994,200	392,994,200	
Accum Depreciation				(5,463,858)	(16,391,573)	(27,319,288)	(38,378,097)	(49,493,090)	(60,835,970)	(72,178,850)	(83,936,894)	(95,694,939)	(107,868,149)	(120,228,636)	(132,616,722)	(145,017,819)	(157,418,916)	(170,609,733)	(183,800,550)	(197,031,977)	(210,450,681)	(224,284,550)	(238,118,419)	(251,952,288)	(266,201,322)	(280,450,356)	(294,927,278)	(309,591,477)	(324,296,285)	(339,001,094)	(354,257,878)	(369,752,407)	(385,246,936)	(392,994,200)	
Accum Deferred Income Tax				(32,076,999)	(33,220,381)	(33,966,627)	(34,344,021)	(34,425,232)	(34,200,725)	(33,753,854)	(33,009,955)	(32,344,838)	(31,630,954)	(31,019,300)	(30,417,549)	(29,769,127)	(29,077,101)	(28,327,610)	(27,819,176)	(27,244,313)	(26,629,317)	(26,030,208)	(25,526,556)	(23,324,529)	(19,420,716)	(15,625,723)	(11,749,024)	(7,861,789)	(9,928,063)	83,173	4,234,433	8,327,788	12,481,907	(0)	
Working Capital				3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	
Net Rate Base-EOY		10,854,621	194,881,455	242,623,344	230,552,247	218,878,285	210,767,082	200,995,878	195,657,505	184,761,497	184,277,351	173,184,423	172,255,097	165,256,264	154,169,929	142,747,254	131,038,183	138,626,857	125,944,474	114,317,911	106,264,202	103,559,442	90,229,225	78,597,383	78,782,162	68,328,121	63,507,899	57,480,935	47,739,852	37,046,280	39,940,755	34,569,581	23,229,171	3,000,000	
Net Rate Base-Avg				130,696,886	236,587,795	224,715,266	214,822,684	205,881,480	198,326,692	190,209,501	184,519,424	178,730,887	172,719,760	168,755,681	159,713,097	148,458,592	136,892,719	134,832,520	132,285,666	120,131,192	110,291,057	104,911,822	96,894,334	84,413,304	78,689,772	73,555,141	65,918,010	60,494,417	52,610,393	42,393,066	38,493,517	37,255,168	28,899,376	6,557,293	

UP Gen Project (U-18224) -- IRP

Spreadsheet Name: IRP Attachment C - UP Gen UMERC Allocation Impact (MPSC Filing-CO2).xlsx
Sheet Name: UP Gen (Base Rev Rqrmnt Calc)

= Input Field

O&M and A&G Inflation Rate: **2.00%**

Capital Cost Allocation: **50.00%**

						(A) * (B)						(C+D+E+F+G+H)
				(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	Year	Months In-Serv	Asset Life	Average Rate Base	Economic Cost of Capital	"Return On" Rate Base	Tax Impact AFUDC Amoritization	Depreciation Expense	Allocated A&G Expense	NNG Pipeline Cost	Property Tax	Total Base Revenue Requirement
In-Service 6/30/2019	2019	**6**	**30**	$65,348,443	**10.53%**	$6,878,994	$42,858	$2,731,929	**$867,249**	**$2,155,836**	**$2,927,782**	$15,604,647
	2020	12	30	$118,293,898	10.53%	$12,452,371	$85,716	$5,463,858	$1,769,187	$4,311,672	$5,855,563	$29,938,366
	2021	12	30	$112,357,633	10.53%	$11,827,482	$85,716	$5,463,858	$1,804,571	$4,311,672	$5,855,563	$29,348,861
	2022	12	30	$107,411,342	10.53%	$11,306,803	$85,716	$5,529,405	$1,840,662	$4,311,672	$5,855,563	$28,929,821
	2023	12	30	$102,940,740	10.53%	$10,836,199	$85,716	$5,557,496	$1,877,475	$4,311,672	$5,855,563	$28,524,122
	2024	12	30	$99,163,346	10.53%	$10,438,567	$85,716	$5,671,440	$1,915,025	$4,311,672	$5,855,563	$28,277,982
	2025	12	30	$95,104,750	10.53%	$10,011,333	$85,716	$5,671,440	$1,953,325	$4,311,672	$5,855,563	$27,889,049
	2026	12	30	$92,259,712	10.53%	$9,711,846	$85,716	$5,879,022	$1,992,392	$4,311,672	$5,855,563	$27,836,211
	2027	12	30	$89,365,444	10.53%	$9,407,177	$85,716	$5,879,022	$2,032,240	$4,311,672	$5,855,563	$27,571,390
	2028	12	30	$86,359,880	10.53%	$9,090,792	$85,716	$6,086,605	$2,072,884	$4,311,672	$5,855,563	$27,503,232
	2029	12	30	$84,377,840	10.53%	$8,882,150	$85,716	$6,180,244	$2,114,342	$4,311,672	$5,855,563	$27,429,687
	2030	12	30	$79,856,548	10.53%	$8,406,210	$85,716	$6,194,043	$2,156,629	$4,311,672	$5,855,563	$27,009,833
	2031	12	30	$74,229,296	10.53%	$7,813,849	$85,716	$6,200,548	$2,199,762	$4,311,672	$5,855,563	$26,467,110
	2032	12	30	$68,446,359	10.53%	$7,205,101	$85,716	$6,200,548	$2,243,757	$4,311,672	$5,855,563	$25,902,357
	2033	12	30	$67,416,260	10.53%	$7,096,666	$85,716	$6,595,409	$2,288,632	$4,311,672	$5,855,563	$26,233,657
	2034	12	30	$66,142,833	10.53%	$6,962,617	$85,716	$6,595,409	$2,334,405	$4,311,672	$5,855,563	$26,145,381
	2035	12	30	$60,065,596	10.53%	$6,322,888	$85,716	$6,615,713	$2,381,093	$4,311,672	$5,855,563	$25,572,645
	2036	12	30	$55,145,528	10.53%	$5,804,970	$85,716	$6,709,352	$2,428,715	$4,311,672	$5,855,563	$25,195,988
	2037	12	30	$52,455,911	10.53%	$5,521,844	$85,716	$6,916,935	$2,477,289	$4,311,672	$5,855,563	$25,169,018
	2038	12	30	$48,447,167	10.53%	$5,099,858	$85,716	$6,916,935	$2,526,835	$4,311,672	$5,855,563	$24,796,578
	2039	12	30	$42,206,652	10.53%	$4,442,942	$85,716	$6,916,935	$2,577,371	$4,311,672	$5,855,563	$24,190,198
	2040	12	30	$39,344,886	10.53%	$4,141,694	$85,716	$7,124,517	$2,628,919	$4,311,672	$5,855,563	$24,148,080
	2041	12	30	$36,777,571	10.53%	$3,871,442	$85,716	$7,124,517	$2,681,497	$4,311,672	$5,855,563	$23,930,407
	2042	12	30	$32,959,005	10.53%	$3,469,475	$85,716	$7,238,461	$2,735,127	$4,311,672	$5,855,563	$23,696,014
	2043	12	30	$30,247,208	10.53%	$3,184,014	$85,716	$7,332,099	$2,789,830	$4,311,672	$5,855,563	$23,558,894
	2044	12	30	$26,305,197	10.53%	$2,769,053	$85,716	$7,352,404	$2,845,626	$4,311,672	$5,855,563	$23,220,034
	2045	12	30	$21,196,533	10.53%	$2,231,282	$85,716	$7,352,404	$2,902,539	$4,311,672	$5,855,563	$22,739,176
	2046	12	30	$19,246,759	10.53%	$2,026,037	$85,716	$7,628,392	$2,960,589	$4,311,672	$5,855,563	$22,867,969
	2047	12	30	$18,627,584	10.53%	$1,960,858	$85,716	$7,747,264	$3,019,801	$4,311,672	$5,855,563	$22,980,875
	2048	12	30	$14,449,688	10.53%	$1,521,066	$85,716	$7,747,264	$3,080,197	$4,311,672	$5,855,563	$22,601,479
	2049	6	30	$3,278,646	10.53%	$345,131	$42,858	$3,873,632	$1,570,901	$2,155,836	$2,927,782	$10,916,139

UP Gen Project (U-18224) -- IRP

Spreadsheet Name: IRP Attachment C - UP Gen UMERC Allocation Impact (MPSC Filing-CO2).xlsx
Sheet Name: UP Gen Cost

= Input Field

Energy/LMP Inflation Rate: **2.00%**

				(A * C)					0.1 * (G * H)	(G * B)	(I + J) - (D + E + F)		(H + I)
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(H)	(I)	(J)
Year	**Market Capacity Value ($/MW-Year)**	**UP Gen Estimated LMP ($/MWh)**	**UP Gen Excess Capacity (MW)**	**UP Gen Excess Capacity Value**	**UP Gen Energy Sales Value**	**UP Gen Ancillary Sales Value**	**UP Gen Total UMERC Load (MWh)**	**UP Gen REC Cost ($/REC)**	**UP Gen Renewables Cost**	**UP Gen Load Purchase Cost**	**Annualized UP Gen Total Energy Costs**	**Annualized UP Gen Base Rev Req Costs**	**Annualized Up Gen Total Costs**
2017													
2018													
2019	**$26,250**	**$43.33**	**91.2**	$2,394,263	**$5,835,283**	**$525,600**	**640,712**	**$3.00**	$192,214	$27,762,051	$19,199,119	$31,209,294	$50,408,413
2020	**$35,000**	$44.20	91.2	$3,192,350	$5,951,989	$536,112	640,712	$3.06	$196,058	$28,317,292	$18,832,899	$29,938,366	$48,771,265
2021	**$43,750**	$45.08	91.2	$3,990,438	$6,071,028	$546,834	640,712	$3.12	$199,979	$28,883,638	$18,475,317	$29,348,861	$47,824,177
2022	**$52,500**	$45.98	91.2	$4,788,525	$6,192,449	$557,771	640,712	$3.18	$203,979	$29,461,311	$18,126,544	$28,929,821	$47,056,365
2023	**$61,250**	$46.90	91.2	$5,586,613	$6,316,298	$568,926	640,712	$3.25	$208,058	$30,050,537	$17,786,758	$28,524,122	$46,310,880
2024	**$61,250**	$47.84	91.2	$5,586,613	$6,442,624	$580,305	640,712	$3.31	$212,219	$30,651,548	$18,254,226	$28,277,982	$46,532,208
2025	**$61,250**	$48.80	91.2	$5,586,613	$6,571,476	$591,911	640,712	$3.38	$216,464	$31,264,578	$18,731,042	$27,889,049	$46,620,091
2026	**$61,250**	$49.77	91.2	$5,586,613	$6,702,906	$603,749	640,712	$3.45	$220,793	$31,889,870	$19,217,395	$27,836,211	$47,053,607
2027	**$61,250**	$50.77	91.2	$5,586,613	$6,836,964	$615,824	640,712	$3.51	$225,209	$32,527,667	$19,713,476	$27,571,390	$47,284,865
2028	**$61,250**	$51.78	91.2	$5,586,613	$6,973,703	$628,141	640,712	$3.59	$229,713	$33,178,221	$20,219,477	$27,503,232	$47,722,710
2029	**$61,250**	$52.82	91.2	$5,586,613	$7,113,177	$640,703	640,712	$3.66	$234,307	$33,841,785	$20,735,599	$27,429,687	$48,165,286
2030	**$61,250**	$53.88	91.2	$5,586,613	$7,255,441	$653,518	640,712	$3.73	$238,993	$34,518,621	$21,262,043	$27,009,833	$48,271,876
2031	**$61,250**	$54.95	91.2	$5,586,613	$7,400,550	$666,588	640,712	$3.80	$243,773	$35,208,993	$21,799,016	$26,467,110	$48,266,127
2032	**$61,250**	$56.05	91.2	$5,586,613	$7,548,561	$679,920	640,712	$3.88	$248,649	$35,913,173	$22,346,729	$25,902,357	$48,249,086
2033	**$61,250**	$57.17	91.2	$5,586,613	$7,699,532	$693,518	640,712	$3.96	$253,622	$36,631,437	$22,905,396	$26,233,657	$49,139,053
2034	**$61,250**	$58.32	91.2	$5,586,613	$7,853,523	$707,388	640,712	$4.04	$258,694	$37,364,065	$23,475,236	$26,145,381	$49,620,617
2035	**$61,250**	$59.48	91.2	$5,586,613	$8,010,593	$721,536	640,712	$4.12	$263,868	$38,111,347	$24,056,473	$25,572,645	$49,629,118
2036	**$61,250**	$60.67	91.2	$5,586,613	$8,170,805	$735,967	640,712	$4.20	$269,145	$38,873,574	$24,649,335	$25,195,988	$49,845,322
2037	**$61,250**	$61.89	91.2	$5,586,613	$8,334,221	$750,686	640,712	$4.28	$274,528	$39,651,045	$25,254,054	$25,169,018	$50,423,072
2038	**$61,250**	$63.12	91.2	$5,586,613	$8,500,905	$765,700	640,712	$4.37	$280,019	$40,444,066	$25,870,867	$24,796,578	$50,667,445
2039	**$61,250**	$64.39	91.2	$5,586,613	$8,670,924	$781,014	640,712	$4.46	$285,619	$41,252,947	$26,500,017	$24,190,198	$50,690,215
2040	**$61,250**	$65.67	91.2	$5,586,613	$8,844,342	$796,634	640,712	$4.55	$291,332	$42,078,006	$27,141,749	$24,148,080	$51,289,829
2041	**$61,250**	$66.99	91.2	$5,586,613	$9,021,229	$812,567	640,712	$4.64	$297,158	$42,919,566	$27,796,316	$23,930,407	$51,726,723
2042	**$61,250**	$68.33	91.2	$5,586,613	$9,201,653	$828,818	640,712	$4.73	$303,101	$43,777,958	$28,463,975	$23,696,014	$52,159,989
2043	**$61,250**	$69.69	91.2	$5,586,613	$9,385,687	$845,395	640,712	$4.83	$309,164	$44,653,517	$29,144,987	$23,558,894	$52,703,881
2044	**$61,250**	$71.09	91.2	$5,586,613	$9,573,400	$862,303	640,712	$4.92	$315,347	$45,546,587	$29,839,619	$23,220,034	$53,059,653
2045	**$61,250**	$72.51	91.2	$5,586,613	$9,764,868	$879,549	640,712	$5.02	$321,654	$46,457,519	$30,548,143	$22,739,176	$53,287,319
2046	**$61,250**	$73.96	91.2	$5,586,613	$9,960,166	$897,140	640,712	$5.12	$328,087	$47,386,669	$31,270,838	$22,867,969	$54,138,808
2047	**$61,250**	$75.44	91.2	$5,586,613	$10,159,369	$915,082	640,712	$5.22	$334,649	$48,334,403	$32,007,987	$22,980,875	$54,988,862
2048	**$61,250**	$76.95	91.2	$5,586,613	$10,362,556	$933,384	640,712	$5.33	$341,342	$49,301,091	$32,759,879	$22,601,479	$55,361,358
2049	**$61,250**	$78.49	91.2	$5,586,613	$10,569,807	$952,052	640,712	$5.43	$348,168	$50,287,113	$33,526,809	$21,832,279	$55,359,088

