Founded in 1852
by Sidney Davy Miller

SHERRI A. WELLMAN
TEL (517) 483-4954
FAX (517) 374-6304
E-MAIL wellmans@millercanfield.com

**Miller, Canfield, Paddock and Stone, P.L.C.**
One Michigan Avenue, Suite 900
Lansing, Michigan 48933
TEL (517) 487-2070
FAX (517) 374-6304
www.millercanfield.com

MICHIGAN: Ann Arbor
Detroit • Grand Rapids
Kalamazoo • Lansing • Troy
FLORIDA: Tampa
ILLINOIS: Chicago
NEW YORK: New York
OHIO: Cincinnati • Cleveland
CANADA: Windsor
CHINA: Shanghai
MEXICO: Monterrey
POLAND: Gdynia
Warsaw • Wrocław

February 12, 2019

Ms. Kavita Kale, Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Post Office Box 30221
Lansing, MI 48909

**RE: In the matter of Upper Peninsula Power Company for Approval of an Integrated Resource Plan under MCL 460.6t and for other relief.**
**Case No: U-20350**

Dear Ms. Kale:

Included in this electronic file in the above-captioned case is the Redacted Version of Upper Peninsula Power Company's Application and Testimony and Exhibits of Upper Peninsula Power Company witnesses Gradon R. Haehnel, Andrew McNeally, Eric W. Stocking, and David R. Tripp, P.E. Confidential materials are being filed under seal with the Michigan Public Service Commission.

In accordance with the filing procedures adopted by the Michigan Public Service Commission in Case Nos. U-15896 and U-18461: (i) copies of the IRP filing are being provided to parties in Case No. U-20276 electronically and will be made available to all requesting parties of this case, and (ii) the public workpapers of Upper Peninsula Power Company's witnesses are being provided on electronic disk to the Michigan Public Service Commission Staff. This is a paperless filing and is therefore being filed only in electronic format. Also enclosed is Proof of Service reflecting electronic service upon the parties to Case No. U-20276

Very truly yours,

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

By: ______________________________
Sherri A. Wellman

PMC/ark
Enclosures

cc: Parties to Case No. U-20276
Gradon Haehnel

32995051.2\130062-00115

**S T A T E O F M I C H I G A N**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

*** * * ***

| | | |
|---|---|---|
| In the matter of the application of<br>**UPPER PENINSULA POWER COMPANY**<br>for approval of its integrated resource plan<br>pursuant to MCL 460.6t and for other relief. | )<br>)<br>)<br>) | Case No. U-20350 |

**APPLICATION**

Upper Peninsula Power Company ("UPPCO" or the "Company") respectfully requests the Michigan Public Service Commission ("MPSC" or the "Commission") to approve the Company's Integrated Resource Plan ("IRP") pursuant to Section 6t of 2016 PA 341, MCL 460.6t ("Act 341"). In support of this Application, UPPCO respectfully represents to the Commission as follows:

## I. Introduction

1. UPPCO is a Michigan corporation with principal offices located in Marquette, Michigan, and is engaged as a public utility in the generation, purchase, distribution, and sale of electric energy in its service territory in the Upper Peninsula of Michigan.

2. UPPCO serves cities, villages, and townships located in the counties of Alger, Baraga, Delta, Houghton, Iron, Keweenaw, Marquette, Ontonagon, and Schoolcraft.

3. UPPCO's retail electric business is subject to the jurisdiction of the Commission 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., and 1939 PA 3, as amended, MCL 460.1, et seq. Pursuant to these statutory provisions the Commission has the power and jurisdiction to regulate UPPCO's retail electric rates.

4. On December 21, 2016, in Case Nos. U-15896 and U-18461 the Commission issued its Order approving filing instructions for IRPs and establishing the application deadline filing schedule. Subsequently, on August 28, 2018, the Commission issued its order amending its filing schedule, specifically directing UPPCO to file its first IRP no later than December 14, 2018.

5. On December 3, 2018, as the result of an unforeseen event occurring on November 28, 2018, at the Company's Portage facility, UPPCO filed a motion for a 60-day extension of time to file its IRP. In its December 6, 2018 Order in this docket, the Commission granted UPPCO's motion for extension and directed UPPCO to file its first IRP on February 12, 2019.

6. In Case No. U-18094, the Commission addressed the Public Utility Regulatory Policies Act of 1978 ("PURPA") as relating to UPPCO. Specifically, the Commission found in its September 28, 2017 Order that until May 31, 2020, UPPCO's avoided capacity cost should be set at the Company's capacity price at the time the PURPA contract is entered into and directed that the method for determining the Company's avoided cost would be taken up in the Company's next PURPA review to be filed February 1, 2019. On February 7, 2019, following the filing of a motion by UPPCO, the Commission issued its Order granting the Company's request to extend the February 1, 2019 filing date and permit UPPCO to make its PURPA filing in its IRP proceeding on February 12, 2019.

7. In this filing, UPPCO is presenting its comprehensive IRP and addressing PURPA. In developing this IRP, the Company assessed its capacity resource portfolio in light of capacity needs, regulatory and environmental compliance and the planning objectives as set forth by the Commission and the Company. The remainder of this Application describes the

development and an overview of the Company's IRP and addresses UPPCO's PURPA avoided cost proposal.

## II. <u>Development and Overview of IRP</u>

8. The required components of an IRP filing are specifically provided in MCL 460.6t(5)(a)-(o). Furthermore, MCL 460.6t(8) provides that the Commission shall approve a proposed IRP if the Commission determines that the IRP represents the most reasonable and prudent means of meeting the electric utility's energy and capacity needs. To make such a determination, the Commission must consider whether the proposed IRP appropriately balances the following factors:

> (i) Resource adequacy and capacity to serve anticipated peak electric load, applicable reserve margin, and local clearing requirement.
>
> (ii) Compliance with applicable state and federal environmental regulations.
>
> (iii) Competitive pricing.
>
> (iv) Reliability.
>
> (v) Commodity price risks.
>
> (vi) Diversity of generation supply.
>
> (vii) Whether the proposed levels of peak load reduction and energy waste reduction are reasonable and cost effective. Exceeding the renewable energy resources and energy waste reduction goal in section 1 of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1001, by a utility shall not, in and of itself, be grounds for determining that the proposed levels of peak load reduction, renewable energy, and energy waste reduction are not reasonable and cost effective.

9. Pursuant to MCL 460.6t, the Commission was required to: (i) establish modeling scenarios and assumptions each electric utility should include in addition to its own scenarios

and assumptions in developing an IRP and (ii) establish filing requirements, including application forms and instructions, and filing deadlines for an IRP filed by a utility regulated by the Commission. Specifically, MCL 460.6t(1)(f) provides that the Commission shall:

> (f) Establish the modeling scenarios and assumptions each electric utility should include in addition to its own scenarios and assumptions in developing its integrated resource plan filed under subsection (3), including, but not limited to, all of the following:
>
> (i) Any required planning reserve margins and local clearing requirements.
>
> (ii) All applicable state and federal environmental regulations, laws, and rules identified in this subsection.
>
> (iii) Any supply-side and demand-side resources that reasonably could address any need for additional generation capacity, including, but not limited to, the type of generation technology for any proposed generation facility, projected energy waste reduction savings, and projected load management and demand response savings.
>
> (iv) Any regional infrastructure limitations in this state.
>
> (v) The projected costs of different types of fuel used for electric generation.

Furthermore, MCL 460.6t(3) provides, in relevant part, that:

> The commission shall issue an order establishing filing requirements, including application forms and instructions, and filing deadlines for an integrated resource plan filed by an electric utility whose rates are regulated by the commission.

In compliance with the above statutory provisions, the Commission issued an Order dated November 21, 2017 in Case No. U-18418 approving "Michigan Integrated Resource Planning Parameters." The Commission also issued an Order December 20, 2017 in Case Nos. U-15895 *et al.*, which approved "Integrated Resource Plan Filing Requirements." These documents set forth all required IRP modeling scenarios and assumptions, requirements, instructions, and guidelines for utilities seeking relief pursuant to MCL 460.6t.

10. The Company's IRP meets the statutory requirements for an IRP filed before the Commission. The Company's testimony and exhibits which accompany this Application address the components required to be included in an IRP, and address the factors which the Commission shall consider in approving an IRP, and establish that the Company's plan represents "the most reasonable and prudent means of meeting the electric utility's energy and capacity needs."

11. The Company's IRP also meets the Commission's adopted modeling scenarios, assumptions, and filing requirements. The modeling process used by the Company to develop the IRP was rigorous and comprehensive, consistent with good utility practice, followed all applicable Commission rules, and ultimately ensures the identification of the most reasonable and prudent resources to serve customers in a cost-effective and reliable manner.

12. Consistent with recommendations in the Commission's filing requirements, the Company conducted a series of public outreach events during its IRP modeling efforts which sought to inform the public regarding the Company's IRP activities and solicit feedback which would be used in the development of the Company's IRP. Public open houses were held on January 1, 2018, January 11, 2018, January 16, 2018 and January 18, 2018. More detailed stakeholder engagement with commercial and industrial customer stakeholders were held through October, November and December 2018. Exhibits A-2 (GRH-2) through A-5 (GRH-5) provide greater detail concerning the Company's public outreach efforts and the feedback received from the public.

13. Subsequent to the completion of the Company's IRP modeling efforts, the Company established a plan which represents the Company's preferred course of action ("PCA")

for meeting the energy and capacity needs of customers through the 2037 planning period. UPPCO's PCA consists of:

a. Increasing Energy Waste Reduction ("EWR") to 1.5% of the Company's total electric load.

b. Adding 125 megawatt ("MW") of both capacity and energy by entering a long-term Purchased Power Agreement ("PPA"). The capacity and energy will be from a new solar generation facility that will be constructed and located in the Upper Peninsula ("UP"). This new facility will be on-line by May of 2022, and the pricing will be fixed for a term of 25 years.

c. Construction of an up to 20 MW Reciprocating Internal Combustion Engine ("RICE") facility in the eastern end of UPPCO's service territory, and will provide reliability benefits to UPPCO's customers as well as the eastern part of the UP.

d. Retirement of UPPCO's existing oil-fired Portage combustion turbine generating facility. Due to the recent catastrophic mechanical failure at UPPCO's Portage generation facility and pending the current and ongoing insurance investigation and evaluation process, if UPPCO decides to retire the Portage Oil Fired Combustion Unit, UPPCO seeks approval to apply any insurance payout as a direct credit to the proposed RICE unit generation, thereby directly lowering costs to customers.

e. Increasing the capacity of UPPCO's existing hydroelectric generating facilities. UPPCO will move the Hoist and McClure generating units "in front of the meter," thereby allowing UPPCO to report their respective capacity to MISO as part of UPPCO's annual maximum generation. The result of this metering construct and reconfiguration will increase the reported capacity of these two units by a combined 7.6 MW which will provide a direct benefit to customers in the form of avoided capacity cost purchases in the future.

f. Locking in the most cost-effective pricing through competitive bidding. UPPCO's PCA provides dedicated generation sources for all of UPPCO's customer's capacity needs for greater than a 10-year planning horizon.

14. The Company's PCA was evaluated with a complex and robust risk assessment methodology. The Company's risk assessment methodology, which is consistent with the risk assessment methodology mandated by the Commission in Case Nos. U-15896 *et al.,* used a three-step process to assess the levels of risk related to selecting a resource portfolio. These steps included: (i) portfolio optimization reviews; (ii) a net present value review of portfolio optimizations; and (iii) an evaluation of the PCA and an expanded sensitivity analysis. The

Company's risk assessment was performed by Black & Veatch, and is contained in Exhibit (A-1) (GRH-1) which is the Black & Veatch Report.

15. The Company's plan is a fully integrated proposal that ties the planned evolution of the Company's resource portfolio through 2037 to the numerous proposals described above and in the testimony and exhibits filed in this proceeding. Since the Company's plan is a fully integrated proposal with numerous components, modification to, or rejection of, a proposal made in the plan impacts the plan's viability and the Company's willingness to execute on the remaining portions of the plan not modified or rejected. As such, the Company reserves the right to abandon or amend its plan if the Commission rejects or modifies any of the Company's proposals presented in this IRP.

16. An IRP report which, among other things, details the Company's existing electric generating fleet and PPAs, resource adequacy through 2037, and analysis and decisions in selecting the PCA and proposed resource acquisition strategy are provided with this filing as Exhibit A-1 (GRH-1).

## III. <u>IRP Cost Approvals</u>

17. MCL 460.6t(11) provides that, in approving an IRP, the Commission shall specify the approved costs for future recovery as follows:

> In approving an integrated resource plan under this section, the commission shall specify the costs approved for the construction of or significant investment in an electric generation facility, the purchase of an existing electric generation facility, the purchase of power under the terms of the power purchase agreement, or other investments or resources used to meet energy and capacity needs that are included in the approved integrated resource plan. The costs for specifically identified investments, including the costs for facilities under subsection (12), included in an approved integrated resource plan that are commenced within 3 years after the commission's order approving the initial plan, amended plan, or

plan review are considered reasonable and prudent for cost recovery purposes.

18. Consistent with MCL 460.6t(11), the Company is proposing the recovery of costs will be commenced within three years of the Commission's expected approval of the Company's IRP and plan. Since a final order is required to be issued no later than 360 days after an electric utility files an IRP, the Company has used February 7, 2020 through February 7, 2025 as the five-year cost recovery approval period in this case. See MCL 460.6t(7).

## IV. PURPA Proposal

19. Michigan Law requires all rates to be just and reasonable, MCL 460.54, MCL 460.557(4), MCL 462.22(a).

20. PURPA provides that no state Commission in setting rates for a utility to pay a Qualifying Facility ("QF") "shall provide for a rate which exceeds the incremental cost to the electric utility of alternative energy." 16 USC 824a-3(b). PURPA defines the "incremental cost of alternative electric energy" as "the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small producer, such utility would generate or purchase from another source." 16 USC 824a-3(d). The Federal Energy Regulatory Commission ("FERC") regulations which implement PURPA provide that the rates set by state commissions must "[b]e just and reasonable to the electric consumers of the electric utility" and that [n]othing in [the regulations] requires any electric utility to pay more than the avoided costs for purchases." 18 CFR 292.304(a)(1)-(2). The regulations define "avoided costs" as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." 18 CFR 292.101(b)(6).

21. The Commission's September 28, 2017 Order in Case No. U-18094 established that until May 31, 2020, UPPCO's avoided capacity cost should be set at the Company's capacity price at the time the PURPA contract is entered into. With this filing, UPPCO is proposing to continue that practice. The Company represents that its proposal will result in just and reasonable customer rates, and will avoid a situation in which the Company will pay more that the avoided costs of purchases.

## V. <u>Testimony and Exhibits, and Other Matters</u>

22. UPPCO is, concurrently with this Application, filing written testimony and exhibits in support of its IRP and other relief UPPCO is seeking in this case. Reference to this material will provide additional details on the relief being sought. The relief described in the testimony and exhibits should be considered as if specifically requested in this Application. UPPCO 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. UPPCO also specifically reserves the right, pursuant to MCL 460.6t(7), to update the cost estimates within 150 days of the filing of this Application.

23. In addition to the issues described above, it is possible that other pending or to-be-filed proceedings or other events may have impacts upon the Company's requests in this proceeding. These impacts will be evaluated for materiality and may need to be considered in the results of this proceeding.

24. All proposals made by the Company in this IRP are integrally part of the Company's plan. Since the Company's PCA is a fully integrated proposal with numerous components, modification to or rejection of a proposal made in the plan impacts the PCA's

viability and the Company's willingness to execute on the remaining portions of the PCA not modified or rejected. As such, the Company reserves the right to abandon or amend its plan if the Commission rejects or modifies any of the Company's proposals presented in this IRP.

25. The IRP filing requirements approved by the Commission's December 20, 2017 Order in Case No. U-15896 *et al.* state:

> A non-multi-state Michigan electric utility serving fewer than 1,000,000 customers may elect to file an IRP, based on its specific circumstances, that deviates from these requirements, but that is subject to the Staff's ability to request supplemental information.

26. As a small utility, UPPCO has less time and resources to devote to rapidly changing circumstances that affect the Company's planning horizon, such as a recent fire at UPPCO's Portage CT facility. UPPCO represents that it has diligently endeavored to comply with the Commission's IRP filing requirements. Consequently, if needed, UPPCO requests the ability to supplement the information contained in this IRP as envisioned by the IRP filing requirements.

27. As required in the Commission's IRP filing requirements approved in Case No. U-15896 *et al.*, the Company has included a Letter of Transmittal as Attachment A to this Application. The Company's Letter of Transmittal expresses a commitment to the Company's approved preferred resource plan and resource acquisition strategy, and has been signed by an officer of the Company who has authority to commit the Company to the resource acquisition strategy acknowledging that the Company reserves the right to make changes to its resource acquisition strategies as appropriate due to changing circumstances.

28. Furthermore, due to the confidential nature of information contained in and included with the Company's IRP filing, the Company is proposing entry of a protective order. The Company's proposed protective order is included as Attachment B to this Application. The

Company requests that the entry of its proposed protective order be considered during the prehearing conference for this matter.

**WHEREFORE,** UPPER PENINSULA POWER COMPANY respectfully requests that the Commission find that the Company's Integrated Resource Plan and Preferred Course of Action represent the most reasonable and prudent means of meeting the electric utility's energy and capacity needs. In reaching that finding, the Company further requests that the Commission:

A. Approve the Company's proposal to enter into a 125 MW, 25-year solar PPA at a fixed price, with a Company option to purchase up to 53% of the solar generating facility after a minimum of five and a half years;

B. Approve the Financial Compensation Mechanism and $/Megawatt Hour rider, as proposed, to adequately compensate the utility for the risks associated with imputed debt regarding both the size and term of the Purchase Power Agreement;

C. Approve the Company's proposal for the construction of up to 20 MW of RICE generation to provide improved reliability to UPPCO's customers on the eastern end of its service territory and to provide load balancing generation needed because of the increasing prevalence on intermittent, renewable generation;

D. Approve the Company's proposal to increase and transition its Energy Waste Reduction savings targets to 1.5% or whichever target can be reasonably and prudently cost justified for its customers by the end of its intended next three-year plan pursuant to the outcome of a separate contested case proceeding.

E. Approve the retirement of UPPCO's Portage CT generation facility and authorize UPPCO to apply any insurance payout as a direct credit to the cost to the proposed RICE unit generation;

F. Approve UPPCO's proposal to set its PURPA avoided cost rates at the equivalent capacity value of the Company's existing PPAs and the energy value at the LMP, market-based avoided cost, and recognize UPPCO's demonstration of a forward looking 10 years of capacity.

G. Approve the establishment of a regulatory asset which provides for the full recovery of all Integrated Resource Plan-related costs pursuant to Section 6t of 2016 PA 341, MCL 460.6t, the Commission's December 20, 2017 and all other applicable laws; and

H. Grant such other and further relief and authorizations as may be lawful and proper.

Respectfully submitted,

UPPER PENINSULA POWER COMPANY

Dated: February 12, 2019

By: ______________________________

One of Its Attorneys
Sherri A. Wellman (P38989)
Paul M. Collins (P69719)
Miller Canfield Paddock and Stone P.L.C.
One Michigan Avenue, Suite 900
Lansing, MI 48933
(517) 487-2070

32805656.3\130062-00115

**STATEOFMICHIGAN**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

* * * *

| | | |
|---|---|---|
| In the matter of the application of<br>**UPPER PENINSULA POWER COMPANY**<br>for approval of its integrated resource plan<br>pursuant to MCL 460.6t and for other relief. | )<br>)<br>)<br>) | Case No. U-20350 |

**LETTER OF TRANSMITTAL**

I, James E. Larsen, hereby express Upper Peninsula Power Company's commitment to the Company's approved Integrated Resource Plan Proposed Course of Action, which represents the Company's preferred resource plan and resource acquisition strategy, and hereby sign this Letter of Transmittal as an officer of the Company having the authority to commit the Company to the resource acquisition strategy, acknowledging that the Company reserves the right to make changes to its resource acquisition strategies as appropriate due to changing circumstances.

Dated: February 12, 2019

James C. Larsen
Chief Executive Officer
Upper Peninsula Power Company

32947136.1\130062-00115

**S T A T E  O F  M I C H I G A N**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

*** * * ***

| | | |
|---|---|---|
| In the matter of the application of<br>**UPPER PENINSULA POWER COMPANY**<br>for approval of its integrated resource plan<br>pursuant to MCL 460.6t and for other relief. | )<br>)<br>)<br>) | Case No. U-20350 |

**PROTECTIVE ORDER**

This Protective Order governs the use and disposition of Protected Material that Upper Peninsula Power Company ("Applicant") or any other Party discloses to another Party during the course of this proceeding. The Applicant or other Party disclosing Protected Material is referred to as the "Disclosing Party"; the recipient is the "Receiving Party" (defined further below). The intent of this Protective Order is to protect non-public, confidential information and materials so designated by the Applicant or by any other party, which information and materials contain confidential, proprietary, or commercially sensitive information. This Protective Order defines "Protected Material" and describes the manner in which Protected Material is to be identified and treated. Accordingly, it is ordered:

**I. "Protected Material" and Other Definitions**

A. For the purposes of this Protective Order, "Protected Material" consists of trade secrets or confidential, proprietary, or commercially sensitive information provided in Disclosing Party's discovery or audit responses, any witness' related exhibit and testimony, and any arguments of counsel describing or relying upon the Protected Material. Subject to challenge under Paragraph IV.A, Protected Material shall consist of non-public confidential information and materials including, but not limited to, the following information disclosed during the course of this case if it is marked as required by this Protective Order:

1. Trade secrets or confidential, proprietary, or commercially sensitive information provided in response to discovery, in response to an order issued by the presiding hearing officer or the Michigan Public Service Commission ("MPSC" or the "Commission"), in testimony or exhibits filed later in this case, or in arguments of counsel;

2. To the extent permitted, information obtained under license from a third-party licensor, to which the Disclosing Party or witnesses engaged by the Disclosing Party is a licensee, that is subject to any confidentiality or non-transferability clause. This information includes reports; analyses; models (including related inputs and outputs); trade secrets; and confidential, proprietary, or commercially sensitive information that the Disclosing Party or one of its witnesses receives as a licensee and is authorized by the third- party licensor to disclose consistent with the terms and conditions of this Protective Order; and

3. Information that could identify the bidders and bids, including the winning bid, in a competitive solicitation for a power purchase agreement or in a competitively bid engineering, procurement, or construction contract at any stage of the selection process *(i.e.*, before the Disclosing Party has entered into a power purchase agreement or selected a contractor).

B. The information subject to this Protective Order does not include:

1. Information that is or has become available to the public through no fault of the Receiving Party or Reviewing Representative and no breach of this Protective Order, or information that is otherwise lawfully known by the Receiving Party without any obligation to hold it in confidence;

2. Information received from a third party free to disclose the information without restriction;

3. Information that is approved for release by written authorization of the Disclosing Party, but only to the extent of the authorization;

4. Information that is required by law or regulation to be disclosed, but only to the extent of the required disclosure; or

5. Information that is disclosed in response to a valid, non-appealable order of a court of competent jurisdiction or governmental body, but only to the extent the order requires.

C. "Party" refers to the Applicant, MPSC Staff ("Staff'), Michigan Attorney General, or any other person, company, organization, or association that is granted intervention in Case No. U-20350 under the Commission's Rules of Practice and Procedure, Mich Admin Code, R 792.10401 et al.

D. "Receiving Party" means any Party to this proceeding who requests or receives access to Protected Material, subject to the requirement that each Reviewing Representative sign a Nondisclosure Certificate attached to this Protective Order as Attachment 1.

E. "Reviewing Representative" means a person who has signed a Nondisclosure Certificate and who is:

1. An attorney who has entered an appearance in this proceeding for a Receiving Party;

2. An attorney, paralegal, or other employee associated, for the purpose of this case, with an attorney described in Paragraph I.E.1;

3. An expert or employee of an expert retained by a Receiving Party to advise, prepare for, or testify in this proceeding; or

4. An employee or other representative of a Receiving Party with significant responsibility in this case.

A Reviewing Representative is responsible for assuring that persons under his or her supervision and control comply with this Protective Order.

F. "Nondisclosure Certificate" means the certificate attached to this Protective Order as Attachment 1, which is signed by a Reviewing Representative who has been granted access to Protected Material and agreed to be bound by the terms of this Protective Order.

**II. Access to and Use of Protected Material**

A. This Protective Order governs the use of all Protected Material that is marked as required by Paragraph III.A and made available for review by the Disclosing Party to any Receiving Party or Reviewing Representative. This Protective Order protects: (i) the Protected Material; (ii) any copy or reproduction of the Protected Material made by any person; and (iii) any memorandum, handwritten notes, or any other form of information that copies, contains, or discloses Protected Material. All Protected Material in the possession of a Receiving Party shall be maintained in a secure place. Access to Protected Material shall be limited to persons authorized to have access subject to the provisions of this Protective Order.

B. Protected Material shall be used and disclosed by the Receiving Party solely in accordance with the terms and conditions of this Protective Order. A Receiving Party may authorize access to, and use of, Protected Material by a Reviewing Representative identified by the Receiving Party, subject to Paragraphs III and V below, only as necessary to analyze the Protected Material; make or respond to discovery; present evidence; prepare testimony, argument, briefs, or other filings; prepare for cross-examination; consider strategy; and evaluate settlement. These individuals shall not release or disclose the content of Protected Material to any other person or use the information for any other purpose.

C. The Disclosing Party retains the right to object to any designated Reviewing Representative if the Disclosing Party has reason to believe that there is an unacceptable risk of misuse of confidential information. If a Disclosing Party objects to a Reviewing Representative, the Disclosing Party and the Receiving Party will attempt to reach an agreement to accommodate that Receiving Party's request to review Protected Material. If no agreement is reached, then either the Disclosing Party or the Receiving Party may submit the dispute to the presiding hearing officer. If the Disclosing Party notifies a Receiving Party of an objection to a Reviewing Representative, then the Protected Material shall not be provided to that Reviewing Representative until the objection is resolved by agreement or by the presiding hearing officer.

D. Before reviewing any Protected Material, including copies, reproductions, and copies of notes of Protected Material, a Receiving Party and Reviewing Representative shall sign a copy of the Nondisclosure Certificate (Attachment 1 to this Protective Order) agreeing to be bound by the terms of this Protective Order. The Reviewing Representative shall also provide a copy of the executed Nondisclosure Certificate to the Disclosing Party.

E. Even if no longer engaged in this proceeding, every person who has signed a Nondisclosure Certificate continues to be bound by the provisions of this Protective Order. The obligations under this Protective Order are not extinguished or nullified by entry of a final order in this case and are enforceable by the MPSC or a court of competent jurisdiction. To the extent Protected Material is not returned to a Disclosing Party, it remains subject to this Protective Order.

F. Members of the Commission, Commission staff assigned to assist the Commission with its deliberations, and the presiding hearing officer shall have access to all Protected Material that is submitted to the Commission under seal without the need to sign the Nondisclosure Certificate.

G. A Party retains the right to seek further restrictions on the dissemination of Protected Material to persons who have or may subsequently seek to intervene in this MPSC proceeding.

H. Nothing in this Protective Order precludes a Party from asserting a timely evidentiary objection to the proposed admission of Protected Material into the evidentiary record for this case.

**III. Procedures**

A. The Disclosing Party shall mark any information that it considers confidential as "CONFIDENTIAL: SUBJECT TO THE PROTECTIVE ORDER ISSUED IN CASE NO. U-20350." If the Receiving Party or a Reviewing Representative makes copies of any Protected Material, they shall conspicuously mark the copies as Protected Material. Notes of Protected Material shall also be conspicuously marked as Protected Material by the person making the notes.

B. If a Receiving Party wants to quote, refer to, or otherwise use Protected Material in pleadings, pre-filed testimony, exhibits, cross-examination, briefs, oral argument, comments, or in some other form in this proceeding (including administrative or judicial appeals), the Receiving Party shall do so consistent with procedures that will maintain the confidentiality of the Protected Material. For purposes of this Protective Order, the following procedures apply:

1. Written submissions using Protected Material shall be filed in a sealed record to be maintained by the MPSC's Docket Section, or by a court of competent jurisdiction, in envelopes clearly marked on the outside, "CONFIDENTIAL —SUBJECT TO THE PROTECTIVE ORDER ISSUED IN CASE NO. U-20350. Simultaneously, identical documents and materials, with the Protected Material redacted, shall be filed and disclosed the same way that evidence or briefs are usually filed;

2. Oral testimony, examination of witnesses, or argument about Protected Material shall be conducted on a separate record to be maintained by the MPSC's Docket Section or by a court of competent jurisdiction. These separate record proceedings shall be closed to all persons except those furnishing the Protected Material and persons otherwise subject to this Protective Order. The Receiving Party presenting the Protected Material during the course of the proceeding shall give the presiding officer or court sufficient notice to allow the presiding officer or court an opportunity to take measures to protect the confidentiality of the Protected Material; and

3. Copies of the documents filed with the MPSC or a court of competent jurisdiction, which contain Protected Material, including the portions of the exhibits, transcripts, or briefs that refer to Protected Material, must be sealed and maintained in the MPSC's or court's files with a copy of the Protective Order attached.

C. It is intended that the Protected Material subject to this Protective Order should be shielded from disclosure by a Receiving Party. If any person files a request under the Freedom of Information Act with a governmental agency participating in this proceeding, including, but not limited to, the MPSC, the MPSC Staff, and the Michigan Attorney General, seeking access to documents subject to this Protective Order, the governmental agency shall immediately notify the Disclosing Party, and the Disclosing Party may take whatever legal actions it deems appropriate to protect the Protected Material from disclosure. In light of Section 5 of the Freedom of Information Act, MCL 15.235, the notice must be given at least five (5) business days before the governmental agency grants the request in full or in part.

**IV. Termination of Protected Status**

A. Receiving Party reserves the right to challenge whether a document or information is Protected Material and whether this information can be withheld under this Protective Order. In response to a motion, the Commission or the presiding hearing officer in this case may revoke a document's protected status after notice and hearing. If the presiding hearing officer revokes a document's protected status, then the document loses its protected status after 14 days unless a Party files an application for leave to appeal the ruling to the Commission within that time period. Any Party opposing the application for leave to appeal shall file an answer with the Commission no more than 14 days after the filing and service of the appeal. If an application is filed, then the information will continue to be protected from disclosure until either the time for appeal of the Commission's final order resolving the issue has expired under MCL 462.26 or, if the order is appealed, until judicial review is completed and the time to take further appeals has expired.

B. If a document's protected status is challenged under Paragraph IV.A, the Receiving Party challenging the protected status of the document shall explicitly state its reason for challenging the confidential designation. The Disclosing Party bears the burden of proving that the document should continue to be protected from disclosure.

**V. Retention of Documents**

Protected Material remains the property of the Disclosing Party and only remains available to the Receiving Party until the time expires for petitions for rehearing of a final MPSC order in Case No. U-20350 or until the MPSC has ruled on all petitions for rehearing in this case (if any). However, an attorney for a Receiving Party who has signed a Nondisclosure Certificate and who is representing the Receiving Party in an appeal from an MPSC final order in this case may retain copies of Protected Material until either the time for appeal of the Commission's fmal order resolving the issue has expired under MCL 462.26 or, if the order is appealed, until judicial review is completed and the time to take further appeals has expired. On or before the time specified by the preceding sentences, the Receiving Party shall return to the Disclosing Party all Protected Material in its possession or in the possession of its Reviewing Representatives-including all copies and notes of Protected Material-or certify in writing to the Disclosing Party that the Protected Material has been destroyed.

**VI. Limitations and Disclosures**

The provisions of this Protective Order do not apply to a particular document, or portion of a document, described in Paragraph II.A if a Receiving Party can demonstrate that it has been previously disclosed by the Disclosing Party on a non-confidential basis or meets the criteria set forth in Paragraphs I.B.1 through I.B.S. A Receiving Party intending to disclose information taken directly from materials identified as Protected Material must-before actually disclosing the information-do one of the following: (i) contact the Disclosing Party's counsel of record and obtain written permission to disclose the information, or (ii) challenge the confidential nature of the Protected Material and obtain a ruling under Paragraph IV that the information is not confidential and may be disclosed in or on the public record.

**VII. Remedies**

If a Receiving Party violates this Protective Order by improperly disclosing or using Protected Material, the Receiving Party shall take all necessary steps to remedy the improper disclosure or use. This includes immediately notifying the MPSC, the presiding hearing officer, and the Disclosing Party, in writing, of the identity of the person known or reasonably suspected to have obtained the Protected Material. A Party or person that violates this Protective Order remains subject to this paragraph regardless of whether the Disclosing Party could have discovered the violation earlier than it was discovered. This paragraph applies to both inadvertent and intentional violations. Nothing in this Protective Order limits the Disclosing Party's rights and remedies, at law or in equity, against a Party or person using Protected Material in a manner not authorized by this Protective Order, including the right to obtain injunctive relief in a court of competent jurisdiction to prevent violations of this Protective Order.

______________________________
Administrative Law Judge

Attachment 1

**S T A T E O F M I C H I G A N**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

*** * * ***

| | | |
|---|---|---|
| In the matter of the application of<br>**UPPER PENINSULA POWER COMPANY**<br>for approval of its integrated resource plan<br>pursuant to MCL 460.6t and for other relief. | )<br>)<br>)<br>) | Case No. U-20350 |

**<u>NONDISCLOSURE CERTIFICATE</u>**

By signing this Nondisclosure Certificate, I acknowledge that access to Protected Material is provided to me under the terms and restrictions of the Protective Order issued in Case No. U-20350, 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 understand that the substance of the Protected Material (as defined in the Protective Order), any notes from Protected Material, or any other form of information that copies or discloses Protected Material, shall be maintained as confidential and shall not be disclosed to anyone other than in accordance with the Protective Order.

Reviewing Representative

Date: __________, 2019

_____________________________________
Title:
Representing:

_____________________________________
Printed Name

32841412.1\130062-00115

**STATE OF MICHIGAN**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

* * * * *

| | | |
|---|---|---|
| In the matter of the application of | ) | |
| **UPPER PENINSULA POWER COMPANY** | ) | |
| for approval of its integrated resource plan | ) | Case No. U-20350 |
| pursuant to MCL 460.6t and for other relief. | ) | |

**DIRECT TESTIMONY AND EXHIBITS OF**

**GRADON R. HAEHNEL**

**FOR**

**UPPER PENINSULA POWER COMPANY**

**February 12, 2019**

Q. Please state your name and business address.

A. My name is Gradon R. Haehnel and my business address is 1002 Harbor Hills Drive, Marquette, Michigan 49855.

Q. By whom are you employed and in what capacity?

A. I am employed by Upper Peninsula Power Company ("UPPCO" or the "Company") as Director of Regulatory Affairs.

Q. Briefly describe your education background and employment history.

A. I earned my Bachelor of Science degree in Finance from Indiana University of Pennsylvania in 1995. I earned a Master of Science in Resource and Applied Economics from the University of Alaska-Fairbanks in 2004. Within the regulated electric utility industry, I began my professional career at Bangor Hydro Electric Company, as a Rates and Regulatory Analyst in 2005. By 2008, I was the Manager of Rates and primarily responsible for the development of distribution, transmission, and stranded cost revenue requirements, sales and revenue forecasting, as well as the various associated rate and tariff filings at the Maine Public Utilities Commission ("MPUC") and the Federal Energy Regulatory Commission ("FERC"). By 2012, Bangor Hydro Electric Company had acquired Maine Public Service Company becoming a newly formed regulated transmission and distribution utility in Maine, called Emera Maine. At the newly formed Emera Maine, I assumed the role of Manager of Engineering and Asset Management ("Asset Manager") where I was primarily responsible for the operational functions of asset management, capital planning, transmission and distribution engineering, and transmission development. From 2014 through 2016, I worked in the role of Senior Asset Manager at Emera Maine which additionally included oversight of the operational functions of resource planning, scheduling, and dispatch. In 2016, I joined UPPCO as Manager of Financial Planning and Analysis where I was primarily responsible for the development and implementation of financial forecasting, budgeting, and reporting processes during the latter stages of UPPCO's SAP system implementation. In early 2017, I assumed the role of Director of Regulatory Affairs for UPPCO.

Q. Have you previously testified in any regulatory proceedings?

A. Yes. I have testified in several cases before the MPSC in my various roles as Rates and Regulatory Analyst, Manager of Rates, Asset Manager and Senior Asset Manager. Most recently I sponsored testimony and exhibits in Michigan Public Service Commission ("MPSC" or the "Commission") Case Nos. U-18265, U-18254, U-18335, U-18467, U-20111, U-20184, and U-20276 on behalf of UPPCO.

Q. What is the purpose of your direct testimony.

A. The purpose of my direct testimony is to provide an overview of the Company's Integrated Resource Plan ("IRP") filing and to provide testimony that supports several facets of UPPCO's IRP filing, as outlined below. Specifically, my direct testimony includes:

i. IRP introduction and overview
ii. Company witness and support
iii. Proposed Course of Action ("PCA")
iv. Request for Proposals ("RFP") and Results
v. Stakeholder engagement
vi. Statutory and regulatory compliance
vii. Support for Financial Compensation Mechanism ("FCM")
viii. Support for the rate impact and financial information
ix. IRP request for approval

Q. What is the Company seeking approval for in this IRP?

A. The Company is seeking approval of this IRP, including cost recovery for investments, contracts and resources that will be utilized to meet customers' energy and capacity needs within the five years following Commission approval. The investments, contracts and resources are part of the Company's PCA. The PCA is the key outcome of the IRP representing the Company's plan for meeting customers' capacity needs over the next 20 years.

Q. Have you prepared any exhibits in conjunction with your direct testimony?

A. Yes, I am sponsoring the following exhibits:

- Exhibit A-1 (GRH-1) Black & Veatch Report
- Exhibit A-2 (GRH-2) Stakeholder I Presentation
- Exhibit A-3 (GRH-3) IRP Survey Questionnaire
- Exhibit A-4 (GRH-4) IRP Survey Results
- Exhibit A-5 (GRH-5) Stakeholder II Presentation
- Exhibit A-6 (GRH-6) IRP Filing Requirements
- Exhibit A-7 (GRH-7) PPA FCM [CONFIDENTIAL]
- Exhibit A-8 (GRH-8) Summary Inputs and Outputs [CONFIDENTIAL]
- Exhibit A-9 (GRH-9) Revenue Requirements Summary [CONFIDENTIAL]
- Exhibit A-10 (GRH-10) RICE Revenue Requirement
- Exhibit A-11 (GRH-11) Solar PPA Revenue Requirement [CONFIDENTIAL]
- Exhibit A-11 (GRH-12) Hydro Capacity Revenue Requirement

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

A. Yes.

## Section I. IRP Introduction and Overview

Q. Please provide an introduction and overview of UPPCO's 2019 IRP.

A. An IRP explains, at a particular point in time, how an electric utility company plans on meeting the projected peak demand and energy requirements of the customers it serves. By Michigan statute, UPPCO is required to provide an IRP that encompasses a 20-year forecast period (2018-2037). The Company's primary planning objective was to create a well-diversified, balanced portfolio of energy and capacity resources. Through this portfolio approach and the development of its IRP, UPPCO focused on providing value to customers through 1) greater price stability over the long-term (i.e., hedge against market price volatility), and 2) greater diversification of power supply resources.

Q. What statutes influenced UPPCO's planning objectives?

A. Section 6t of Public Act 341 requires the Commission to approve an IRP if it determines the plan represents the most reasonable and prudent means of meeting the electric utility's energy and capacity needs. To make this determination, the commission shall consider whether the plan appropriately balances all of the following factors:

i. Resource adequacy and capacity sufficient in quantity to serve anticipated peak electric load plus applicable Planning Reserve Margin Requirement ("PRMR") and Local Clearing Requirement ("LCR");

ii. Compliance with applicable state and federal environmental regulations;

iii. Competitive pricing;

iv. Reliability;

v. Commodity price risks;

vi. Diversity of generation supply; and

vii. Whether the proposed levels of peak load reduction and EWR are reasonable and cost effective.

Further, UPPCO prioritized having its IRP reflect the values of the communities it serves. UPPCO initiated two sets of stakeholder engagement meetings to provide information and receive critical input and feedback into its IRP process. It was resoundingly clear based on feedback that clean, renewable solutions were a leading choice from its residential customers for potential generation solutions. Further, UPPCO's commercial customers also valued clean, renewable generation and advocated for decision making that would balance cost considerations with long-term sustainable solutions. As a rural, electric utility, UPPCO strives to provide excellent reliability to its customers. UPPCO, therefore, also prioritized ensuring the delivery of safe, reliable and efficient power to its customers at competitive costs.

Q. What are the primary attributes of UPPCO's 2019 IRP filing?

A. UPPCO's 2019 IRP contains the following attributes:

i. First and foremost: stakeholder input. Through early and frequent stakeholder proceedings, UPPCO advocated for transparency and collaboration. Throughout the IRP modeling process, UPPCO has engaged Commission Staff and other key stakeholders, and incorporated feedback, where appropriate, to improve the plan and the process used to develop it.

ii. Clean, sustainable energy sources. When compared to its peer electric utilities in the state of Michigan, UPPCO is taking a leadership position by providing approximately 57% of its energy requirements through clean, renewable generation sources by 2022. UPPCO believes it is challenging the existing paradigm that states that sources of new, clean renewable energy are more expensive than traditional forms of power supply.

iii. Stable pricing that is insulated from market sensitivities. In addition to being sourced from clean and renewable generation, almost 60% of UPPCO's power supply portfolio mix will naturally hedge UPPCO customers from typical market price volatility and risk present in the Midcontinent Independent System Operator ("MISO") market.

iv. Maximizing the value of existing resources. UPPCO continues to invest in and leverage its existing internal hydro generation by increasing the unit capability coincident to the MISO peak, through new metering infrastructure and configuration changes, which result in an incremental 7.6 MW of capacity with an immediate, direct benefits and savings to customers in the form of avoided capacity purchases.

v. Competitive bidding to ensure the best value for customers and cost-effective pricing. Through a robust Request for Proposals process informed by its IRP modeling efforts, UPPCO has established a competitive bidding process evaluating both Engineering, Procurement and Construction ("EPC") build-transfer proposals, as well as, 25-year, long-term PPA proposals for solar generation facilities located and constructed in the Upper Peninsula ("UP").

vi. Rigorous and thorough analysis. Even though UPPCO is a small electric utility serving less than 1,000,000 customers, and as such, could seek waiver from the full filing requirements established by the Commission in Case No. U-18461, UPPCO believes it has adhered to all the required and recommended modeling scenarios, assumptions, inputs and sources in order to present as robust a solution as possible.

**Section II: Company Witnesses and Support**

Q. Please provide an overview of Company witnesses and the topics they will present evidence in support of this IRP filing.

A. In addition to my testimony and exhibits, the following witnesses are also presenting testimony and exhibits in support of UPPCO's IRP:

Company witness Eric W. Stocking describes (i) the development of the Company's electric sales and peak demand forecast from 2019 – 2037; (ii) UPPCO's current power supply procurement strategy, resource adequacy, and risk mitigation; and (iii) UPPCO's proposal for establishing the PURPA avoided cost in this proceeding.

Company witness David R. Tripp describes (i) the Company's existing, owned generation resources and planned efforts to maximize the benefits of these resources and (ii) the pre-filing Request for Proposal ("RFP") process that was used to identify potential new power supply resources and the results of the RFP process.

Company witness Andrew McNeally describes (1) an overview of UPPCO's current EWR plan, (2) discusses UPPCO's transition to an EWR energy reduction target of 1.5%, and (3) highlights some risks associated with UPPCO's ongoing EWR plan development.

Q. Has the Company developed a report in support of its IRP?

A. Yes. UPPCO engaged Black & Veatch Ltd. of Michigan, LLC ("Black & Veatch") to assist in the development of an IRP that facilitates the selection of future supply options over the course of the next twenty years. The Black & Veatch Report, sponsored as Exhibit A-1 (GRH-1) and with accompanying appendices, describe the analyses conducted and the underlying assumptions that produced a 20-year resource plan that will meet UPPCO's energy and capacity requirements.

**Section III. Proposed Course of Action**

Q. What is the Company's PCA?

A. The Company's PCA proposes the following:

i. 1.5% EWR: Increasing Energy Waste Reduction ("EWR") to 1.5% of the Company's total electric load. UPPCO's current biennial EWR plan (approved by the Commission in MPSC Case No. U-18265), exceeds the current statutory requirement of 1% savings and targets 1.14% savings for the 2018 and 2019 planning years. UPPCO proposes to address the costs and terms of this EWR increase in its next EWR plan proceeding, which will be filed in accordance with Section 71 of 2008 PA 2015, as amended by 2016 PA 342. Company witness Andrew H. McNeally, UPPCO's Energy Efficiency Program Administrator, speaks in greater detail regarding this transition and the current issues being actively managed related to EWR.

ii. Solar PPA: Adding 125 megawatt ("MW") of both capacity and energy by entering a long-term Purchased Power Agreement ("PPA"). The capacity and energy will be from a new solar generation facility that will be constructed and located in the UP of Michigan at a fixed price of $ ________ per megawatt hour ("MWh"). This new facility will be on-line by May of 2022, and the pricing will be fixed for a term of 25 years. Consequently, by May of 2022, in conjunction with UPPCO's current portfolio of internal hydro generation, UPPCO projects that approximately 57% of its energy requirements will be sourced through clean, renewable generation and will be naturally hedged against MISO market pricing which is largely influenced by natural gas fuel price fluctuations, among other factors.

iii. RICE 2022: Construction of up to 20 MW of a Reciprocating Internal Combustion Engine ("RICE") facility located near ________, MI, which resides on the southeast end of UPPCO's service territory and will provide reliability benefits to UPPCO's customers as well as the eastern part of the UP.

iv. Portage Retirement: Retirement of UPPCO's existing oil-fired Portage combustion turbine generating facility. The existing Portage generating unit is a 45-year-old, oil-fired Combustion Turbine ("CT") that provides approximately 22 MW of nameplate generation capacity for UPPCO's customers. In late November of 2018, when UPPCO was in the latter stages of its IRP modeling efforts, Portage experienced a catastrophic mechanical failure. The Portage generating unit represents approximately 14% of UPPCO's current total capacity levels and approximately 45% of UPPCO's company-owned capacity levels. Regarding the Portage generating unit failure and its retirement, UPPCO is currently evaluating and working with its insurance carrier to fully understand its options following the mechanical failure. UPPCO anticipates that a reasonable outcome from the insurance claims process may either entail the rebuild of the oil-fired unit at the Portage location or a potential claim value that UPPCO would utilize to offset the cost of the RICE unit being proposed, here within.

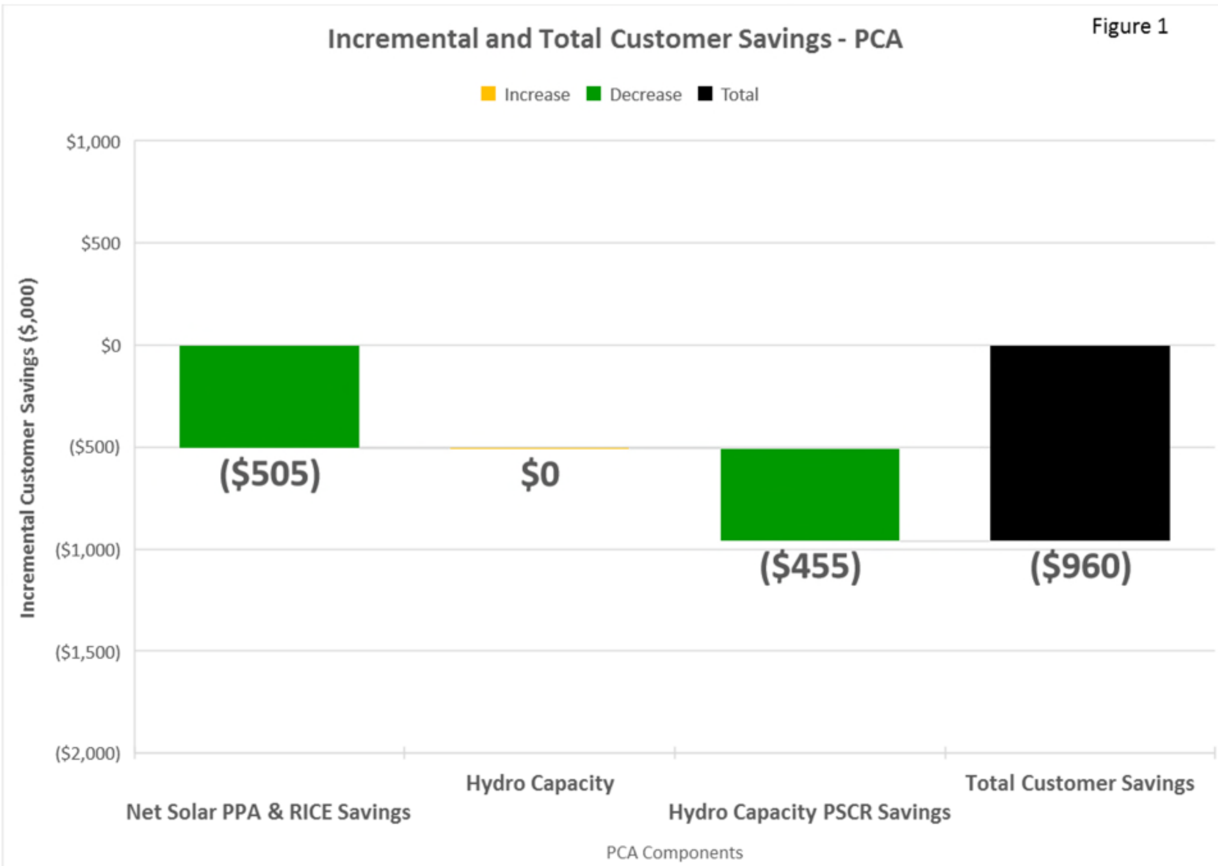
v. Hydro Capacity: Increasing the capacity of UPPCO's existing hydroelectric generating facilities. UPPCO will move the Hoist and McClure generating units "in front of the meter," thereby allowing UPPCO to report their respective capacity to MISO as part of UPPCO's annual maximum generation. The result of this metering construct and reconfiguration will increase the reported capacity of these two units by a combined 7.6 MW which will provide a direct benefit to customers in the form of avoided capacity cost purchases in the future. Company witness David R. Tripp, describes the metering reconfiguration in greater detail in his direct testimony.

vi. PURPA: As discussed in Company witness Eric W. Stocking's testimony, UPPCO further proposes to set its PURPA avoided cost at a level equal to the market based avoided cost of energy and capacity. UPPCO will utilize the avoided cost rates proposed in this proceeding as the baseline for any QF contract negotiations. Since UPPCO customers will pay and potentially subsidize any difference between the QF contract rates and the price at which UPPCO sells the excess energy and capacity in the market, UPPCO believes the transparency of this proceeding will balance all parties' interests.

This PCA (i) represents the most reasonable and prudent means of meeting the Company's energy and capacity needs through 2037 and (ii) provides for reliable electric service, at a reasonable cost, through a combination of existing generation resources, renewable energy resources, purchased power agreements, and energy waste reduction programs. In developing this IRP, UPPCO assessed its power supply resource portfolio considering both capacity and energy needs, as well as, regulatory and environmental compliance, and the planning objectives set forth by the Commission and the Company. Being mindful of both sustainable and renewable generation resources as a value stream in providing power to its customers over the long run, as well as the natural hedge value of these resources against long-term market price volatility, UPPCO sought to balance long-term price stability with resource sustainability.

Q. As a result of UPPCO's PCA, what are the total customer savings?

A. Customers rates will be lowered. On a Net Present Value ("NPV") basis, UPPCO customers will realize just shy of a $1 million savings per year. As demonstrated in Figure 1 below, which is a waterfall diagram of the incremental changes associated with each component of the PCA, customers will realize savings of almost $1 million each year.




Q. Why does the PCA not include a Demand Response ("DR") component?

A. UPPCO does not propose additional DR because approximately 52% of the Company's total capacity requirement is currently served under either the Company's Real Time Market Pricing tariff or is otherwise interruptible. Because a large portion of UPPCO's large commercial and industrial customers already participate in demand response programs, the Company does not believe the additional DR efforts would be cost-effective.

Q. Does the PCA include the Escanaba Hydro facilities?

A. The IRP base modeling assumes both the energy and capacity from these units, as these facilities were submitted for inclusion in Case No. U-20276. As such, they are not included in the PCA but rather in the base model, pending the outcome of Case U-20276.

**IV. Request for Proposals and Results**

Q. Please describe the process UPPCO utilized for its pre-filing RFP.

A. For a description of the overall RFP process, please see Company witness David R. Tripp's testimony.

Q. How many RFP processes has UPPCO commenced prior to its IRP filing? Please explain.

A. Two. UPPCO has initiated an RFP process to obtain bids for energy and capacity sources from (i) solar generation facilities, and (ii) RICE generation facilities.

Q. Please describe the solar generation RFP.

A. UPPCO sought to acquire up to 20 MW of AC solar photovoltaic ("PV") generating capacity with a Commercial Operation Date ("COD") commencing on or before June 1, 2022, all located in the Upper Peninsula of Michigan. As such, the capacity could be met by a single 20 MW facility or multiple facilities of lower capacity. For purposes of this RFP, AC capacity referred to the net generating capacity at the facility's point of interconnection ("POI"), as controlled by the plant supervisory control and data acquisition ("SCADA") system. Respondents could propose solutions with an aggregate inverter capacity exceeding the 20 MW AC limit at the point of interconnection, if advantageous.

Q. Please describe the options scoped within the solar generation RFP.

A. Solar generation options:

- Build Transfer/EPC or Build-Own-Operate-Transfer PPA with a purchase option. In this option, the Developer is responsible for development, turn key EPC construction and commissioning of Solar PV facilities up to the POI with UPPCO's Generation Step-up ("GSU") transformer. UPPCO is responsible for design and construction of related interconnection facilities. UPPCO to provide the project land through lease or purchase and the interconnection substation. Option for Respondent to own and operate the facilities and sell energy and capacity under a PPA to UPPCO with an option for UPPCO to purchase any time after 5 years plus one day. Option for Respondent to provide long term O&M of the facility.
    a. Interconnected on UPPCO's established distribution system with capacity options consisting of 20MW constructed in two (2) - 10 MW installations. Increments of 10 MW AC.
- Build Transfer/EPC or Build-Own-Operate-Transfer PPA with a purchase option. Developer is responsible for development, turn key EPC construction and commissioning of Solar PV and related interconnection facilities. UPPCO to provide the project land for 20MW capacity option through lease or purchase. Alternatively, Respondent may opt to provide land. Option for Respondent to own and operate the facilities for specified term and sell energy and capacity under a PPA to UPPCO, with an option for UPPCO to purchase any time after 5 years plus one day. Option for Respondent to provide long term O&M of the facility.
    a. Interconnected at transmission voltage anywhere in Load Resource Zone 2 of MISO with capacity options of 20 MW in increments of 5, 10 or 20 MW AC.

- Equity Ownership. In this option, UPPCO enters a 25-year PPA (for energy and capacity) with an equity investment made in year 6 from COD. The Developer and its partners will be responsible for fully executing development, construction, commissioning and performing O&M of the facility.
    a. Interconnection at transmission voltage anywhere in the Upper Peninsula of Michigan with a capacity of up to 20 MW AC.

Q. Please describe the RICE generation RFP.

A. UPPCO is seeking to acquire 18 to 20 MW of natural gas-fired RICE generating facility with a COD commencing on or before June 1, 2022, located in UPPCO's established service territory within MISO Load Resource Zone 2 in Michigan. As such, this capacity can be met by simple cycle single or two engine generation in an enclosed facility. For purposes of the RFP, capacity refers to the net generating capacity at the facility's POI, as controlled by the plant SCADA system. The Respondents shall define the incoming gas, water, chemical (if necessary, for exhaust treatment) requirements and the outgoing electrical generating capacity for the facility. Through the RFP process, UPPCO intends to provide more detailed Minimum Functional Specifications to the Respondents during the RFP process. UPPCO intends to structure the minimum requirements such that Respondents will have flexibility to propose technical solutions which maximize overall financial benefit of the project.

Q. Are these RFP processes still ongoing?

A. Yes. The RFP process will be completed when a resulting contract is signed by both parties, which will become effective pursuant to a subsequent Commission order. Regarding UPPCO's Solar RFP, UPPCO has received all bids and has identified its preferred bids. Further, the Company has notified one or more of the respondents of the Company's intent to initiate discussions that will lead into substantive contract negotiations. Regarding UPPCO's RICE RFP, UPPCO has initiated the RFP process with potential respondents and will update associated costs and terms pursuant to MCL 460.6t (7), prior to the 150-day mark in the case schedule.

Q. Please describe the Solar RFP bid results.

A. UPPCO received 30 bids from 6 different bidders. As evidenced in Company Witness David R. Tripp's Exhibit A-20 (DRT-3) Solar RFP Evaluation Summary, the PPAs, including those with purchase options, were more economic than EPC alternatives for UPPCO's customers at this time.

Q. Who is UPPCO's preferred bidder on the Solar RFP?

A. _______________, which was bid for 20 MW of a 125 MW facility.

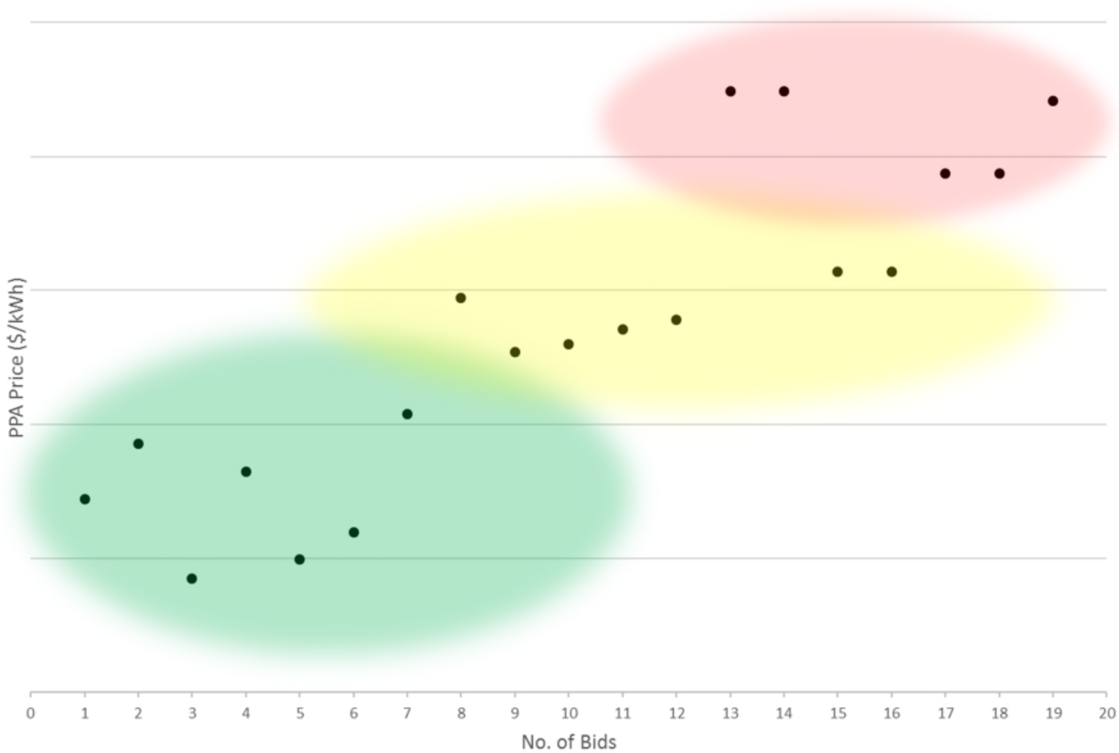
Q. Does Mr. Tripp's Exhibit A-20 (DRT-3) support this bid preference?

A. Yes, UPPCO's preferred bid and bidder represent the lowest Levelized Cost of Entry ("LCOE").

Q. Please provide a graphical representation of most relevant PPA bid prices.

A. See below, Figure 2.

**Solar RFP Bid Prices (including assumed Interconnection Costs)** Figure 2




Q. Please summarize your observations from the sample of PPA bid prices provide in Figure 2.

A. First, the Solar RFP was extremely competitive with several PPA bids that resulted in, assumedly, three natural groupings of bid prices, as identified above in the three separate color bands. For purposes of confidentiality, UPPCO has removed the scale, pricing, and bidder names. That being said, UPPCO's preferred bid and bidder resides in the green, lower priced band. Also, UPPCO's bid, as represented in the chart above, includes the levelized FCM charge, which is expressed in $/MWh.

Q. Do other bids reflected in Figure 2 include the levelized FCM charge? Please explain.

A. No. UPPCO has included the levelized FCM charge in its preferred bid to augment the competitiveness of the fixed price PPA with an FCM in relation to the other bid prices that do not include it. Said alternatively, UPPCO's preferred bid price with an FCM is still one of the most competitive bids being evaluated.

Q. How has the Solar RFP process informed UPPCO's PCA?

A. While the bids came back in alignment with the scope of the RFP document, the pricing and information was such that UPPCO evaluated increasing the size of its energy and capacity purchases to 125 MW from the original 20 MW target. This is further discussed in Company witness Eric W. Stocking's testimony.

Q. Why is the increase in size from 125 MW from 20 MW justified in this case?

A. UPPCO has a high degree of confidence in the RFP process which was undertaken, and which has resulted in over 30 evaluated bids from various respondents. With its preferred bid price identified, UPPCO ran an additional IRP modeling scenario to include a Business-As-Usual modeling run with 125 MW of a fixed price Solar PPA. As evidenced in Black & Veatch's Report in Section 10, the 125 MW Solar PPA came back with the least cost Cumulative Present Worth Calculation ("CPWC").

Q. What happens if UPPCO is not able to come to agreement with its preferred bidder and bid price through the Solar RFP process?

A. UPPCO will continue an objective pursuit of the best project and will contemporaneously evaluate the other smaller, yet still reasonably priced competitive bids and bidders.

Q. Will UPPCO's approach through the RICE RFP process be similar to that of the Solar RFP process?

A. Yes.

## V. Stakeholder Engagement

Q. Did the Company employ a stakeholder engagement process to develop this IRP? Please explain.

A. Yes. UPPCO's stakeholder engagement process had three distinct components of engagement. The first of UPPCO's stakeholder engagement process consisted of the Company hosting four (4) public forums throughout its service territory in Q1 of 2018. The second component of UPPCO's stakeholder engagement process was via direct meetings that were held with UPPCO's largest commercial and industrial customers throughout 2018 and Q1 of 2019. The third and final component of UPPCO's stakeholder engagement process encompassed ongoing engagement and education with state and local elected and appointed officials, Independent Power Producers and developers of energy projects, other electric utilities, and any other stakeholders expressing an interest in UPPCO's IRP. UPPCO's stakeholder engagement activities took place throughout all of 2018 and are expected to continue during 2019.

Q. Please explain the first component of the stakeholder engagement process.

A. In early 2018, the Company held several public forums to gather insight, viewpoints, and feedback from its customers. Customers and interested stakeholders had an opportunity to meet with UPPCO staff involved in the IRP process, as well as representatives from the Company's Regulatory, Generation, Energy Waste Reduction and Customer Service departments. The locations of the IRP forums were, as follows:

- 1/9/2018: Terrace Bay Hotel – 7146 P. Rd., Gladstone, MI
- 1/11/2018: Finlandia University Jutila Center – 200 Michigan St., Hancock, MI
- 1/16/2018: River Rock Lanes Banquet Center – 1011 North Rd., Ishpeming, MI
- 1/18/2018: American Legion Post – 610 W. Munising Ave., Munising, MI

Exhibit A-1 (GRH-2) Stakeholder I Presentation is UPPCO's formal presentation from these events.

Q. What major themes and lessons emerged from Phase I of the stakeholder engagement process?

A. As evidenced in Exhibit A-3 (GRH-3) IRP Survey Questionnaire and Exhibit A-4 (GRH-4) IRP Survey Results, it became clear that UPPCO's customers value clean, renewable energy options, as well as a well-diversified, balanced power supply portfolio that would limit UPPCO's reliance on short-term market purchases in the market that are subject to associated risks of price volatility. Specifically, the survey indicated the following:

- Question 4 –A balanced portfolio of energy resources and renewable energy sources were ranked highest when asked where energy should come from in the future
- Question 7 – 97% of respondents said it was "important" (30%) or "very important" (67%) that UPPCO own enough generation to provide long-term price stability
- Question 8 –73% of respondents agreed (21%) or strongly agreed (52%) that UPPCO should exceed State renewable energy mandates
- Question 10 – 79% of respondents agreed (42%) or strongly agreed (37%) that generation resources should be located in the Upper Peninsula

Q. Please explain the second component of the stakeholder engagement process.

A. The second component of UPPCO's IRP stakeholder engagement process was directed at the commercial and industrial customers. By directly meeting with more than 40 individual businesses, UPPCO was able to deliver key IRP messaging while receiving critical feedback from its key commercial and industrial stakeholders. Exhibit A-5 (GRH-5) Stakeholder II Presentation shows the formal presentation that UPPCO gave at these meetings.

Q. What major themes and lessons emerged from this component of the IRP stakeholder engagement process?

A. First, UPPCO's commercial and industrial customers appreciated the direct, one-on-one communication that took place with key UPPCO account executives. Overall, UPPCO's commercial and industrial customers understand the value proposition before the Company regarding building a sustainable and renewable energy future for all customers. In general, fact-based decision making based on a rigorous process with consistent and clear communication is what UPPCO's commercial and industrial customers value most.

Q. In addition to the public forums and direct commercial and industrial customer meetings, what other types of stakeholder engagement took place?

A. Throughout this process, the Company has engaged with various elected and appointed government officials and UP electric companies, to ensure that open lines of communications were established with stakeholders across the UP and Michigan. Also, the Company has met several times with the Commission Staff, and other groups that regularly intervene in Commission proceedings, to keep them abreast of the IRP's focus and process.

Q. What feedback from these meetings was incorporated into UPPCO's IRP?

A. UPPCO was told by stakeholders, including Cloverland Electric, that the greatest need for additional generation is in the eastern portion of the UPPCO's service territory. This is discussed in greater detail in Witness Stocking testimony.

Q. What other key issues has UPPCO been mindful of through the IRP stakeholder engagement process?

A. UPPCO's stakeholders are focused on the bottom-line in terms of impact on their electric bills. The Company's customers do not view the IRP process as a stand-alone issue. Between UPPCO's filed rate case in U-20276, UPPCO's AMI metering investment, the 2017 Tax Cut and

Jobs Act tax reform refunds, and the expiration of the Presque Isle Power Plant related System Support Resource ("SSR"), UPPCO's customers are consistently monitoring and tracking the drivers that will potentially impact their bills. Any messaging regarding UPPCO's IRP process, must be delivered within the context of UPPCO's other key issues and initiatives.

Q. What other tools has the Company developed to enhance customer communication regarding its IRP process?

A. UPPCO has developed a webpage page directly supporting its efforts. This page is located at: https://www.uppco.com/home/irp/.

Q. Was the stakeholder engagement process successful?

A. The stakeholder engagement process provided a valuable opportunity for UPPCO to continue to build and strengthen its relationship with its customers and interested stakeholders. Through this process, UPPCO was able to incorporate insights and feedback into the IRP modeling process and ultimately develop a PCA that is a balanced representation of customers' interests and considerations, as well as, UPPCO's corporate objectives.

**Section VI. Regulatory and Statutory Compliance**

Q. Why has the Company filed this IRP?

A. Pursuant to Section 6t of Public Act 341, the Commission issued an order in MPSC Case No. U-18461 establishing filing requirements, including application forms, instructions, and filing deadlines for an IRP to be filed by electric utilities whose rates are regulated by the Commission by April 20, 2019 and within five years thereafter. The Commission's August 18, 2018 Order in Case No. U-18461 required UPPCO file its IRP by December 14, 2018. On December 6, 2018, the

Commission issued an Order granting UPPCO's request to extend the filing deadline for this IRP until February 12, 2019.

Q. Please provide an overview of the statutory framework and filing requirements for IRPs.

A. In the Commission established "IRP Filing Requirements" in the final order issued in MPSC Case No. U-18461. The Commission also led a collaborative stakeholder engagement process, which culminated in IRP planning parameters in the "Michigan Integrated Resource Planning Parameters" document ("IRP Modeling Parameters") approved in MPSC Case No. U-18418. In their entirety, these documents set forth all required IRP modeling scenarios and assumptions, requirements, instructions, and guidelines for utilities seeking relief pursuant to MCL 460.6t.

Q. Does the Company's IRP meet the statutory requirements for an IRP to be filed before the Commission?

A. Yes. The Company's IRP meets the statutory requirements for an IRP filed before the Commission. The Company's testimony and exhibits which accompany this Application address the components required to be included in an IRP and address the factors which the Commission shall consider in approving an IRP and establish that the Company's PCA represents "the most reasonable and prudent means of meeting the electric utility's energy and capacity needs."

Q. Does the Black & Veatch Report comply with the IRP report requirements from the Commission's December 20, 2017 Order in Case No. U-15986, et al.?

A. Yes. Please see Exhibit A-6 (GRH-6), IRP Filing Requirements, which is a list of the cross-references between the Commission's IRP report requirements and the relevant section in the Black & Veatch Report.

Q. As outlined in Section VIII of the IRP Modeling Parameters, please describe the modeling scenarios, sensitivities and assumptions utilized by UPPCO in its 2019 IRP.

A. Because three modeling scenarios are required for utilities located in the Michigan portion of MISO Zone 2, UPPCO utilized the following scenarios:

- Scenario 1: Business as Usual
- Scenario 2: Emerging Technologies
- Scenario 4: High Market Price Variant

The scenario analyses and results are described in greater detail in Section 9.0 of the Black & Veatch Report.

Q. As recommended in Section IX of the IRP Modeling Parameters, please provide a summary table of UPPCO's IRP modeling inputs and assumptions.

A. Please reference Appendix B of the Black & Veatch Report, which outlines the principal considerations and assumptions utilized in UPPCO's 2019 IRP.

Q. Pursuant to MCL 460.6t (6), has UPPCO issued a pre-filing RFP or RFPs to provide any new supply-side generation capacity resources?

A. Yes. As informed by UPPCO's IRP modeling efforts and prior to its February 12, 2019 IRP filing, UPPCO initiated its RFP processes to seek new supply-side capacity resources for either a solar generation facility or solar PPA option, as well as a RICE generating unit option. Also, pursuant to MCL 460.6t (7), prior to the 150-day mark in the case schedule, UPPCO plans to file an update to any cost estimates that may materially change including but not limited to bid pricing resulting from the ongoing RFP bid processes.

Q. Has UPPCO sought explicit waivers from its IRP filing requirements, as outlined in MCL 460.6t?

A. No. As a small utility serving fewer than 1,000,000 customers, UPPCO appreciates the flexibility as outlined in the IRP Filing Requirements (page 9). However, as a small utility that greatly values this IRP process, UPPCO has deliberately sought to adhere to the robust standards outlined by the Commission. UPPCO's understanding is that while a non-multistate Michigan electric utility serving less than 1,000,000 customers may elect to file an IRP that may deviate from the requirements as stated in the IRP Filing Requirements, that utility will be afforded an opportunity to provide pertinent supplemental information subject to Staff's requests. Further, UPPCO understands that the Commission shall review any such exchanges under the traditional "just and reasonable" standard.

Q. Please describe Michigan's renewable portfolio standard.

A. In December 2016, Governor Snyder signed Public Act 342 of 2016 ("PA 342") into law. PA 342, which became effective on April 20, 2017, amends Public Act 295 of 2008 ("PA 295"), increasing the renewable portfolio standard from 10% in 2015 to at least 12.5% in both 2019 and 2020 with a final requirement of at least 15% in 2021. PA 295, as amended by PA 342, includes a goal of meeting not less than 35% of the state's electric needs through a combination of energy waste reduction and renewable energy by 2025.

Q. Has the Company integrated the requirements of its PURPA review application into its February 12, 2019 IRP filing?

A. Yes. Pursuant MCL § 460.6t(5), this IRP plan addresses the avoided costs and capacity requirements typically included in a PURPA review application. On February 22, 2018, in MPSC Case No. U-20095, the Commission requested comments from interested parties on the determination of utility capacity requirements over a 10-year planning horizon and the criteria for evaluating a legally enforceable obligation in the context of PURPA's requirements that rate-regulated utilities file proposed avoided cost calculation methods and costs. In its Order issued on October 5, 2018 ("October 5 Order") in Case No. U-20095, the Commission found that "given the close relationship between a utility's capacity needs and avoided costs, it is appropriate to address both capacity needs and avoided costs in an IRP proceeding." [p. 17] As evidenced in (1) UPPCO's notice to extend the deadline filing for its PURPA review application on January 29, 2019 in Case No. U-18094, (2) in light of the findings in the Commission's October 5 Order, and (3) in the interest of avoiding duplicative efforts while presenting a robust and comprehensive IRP filing, UPPCO has integrated the requirements of its PURPA review application into this filing. By its February 7, 2019 Order in Case No. U-18094, the Commission authorized UPPCO to integrate is PURPA filing in this IRP.