NOTE: Above calculation excludes transmission costs which will be the same regardless of scenario

UP Gen Project (U-18224) -- IRP

Spreadsheet Name: IRP Attachment C - UP Gen UMERC Allocation Impact (MPSC Filing-CO2).xlsx
Sheet Name: PPA Costs

= Input Field

Energy/LMP Inflation Rate: **2.00%**

							(A*C)+(B*D)-(E*F)							(H*J)+(I*K)-(L*M)	(G + N)
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
Year	**WE Zone Capacity Rate ($/kW-Month)**	**WE Zone Energy Rate ($/MWh)**	**WE Zone Average Demand (MW/Month)**	**WE Zone Annual Energy (MWh)**	**WE Zone Non-Firm Load (MW/Month)**	**WE Zone Non-Firm Credit ($/kW-Month)**	**WE Zone PPA Costs**	**WPS Zone Capacity Rate ($/kW-Month)**	**WPS Zone Energy Rate ($/MWh)**	**WPS Zone Average Demand (MW/Month)**	**WPS Zone Average Energy (MWh)**	**WPS Zone Non-Firm Load (MW/Month)**	**WPS Zone Non-Firm Credit ($/kW-Month)**	**WPS Zone PPA Costs**	**UMERC PPA Total Costs**
2017	**$27.25**	**$24.35**	**55.67**	**380,412**	**6.00**	**7.926**	$26,896,450	**$18.60**	**$30.05**	**36.20**	**260,300**	**14.27**	**7.000**	$14,703,175	$41,599,625
2018	**$27.90**	**$24.90**	55.67	380,412	6.00	7.926	$27,539,903	**$19.00**	**$30.95**	36.20	260,300	14.27	7.000	$15,111,205	$42,651,108
2019	**$28.02**	**$21.01**	55.67	380,412	6.00	7.926	$26,138,688	**$19.35**	**$36.41**	36.20	260,300	14.27	7.000	$16,685,256	$42,823,945
2020	**$28.57**	**$21.71**	55.67	380,412	6.00	7.926	$26,772,399	**$19.75**	**$37.36**	36.20	260,300	14.27	7.000	$17,106,301	$43,878,700
2021	**$29.17**	**$22.51**	55.67	380,412	6.00	7.926	$27,477,552	**$20.15**	**$38.36**	36.20	260,300	14.27	7.000	$17,540,361	$45,017,914
2022	**$29.77**	**$23.26**	55.67	380,412	6.00	7.926	$28,163,685	**$20.55**	**$39.36**	36.20	260,300	14.27	7.000	$17,974,421	$46,138,107
2023	**$30.37**	**$24.06**	55.67	380,412	6.00	7.926	$28,868,839	**$20.95**	**$40.41**	36.20	260,300	14.27	7.000	$18,421,496	$47,290,335
2024	**$30.97**	**$24.96**	55.67	380,412	6.00	7.926	$29,612,034	**$21.40**	**$41.51**	36.20	260,300	14.27	7.000	$18,903,306	$48,515,340
2025	**$31.62**	**$25.81**	55.67	380,412	6.00	7.926	$30,369,610	**$21.80**	**$42.71**	36.20	260,300	14.27	7.000	$19,389,426	$49,759,036
2026	**$32.27**	**$26.66**	55.67	380,412	6.00	7.926	$31,127,186	**$22.25**	**$43.76**	36.20	260,300	14.27	7.000	$19,858,221	$50,985,407
2027	$32.91	$27.19	55.67	380,412	6.00	7.926	$31,761,143	$22.70	$44.64	36.20	260,300	14.27	7.000	$20,279,359	$52,040,503
2028	$33.57	$27.74	55.67	380,412	6.00	7.926	$32,407,780	$23.15	$45.53	36.20	260,300	14.27	7.000	$20,708,920	$53,116,700
2029	$34.24	$28.29	55.67	380,412	6.00	7.926	$33,067,349	$23.61	$46.44	36.20	260,300	14.27	7.000	$21,147,072	$54,214,421
2030	$34.93	$28.86	55.67	380,412	6.00	7.926	$33,740,109	$24.09	$47.37	36.20	260,300	14.27	7.000	$21,593,987	$55,334,096
2031	$35.63	$29.43	55.67	380,412	6.00	7.926	$34,426,325	$24.57	$48.31	36.20	260,300	14.27	7.000	$22,049,840	$56,476,165
2032	$36.34	$30.02	55.67	380,412	6.00	7.926	$35,126,265	$25.06	$49.28	36.20	260,300	14.27	7.000	$22,514,811	$57,641,075
2033	$37.07	$30.62	55.67	380,412	6.00	7.926	$35,840,203	$25.56	$50.27	36.20	260,300	14.27	7.000	$22,989,081	$58,829,284
2034	$37.81	$31.24	55.67	380,412	6.00	7.926	$36,568,421	$26.07	$51.27	36.20	260,300	14.27	7.000	$23,472,836	$60,041,257
2035	$38.56	$31.86	55.67	380,412	6.00	7.926	$37,311,203	$26.59	$52.30	36.20	260,300	14.27	7.000	$23,966,266	$61,277,469
2036	$39.33	$32.50	55.67	380,412	6.00	7.926	$38,068,840	$27.12	$53.34	36.20	260,300	14.27	7.000	$24,469,565	$62,538,405
2037	$40.12	$33.15	55.67	380,412	6.00	7.926	$38,841,630	$27.67	$54.41	36.20	260,300	14.27	7.000	$24,982,930	$63,824,560
2038	$40.92	$33.81	55.67	380,412	6.00	7.926	$39,629,876	$28.22	$55.50	36.20	260,300	14.27	7.000	$25,506,562	$65,136,439
2039	$41.74	$34.49	55.67	380,412	6.00	7.926	$40,433,887	$28.79	$56.61	36.20	260,300	14.27	7.000	$26,040,667	$66,474,555
2040	$42.58	$35.18	55.67	380,412	6.00	7.926	$41,253,979	$29.36	$57.74	36.20	260,300	14.27	7.000	$26,585,454	$67,839,433
2041	$43.43	$35.88	55.67	380,412	6.00	7.926	$42,090,472	$29.95	$58.90	36.20	260,300	14.27	7.000	$27,141,137	$69,231,608
2042	$44.30	$36.60	55.67	380,412	6.00	7.926	$42,943,695	$30.55	$60.07	36.20	260,300	14.27	7.000	$27,707,933	$70,651,628
2043	$45.18	$37.33	55.67	380,412	6.00	7.926	$43,813,982	$31.16	$61.27	36.20	260,300	14.27	7.000	$28,286,065	$72,100,047
2044	$46.09	$38.08	55.67	380,412	6.00	7.926	$44,701,675	$31.78	$62.50	36.20	260,300	14.27	7.000	$28,875,760	$73,577,435
2045	$47.01	$38.84	55.67	380,412	6.00	7.926	$45,607,122	$32.42	$63.75	36.20	260,300	14.27	7.000	$29,477,249	$75,084,371
2046	$47.95	$39.62	55.67	380,412	6.00	7.926	$46,530,678	$33.06	$65.03	36.20	260,300	14.27	7.000	$30,090,768	$76,621,445
2047	$48.91	$40.41	55.67	380,412	6.00	7.926	$47,472,705	$33.73	$66.33	36.20	260,300	14.27	7.000	$30,716,557	$78,189,261
2048	$49.89	$41.22	55.67	380,412	6.00	7.926	$48,433,572	$34.40	$67.65	36.20	260,300	14.27	7.000	$31,354,861	$79,788,434
2049	$50.88	$42.04	55.67	380,412	6.00	7.926	$49,413,657	$35.09	$69.01	36.20	260,300	14.27	7.000	$32,005,932	$81,419,589

NOTE: Above calculation excludes transmission costs which will be the same regardless of scenario

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

****

In the Matter of the Application of	)	
Upper Michigan Energy Resources Corporation	)	
for approval of a Certificate of Necessity	)	
pursuant to MCL 460.6s for	)	Case No. U-18224
Two Reciprocating Internal Combustion Engine	)	
Electric Generation Facilities Located in the	)	
Upper Peninsula of Michigan,	)	
Approval of Certificate(s) of Public Convenience	)	
And Necessity, approval of a Special Contract with	)	
Tilden Mining Company L.C.,	)	
and related accounting and ratemaking	)	
authorizations.	)	

** Public Version **

DIRECT TESTIMONY AND EXHIBIT

OF

JAMES A. SCHUBILSKE

ON BEHALF OF

UPPER MICHIGAN ENERGY RESOURCES CORPORATION

Q. Please state your name and business address.

A. My name is James A. Schubilske. My business address is 231 West Michigan Street, Milwaukee, Wisconsin 53203.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of Upper Michigan Energy Resources Corporation ("UMERC" or the "Company").

Q. By whom are you employed and what is your position?

A. I am currently the Vice President and Treasurer of WEC Energy Group, Inc. ("WEC Energy Group").

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science in Business Administration Degree, with specialization in finance and information systems, from Marquette University in May 1987. In December 1996, I received a Master of Business Administration Degree from Marquette University.

Regarding my professional experience, I accepted a position with Wisconsin Electric Power Company ("WEPCo") as an analyst in the Office of Financial Management in September 1987. I held various positions in Finance before assuming the position of Investor Relations Coordinator in June of 1995. In June 2000, I assumed the position of Assistant Treasurer of WEPCo and Wisconsin Energy Corporation (now known as WEC Energy Group). My responsibilities at that time included long-term financial forecasts, project analysis and special studies. I also shared responsibility for securities issuances. In March 2011, I became Assistant Treasurer – Regulatory Affairs and Policy. My responsibilities included regulatory proceeding coordination, cost of service and rate design. In 2013, I became Vice President – State Regulatory Affairs. Effective April 1, 2016, I became Vice President and Treasurer of WEC Energy Group.

Q. Have you ever testified in any regulatory proceedings before this Commission?

A. Yes. I pre-filed testimony in Michigan Public Service Commission ("Commission" or "MPSC") Case No. U-15220, Case No. U-16830 (WEPCo's last Michigan rate case), and I testified Case No. U-18061, the case in which the Commission approved a settlement agreement providing for the establishment of UMERC.

Q. Have you previously testified before the Public Service Commission of Wisconsin ("PSCW")?

A. Yes. I previously provided testimony before the PSCW in the Declaratory Ruling phase of the Power The Future ("PTF") program, as well as in the certificate of public convenience and necessity proceedings for the Port Washington and Elm Road Generating Stations. In addition, I provided testimony regarding cost of capital and capital structure in WEPCo's 2006 test year rate filing (05-UR-102).

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to support UMERC's Application filed in this docket. I will describe the plans for financing the capital cost of the proposed Reciprocating Internal Combustion Engine ("RICE") electric generation facilities, as well as describe the regulatory treatment of costs and revenues associated with this project with the Tilden Mining Company, L.C. ("Tilden") and UMERC's other customers, and support the Application's request for accounting approvals. For purposes of this testimony, references to "non-Tilden customers" are to all UMERC retail customers other than Tilden Mining Company, L.C.

Q. Are you sponsoring any exhibits?

A. Yes, Exhibit A-__ (JAS-1), which shows UMERC's estimated Allowance for Funds Used During Construction ("AFUDC").

Q. Mr. Sherman describes the Retail Large Curtailable Special Contract between WEC Energy Group and Tilden dated August 12, 2016 ("Tilden Special Contract"), and requests approval of the Tilden Special Contract. Is UMERC also requesting approval of the regulatory treatment and allocation of costs of the RICE electric

generation facilities between Tilden and the other UMERC retail electric customers?

A. Yes.

Q. In your opinion, is the Tilden Special Contract typical of special contracts approved in Michigan?

A. No. This contract presents rather unique circumstances. It is the foundation for the construction of the RICE electric generation facilities because without the Tilden Special Contract, UMERC would not be constructing the RICE units to serve non-Tilden customers.

Q. Will the Commission's approval of the Tilden Special Contract benefit non-Tilden customers?

A. Yes, in several ways. First, non–Tilden customers benefit financially. As described in the testimony of Mr. Jeff Knitter, using the forecasted capital and operating costs of these RICE units combined with the assignment of costs between the Tilden Special Contract and the non-Tilden customers consistent with the Tilden Special Contract, all UMERC customers benefit in both the long and short term. The RICE units provide not only an approximately $161 million net present value ("NPV") benefit as compared to "business as usual" over 20 years, but also costs slightly less in the early years of the project as compared to business as usual. Second, again as described by Mr. Knitter, the reliability benefits that UMERC and other customers located in the Upper Peninsula of Michigan ("UP") are significant and un-paralleled. Without the special contract with Tilden, UMERC would not construct the RICE units and the non-Tilden customers would not receive these financial or reliability benefits.

Q. Are shareholders taking on risk and cost burdens with the Tilden Contract?

A. Yes, as discussed in Mr. Sherman's testimony, UMERC has committed to keep the non-Tilden customers financially harmless for recovery of Tilden's portion of the capital investment, depreciation expense, and return on investment, taxes and fixed operating costs in the new generator units so that such costs are not passed on to UMERC's ratepayers if Tilden involuntary terminates the Tilden Special Contract and is not able to make required payments. Further, as I will explain later, there are financial implications to shareholders if the installed costs of the RICE units exceed [begin confidential] [redacted] [end confidential].

Q. Please describe the rate treatment that UMERC is requesting in this proceeding with respect to the cost of power from the RICE electric generation facilities.

A. UMERC is requesting approval of UMERC's allocation of the cost of power from the RICE electric generation facilities to UMERC's non-Tilden customers, and a certificate of necessity that such costs will be recoverable in rates from UMERC's non-Tilden customers in a future rate proceeding. UMERC is specifically requesting that in future base rate case filings, costs are allocated consistent with the Tilden Special Contract. These costs, which I discuss later in this testimony, include (but are not limited to) the capital costs, operation and maintenance ("O&M"), generation administrative and general ("A&G") expenses, and property taxes.

Q. How is UMERC requesting to recover generation-related O&M costs?

A. Pursuant to the Tilden Special Contract, Tilden will be billed 100% of the actual generation O&M costs. The non-Tilden UMERC customers will <u>not</u> be requested to pay

for these costs during the 20-year Special Contract Term. In the first full year of service, the O&M costs are projected to be approximately $5.3 million.

Q. How is UMERC requesting to recover property taxes?

A. The Company requests to recover all of the forecasted property taxes for the RICE electric generation facilities from non-Tilden UMERC customers via base rates. In the first full year in service, property taxes are estimated to be $5.9 million.

Q. What is the basis for the property tax estimate?

A. The property tax is based on the estimated taxable generation project cost split between the townships where the RICE electric generation might be located. Assuming an assessed value of 50% of the taxable property times the respective 2015 property tax rate in each township yields the annual property tax estimate. A 1% administrative fee is added, resulting in the total property tax and administrative fee estimate.

Q. How is UMERC requesting to recover generation A&G expenses?

A. Under the Tilden Special Contract, Tilden will be billed [begin confidential] [redacted] [end confidential] per month, adjusted annually using a Consumer Price Index. The Company will seek to recover the remaining generation A&G costs allocated to the UMERC generating facilities from non-Tilden UMERC customers via base rates. At this time, the generation A&G costs in the first full year of service is estimated to be [begin confidential] [redacted] [end confidential], with approximately $1.77 million allocated to the non-Tilden customers.

Q. Please address the requested capital cost allocation.

A. One of the main components of the Tilden Special Contract is that Tilden will pay for approximately 50% of the capital costs of the RICE electric generation facilities.

Specifically, Tilden will pay for a fixed rate of [begin confidential] [redacted] [end confidential] times the installed generation capacity to UMERC over the 20-year term with 50% of this rate credited back to Tilden to reflect all of Tilden's load being non-firm and subject to interruption by the Midcontinent Independent System Operator, Inc. ("MISO") for emergency events. The remaining 50% of the capital costs would be recovered via base electric rates from the non-Tilden UMERC customers.

Q. Can you explain this in total project dollars?

A. Yes. If the actual installed cost of 183MW is $277,200,000 or $1515/kw, UMERC would recover 50% of the $277,200,000 or $138,600,000 of capital costs from UMERC non-Tilden customers via base electric rates in a future rate case proceeding. The Company would recover [begin confidential] [redacted] [end confidential] from Tilden over the 20-year term of the Special Contract. The Company would not collect approximately [begin confidential] [redacted] [end confidential] from either Tilden or non-Tilden customers.

Q. So, essentially, to the extent the actual installed costs of the RICE electric generation facilities are more than $1,515/kw, the non-Tilden customers pay for 50% of the actual total project costs and shareholders bear the burden of installed capital costs that cannot be recovered from Tilden?

A. Yes.

Q. How do the amount and timing of the Tilden payments for its capital cost share line up with actual company costs?

A. Generally speaking, revenue requirements for a utility asset are higher in the early years of service and tend to decline over time as depreciation reduces the amount of rate base. Utility asset recovery is also spread over the expected useful life of the asset. The payments do not track this cost curve but instead are levelized over the 20-year period of the Tilden Special Contract to meet both the customer and Company needs over the 20-year term.

Q. How will any future plant capital investment costs be recovered?

A. The Company would seek to recover 50% of future capital costs from UMERC non-Tilden customers via base electric rates. The Company will recover the other 50% from Tilden over the remaining term of the Special Contract.

Q. Would the Company's requested rate and regulatory treatment and cost allocation apply for the 20-year term of the Special Contract?

A. Yes.

Q. **Will Tilden be subject to the UMERC Power Supply Cost Recovery ("PSCR") Factor and mechanism?**

A. No, as set forth in the Tilden Special Contract. The electric load served under the Tilden Special Contract will be provided by either the operation of the RICE election generation facilities, hourly purchases from MISO, or a combination of the two. This could change hourly depending on the hourly load of Tilden and the amount of generation produced by the RICE electric generation facilities as dispatched by MISO. To the extent RICE electric generation facilities are operated for Tilden load, Tilden will be responsible for the cost of gas to operate the RICE electric generation facilities associated with the Tilden load. In addition to the cost of gas to generate electricity to meet the Tilden load,

Tilden will be responsible for any hourly purchases from the MISO to meet the Tilden load as well as transmission and other MISO costs that are generally included in PSCR costs on an actual basis.

Q. Will UMERC have a PSCR clause for non-Tilden customers?

A. Yes.

Q. Please describe the Company's proposed administration of the PSCR mechanism after the RICE electric generation facilities become operational.

A. Tilden will be paying for fuel costs to operate the RICE units for its load, purchases and sales of power from MISO for its load and output of the RICE units operated for its load, and transmission costs per the terms of the Tilden Special Contract. Tilden will not be subject to a PSCR clause factor under the terms of the contract. The Company requests to have all of the UMERC power supply cost recovery costs included in the PSCR calculation, including the costs associated with serving Tilden's load. The monthly revenues that would be billed to Tilden for energy and transmission would be credited to the total UMERC PSCR with the remaining amount of power supply costs (including electric transmission and natural gas pipeline costs) that would be collected from non-Tilden customers via the PSCR mechanism.

Q. Please describe how the proposed cost allocation changes at the end of the Tilden Special Contract.

A. The Tilden Special Contract cost allocation will either end at the end of the 20-year term, or earlier if Tilden voluntarily or involuntarily terminates the contract. If Tilden continues to operate after the Tilden Special Contract ends, I would expect Tilden to either (1) seek to negotiate a new special contract or (2) become a retail customer of

UMERC. If Tilden is no longer operational, then any residual load from Tilden most likely move to a UMERC retail tariff.

Q. How will the recovery of the costs of operating the RICE units be impacted at the end of the Tilden Special Contract?

A. As I mentioned earlier, the Tilden Special Contract is designed to recover 50% of the capital investment of the RICE units from Tilden over a 20 year period. After the end of the Tilden Special Contract, non-Tilden UMERC customers will be responsible for (1) 50% of the unrecovered capital investment made during the period the Tilden Special Contract is in effect, plus (2) 100% of the generation O&M, property tax and generation related A&G costs, plus (3) 100% of any incremental capital investment made subsequent to the end of the Tilden Special Contract. If UMERC enters into a new special contract with Tilden, 100% of the revenues collected from Tilden under this new special contract will be subtracted from the UMERC generation costs to determine the revenues collected from the non-Tilden UMERC customers.

Q. What are the options available to UMERC to finance the new generation facilities?

A. UMERC's parent company, WEC Energy Group, expects to finance approximately half of the new generation facilities through an equity contribution to UMERC. The other half of the financing will be provided by external debt financing. The external debt financing for the generating facilities can be provided through project finance, debt registered with the Securities and Exchange Commission ("SEC"), or debt issued in the private placement market.

Q. Please describe each of the external debt financing options.

A. Project debt typically is limited to the asset being financed. The lenders rely on the project's cash flows and assets for repayment. In analyzing the cash flows from the project, lenders will examine any power purchase agreements ("PPA") in place, the length of those PPAs and the creditworthiness of the counterparty to the PPA. As such, project finance is typically described as non-recourse financing as it does not rely on the overall creditworthiness and liquidity of the Company that will own the asset. The interest rate on project finance debt is typically higher than the interest rate on debt that relies on the general creditworthiness of the whole company.

Certain companies have the option of issuing external debt through a registration statement with the SEC. This is called "SEC-registered debt." To issue such debt, companies have to be SEC registrants, meaning they have to file periodic financial statements with the SEC and abide by specific disclosure roles. Investors for SEC-registered debt typically also require credit ratings from two nationally recognized statistical rating organizations commonly known as rating agencies. Other requirements for SEC-registered debt include accounting opinions and comfort letters. The various requirements for SEC-registered debt are onerous, especially for smaller companies who do not have a lot of debt outstanding to absorb the costs. There can be pricing benefits in issuing SEC-registered debt if the specific debt issuance is large enough to be included in bond indices. Debt issuances in amounts greater than $250 million are eligible to be included in bond indices, which increases their liquidity in the secondary market.[1] As such, index-eligible debt can benefit from SEC registration.

[1] As of April 1, 2017, the Bloomberg Barclays US Fixed Income Index will only include issuances that have a size of $300 million or greater.

Companies also have the option of issuing debt in the private placement market. This type of debt requires no registration with the SEC and no credit ratings from the rating agencies. Investors in the private placement market tend to be buy-and-hold investors and they do not typically value liquidity. Debt issuances in amounts less than $250 million typically price efficiently in the private placement market.

Q. Which option does UMERC plan on using to finance the new generation facilities?

A. UMERC plans on issuing external debt in the private placement market to finance the new generation facilities.

Q. Please explain why.

A. A private placement debt financing for the new generation facilities is optimal because of the reasons listed below.

- The required debt financing is expected to be less than $250 million based on current project cost estimates. As discussed above, issuances less than $250 million price better in the private placement market.
- UMERC does not plan on being an SEC registrant due to the associated costs of registration. Given that the size of the planned debt financing is less than $250 million, there would likely be no pricing benefit to issuing SEC-registered debt.
- By issuing debt in the private placement market that relies on UMERC's overall creditworthiness, the debt should price better than non-recourse project financing.

Q. Will UMERC consider other external debt financing options?

A. Yes. The current financing plan for the external debt portion of the generation facilities is based on current market conditions. UMERC will continue to monitor capital markets

and will make a final determination on the financing option that results in optimal execution and pricing.

Q. Are there any options for WEC Energy Group to mitigate the cost of financing?

A. WEC Energy Group has the option of providing a parent guarantee to UMERC. However, because UMERC will be a regulated utility, UMERC is viewed by debt investors as more creditworthy and less risky than its parent WEC Energy Group. Therefore, a guarantee by WEC Energy Group would not be expected to reduce the cost of financing.

Q. What is UMERC requesting with respect to current return versus deferred return on construction work in progress ("CWIP") during the construction phase of the proposed new generation project?

A. The new RICE electric generation project will be a large discrete construction project that is not reflected in current UMERC rates. The Company is requesting CWIP in rate base with 100% AFUDC offset, which provides no current return on but rather allows 100% deferred return on CWIP by accruing AFUDC on the entire CWIP balance during the construction period. Accruing a deferred return on this CWIP project will ensure that customers do not pay more for carrying cost than is appropriate while allowing UMERC to ultimately recover the proper amount of construction carrying cost in future ratemaking after the project has gone in-service. Total AFUDC is approximately $11.5 million based on an AFUDC rate of 6.28% applied to 100% of the forecasted monthly CWIP balances. The AFUDC rate incorporates deferred income tax balances associated with the new generation project as zero cost capital with the remaining financing requirement split evenly between equity with a cost rate of 10.0% and debt with a cost

rate of 4.2%. See my Exhibit A-__ (JAS-1). If the Commission does not approve 100% deferred return on the new generation CWIP during construction, UMERC would need to request rate adjustments prior to construction to reflect current rate recovery of any portion of the CWIP carrying cost not being deferred.

Q. Are there any regulatory accounting approvals required with respect to the Tilden Special Contract?

A. Yes. Based on the settlement agreement, the Tilden Special Contract provides a levelized mortgage-style payment to UMERC of 50% of the project's capital cost rather than recovery under the typical declining regulatory revenue requirement curve. Under typical rate recovery, the capital carrying cost recovery is higher in the early years and declines over time as the asset is depreciated. Since the contract with Tilden is levelized, UMERC will essentially under-recover on Tilden's share of the capital cost in the early years of the contract and over-recover on the "back-end" of the contract to achieve full recovery of the project's capital allocated to the Tilden Special Contract over a 20 year period. UMERC requests authorization to track the capital cost recovery specific to Tilden's 50% share, and requests a commitment in the Commission's order that capital cost recovery for the 50% share of the project allocated to non-Tilden UMERC customers will not be impacted by the recovery of capital cost under the Tilden Special Contract.

Q. Does this complete your testimony?

A. Yes.

MIICHIGAN PUBLIC SERVICE COMMISSION
Upper Michigan Energy Resources Corporation

Estimated AFUDC Financing Cost During Construction

	2016	2017	2018	2019	2020	Total
1. Construction Cash Flow ($ Million)	3.2	7.5	178.5	75.5	1.0	265.7
2. Estimated AFUDC ($ Million)	-	0.2	5.6	5.8	-	11.5

Assumptions
Expenditures start August of 2016.
Assumes CON is approved September of 2017 and AFUDC accruals start at that time.
Assumes 100% deferred return on CWIP during construction.
AFUDC rate is the weighted cost of capital of 6.28% and includes deferred income taxes as zero cost capital with the remaining capitalization split evenly between equity at 10.0% and debt at 4.2%.
Primary in-service date is May of 2019 and AFUDC accruals stop at that time.
Trailing dollars after May of 2019 go in-service as spent.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*** * * * ***

In the Matter of the Application of	)	
Upper Michigan Energy Resources Corporation	)	
for approval of a Certificate of Necessity	)	
pursuant to MCL 460.6s for	)	Case No. U-18224
Two Reciprocating Internal Combustion Engine	)	
Electric Generation Facilities Located in the	)	
Upper Peninsula of Michigan	)	
Approval of Certificate(s) of Public Convenience	)	
And Necessity, approval of a Special Contract with	)	
Tilden Mining Company L.C.	)	
and for related accounting and ratemaking	)	
authorizations.	)	

DIRECT TESTIMONY AND EXHIBIT

OF

ANDREW W. SUTHERLAND

ON BEHALF OF

UPPER MICHIGAN ENERGY RESOURCES CORPORATION

Q. Please state your name and business address.

A. My name is Andrew W. Sutherland. My business address is 5405 Data Court, Ann Arbor, Michigan 48108.

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

A. I am employed by HDR Engineering, Inc. ("HDR"). My position is as a Project Manager, Senior Mechanical Engineer, and Associate Vice President.

Q. Please provide your educational background.

A. I have a Bachelor of Science degree in Mechanical Engineering from Michigan State University. I have held a Professional Engineers license in Michigan since 2003.

Q. Please describe your business experience.

A. My professional career has been spent as a consulting engineer in the power industry with HDR's Ann Arbor, Michigan, office (f/k/a Cummins & Barnard) where I have been employed since 1999. In my early career, I functioned primarily as a heat balance engineer modeling thermal systems for coal and natural gas facilities. More recently, I have supported and led technology assessments evaluating the most efficient, lowest cost, and/or most flexible option for generation. These assessments have included detailed review of installation and operating costs for turbine-based and engine-based generation facilities. I have also worked as a mechanical or lead engineer on design projects for the installation of both turbine and engine generation. I have completed generation technology assessments and feasibility analyses for industrial, utility, and developer clients. I have led analyses of the Presque Isle Power Plant ("PIPP"), including Air Quality Control Systems retrofit, gas conversion, and Dry Sorbent Injection ("DSI") testing. I served as the lead engineer for the recently completed DSI system installation at PIPP.

Q. What is the purpose of your testimony?

A. I am testifying in support of the Application filed by Upper Michigan Energy Resources Corporation ("UMERC") in this case. Specifically, I am sponsoring and supporting a report entitled "Northern Michigan Power Generation Technology Comparison", which was prepared by HDR ("HDR Report"). HDR prepared this report to evaluate the most

feasible options for UMERC to generate power in the Marquette and Keweenaw Peninsula area to serve its customers. The Marquette area is currently served by PIPP, which consists of five coal-fired steam generators, and is owned and operated by Wisconsin Electric Power Company.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring Exhibit A-__ (AWS-1), which is the HDR Report that I referenced earlier.

Q. What was your role in preparing the HDR Report, Exhibit A-_ (AWS-1)?

A. This report was prepared under my control and supervision. I was the project manager, lead engineer, and the person primarily responsible for the report content. I coordinated other HDR engineers in the solicitation of equipment manufacturer information, evaluated the comparison factors for each of the Options discussed in the report, and wrote the majority of the report. I was also involved in previous HDR analyses of PIPP and provided input on existing conditions at the facility.

Q. Why was the HDR Report prepared?

A. HDR was requested to prepare an evaluation of the most feasible options for generating power in the Marquette and Keweenaw Peninsula area.