**VII. FCM Implementation**

Q. Is the Company proposing to receive a financial compensation mechanism that would be applied to the long-term, 25-year, fixed price solar PPA proposed here within?

A. Yes.

Q. Is the Company proposing to receive a financial compensation mechanism for existing PPAs?

A. No.

Q. Why is there a need for a PPA Financial Compensation Mechanism?

A. PPAs are agreements that contractually obligate UPPCO to purchased energy and capacity from a counterparty at a pre-determined price over a predetermined length of time. Long-term PPAs have similar financial characteristics as long-term debt and are often considered "off-balance sheet". However, since PPA obligations have fixed payments, similar to interest payments, these obligations reduce financial flexibility and increase the risk of default for the utility. Often, the incorporation of PPA obligations financial credit risk analysis is referred to as "imputed" debt.

Q. In accordance with UPPCO's PCA, what portion does the 125 MW Solar PPA represent of UPPCO's total power supply portfolio in terms of both energy and capacity?

A. The Solar PPA represents approximately 40% of UPPCO's total energy and approximately 55% of UPPCO's Zonal Resource Credits ("ZRCs") in 2025.

Q. Does the presence of a long-term PPA impact the financial profile and credit of the Company?

A. Yes, the a long-term PPA increases the financial support provided by equity capital and impacts the credit of a utility as a result of the imputed debt from PPAs. This increased financial burden and these credit costs are borne by customers and investors of the Company and unless addressed, unfairly shifts costs from the PPA provider to these stakeholders.

Q. Do long-term PPAs have an impact on the Company's ability to attract capital?

A. To the extent assets are owned by a utility, the Company raises debt and equity directly to fund the investment. In contrast, for assets operated under a long-term PPA, while the debt may not be raised directly by UPPCO, the financial support for the capital ultimately remains with the utility. Capital raised by an Independent Power Producer ("IPP") is in the form of an obligation of UPPCO and therefore competes directly with the capital raised by the Company and can, in turn, increase the cost of capital for the Company.

Q. Would a long-term PPA be possible without equity capital from UPPCO?

A. No, without the credit worthiness of UPPCO, which is supported by equity capital, the long-term PPA provider would be unable to raise the appropriate capital. A long-term PPA utilizes the equity capital of the Company and a proper compensation is essential to a fair rate of return. While long-term PPA's have the potential to add value to customers, without equity capital provided by investors, the realization of these benefits would not be possible.

Q. How does the Company propose to apply the FCM to the long-term PPA?

A. As the Company books generation and associated expense according to the terms of the long-term PPA on a monthly basis, the FCM will be added to the total PPA expense booked for the month. The counterparty will receive the compensation associated with the rates included in the long-term PPA and the Company will retain the financial compensation. The FCM is determined on a $/MWh basis, so the Company will multiply the approved FCM for the long-term PPA by the amount of generation booked for the month, including any prior period adjustments.

Q. Which cost recovery mechanism is the Company to proposing to utilize to recover the FCM?

A. The Company intends to recover the FCM through base rates.

Q. Why is the Company proposing an FCM in this proceeding?

A. This IRP identifies several long-term supply resources. Many of the long-term supply resources require the Company to decide between utility asset ownership and contracting with a non-utility owner through a long-term PPA.

Q. How are PPA costs reflected in customer rates?

A. The MPSC reviews and approves PPA contracts subject to certain statutory criteria. PPA costs are addressed in annual Power Supply Cost Recovery ("PSCR") proceedings and Renewable Energy ("RE") Plan proceedings. Projected PPA costs are included in the PSCR Plan and RE cases. Actual PPA costs are reconciled in the annual PSCR reconciliation with any over-recovery or under-recovery addressed in future PSCR proceedings or RE cost reconciliation proceedings. The cost of purchased power is passed through to customers without mark-up or earnings potential.

Q. How is the traditional regulatory model contrary to what a non-regulated business may experience?

A. A regulated utility choosing to enter into a PPA versus constructing or acquiring an asset is foregoing potential earnings; thereby, one might argue that any investor-owned utility ("IOU") decision to forgo an earnings opportunity would violate their fiduciary obligation to the IOU's owners.

Q. How does PA 341 provide the Commission the opportunity to address the aforementioned bias in the traditional regulatory model?

A. PA 341 permits the Commission to approve mechanisms which compensate utilities for entering into PPAs. Specifically, Section 6t(15) provides that:

> "For power purchase agreements that a utility enters into after the effective date of the amendatory act that added this section with an entity that is not affiliated with that utility, the commission shall consider and may authorize a financial incentive for that utility that does not exceed the utility's weighted average cost of capital."

Q. Does the FCM proposed by the Company meet the criteria established in Section 6t(15) of 2016 PA 341?

A. Yes.

Q. How should the FCM be reflected in customer rates?

A. Recovery through general base rate is appropriate. UPPCO proposes a levelized FCM charge based on a $/MWh that would allow for its recovery over the long-term through general base rates.

Q. Have any other Michigan utilities proposed an FCM?

A. Yes, Consumers Energy proposed an FCM in its IRP proceeding, Case No. U-20165. UPPCO's proposal is modeled very similarly to this proposal.

Q. Please describe the proposed FCM.

A. The fixed charge would be calculated as follows:

(a) Calculate the equity required to offset imputed debt for each year of the PPA. The imputed debt will equal the NPV of the PPA payments multiplied by 25% (PPA Imputed Debt = Required Equity Capital);

(b) Multiply the required equity capital resulting from the calculation in a) by the Company's authorized ROE from its most recent general electric rate case for PPAs supported by non-renewable generation assets or the authorized ROE in its Renewable Energy Plan for PPAs supported by renewable generation assets; and

(c) Gross up the results from the calculation in b) by the factor used for calculating the Company's revenue requirement in its most recent electric rate case.

Q. Please describe how the imputed debt level is derived?

A. There are a number of potential methodologies available to calculate the imputed debt created by a PPA. The most simple and straightforward methodology, which I propose the Commission adopt, would be to calculate the NPV of the PPA payments using the Company's Weighted Average Cost of Capital ("WACC") and apply a risk weighting of 25% to determine the percentage of the NPV that would be treated as debt. Given that PPA payments are similar to debt payments, calculating the NPV of those PPA payments would be akin to determining the face value of the debt being issued. This methodology is consistent with the methodology used by rating agencies and offers simplicity in determining the imputed debt of the PPA.

Q. Please describe UPPCO's rationale for the FCM?

A. The imputed debt created by the presence of the PPA is supported by the equity capital of the Company and, in order to maintain a balanced capital structure, the Company would need to have incremental equity available to support this imputed debt or, alternatively, the Company would need incremental earnings to support the Company's credit and ensure a fair return. The proposed incentive compensation mechanism would calculate the imputed debt of the PPA and allow the utility to earn compensation equal to the rate of return for the incremental equity used to the support the PPA.

Q. Please describe the rationale for creating a levelized cost for the compensation mechanism.

A. As the PPA reaches maturity, the amount of imputed debt decreases and therefore the required compensation would also decrease, which is akin to bond amortizing. To calculate the levelized cost, the NPV of the compensation payments is discounted at the authorized ROE and then levelized using the Company's WACC.

Q. Does the compensation mechanism, as described, meet the requirements of PA 341?

A. Yes. Because the compensation mechanism first calculates the imputed debt of the utility – this incremental debt is balanced with the equal equity to which the authorized ROE is applied, thus ensuring the compensation to the utility is weighted equally between equity and debt and therefore no greater than its WACC.

Q. Please provide UPPCO's calculation of its FCM charge.

A. As evidenced in Exhibit A-7 (GRH-7) PPA FCM, UPPCO calculates the annual FCM charge via the Imputed Debt method to be $__________ or a levelized $__________MWh.

Q. How does UPPCO represent the FCM charge in its revenue requirement calculation?

A. As UPPCO represents a Net Levelized Revenue Requirement value, UPPCO also utilizes the levelized FCM value in its calculation.

Q. When compared to an equivalent Investor Owned Scenario of an equivalent solar project size, how does the levelized Imputed Debt FCM value with a PPA compare to levelized Common Equity After Tax Return on Rate Base value?

A. The Imputed Debt value is $__________versus $__________ for the levelized Common Equity After Tax Return value.

**VIII. Rate Impact and Financial Information**

Q. What is the projected year impact of the PCA?

A. Both the RICE 2022 and Solar PPA solutions are intended to commence production by May 31, 2022. The Hydro Capacity solution, which is the reconfiguration of the meters for both the Hoist and McClure hydroelectric facilities, is intended to be operational by March 1, 2019.

Q. What are the key projects of the PCA that will have associated revenue requirements that UPPCO will calculate?

A. As defined earlier in my testimony defining the PCA, the following are the projects that will be evaluated:

- RICE 2022
- Solar PPA (with and without FCM)
- Hydro Capacity

Q. What financial inputs and assumptions were utilized to derive the Company's calculated PCA revenue requirements?

A. As evidenced in Exhibit A-8 (GRH-8) Summary Inputs and Results, the following financial inputs and assumptions are utilized to derive the Company's revenue requirement calculations.

- Project Name
- Depreciable Life
- Tax Life
- In Service Year
- In Service Quarter
- Construction Cost
- Federal Income Tax
- State Income Tax
- Effective Statutory Rate
- MI Property Tax
- Present Value Year
- Discount Rate
- Non-Gen Incremental O&M ($ Total)
- Non-Gen O&M Savings ($ Total)
- O&M Escalation Rate

Q. What key generation inputs and assumptions were utilized to derive the Company's calculated PCA revenue requirements?

A. As evidenced in Exhibit A-8 (GRH-8) Summary Inputs and Results, the following generation inputs and assumptions are utilized to derive the Company's revenue requirement calculations.

- Generation Fixed O&M ($ Total)
- Generation Variable O&M ($/MWH)
- Renewable Technology for ITC|PTC
- Eligible for ITC
- % Eligible for ITC (Default = 100%)
- Eligible for PTC
- Inflation Rate (PTC forecast)
- Are there avoided PSCR costs?
- 10 yr. Annual Generation (MWh)
- ZRC | Capacity (MW)
- No. of RECs
- REC Value ($/REC)

Q. What key IRP inputs and assumptions were utilized to derive the Company's calculated PCA revenue requirements?

A. As evidenced in Exhibit A-8 (GRH-8) Summary Inputs and Results, the following IRP inputs and assumptions are utilized to derive the Company's revenue requirement calculations.

- Name Plate
- Capital Cost ($/kW)

- Fixed O&M ($/kW-yr)
- Capacity Factor
- Non-Fuel Variable O&M ($/MWh)
- Fuel Cost ($/MWh)
- Fixed Price PPA)

Q. What additional assumptions did UPPCO make?

A. UPPCO made the following additional revenue requirement modeling assumptions:

- In-service dates: Book depreciation is calculated based on in-service quarter; tax depreciation is based on MACRS half-year convention, unless project is installed in Q4.
- Present value year: Input year for financial base year $ dollars.
- Production Tax Credit ("PTC"): Effective for wind resources (per workbook); applies to first 10 years of operation; phases out after 2019; resource may qualify for PTC or ITC (but not both); utilizes inflation rate to forecast PTC $/MWH value; and calculated by multiplying annual gen (MWH) by PTC $/MWH value.
- Investment Tax Credit ("ITC"): Effective for wind and solar resources (per workbook); wind phases out after 2019; solar steps down to 10% at 2022; resource may qualify for PTC or ITC (but not both); and ITC is normalized over the life of the asset and appears as an adjustment to rate base.
- UPPCO sourced any PTC and ITC assumptions and phase-outs from www.dsireusa.org.

Q. Please identify the incremental revenue requirement exhibits that derive the Company's PCA revenue requirement calculations.

A. Please reference the following exhibits for the detailed calculation that support Exhibit A-8 (GRH-8) Summary Inputs and Outputs:

- Exhibit A-8 (GRH-8) Summary Inputs and Outputs
- Exhibit A-9 (GRH-9) Revenue Requirement Summary
- Exhibit A-10 (GRH-10) RICE 2022 Revenue Requirement
- Exhibit A-11 (GRH-11) Solar PPA Revenue Requirement
- Exhibit A-12 (GRH-12) Hydro Capacity Revenue Requirement
- Exhibit A-7 (GRH-7) PPA FCM

Q. Please identify the key components of the supporting revenue requirement exhibits, as noted above.

A. The revenue requirement exhibits include the calculation of the following incremental components:

- Projected year-on-year impact of the PCA
- Revenue requirement, including production and avoided PSCR energy and capacity costs
- Rate base
- Cumulative book value
- Variable O&M
- Fixed O&M
- Fuel

Q. Are emissions and effluent additive costs included in the revenue requirement analysis?

A. No. Based on upon the prospective bids from the ongoing RFP process for RICE 2022, UPPCO will include any updated costs prior to the 150-day milestone afforded by MCL 460.6t (7).

Q. Do you present the PCA revenue requirement results on a levelized basis?

A. Yes. As evidenced in Exhibit A-8 (GRH-8) Summary Inputs and Results, I derive levelized values for (1) revenue requirements, (2) PSCR savings, and (3) net levelized revenue requirements which represents the sum of the revenue requirements and PSCR savings and cost basis, as well as a $/MWh basis.

Q. Please summarize how you segmented the incremental revenue requirement analysis.

A. As evidenced in Exhibit A-8 (GRH-8) Summary Inputs and Results, UPPCO takes the Levelized Revenue Requirement values as seen on line 43 and adds the value to the associated Levelized PSCR Savings as seen on line 44 in order to solve for a Net Levelized Revenue Requirement, as demonstrated on line 45.

Q. Please summarize the Levelized Revenue Requirements for UPPCO's PCA.

A. As evidenced in Exhibit A-8 (GRH-8) Summary Inputs and Results, all three components of UPPCO's PCA: RICE 2022, Solar PPA, and Hydro Capacity have the following associated and incremental revenue requirement impacts:

- On a levelized basis, RICE 2022 has a levelized revenue requirement of $_____________(line 43, column b).
- On a levelized basis, Solar PPA has a levelized revenue requirement of $___________ (line 43, column d) – as this value represents the obligation of the long-term PPA. When adding the levelized FCM value of $___________(line 57, column d), the levelized revenue requirement with FCM is $_______________.
- On a levelized basis, Hydro Capacity has a levelized revenue requirement of $______ (line 43, column e).

Q. Please summarize the Power Supply Cost Recovery ("PSCR") Savings for UPPCO's PCA.

A. As evidenced in Exhibit A-8 (GRH-8) Summary Inputs and Results, all three components of UPPCO's PCA: RICE 2022, Solar PPA, and Hydro Capacity have associated PSCR savings due to avoided PSCR costs:

- On a levelized basis, RICE 2022 has $____________ (line 44, column b) of PSCR savings.
- On a levelized basis, Solar PPA has $____________ (line 44, column d) PSCR savings.
- On a levelized basis, Hydro Capacity has $__________ (line 44, column e) PSCR savings.

Q. Please summarize the Net Levelized Revenue Requirement for UPPCO's PCA.

A. As evidenced in Exhibit A-8 (GRH-8) Summary Inputs and Results, the Net Levelized Revenue Requirement for the components of the PCA are:

- On a levelized basis, RICE 2022 has an incremental revenue requirement of $____________ (line 45, column b).
- On a levelized basis, Solar PPA has an incremental revenue requirement of ($___________) (line 45, column d). When adding the FCM value of $____________ (line 57, column d), the Solar PPA has an incremental revenue requirement of ($_____________).
- On a levelized basis, Hydro Capacity has an incremental revenue requirement of ($___________) (line 45, column e).

Q. In total, what is the PCA revenue requirement for all three components: RICE 2022, Solar PPA, and Hydro Capacity?

A. As evidenced in Exhibit A-8 (GRH-8) Summary Inputs and Results:

- On a levelized basis, the total incremental revenue requirement is $________________ (line 53, column b), which includes the firm payment obligations from a 25-year PPA. When adding the FCM value of $___________ (line 57, column d), the total incremental revenue requirement is $_____________ (line 53, column d).
- On a levelized basis, the total PSCR Savings has an incremental revenue requirement of ($___________) (line 54, column d).
- On a levelized basis, the total incremental net revenue requirement is ($___________) (line 55, column b).  When adding the FCM value of $___________ (line 57, column d), the total incremental revenue requirement is ($___________) (line 55, column d).

**Section IX:  IRP Request for Approval**

Q.	Please summarize what the Company is requesting in this filing?

A.	The Company is requesting that the Commission:

i. Find that the Company's IRP and PCA represent the most reasonable and prudent means of meeting the electric utility's energy and capacity needs.  In reaching that finding, the Company further requests that the Commission:

   a. Approve the Company's proposal to enter into a 125 MW, 25-year solar PPA at a fixed price, with a Company option to purchase up to 53% of the solar generating facility after a minimum of five and a half years;
   b. Approve the FCM and $/MWh rider, as proposed, to adequately compensate the utility for the risks associated with imputed debt regarding both the size and term of the PPA;

c. Approve the Company's proposal for the construction of up to 20 MW of RICE generation to be located in or around ___________, Michigan in order to provide improved reliability to UPPCO's customers on the eastern end of its service territory and to provide load balancing generation needed because of the increasing prevalence on intermittent, renewable generation.

d. Approve the Company's proposal to increase and transition its EWR savings targets to 1.5% or whichever target can be reasonably and prudently cost justified for its customers by the end of its intended next two-year plan pursuant to the outcome of a separate contested case proceeding.

e. Due to the recent catastrophic mechanical failure at UPPCO's Portage generation facility and pending the current and ongoing insurance investigation and evaluation process, UPPCO seeks approval to apply any insurance payout as a direct credit to the proposed RICE generation, thereby directly lowering costs to customers.

f. Approve UPPCO's proposal to set its PURPA avoided cost rates at the equivalent capacity value of the Company's existing PPAs and the energy value at the LMP, market-based avoided cost, and recognize UPPCO's demonstration of a forward looking 10 years of capacity.

g. Approve the establishment of a regulatory asset which provides for the full recovery of all IRP related costs pursuant to Section 6t of 2016 PA 341, MCL 460.6t, the Commission's December 20, 2017 and all other applicable laws. UPPCO proposes to amortize the value of the regulatory asset over a rolling five-year term so that it is fully amortized in advance of the Commission's ruling in UPPCO's next IRP case filing which will take place five years after February 12, 2019.

Q. Does this complete your direct testimony?

A. Yes, it does.

# INTEGRATED RESOURCE PLANNING STUDY

**BLACK & VEATCH PROJECT NO. 196843**



**PREPARED FOR**

Upper Peninsula Power Company

11 FEBRUARY, 2018

# Special Notice

Acceptance of this report, or use of any information contained in this report, by any party receiving this report (each a “Recipient”) shall constitute an acknowledgement and acceptance by such Recipient of, and agreement by such Recipient to be bound by, the following:

(1) This report was prepared for Upper Peninsula Power Company (“Client”) by Black & Veatch Ltd. of Michigan (“Black & Veatch”) and is based on information not within the control of Black & Veatch. In preparing this report, Black & Veatch has assumed that the information, both verbal and written, provided by others is complete and correct. Black & Veatch does not guarantee the accuracy of the information, data or opinions contained in this report and does not represent or warrant that the information contained in this report is sufficient or appropriate for any purpose.

(2) This report should not be construed as an invitation or inducement to any Recipient or other party to engage or otherwise participate in the proposed or any other transaction, to provide any financing, or to make any investment. Recipient acknowledges and agrees that it is not reasonably feasible for Black & Veatch to conduct a comprehensive investigation and make definitive determinations for the compensation provided and without thorough verification of the information upon which the Services were performed, and therefore Black & Veatch can offer no guarantee or assurances that any facts, observations, analysis, projections, opinions, or other matters contained in the report will be more accurate, either at the time the report is issued or at any other time.

(3) Recipient is not entitled to make any copies of any portion of this report, use extracts therefrom or transmit any part thereof to any other party in any form, including without limitation electronic or printed media of any kind.

(4) TO THE FULLEST EXTENT PERMITTED BY LAW, BLACK & VEATCH’S TOTAL LIABILITY, ON A CUMULATIVE AND AGGREGATE BASIS, TO CLIENT AND ALL RECIPIENTS AND OTHER PARTIES, RESULTING FROM BLACK & VEATCH’S ACTIONS IN RELATION TO THE CREATION AND DISSEMINATION OF THIS REPORT, WILL BE LIMITED TO THE AMOUNT OF COMPENSATION (EXCLUSIVE OF THE REIMBURSEMENT OF COSTS AND EXPENSES) ACTUALLY RECEIVED BY BLACK & VEATCH FROM CLIENT FOR THE CREATION OF THIS REPORT UNDER THE IESA. Recipient hereby waives any right to seek or collect damages in excess thereof and releases Black & Veatch from any and all damages or losses which, if required to be paid to Recipient, would result in Black & Veatch paying total damages to any and all parties, including Client and all Recipients, in an amount that would exceed the limit set forth in the previous sentence.

The exclusive venue for any claim, cause of action, legal proceeding, or lawsuit relating to this report shall be the state and federal courts located in New York City, Borough of Manhattan, State of New York. Recipient and any other party irrevocably waive each argument, objection, defense, assertion, or claim that venue is improper for any reason in the state and federal courts in New York City, Borough of Manhattan, State of New York for any claim, cause of action, legal proceeding, or lawsuit brought in said courts or that such claims have been brought in an inconvenient forum.

The above terms and conditions are governed by and shall be governed by and construed in accordance with the laws of the State of New York, without giving effect to the conflicts of laws principles thereof other than Sections 5-1401 and 5-1402 of the General Obligations Law of the State of New York.

IF ANY RECIPIENT IS NOT WILLING TO ACKNOWLEDGE AND ACCEPT, OR AGREE TO, THE TERMS SET FORTH ABOVE, IT MUST RETURN THIS REPORT TO BLACK & VEATCH IMMEDIATELY WITHOUT MAKING ANY COPIES THEREOF, EXTRACTS THEREFROM OR USE (INCLUDING DISCLOSURE) THEREOF. A RECIPIENT’S FAILURE SO

TO RETURN THIS REPORT SHALL CONSTITUTE ITS ACKNOWLEDGEMENT AND ACCEPTANCE OF AND AGREEMENT TO THE TERMS SET FORTH ABOVE.

# Table of Contents

## LIST OF TABLES

## LIST OF FIGURES

# 1.0 Executive Summary

Black & Veatch Ltd. of Michigan, LLC (Black & Veatch) was engaged by the Upper Peninsula Power Company (UPPCO) to develop an integrated resource plan (IRP) to facilitate the selection of future supply options for the next twenty years (2018-2037). UPPCO is a regulated electric utility company, with generation and distribution assets which serve customers in the Upper Peninsula of Michigan. UPPCO is also a member of the Midcontinent Independent System Operator, Inc. (MISO), which enables UPPCO to purchase and sell energy, capacity and ancillary services to the MISO market.

An IRP is a long term comprehensive plan developed to help ensure that the utility can meet its customer's annual peak and energy needs over the planning horizon in a cost-effective manner, while also meeting system reliability needs, state policy goals. The IRP summarized in the Report provides an assessment of the future electric energy needs of UPPCO customers over the next twenty years and summarizes the preferred plan for meeting those needs in a safe, reliable, cost-effective and environmentally responsible manner.

This IRP was developed in order to address requirements established by the Michigan Public Service Commission (MPSC) as outlined in guidelines issued on November 21, 2017. [1] In addition, UPPCO requested specific study alternatives to assess the cost of self-generating capacity to reduce reliance on market purchases and exposure to future cost uncertainty and volatility. The recommended plan meets Michigan's renewable portfolio standard (RPS) 2021 renewable energy target of 15 percent, as well as the 2015 and 2019 intermediate targets of 10 percent and 12.5 percent, respectively. The load forecast reflects a continuation of UPPCO's long history of encouraging energy efficiency and demand reduction.

This Report and the accompanying appendices describe the analyses conducted and the underlying assumptions that produced a 20-Year Resource Plan to meet customers' energy needs through 2037. Incorporated into the IRP are anticipated changes facing UPPCO, the utility industry, and Michigan over the 20-year planning period.

Although significant changes within the electric utility industry are anticipated to occur over the 20-year planning horizon for the IRP, UPPCO must plan for sufficiency supplies of electricity while also maintaining reasonable and fair prices and achieving safety, environmental, operational, and reliability goals. During the preparation of the IRP, Black & Veatch considered a wide variety of supply and demand-side alternatives that could meet these many objectives. The IRP process has also taken into consideration the need to establish a flexible plan that will allow UPPCO to respond to uncertainty regarding technological and future regulatory change. Goals established by UPPCO to guide development of the IRP are presented in Figure 1-1.

[1] Michigan Integrated Resource Planning Parameters pursuant to Public Act 341 of 2016, Section 6t; https://www.michigan.gov/documents/mpsc/11-21-2017_MIRPP_Final_606706_7.pdf

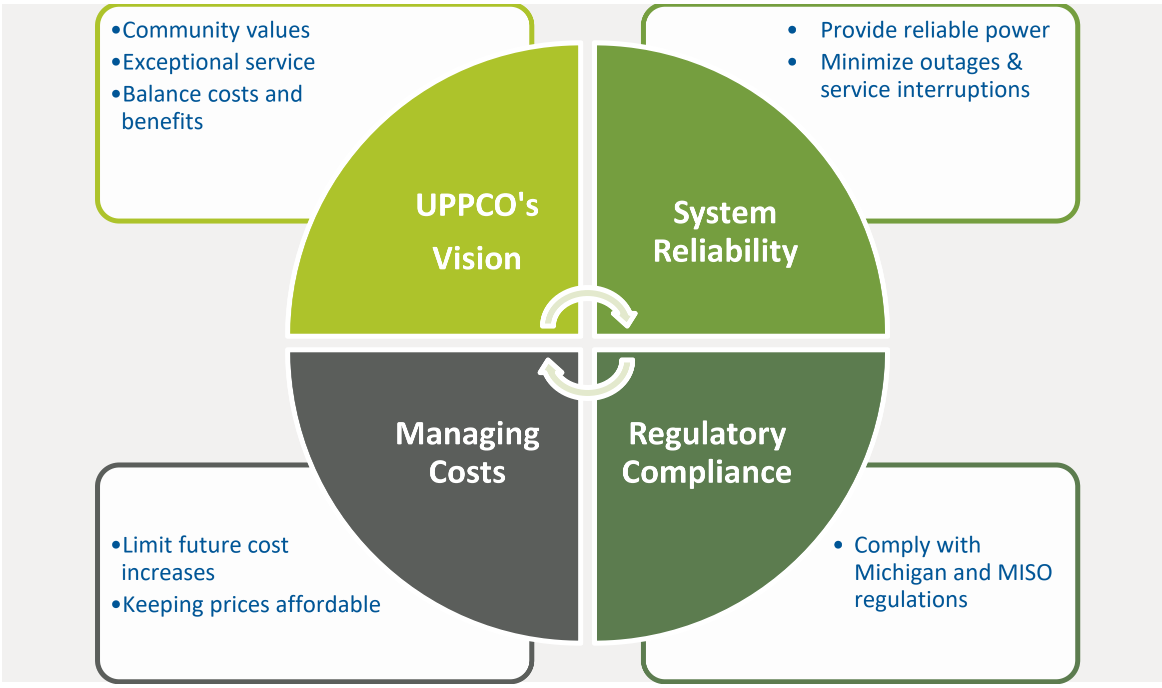



**Figure 1-1 IRP Objectives**

A summary of the 20-Year Resource Plan is provided in Section 1.2. Supporting information, including studies, data, analyses and results plus associated exhibits for the IRP analysis is provided in the following sections of the Report:

- Section 2.0 Purpose and Background
- Section 3.0 Existing Resources and System Description
- Section 4.0 Demand Forecast
- Section 5.0 Demand Response Resources
- Section 6.0 Demonstration of Need
- Section 7.0 Supply Side Resources
- Section 8.0 Transmission and Distribution System
- Section 9.0 Scenario Analysis and Results
- Section 10.0 IRP Recommendations
- Section 11.0 Risk Analysis
- Section 12.0 Rate Impact

Standardized tables requested by the MPSC are located in Appendix A and Appendix B. The organization and contents of this IRP reflect the requirements established in the MPSC IRP guidelines.

## 1.1 UTILITY BACKGROUND

UPPCO was founded as Peninsula Electric Light and Power Company in 1884, and merged with Houghton County Electric Light Company, Copper District Power Company, and Iron Range Light and Power to form UPPCO in 1947. UPPCO was acquired by Wisconsin Public Service Resources Corporation (Integrys) in 1998, but returned to stand-alone independent operation in 2014.

At the time of this Report, UPPCO serves approximately 52,000 electric retail customers in ten of the 15 counties in Michigan's upper peninsula. UPPCO's service territory of 4,460 square miles covers primarily rural countryside, as shown in Figure 1-2. UPPCO's serves residential, small commercial, medium commercial, and large industrial customers, including forest products, tourism and manufacturing.

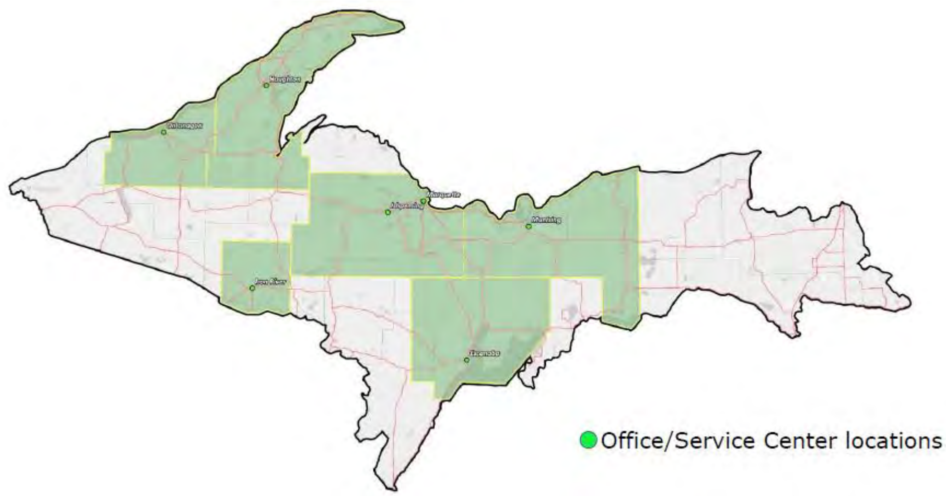



**Figure 1-2 UPPCO's Service Territory**

UPPCO's generation assets include seven hydroelectric renewable energy generation facilities and two combustion turbines providing a total generation capacity of approximately 80 megawatts. UPPCO also owns approximately 4,354 distribution line miles through Michigan's upper peninsula and operates 58 distribution substations.

UPPCO currently fills its non-Real Time Market Pricing (RTMP) energy needs via a combination of generation from its owned assets, two hydroelectric PPAs, short-term firm delivery PPA's, and spot market purchases from the MISO market, as summarized below in Figure 1-3.

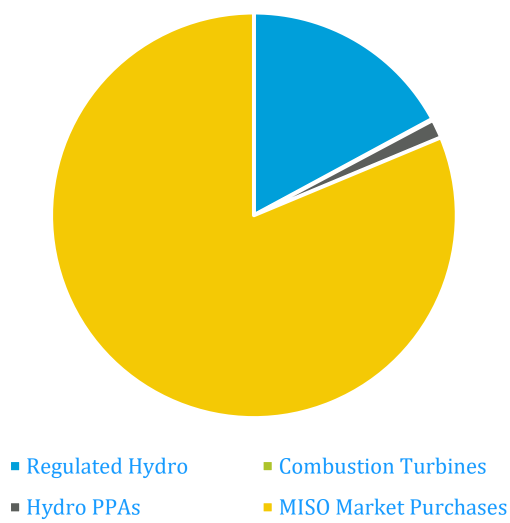



**Figure 1-3 Sources of UPPCO Energy**

For 2018, UPPCO has purchased approximately 70.7 percent of its energy needs through a series of short term power purchase agreements (PPAs) following competitive auctions, leaving the company with approximately 11 percent spot market exposure. For 2019 calendar year, UPPCO has also locked in 25 MW of around-the-clock energy, as well as various short-term on and off-peak purchases, leaving its projected non-RTMP energy needs 84 percent covered.

UPPCO is regulated by the Federal Energy Regulatory Commission (FERC) and the Michigan Public Service Commission (MPSC).

## 1.2 SUMMARY OF 20 YEAR RESOURCE PLAN

The UPPCO IRP, described herein, was based on the load forecast developed by UPPCO described in Section 1.0. The competing expansion plan scenarios were designed to meet the UPPCO load requirements and other planning objectives stated herein.

Section 6.1 of this report explains that UPPCO has sufficient generating capacity to meet the capacity and energy needs through the 2037 planning period, and a business as usual (BAU) existing system scenario would also be adequate to meet Michigan's renewable generation and environmental mandates. However, UPPCO's current energy procurement strategy is heavily dependent upon market and power purchase agreement (PPA) purchases, exposing UPPCO and its customers to potential price volatility stemming from the predominance of natural gas generation units setting the margin in the MISO market. As a result, several expansion plan scenarios that increase the percentage of UPPCO's owned generation, while continuing to optimize UPPCO's portfolio, have been evaluated. The planning reserve margin (PRM), renewable portfolio standard (RPS), and incremental energy efficiency (EE) as a percentage of energy demand, must meet or exceed the minimum requirements in order for any potential scenario to be viable. PRM must be at least 8.4 percent, RPS must be 15 percent from 2021 onwards, and the EE + RPS percentage must be 35 percent from 2025 onwards.

Based on the supply side resource characteristics and additional assumptions and methods described in Section 7.0, the long-term cumulative present worth cost (CPWC) of thirty three competing resource expansion plans are developed and presented in Section 9.0. The CPWC includes all incremental costs of the planning period, as shown in Figure 1-4.

| | | | | | | |
|---|---|---|---|---|---|---|
| **Cumulative Present Worth Cost** | = | **PPA Energy Purchases** | + | **Net MISO Market Energy Purchases** | + | **PPA Capacity Purchases** |
| | | Cost associated with the Hydro PPA's and the PPA's for energy market purchases. | | Net Revenue from exclusively the MISO energy market | | Fixed costs associated with capacity purchases from Hydro PPA's, PPA's for capacity market purchases, and MISO capacity purchases. |
| **Energy Efficiency Package Investments** | + | **Generation Fixed Costs** | + | **Generation Variable Costs** | + | **New Generation Fixed Investment** |
| Investment costs associated with energy efficiency packages. | | Fixed costs associated with the additions of new generation assets including solar, thermal, winds, and oil-fired. | | Variable costs associated with the additions of new generation assets including solar, thermal, winds, and oil-fired. | | CAPEX costs associated with the additions of new generation assets including solar, thermal, winds, and biomass. |

**Figure 1-4 CPWC Component Breakdown**

Those components are then tabulated for each year of the 20 year planning period, discounted, and aggregated into a single CPWC which may be compared across all scenarios.

The viability of each course of action modeled by Black & Veatch was compared on a CPWC basis to a relevant BAU case, in order to isolate and evaluate the benefits of each course of action. The BAU Base case assumes BAU operations, that is, UPPCO would not pursue any new sources of energy and capacity, as well as base case best estimate assumptions for variable such as load and gas prices. Sensitivity cases for different courses of action are subsequently compared to revised BAU cases, which each consider changed variables according to the sensitivity but no new courses of action.

Black & Veatch understands that the state of Michigan requires analyses of the following three scenarios: (BAU), emerging technology (Emerging Technology), and high energy market prices, as discussed further in Section 2.2. Black & Veatch conducted analyses of the cumulative present worth cost (CPWC) and levelized cost over a 20-year period for several unique possible cases within each of the three scenarios as summarized in Figure 1-5 and Table 1-1. Twenty BAU, five emerging technology, and eight high market cases were analyzed for a total of 33 unique cases.