Q. What was the conclusion of the HDR Report?

A. The HDR Report concluded that Reciprocating Internal Combustion Engine ("RICE") technology provides the lowest evaluated cost of generation for the magnitude of power and redundancy (140 MW firm with two generators off line) analyzed for power generation options in the Marquette / Keweenaw Peninsula area. For Option 1B, as described in the HDR Report, which would use eight RICE units in the Marquette area

and two units in the Keweenaw area, the total cost of generation was evaluated to be nominally 25% lower than the next closest non-RICE option.

Q. What generation options were evaluated for serving the Marquette area load?

A. The following options were considered:

- Option 1A: 10 RICE engines located in the Marquette area;
- Option 1B: 8 RICE engines in the Marquette area and 2 RICE engines located in the Keweenaw area;
- Option 2: 6x0 Simple Cycle Combustion Turbines (SC-CTG);
- Option 3: 2x2x1 Combined Cycle Combustion Turbine plants;
- Option 4: Conversion of the existing PIPP facility to natural gas firing; and
- Option 5: Retrofit the existing PIPP facility with air quality control system ("AQCS") equipment to meet regulations.

Q. For each option evaluated, what factors were used in the evaluation?

A. The Options were compared on a Cost of Generation basis in $/MWh. The Cost of Generation for each case was developed by combining the following factors:

- Fuel Only Cost of Generation;
- Capital Recovery;
- Fixed Operations and Maintenance ("O&M") Costs; and
- Variable O&M Costs.

Fuel Only Cost of Generation was determined by dividing annual generation by annual fuel cost. Annual fuel cost was calculated from each Option's average operating net heat rate (efficiency), the assumed unit cost of fuel, and the annual generation.

Capital Recovery was determined using each Option's estimated Project Cost, the annual generation, and an assumed Fixed Charge Rate of 10.5%.

Fixed O&M Costs included fixed maintenance, labor costs, and plant life extension costs (where applicable). Fixed maintenance is defined as maintenance costs required regardless of how frequently the equipment is run. The fixed maintenance required for each option were developed based on prior HDR evaluations, budgetary information from equipment suppliers, and data provided by the plant where applicable. Labor costs were estimated based on typical staffing levels required for operation and maintenance of each facility. Plant Life Extension Costs were based on HDR's previous (2012) evaluation of PIPP in which annual costs were estimated for replacement and/or repair of existing equipment to maintain the plant output and reliability.

Variable O&M Costs are costs directly tied to how the equipment is operated, such as number of starts and stops and annual hours of operation. The Variable O&M Costs were estimated from similar previous HDR evaluations and equipment supplier budgetary data.

Q. Describe how the Project Costs used in the evaluation were developed.

A. Project Cost estimates were prepared at a high level for each case. The costs used were a combination of recent similar project experience, vendor data, previous analysis, and HDR in-house data, depending on the Option. For Options 1A and 1B, equipment bids were solicited to confirm the estimated cost for the generating equipment. HDR then prepared cost estimates for the installation of the equipment, scaled up from similar previous projects that we have been involved in. Option 2 costs were scaled from a recent similar project for which we had both, equipment pricing and engineering, procurement, and constructing ("EPC") pricing. Option 3 costs were developed from a similar combined cycle facility scaled up to match the conditions of Option 3. Options 4

and 5 were modified from HDR's previous analyses at PIPP, adjusted for conversion of only 4 out of 5 Units, assuming retirement of the fifth unit.

Off site costs for gas and electrical interconnection were provided by others. HDR did not prepare estimates for these costs.

Allowance for funds used during construction ("AFUDC"), Contingency, and Escalation were applied as a percentage at what HDR considers to be standard industry rates.

Q. What conclusions were drawn from HDR's evaluation of the most feasible options?

A. The conclusions from HDR's evaluation were that, of the options evaluated, the RICE technology provides the lowest evaluated cost for generating 140 MW of firm power with N-2 redundancy in the Marquette and Keweenaw Peninsula areas (Option 1B). The redundancy requirements of the area support selection of multiple smaller generators as a single unit outage has a lesser impact. The equivalent simple cycle gas-turbine facility (Option 2) has a slightly higher cost and a slightly lower efficiency, resulting in a higher cost of generation. A gas turbine combined cycle facility (Option 3) has better efficiency but higher capital cost, resulting in a higher cost of generation. The PIPP gas and coal options (Options 4 and 5) are not cost effective due to the high O&M cost of extending the life of the existing plant equipment.

Q. Does this conclude your testimony?

A. Yes.

Miller Canfield
Northern Michigan Power Generation Technology Comparison

January 2017

10045537

5405 Data Court
Ann Arbor, Michigan 48108

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1.0 EXECUTIVE SUMMARY

HDR has prepared this evaluation of the most feasible options for generating power in the Marquette and Keweenaw Peninsula area. The Marquette area is currently served by the Presque Isle Power Plant (PIPP), which consists of five coal fired steam generators. Aging equipment and environmental regulations necessitate action to be taken as the existing facility, in its current configuration, will not meet long-term requirements.

HDR's evaluation shows that the Reciprocating Internal Combustion Engine (RICE) technology provides the lowest evaluated cost of generation for new generation options in the Marquette / Keweenaw Peninsula area. The Total Cost of Generation for the preferred Option (henceforth Option 1B) is $73.78/MWh, which is nominally 25% lower than the next closest non-RICE option. The PIPP generation options rank last in total cost of generation, despite gas repowering having a lower capital cost than any of the other Options considered. This confirms the conclusion that long-term generation at PIPP is not a long-term economically viable alternative. In addition, Option 5 presents the risk of substantial future environmental costs, most notably CO_2 regulations, the cost of which were not included in this analysis.

The electrical demand on which this evaluation is based is a peak capacity of 180 MW, with a firm output of 140 MW. "Firm" has been defined as 140 MW output with two units removed from service (N-2 redundancy).

The following electrical generation options were considered:

- Option 1A: 10 Reciprocating Internal Combustion Engines (RICE) located in the Marquette area
- Option 1B: 8 RICE engines in Marquette and 2 RICE engines located in the Keweenaw area
- Option 2: 6x0 Simple Cycle Combustion Turbines (SC-CTG)
- Option 3: 2x2x1 Combined Cycle Combustion Turbine plants
- Option 4: Conversion of the existing PIPP facility to natural gas firing
- Option 5: Retrofit the existing PIPP facility with AQCS equipment to meet regulations

The results of HDR's Analysis are summarized in the Table 1.0-1: Options Comparison at the end of this Section. Option 1B is shown to have the lowest overall cost of generation. Option 1B represents a substantially lower capital investment than required for the combustion turbine options and is at a much higher efficiency than the existing plant repowering/conversion options, resulting in the lowest net cost of generation over the evaluation lifecycle.

Options 4 and 5 relied heavily on analysis completed as part of HDR's 2012 PIPP Options Comparison report, 160285-CZR-M0001. While Option 4 requires substantially less capital investment than the other Options considered, reuse of the existing steam turbines is much less efficient than generation with RICE or CTGs resulting in a higher cost of generation. Each option considered annual operating costs, such as the fuel based cost of generation, fixed and variable O&M, and capital costs in each condition. Interconnection costs for gas and electric, and transmission system upgrade costs (where applicable) were provided by others.

Multiple simple cycle and combined cycle arrangements were evaluated for Options 2 and 3. The results presented in this evaluation are non-specific to any particular equipment supplier. The 140 MW N-2 firm capacity requirement led to selection of multiple smaller CTGs (nominally 40 MW each) as achieving that redundancy, as the utilization of larger turbines results in excessive cost and generating capacity. Six simple cycle CTGs were assumed, although some models in this class could achieve the required output

and redundancy with 5 CTGs. Likewise, Option 3 for combined cycle was based on two independent 2x1 arrangements such that 140 MW could be achieved with two CTGs out of service.

Table 1.0-1: Options Comparison

Project Capital Cost Summary	Option 1A	Option 1B	Option 2	Option 3	Option 4	Option 5
Summary of Options	**RICE 10x0**	**RICE 8x2**	**SC 6x0 CTG**	**CC 2x2x1 CTG**	**PIPP Gas Conv**	**PIPP Coal Retrofit**
Gross Output (kW)	188,170	188,170	228,996	281,000	320,000	320,000
Net Output (kW)	182,525	182,525	222,126	271,165	305,600	296,000
N-2 Net Output (kW)	146,020	146,020	148,084	140,500	143,250	138,750
Gross Heat Rate (Btu/kWH-HHV)	8,200	8,200	9,300	6,900	10,500	10,500
Net Heat Rate (Btu/kWH-HHV)	8,500	8,500	9,560	7,192	11,000	11,300
Equipment Supply Price	$95,700,000	$95,700,000	$113,000,000	$125,000,000	$17,000,000	$50,000,000
Prime Mover Gross Cost/kW	$508.58	$508.58	$493.46	$444.84	$53.13	$156.25
EPC Pricing (assumed OFE)	$84,600,000	$96,975,000	$135,000,000	$175,000,000	$50,000,000	$122,000,000
Total EPC / OEM	$180,300,000	$192,675,000	$248,000,000	$300,000,000	$67,000,000	$172,000,000
Net Cost/kW (OEM / EPC Only)	$987.81	$1,055.61	$1,116.48	$1,106.34	$219.24	$581.08
Owner Costs (10% of OEM/EPC)	$18,000,000	$19,300,000	$24,800,000	$30,000,000	$6,700,000	$17,200,000
Facility Total Project Cost	**$198,300,000**	**$211,975,000**	**$272,800,000**	**$330,000,000**	**$73,700,000**	**$189,200,000**
Net Cost/kW	$1,086.43	$1,161.35	$1,228.13	$1,216.97	$241.16	$639
Off Site Costs						
Gas Line Cost	$2,000,000	$8,000,000	$3,000,000	$3,000,000	$20,000,000	$ -
Interconnect Cost	$2,000,000	$4,000,000	$2,000,000	$2,000,000	$ -	$ -
Subtotal Cost including Gas / Sub	**$202,300,000**	**$223,975,000**	**$277,800,000**	**$335,000,000**	**$93,700,000**	**$189,200,000**
AFUDC (11%)	$22,250,000	$24,640,000	$30,560,000	$36,850,000	$10,310,000	$20,810,000
Contingency (5%)	$10,120,000	$11,200,000	$13,890,000	$16,750,000	$4,690,000	$9,460,000
Escalation (2% annually for 2-years)	$8,090,000	$8,960,000	$11,110,000	$13,400,000	$3,750,000	$7,570,000
Total Project Cost (w/o Trans)	**$242,760,000**	**$268,775,000**	**$333,360,000**	**$402,000,000**	**$112,450,000**	**$227,040,000**
Net Cost/kW	$1,330.01	$1,472.54	$1,500.77	$1,482.49	$367.96	$767.03
Transmission Upgrade Cost	$100,000,000	$ -	$100,000,000	$100,000,000	$100,000,000	$100,000,000
Grand Total Project Cost	**$342,760,000**	**$268,775,000**	**$433,360,000**	**$502,000,000**	**$212,450,000**	**$327,040,000**
Net Cost/kW	$1,877.88	$1,472.54	$1,950.96	$1,851.27	$695.19	$1,104.86
Cost of Generation Summary	**Option 1A**	**Option 1B**	**Option 2**	**Option 3**	**Option 4**	**Option 5**
Summary of Options	**RICE 10x0**	**RICE 8x2**	**SC 6x0 CTG**	**CC 2x2x1 CTG**	**PIPP Gas Conv**	**PIPP Coal Retrofit**
Annual Generation (MWH)	906,603	906,603	906,714	905,854	906,835	906,835
Fuel Consumption (MMBTU/yr)	7,706,126	7,706,126	8,668,188	6,514,903	9,975,187	10,247,238
Fuel Cost ($/yr)	$26,970,000	$26,970,000	$30,340,000	$22,800,000	$34,910,000	$25,620,000
Fuel Only Cost of Gen ($/MWH)	**$29.75**	**$29.75**	**$33.46**	**$25.17**	**$38.50**	**$28.25**
Capital Recovery ($/MWH)	**$39.70**	**$31.13**	**$50.18**	**$58.19**	**$24.60**	**$37.87**
Fixed O&M Costs:						
Fixed Maintenance ($/yr)	$6,000,000	$6,000,000	$6,500,000	$7,000,000	$9,000,000	$11,000,000
Labor ($/yr)	$960,000	$1,200,000	$1,200,000	$1,800,000	$13,800,000	$19,200,000
Plant Life Extension Costs ($/yr)	-	-	-	-	$10,000,000	$25,000,000
Total Fixed O&M Costs ($/yr)	**$6,960,000**	**$7,200,000**	**$7,700,000**	**$8,800,000**	**$32,800,000**	**$55,200,000**
Total Fixed O&M Costs ($/MWH)	**$7.68**	**$7.94**	**$8.49**	**$9.71**	**$36.17**	**$60.87**
Variable O&M Costs ($/yr)	**$4,500,000**	**$4,500,000**	**$5,250,000**	**$4,500,000**	**$3,000,000**	**$6,750,000**
Variable O&M Costs ($/MWH)	**$4.96**	**$4.96**	**$5.79**	**$4.97**	**$3.31**	**$7.44**
Total Cost of Generation ($/MWH)	**$82.09**	**$73.78**	**$97.93**	**$98.04**	**$102.57**	**$134.43**

Notes:
Owner's costs taken as 10% of Total EPC / OEM cost except where otherwise noted.
Off Site Costs for gas pipeline and electrical interconnection provided by We Energies
CC CTG N-2 Option includes 8 MW of duct firing to achieve 140 MW with single 2x1.

2.0 INTRODUCTION

Miller Canfield requested HDR to prepare an evaluation of the various options for long-term power generation in the greater Marquette, MI area currently served from Presque Isle Power Plant (PIPP). The options reviewed the most feasible generation solutions including:

- Installation of Reciprocating Internal Combustion Engines (RICE),
- Installation of Simple Cycle Combustion Turbines (SC-CTG),
- Installation of a Combined Cycle generation facility,
- Converting PIPP to gas firing, with a new gas pipeline to serve the plant, and
- Retrofitting the plant with AQCS equipment as required to meet anticipated regulations.

The objective of the analysis is to identify a high level life-cycle cost of generation for each of the options for the parameters identified.

2.1 EVALUATION PARAMETERS

Evaluation parameters were agreed to between HDR and Miller Canfield early in the review and are summarized as follows:

- The peak generating capacity required to be met is 180 MW.
- The "firm" generating capacity is to be 140 MW.
    - Firm capacity for this analysis was defined as N-2, meaning two generators out of service.
- Specific site interconnection analysis was not performed by HDR as part of this effort beyond what was taken from our previous analysis at PIPP. All gas and electrical interconnection costs were provided by others.
- Some of the Options require upgrade of the electrical transmission system. The costs of these upgrades were provided by others.

3.0 SUMMARY OF OPTIONS

The following is a brief summary of the generation options that were evaluated for serving the Marquette area load as evaluated within this report.