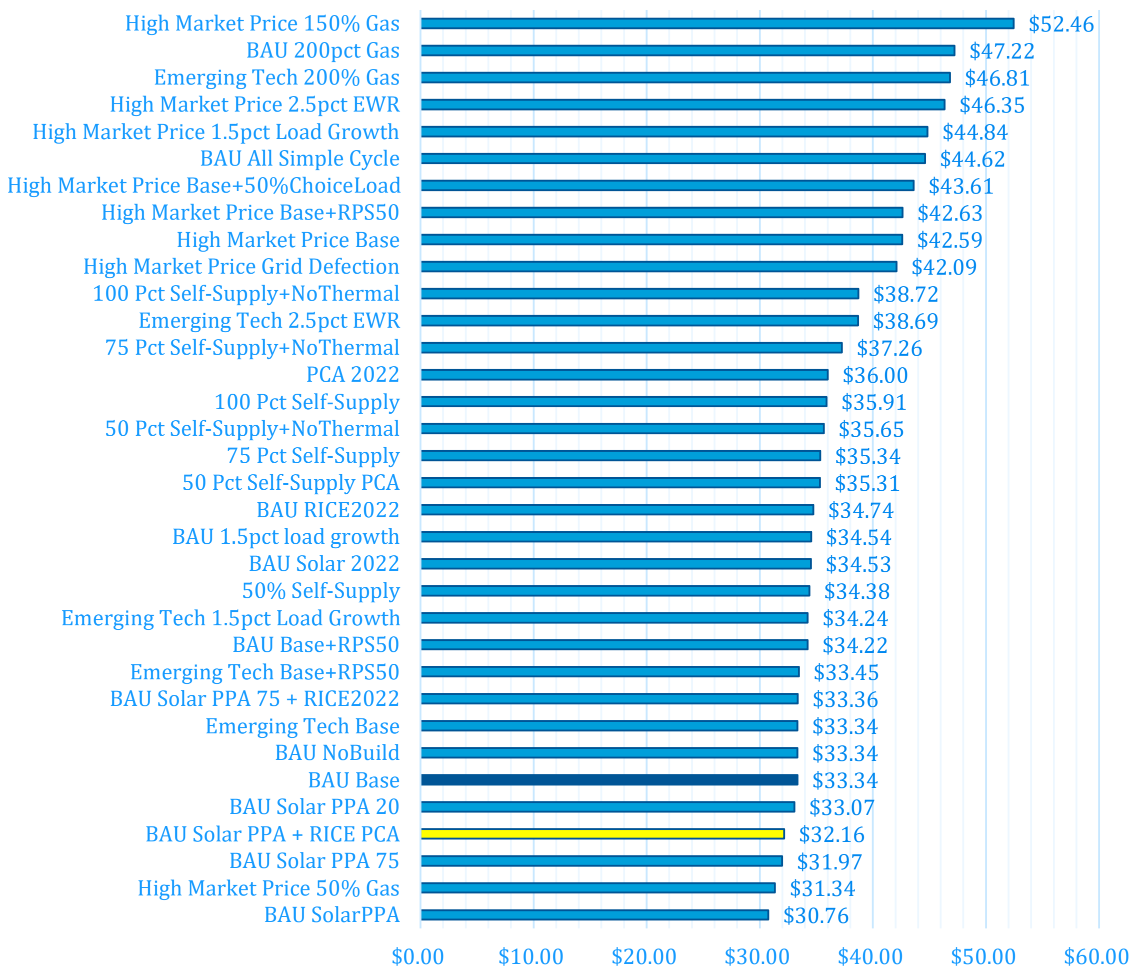



**Figure 1-5 Comparison of All Scenario Levelized Costs ($/MWh)**

Black & Veatch notes that many of these scenarios evaluated in this IRP were selected in order to comply with Michigan requirements or to sensitize different energy procurement strategies to technology and market changes, but do not represent a selectable IRP case to UPPCO (e.g. UPPCO cannot chose higher or lower MISO market costs, and those scenarios should only be compared to their respective base cases). Those scenarios which are informative but not selectable are identified in Table 1-1.

### Table 1-1 CPWC Comparison of All IRP Cases ($000)

| SCENARIO | CPWC ($000) | RANK (CPWC) | CPWC DELTA (%) | ENERGY (GWh) | LEVELIZED COST ($/MWh) | SELECTABLE CASE? (Y/N) |
|---|---|---|---|---|---|---|
| BAU Base | 199,769 | 5 | 0% | 6,065 | $32.94 | No |
| 100% Self-Supply | 215,378 | 17 | 8% | 6,065 | $35.51 | Yes |
| 50% Self-Supply | 206,117 | 11 | 3% | 6,065 | $33.98 | Yes |
| 50% Self-Supply Solar + Thermal | 211,768 | 14 | 6% | 6,065 | $34.92 | Yes |
| 75% Self-Supply | 211,939 | 15 | 6% | 6,065 | $34.94 | Yes |
| 100% Self-Supply+NoThermal | 232,409 | 21 | 16% | 6,065 | $38.32 | Yes |
| 50% Self-Supply+NoThermal | 213,818 | 16 | 7% | 6,065 | $35.25 | Yes |
| 75% Self-Supply+NoThermal | 223,567 | 19 | 12% | 6,065 | $36.86 | Yes |
| BAU Base+RPS50 | 205,150 | 10 | 3% | 6,065 | $33.83 | No |
| BAU 1.5% load growth | 237,545 | 23 | 19% | 6,951 | $34.18 | No |
| BAU 200% Gas | 283,961 | 30 | 42% | 6,065 | $46.82 | No |
| BAU All Simple Cycle | 263,057 | 27 | 32% | 6,065 | $43.37 | Yes |
| **BAU Solar PPA 125 + RICE PCA** | **195,054** | **4** | **-2%** | **6,064** | **$32.16** | **Yes** |
| BAU Solar PPA 125 | 186,563 | 2 | -7% | 6,065 | $30.76 | Yes |
| BAU Solar PPA 75 | 193,904 | 3 | -3% | 6,065 | $31.97 | Yes |
| BAU Solar PPA 20 | 200,558 | 8 | 0% | 6,065 | $33.07 | Yes |
| BAU Base Case | 202,182 | 9 | 1% | 6,064 | $33.34 | Yes |
| BAU Solar 2022 | 209,426 | 12 | 5% | 6,065 | $34.53 | Yes |
| BAU RICE 2022 | 210,672 | 13 | 5% | 6,064 | $34.74 | Yes |
| BAU PCA 2022 | 218,367 | 18 | 9% | 6,066 | $36.00 | Yes |

| | | | | | | |
|---|---|---|---|---|---|---|
| Emerging Technology 1.5% Load Growth | 235,443 | 22 | 18% | 6,951 | $33.87 | No |
| Emerging Technology 2.5% EWR | 232,234 | 20 | 16% | 6,065 | $38.29 | No |
| Emerging Technology 200% Gas | 284,235 | 31 | 42% | 6,065 | $46.86 | No |
| Emerging Technology Base | 199,769 | 5 | 0% | 6,065 | $32.94 | No |
| Emerging Technology Base+RPS50 | 200,483 | 7 | 0% | 6,065 | $33.06 | No |
| High Market Price 1.5% Load Growth | 307,763 | 32 | 54% | 6,951 | $44.28 | No |
| High Market Price 150% Gas | 314,707 | 33 | 58% | 6,065 | $51.89 | No |
| High Market Price 2.5% EWR | 277,319 | 28 | 39% | 6,065 | $45.72 | No |
| Low Market Price 50% Gas | 186,342 | 1 | -7% | 6,065 | $30.72 | No |
| High Market Price Base | 254,562 | 25 | 27% | 6,065 | $41.97 | No |
| High Market Price Base+50% ChoiceLoad | 281,195 | 29 | 41% | 6,540 | $43.00 | No |
| High Market Price Base+RPS50 | 254,768 | 26 | 28% | 6,065 | $42.01 | No |
| High Market Price Grid Defection | 244,250 | 24 | 22% | 5,889 | $41.47 | No |

The results of the expansion planning scenario analysis are reported in Section 9.0. Black & Veatch's recommendations based on those results as well as discussion with UPPCO recording their system needs and priorities are provided in Section 9.1.17, and additional sensitivity analysis of key cost drivers which could affect the economics and preference of these scenarios is provided in 11.0.

Overall, Black & Veatch has recommended the BAU Solar PPA 125 + RICE Preferred Course of Action (PCA) scenario, under which UPPCO would increase the overall portion of its energy needs derived from non-MISO market assets through a 125 MW solar power purchase agreement (PPA), in addition to owning a new reciprocating internal combustion engine (RICE) thermal generation unit.

When comparing the Solar PPA 125 + RICE PCA scenario's CPWC to the current BAU Base scenario's CPWC, the Solar PPA 125 PCA scenario's CPWC is approximately 7 percent lower. In addition to a lower CPWC, the PCA reduces UPPCO's heavy reliance on market purchases and market exposure and diversifies UPPCO's energy portfolio. When compared to the thirty two other alternative scenarios, the Solar PPA 125 + RICE PCA scenario results in one of the lowest CPWCs (ranked 3rd out of 33), but is still not the lowest CPWC option.

As discussed in Sections 9.0 and 9.1.17, the Solar PPA 125 + RICE PCA scenario provides additional benefits to UPPCO beyond a relatively low CPWC, which UPPCO must consider in its mission to provide its customers with reliable power.

When compared to other low CPWC alternate scenarios, the Solar PPA 125 + RICE PCA scenario provides among the greatest diversity of energy resources. This helps to reduce exposure to risks associated with any particular technology or fuel type. By having a balanced mix of resources, the risk associated with fuel costs, fuel supply disruption and technology risks can be avoided.

The Solar PPA 125 + RICE PCA scenario also minimizes exposure to potentially volatile fuel and spot market prices. By adding non-MISO market, UPPCO's reliance upon the heavily natural gas-influenced MISO market is reduced, and by providing that capacity via solar and RICE, exposure to gas prices is reduced further.

# 2.0 Purpose and Background

This section provides an overview of the integrated resource planning process, a summary of relevant regulatory policies that guide development of the IRP, including legislation and related regulatory requirements. A summary level description of the methodology used to perform study evaluations is also provided; the methodology is further described later in the Report. This section also describes the public stakeholder process conducted by UPPCO to welcome input into the IRP process.

## 2.1 OVERVIEW OF INTEGRATED RESOURCE PLANNING PROCESS

Integrated resource planning is a process undertaken by utilities to identify the long-term plan that provides adequate resources to meet future peak and energy needs, while also achieving other utility goals. These additional goals include maintaining a targeted reserve margin to help ensure system reliability, and achieving a reasonable balance between fiscal responsibility and environmental stewardship. In this manner, effective resource planning offers economic benefits to consumers, while minimizing environmental impacts. An effective resource plan should also provide the utility with flexibility to accommodate uncertainties and risk related to future conditions, including commodity pricing risk, technological change, and regulatory change.

IRPs require the use of sophisticated analytical tools that allow comparisons of the costs and benefits among alternative supply side and demand side resource options that, together, may constitute a long-term expansion plan. Most commonly, detailed computer models that simulate utility operation on an hour-by-hour basis are used to develop the long-term costs of an expansion plan. Multiple expansion plans are developed and compared in an IRP analysis to determine the best long-range plan for the utility. Supply side options typically include the evaluation of conventional resources, renewable energy resources, and distributed energy resources. Demand side options can include demand response programs, energy efficiency programs, and other "behind the meter" options, all of which can serve to reduce the overall utility load.

The key steps of IRP development undertaken by Black & Veatch are shown in Figure 2-1.


**Figure 2-1 Black & Veatch's Integrated Resource Planning Process**

Black & Veatch's first step is to characterize existing generating resources to understand the system conditions and characteristics, including performance, costs, and reliability. Black & Veatch then works closely with the client to identify future goals and constraints, which pertain to retirement plans, upgrades, environmental considerations, fuel diversity, reliability constraints, and other goals or concerns. A load forecast is then created to ensure sufficient capacity will be able to be maintained to cover projected peak demands plus reserve margins for all years during the 20-year planning horizon. Once these steps are completed, Black & Veatch looks to develop generating resource alternatives that consider various capacity and energy alternatives which can reliably and cost effectively meet future projected capacity and energy requirements, while meeting such goals as renewable energy generation, demand response, and intermittent capacity needs. Black & Veatch utilizes a fundamental market model and key assumptions of energy efficiency trends, fuel price forecast, reliability concerns, emission prices, and other sensitives, to forecast future wholesale market prices. The fundamental market model is created by using the PROMOD IV cost model, which allows Black & Veatch to look at hourly production costs to project costs to meet power supply needs, which includes assumptions on long-term planning for hourly loads, economically dispatching units based on hour generation output and costs, and chronological constraints, such as ramp rates. The final step is for Black & Veatch to use the economic analysis and other models to determine the optimal generation resource portfolio based on the lowest cost portfolio which meets power supply needs and strategic objectives.

## 2.2 REGULATORY ENVIRONMENT

UPPCO is a regulated electric utility company, with generation and distribution assets which serve customers in the upper peninsula of Michigan, and must follow Michigan energy legislation. Such legislation as it pertains to this IRP is established by the MPSC. On December 21, 2016 the MPSC enacted public act (PA) 341, which requires all Michigan regulated utilities to file an IRP no later than April 2018, and then update each five years thereafter. PA 341 also established draft guidelines for what information, considerations, and analyses must be included in the IRP. On October 11, 2017, the MSPC issued order U-18461 requesting comments and feedback on the draft IRP guidelines established in PA 341. Based on that feedback, the MPSC finalized IRP guidelines with order U-18418 on November 21, 2017. This process is summarized below in Figure 2-2.

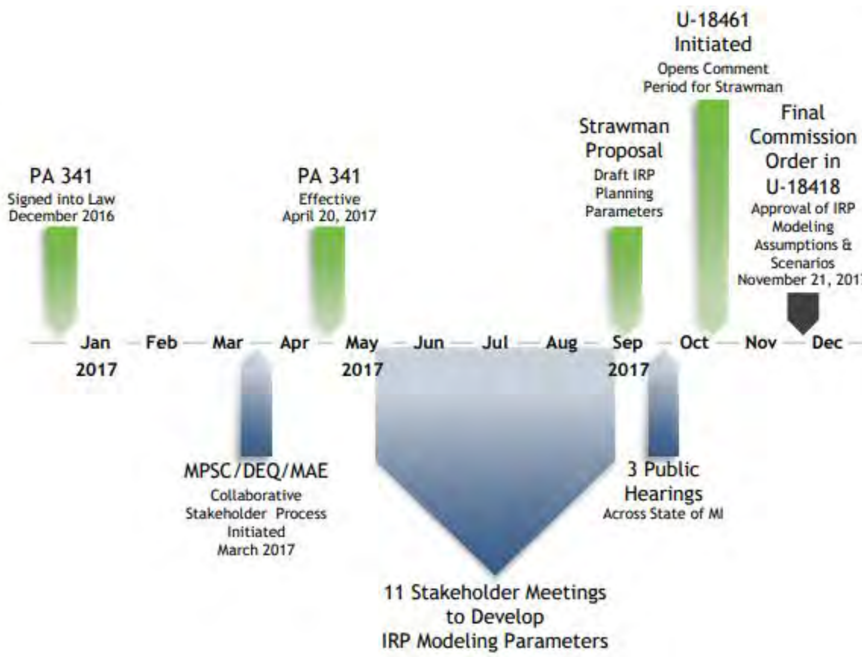



**Figure 2-2 Michigan IRP Establishment Process**

As noted in Section 1.2, all IRPs must consider certain modeling scenarios as summarized in Figure 2-3. Note that the high market price variant scenarios and environmental policy scenarios are specific to upper and lower peninsula utilities, respectively, and accordingly environmental policy scenarios are not applicable to UPPCO's IRP. In addition to these required scenarios, each utility may also define and evaluate additional scenarios to address the specific needs of their system.


**Figure 2-3 Michigan IRP Scenario Requirements**

The MPSC also requires specific inputs and assumptions behind the IRP to be made explicit, as summarized below:

- Forecasting
  - Long-term forecast of sales and peak demand under various scenarios.
  - Projected impact on rates for the periods covered.
  - An analysis of the cost, capacity factor, and viability of all reasonable generation options available to meet projected capacity needs.
  - Plans for meeting current and future capacity needs with cost estimates.
- Renewable Energy
  - Projected renewable energy purchased or produced.
  - An analysis of how combined renewable energy and energy waste reduction will compare to the state's 35 percent goal.
- Energy Waste Reduction
  - Plan for eliminating energy waste.
- Demand Response
  - Projected load management and demand response savings and costs from utility programs.
  - Forecast of utility's peak demand and the amount peak reduction it expects to achieve.
- Transmission Interconnections
  - An analysis of new or upgraded transmission options.
- Current/Projected Generation and Fuel
  - Current utility generation portfolio data
  - Project long-term firm gas transportation or storage contracts for any new generation.
  - Projected energy and capacity purchased or produced by the electric utility from a cogeneration resource.

Black & Veatch has reviewed these requirements, and has structured this Report to provide this information in each of the major Report sections, as well as appendices.

Finally, the MPSC establishes requirements for how each of the required and utility-opted scenarios be evaluated in the IRP to determine the most reasonable and prudent means of meeting energy and capacity needs by considering whether each scenario appropriately balances each of the following:

- Resource adequacy
- Compliance with applicable environmental regulations

- Competitive pricing
- Reliability
- Commodity price risks
- Diversity of generation supply
- Whether the proposed levels of peak load reduction and energy waste reduction are reasonable and cost effective

Black & Veatch has prepared this IRP in consideration of the aggregate of the above guidance and recommendations from the MPSC.

## 2.3 METHODOLOGY USED FOR ANALYSIS

Two commercial software models were utilized to support the analysis, PROMOD® and PLEXOS®, which are licensed by Black & Veatch from ABB/Ventyx and Energy Exemplar, respectfully. A model of the MISO market (MISO Model) was developed using PROMOD to simulate an hourly forecast of wholesale energy and capacity prices over the 20-year planning horizon of the IRP. The regional price forecast is used to establish prices at which UPPCO can sell into or purchase electricity from the MISO market over the study horizon. A model of the UPPCO system was also developed in PLEXOS to support the evaluation of the least cost expansion plan (UPPCO System Model). The UPPCO System Model incorporates specific generation parameters for existing UPPCO units and existing PPA purchases. Market prices from the MISO Model were used as inputs to determine the costs and revenue associated with serving load and selling power into the MISO market.

PLEXOS was selected for the evaluation of the least cost expansion plan due to its ability to simulate long-term resource expansion analysis based on a detailed representation of utility load shape(s), granular representation of generator operating characteristics and cost, and customizable constraints on system planning requirements and/or system operation. Examples of constraints or criteria that can be included in the model include a system planning reserve margin and target levels of renewable energy. Using such constraints and input data such as UPPCO's load forecast for energy and peak demand, PLEXOS determines the least cost expansion plan by assessing all possible combinations of expansion options for the time period under evaluation and selecting the plan that has the lowest costs, accounting for lifecycle investment costs, fuel costs, and fixed and variable operations and maintenance (O&M) costs.

## 2.4 OVERVIEW OF STAKEHOLDERS

When conducting an IRP, a utility will typically seek input and participation from several types of constituents, generally summarized in Figure 2-4.

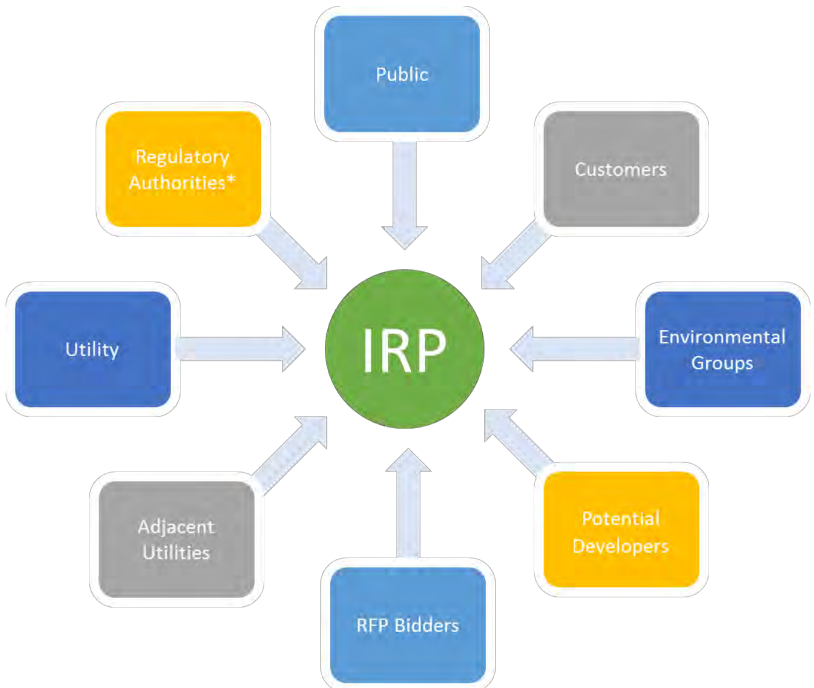



**Figure 2-4 Typical IRP Stakeholders**

Actions taken by UPPCO to reach out to potential stakeholders included a dedicated web page on the UPPCO website providing IRP information and contacts, and several town hall style stakeholder engagement meetings hosted in January 2018 at different locations throughout UPPCO's service area. UPPCO representatives also met one on one with larger industrial users .

Participants who joined the stakeholder planning process included those involved with economic development and commerce, customers, developers, governmental agencies, consultants, the press and other interested parties. Topics covered in these stakeholder meetings included:

- Increasing stakeholders' understanding of the IRP process, key assumptions, and challenges
- Understanding stakeholder concerns and concepts
- Providing a forum for productive stakeholder feedback at key points in the IRP process to inform UPPCOs decision making
- Explaining the need to comply with MPSC rules and objectives

This IRP benefited from UPPCO's public input process. The stakeholder process involved seeking groups who have an interest in UPPCO's future resource plan, and inviting their participation such that all relevant issues were identified and addressed. All participants were invited to complete a questionnaire, and those results were compiled and used to better quantify the stake holder perceptions.

Through this process, participants were engaged and involved early in the process. The end result was that the concerns and perspectives of all stakeholders were considered, with the resulting resource plan achieving what UPPCO considers to be an appropriate balance of utility and stakeholder objectives.

# 3.0 Existing Resources and System Description

Black & Veatch notes it is important to first consider UPPCO's existing resources as the status quo that the potential new supply side resource scenarios will be compared against. UPPCO currently meets its energy use requirements with the following four resources: (i) Regulated hydroelectric self-generation, (ii) oil fired combustion turbine self-generation, (iii) PPA energy, and (iv) wholesale market plus MISO spot market purchases. An overview of UPPCO's reliance on its existing resources is stated in the table below:

**Table 3-1 UPPCO's Current Energy Sources**

| RESOURCE TYPE | PERCENT OF ENERGY NEED FULFILLED |
|---|---|
| Hydro Generation | 17.1 |
| Thermal Generation | 0.10 |
| **Subtotal – Owned Generation** | **17.2** |
| Hydroelectric PPA Purchases | 1.50 |
| Short-Term PPA & MISO Market Purchases | 81.20 |
| **Subtotal – Purchased Energy** | **82.7** |

As shown above, UPPCO's current energy procurement strategy is heavily reliant upon market purchases, which leaves UPPCO exposed to market volatility risk, as further discussed in Section 6.3.

A map of UPPCO's owned generation fleet is shown in Figure 3-1.

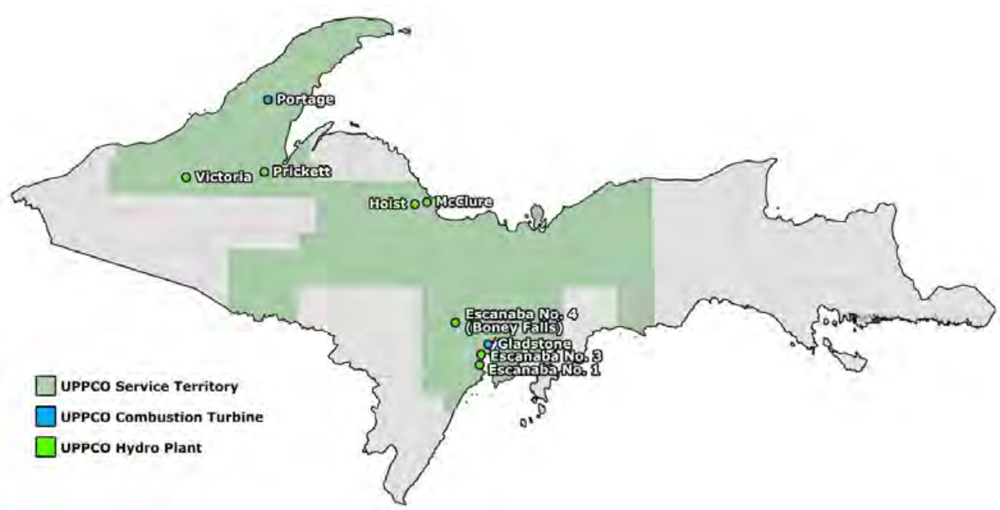



**Figure 3-1 UPPCO Owned Generation Assets**

A more detailed overview of UPPCO's existing major energy resources is provided in the following subsections.

## 3.1 HYDRO ENERGY RESOURCES

UPPCO's owns seven hydroelectric generation facilities, as summarized in Table 3-2.

**Table 3-2 UPPCO's Hydro Generation Assets**

| NAME | TYPE | NO. OF UNITS | INSTALLATION YEAR | CAPACITY (KW) |
|---|---|---|---|---|
| Hoist | Hydroelectric | 2 | 1916 | 3,400 |
| McClure | Hydroelectric | 2 | 1919 | 8,480 |
| Prickett | Hydroelectric | 2 | 1931 | 2,000 |
| Victoria | Hydroelectric | 2 | 1930 | 12,200 |
| Boney Falls* | Hydroelectric | 3 | 1921 | 4,100 |
| Escanaba 1* | Hydroelectric | 3 | 1907/1920 | 1,600 |
| Escanaba 3* | Hydroelectric | 2 | 1914 | 2,500 |
| *These facilities are owned by UPPCO, however all energy produced is sold exclusively to Verso. | | | | |

UPPCO's existing renewable energy resources are comprised of four regulated hydroelectric stations: Hoist, McClure, Prickett, and Victoria. Total capacity of these assets is 26,080 kW, with a summer capacity of 15,300 kW. Collectively. These hydro assets produce approximately 17.1 percent of UPPCO's energy needs, which is approximately **[100,00]** MWh annually. The direct cost of these hydro facilities is $**[27]**/MWh based on generation and O&M costs reported by UPPCO. After considering $**[40]** million in legacy FERC mandated capital spending from 2008-2012 and property tax impact, the all-in energy and capacity cost of the hydro assets is effectively $**[137]**/MWh.

One potential way that UPPCO can seek to reduce its reliance on market energy and capacity purchases would be through incremental generation at these existing facilities. UPPCO reports that its generation group completed a study of the feasibility of supplemental generation at two of the regulated hydro facilities, Hoist and McClure.

In addition to these regulated hydro facilities, UPPCO also owns Boney Falls, Escanaba 1, and Escanaba 3, which provide another 8.2 MW of name plate capacity (actual reported capacity is 1.3) , but are not connected to the grid to serve UPPCO's general load, and are fully contracted to a single industrial customer, Verso. Black & Veatch understands that UPPCO is investigating the cost/feasibility of connecting these three non-regulated hydro facilities to the grid and seeking to have these reclassified as regulated assets. UPPCO purchased these hydro facilities from a predecessor to Verso in 1997, then operated them under a 15 year PPA that was extended again for another 10 years in 2012. Power from the facilities is currently delivered directly and exclusively to

Verso's Escanaba paper mill, and is sold at low margin rates that do not adequately cover some significant repair/upgrade work required at the dams.

Should UPPCO be successful in adding incremental generation at Hoist and McClure and in moving its three non-regulated hydro generating facilities over to the regulated side, an average of **[31,600]** MWh of generation would be added to the regulated side.

## 3.2 THERMAL RESOURCES

UPPCO's existing thermal generation assets consist of two natural gas/fuel oil combustion turbines called Portage and Gladstone. Total capacity of the assets is 46,367 kW, with a summer capacity of 33,800 kW, as summarized below.

**Table 3-3 UPPCO's Thermal Energy Resources**

| NAME | TYPE | # OF UNITS | INSTALLATION YEAR | CAPACITY (KW) |
|---|---|---|---|---|
| Gladstone | Gas Turbine/Fuel Oil | 1 | 1975/1987 | 22,567 |
| Portage | Gas Turbine/ Fuel Oil | 1 | 1973 | 23,800 |

These combustion turbines produce approximately 0.1 percent of UPPCO's energy needs, which is approximately 837 MWh annually. The direct cost of the turbines is $**[305.76]**/MWh. Although the generation cost is relatively high compared to other energy sources available to UPPCO a dollar per megawatt basis, these combustion turbines are able to quickly ramp up for peaking needs, and have been utilized as a cheap way of providing capacity; costing only $**[452,000]** of balance sheet value for 33 MW of capacity. However, due to a turbine failure at the Portage unit in December 2018, UPPCO has elected to retire the Portage unit immediately in January 2019, and anticipates retiring the Gladstone unit in January 2022. Accordingly, IRP scenarios have been structured to meet UPPCO's energy needs without further reliance on these owned thermal resources.

## 3.3 PPA

UPPCO employs two types of PPA, those which provide UPPCO with a fixed capacity allocation which may be counted towards UPPCO's required capacity reserve margin, and those which allocate only energy to UPPCO.

A summary of UPPCO's current PPAs is provided in the following sections.

### 3.3.1 Capacity PPAs

As reported in MPSC Case No. U-18441, UPPCO has executed two capacity agreements which cover the planning years of 2017-2021 with Dairyland Power Cooperative (Dairyland) and Alliant Energy Corp Services (Alliant), as summarized in Tables 6-5 and 6-6. A planning year is defined as June 1st of one year through May 31st of the following year (i.e planning year 2018 is June 1, 2018 – May 31, 2019). Capacity, for the purpose of this agreement is known as Zonal Resource Credits (ZRC) which are sourced from LRZ 2. One ZRC represents one MW of unforced capacity. UPPCO has planned to purchase 25 ZRCs in the 2017-2019 planning years, and then reduce to 20 ZRCs for the 2020 and 2021 planning years.

**Table 3-4 Alliant Energy ZRC Overview**

| PLANNING YEAR | NUMBER OF ZRCS | CONTRACT PRICE ($/ZRC/YEAR) | PURCHASE PRICE |
|---|---|---|---|
| 2017 | 25 | $25,200 | $630,000 |
| 2018 | 25 | $30,000 | $750,000 |
| 2019 | 25 | $36,000 | $900,000 |

**Table 3-5 Dairyland ZRC Overview**

| PLANNING YEAR | NUMBER OF ZRCS | CONTRACT PRICE($/ZRC/YEAR) | PURCHASE PRICE |
|---|---|---|---|
| 2020 | 20 | $15,000 | $300,000 |
| 2021 | 20 | $20,000 | $400,000 |

The price per ZRC is expected to be high under Alliant in the 2018 to 2019 year with prices at $30,000/ZRC and $36,000/ZRC respectively. With the new Dairyland agreement, ZRC prices are reduced to $15,000 and $20,000 in 2020 and 2021, respectively,

### 3.3.2 Energy PPAs

UPPCO currently has five long term energy PPAs; three with TransAlta Energy Marketing and two with NextEra Energy Power Marketing. A summary of the key details of these PPAs is provided in Table 6-4. All PPAs are effective for the 2019 year. UPPCO will receive approximately a total of 413,160 MWh from the five PPAs at an average price of $33.47/MWh.

**Table 3-6 UPPCO PPA Overview**

| SELLER | CONTRACT QUANTITY (MW) | TOTAL CONTRACT QUANTITY (MWH) | CONTRACT PRICE ($/MWH) |
|---|---|---|---|
| NextEra Energy Power Marketing | 25 | 219,000 | $32.65 |
| NextEra Energy Power Marketing | 10 | 21,600 | $36.24 |
| TransAlta Energy Marketing | 10 | 87,600 | $31.44 |
| TransAlta Energy Marketing | 10 | 40,800 | $36.48 |
| TransAlta Energy Marketing | 10 | 44,160 | $30.55 |

UPPCO also has two 10-year PPAs _ for its formerly owned hydro assets, AuTrain and Cataract. Total installed capacity (ICAP) of these assets is 1,000 KW and total unforced capacity (UCAP) of the assets is 1,000 KW. A summary of these assets is shown in Table 3-7:

**Table 3-7 UPPCO's PPA Resources**

| ELECTRIC GENERATOR NAME | RENEWABLE TYPE | INSTALLED CAPACITY (KW) | UNFORCED CAPACITY (KW) |
|---|---|---|---|
| Autrain Hydro | Hydro | 500 | 500 |
| Cataract Hydro | Hydro | 500 | 500 |

These hydroelectric PPAs provide approximately 1.5 percent of UPPCO's energy needs, which is approximately 8,558 MWh annually. The direct cost of energy via these hydro PPAs is $ **[77.64]**/MWh. Due to this relatively high cost of energy, UPPCO reports that it is likely to allow these hydroelectric PPAs to expire at the end of their current terms, which will be in 2022.

## 3.4 MISO OVERVIEW AND SHORT-TERM ENERGY RESOURCES

UPPCO is a member MISO, which enables UPPCO to purchase and sell energy, capacity and ancillary services on the MISO market. Short term energy and MISO purchases currently fulfill 81.2 percent of UPPCO's energy needs, which is approximately 474,498 MWh annually. The direct cost for market purchases is was $**[34]**/MWh as of the April 2017 MISO capacity auction. In addition to the spot market, transmission costs of $**[15.88]**/MWh must also be considered, giving a combined energy, capacity, and transmission cost of approximately $**[54]**/MWh.

With low natural gas-prices, gas-fired power generation continues to be setting the marginal dispatching price of generation in the U.S. (as it has for approximately the past decade when gas supplanted coal-fired generation as the marginal price setter), and UPPCO's customers are currently benefiting from low energy prices. With over 900 MW of generation over-capacity in MISO Zone 2 (which covers eastern Wisconsin and Michigan's Upper Peninsula), UPPCO has also been able to lock in significantly lower capacity and energy prices over the next few years.

What needs to be considered in this forward-looking IRP, however, is that UPPCO and its customers have significant market risk, with over 80 percent of UPPCO's power needing to be purchased from the spot/wholesale. While UPPCO has been able to cover its shorter-term requirements with power and capacity purchases through 2019 at attractive prices, adding generation serves as a prudent hedge against market volatility, of which UPPCO's customers have significant exposure.

As shown in Figure 3-2 below, both natural gas prices, as well as MISO energy prices (which track closely with gas price fluctuations) have seen considerable volatility over both short and longer term horizons, and there are no assurances that the market will be able to continue to deliver such low energy prices into the future.

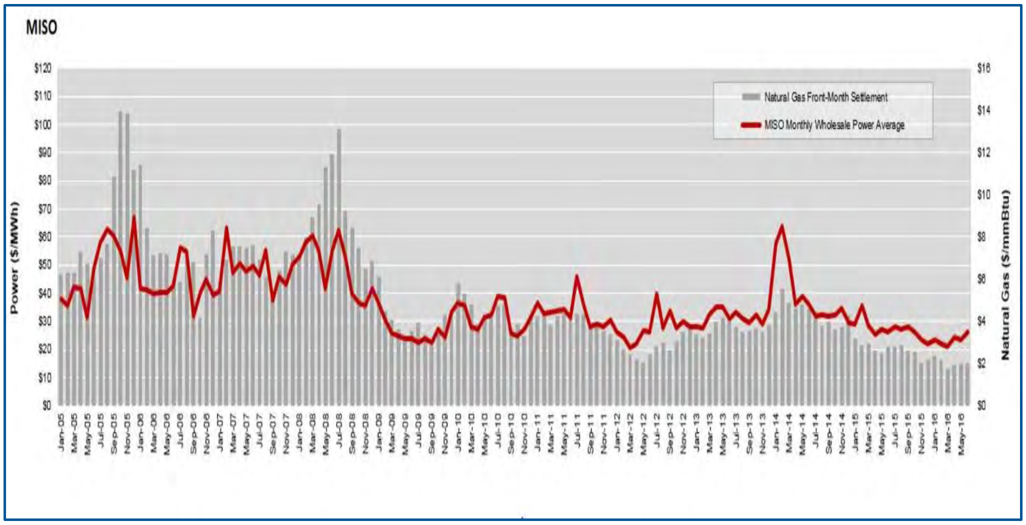



**Figure 3-2 Historical MISO Monthly Spot Market Price and Natural Gas Price (2006 – 2016)**

Capacity prices across MISO have also seen significant volatility just over the past few years alone, as shown in Figure 3-3. As described in this Report, UPPCO's current 18 percent market exposure to capacity prices (25 MW) is much less than its 81 percent exposure to market energy prices, given that UPPCO gets capacity credit for its mostly idled combustion turbines, and does not need to cover capacity needs for the energy usage from its interruptible industrial customers.


**Figure 3-3 Historical MISO Capacity Pricing (2014 – 2017)**

# 4.0 Demand Forecast

A fundamental element of an IRP analysis is the development of the long-term (2018-2037) system peak demand and energy forecasts. The forecast results in a projection of the capacity and energy requirements on the UPPCO system that the utility must plan to meet through self-owned generation or purchase arrangements.

Sufficient capacity must be secured to cover UPPCO's projected peak annual demand as well as UPPCO's capacity reserve requirement. Reserves are an amount over and above the projected system peak that utility's will plan to maintain in the event that the forecasted demand is higher than anticipated due to extreme weather conditions or higher than expected load growth, or in the event that capacity resources are not available due to a forced outage, a transmission line failure, or another unexpected event, as further discussed in Section 6.1.

## 4.1 DEMAND FORECAST METHODOLOGY AND ASSUMPTIONS

The need for additional resources is driven based on consideration of two key criterion: (1) the difference between UPPCO's current installed capacity and projected peak demand plus reserves, and (2) need for additional renewable energy resources based on state mandates or utility targets. The determination of need is driven by the load forecast, which is a key input for any long term planning study.

UPPCO has developed a load forecast for use in this IRP, based on UPPCO's historical actual energy and peak demands, as well as UPPCO's observations on customer usage trends in order to extrapolate load into the future. UPPCO provided historical substation-by-substation loads for Black & Veatch's review as a basis for the IRP model load forecast.

Revisions were made to adjust the forecast for interruptible loads and EWR programs, both of which effectively reduce the need for additional future resources.

## 4.2 ANNUAL FORECASTED PEAK DEMAND

UPPCO's total load consists of several elements, broadly split into UPPCO's firm, native load, that is the load of UPPCO's uninterruptable customer base inside of its service territory, as well as additional, interruptible loads that UPPCO may also serve opportunistically or otherwise on a non-firm basis. Specifically, UPPCO provides sufficient annual energy to meet the following loads:

- UPPCO's own native load.
- RTMP service of a large industrial customer, Verso (formerly,NewPage Corporation). Verso buys power from UPPCO on an interruptible basis as an RTMP customer, and self-generates power..
- Opportunity sales into the MISO market, when excessive generation beyond its firm load which can be provided economically comparted to MISO's market price.
- Auxiliary load used at UPPCO generating facilities.
- Transmission and distribution losses.

A buildup of UPPCO's total served load is shown below in Figure 4-1.

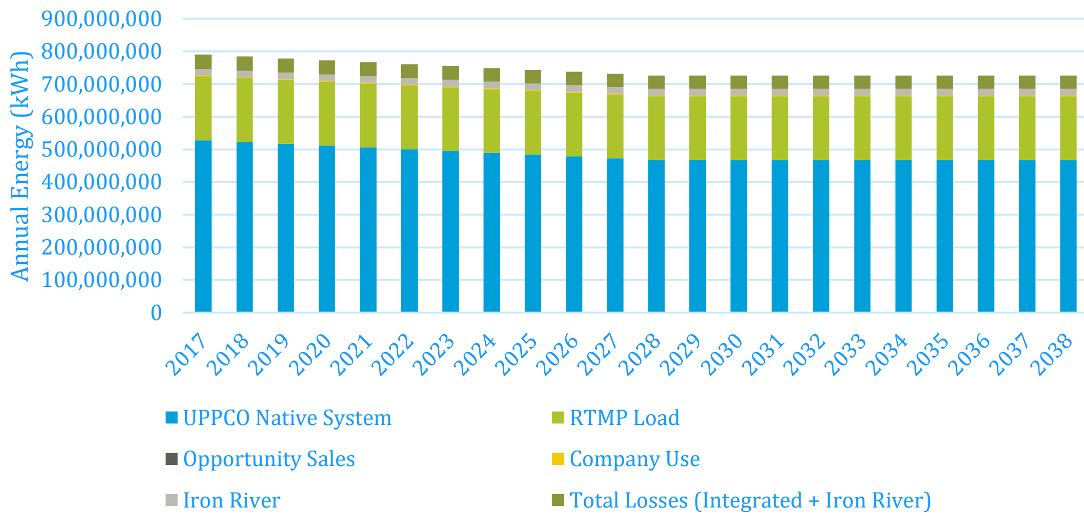



**Figure 4-1 Buildup of UPPCO Annual Energy Load**

In addition to annual energy, UPPCO has forecast a peak demand. Again, UPPCO is only responsible for meeting its own native load on a firm, uninterruptable basis. UPPCO's native load and the MISO-required 8.4 percent reserve margin further discussed in Section 6.1, as well as the peak demand of the full load served expected to be served by UPPCO during the planning period is shown in Figure 4-2.

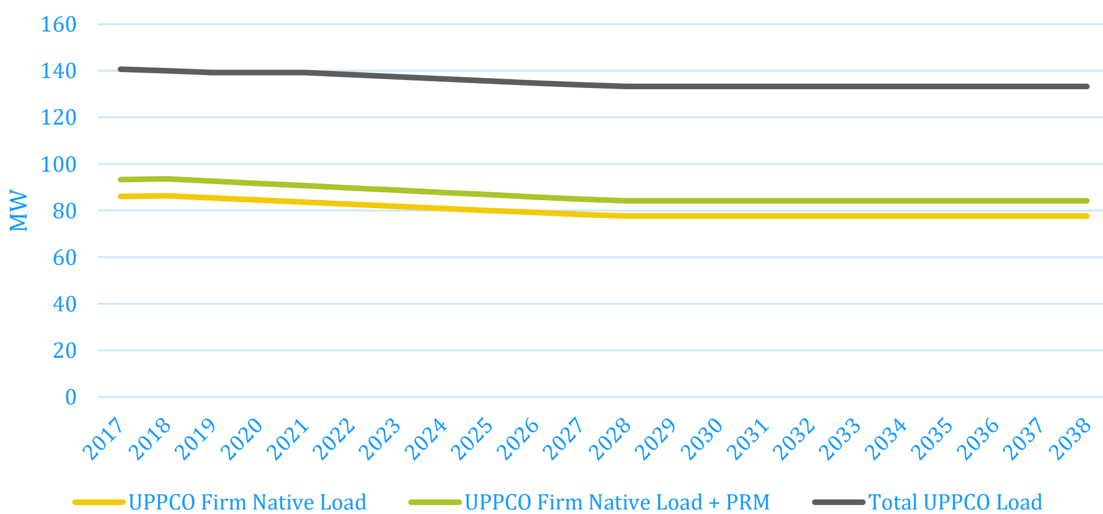



**Figure 4-2 UPPCO Annual Peak Demand Forecast**

# 5.0 Demand Response Resources

## 5.1 DEMAND RESPONSE

UPPCO does not currently offer demand response programs such as TOD pricing or smart meter optional load shedding. However, as discussed in the previous section, a large portion of UPPCO's load (approximately 28.8 percent of annual energy and 44.9 percent of demand in 2018) is served on an interruptible basis. In the event of a extremely high load, if UPPCO is not able to generate and procure enough energy to meet to load of its native system as well as these interruptible customers, then the interruptible customers' may be shed without penalty to UPPCO. Based on Black & Veatch's load forecast as shown previously in Figure 4-2, in 2018 UPPCO has 63.2 MW of load management resources (those interruptible customers) and 86 MW of uninterruptable native load.

## 5.2 DISTRIBUTED GENERATION

Black & Veatch understands the importance of considering smaller scale generation which is scattered throughout UPPCO's service area and hooked up directly to a distribution grid in order to service a local load, also known as distributed generation. UPPCO currently has a healthy grid system with a relatively high amount of redundancy that does not require generation inputs at specific location to help stabilize the grid. In addition, UPPCO's largest industrial customers are interested in paying lower priced interruptible rates rather than ensuring that they have continuous power that could require supplemental or dedicated power supplies that you would see in a distributed generation system.

UPPCO has studied potential benefits of distributed generation, mainly the possibility of transmission cost reductions by having generation hooked up directly to the distribution grid and servicing local loads. Currently, UPPCO customers pay an aggregate $9.3 million per year in transmission charges, equating to approximately $16/MWh. In theory, smaller generation assets hooked up to a distribution grid could reduce transmission charges. But, MISO does not currently allow the exclusion of behind the meter generation from its load share calculations, while ATC calculates its load share ratio based on the average of last twelve months' system peak hourly loads. Therefore, UPPCO must report to both MISO and ATC in determining transmission charges without any behind the meter generation netting. Because of the current provisions with behind the meter generation, a distributed generation system does not seem to be a way of reducing transmissions costs as PSCR charges will still be passed on to the customers. At least for the near future, UPPCO will continue to report its gross loads to MISO.

While transmission cost savings may not currently be a driver behind distributed generation, there are certain benefits of having local generation, including reduced transmission congestion charges, reduced line losses, greater reliability, and avoidance of lengthy and costly MISO transmission interconnection. In order to examine where any potential smaller scale generation may be situated, Table 5-1 lists the largest UPPCO distribution loads serviced at the various substation interconnection points (sized from largest to smallest peak load). In addition to listing the average and minimum loads serviced via each substation, Table 5-1 also lists the number and type of customers served at each substation. Finally, given the limited availability of natural gas in many parts of our service territory, the final column highlights the distance from the substation to the nearest gas transmission line.

### Table 5-1 UPPCO Substation Utilization

| Interconnection Point | 2016 Peak (MW) | 2016 Minimum Load (MW) | 2016 Average Load (MW) | Meters | Residential | Commercial | Industrial | Distance to Gas Interconnection (mi) |
|---|---|---|---|---|---|---|---|---|
| Mead | 37.00 | 2.00 | 20.00 | 1 | | | 100.0% | 3.1 |
| Barnum | 20.11 | 6.40 | 11.50 | 7,718 | 54.0% | 23.0% | 23.0% | 2.2 |
| Munsing | 13.09 | 2.80 | 5.55 | 3,031 | 50.9% | 26.4% | 22.7% | 10.8 |
| Osceola | 12.35 | 6.50 | 9.00 | 8,305 | 64.2% | 24.5% | 11.3% | 2.7 |
| MTU | 10.65 | 3.90 | 5.90 | 1,361 | 33.3% | 62.5% | 4.3% | 4.7 |
| Henry St. | 9.57 | 4.00 | 6.00 | 4,008 | 79.3% | 20.8% | | 5.8 |
| L'Anse | 8.50 | 3.50 | 5.00 | 495 | 77.3% | 22.8% | | 1.7 |
| Lincoln Ave | 7.96 | 3.20 | 5.10 | 4,351 | 46.7% | 39.6% | 13.7% | 2.8 |
| Humbolt Mine | 5.31 | 3.10 | 3.95 | 2 | | | 100.0% | 1.8 |
| Homer Rd. | 5.03 | 2.50 | 1.00 | 1 | | | 100.0% | 0.1 |
| KI Sawyer | 5.02 | 2.00 | 3.00 | 1,569 | 40.0% | 10.0% | 50.0% | 0.5 |
| Freeman - 34.5 kV | 4.88 | 1.00 | 3.00 | 10 | 60.9% | 34.0% | 5.1% | 0.9 |
| Gwinn | 4.39 | 0.50 | 2.00 | 3,338 | 80.0% | 20.0% | | 3.7 |
| Elevation Bank 1 | 4.38 | 2.75 | 3.00 | 4,533 | 62.0% | 38.00% | | 6.8 |
| Delta 1 | 4.32 | 1.50 | 2.50 | 5,166 | 37.3% | 62.7% | | 3.1 |
| Atlantic | 4.22 | 2.00 | 2.50 | 2,568 | 43.9% | 42.60% | 13.60% | 8 |
| Delta 2 | 3.99 | 1.70 | 2.50 | | 37.3% | 62.70% | | 3.1 |
| Elevation Bank 2 | 3.98 | 2.00 | 2.50 | | 87.9% | 11.90% | 0.30% | 6.8 |
| Ontonagon | 3.06 | 1.20 | 2.00 | 2,143 | 57.4% | 40.20% | 2.40% | 1.1 |
| Timber Products | 2.47 | | 0.75 | 5 | | | 100.0% | 16.4 |
| Bayview | 2.34 | | | 1,062 | 87.9% | 12.2% | | 3.4 |
| Keweenaw | 1.94 | 0.40 | 1.00 | 1,495 | 75.0% | 25.0% | | 17.1 |
| Masonville | 1.82 | | | 1,316 | 79.1% | 20.9% | | 0.7 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| M-38 | 1.56 | 0.10 | 0.70 | 1,233 | 84.0% | 16.1% | | 5.6 |
| Alger | 1.53 | 0.80 | 1.00 | 352 | 18.9% | 78.4% | 2.70% | 11.3 |
| Shingleton | 1.36 | | | 647 | 85.0% | 15.0% | | 19.8 |
| Perch Lake | 1.33 | 0.55 | 0.80 | 1,405 | 85.0% | 15.0% | | 0.8 |
| Chatham | 1.21 | 0.50 | 0.70 | 942 | 80.3% | 19.8% | | 1.4 |
| White Pine Village | 0.92 | 0.35 | 0.50 | 684 | 85.0% | 15.0% | | 2.3 |
| Seny | 0.79 | 0.35 | 0.50 | 679 | 85.0% | 15.0% | | 16.9 |
| Winona | 0.74 | 0.30 | 0.40 | 462 | 82.1% | 17.9% | | 13.5 |

As shown in Table 5-1, the largest load served on the list is at the Mead substation, which solely services Verso Corporation under the RTMP pricing. Thereafter, there are a number of distribution load centers that could be serviced with smaller scale generators in the 1-10 MW size range. Should generation exceed the load on the distribution lines at a particular time, then excess power would be pushed on to the ATC transmission lines. If such circumstances were possible, then ATC would be required to perform additional studies to evaluate the impact on its lines from these incremental power flows, which would further add to the cost of development and possibly interconnection.

As further discussed in Section 7.1, in this IRP Black & Veatch and UPPCO have considered multiple options for distributed generation within the 1-10 MW range identified above, most notable small scale solar installations and reciprocating engines.

## 5.3 ENERGY WASTE REDUCTION

The Michigan statewide EWR assessment was formed based on two, utility specific, 20-year potential studies conducted by GDS Associates in 2016. These studies are considered by the MPSC to represent economically and technically achievable energy values that are consistent with the requirements of the energy law P.A 295. The analysis in the studies utilized historic and forecasted data of customers, sales, and peak load in the upper peninsula, providing EWR potential under base case assumptions. EWR requirements for all the scenarios modeled in Section 9.0 are equivalent; incremental energy efficiency as a percentage of energy demand should be at least 35 percent by 2025.

UPPCO has been a part of the Efficiency United program since the passage of SB295, however with UPPCO's 2018-2019 EWR plan, UPPCO proposes to take the EWR effort in-house to customize programs to its unique territory and reduce overall costs while still reaching goals. The proposed programs follow the same overall framework of the existing programs through Efficiency United. Incentives and the measure mix have been adjusted to meet the UPPCO market and some additional delivery enhancements should help improve participation cost effectively. UPPCO's proposed programs consist of the following.

- Residential Programs:
  - Income Qualified Services
  - Energy Star Lighting and Appliances
  - Home Performance
  - Home Energy Reports
  - Appliance Recycling
- Business Programs:
  - Business Prescriptive
  - Business Custom
  - Small Business Direct Install

A summary of the estimated participation, budget, and energy savings for the programs is listed in Table 5-2.

**Table 5-2 UPPCO EWR Programs Overview**

| PROGRAM | ESTIMATED PARTICIPATION (CUSTOMERS) | | ESTIMATED ANNUAL BUDGET | | ESTIMATED ENERGY SAVINGS (KWH) | |
|---|---|---|---|---|---|---|
| | 2018 | 2019 | 2018 | 2019 | 2018 | 2019 |
| Income Qualified Services | 1,711 | 1,711 | $267,320 | $272,666 | 199,782 | 199,782 |
| Energy Star Lighting and Appliances | 35,405 | 35,405 | $144,958 | $147,858 | 947,625 | 947,625 |
| Home Performance | 2,758 | 2,758 | $244,730 | $249,624 | 570,551 | 570,551 |
| Home Energy Reports | 12,000 | 12,000 | $41,250 | $41,250 | 680,400 | 680,400 |
| Appliance Recycling | 375 | 188 | $76,325 | $32,625 | 344,955 | 172,478 |
| Business Prescriptive | 49,500 | 49,629 | $166,223 | $173,025 | 2,775,193 | 2,775,698 |
| Business Custom | 30 | 31 | $440,000 | $465,800 | 2,700,000 | 2,800,000 |
| Small Business Direct Install | 2,258 | 2,446 | $70,733 | $76,736 | 609,521 | 628,092 |

Figure 5-1 compares UPPCO's actual historical EWR energy savings to the projected EWR savings throughout the IRP planning period. Overall, UPPCO forecast similar EWR participation and results using similar EWR programs and initiatives to those in the past.

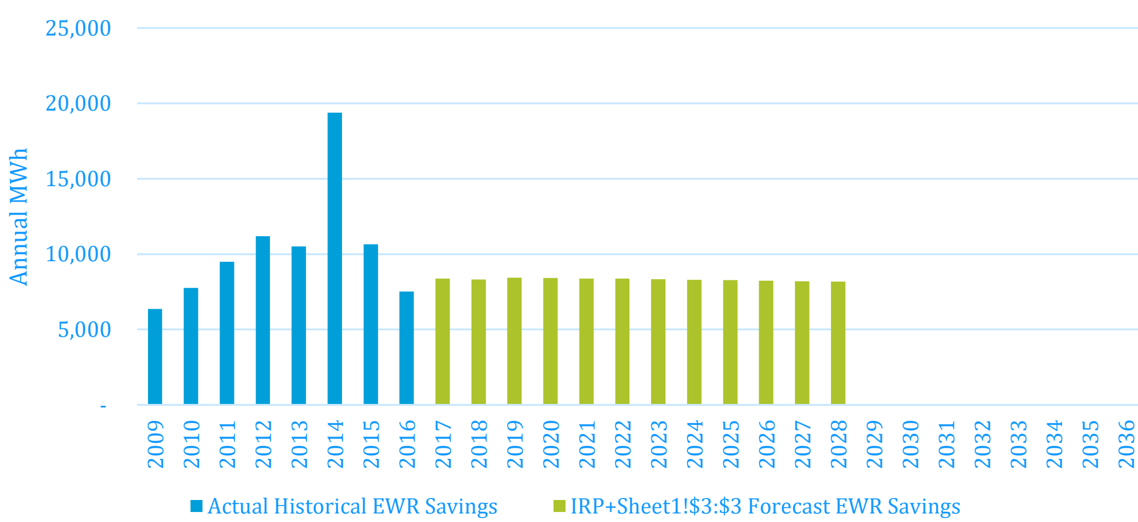



**Figure 5-1 Annual Incremental EWR Savings**

# 6.0 Demonstration of Need

The development of UPPCO's demand load forecast allows a comparison of energy and capacity requirements with UPPCO's existing and additional near-term resources. The result are a determination of the adequacy of existing and near-term additional resources to meet UPPCO's needs and renewable energy requirements during the 2018-2037 planning period.

Under the BAU Base Case scenario, UPPCO currently has sufficient existing and near-term capacity resources to meet its projected peak demand and planning reserve requirements over the study period without the need to procure additional capacity, as well as RPS requirements. However, UPPCO will require additional energy resources to have less of a reliance in the wholesale and spot market in order to improve reliability and mitigate market risk for its customers. The need for additional resources established in this section leads to the development of several future expansion scenarios that are modeled and presented from an economic cost and renewable energy perspective in Section 9.0. When modeling the future expansion scenarios, Black & Veatch has considered factors such as, capacity need, renewable energy requirements, and system reliability.

## 6.1 CAPACITY NEED

UPPCO has a capacity Planning Reserve Margin (PRM) of 8.4 percent, which has been determined by MISO's annual Loss of Load Expectation (LOLE) report. The PRM is a local reliability requirement in Michigan and is a measure of the resources required to be physically located inside a local resource without considering imports from outside of the zone. The purpose of the PRM is to provide additional capacity cushion above the expected maximum demand, in order to ensure that adequate capacity is available in times of high demand without the need for load shedding or the risk of unserved load. Because UPPCO's peak demand occurs in the winter and is non-coincidental with MISO's summer peak, the practical risk of a capacity shortage during UPPCO's peak is relatively small, however, for regulatory purposes UPPCO must still meet its PRM.

UPPCO is only required to maintain a PRM above and beyond its own native, firm load, and interruptible loads such as Verso and opportunity sales to the MISO market are not included in this calculation.

A summary of UPPCO's peak capacity sources and requirements over the planning period is shown in Figure 6-1.

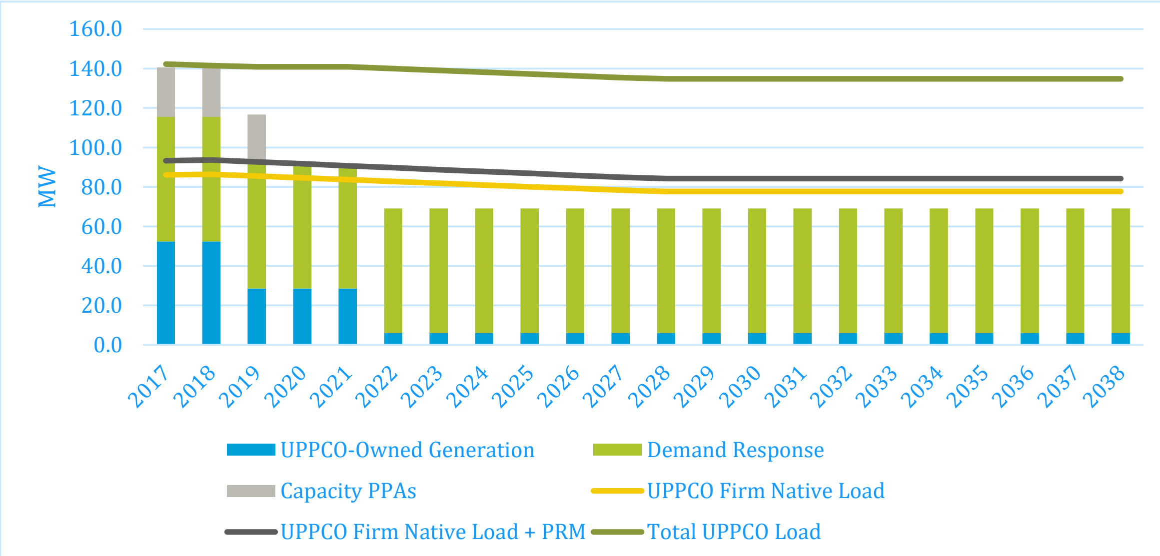



**Figure 6-1 UPPCO's Capacity Requirement Projection and Capacity Sources**

As discussed in Section 1.0, UPPCO's full peak demand including interruptible loads is 142.2 MW in 2018, which is materially consistent with UPPCO's available capacity of 140.5 MW. As discussed in Section 3.3.1, 25 MW of PPA capacity will expire in 2021, reducing UPPCO's available capacity to 115.5 MW in 2022, which is maintained throughout the planning period. UPPCO's highest firm demand of 86 MW occurs in 2018, resulting in a required capacity of 93.3 MW including the PRM.

Additionally UPPCO's two owned combustion turbines, which collectively provide approximately 50 MW of capacity at the time of this Report, which will no longer contribute to UPPCO's capacity balance upon their retirements in 2019 and 2020. UPPCO will accordingly need additional firm capacity beginning in 2022 in order to meet PRM requirements.

## 6.2 RENEWABLE ENERGY REQUIREMENTS

As per Michigan legislation and generation assessment, an evaluation must be completed to determine if additional supplemental renewable generation is required to achieve Michigan's RPS. The current RPS standard in Michigan is 10 percent, with an increase to 12.5 percent in 2019 and another increase to 15 percent from 2021 onwards.

UPPCO is currently exceeding the 10 percent RPS requirement, and is expected to reach 17 percent RPS in 2021. This is primarily because UPPCO has a declining load forecast. UPPCO does not have additional renewable generation being added to the system in this time period.

**Table 6-1 Michigan's Required RPS Target VS. UPPCO's Projected RPS in Base Case**

| YEAR | MICHIGAN RPS TARGET | UPPCO ACTUAL/ FORECAST AMOUNT |
|---|---|---|
| 2015 | 10% | 15% |
| 2019 | 12.50% | 15% |
| 2020 | 12.50% | 18% |
| 2021 | 15% | 17% |
| 2022+ | 15% | 17% |

As shown above, UPPCO comfortably meets the future expanded RPS targets utilizing its current regulated hydro generation facilities, including the Escanaba units used to serve Verso's load. Black & Veatch notes that, although RTMP sales do not require regulated capacity coverage through the PRM, UPPCO is required to include these sales within the RPS calculations. Although renewables may be selected as a source of new generation based on economic, fossil fuel price hedge, or other environmental reasons, they need not be selected strictly in order to meet the Michigan RPS standards.

## 6.3 MARKET EXPOSURE MITIGATION

It is important to note that UPPCO's demonstration of expansion need largely stems from its current exposure to market risk, with 81.2 percent of power being purchased from the spot and wholesale market. Although UPPCO has been able to purchase power and capacity through 2019 at competitive prices, both natural gas and MISO energy prices are noticeably volatile over both short-term and long-term horizons as discussed in Section 3.4. There are no assurances that MISO will continue to offer similar competitive prices in the future as the projected wholesale energy prices are generally expected to steadily increase over the next 20-year period, as shown in Figure 6-2.

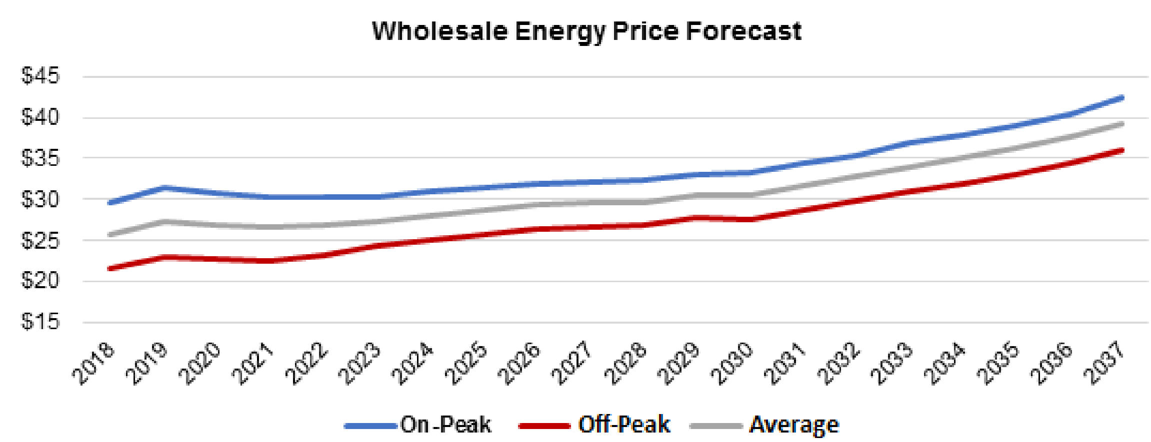



**Figure 6-2 Projected MISO Wholesale Energy Prices**

Accordingly, in order to mitigate market risk and improve reliability for its customers and, UPPCO should consider self-owned generation as a means of hedging its exposure to increases and fluctuations in energy and capacity prices. Specifically, UPPCO's efforts to further leverage its existing hydroelectric generators through capacity expansions at Hoist and McClure would not only reduce the need for market purchases and exposure to market pricing, but would do so with assets which are not exposed to natural gas fuel pricing, which may be highly correlated to overall market pricing.

A distinction between UPPCO's market exposure to capacity prices and market energy prices should also be noted. Capacity prices for MISO have also been noticeably volatile throughout the past few years, but UPPCO only meets 18 percent of its capacity need from the market, compared to the 81 percent market exposure for its energy need.

## 6.4 SYSTEM AND LOCAL RELIABILITY CRITERIA

Aside from the above identified and discussed drivers, Black & Veatch and UPPCO have not identified or incorporated additional system or local reliability criteria into the development of this IRP.

# 7.0 Supply Side Resources

In consideration of the objective of achieving long-term reliability, stable electric costs, and fuel diversity to lower risk of dependence on a single fuel source or the market, UPPCO developed a list of multiple resource options to evaluate as candidates to serve UPPCO's future needs. All incremental options considered in the analysis were solar, combustion turbines, wind, RICE, biomass, and battery energy storage resources. These options are discussed further in this section.

## 7.1 TECHNOLOGY, COST, AND PERFORMANCE

Black & Veatch and UPPCO have carefully selected resource candidates based on technology, capacity, CAPEX costs, O&M costs, performance, and emission rates. The following technologies have been considered:

- Renewable resources
  - Solar photovoltaic
  - Wind (on-shore)
  - Biomass
- Conventional
  - Simple Cycle combustion turbine
  - Natural gas reciprocating engine
- Energy storage
  - Li-ion batteries

Each of these options, and their key considerations as they pertain to UPPCO, are discussed in the following sections.

### 7.1.1 Solar PV

Solar is the fastest growing energy source in the U.S., with 9.5 gigawatts of utility-scale solar power added in the U.S. last year alone – more than the previous three years combined. The biggest driver behind solar power's emergence is dramatic price declines in panel and installation pricing – with prices having fallen by 70 percent over the past 6 years, as demonstrated below in Figure 7-1.

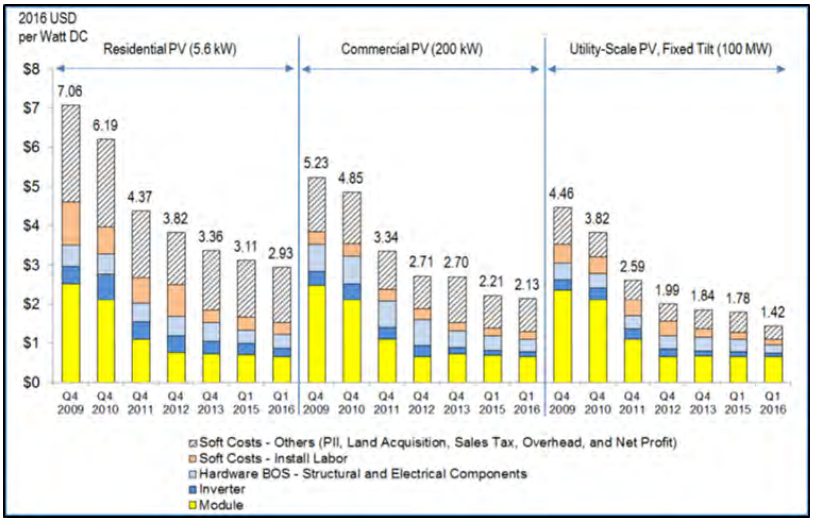



**Figure 7-1 Solar PV Installed Costs, 2016 (Source: NREL)**

While Michigan is currently ranked 35th in the U.S. for solar power generation by state, it saw a doubling of its capacity last year from 15.9 MW to 37.5 MW. A further 470 MW of solar generation is projected for Michigan over the next 5 years, including an advanced 112 MW development in Muskegon County in lower Michigan.

While there is a misconception that Michigan is too far north for economic solar, this is not the case. Michigan gets the same amount of sunlight as many states that are installing far more solar energy. Overall, fixed-tilt solar projects in Michigan's upper peninsula are projected to have an average capacity factor of 14 percent (versus 28 percent for similar projects in the U.S. Southwest). Although REC prices at present are low, solar projects in Michigan get 3 RECs per MWh vs. 1 REC for other renewable generation. An additional 0.2 RECs are given for energy delivered during peak periods, an addition 0.1 REC given for projects built using Michigan labor and a final 0.1 RECs given for projects that incorporate Michigan-made components. Additionally, in Michigan, low winter generation due to the low angle of the sun plus snow are offset by long sunny summer days – helping MISO to give solar an initial capacity credit of 50 percent of name plate.

UPPCO has selected a wide variety of solar PV options, from varying capacity to varying build years. UPPCO is considering 2 MW community-scale fixed, 20 MW utility-scale fixed tilt, and 100 MW utility scale tracking as is its owned-generation solar PV resource options, as well as 20, 75, and 125 MW solar PPAs. The installed costs of these resources are expected to continue to drop, and therefore the IRP modeled costs of these resources are dependent on the year in which they are built, Black & Veatch has modeled the costs of the 100 MW and 2 MW units upon reviewing National Renewable Energy Laboratory (NREL) data pertinent to similar mid-range PV cost. Black & Veatch utilized a smaller plant with which it has considerable experience with as a reference to determine the 20 MW unit costs, accounting for the economies of scale impact.

This IRP considers installations in 2017, 2020, 2021, 2022, and 2026. An overview of the potential solar PV resources considered in the IRP is provided in Table 7-1.

### Table 7-1 Solar PV Resource Candidates Overview

| SOLAR PV TECHNOLOGY DESCRIPTION | ESTIMATE BASE YEAR | CAPACITY (MW) | CAPACITY FACTOR | CONSTRUCTION COSTS ($/KW) | FIXED O&M ($/KW-YR) | FINANCING YEARS |
|---|---|---|---|---|---|---|
| Utility-Scale, Crystalline, Tracking | 2017 | 100 | 20% | $1,730 | 14.4 | 20 |
| Utility-Scale, Crystalline, Tracking | 2020 | 100 | 20% | $1,490 | 13.2 | 20 |
| Utility-Scale, Crystalline, Tracking | 2021 | 100 | 20% | $1,470 | 13.2 | 20 |
| Utility-Scale, Crystalline, Tracking | 2026 | 100 | 20% | $1,370 | 12 | 20 |
| Utility-Scale, Crystalline, Tracking | 2017 | 20 | 20% | $1,910 | 15.84 | 20 |
| Utility-Scale, Crystalline, Tracking | 2020 | 20 | 20% | $1,640 | 14.52 | 20 |
| Utility-Scale, Crystalline, Tracking | 2021 | 20 | 20% | $1,620 | 14.52 | 20 |
| Utility-Scale, Crystalline, Tracking | 2026 | 20 | 20% | $1,500 | 13.2 | 20 |
| Community-Scale, Crystalline, Fixed | 2017 | 2 | 15% | $2,950 | 19.2 | 20 |
| Community-Scale, Crystalline, Fixed | 2020 | 2 | 15% | $2,530 | 14.4 | 20 |
| Community-Scale, Crystalline, Fixed | 2021 | 2 | 15% | $2,440 | 14.4 | 20 |
| Community-Scale, Crystalline, Fixed | 2026 | 2 | 15% | $1,970 | 9.6 | 20 |

A comparison of the general capital costs per kW assuming a non-emerging technology scenario and an emerging technology scenario are shown in Table 7-2. In the emerging technology scenario, all capital costs are expected to be reduced by 35 percent.

**Table 7-2 Solar PV Capital Costs**

| YEAR | NON- EMERGING TECHNOLOGY | | | EMERGING TECHNOLOGY | | |
|---|---|---|---|---|---|---|
| | SOLAR PV 100 MW | SOLAR PV 20 MW | SOLAR PV 2 MW | SOLAR PV 100 MW | SOLAR PV 20 MW | SOLAR PV 2 MW |
| 2020 | $1,242 | $1,242 | $2,128 | $807 | $807 | $1,383 |
| 2021 | $1,227 | $1,227 | $2,102 | $798 | $798 | $1,367 |
| 2022 | $1,212 | $1,212 | $2,128 | $788 | $788 | $1,383 |
| 2023 | $1,198 | $1,198 | $2,128 | $779 | $779 | $1,383 |
| 2024 | $1,183 | $1,183 | $2,128 | $769 | $769 | $1,383 |
| 2025 | $1,169 | $1,169 | $2,102 | $760 | $760 | $1,367 |
| 2026 | $1,155 | $1,155 | $2,077 | $751 | $751 | $1,350 |
| 2027 | $1,141 | $1,141 | $2,052 | $742 | $742 | $1,334 |
| 2028 | $1,128 | $1,128 | $2,028 | $733 | $733 | $1,318 |
| 2029 | $1,114 | $1,114 | $2,003 | $724 | $724 | $1,302 |
| 2030 | $1,101 | $1,101 | $1,979 | $715 | $715 | $1,287 |
| 2031 | $1,088 | $1,088 | $1,956 | $707 | $707 | $1,271 |
| 2032 | $1,074 | $1,074 | $1,932 | $698 | $698 | $1,256 |
| 2033 | $1,062 | $1,062 | $1,909 | $690 | $690 | $1,241 |
| 2034 | $1,049 | $1,049 | $1,886 | $682 | $682 | $1,226 |
| 2035 | $1,036 | $1,036 | $1,863 | $674 | $674 | $1,211 |
| 2036 | $1,024 | $1,024 | $1,841 | $665 | $665 | $1,197 |
| 2037 | $1,012 | $1,012 | $1,819 | $658 | $658 | $1,182 |

### 7.1.2 Wind

Similar to solar, wind generation will not incur any fuel operating costs, however its relatively high capital costs requires a strong wind resource to justify its economics. Michigan's best wind resources occur in the 'thumb', which is where the majority of the state's projects have been built, or off-shore in areas like the Keweenaw, where strong permitting opposition would be expected.