3.1 INSTALLATION OF 10 RICE UNITS IN THE MARQUETTE AREA – OPTION 1A

This option evaluates the cost of generation from the use of multiple RICE units. Engines are available in sizes up to nominally 18 MW, meaning at least ten units are required to meet the peak generation of 180 MW. Vendor data was collected to confirm HDR's performance, capital cost, and maintenance cost modeling for a RICE based project.

3.2 INSTALLATION OF 8 RICE UNITS IN THE MARQUETTE AREA AND 2 RICE UNITS IN THE KEWEENAW AREA – OPTION 1B

This option is also based on RICE technology, however it is assumed that two of the units would be located in the Keweenaw Peninsula area. Locating units in the Keweenaw Peninsula provides relief for the required transmission system upgrades between Marquette and the Keweenaw (estimated by others at $100M). The construction cost of Option 1B is higher given the two construction sites, but all equipment and performance is otherwise identical to that of Option 1A.

3.3 INSTALLATION OF 6 SIMPLE CYCLE CTGS IN THE MARQUETTE AREA – OPTION 2

Option 2 is comparable to Option 1A except based on gas turbine technology rather than RICE. Combustion Turbines have much larger single unit capacities than engines, including single units that could provide the entire 180 MW. However, given the N-2 redundancy requirements for the area, a CTG size of 40-50 MW was determined to be an ideal balance of unit redundancy vs economics. There are also several CTG models available in this size range. It was assumed that six simple cycle CTGs would be required to meet the 140 MW firm capacity, although five larger units could also potentially satisfy this parameter. Given the larger unit size, the maximum generating capacity of Option 2 is larger than Option 1.

3.4 INSTALLATION OF COMBINED CYCLE FACILITY IN THE MARQUETTE AREA – OPTION 3

Option 3 is based on combined cycle technology, meaning combustion turbines are combined with heat recovery to generate additional power in a steam turbine bottoming cycle. While this results in by far the most efficient case from a fuel consumption perspective, it is also more costly than the other Options. Several plant configurations were evaluated and the most feasible options for meeting the identified loads were further developed and analyzed. A traditional configuration for a combined cycle facility is a 2x1 (two CTGs and heat recovery boilers feeding a single steam turbine), however a 2x1 sized for 180 MW would not satisfy the N-2 redundancy requirements. After consideration of several cycles, an arrangement of two smaller 2x1 plants with CTGs again in the 40-50 MW size range was determined to have the most favorable combination of sufficient shafts to maintain redundancy, performance, and capital cost. As noted in Option 2, there are several CTGs in the 40-50MW size range from which this cycle could be based on.

3.5 GAS CONVERSION OF THE PRESQUE ISLE POWER PLANT – OPTION 4

Option 4 reviews the impact of converting the plant to natural gas based firing. This option was largely based on HDR's previous evaluation of PIPP options (HDR document 160285-CZR-M0001). The existing Units 7-9 generate nominally 85-90 MW, and Units 5 and 6 generate nominally 65 MW at full load. As such, conversion of 4 of the 5 existing units would be required to meet the 140 MW firm generating capacity requirement (with either Unit 5 or 6 being retired).

In HDR's 2012 analysis, vendor input was obtained to estimate the cost of replacing the existing coal burners with natural gas burners, as well as incorporating Flue Gas Recirculation (FGR) and other modifications required to meet long term environmental regulations on gas firing. Given the aging balance of plant equipment, estimated costs for additional life extension of non-coal related equipment was also incorporated into this Option.

3.6 AQCS RETROFIT OF EXISTING PLANT – OPTION 5

This option also relied on HDR's 2012 PIPP analysis as a basis. Option 5 assumes PIPP continues to serve area demand by firing coal. Continued coal combustion will require multiple forms of air quality control. While the plant has completed the addition of a Dry Sorbent Injection (DSI) system since the 2012 report, it is anticipated that additional SOx control in the form of dry scrubbers will be required to achieve long-term emissions compliance. Other emissions compliance equipment include new dry low NOx burners in combination with a rotating opposed fire air (ROFA) system for NOx control on Unit 6 and SCR on Units 7-9.. It is anticipated that SCR systems on at least Units 7-9 would be required for long-term NOx compliance with coal operation at PIPP, however the timing of that requirement is currently unclear. Future regulations on CO2 are also currently unclear, but are expected to be enacted in

some form, which makes the long-term viability of the PIPP plant on coal questionable. In the 2012 report, a plant life extension review was also completed to identify at a high level the cost of maintaining sufficient reliability at the plant over the next 20-years, the costs for which have been incorporated into this Option.

4.0 EVALUATION CRITERIA

Each of the options reviewed was evaluated based on the criteria identified by Miller Canfield to determine the lifecycle cost of generation for each Option. The evaluation included the following factors:

- Net capacity
- Full load net heat rate
- Emissions
- Reliability
- Capital Cost
- O&M Costs

The results of the options analysis are summarized in the comparison table provided in Section 1.

4.1 OPTION 1A: INSTALLATION OF 10 RICE UNITS IN THE MARQUETTE AREA

RICE units are available from multiple manufacturers in the size range anticipated for this project. Performance and cost information was initially based on HDR's in-house equipment database. HDR also solicited and received budgetary quotations from two equipment manufacturers to validate the performance and cost assumptions prepared.

4.1.1 Performance Characteristics

Based on HDR heat balances and equipment supplier data, the gross output from 10 RICE units is estimated to be 188,170 kW. An auxiliary load of 3% was assumed resulting in a plant Net Output of 182,525 kW. The firm N-2 net output is 146,020 kW.

The Unit Heat Rate was also based on previous HDR heat balances, validated with equipment supplier data. The Gross Heat Rate was estimated as 8,200 BTU/kWh with a corresponding Net Heat Rate of 8,500 BTU/kWh. These heat rates represent the overall dispatched heat rate (i.e. not full load). The RICE units are more efficient than the equivalent simple cycle gas turbines (Option 2) particularly at part load where engine performance drops off much less so than CTGs. Either simple cycle alternative is far less efficient than the combined cycle equivalent (Option 3), however the simple cycle arrangement offers greater operational flexibility.

The numerous units and favorable part load efficiency for Option 1A results in a very flexible plant that can be dispatched over a wide range of loads with little impact on performance.

4.1.2 Facility Cost Estimate

The cost estimate for this Option was developed from a similar previous HDR estimate, adjusted for local conditions and for the equipment pricing received. The overall equipment supply cost was estimated as $95,700,000. This cost includes controls, delivery, and all costs attributed to the equipment supplier. The balance of project direct costs are wrapped into the EPC Pricing value of $84,600,000, which again is based on a previous similar project cost.

Owner's costs for the project were included at 10%, not including site gas and electrical interconnection costs. The resulting total on-site project direct cost is estimated at $198,300,000, or a net $/kW cost of $1,086/kW.

4.1.2.1 Site Utility Interconnection Costs

The site of the RICE installation was assumed at a location with close proximity to sufficient gas and electric service. The utility costs were provided by others as $2,000,000 for natural gas and $2,000,000 for electrical interconnection.

An additional transmission system cost of $100,000,000 (estimated by others) was applied to this option to account for upgrades required to transmit the power from Marquette to the Keweenaw Peninsula.

4.1.2.2 Indirect Costs

Additional allowances for project indirect costs were applied including AFUDC at 11% and 5% contingency, each applied to the total facility cost. Two years of escalation was also applied at an assumed rate of 2% annually.

Summing each of these factors results in a total project cost estimate for Option 1A of $342,760,000, or a net cost of $1,878/kW.

4.1.3 Cost of Generation Summary

A simple cost of generation was developed for each option based on the fuel based cost of generation, capital cost recovery, and fixed and variable O&M. The costs were distributed over annual generation based on an assumed capacity factor of 55%, resulting in annual generation of 906,600 MWHs.

- Fuel Only COG was calculated as $29.75/MWh using a natural gas cost of $3.50/MMBTU.
- Capital Recovery was calculated as $39.70/MWh using a fixed charge rate of 10.5%
- Fixed O&M was estimated as $7.68/MWh
    - Annual Fixed Maintenance was estimated as $6,000,000 based on supplier data and HDR in-house data. Annual Labor was estimated as $960,000 based on an estimated staff of 8 full-time-equivalents to adequately operate the plant.
- Variable O&M was estimated as $4.96 using an annual variable cost of $4.5M/yr, based on supplier data and HDR in-house data.

The total Cost of Generation for Option 1A was estimated as $82.09/MWh which ranked 2nd of the Options reviewed.

4.2 OPTION 1B: 8 RICE UNITS IN MARQUETTE, 2 RICE UNITS IN KEWEENAW

Option 1B is similar to Option 1A however rather than assuming all 10 RICE units are located in Marquette, it is assumed two of the Units are located in the Keweenaw Peninsula to alleviate the costs for upgrading the transmission system between the locations. Performance characteristics for the two Options are identical. Equipment costs are also identical to Option 1A, however the EPC costs are increased given the two independent construction sites. Evaluation parameters are summarized in the following sub-sections.

4.2.1 Performance Characteristics

See Section 4.1.1

4.2.2 Facility Cost Estimate

HDR developed EPC costs assuming two independent mobilizations at each site. The EPC direct cost for Option 1B is estimated as $96,975,000.

As with Option 1A, Owner Costs were applied at 10% of the net direct cost, resulting in a total on-site project direct cost estimate of $211,975,000, or a net $/kW cost of $1,161/kW.

4.2.2.1 Site Utility Interconnection Costs

Given the multiple sites, the utility interconnection costs for Option 1B are higher than Option 1A. These costs were provided by others as $8,000,000 for natural gas and $4,000,000 for electrical interconnection. As with Option 1A, Indirect costs for AFUDC, Contingency, and Escalation were applied as a percentage of the direct cost (see Section 4.1.2.2)

While the total site direct costs for Option 1B are $268,775,000, which is $26M higher than Option 1A, Option 1B does not require the transmission system upgrades (estimated at $100M) therefore the total project cost estimate for Option 1B of $268,775,000 ($1,473/kW) is nominally $75M lower than Option 1A.

4.2.3 Cost of Generation Summary

The cost of generation for Option 1B is similar to that described for Option 1A in Section 4.1.3, with the following exceptions:

- Capital Recovery was calculated as $31.13/MWh using a fixed charge rate of 10.5%
- Fixed O&M was estimated as $7.94/MWh
    - Annual Labor was increased to $1,200,000 based on 10 full-time-equivalents to account for staffing the multiple sites.

The total Cost of Generation for Option 1B was estimated as $73.78/MWh which ranked 1st of the Options reviewed.

4.3 OPTION 2: INSTALLATION OF 6 SIMPLE CYCLE CTGS

Multiple potential simple cycle CTGs were initially screened at a high level. Achievement of the 140 MW firm N-2 generating capacity resulted in multiple smaller (~40 MW) simple cycle CTGs providing more favorable economic results than larger CTGs, therefore the evaluation parameters were based on data for that size of unit. Performance and cost information was based on HDR's in-house equipment database and recent project bids for equipment in a similar installation.

4.3.1 Performance Characteristics

Performance data was developed using HDR's heat balance software (Thermoflow / GT Pro), supplemented by equipment supplier data. The gross output from the six simple cycle CTGs is estimated to be 228,996 kW. An auxiliary load of 3% was assumed resulting in a plant Net Output of 222,126 kW and a firm N-2 net output of 148,084 kW.

Heat Rates were also based on HDR heat balances, validated with equipment supplier data. The Gross Heat Rate was estimated as 9,300 BTU/kWh with a corresponding Net Heat Rate of 9,560 BTU/kWh. As with Option 1, these heat rates represent the overall dispatched heat rate, however the lower number of Units and higher overall capacity to meet the same demand result in a lower average capacity factor. In addition, CTG performance is impacted more significantly than RICE units at part load. As such, the average heat rate / efficiency for Option 2 is substantially less than that of Option 1 whereas the nameplate full load efficiencies of CTGs and RICE are relatively close (although RICE units do typically have a better full load efficiency). As with Option 1, Option 2 is far less efficient than the combined cycle equivalent (Option 3), however the simple cycle arrangement offers greater operational flexibility. Option 2 is not as flexible as Option 1 as it is based on multiple larger units that are more heavily derated at part load, however Option 2 provides much more flexible and responsive output than the much more efficient combined cycles discussed in Option 3.

4.3.2 Facility Cost Estimate

HDR's estimated cost for Option 2 was based on recent bid data for a similar simple cycle facility with multiple equipment suppliers in the range of turbines evaluated. HDR's in-house data was adjusted for local conditions to develop the full EPC price. The cost estimate for supply of the CTGs in Option 2 is estimated as $113,000,000, or $493/kW. This cost includes controls, delivery, and all costs attributed to the equipment supplier. While the overall equipment price is higher than that of Option 1, the $/kW is lower, given the additional (unutilized) capacity of the larger CTGs. The balance of project direct costs are wrapped into the EPC Pricing value of $135,000,000, which again is based on a previous similar project cost.

As with Option 1, Owner costs for the project were included at 10%, not including site gas and electrical interconnection costs. The resulting total on-site project direct cost is estimated at $272,800,000, or a net $/kW cost of $1,228/kW.

4.3.2.1 Site Utility Interconnection Costs

The project site for Option 2 is considered equivalent to that of Option 1A with the only difference in Utility Interconnection costs being a slightly higher gas interconnection cost of $3,000,000 to account for the larger gas supply requirement of the CTGs. The utility interconnection costs were provided by others. Option 2 also requires the additional transmission system upgrade cost of $100,000,000 (estimated by others) to account for transmission from Marquette area to the Keweenaw Peninsula.

4.3.2.2 Indirect Costs

Indirect costs and escalation were applied at the same rates as discussed for Option 1A in Section 4.1.2.2.

Summing each of these factors results in a total project cost estimate for Option 2 of $433,360,000, or a net cost of $1,951/kW. This project cost is 60% higher than the equivalent Option 1B cost.

4.3.3 Cost of Generation Summary

The cost of generation for Option 2 was developed on the same basis as described in Section 4.1.3 for Option 1A. The costs were distributed over annual generation based on an assumed capacity factor of 45% to provide roughly the same generation as in Option 1A, 906,700 MWH/yr.

- Fuel Only COG was calculated as $33.46/MWh using a natural gas cost of $3.50/MMBTU.
- Capital Recovery was calculated as $50.18/MWh using a fixed charge rate of 10.5%
- Fixed O&M was estimated as $8.49/MWh
    - Annual Fixed Maintenance was estimated as $6,500,000 based on supplier data and HDR in-house data. Annual Labor was estimated as $1,200,000 to adequately staff the plant.
- Variable O&M was estimated as $5.79 resulting in annual variable cost of $5.25M/yr, based on supplier data and HDR in-house data.

The total Cost of Generation for Option 2 was estimated as $97.93/MWh which ranked 3rd of the Options reviewed.

4.4 OPTION 3: COMBINED CYCLE FACILITY

Combined cycle generation was reviewed as part of HDR's 2012 report which served as the basis for this evaluation. The 2012 review considered a larger total capacity and was therefore based on 7EA gas turbines (nominally 80 MW). In addition, the redundancy requirements of the current evaluation necessitate smaller turbines be used such that the impact of two units out of service is mitigated. The revised combined cycle facility evaluated in Option 3 was therefore based on two 2x1 trains utilizing nominally 45 MW CTGs with each 2x1 train achieving the 140 MW firm capacity requirement. As noted in 4.3, there are multiple CTG options in this size range.

4.4.1 Performance Characteristics

HDR prepared heat balances for Option 3, resulting in a Gross Output of 281,000 kW. The Auxiliary load for the combined cycle facility is estimated as 3.5% resulting in a plant Net Output of 271,165 kW. The firm N-2 net output is 140,500 kW (note that a minimal level of duct firing was modeled in the HDR heat balances to maintain the net output greater than 140 MW with a single 2x1 train).

The developed heat balances provided a Gross Heat Rate of 6,900 BTU/kWh with a corresponding Net Heat Rate of 7,192 BTU/kWh. As with the previous Options, these heat rates represent the overall dispatched heat rate, which is at a substantially lower capacity factor of 55% given the higher maximum generating capacity. The combined cycle arrangement is not nearly as flexible as the simple cycle engine/turbine options, however despite periods of part load operation Option 3 is by far the most efficient case evaluated given the heat recovery bottoming cycle. As a single train could provide the full capacity of 140 MW, this load could be served at near full load efficiency. 180 MW would require part loading multiple units which would substantially derate the overall efficiency.

4.4.2 Facility Cost Estimate

Reference data for combined cycles in this size range are less common than larger facilities, however HDR used applicable project costs from similarly sized facilities on a $/kW bases adjusted for local conditions to develop the overall anticipated direct cost. The overall equipment supply cost was estimated as $125,000,000. This cost includes controls, delivery, and all costs attributed to the equipment supplier. The EPC cost was estimated as $175,000,000. Incorporating Owner costs at 10%, not including site gas and electrical interconnection costs results in a total on-site project direct cost estimate of $330,000,000, or a net $/kW cost of $1,217/kW. While the $/kW for this Option is similar to Options 1 and 2, the overall capacity is well above the required 180 MW, and the overall cost estimate is by far the highest of any of the options evaluated, which is logical given the additional balance of plant equipment and complexity of construction in comparison to the simple cycle options.

4.4.2.1 Site Utility Interconnection Costs

Utility interconnection costs for Option 3 were provided by others and are identical to Option 2 at $3,000,000 for natural gas and $2,000,000 for electrical interconnection. Option 3 also requires the transmission system cost of $100,000,000 (estimated by others) to transmit the power from Marquette to the Keweenaw Peninsula.

4.4.2.2 Indirect Costs

Additional allowances for project indirect costs were applied including AFUDC at 11% and 5% contingency, each applied to the total facility cost. Two years of escalation was also applied at an assumed rate of 2% annually.

Summing each of these factors results in a total project cost estimate for Option 3 of $502,000,000, or a net cost of $1,851/kW.

4.4.3 Cost of Generation Summary

The cost of generation for Option 3 was developed using the same basis as the other Options described previously. The costs were distributed over annual generation, which as noted earlier given the larger capacity of this Option results in a lower assumed capacity factor of 37%, or an annual generation of 905,800 MWHs.

- Fuel Only COG was calculated as $25.17/MWh using a natural gas cost of $3.50/MMBTU.
- Capital Recover was calculated as $58.19/MWh using a fixed charge rate of 10.5%
- Fixed O&M was estimated as $9.71/MWh

  - Annual Fixed Maintenance was estimated as $7,000,000 based on supplier data and HDR in-house data. Annual Labor was estimated as $1,800,000 based on a staff of nominally 15 employees to operate and maintain the facility.
- Variable O&M was estimated as $4.97 using an annual variable cost of $4.5M/yr, based on supplier data and HDR in-house data.

The total Cost of Generation for Option 3 was estimated as $98.04/MWh which ranked 4th of the Options reviewed.

4.5 OPTION 4: CONVERSION OF PIPP TO NATURAL GAS

HDR updated the evaluation from our 2012 analysis for converting PIPP to natural gas. The conversion would consist of replacing the existing pulverized coal burners and piping with equivalent heat duty natural gas burners. To meet the generating requirements in the revised evaluation requires conversion of four of the five existing units, with either Unit 5 or 6 being retired and any two of the remaining units being able to meet the N-2 140 MW firm requirement.

HDR's 2012 review utilized a Doosan review completed for We Energies of a similar conversion of the VAPP boilers to gas firing. The report provides a comprehensive analysis of the scope, cost, and resulting performance of converting the VAPP units to gas firing. As VAPP's units are very similar to PIPP Units 5 and 6, the results of the Doosan report are believed to be broadly applicable to PIPP. Second, HDR utilized budgetary information from Peabody Engineering on scope, estimate and performance information on converting the PIPP units to gas firing.

For conversion of PIPP to gas the majority of work within the plant is in replacing the boiler burners and making furnace modifications for accommodating the different flame/fireball characteristics resulting from natural gas combustion.

4.5.1 Performance Characteristics

The Gross Output for the PIPP plant with Units 6-9 in operating is estimated as 320,000 kW. A list of plant auxiliary loads was reviewed to determine the percentage of plant load that drives fuel and ash handling equipment. Based on the removal of those loads versus current auxiliary load rates, the average plant auxiliary load following conversion to gas is estimated to be 4.5%. Using that auxiliary load results in a net output of 305,600 kW and a firm N-2 net output of 143,250 kW.

Efficiency of the units when operating on natural gas was estimated to be slightly lower than the existing facility based on input from the equipment suppliers. In addition, the units would generally be dispatched at a lower load than those currently served to meet the nominally 140-180 MW demand. The gross heat rate for Option 4 was estimated as 10,500 BTU/kWh, and the equivalent net heat rate is 11,000 BTU/kWh.

Continued operation of PIPP results in drastically reduced operational flexibility in comparison to Options 1-3. The Units generally required day-ahead notice for unit start-ups. Once operating at full pressure, load can generally be adjusted as desired within about one-hour, however the minimum load of the units is nominally 60% of full load, and the fewer larger units provides fewer dispatch options than the multiple shafts of the RICE and/or CTG options.

4.5.2 Facility Cost Estimate

The cost for conversion of the PIPP facility to natural gas was scaled for four of five units based on what was developed in the 2012 analysis, which was based on vendor budgetary input. The overall equipment supply cost is estimated as $17,000,000. This cost includes burners and an Over Fire Air system. The EPC cost for incorporation of this equipment is estimated as $50,000,000. Incorporating Owner costs at 10%, not including site gas and electrical interconnection costs results in a total on-site project direct cost

estimate of $73,700,000, or a net $/kW cost of $241/kW. The equipment and installation costs are relatively low in comparison to the other options and as such Option 4 is by far the least expensive option reviewed, both in terms of $/kW and total capital cost.

4.5.2.1 Site Utility Interconnection Costs

Given the lower efficiency and larger capacity of Option 4, as well as the physical location of PIPP, the gas interconnection costs are substantially higher at $20,000,000 (provided by others). As the existing generators would be reused, there are no electrical interconnection costs associated with Option 4. This Option would still require the transmission system upgrade cost of $100,000,000 for transmission from Marquette to the Keweenaw Peninsula.

4.5.2.2 Indirect Costs

Additional allowances for project indirect costs were applied on the same basis as the other options including AFUDC at 11% and 5% contingency, each applied to the total facility cost. Two years of escalation was also applied at an assumed rate of 2% annually.

Summing each of these factors results in a total project cost estimate for Option 4 of $212,450,000, or a net cost of $695/kW.

4.5.3 Cost of Generation Summary

Option 4 cost of generation is applied to generation at an assumed capacity factor of 32% as required to achieve an annual generation of 906,800 MWHs.

- Fuel Only COG was calculated as $38.50/MWh using a natural gas cost of $3.50/MMBTU.
- Capital Recovery was calculated as $24.60/MWh using a fixed charge rate of 10.5%
- Fixed O&M was estimated as $36.17/MWh
    - Annual Fixed Maintenance was estimated as $9,000,000 and annual labor was estimated as $13,800,000 as taken from the 2012 report. A life extension cost of $10,000,000 was also included as described further in Section 4.5.4.
- Variable O&M was estimated as $3.31 using an annual variable cost for the plant of $3M/yr.

It is expected that after the initial investment to convert the plant to gas that maintenance costs at the plant would drop from the current levels due to the removal of fuel and ash handling systems. Less staff would be required without the operation and maintenance of fuel and ash handling.

The total Cost of Generation for Option 4 was estimated as $102.57/MWh which ranked 5th of the Options reviewed.

4.5.4 Life Extension of Existing Units and Plant

As Option 4 relies on equipment that is already substantially aged, there are additional costs associated with maintaining balance of plant equipment that are not required for the new facilities evaluated in Options 1-3. As estimated in HDR's 2012 analysis, the cost for life extension of PIPP following conversion of the plant to natural gas is estimated as roughly $10 million annually. The annual cost is based on the portion of the items identified in the life extension analysis related to fuel and ash handling that would no longer require maintenance following conversion.

4.6 OPTION 5: AQCS RETROFIT OF PIPP

Option 5 evaluates retrofit of Air Quality Control equipment at PIPP to allow continued operation on coal. PIPP faces several pending regulations in various states of completion and/or litigation with makes the extent of AQCS scope required somewhat nebulous. HDR issued a report titled AQCS Upgrade Cost Estimate for Presque Isle Power Plant in January, 2011 (HDR Report 152561-CZR-M0001) which

detailed the likely retrofits required to address the anticipated standards and the expected costs for each. Results from that analysis were used as the baseline for this section.

Based on projections of the most likely regulations, it is anticipated PIPP will eventually be required to employ Dry FGD on all operating units, as well as SCR on at least Units 7, 8, and 9. PIPP has already installed and commissioned a PAC and sorbent injection system for the intermediate period between the enactment of MATS regulations and the still pending CATR and NAAQS standards requiring compliance in 2017-2018. These AQCS retrofits do not address the potential carbon tax on CO2 emissions which also jeopardizes the long-term viability of the PIPP facility's operation on coal.

4.6.1 SCR Application to PIPP Unit 7, 8 and 9

The anticipated arrangement identified in HDR's 2012 analysis is for an SCR reactor to be furnished for each of the three boilers with the flue gas re-directed to the SCR reactor at the outlet of the existing hot-side ESPs. The flue gas discharged from the hot-side precipitator will be ducted to the top of the SCR reactor located outside along to east wall of the boiler building above the ductwork to the Toxecon fabric filters. The flue gas from the outlet of the SCR will be ducted back to the inlet of the air heater.

4.6.2 DFGD Scrubber Application to PIPP Site

Multiple DFGD arrangements have been considered. The current estimate considered is based on one DFGD scrubber and fabric filter installed for the flue gas flow rate of either Unit 5 or 6 (whichever remains active) and one common DFGD scrubber and fabric filter installed for the combined flue gas flow rate of Units 7 through 9. The cost estimate assumes a dedicated slaked lime or lime hydration system for each scrubber system to allow each option to be evaluated individually, some savings could be obtained by using a common reagent preparation system. The reagent preparation system will include a storage silo for pebble lime and a system for storing prepared reagent.

The DFGD unit and fabric filter for Units 7 through 9 will be located in the area east of the access road by the Unit 7 through 9 chimney. This location will require the decommissioning and abandonment of the Unit 5 and 6 coal reclaim grizzly. The ductwork return from the Toxecon fabric filter will be modified. Each duct will be routed to a common header and ducted into the inlet of the DFGD system. The outlet of the DFGD unit will be ducted into a new fabric filter. The outlet of the new fabric filter will be ducted to the inlet of three new ID booster fans, which will be ducted back to Units 7 through 9 chimney.

4.6.3 Performance Characteristics

As noted in Option 4, the Gross Output for the PIPP plant with Units 6-9 in operating is estimated as 320,000 kW. The average plant auxiliary load will increase from current levels to serve the additional AQCS equipment and was estimated as 7.5%. Using that auxiliary load results in a net output of 296,000 kW and a firm N-2 net output of 138,750 kW.

Efficiency of the units when operating on coal will drop slightly from the current average assuming a lower future dispatch. The gross heat rate for Option 5 was estimated as 10,500 BTU/kWh, and the equivalent net heat rate is 11,300 BTU/kWh.

As noted in Option 4, the operational flexibility of the PIPP facility is drastically reduced in comparison to Options 1-3. Load can generally be adjusted as desired within about one-hour, however the minimum load of the units is nominally 60% of full load and start-up of units takes several hours. The fewer larger units provides much fewer dispatch options than the multiple shafts of the RICE and/or CTG options.

4.6.4 Facility Cost Estimate

Option 5 cost was estimated based on previous analysis estimates for DFGD and SCR addition, scaled to incorporation on four of five units. The overall equipment supply cost is estimated as $50,000,000. This cost includes SCRs on Units 7, 8, and 9, a DFGD system on Unit 6, a DFGD common system for Units 7-

9, and required BOP support equipment. The EPC cost for construction is estimated as $122,000,000. Incorporating Owner costs at 10%, not including site gas and electrical interconnection costs results in a total on-site project direct cost estimate of $189,200,000, or a net $/kW cost of $639/kW.

4.6.4.1 Site Utility Interconnection Costs

As Option 5 utilizes the existing facilities, there are no new utility interconnection costs. This Option would still require the transmission system upgrade cost of $100,000,000 for transmission from Marquette to the Keweenaw Peninsula.

4.6.4.2 Total Costs

Indirect costs for AFUDC, Contingency, and Escalation are applied consistently as with the other Options. Summing each of these factors results in a total project cost estimate for Option 5 of $327,040,000, or a net cost of $1,105/kW.

4.6.5 Cost of Generation Summary

Option 5 cost of generation is applied to generation at an assumed capacity factor of 32% as required to achieve an annual generation of 906, 800 MWHs.

- Fuel Only COG was calculated as $28.25/MWh using a coal cost of $2.50/MMBTU.
- Capital Recovery was calculated as $37.87/MWh using a fixed charge rate of 10.5%
- Fixed O&M was estimated as $60.87/MWh
    - Annual Fixed Maintenance was estimated as $11,000,000 and annual labor was estimated as $19,200,000. A life extension cost of $25,000,000 was also included as developed in the 2012 report.
- Variable O&M was estimated as $7.44 using an annual variable cost for the plant of $6.75M/yr.

The total Cost of Generation for Option 5 was estimated as $134.43/MWh which ranked 6th of the Options reviewed.

4.6.6 Life Extension of Existing Units and Plant

As with Option 4, Option 5 relies on existing aging equipment with substantially higher maintenance costs than new equipment. As estimated in HDR's 2012 analysis, the cost for life extension of PIPP to continue operation on coal is estimated as $25 million annually.

5.0 SUMMARY COMPARISON

The evaluation criteria the Options were compared on are summarized in Table 1.0-1 at the end of Section 1. The Table is segregated into performance criteria such as generating capacity and heat rates, capital costs, and cost of generation factors including fuel costs, capital recovery, variable O&M, fixed O&M, and life extension costs. The generation data summarizes the expected plant heat rate to supply the average area demand. The capital cost section breaks down the various costs for each of the options assuming Owner Furnished Equipment for the Prime Movers and construction via an EPC contract.