As seen below in Figure 7-2, there is currently one operating wind farm in Michigan's upper peninsula. This 28 MW project (14 Gamesa turbines x 2 MW) was built in 2012 just east of Escanaba, and reports an actual capacity factor of 32.5 percent in 2016 and 33.5 percent in 2015.

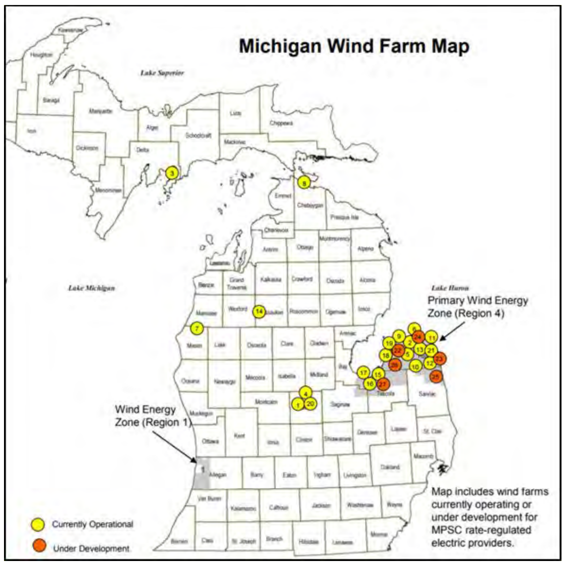



**Figure 7-2 Map of Michigan Wind Projects (Source: NREL)**

NREL performed a study which analyzed the 10-minute wind power generation data for three years for 57 sites in Michigan. Based on that study, NREL came up with a Michigan on-shore average capacity of 33 percent, which is materially consistent with the reported capacity factor of the upper peninsula Escanaba project. Many of these projects are located in the 'thumb' area of the lower peninsula which has higher winds than in the rest of the state. Continuous improvements in wind technology however are steadily enhancing a turbine's ability to generate power from a given wind source. For this IRP analysis, a capacity factor of 34 percent is assumed for determining power generation. To determine capacity factor credits from MISO, 13.9 percent is assumed, which is the current average figure which MISO uses for wind projects located in UPPCO's Zone 2.

UPPCO has selected two varying capacity wind resources, 100 MW and 20 MW, as potential future resources. Similar to the solar resources above, Black & Veatch has determined the costs of the 100 MW and 20 MW units upon reviewing NREL data pertinent to similar mid-range onshore wind costs as well an estimated factor to account for the impact of economies of scale.

All cost estimates of the wind resources are based on a build year of 2017. An overview of the potential wind resources' capacity and cost is shown in Table 7-3:

**Table 7-3 Wind Resource Candidates Overview**

| WIND TECHNOLOGY DESCRIPTION | CAPACITY (MW) | CAPACITY FACTOR | CONSTRUCTION COSTS ($/KW) | FIXED O&M ($/KW-YR) |
|---|---|---|---|---|
| Wind On-Shore | 100 | 34% | $1,971 | 50 |
| Wind On-Shore | 20 | 34% | $2,180 | 55 |

### 7.1.3 Biomass

UPPCO has also started discussions with another company, Potlach (located near the Sawyer airport), which produces 80,000 tons of waste wood per year, half of which it uses internally to generate steam, and half of which it also sells to Verso (plus a small amount to landscaping companies in the lower peninsula for mulch). UPPCO is currently evaluating the economics of utilizing wood fuel from Potlach versus TP. Preliminary modeling will also dictate the maximum price that could be paid for the waste wood in order to generate positive economics. TP and Potlach could then consider whether they would be willing to forego current higher sales prices in order to lock in longer-term, more secure off-take agreements for this waste wood today. Alternatively, UPPCO could have the preliminary analysis completed, such that if circumstances change with Verso, the company could be in a position to move quickly with tying up/optioning the waste-wood under pre-negotiated terms.

UPPCO has considered one generic biomass unit as a potential future resource in this IRP. All cost estimates of the biomass resource are based on a build year of 2017 and a financing period of 30 years. An overview of the potential biomass resource capacity, cost, and performance is shown in Table 7-4.

**Table 7-4 Biomass Resource Candidate Cost and Performance**

| WIND TECHNOLOGY DESCRIPTION | CAPACITY (MW) | CONSTRUCTION COSTS ($/KW) | FIXED O&M ($/KW-YR) | NON-FUEL VARIABLE O&M | NET HR (BTU/KWH HHV) | EFOR (%) | POH (HRS/YR) |
|---|---|---|---|---|---|---|---|
| Biomass | Generic | $4,441 | $108 | $5 | 13,500 | 9 | 701 |

### 7.1.4 Conventional Technology

There are a variety of natural gas-fired generating units on the market that serve different niches and functions. Based on UPPCO's system size and needs, UPPCO would benefit most from a generator that is a modular, fast-start, back-up/peaking units such RICE that are currently being installed elsewhere in the upper peninsula by MBLP and UMERC

RICE units have been selected as the source of new generation in the upper peninsula for MBLP (3 x 16.7 MW units for a total of 50 MW) and UMERC (up 10 x 18 MW units for a total of 180 MW). While RICE units are more expensive to install than other small conventional generation, they are generally more efficient with a lower heat rate of 8,500 BTU/kWh, allowing the units to be dispatched with much greater economic frequency (46.2 percent of the time for the other upper peninsula examples).

The benefits of RICE generation to UPPCO include:

- Peaking Capacity – The low heat rate and low maintenance provide cost-effective peaking power at a high efficiency.
- Backup for Renewable Generation – Power output from renewable resources can vary significantly over short periods of time. The 5-minute start time, combined with frequent start/stop capabilities, makes RICE a great load-following resource when paired with solar/wind.
- System Regulation / VAR Support.

Natural gas supply sufficient to run RICE units up to 18 MW in size is available in the Upper Peninsula, however UPPCO does not currently have any spoken-for supply, which would need to be contracted to facilitate the installation of these RICE units.

Black & Veatch has reviewed the Wartsila Indicative Equipment Pricing Estimate, published October 2017, in order to determine the technical attributes of all the Wartsila units except 18V50SG. Technical attributes of the Wartsila unit 18V50SG were determined by Black & Veatch through industry comparisons and NREL estimates. A summary of the cost, performance, and emission rates of these resources in shown in the tables below.

**Table 7-5 RICE Cost Characteristics**

| CONVENTIONAL TECHNOLOGY DESCRIPTION | CAPACITY (MW) | CONSTRUCTION COSTS ($/KW) | FIXED O&M ($/KW-YR) | NON-FUEL VARIABLE O&M ($/MWH) | FINANCING YEARS |
|---|---|---|---|---|---|
| Reciprocating Engines - 1x0 Wartsila 9L34SG (Natural Gas) | 4 | $3,320 | $14 | $20 | 30 |
| Reciprocating Engines - 1x0 Wartsila 16V34SG (Natural Gas) | 7 | $2,100 | $14 | $20 | 30 |
| Reciprocating Engines - 1x0 Wartsila 20V34SG (Natural Gas) | 9 | $1,800 | $14 | $20 | 30 |
| Reciprocating Engines - 3x0 Wartsila 18V50SG (Natural Gas) | 56 | $1,560 | $19 | $20 | 30 |

**Table 7-6 RICE Technical Characteristics**

| | PERFORMANCE | | | EMISSION RATES | | |
|---|---|---|---|---|---|---|
| CONVENTIONAL TECHNOLOGY DESCRIPTION | NET HR (BTU/KWH HHV) | EFOR (%) | POH (HRS/YR) | $NO_X$ (LB/MMBTU) | $SO_2$ (LB/MMBTU) | $CO_2$ (LB/MMBTU) |
| Reciprocating Engines - 1x0 Wartsila 9L34SG (Natural Gas) | 8,300 | 2 | 150 | 0.01 | 0.0005 | 114.9 |
| Reciprocating Engines - 1x0 Wartsila 16V34SG (Natural Gas) | 8,220 | 2 | 150 | 0.01 | 0.0005 | 114.9 |
| Reciprocating Engines - 1x0 Wartsila 20V34SG (Natural Gas) | 8,200 | 2 | 150 | 0.01 | 0.0005 | 114.9 |
| Reciprocating Engines - 3x0 Wartsila 18V50SG (Natural Gas) | 8,120 | 2 | 150 | 0.015 | 0.0006 | 114.9 |

### 7.1.5 Energy Storage

UPPCO has considered one li-ion battery unit a potential future resource. All cost estimates of the resources are based on a build year of 2017 and a financing period of 20 years. Black & Veatch has reviewed Lazards's Levelized Cost of Storage Analysis 3.0, in order to determine the cost and performance of the li-ion battery. An overview of the potential battery resources' capacity and cost, and performance is shown in the table below:

**Table 7-7 Energy Storage Resource Candidate Overview**

| ENERGY STORAGE TECHNOLOGY DESCRIPTION | CONSTRUCTION COSTS ($/KW) | FIXED O&M ($/KW-YR) | NON-FUEL VARIABLE O&M | EFOR (%) | POH (HRS/YR) |
|---|---|---|---|---|---|
| Energy Storage - Batteries: Li-Ion (30 Minute Duration) | $1,200 | $8 | $2 | 1 | 88 |

A major benefit of battery storage is the ability to provide multiple services in one location to meet the needs of the grid. Battery storage can be configured to respond to grid needs in less than a second, thereby providing the capability for a faster response time than conventional generation resources. Some of the potential benefits and applications of battery storage are:

- **Load Shifting:** In load shifting applications, batteries are charged with lower priced energy (which can help mitigate curtailment of excess renewable generation (when renewable generation exceeds demand) and the stored energy used at a later time (such as during evening ramping periods).

- **Peaking Supply:** The power output capacity of batteries can be used to meet capacity resource adequacy requirements and replace conventional peaking capacity to provide short-term power needs during periods of peak demand.
- **Frequency Regulation and Voltage Support:** Battery storage can be used to mitigate load and generation imbalances and maintain grid frequency and voltage.
- **Spinning Reserve:** Batteries can be utilized to provide energy needs within 10 minutes, as an alternative to conventional generation that must be kept online and synchronized to the grid in anticipation of a need.
- **Firming of Intermittent Resources:** Batteries can be used to “firm” energy production of a variable energy resource (such as solar or wind generation) and provide a more predictable energy profile to the grid.

Battery storage applications are often selected for primary use in either a power or energy application. Power applications tend to be of shorter duration (approximately 15 minutes to one hour) with operational profiles involving frequent rapid responses or cycles. Energy applications generally require longer duration (approximately 1 hour or more).

Because UPPCO does not utilize variable time-of day pricing to incentivize off-peak energy consumption, battery storage would likely not be materially beneficial for load shifting purposes. Battery storage would also only offer limited benefits to the UPPCO system for peak supply and spinning reserve, as UPPCO has adequate, cheaper options for capacity, and this IRP is focused on UPPCO’s greater need for reliable, low cost energy rather than procuring additional capacity. However, battery storage could provide benefits to UPPCO in firming up intermittent resources, and as such as been evaluated in solar + storage applications in Black & Veatch’s modeling. Overall, battery storage is still an expensive, novel technology, and at this and over the IRP forecast horizon, it may be difficult for the benefits of battery storage to outweigh the costs in UPPCO’s system.

## 7.2 TRANSPORTATION ELECTRIFICATION

The introduction of electric vehicles produces a new means of energy consumption within a utility’s service area, as customers charge those vehicles at their homes, offices, or other locations. Not only do electric vehicles consume additional energy, but they may also shift energy usage trends and locations (if customers are opting to charge at home versus at a communal location, substation loading levels may vary). In some cases, this may be used in a utilities favor, by utilizing time of day (TOD) energy pricing to incentivize customers to charge their vehicles at night during low demand hours, and potentially use those electric vehicles as a crowdsourced, distributed energy storage system to be used for demand response if needed by the utility during peak demand hours.

While UPPCO has studied the potential for transportation electrification in its service area, and provides resources for its customers who are interested in electric vehicle purchases on the UPPCO website, UPPCO does not anticipate material levels of electric vehicle adoption in its service area during the IRP planning period, and accordingly those effects have into been incorporated into this analysis. However, to the extent that there may be accelerated wide area adoption of electric vehicles within the UPPCO service territory, this will have the effect of increasing the market volatility exposure that is borne by UPPCO's customers, as UPPCO is not currently planning to serve this requirement with fixed cost resources.

# 8.0 Transmission and Distribution System

## 8.1 BULK TRANSMISSION SYSTEM

UPPCO does not directly own bulk transmission assets, but interconnects with and utilizes transmissions assets owned and operated by the American Transmission Company (ATC). ATC owns or operates transmission facilities in Wisconsin, Illinois, Minnesota, and Michigan's upper peninsula, consisting of approximately 9,440 line-miles, 96 wholly owned substations, and 419 jointly owned substations.

ATC's transmission system as it relates to UPPCO's service area is shown in Figure 8-1.

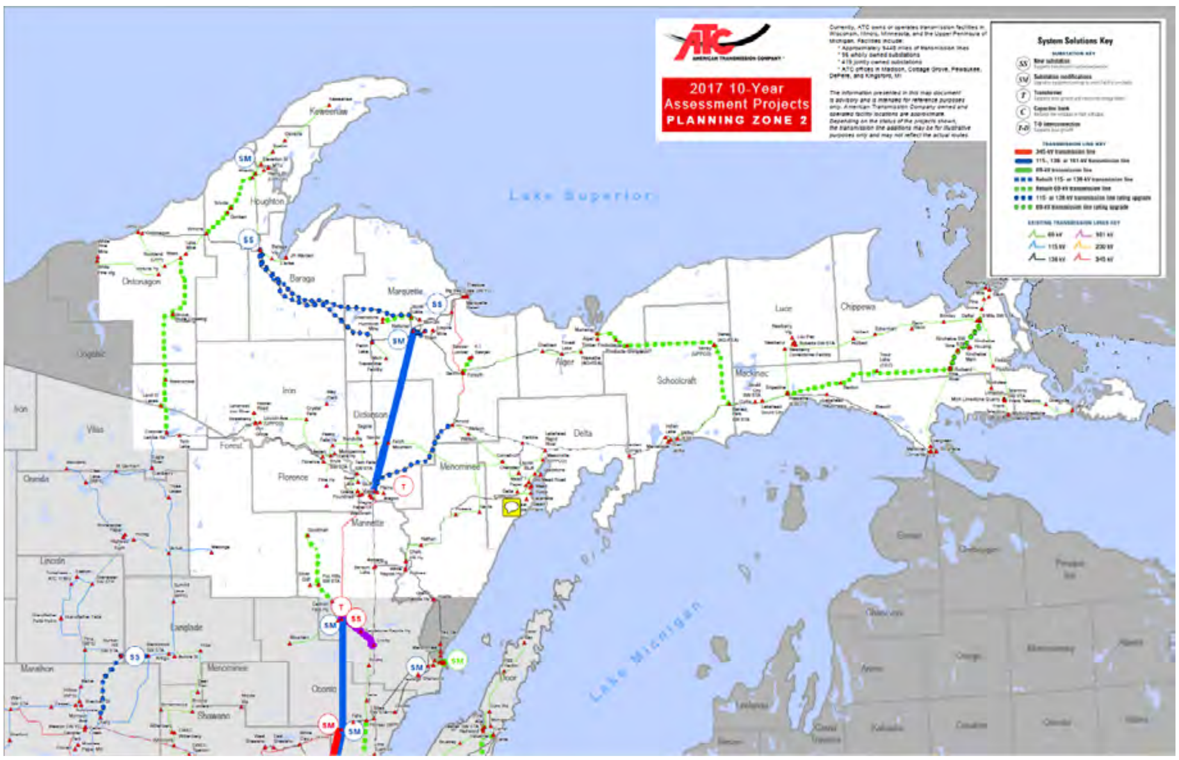



**Figure 8-1 ATC Transmission System**

Because UPPCO does not own bulk transmission assets, this IRP has not considered transmission expansion or upgrade scenarios. Transmission carrying capacity information provided by UPPCO and Black & Veatch's PROMOD modeling have confirmed that UPPCO's existing transmission rights are adequate to fully dispatch the generation considered in each of the IRP scenarios modeled, and therefore transmission upgrades are not required to realize the benefits of those scenarios.

## 8.2 DISTRIBUTION SYSTEM

UPPCO owns and operates an electric distribution system consisting of 4,468 line-miles of distribution lines, as well as 46 distribution substations. A summary of UPPCO's line miles by purpose is provided in Table 8-1.

**Table 8-1 Summary of UPPCO Distribution Lines**

| DISTRIBUTION LINE TYPE | LINE MILES |
|---|---|
| Primary Overhead | 2,185 |
| Primary Underground | 725 |
| Secondary Overhead | 633 |
| Secondary Underground | 42 |
| Service Overhead | 556 |
| Service Underground | 328 |
| **Total** | **4,468** |

Of UPPCO's 46 distribution substations, 15 are joint-use facilities with ATC, where ATC owns assets in the same substation. UPPCO is typically connected to ATC's system at the primary voltage of 69 kV with a few sites connected at 138 kV volts. UPPCO's standard distribution (secondary) voltage is 12,470/7,200 volts. Additionally, some dedicated industrial or wholesale substations have a 4,160/2,400 or 13,800 secondary voltage.

Twenty-nine of UPPCO's distribution substations have remote control/monitoring via UPPCO's System Control and Data Acquisition system (SCADA). These SCADA sites are monitored/controlled via the UPPCO System Operating Center based in Ishpeming, Michigan.

# 9.0 Scenario Analysis and Results

Black & Veatch modeled several scenarios, each considering different methods to meet UPPCO's energy, capacity, and RPS needs through different combinations and permutations of new generation and PPAs. Each of these scenarios were compared to each other, as well as the BAU Base case, on a CPWC basis to determine the least-cost option. Additionally, these scenarios were also compared with altered variables such as load growth, market pricing, and gas pricing in order to determine the merit order of least cost solutions not only under base case assumptions, but also to understand each scenario's exposure to risk and pricing volatility under different assumptions. Accordingly, each scenario should only be compared to those similar scenarios, e.g. BAU cases should be compared to BAU cases, emerging technology cases should be compared to other emerging technology cases, and so on.

Additionally, several cases were modeled and evaluated prior to UPPCO's decision to retire the Portage and Gladstone combustion turbine units in 2019 and 2022, respectively. While those cases which consider the combustion turbines as part of UPPCO's generation portfolio after those retirement dates no longer represent viable IRP cases, they are still discussed in this Report as their results were ultimately used to help iterate and refine the IRP's evaluation of optimal solutions.

The following sections outline the results of each scenario evaluated, including the 50% Self-Supply PCA, which was iteratively designed based on observations from each of the results from Section 9.1. Black & Veatch notes that, while minimizing CPWC costs is an important factor in selecting the best case for an IRP, it is not the only factor to be considered, as discussed further in Sections 10 and 11.

## 9.1 SCENARIO ANALYSES

### 9.1.1 BAU: Base Case

In this case, the BAU base case is considered. UPPCO would continue to purchase energy and capacity from the MISO capacity market resulting in average annual fixed costs of $2.449 million for the 20-year period as well as annual investment costs of $5.280 million for the energy efficiency packages. Oil-fired and PPA- capacity fixed annual costs are also considered. PRM for this case is 8.4 percent with an RPS in 2021 of 17 percent and an EE percentage of 42 percent in 2025. CPWC for this case is $202.182 million with a rank of 2. The detailed results of this case are shown in Table 9-1. The cost components of the CPWC are represented graphically in Figure 9-1.

**Table 9-1 CPWC for BAU Base Case ($000)**

| YEAR | PPA ENERGY PURCHASES | NET MISO MARKET ENERGY PURCHASES | PPA CAPACITY PURCHASES | ENERGY EFFICIENCY PACKAGE INVESTMENTS | GENERATION FIXED COSTS | GENERATION VARIABLE COSTS | NEW GENERATION FIXED INVESTMENT |
|---|---|---|---|---|---|---|---|
| 2018 | $12,445 | $1,718 | $700 | $3,382 | 134 | $- | $- |
| 2019 | $13,560 | $784 | $1,879 | $3,382 | 238 | $- | $- |
| 2020 | $4,150 | $7,967 | $1,012 | $3,382 | 19 | $- | $- |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 2021 | $- | $11,301 | $1,125 | $5,615 | 44 | $- | $- |
| 2022 | $- | $11,006 | $929 | $5,615 | 8 | $- | $- |
| 2023 | $- | $10,824 | $3,114 | $5,615 | 0 | $- | $- |
| 2024 | $- | $10,593 | $3,103 | $5,615 | 0 | $- | $- |
| 2025 | $- | $10,445 | $3,076 | $5,615 | 0 | $- | $- |
| 2026 | $- | $10,386 | $3,086 | $5,615 | 0 | $- | $- |
| 2027 | $- | $10,076 | $3,067 | $5,615 | 0 | $- | $- |
| 2028 | $- | $9,665 | $3,056 | $5,615 | 0 | $- | $- |
| 2029 | $- | $9,422 | $3,048 | $5,615 | 0 | $- | $- |
| 2030 | $- | $9,363 | $3,048 | $5,615 | 0 | $- | $- |
| 2031 | $- | $9,404 | $3,048 | $5,615 | 0 | $- | $- |
| 2032 | $- | $9,411 | $3,056 | $5,615 | 0 | $- | $- |
| 2033 | $- | $9,391 | $3,048 | $5,615 | 0 | $- | $- |
| 2034 | $- | $9,361 | $3,048 | $5,615 | 0 | $- | $- |
| 2035 | $- | $9,265 | $3,048 | $5,615 | 0 | $- | $- |
| 2036 | $- | $9,373 | $3,056 | $5,615 | 0 | $- | $- |
| 2037 | $- | $9,376 | $3,048 | $5,615 | 0 | $- | $- |

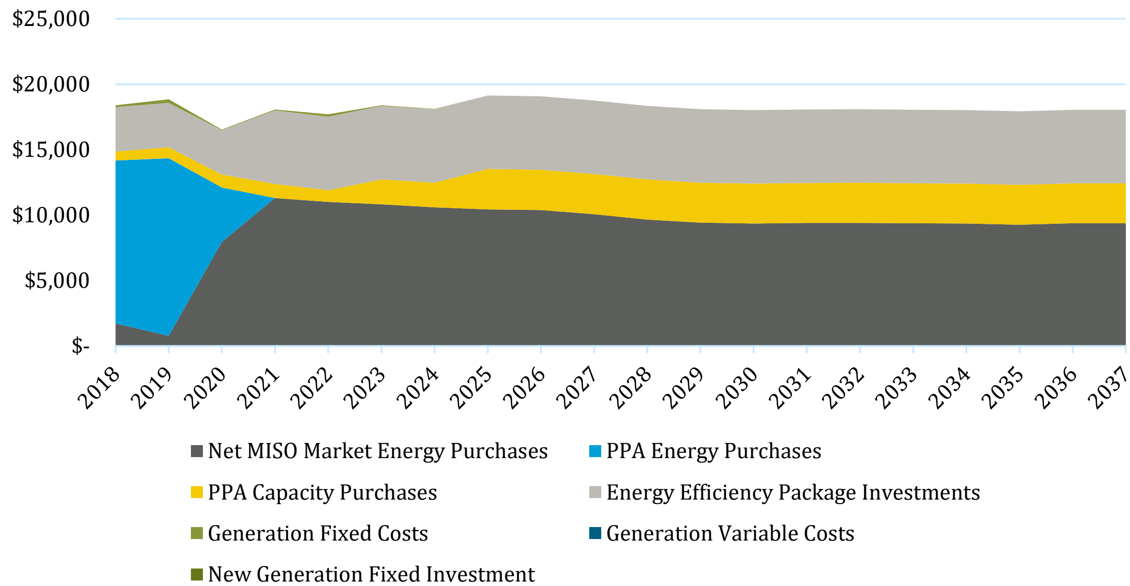



**Figure 9-1 Components of the BAU Base Case CPWC**

### 9.1.2 BAU: 100% Self-Supply

In this case, BAU with 100 percent self-supply is considered. UPPCO would employ a 36.3 MW thermal expansion commencing in 2024 with firm capacity of 18.1 MW from 2024 to 2030 and an increase to 36.3 MW from 2031 onwards. The thermal expansion fixed annual costs range from $344,000 to $686,000 and annual investment costs escalate from $2.107 million to $4.215 million in accordance with the firm capacity. MISO capacity market costs, oil-fired costs, and PPA capacity costs are also considered. PRM for this case is 8.4 percent with an RPS in 2021 of 17 percent and an EE percentage of 42 percent in 2025. In the base case, UPPCO would receive 100 percent of energy from owned resources. CPWC for this case is $215.378 million with a rank of 9. The detailed results of this case are shown in figure Table 9-2. The cost components of the CPWC are represented graphically in Figure 9-2.

**Table 9-2 CPWC for BAU 100% Self-Supply ($000)**

| YEAR | PPA ENERGY PURCHASES | NET MISO MARKET ENERGY PURCHASES | PPA CAPACITY PURCHASES | ENERGY EFFICIENCY PACKAGE INVESTMENTS | GENERATION FIXED COSTS | GENERATION VARIABLE COSTS | NEW GENERATION FIXED INVESTMENT |
|---|---|---|---|---|---|---|---|
| 2018 | $12,445 | $1,718 | $700 | $3,382 | $134 | $- | $- |
| 2019 | $13,560 | $784 | $838 | $3,382 | $284 | $- | $- |
| 2020 | $4,150 | $7,967 | $976 | $3,382 | $47 | $- | $- |
| 2021 | $- | $11,302 | $1,090 | $5,615 | $73 | $- | $- |
| 2022 | $- | $11,006 | $893 | $5,615 | $199 | $- | $- |
| 2023 | $- | $10,825 | $1,894 | $5,615 | $58 | $- | $- |
| 2024 | $- | $9,329 | $802 | $5,615 | $365 | $1,093 | $2,107 |
| 2025 | $- | $9,216 | $2,002 | $5,615 | $343 | $1,067 | $2,107 |
| 2026 | $- | $8,391 | $2,012 | $5,615 | $343 | $1,913 | $2,107 |
| 2027 | $- | $7,497 | $1,993 | $5,615 | $343 | $2,664 | $2,107 |
| 2028 | $- | $6,558 | $1,979 | $5,615 | $344 | $3,388 | $2,107 |
| 2029 | $- | $5,729 | $1,974 | $5,615 | $343 | $4,229 | $2,107 |
| 2030 | $- | $4,895 | $1,974 | $5,615 | $343 | $5,487 | $2,107 |
| 2031 | $- | $3,204 | $900 | $5,615 | $686 | $6,759 | $4,215 |
| 2032 | $- | $2,311 | $902 | $5,615 | $688 | $8,028 | $4,215 |
| 2033 | $- | $1,513 | $900 | $5,615 | $686 | $9,298 | $4,215 |
| 2034 | $- | $712 | $900 | $5,615 | $686 | $10,560 | $4,215 |
| 2035 | $- | $(54) | $900 | $5,615 | $686 | $11,819 | $4,215 |
| 2036 | $- | $(6) | $902 | $5,615 | $688 | $12,016 | $4,215 |
| 2037 | $- | $(26) | $900 | $5,615 | $686 | $12,070 | $4,215 |

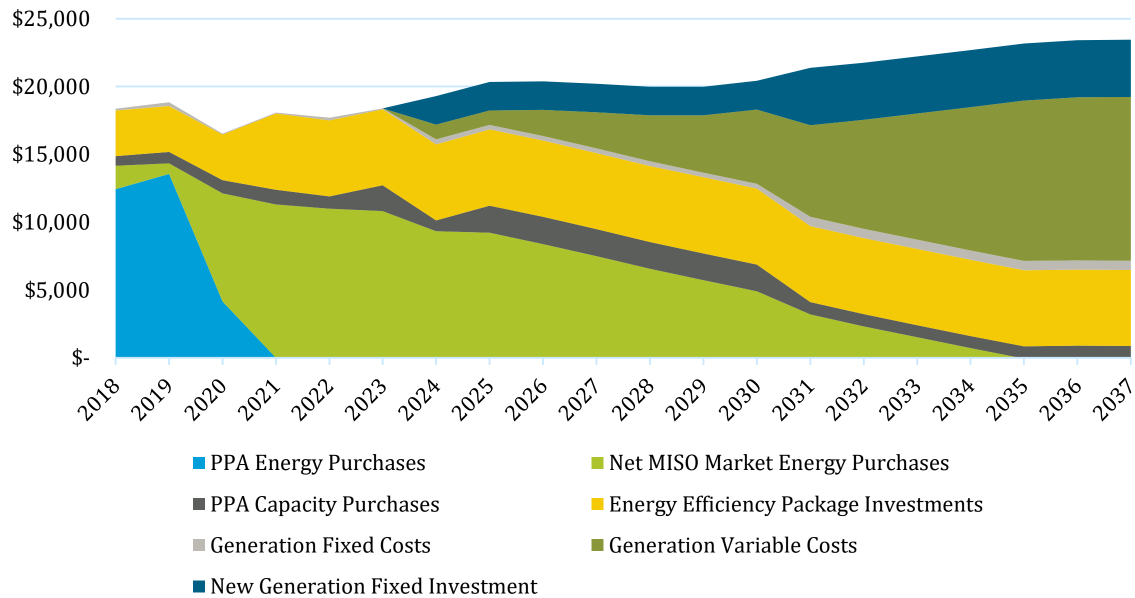



**Figure 9-2 Components of BAU 100% Self-Supply CPWC**

### 9.1.3 BAU: 50% Self-Supply

In this case, BAU with 50 percent self-supply is considered. UPPCO would employ a 7.3 MW thermal expansion commencing in 2023 with firm capacity of 7.3 MW from inception. The thermal expansion fixed annual costs range is approximately $101,500 and annual investment costs of $1.237 million. MISO capacity market costs, oil-fired costs, and PPA capacity costs are also considered. PRM for this case is 8.4 percent with an RPS in 2021 of 17 percent and an EE percentage of 42 percent in 2025. In the 50 percent self-supply case, UPPCO would receive 50 percent of energy from owned resources. CPWC for this case is $206.117 million with a rank of 5. The detailed results of this case are shown in Table 9-3. The cost components of the CPWC are represented graphically in Figure 9-3.

**Table 9-3 CPWC for BAU 50% Self-Supply ($000)**

| YEAR | PPA ENERGY PURCHASES | NET MISO MARKET ENERGY PURCHASES | PPA CAPACITY PURCHASES | ENERGY EFFICIENCY PACKAGE INVESTMENTS | GENERATION FIXED COSTS | GENERATION VARIABLE COSTS | NEW GENERATION FIXED INVESTMENT |
|---|---|---|---|---|---|---|---|
| 2018 | $12,445 | $1,718 | $700 | $3,382 | $134 | $- | $- |
| 2019 | $13,560 | $784 | $838 | $3,382 | $284 | $- | $- |
| 2020 | $4,150 | $7,967 | $976 | $3,382 | $47 | $- | $- |
| 2021 | $- | $11,302 | $1,090 | $5,615 | $73 | $- | $- |
| 2022 | $- | $11,006 | $893 | $5,615 | $199 | $- | $- |
| 2023 | $- | $10,330 | $1,459 | $5,615 | $159 | $430 | $1,237 |
| 2024 | $- | $9,450 | $1,444 | $5,615 | $123 | $1,221 | $1,237 |
| 2025 | $- | $8,715 | $2,642 | $5,615 | $101 | $2,146 | $1,237 |
| 2026 | $- | $8,763 | $2,652 | $5,615 | $101 | $1,924 | $1,237 |
| 2027 | $- | $8,774 | $2,633 | $5,615 | $101 | $1,437 | $1,237 |
| 2028 | $- | $8,763 | $2,621 | $5,615 | $102 | $921 | $1,237 |
| 2029 | $- | $8,902 | $2,614 | $5,615 | $101 | $468 | $1,237 |
| 2030 | $- | $8,843 | $2,614 | $5,615 | $101 | $467 | $1,237 |
| 2031 | $- | $8,883 | $2,614 | $5,615 | $101 | $468 | $1,237 |
| 2032 | $- | $8,899 | $2,621 | $5,615 | $102 | $460 | $1,237 |
| 2033 | $- | $8,870 | $2,614 | $5,615 | $101 | $469 | $1,237 |
| 2034 | $- | $8,855 | $2,614 | $5,615 | $101 | $470 | $1,237 |
| 2035 | $- | $8,754 | $2,614 | $5,615 | $101 | $471 | $1,237 |
| 2036 | $- | $8,854 | $2,621 | $5,615 | $102 | $469 | $1,237 |
| 2037 | $- | $8,868 | $2,614 | $5,615 | $101 | $485 | $1,237 |

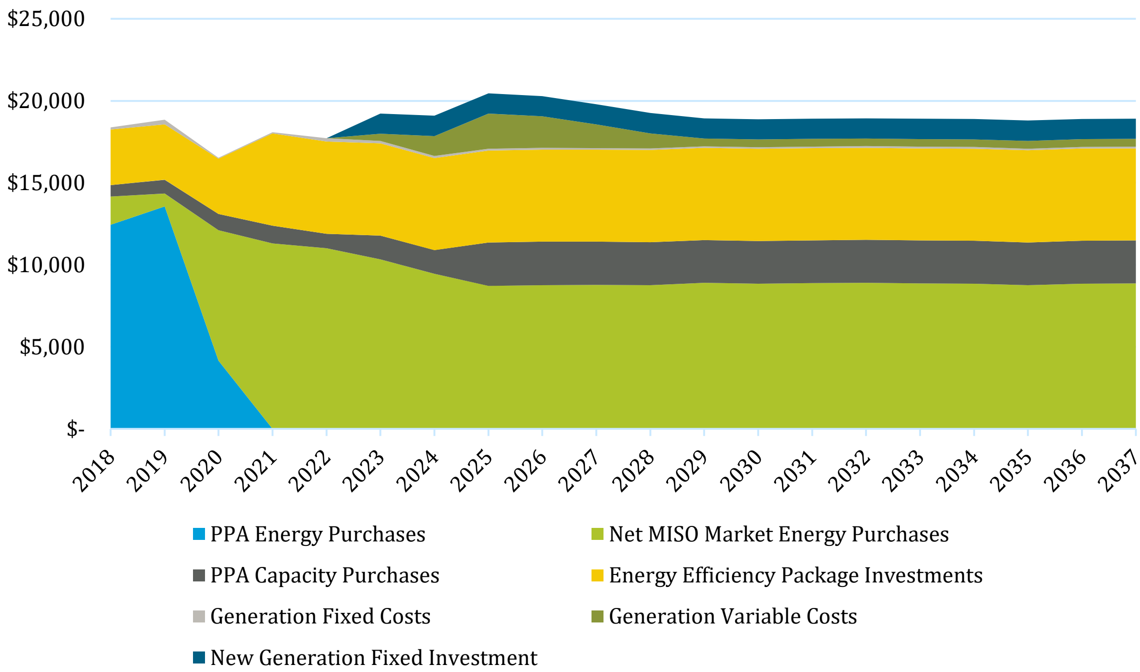



**Figure 9-3 Components of BAU 50% Self-Supply CPWC**

### 9.1.4 BAU: 75% Self-Supply

In this case, BAU with 75 percent self-supply is considered. UPPCO would employ an 18.1 MW thermal expansion commencing in 2023 with firm capacity of 18.1 from inception. The thermal expansion fixed annual costs range is approximately $343,000 and annual investment costs of $2.107 million. MISO capacity market costs, oil-fired costs, and PPA capacity costs are also considered. PRM for this case is 8.4 percent with an RPS in 2021 of 17 percent and an EE percentage of 42 percent in 2025. In the 75 percent self-supply case, UPPCO would receive 75 percent of energy from owned resources. CPWC for this case is $211.939 million with a rank of 7. The detailed results of this case are shown in Table 9-5. The cost components of the CPWC are represented graphically in Figure 9-5.

**Table 9-4 CPWC for BAU 75% Self-Supply ($000)**

| YEAR | PPA ENERGY PURCHASES | NET MISO MARKET ENERGY PURCHASES | PPA CAPACITY PURCHASES | ENERGY EFFICIENCY PACKAGE INVESTMENTS | GENERATION FIXED COSTS | GENERATION VARIABLE COSTS | NEW GENERATION FIXED INVESTMENT |
|---|---|---|---|---|---|---|---|
| 2018 | $12,445 | $1,718 | $700 | $3,382 | $134 | $- | $- |
| 2019 | $13,560 | $784 | $838 | $3,382 | $284 | $- | $- |
| 2020 | $4,150 | $7,967 | $976 | $3,382 | $47 | $- | $- |
| 2021 | $- | $11,302 | $1,090 | $5,615 | $73 | $- | $- |
| 2022 | $- | $11,006 | $893 | $5,615 | $199 | $- | $- |
| 2023 | $- | $10,825 | $1,894 | $5,615 | $58 | $- | $- |
| 2024 | $- | $9,329 | $802 | $5,615 | $365 | $1,093 | $2,107 |
| 2025 | $- | $9,020 | $2,002 | $5,615 | $343 | $1,294 | $2,107 |
| 2026 | $- | $8,047 | $2,012 | $5,615 | $343 | $2,335 | $2,107 |
| 2027 | $- | $7,142 | $1,993 | $5,615 | $343 | $3,135 | $2,107 |
| 2028 | $- | $6,187 | $1,979 | $5,615 | $344 | $3,910 | $2,107 |
| 2029 | $- | $5,364 | $1,974 | $5,615 | $343 | $4,804 | $2,107 |
| 2030 | $- | $4,547 | $1,974 | $5,615 | $343 | $6,112 | $2,107 |
| 2031 | $- | $4,591 | $1,974 | $5,615 | $343 | $6,121 | $2,107 |
| 2032 | $- | $4,591 | $1,979 | $5,615 | $344 | $6,132 | $2,107 |
| 2033 | $- | $4,574 | $1,974 | $5,615 | $343 | $6,137 | $2,107 |
| 2034 | $- | $4,532 | $1,974 | $5,615 | $343 | $6,147 | $2,107 |
| 2035 | $- | $4,480 | $1,974 | $5,615 | $343 | $6,136 | $2,107 |
| 2036 | $- | $4,531 | $1,979 | $5,615 | $344 | $6,241 | $2,107 |
| 2037 | $- | $4,549 | $1,974 | $5,615 | $343 | $6,274 | $2,107 |

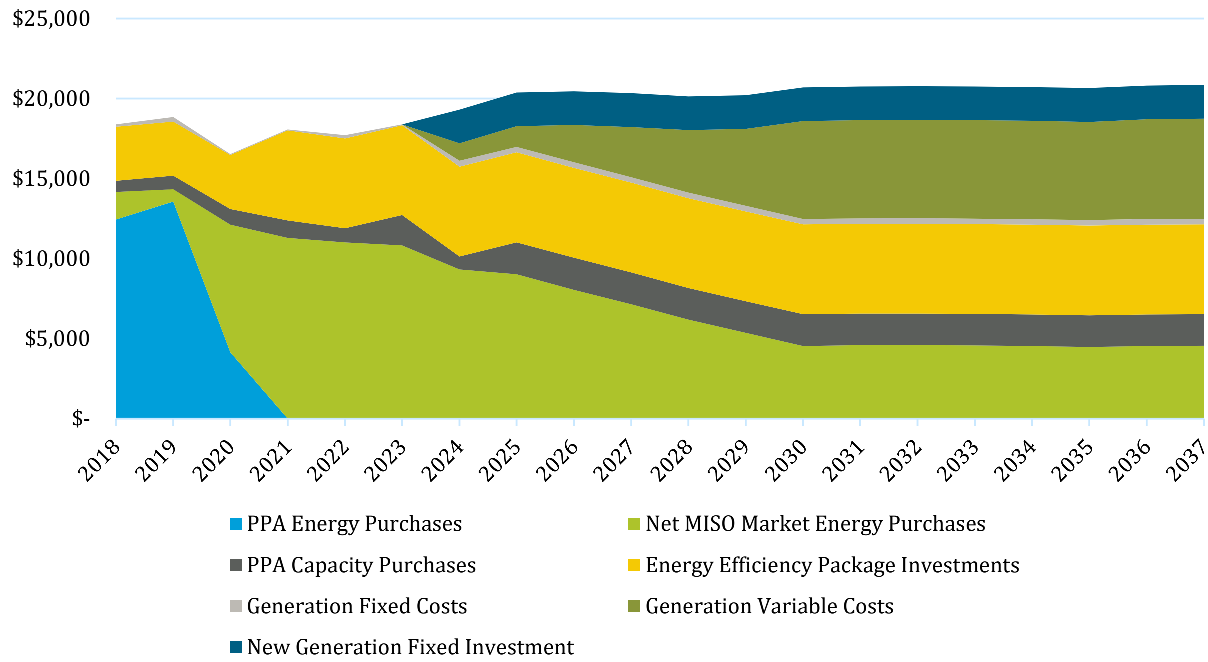



**Figure 9-4 Components of the BAU 75% Self-Supply CPWC**

### 9.1.5 BAU: 100% Self-Supply + No Thermal

In this case, BAU with 100 percent self-supply and no thermal expansion is considered. UPPCO would employ a 10 MW solar expansion, 20 MW solar expansion, and 20 MW wind expansion. The 10 MW solar expansion would commence in 2024 with firm capacity of 5 MW in 2024 increased to 40 MW by 2037 with annual average fixed costs of $868,000 and average annual investment costs of $6.008 million. The 20 MW solar expansion would commence in 2027 with firm capacity of 10 MW in 2025 increased to 30 MW by 2037 with annual average fixed costs of $475,000 and average annual investment costs of $3.212 million. The 20 MW wind expansion would commence in 2030 with firm capacity of 2.1 MW in 2030 increased to 4.2 MW by 2037 with annual average fixed costs of $1.544 million and average annual investment costs of $6.453 million. MISO capacity market costs, oil-fired costs, and PPA capacity costs are also considered. PRM for this case is 33.1 percent with an RPS in 2021 of 18 percent and an EE percentage of 45 percent in 2025. In the BAU with a 100 percent self-supply and no thermal expansion case, UPPCO would be able to receive 100.2 percent of energy from owned resources. CPWC for this case is $232.409 million with a rank of 12. The detailed results of this case are shown in Table 9-6. The cost components of the CPWC are represented graphically in Figure 9-6.

**Table 9-5 CPWC for BAU with 100% Self-Supply and No Thermal Expansion ($000)**

| YEAR | PPA ENERGY PURCHASES | NET MISO MARKET ENERGY PURCHASES | PPA CAPACITY PURCHASES | ENERGY EFFICIENCY PACKAGE INVESTMENTS | GENERATION FIXED COSTS | GENERATION VARIABLE COSTS | NEW GENERATION FIXED INVESTMENT |
|---|---|---|---|---|---|---|---|
| 2018 | $12,445 | $1,718 | $700 | $3,382 | $134 | $- | $- |
| 2019 | $13,560 | $784 | $838 | $3,382 | $284 | $- | $- |
| 2020 | $4,150 | $7,967 | $976 | $3,382 | $47 | $- | $- |
| 2021 | $- | $11,302 | $1,090 | $5,615 | $73 | $- | $- |
| 2022 | $- | $11,006 | $893 | $5,615 | $199 | $- | $- |
| 2023 | $- | $10,825 | $1,894 | $5,615 | $58 | $- | $- |
| 2024 | $- | $10,166 | $1,582 | $5,615 | $172 | $- | $1,077 |
| 2025 | $- | $9,565 | $2,483 | $5,615 | $300 | $- | $2,141 |
| 2026 | $- | $8,591 | $1,901 | $5,615 | $600 | $- | $4,245 |
| 2027 | $- | $7,399 | $1,289 | $5,615 | $900 | $- | $6,322 |
| 2028 | $- | $6,562 | $977 | $5,615 | $1,053 | $- | $7,349 |
| 2029 | $- | $5,372 | $382 | $5,615 | $1,350 | $- | $9,378 |
| 2030 | $- | $3,574 | $259 | $5,615 | $2,270 | $- | $13,064 |
| 2031 | $- | $3,537 | $259 | $5,615 | $2,250 | $- | $13,064 |
| 2032 | $- | $1,796 | $136 | $5,615 | $3,159 | $- | $16,753 |

| YEAR | PPA ENERGY PURCHASES | NET MISO MARKET ENERGY PURCHASES | PPA CAPACITY PURCHASES | ENERGY EFFICIENCY PACKAGE INVESTMENTS | GENERATION FIXED COSTS | GENERATION VARIABLE COSTS | NEW GENERATION FIXED INVESTMENT |
|---|---|---|---|---|---|---|---|
| 2033 | $- | $1,836 | $135 | $5,615 | $3,110 | $- | $16,753 |
| 2034 | $- | $465 | $- | $5,615 | $3,560 | $- | $19,618 |
| 2035 | $- | $(432) | $- | $5,615 | $3,860 | $- | $21,505 |
| 2036 | $- | $(553) | $- | $5,615 | $3,830 | $- | $21,505 |
| 2037 | $- | $(543) | $- | $5,615 | $3,820 | $- | $21,505 |

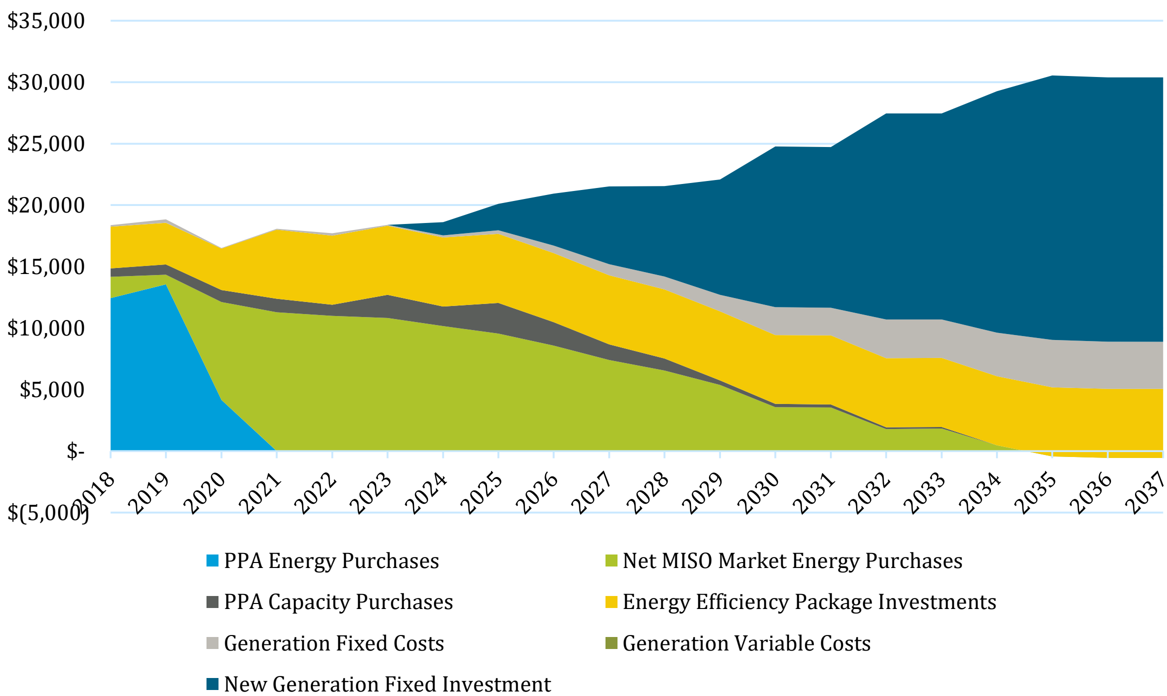



**Figure 9-5 Components of the BAU with 100% Self-Supply and No Thermal Expansion CPWC**

### 9.1.6 BAU: 50% Self-Supply + No Thermal

In this case, BAU with 50 percent self-supply and no thermal expansion is considered. UPPCO would employ a 10 MW solar expansion and 20 MW solar expansion. The 10 MW solar expansion would commence in 2023 with firm capacity of 5 MW from 2023 onwards with annual average fixed costs of $150,000 and average annual investment costs of $1.091 million. The 20 MW solar expansion would commence in 2024 with firm capacity of 10 MW in 2024 increased to 20 MW from 2025 onwards with annual average fixed costs of $600,000 and average annual investment costs of $4.283 million. MISO capacity market costs, oil-fired costs, and PPA capacity costs are also considered. PRM for this case is 8.4 percent with an RPS in 2021 of 17 percent and an EE percentage of 50 percent in 2025. In the BAU with 50 percent self-supply and no thermal expansion case, UPPCO would be able to receive 59.2 percent of energy from owned resources. CPWC for this case is $213.818 million with a rank of 8. The detailed results of this case are shown in Table 9-7. The cost components of the CPWC are represented graphically in Figure 9-7.

**Table 9-6 CPWC for BAU with 50% Self-Supply and No Thermal Expansion ($000)**

| YEAR | PPA ENERGY PURCHASES | NET MISO MARKET ENERGY PURCHASES | PPA CAPACITY PURCHASES | ENERGY EFFICIENCY PACKAGE INVESTMENTS | GENERATION FIXED COSTS | GENERATION VARIABLE COSTS | NEW GENERATION FIXED INVESTMENT |
|---|---|---|---|---|---|---|---|
| 2018 | $12,445 | $1,718 | $700 | $3,382 | $134 | $- | $- |
| 2019 | $13,560 | $784 | $838 | $3,382 | $284 | $- | $- |
| 2020 | $4,150 | $7,967 | $976 | $3,382 | $47 | $- | $- |
| 2021 | $- | $11,302 | $1,090 | $5,615 | $73 | $- | $- |
| 2022 | $- | $11,006 | $893 | $5,615 | $199 | $- | $- |
| 2023 | $- | $10,408 | $1,597 | $5,615 | $218 | $- | $1,091 |
| 2024 | $- | $9,309 | $988 | $5,615 | $472 | $- | $3,245 |
| 2025 | $- | $8,243 | $1,595 | $5,615 | $750 | $- | $5,374 |
| 2026 | $- | $8,142 | $1,605 | $5,615 | $750 | $- | $5,374 |
| 2027 | $- | $7,846 | $1,586 | $5,615 | $750 | $- | $5,374 |
| 2028 | $- | $7,449 | $1,571 | $5,615 | $752 | $- | $5,374 |
| 2029 | $- | $7,172 | $1,567 | $5,615 | $750 | $- | $5,374 |
| 2030 | $- | $7,117 | $1,567 | $5,615 | $750 | $- | $5,374 |
| 2031 | $- | $7,128 | $1,567 | $5,615 | $750 | $- | $5,374 |
| 2032 | $- | $7,147 | $1,571 | $5,615 | $752 | $- | $5,374 |
| 2033 | $- | $7,149 | $1,567 | $5,615 | $750 | $- | $5,374 |
| 2034 | $- | $7,131 | $1,567 | $5,615 | $750 | $- | $5,374 |
| 2035 | $- | $7,048 | $1,567 | $5,615 | $750 | $- | $5,374 |
| 2036 | $- | $7,086 | $1,571 | $5,615 | $752 | $- | $5,374 |

| YEAR | PPA ENERGY PURCHASES | NET MISO MARKET ENERGY PURCHASES | PPA CAPACITY PURCHASES | ENERGY EFFICIENCY PACKAGE INVESTMENTS | GENERATION FIXED COSTS | GENERATION VARIABLE COSTS | NEW GENERATION FIXED INVESTMENT |
|---|---|---|---|---|---|---|---|
| 2037 | $- | $7,106 | $1,567 | $5,615 | $750 | $- | $5,374 |

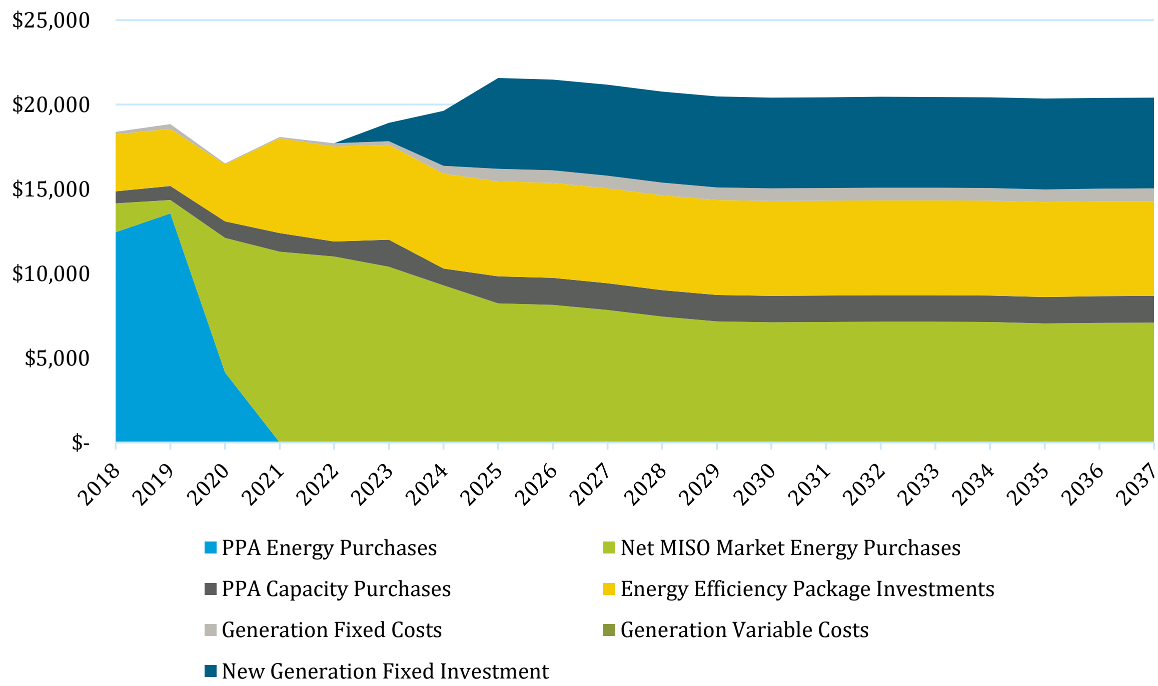



**Figure 9-6 Components of the BAU with 50% Self-Supply and No Thermal Expansion CPWC**

### 9.1.7 BAU: 75% Self-Supply + No Thermal

In this case, BAU with 75 percent self-supply and no thermal expansion is considered. UPPCO would employ a 10 MW solar expansion and 20 MW solar expansion. The 10 MW solar expansion would commence in 2025 with firm capacity of 5 MW from 2023 increased to 40 MW by 2037 with annual average fixed costs of $935,000 and average annual investment costs of $6.434 million. The 20 MW solar expansion would commence in 2024 with firm capacity of 10 MW in 2024 increased to 20 MW from 2027 onwards with annual average fixed costs of $536,000 and average annual investment costs of $3.787 million. MISO capacity market costs, oil-fired costs, and PPA capacity costs are also considered. PRM for this case is 17.7 percent with an RPS in 2021 of 17 percent and an EE percentage of 47 percent in 2025. In the BAU with 75 percent self-supply and no thermal expansion case, UPPCO would be able to receive 75 percent of energy from owned resources. CPWC for this case is $223.568 million with a rank of 10. The detailed results of this case are shown in Table 9-8. The cost components of the CPWC are represented graphically in Figure 9-8.

**Table 9-7 CPWC for BAU with 75% Self-Supply and No Thermal Expansion ($000)**

| YEAR | PPA ENERGY PURCHASES | NET MISO MARKET ENERGY PURCHASES | PPA CAPACITY PURCHASES | ENERGY EFFICIENCY PACKAGE INVESTMENTS | GENERATION FIXED COSTS | GENERATION VARIABLE COSTS | NEW GENERATION FIXED INVESTMENT |
|---|---|---|---|---|---|---|---|
| 2018 | $12,445 | $1,718 | $700 | $3,382 | $134 | $- | $- |
| 2019 | $13,560 | $784 | $838 | $3,382 | $284 | $- | $- |
| 2020 | $4,150 | $7,967 | $976 | $3,382 | $47 | $- | $- |
| 2021 | $- | $11,302 | $1,090 | $5,615 | $73 | $- | $- |
| 2022 | $- | $11,006 | $893 | $5,615 | $199 | $- | $- |
| 2023 | $- | $10,825 | $1,894 | $5,615 | $58 | $- | $- |
| 2024 | $- | $9,737 | $1,285 | $5,615 | $322 | $- | $2,154 |
| 2025 | $- | $9,124 | $2,187 | $5,615 | $450 | $- | $3,219 |
| 2026 | $- | $8,142 | $1,605 | $5,615 | $750 | $- | $5,322 |
| 2027 | $- | $6,953 | $993 | $5,615 | $1,050 | $- | $7,399 |
| 2028 | $- | $6,119 | $680 | $5,615 | $1,203 | $- | $8,426 |
| 2029 | $- | $4,922 | $86 | $5,615 | $1,500 | $- | $10,455 |
| 2030 | $- | $3,959 | $- | $5,615 | $1,800 | $- | $12,460 |
| 2031 | $- | $3,928 | $- | $5,615 | $1,800 | $- | $12,460 |
| 2032 | $- | $3,976 | $- | $5,615 | $1,805 | $- | $12,460 |
| 2033 | $- | $3,974 | $- | $5,615 | $1,800 | $- | $12,460 |
| 2034 | $- | $3,995 | $- | $5,615 | $1,800 | $- | $12,460 |
| 2035 | $- | $3,912 | $- | $5,615 | $1,800 | $- | $12,460 |
| 2036 | $- | $3,884 | $- | $5,615 | $1,805 | $- | $12,460 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 2037 | $- | $3,915 | $- | $5,615 | $1,800 | $- | $12,460 |

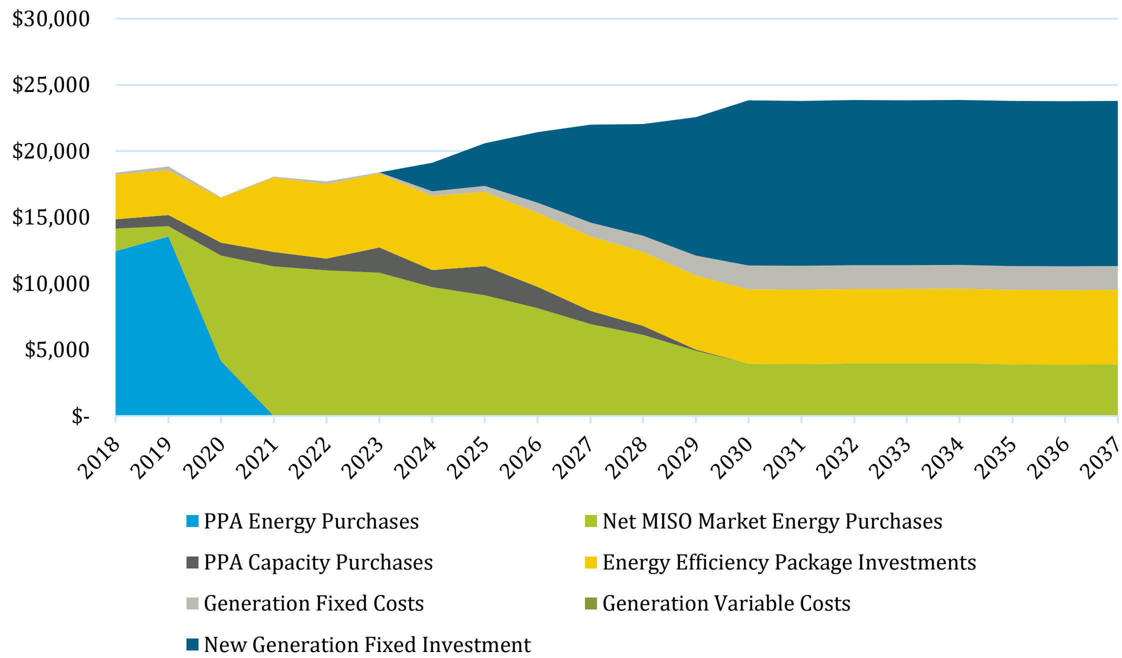



**Figure 9-7 Components of the BAU with 75% Self-Supply and No Thermal Expansion CPWC**

### 9.1.8 BAU: Base + RPS50

In this case, the BAU base case plus RPS50 is considered. UPPCO would employ a 10 MW solar expansion which would commence in 2030 with firm capacity of 25 MW from 2030 onwards with annual average fixed costs of $750,000 and average annual investment costs of $5.012 million. MISO capacity market costs, oil-fired costs, and PPA capacity costs are also considered. PRM for this case is 8.4 percent with an RPS in 2021 of 17 percent and an EE percentage of 42 percent in 2025. In BAU base case plus RPS50 case, UPPCO would be able to receive 59.2 percent of energy from owned resources. CPWC for this case is $205.150 million with a rank of 4. The detailed results of this case are shown in Table 9-9. The cost components of the CPWC are represented graphically in Figure 9-9.

**Table 9-8 CPWC BAU Base Case Plus RPS50 ($000)**

| YEAR | PPA ENERGY PURCHASES | NET MISO MARKET ENERGY PURCHASES | PPA CAPACITY PURCHASES | ENERGY EFFICIENCY PACKAGE INVESTMENTS | GENERATION FIXED COSTS | GENERATION VARIABLE COSTS | NEW GENERATION FIXED INVESTMENT |
|---|---|---|---|---|---|---|---|
| 2018 | $12,445 | $1,718 | $700 | $3,382 | $134 | $- | $- |
| 2019 | $13,560 | $784 | $838 | $3,382 | $284 | $- | $- |
| 2020 | $4,150 | $7,967 | $976 | $3,382 | $47 | $- | $- |
| 2021 | $- | $11,302 | $1,090 | $5,615 | $73 | $- | $- |
| 2022 | $- | $11,006 | $893 | $5,615 | $199 | $- | $- |
| 2023 | $- | $10,825 | $1,894 | $5,615 | $58 | $- | $- |
| 2024 | $- | $10,594 | $1,880 | $5,615 | $21 | $- | $- |
| 2025 | $- | $10,446 | $3,076 | $5,615 | $- | $- | $- |
| 2026 | $- | $10,384 | $3,086 | $5,615 | $- | $- | $- |
| 2027 | $- | $10,080 | $3,067 | $5,615 | $- | $- | $- |
| 2028 | $- | $9,665 | $3,056 | $5,615 | $- | $- | $- |
| 2029 | $- | $9,423 | $3,048 | $5,615 | $- | $- | $- |
| 2030 | $- | $7,117 | $1,567 | $5,615 | $750 | $- | $5,012 |
| 2031 | $- | $7,128 | $1,567 | $5,615 | $750 | $- | $5,012 |
| 2032 | $- | $7,147 | $1,571 | $5,615 | $752 | $- | $5,012 |
| 2033 | $- | $7,149 | $1,567 | $5,615 | $750 | $- | $5,012 |
| 2034 | $- | $7,131 | $1,567 | $5,615 | $750 | $- | $5,012 |
| 2035 | $- | $7,048 | $1,567 | $5,615 | $750 | $- | $5,012 |
| 2036 | $- | $7,086 | $1,571 | $5,615 | $752 | $- | $5,012 |
| 2037 | $- | $7,106 | $1,567 | $5,615 | $750 | $- | $5,012 |

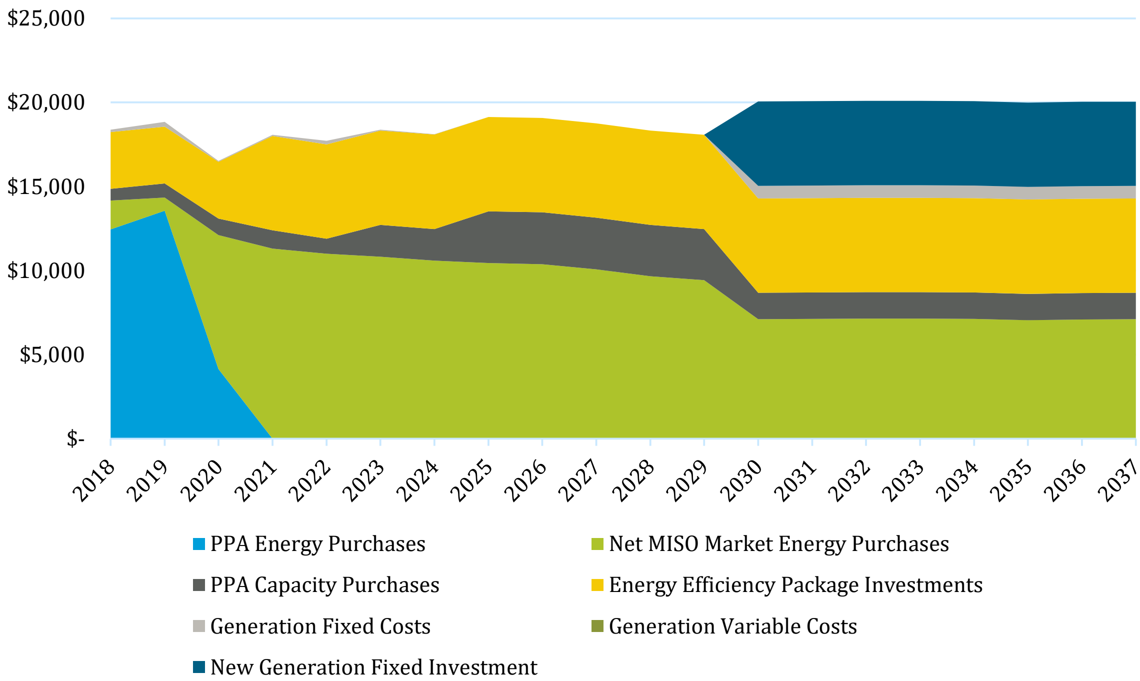



**Figure 9-8 Components of the BAU Base Case Plus RPS50 CPWC**

### 9.1.9 BAU: 1.5% Load Growth

In this case, BAU with a 1.5 percent load growth requirement is considered. UPPCO would employ a 10 MW solar expansion commencing in 2026 with firm capacity of 5 MW from 2026-2033 and 10 MW from 2034 onwards. The solar expansion fixed annual costs escalate from $150,000 to $300,000 and annual investment costs escalate from $1.052 million to $2.007 million in accordance with the firm capacity. MISO capacity market costs, oil-fired costs, and PPA capacity costs are also considered. PRM for this case is 8.4 percent with an RPS in 2021 of 17 percent and an EE percentage of 38 percent in 2025. In the 1.5 percent load growth case, UPPCO would receive 38 percent of energy from owned resources. CPWC for this case is $237.545 million with a rank of 14. The detailed results of this case are shown in Table 9-10. The cost components of the CPWC are represented graphically in Figure 9-10.

**Table 9-9 CPWC for BAU at 1.5% Load Growth ($000)**

| YEAR | PPA ENERGY PURCHASES | NET MISO MARKET ENERGY PURCHASES | PPA CAPACITY PURCHASES | ENERGY EFFICIENCY PACKAGE INVESTMENTS | GENERATION FIXED COSTS | GENERATION VARIABLE COSTS | NEW GENERATION FIXED INVESTMENT |
|---|---|---|---|---|---|---|---|
| 2018 | $12,445 | $2,066 | $700 | $3,382 | $134 | $- | $- |
| 2019 | $13,560 | $1,155 | $838 | $3,382 | $284 | $- | $- |
| 2020 | $4,150 | $8,650 | $1,180 | $3,382 | $47 | $- | $- |
| 2021 | $- | $12,289 | $1,388 | $5,615 | $73 | $- | $- |
| 2022 | $- | $12,265 | $1,272 | $5,615 | $199 | $- | $- |
| 2023 | $- | $12,439 | $2,370 | $5,615 | $58 | $- | $- |
| 2024 | $- | $12,577 | $2,456 | $5,615 | $21 | $- | $- |
| 2025 | $- | $12,831 | $3,751 | $5,615 | $- | $- | $- |
| 2026 | $- | $12,720 | $3,567 | $5,615 | $150 | $- | $1,052 |
| 2027 | $- | $12,822 | $3,650 | $5,615 | $150 | $- | $1,052 |
| 2028 | $- | $12,796 | $3,745 | $5,615 | $150 | $- | $1,052 |
| 2029 | $- | $12,912 | $3,820 | $5,615 | $150 | $- | $1,052 |
| 2030 | $- | $13,166 | $3,908 | $5,615 | $150 | $- | $1,052 |
| 2031 | $- | $13,538 | $3,996 | $5,615 | $150 | $- | $1,052 |
| 2032 | $- | $13,872 | $4,097 | $5,615 | $150 | $- | $1,052 |
| 2033 | $- | $14,183 | $4,177 | $5,615 | $150 | $- | $1,052 |
| 2034 | $- | $14,061 | $3,973 | $5,615 | $300 | $- | $2,007 |
| 2035 | $- | $14,261 | $4,067 | $5,615 | $300 | $- | $2,007 |
| 2036 | $- | $14,792 | $4,174 | $5,615 | $301 | $- | $2,007 |
| 2037 | $- | $15,158 | $4,259 | $5,615 | $300 | $- | $2,007 |

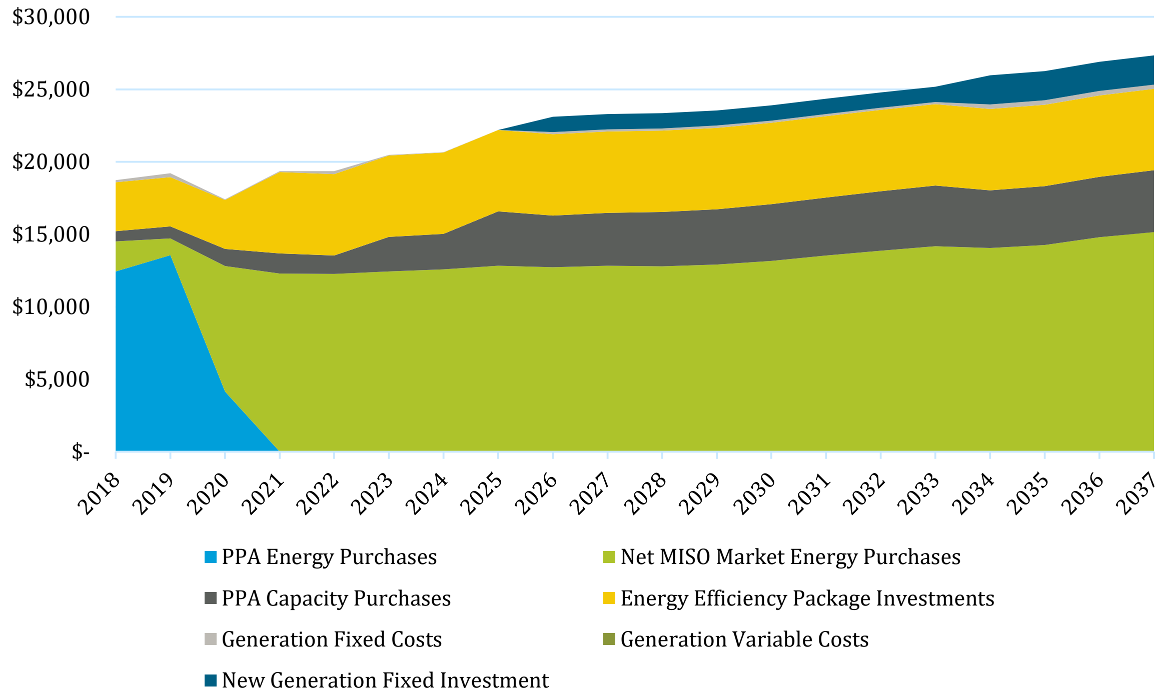



**Figure 9-9 Components of the BAU at 1.5% Load Growth CPWC**

### 9.1.10 BAU: 200% Gas Price

In this case, BAU with a 200 percent gas price rate is considered. UPPCO would employ a 100 MW solar expansion commencing in 2034 with firm capacity of 50 MW from 2034-2037. The solar expansion fixed annual costs escalate are approximately 1.500 million and annual investment costs escalate are approximately $9.551 million. MISO capacity market costs, oil-fired costs, and PPA capacity costs are also considered. PRM for this case is 8.4 percent with an RPS in 2021 of 17 percent and an EE percentage of 42 percent in 2025. In the 200 percent gas price rate, UPPCO would receive 70.5 percent of energy from owned resources. CPWC for this case is $283.961 million with a rank of 21. The detailed results of this case are shown in Table 9-11. The cost components of the CPWC are represented graphically in Figure 9-11.