The fuel only cost of generation is based on the annual generation as a function of output and capacity factor, the assumed fuel cost ($3.50/MMBTU for natural gas for all but Option 5, which uses $2.50/MMBTU for coal), and the heat rate for each Option. The fixed O&M section totals expected labor costs and expected fixed maintenance costs such as equipment overhauls and contracted maintenance. The variable O&M section totals variable maintenance, water supply and treatment costs, and byproduct disposal costs where applicable.

5.1 CAPITAL COST SUMMARY

The estimated cost for each of the options is discussed in the previous Section and summarized in Table 1.0-1. The costs provided in the Table are sub-totaled in phases, first for the total direct cost for the Equipment, EPC Contracts, and Owner Costs, second including site utility interconnection costs, third including project indirects for AFUDC, Contingency, and Escalation, and finally a Grand Total Project Cost including the applicable transmission system upgrade costs.

Option 4 (Conversion of PIPP to gas firing) has the lowest overall project cost relative to the other Options, due to relatively low capital investment in new equipment. Conversely, Option 3 (Combined Cycle Facility) results in the highest estimated project costs given the new power generation and balance of plant equipment required for this Option.

The RICE Options 1A and 1B have total estimated project costs of $343M and $269M respectively, which are substantially less than the simple cycle Option 2 cost of $433M. The excess capacity for Option 2 required to provide adequate redundancy results in this not being an economically viable option in comparison to the RICE options. It is also clear that the dual site location of Option 1B is much more economical in comparison to Option 1A, as the additional estimated EPC cost for executing the project on two separate construction sites is $12.4M compared with the $100M of transmission system upgrades needed in the other Options.

The site Utility Interconnection costs for gas and electric were provided to HDR by others, however HDR considers these values reasonable for each Option. The new generation RICE and CTG options would be located in close proximity to existing gas and electric distribution, therefore resulting in the relatively low interconnection costs shown in Options 1 through 3. The gas interconnection for Option 4 of $20M is substantially higher as a new gas line would be required to be run to the PIPP site.

5.2 NON-FUEL O&M COST SUMMARY

Fixed and Variable O&M values were calculated using vendor inputs and HDR in-house data for Options 1 through 3, and input from We Energies as developed during HDR's 2012 analysis for Options 4 and 5. Fixed O&M for the PIPP based Options 4 and 5 are substantially higher due to the Plant Life Extension costs required to maintain the aging equipment in service on the PIPP site. Another factor adding substantial cost to Options 4 and 5 O&M is plant labor. The current PIPP staff is 165-170 people. With the additional O&M requirements for the AQCS retrofits, the total plant staff as estimated by We Energies will increase.

While the Fixed and Variable O&M values vary between the other options, the magnitude of these variations do not significantly impact the overall cost of generation comparison.

5.3 NON-ECONOMIC EVALUATION PARAMETERS

5.3.1 Emissions Summary

Each of the options presented has the required costs included to achieve the current forecast for emissions regulations. The most problematic of these is Option 5 for which there is no consideration of potential future CO2 regulations. While a carbon tax could impact each of the Options, Option 5 would be the most heavily burdened as coal combustion generates roughly double the CO2 as natural gas. Future significant carbon regulations would likely eliminate the viability of long-term coal operation at PIPP. Ash disposal and waste streams could also present future regulatory challenges with continued coal operation.

5.3.2 Plant Reliability

Each of the options contains a high degree of reliability as the evaluation is based on a firm N-2 capacity of 140 MW supply as a base requirement. The RICE Options present the highest degree of reliability given the number of units available resulting in any single outage not dropping the capacity substantially. The combined cycle option meets the N-2 redundancy, however a loss of a single CTG from each 2x1 train would result in lower efficiency and would not be a preferable long-term operating arrangement. The PIPP based Options 4 and 5 have by far the lowest reliability given they are based on 4 operating units and the aging equipment. Forced outage rates on the PIPP units for either Option are substantially higher than the equivalent RICE and CTG Options.

5.3.3 Plant Start-Up and Operating Flexibility

The RICE and simple cycle CTG options provide by far the lowest start-up times, with each technology offering 10-minute start-up options, but at worst a one-hour starting period. The RICE engines also offer the highest degree of Operating Flexibility, as the multiple units allow meeting the entire load range at or near full load efficiency. Engines also maintain efficiency at part load more effectively than CTGs. While Option 2 does not provide the same flexibility as either Option 1A or 1B, the six shafts still allow the full operating range to be met without having to substantially part load any of the Units.

The minimum combined cycle start times would be as determined by the HRSG manufacturer to prevent excessive thermal stress during warm-up. Based on similar plant installations it has been estimated that the combined cycle evaluated in Option 3 would have a cold-start up period of 4-hours and a hot-start up time of 1-hour.

PIPP start times are approximately 12-hours for a cold unit and 4-hours for a hot unit. Those times are not expected to be impacted significantly by the addition of the AQCS equipment. With conversion to natural gas, it is estimated that start-up times could be reduced to 8-hours for a cold start and 3-hours for a hot start, due to the simplification of the fuel and gas path equipment. Likewise, Options 4 and 5 provide the lowest operation flexibility of any of the options considered given the unit size, ramp rate limitations, and complications with part load of AQCS equipment.

6.0 CONCLUSIONS

HDR's evaluation shows that the RICE technology provides by far the lowest evaluated cost of generation for power generation options in the Marquette / Keweenaw Peninsula area. The Total Cost of Generation for Option 1B of $73.78/MWh is nominally 25% lower than the next closest non-RICE option, which is Options 2 and 3, each at nominally $98/MWh. While Option 1B is not the lowest cost of generation for any of the individual cost breakdowns (fuel cost of generation, capital recovery, or Fixed/Variable O&M), it provides the best balance of reliable and efficient generation at an economic project cost. While the combined cycle alternative (Option 3) has a substantially lower fuel only cost of generation of $25/MWh due to the high efficiency of the cycle, the initial capital costs outweigh the lower operating costs resulting in a higher overall cost of generation.

Options 4 and 5 rank last in total cost of generation, despite Option 4 having much lower capital cost than any of the other Options considered. This is partially a result of the burden of extending the life of the existing plant equipment beyond design life and the continually increasing maintenance dollars required to achieve reliable operation. This evaluation confirms that long-term generation at PIPP is not an economically viable alternative. In addition, Option 5 presents the risk of substantial future environmental costs, most notably CO_2 regulations, the cost of which were not included in this analysis.

While simple cycle turbines and RICE technology typically result in very similar cost of generation values, the additional capacity required to meet the firm capacity requirements in this analysis resulted in the capital cost of Option 2 exceeding that of Option 1B by over 25%. In combination with the slightly higher efficiency of the RICE units, engine technology has a clear cost of generation advantage for the specific parameters of this evaluation.

Although several of the factors in this evaluation were estimated, as noted throughout this document, the evaluation criteria would need to change drastically for Option 1B to not result in the lowest overall cost of generation. RICE technology is the recommended technology for development for future generation in the Marquette / Keweenaw region.

REFERENCES

Reference 1 –HDR Report 160285-CZR-M0001, January, 2012

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*** * * * ***

In the Matter of the Application of Upper Michigan Energy Resources Corporation for approval of a Certificate of Necessity pursuant to MCL 460.6s for Two Reciprocating Internal Combustion Engine Electric Generation Facilities Located in the Upper Peninsula of Michigan, Approval of Certificate(s) of Public Convenience And Necessity, approval of a Special Contract with Tilden Mining Company L.C. and related accounting and ratemaking authorizations.	))))))))))))	Case No. U-18224

UPPER MICHIGAN ENERGY RESOURCES CORPORATION'S MOTION FOR ENTRY OF A PROTECTIVE ORDER

Upper Michigan Energy Resources Corporation ("UMERC"), by its attorneys, pursuant to Rule 432 of the Michigan Administrative Hearing System's Administrative Hearing Rules, R 792.10432, and MCR 2.302(C)(8), respectfully requests entry of a Protective Order to govern the release, use, and disclosure of confidential information, in any matter or form, in this proceeding. In support of its Motion, UMERC states as follows:

1. UMERC is a public service corporation organized under the laws of Michigan with service centers located at 800 Industrial Park Drive, Iron Mountain, Michigan, and 1717 Tenth Avenue, Menominee, Michigan. UMERC is engaged in the generation, distribution, and sale of electric energy in service areas located in the Upper Peninsula of Michigan.

2. UMERC has filed an Application, testimony, and exhibits with the Commission requesting grant of a certificate of necessity pursuant to MCL 460.6s.

3. In order to satisfy the requirements of MCL 460.6s and the Commission's Filing Requirements and Instructions, UMERC's Application, testimony, and exhibits present a wide variety of information, including information or documents which are non-public, proprietary, confidential, or trade secret commercial information.

4 UMERC requests a Protective Order to protect non-public confidential information and materials so designated by the producing party, which information and materials contain confidential, proprietary, or commercially sensitive information, including confidential information provided in discovery, and any witness's related testimony and exhibits and arguments of counsel referring to such confidential information ("Protected Material"). Although the Michigan Public Service Commission's ("MPSC" or "Commission") rules do not expressly address the issuance of protective orders, Rule 403(1) of the Michigan Administrative Hearing System's Administrative Hearing Rules, R 792.10403, states that "[t]hese rules govern practice and procedure in all proceedings before the commission, except as otherwise provided by statute or these rules. In areas not addressed by these rules, the presiding officer may rely on appropriate provisions of the currently effective Michigan court rules." MCR 2.302(C)(8) states:

> "On motion by a party or by the person from whom discovery is sought, and on reasonable notice and for good cause shown, the court in which the action is pending may issue any order that justice requires to protect a party or person from annoyance, embarrassment, oppression, or undue burden or expense, including one or more of the following orders:
>
> > (8) that a trade secret or other confidential research, development, or commercial information not be disclosed or be disclosed only in a designated way;"

Also, Section 80 of the Michigan Administrative Procedures Act specifically provides that a presiding officer may "[r]egulate the course of the hearings…" MCL 24.280. The Commission's "Filing Requirements and Instructions for Certificate of Public Convenience and Necessity Application" further contemplate that proprietary, confidential, and other nonpublic

materials filed as part of the application will be subject to confidentiality agreements and protective orders, by providing

> "Proprietary, confidential, and other non-public materials filed as part of the application shall be clearly identified and marked accordingly and presented in such a way that the proprietary and confidential nature of the materials is preserved pending the execution of any confidentiality agreements and issuance of protective orders. Availability of specific materials in the application may be contingent upon appropriate confidentiality agreements and protective orders."

5. The appropriateness of the issuance of protective orders in Commission proceedings for documents which are confidential, proprietary, or involve trade secrets is well established. For example, protective orders have been issued in Case Nos. U-9322 and U-9611 (July 18, 1990), U-10335 (Nov. 29, 1993), U-10491 and U-10492 (July 19, 1992), U-13221 (March 20, 2002), U-14040 (May 11, 2004), U-15988 (August 3, 2009), U-16166 (July 23, 2010), U-16417 (August 5, 2011), and U-17672 (November 19, 2014). In its Opinion and Order dated June 30, 1994, Case No. U-10282, the Commission discussed the standards that it applies when considering whether to issue a protective order. The Commission stated that before it will enter a protective order, the moving party must show "(1) that the information at issue is a trade secret or otherwise confidential, and (2) that disclosure would work a clearly defined and serious injury."

6. In this case, Protected Material, if publically disclosed, would result in a serious injury to UMERC in its solicitation of bids and contemplated transactions in connection with its construction of a new electric generation facility, power supply negotiations, and the ability to secure reasonable supply agreements and, thereby, affect UMERC's costs to its customers. Some protected material may disclose UMERC's market strategies, and some Protected Material may be governed by UMERC's confidentiality agreements with third parties. The confidential

information UMERC seeks to protect is of such a nature that (i) it may derive actual and potential economic value from being neither generally known to, nor readily ascertainable by, persons who could obtain economic value from its disclosure or use; and (ii) it is the subject of efforts that are reasonable under the circumstances to maintain its secrecy. The confidential information is, therefore, considered a trade secret under Michigan law and is entitled to protection from disclosure by the Commission (see, MCL 445.1902).

7. UMERC represents that any Protected Material is not in the public domain.

8. The proposed Protective Order (Exhibit A hereto) is modeled after other MPSC orders which protected information. The proposed Protective Order defines "Protected Material" and provides that any document filed with the Commission that contains Protected Material shall be placed in a sealed envelope with a copy of the Protective Order attached and maintained in the Commission's files. The proposed Order also provides that materials which UMERC contends are confidential will be marked as "Protected Material." The proposed Order prohibits distribution or dissemination of the protected documentation by MPSC Staff ("Staff") or any properly admitted party except according to the terms of the Protective Order. Further, the proposed Order dictates the use of the documentation in the discovery and litigation phases of this case, and requires that UMERC be given notice of any Freedom of Information Act request filed with the Commission (or Attorney General's ("AG") office) seeking access to the documents. Such notice must be given at least five (5) business days prior to the MPSC, Staff or AG, responding to the request so as to provide UMERC with an opportunity to take whatever legal actions it deems appropriate to protect the documents from disclosure.

9. The proposed Protective Order will not hinder the Commission's, the Administrative Law Judge's, Staff's or any properly admitted party's review of the Application,

testimony and exhibits in MPSC Case No. U-18224, because all will continue to have full access to the confidential information.

WHEREFORE, for the reasons states herein, UMERC respectfully requests the Commission to grant this Motion and enter the proposed Protective Order, attached as Exhibit A.

Respectfully submitted,

UPPER MICHIGAN ENERGY RESOURCES CORPORATION

Dated: January 30, 2017 By: Michael C. Rampe

Digitally signed by: Michael C. Rampe
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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*** * * * ***

In the Matter of the Application of	)	
Upper Michigan Energy Resources Corporation	)	
for approval of a Certificate of Necessity	)	
pursuant to MCL 460.6s for	)	Case No. U-18224
Two Reciprocating Internal Combustion Engine	)	
Electric Generation Facilities Located in the	)	
Upper Peninsula of Michigan,	)	
Approval of Certificate(s) of Public Convenience	)	
And Necessity, approval of a Special Contract with	)	
Tilden Mining Company L.C.	)	
and related accounting and ratemaking	)	
authorizations.	)	

PROTECTIVE ORDER

This Protective Order governs the use and disposition of Protected Material (as defined below) disclosed by Upper Michigan Energy Resources Corporation (UMERC) or any other Party (as defined below) in this case, as set forth herein. The intent of this Protective Order is to protect non-public confidential information and materials so designated by the producing Party,[1] which information and materials contain confidential, proprietary, or commercially sensitive information, including confidential information provided in discovery, and any witness's related testimony and exhibits and arguments of counsel referring to such confidential information ("Protected Material"). This Protective Order describes the manner in which Protected Material is to be identified and treated, and governs its ultimate disposition. Accordingly, IT IS HEREBY ORDERED:

[1] Pursuant to Michigan Public Service Commission 2008 PA 286 Filing Requirements and Instructions for Certificate of Public Convenience and Necessity Application Instructions, Section III, and Michigan Public Service Commission 2008 PA 286 Integrated Resource Planning Filing Guidelines, Section E.

1. This Protective Order shall govern the use of all Protected Material, so identified and marked as required by Paragraph 11, that is filed in this case on a confidential basis and/or made available for review, or produced, by or on behalf of any Party to any Party, Reviewing Representative, the Administrative Law Judge ("ALJ") assigned to this case, or members of the Michigan Public Service Commission ("MPSC") assigned to assist the MPSC in Case No. U-18224. Protected Material shall be used and disclosed by the recipient thereof solely in accordance with the terms and conditions of this Protective Order.

2. This Protective Order protects: (1) the Protected Material; (2) any copy or reproduction of the Protected Material made by any person; and (3) any memoranda, handwritten notes, or any other form of information that copies, contains or discloses Protected Material.

3. The information subject to this Protective Order does not include:

a. Information lawfully known by the Party or Reviewing Representative at the time of disclosure that is not subject to a confidentiality agreement or arrangement; and

b. Information that is or becomes available to the general public through no fault of a Party or Reviewing Representative.

4. "Party" shall mean any party to this proceeding, including the Commission Staff and Attorney General, who produces, requests or receives access to the Protected Material, subject to the requirement that each Reviewing Representative must sign a Nondisclosure Certificate.

5. "Reviewing Representative" shall mean a person who has signed a Nondisclosure Certificate and who is:

a. an attorney who has entered an appearance in this proceeding for a Party;

b. an attorney, paralegal, or other employee associated for purposes of this case with an attorney described in Paragraph 5a;

c. an expert or employee of an expert retained by a Party for purposes of advising, preparing for, or testifying in this proceeding; or

d. an employee or other representative of a Party with significant responsibility for this docket.

A Reviewing Representative is responsible for assuring that persons under his or her supervision and control comply with this Protective Order.

6. "Nondisclosure Certificate" shall mean a certificate substantially in the form of the certificate attached to this Protective Order by which a Reviewing Representative who has been granted access to Protected Material certifies his or her understanding that such access is provided pursuant to the terms of this Protective Order and that he or she agrees to be bound by it.

7. A Party may authorize access to and use of Protected Material by a Reviewing Representative identified by the Party as being necessary in order to analyze the Protected Material, including consultants employed by the Party, but only for the purposes of analyzing the issues, presenting evidence, and preparing testimony, cross-examination, argument, pleadings, briefs, exceptions or other motions or filings in Case No. U-18224. Such persons may not release or disclose the content of Protected Material to any other person or use such information for any other purpose.

8. All persons authorized to review Protected Material, including copies or reproductions, and copies of notes of Protected Material, must, before reviewing any Protected Material, sign a copy of the Nondisclosure Certificate, which evidences an agreement by such

person to be bound by the terms of this Protective Order. A copy of the executed Nondisclosure Certificate shall be provided to all Parties.

9. Protected Material shall remain the property of the producing Party and shall only remain available to the receiving Party or Reviewing Representative until no later than the conclusion of any appeal of any final order issued in this Case No. U-18224. A Party or Reviewing Representative in Case No. U-18224 who has signed a Nondisclosure Certificate and who is participating in an appeal from a final order in this Case No. U-18224 may retain copies of Protected Material until the date the final order in this Case No. U-18224 is no longer subject to judicial review. On or before the date specified by the preceding sentence, with the exception of the provision made in the second to the last sentence of this paragraph, the receiving Party or Reviewing Representative shall return all Protected Material in its possession, including all copies thereof and notes of Protected Material or certify in writing that the Protected Material has been destroyed. Notwithstanding, the attorney for a Party may retain copies of non-public pleadings, orders, transcripts, briefs, comment, and exhibits, which contain Protected Material in Case No. U-18224; provided, a list of retained documents, which identifies the documents containing the Protected Materials, is given to the producing Party within 30 days from the date on which the final order in Case No. U-18224 is no longer subject to judicial review. To the extent Protected Material is not returned by a receiving Party or Reviewing Representative or destroyed pursuant to this Protective Order, it shall remain subject to this Protective Order.

10. The Parties to Case No. U-18224 retain the right to seek further restrictions on the dissemination of Protected Material to Parties or to persons who have or may subsequently seek to intervene in this proceeding.

11. Protected Material made available by the producing Party shall be clearly marked as Protected Material subject to this Protective Order, including by labeling such items as "Confidential." Any copies of Protected Material shall be physically designated as Protected Material by the Party or the person authorized by the Party to make the copy. Notes of Protected Material shall be physically marked as Protected Material by the person making the notes. All Protected Material in the possession of the Party shall be maintained in a secure place. Access to Protected Material shall be limited to persons authorized to have such access subject to the provisions of this Protective Order.

12. Even if no longer engaged or active in this proceeding, every person who has signed a Nondisclosure Certificate shall continue to be bound by the provisions of this Protective Order. The obligations under this Protective Order shall not be extinguished or nullified by entry of a final order in this case and shall be enforceable before the MPSC or in a court of competent jurisdiction.

13. If a Party with access to Protected Material desires to incorporate, utilize, refer to, or otherwise use Protected Material in pre-filed testimony, pleadings, direct or cross-examination, briefs, oral argument, comments or in some other form in this proceeding, such Party shall only do so pursuant to procedures that will maintain the confidentiality of the Protected Material. For purposes of this order, the following procedures are established:

a. Written submissions using Protected Material shall be filed in a sealed record, to be maintained by the Docket Section of the MPSC in envelopes clearly marked on the outside, “CONFIDENTIAL – SUBJECT TO PROTECTIVE ORDER ISSUED IN CASE NO. U-18224.” Simultaneously, identical documents and materials, but with the Protected

Material redacted, shall be filed, offered, introduced, or otherwise disclosed in the usual manner for the submissions of evidence or briefs.

b. Furthermore, with regard to proceedings before the MPSC or presiding officers designated by it, oral testimony, examination of witnesses, or argument on the Protected Material shall be conducted on a separate record to be maintained by the Docket Section of the MPSC. These separate record proceedings shall be closed to all persons except those furnishing the Protected Material and Parties otherwise subject to this Protective Order. The Party presenting the information during the course of the proceeding shall advise the presiding officer receiving testimony of the terms of this Protective Order on sufficient notice to allow the presiding officer an opportunity to take measures within the presiding officer's control to protect the confidentiality of the Protected Material, and suggest that a separate, protected record be made of all testimony concerning the protected information.

c. Copies of documents filed with the MPSC that contain Protected Material, including the portions of the exhibits, transcripts, and brief that refer to Protected Material, must be sealed and maintained in the MPSC's files with a copy of the Protective Order attached.

14. It is intended that the Protected Material subject to this Protective Order should be shielded from disclosure by the receiving Party to the extent permitted by law. If any person files a Freedom of Information Act Request seeking access to documents subject to this Protective Order, the MPSC's Executive Secretary shall immediately notify the producing Party,

and the producing Party may take whatever legal actions it deems appropriate to protect the Protected Material from disclosure. In accordance with Section 5 of the Freedom of Information Act, MCL 15.235, the notice must be given at least five (5) business days prior to the MPSC, its Staff, and/or Attorney General responding to the request. This Protective Order does not prohibit disclosure to the extent, but only to the extent, and for the purpose, but only for the purpose, that such disclosure is: (i) required by law; or (ii) in response to a valid order of a court of competent jurisdiction or governmental body; provided that in all instances above, the Party first provides reasonable written advance (at least five (5) business days prior) notice to the producing Party of the proposed disclosure.

15. The provisions of this Protective Order shall not apply to a particular document or portion of a document described in Paragraph 2 if a Party can demonstrate that it has been previously disclosed on a non-confidential basis or meets the criteria set forth in Paragraph 3a or 3b. Before disclosing a particular document or portion of a document described in Paragraph 2, however, the Party must first provide reasonable notice to the producing Party of its conclusion that the document or portion of a document is not subject to this Protective Order because of prior disclosure. The provisions of this Protective Order shall terminate as to the Protected Material described in Paragraph 2 to the extent that the content of such Protected Material are filed with a state, provincial or federal agency and are not subject to protection from public disclosure, or are otherwise lawfully disclosed.

16. If a Party violates this Order by an improper disclosure or use of Protected Material, then that Party shall take all necessary steps to remedy the improper disclosure or use. This includes immediately notifying the MPSC, the presiding officer, and the producing Party, in writing, of the identity of each person known or reasonably suspected to have obtained the

Protected Material. Parties that violate this Protective Order remain subject to this paragraph regardless of whether the producing Party could have discovered the violation earlier than it was discovered. This paragraph of this Protective Order applies to both inadvertent and intentional violations. Nothing in this Protective Order limits the producing Party's rights and remedies, at law or in equity, against Parties or persons using Protected Material in a manner not authorized by this Protective Order, including the right to obtain injunctive relief to prevent violations of this Protective Order.

17. Upon motion filed by any Party to Case No. U-18224, the MPSC or any presiding officer designated by it may subsequently declare that the protected status of Protected Material should not be continued and immediately communicate that declaration to the producing Party. Thereafter, this Protective Order shall cease to apply to such Protected Material unless, within twenty-one (21) days, the producing Party files a pleading asserting that the information should continue to be protected and setting forth the basis for that assertion. The producing Party shall bear the burden of proving that the asserted Protected Material is entitled to continuing protection from disclosure. If the MPSC or presiding officer finds that an asserted Protected Material no longer qualifies for treatment as Protected Material, it shall remain subject to the protection afforded by this Protective Order for twenty-one (21) days following the issuance of the MPSC's order or the presiding officer's ruling.

18. The obligations of this Protective Order shall not apply if the Protected Material is approved for release by written authorization of the producing Party, but only to the extent of such authorization.

19. The ALJ, the Commissioners, and members of the MPSC assigned to assist the MPSC in Case No. U-18224 may review Protected Materials that are a part of confidential

pleadings, and Protected Materials that are admitted into the record, for purposes of analyzing the issues, issuing rulings, preparing the proposal for decision, and issuing MPSC orders. Such persons may not release or disclose the Protected Material inconsistent with the terms and conditions of this Protective Order.

Dated: _____, 2017

_____
Administrative Law Judge

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*** * * * ***

In the Matter of the Application of	)	
Upper Michigan Energy Resources Corporation	)	
for approval of a Certificate of Necessity	)	
pursuant to MCL 460.6s for	)	Case No. U-18224
Two Reciprocating Internal Combustion Engine	)	
Electric Generation Facilities Located in the	)	
Upper Peninsula of Michigan,	)	
Approval of Certificate(s) of Public Convenience	)	
And Necessity, approval of a Special Contract with	)	
Tilden Mining Company L.C.	)	
and related accounting and ratemaking	)	
authorizations.	)	

NONDISCLOSURE CERTIFICATE

I hereby certify my understanding that access to Protected Material is provided to me pursuant to the terms and restrictions of the Protective Order issued in Case No. U-18224, that I have been given a copy of, and have read, the Protective Order, and that I agree to be bound by the terms of the Protective Order. I am aware that the Applicant and any other producing Party assert that Protected Material, as defined in the Protective Order, includes information that is confidential, proprietary, and commercially sensitive. I understand that the substance of the Protected Material, any notes or other memoranda, or any other form of information that copies or discloses Protected Material, shall be maintained as confidential, shall not be disclosed to anyone other than in accordance with that Protective Order, and shall not be used for any purpose other than in connection with Michigan Public Service Commission Case No. U-18224.

Reviewing Representative

Date: _____ _____

Title:
Representing:

MICHIGAN DEPARTMENT OF LICENSING AND REGULATORY AFFAIRS
PUBLIC SERVICE COMMISSION

ENTRY OF APPEARANCE IN AN ADMINISTRATIVE HEARING

This form is issued as provided for by 1939 PA 3, as amended, and by 1933 PA 254, as amended. The filing of this form, or an acceptable alternative, is necessary to ensure subsequent service of any hearing notices, Commission orders, and related hearing documents.

General Instructions:

Type or print legibly in ink. For assistance or clarification, please contact the Public Service Commission at (517) 241-6180.

Please Note: *The Commission will provide* ***electronic*** *service of documents to all parties in this proceeding.*

THIS APPEARANCE TO BE ENTERED IN ASSOCIATION WITH THE ADMINISTRATIVE HEARING:

Case / Company Name: Upper Michigan Energy Resources Corporation Docket No. U-18224

Please enter my appearance in the above-entitled matter on behalf of:

1. (Name) Upper Michigan Energy Resources Corporation
2. (Name)
3. (Name)
4. (Name)
5. (Name)
6. (Name)
7. (Name)

Name Michael C. Rampe

Address One E. Michigan Avenue, Suite 900

City Lansing State MI

Zip 48933 Phone (517) 483-4928

Email rampe@millercanfield.com

Date January 30, 2017

Signature: Michael C. Rampe

Digitally signed by: Michael C. Rampe
DN: CN = Michael C. Rampe C = US O = Miller Canfield
Date: 2017.01.30 13:42:12 -04'00'

☐ I am not an attorney

☑ I am an attorney whose:

Michigan Bar # is P-58189

_____ Bar # is: _____
(state)

MICHIGAN DEPARTMENT OF LICENSING AND REGULATORY AFFAIRS
PUBLIC SERVICE COMMISSION

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THIS APPEARANCE TO BE ENTERED IN ASSOCIATION WITH THE ADMINISTRATIVE HEARING:

Case / Company Name: Upper Michigan Energy Resources Corporation Docket No. U-18224

Please enter my appearance in the above-entitled matter on behalf of:

1. (Name) Upper Michigan Energy Resources Corporation
2. (Name)
3. (Name)
4. (Name)
5. (Name)
6. (Name)
7. (Name)

Name Theresa A.G. Staley

Address One E. Michigan Avenue, Suite 900

City Lansing State MI

Zip 48933 Phone (517) 483-4928

Email staley@millercanfield.com

Date January 30, 2017

Signature: Theresa A. G. Staley

Digitally signed by: Theresa A. G. Staley
DN: CN = Theresa A. G. Staley C = AD O = Miller Canfield
Date: 2017.01.30 13:42:23 -04'00'

☐ I am not an attorney

☑ I am an attorney whose:

Michigan Bar # is P-56998

_____ Bar # is: _____
(state)

MICHIGAN DEPARTMENT OF LICENSING AND REGULATORY AFFAIRS
PUBLIC SERVICE COMMISSION

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Case / Company Name: Upper Michigan Energy Resources Corporation Docket No. U-18224

Please enter my appearance in the above-entitled matter on behalf of:

1. (Name) Upper Michigan Energy Resources Corporation
2. (Name)
3. (Name)
4. (Name)
5. (Name)
6. (Name)
7. (Name)

Name Ronald W. Bloomberg

Address One E. Michigan Avenue, Suite 900

City Lansing State MI

Zip 48933 Phone (517) 483-4928

Email bloomberg@millercanfield.com

Date January 30, 2017

Signature: Ronald W. Bloomberg Digitally signed by: Ronald W. Bloomberg DN: CN = Ronald W. Bloomberg C = US O = Miller Canfield Date: 2017.01.30 13:42:37 -04'00'

☐ I am not an attorney

☑ I am an attorney whose:

Michigan Bar # is P-30011

_____ Bar # is: _____
(state)