**Table 9-10 CPWC for BAU With a 200% Gas Price Rate ($000)**

| YEAR | PPA ENERGY PURCHASES | NET MISO MARKET ENERGY PURCHASES | PPA CAPACITY PURCHASES | ENERGY EFFICIENCY PACKAGE INVESTMENTS | GENERATION FIXED COSTS | GENERATION VARIABLE COSTS | NEW GENERATION FIXED INVESTMENT |
|---|---|---|---|---|---|---|---|
| 2018 | $12,445 | $2,989 | $700 | $3,382 | $134 | $- | $- |
| 2019 | $13,560 | $1,405 | $838 | $3,382 | $284 | $- | $- |
| 2020 | $4,150 | $14,574 | $976 | $3,382 | $47 | $- | $- |
| 2021 | $- | $20,739 | $1,090 | $5,615 | $73 | $- | $- |
| 2022 | $- | $20,348 | $893 | $5,615 | $199 | $- | $- |
| 2023 | $- | $20,443 | $1,894 | $5,615 | $58 | $- | $- |
| 2024 | $- | $20,312 | $1,880 | $5,615 | $21 | $- | $- |
| 2025 | $- | $20,282 | $3,076 | $5,615 | $- | $- | $- |
| 2026 | $- | $20,269 | $3,086 | $5,615 | $- | $- | $- |
| 2027 | $- | $19,792 | $3,067 | $5,615 | $- | $- | $- |
| 2028 | $- | $19,009 | $3,056 | $5,615 | $- | $- | $- |
| 2029 | $- | $18,649 | $3,048 | $5,615 | $- | $- | $- |
| 2030 | $- | $18,605 | $3,048 | $5,615 | $- | $- | $- |
| 2031 | $- | $18,681 | $3,048 | $5,615 | $- | $- | $- |
| 2032 | $- | $18,664 | $3,056 | $5,615 | $- | $- | $- |
| 2033 | $- | $18,688 | $3,048 | $5,615 | $- | $- | $- |
| 2034 | $- | $9,766 | $86 | $5,615 | $1,500 | $- | $9,551 |
| 2035 | $- | $9,676 | $86 | $5,615 | $1,500 | $- | $9,551 |
| 2036 | $- | $9,668 | $86 | $5,615 | $1,504 | $- | $9,551 |
| 2037 | $- | $9,750 | $86 | $5,615 | $1,500 | $- | $9,551 |

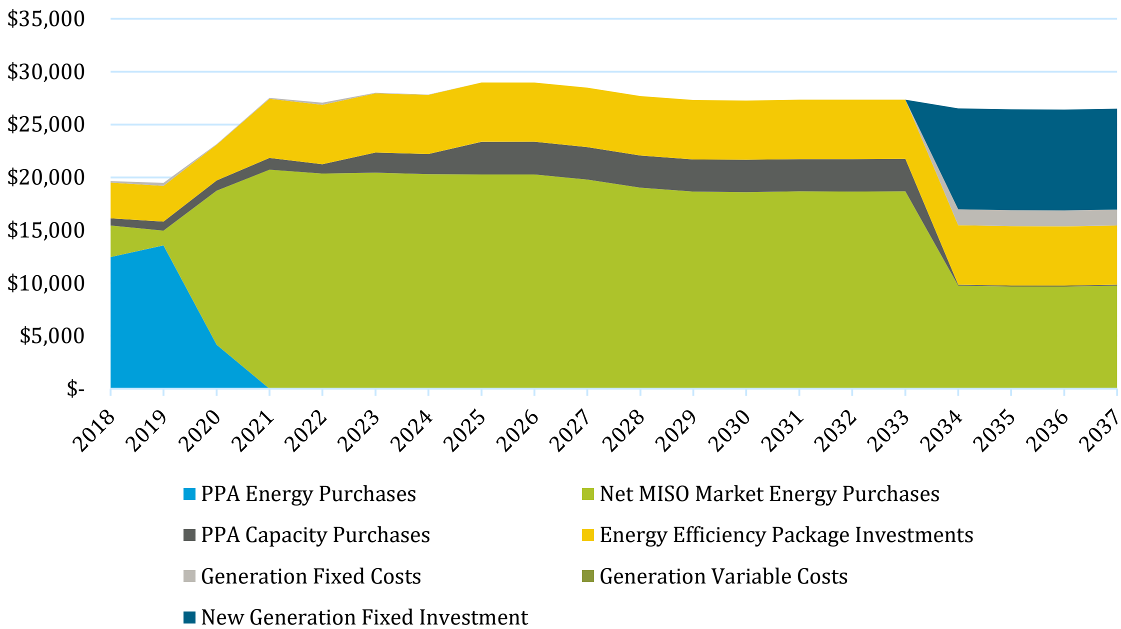



**Figure 9-10 Components of BAU With a 200% Gas Price Rate CPWC**

### 9.1.11 BAU: All Simple Cycle

In this case, BAU with an all simple cycle is considered. UPPCO would employ a 78.4 MW thermal expansion commencing in 2020 with firm capacity of 39.2 MW from 2020-2024 and 78.4 MW from 2025 onwards. The thermal expansion fixed annual costs escalate from $700,000 to $1.406 million and annual investment costs escalate from $5.464 million to $10.928 million in accordance with the firm capacity. Oil-fired costs and PPA capacity costs are also considered. PRM for this case is 37.7 percent with an RPS in 2021 of 17 percent and an EE percentage of 42 percent in 2025. In the BAU all simple cycle case, UPPCO would receive 38 percent of energy from owned resources. CPWC for this case is $263.057 million with a rank of 18. The detailed results of this case are shown in Table 9-12. The cost components of the CPWC are represented graphically in Figure 9-12.

**Table 9-11 CPWC for BAU With a 200% Gas Price Rate ($000)**

| YEAR | PPA ENERGY PURCHASES | NET MISO MARKET ENERGY PURCHASES | PPA CAPACITY PURCHASES | ENERGY EFFICIENCY PACKAGE INVESTMENTS | GENERATION FIXED COSTS | GENERATION VARIABLE COSTS | NEW GENERATION FIXED INVESTMENT |
|---|---|---|---|---|---|---|---|
| 2018 | $12,445 | $1,718 | $700 | $3,382 | $134 | $- | $- |
| 2019 | $13,560 | $784 | $838 | $3,382 | $284 | $- | $- |
| 2020 | $4,150 | $4,326 | $551 | $3,382 | $751 | $3,183 | $5,464 |
| 2021 | $- | $7,849 | $359 | $5,615 | $775 | $3,031 | $5,464 |
| 2022 | $- | $7,542 | $165 | $5,615 | $901 | $3,064 | $5,464 |
| 2023 | $- | $7,640 | $- | $5,615 | $760 | $2,822 | $5,464 |
| 2024 | $- | $7,596 | $- | $5,615 | $725 | $2,644 | $5,464 |
| 2025 | $- | $4,689 | $- | $5,615 | $1,405 | $5,096 | $10,928 |
| 2026 | $- | $4,469 | $- | $5,615 | $1,405 | $5,150 | $10,928 |
| 2027 | $- | $4,483 | $- | $5,615 | $1,405 | $4,899 | $10,928 |
| 2028 | $- | $4,761 | $- | $5,615 | $1,409 | $4,265 | $10,928 |
| 2029 | $- | $4,729 | $- | $5,615 | $1,405 | $4,071 | $10,928 |
| 2030 | $- | $4,806 | $- | $5,615 | $1,405 | $3,917 | $10,928 |
| 2031 | $- | $4,879 | $- | $5,615 | $1,405 | $3,873 | $10,928 |
| 2032 | $- | $4,837 | $- | $5,615 | $1,409 | $3,924 | $10,928 |
| 2033 | $- | $5,186 | $- | $5,615 | $1,405 | $3,522 | $10,928 |
| 2034 | $- | $5,507 | $- | $5,615 | $1,405 | $3,325 | $10,928 |
| 2035 | $- | $5,582 | $- | $5,615 | $1,405 | $3,109 | $10,928 |
| 2036 | $- | $5,471 | $- | $5,615 | $1,409 | $3,264 | $10,928 |
| 2037 | $- | $5,852 | $- | $5,615 | $1,405 | $3,090 | $10,928 |

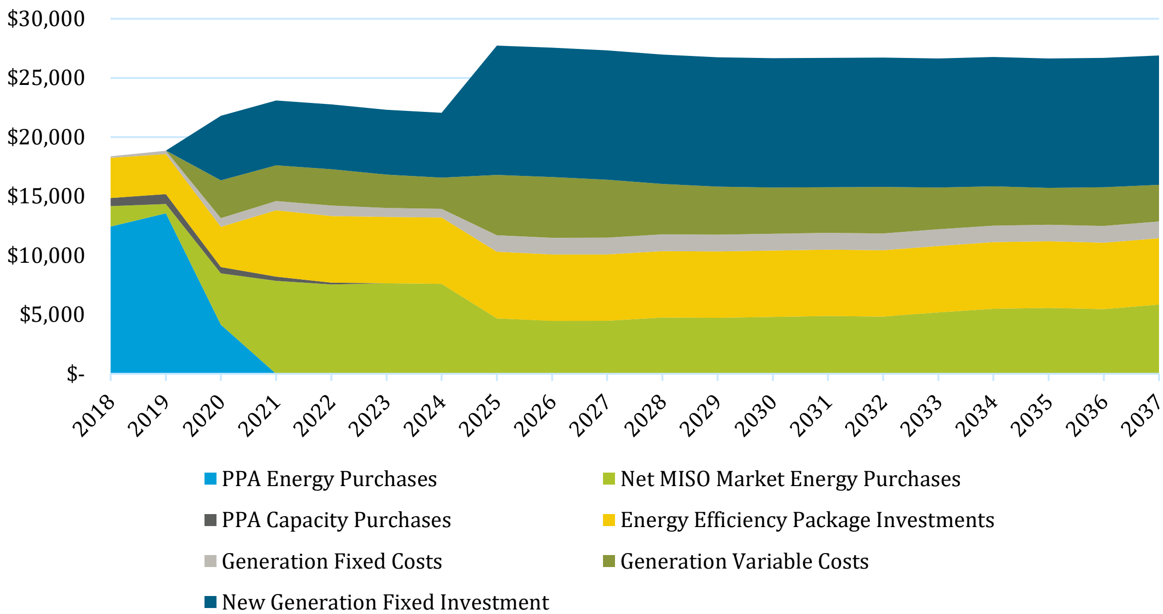



**Figure 9-11 Components of BAU All Simple Cycle CPWC**

### 9.1.12 BAU: RICE 2022

In this case, the BAU base case with a RICE thermal expansion commencing in 2022 is considered. UPPCO would employ a thermal expansion with a firm capacity of 18.1 MW from 2022 onwards with annual average fixed costs of $343,000 and average annual investment costs of $2.053 million. UPPCO would continue to purchase energy and capacity from the MISO capacity market resulting in average annual fixed costs of $1.689 million for the 20-year period, as well as annual investment costs of $5.280 million for the energy efficiency packages. Oil-fired costs and PPA capacity costs are also considered. PRM for this case is 8.4 percent with an RPS in 2021 of 17 percent and an EE percentage of 42 percent in 2025. In the BAU RICE 2020 case, UPPCO would be able to receive 51.1% percent of energy from owned resources. CPWC for this case is $210.672 million with a rank of 9. The detailed results of this case are shown in Table 9-12. The cost components of the CPWC are represented graphically in Figure 9-12.

**Table 9-12 CPWC for BAU RICE 2022 ($000)**

| YEAR | PPA ENERGY PURCHASES | NET MISO MARKET ENERGY PURCHASES | PPA CAPACITY PURCHASES | ENERGY EFFICIENCY PACKAGE INVESTMENTS | GENERATION FIXED COSTS | GENERATION VARIABLE COSTS | NEW GENERATION FIXED INVESTMENT |
|---|---|---|---|---|---|---|---|
| 2018 | $12,445 | $1,718.2 | $700 | $3,382 | $134 | $- | $- |
| 2019 | $13,560 | $784.0 | $1,879 | $3,382 | $238 | $- | $- |
| 2020 | $4,150 | $7,967.3 | $1,012 | $3,382 | $19 | $- | $- |
| 2021 | $- | $11,301.6 | $1,125 | $5,615 | $44 | $- | $- |
| 2022 | $- | $10,058.0 | $165 | $5,615 | $351 | $812 | $1,229 |
| 2023 | $- | $9,527.9 | $2,040 | $5,615 | $343 | $1,129 | $2,107 |
| 2024 | $- | $9,346.0 | $2,027 | $5,615 | $344 | $1,080 | $2,107 |
| 2025 | $- | $9,207.3 | $2,002 | $5,615 | $343 | $1,072 | $2,107 |
| 2026 | $- | $9,113.7 | $2,012 | $5,615 | $343 | $1,077 | $2,107 |
| 2027 | $- | $8,864.8 | $1,993 | $5,615 | $343 | $1,038 | $2,107 |
| 2028 | $- | $8,560.6 | $1,979 | $5,615 | $344 | $934 | $2,107 |
| 2029 | $- | $8,322.4 | $1,974 | $5,615 | $343 | $929 | $2,107 |
| 2030 | $- | $8,327.2 | $1,974 | $5,615 | $343 | $865 | $2,107 |
| 2031 | $- | $8,365.7 | $1,974 | $5,615 | $343 | $863 | $2,107 |
| 2032 | $- | $8,342.2 | $1,980 | $5,615 | $344 | $890 | $2,107 |
| 2033 | $- | $8,397.7 | $1,974 | $5,615 | $343 | $808 | $2,107 |
| 2034 | $- | $8,438.4 | $1,974 | $5,615 | $343 | $771 | $2,107 |
| 2035 | $- | $8,357.6 | $1,974 | $5,615 | $343 | $742 | $2,107 |
| 2036 | $- | $8,408.9 | $1,980 | $5,615 | $344 | $784 | $2,107 |
| 2037 | $- | $8,505.5 | $1,974 | $5,615 | $343 | $739 | $2,107 |

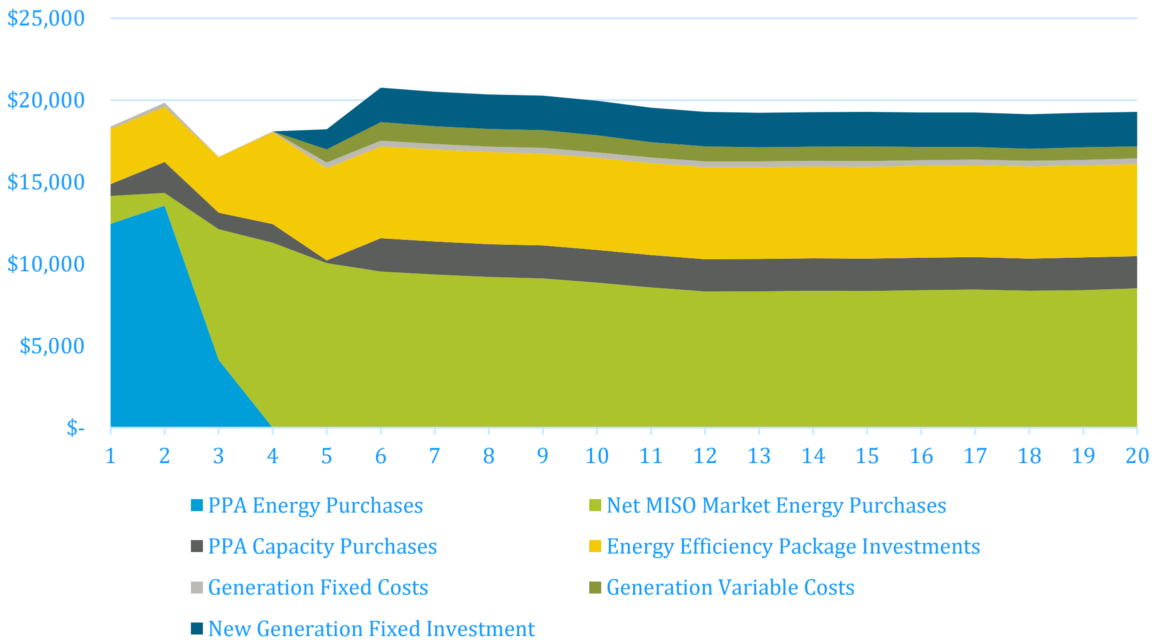



**Figure 9-12 Components of BAU RICE 22 CPWC**

### 9.1.13 BAU: Solar 2022

In this case, the BAU base case with a solar expansion commencing in 2022 is considered. UPPCO would employ a 20 MW solar expansion with a firm capacity of 10 MW from 2022 onwards with annual average fixed costs of $303,000 and average annual investment costs of $2.150 million. UPPCO would continue to purchase energy and capacity from the MISO capacity market resulting in average annual fixed costs of $2.079 million for the 20-year period, as well as annual investment costs of $5.280 million for the energy efficiency packages. Oil-fired costs and PPA capacity costs are also considered. PRM for this case is 8.4 percent with an RPS in 2021 of 17 percent and an EE percentage of 45 percent in 2025. In the BAU Solar 2022 case, UPPCO would be able to receive 52.4% percent of energy from owned resources. CPWC for this case is $209.425 million with a rank of 8. The detailed results of this case are shown in Table 9-13. The cost components of the CPWC are represented graphically in Figure 9-13.

**Table 9-13 CPWC for BAU Solar 2022 ($000)**

| YEAR | PPA ENERGY PURCHASES | NET MISO MARKET ENERGY PURCHASES | PPA CAPACITY PURCHASES | ENERGY EFFICIENCY PACKAGE INVESTMENTS | GENERATION FIXED COSTS | GENERATION VARIABLE COSTS | NEW GENERATION FIXED INVESTMENT |
|---|---|---|---|---|---|---|---|
| 2018 | $12,445 | $1,718.2 | $700 | $3,382 | $134 | $- | $- |
| 2019 | $13,560 | $784.0 | $1,879 | $3,382 | $238 | $- | $- |
| 2020 | $4,150 | $7,967.3 | $1,012 | $3,382 | $19 | $- | $- |
| 2021 | $- | $11,301.6 | $1,125 | $5,615 | $44 | $- | $- |
| 2022 | $- | $10,539.0 | $336 | $5,615 | $328 | $- | $1,287 |
| 2023 | $- | $9,991.1 | $2,522 | $5,615 | $320 | $- | $2,207 |
| 2024 | $- | $9,737.3 | $2,509 | $5,615 | $301 | $- | $2,207 |
| 2025 | $- | $9,564.8 | $2,483 | $5,615 | $300 | $- | $2,207 |
| 2026 | $- | $9,487.1 | $2,494 | $5,615 | $300 | $- | $2,207 |
| 2027 | $- | $9,186.2 | $2,474 | $5,615 | $300 | $- | $2,207 |
| 2028 | $- | $8,778.7 | $2,462 | $5,615 | $301 | $- | $2,207 |
| 2029 | $- | $8,522.3 | $2,455 | $5,615 | $300 | $- | $2,207 |
| 2030 | $- | $8,465.0 | $2,456 | $5,615 | $300 | $- | $2,207 |
| 2031 | $- | $8,494.0 | $2,456 | $5,615 | $300 | $- | $2,207 |
| 2032 | $- | $8,505.8 | $2,462 | $5,615 | $301 | $- | $2,207 |
| 2033 | $- | $8,494.3 | $2,456 | $5,615 | $300 | $- | $2,207 |
| 2034 | $- | $8,468.9 | $2,456 | $5,615 | $300 | $- | $2,207 |
| 2035 | $- | $8,378.4 | $2,456 | $5,615 | $300 | $- | $2,207 |
| 2036 | $- | $8,458.2 | $2,462 | $5,615 | $301 | $- | $2,207 |
| 2037 | $- | $8,468.5 | $2,456 | $5,615 | $300 | $- | $2,207 |

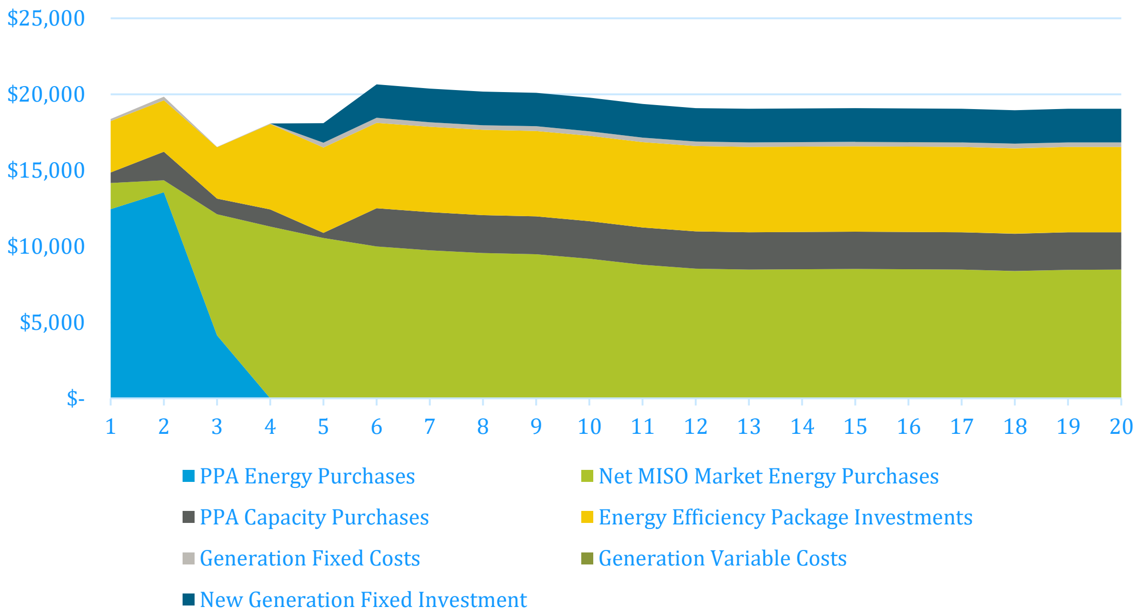



**Figure 9-13 Components of BAU Solar 2022 CPWC**

### 9.1.14 RICE + Solar 2022

Immaterial In this case, PCA in 2022 is considered. UPPCO would employ an 18.1 MW thermal and a 20 MW solar expansion. The 18.1 MW thermal expansion would commence in 2022 with firm capacity of 18.1 MW from 2022 onwards with annual average fixed costs of $343,000 and average annual investment costs of $2.053 million. The 20 MW solar expansion would commence in 2022 with firm capacity of 10 MW from 2022 onwards with annual average fixed costs of $303,000 and average annual investment costs of $2.150 million. UPPCO would continue to purchase energy and capacity from the MISO capacity market resulting in average annual fixed costs of $1.160 million for the 20-year period, as well as annual investment costs of $5.280 million for the energy efficiency packages. Oil-fired costs and PPA capacity costs are also considered. PRM for this case is 8.4 percent with an RPS in 2021 of 17 percent and an EE percentage of 45 percent in 2025. In the PCA 2022 case, UPPCO would be able to receive 55.7% percent of energy from owned resources. CPWC for this case is $218.367 million with a rank of 14. The detailed results of this case are shown in Table 9-14. The cost components of the CPWC are represented graphically in Figure 9-14.

**Table 9-14 CPWC for BAU RICE + Solar 2022 ($000)**

| YEAR | PPA ENERGY PURCHASES | NET MISO MARKET ENERGY PURCHASES | PPA CAPACITY PURCHASES | ENERGY EFFICIENCY PACKAGE INVESTMENTS | GENERATION FIXED COSTS | GENERATION VARIABLE COSTS | NEW GENERATION FIXED INVESTMENT |
|---|---|---|---|---|---|---|---|
| 2018 | $12,445 | $1,718.2 | $700 | $3,382 | $134 | $- | $- |
| 2019 | $13,560 | $784.0 | $1,879 | $3,382 | $238 | $- | $- |
| 2020 | $4,150 | $7,967.3 | $1,012 | $3,382 | $19 | $- | $- |
| 2021 | $- | $11,301.6 | $1,125 | $5,615 | $44 | $- | $- |
| 2022 | $- | $9,594.2 | $165 | $5,615 | $671 | $810 | $2,517 |
| 2023 | $- | $8,699.8 | $1,448 | $5,615 | $663 | $1,126 | $4,314 |
| 2024 | $- | $8,469.8 | $1,432 | $5,615 | $645 | $1,096 | $4,314 |
| 2025 | $- | $8,223.0 | $1,409 | $5,615 | $643 | $1,189 | $4,314 |
| 2026 | $- | $8,197.4 | $1,420 | $5,615 | $643 | $1,094 | $4,314 |
| 2027 | $- | $7,975.3 | $1,400 | $5,615 | $643 | $1,035 | $4,314 |
| 2028 | $- | $7,661.9 | $1,385 | $5,615 | $645 | $944 | $4,314 |
| 2029 | $- | $7,445.3 | $1,382 | $5,615 | $643 | $911 | $4,314 |
| 2030 | $- | $7,407.3 | $1,382 | $5,615 | $643 | $882 | $4,314 |
| 2031 | $- | $7,441.5 | $1,382 | $5,615 | $643 | $874 | $4,314 |
| 2032 | $- | $7,447.2 | $1,385 | $5,615 | $645 | $881 | $4,314 |
| 2033 | $- | $7,509.6 | $1,382 | $5,615 | $643 | $801 | $4,314 |
| 2034 | $- | $7,550.4 | $1,382 | $5,615 | $643 | $768 | $4,314 |
| 2035 | $- | $7,471.8 | $1,382 | $5,615 | $643 | $741 | $4,314 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **2036** | $- | $7,506.7 | $1,385 | $5,615 | $645 | $773 | $4,314 |
| **2037** | $- | $7,573.3 | $1,382 | $5,615 | $643 | $758 | $4,314 |

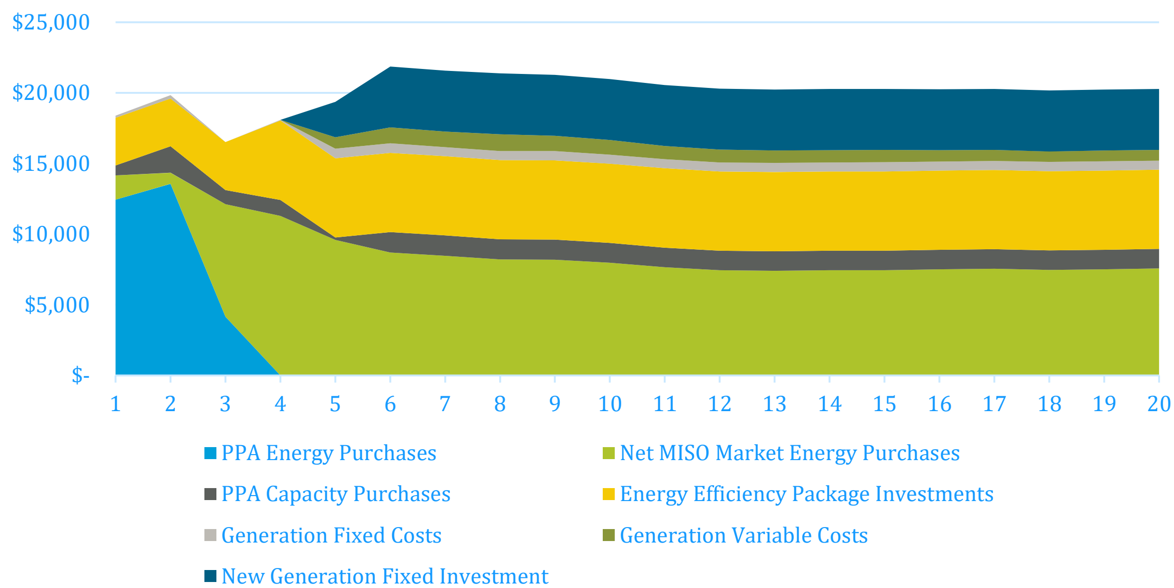



**Figure 9-14 Components of BAU RICE + Solar 2022 CPWC**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **2036** | $- | $3,590.9 | $1,274 | $5,615 | $0 | $6,113 | $- |
| **2037** | $- | $3,656.2 | $1,271 | $5,615 | $0 | $6,113 | $- |

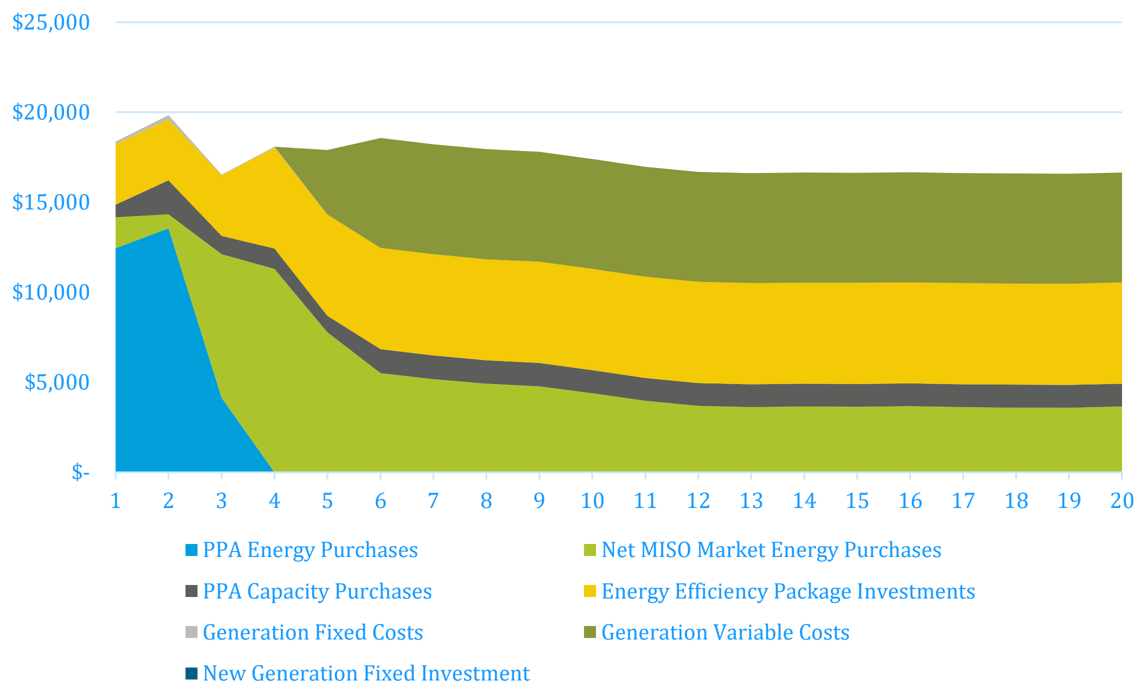



**Figure 9-15 Components of BAU Solar PPA 75 CPWC**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **2036** | $- | $7,831.1 | $2,581 | $5,615 | $0 | $1,713 | $- |
| **2037** | $- | $7,851.3 | $2,574 | $5,615 | $0 | $1,713 | $- |

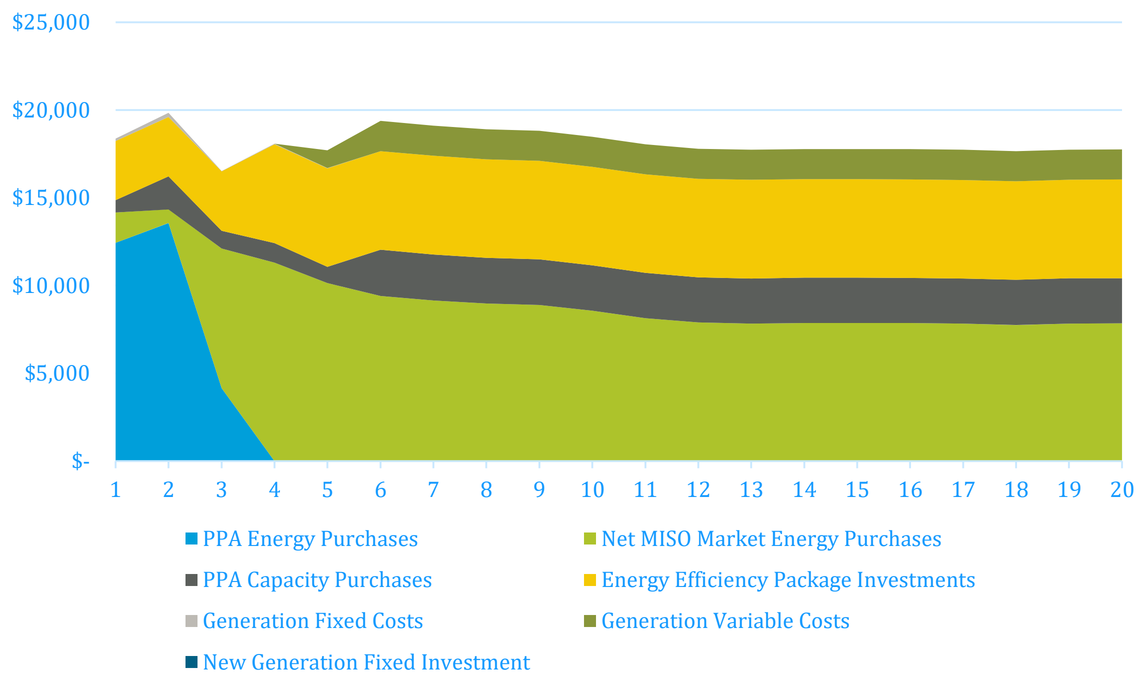



**Figure 9-16 Components of BAU Solar PPA 20 CPWC**

### 9.1.17 Emerging Technology: 1.5% Load Growth

In this case, emerging technology is considered at a 1.5 percent load growth. UPPCO would employ a 10 MW solar expansion commencing in 2026 with firm capacity of 5 MW from 2026 to 2033 and an increase to 10 MW from 2034 onwards. The fixed annual costs escalate from $150,000 to $300,000 and annual investment costs escalate from $684,000 to $1.305 million in accordance with the firm capacity. MISO capacity market costs, oil-fired costs, and PPA capacity costs are also considered. PRM for this case is 8.4 percent with an RPS in 2021 of 17 percent and an EE percentage of 38 percent in 2025. In the emerging technology 1.5 percent load growth case, UPPCO would receive 38 percent of energy from owned resources. CPWC for this case is $235.443 million with a rank of 13. The detailed results of this case are shown in Table 9-13. The cost components of the CPWC are represented graphically in Figure 9-13.

**Table 9-17 CPWC for Emerging Technology at 1.5% Load Growth ($000)**

| YEAR | PPA ENERGY PURCHASES | NET MISO MARKET ENERGY PURCHASES | PPA CAPACITY PURCHASES | ENERGY EFFICIENCY PACKAGE INVESTMENTS | GENERATION FIXED COSTS | GENERATION VARIABLE COSTS | NEW GENERATION FIXED INVESTMENT |
|---|---|---|---|---|---|---|---|
| 2018 | $12,445 | $2,066 | $700 | $3,382 | $134 | $- | $- |
| 2019 | $13,560 | $1,155 | $838 | $3,382 | $284 | $- | $- |
| 2020 | $4,150 | $8,650 | $1,180 | $3,382 | $47 | $- | $- |
| 2021 | $- | $12,289 | $1,388 | $5,615 | $73 | $- | $- |
| 2022 | $- | $12,265 | $1,272 | $5,615 | $199 | $- | $- |
| 2023 | $- | $12,439 | $2,370 | $5,615 | $58 | $- | $- |
| 2024 | $- | $12,577 | $2,456 | $5,615 | $21 | $- | $- |
| 2025 | $- | $12,831 | $3,751 | $5,615 | $- | $- | $- |
| 2026 | $- | $12,720 | $3,567 | $5,615 | $150 | $- | $684 |
| 2027 | $- | $12,822 | $3,650 | $5,615 | $150 | $- | $684 |
| 2028 | $- | $12,796 | $3,745 | $5,615 | $150 | $- | $684 |
| 2029 | $- | $12,912 | $3,820 | $5,615 | $150 | $- | $684 |
| 2030 | $- | $13,166 | $3,908 | $5,615 | $150 | $- | $684 |
| 2031 | $- | $13,538 | $3,996 | $5,615 | $150 | $- | $684 |
| 2032 | $- | $13,872 | $4,097 | $5,615 | $150 | $- | $684 |
| 2033 | $- | $14,183 | $4,177 | $5,615 | $150 | $- | $684 |
| 2034 | $- | $14,061 | $3,973 | $5,615 | $300 | $- | $1,305 |
| 2035 | $- | $14,261 | $4,067 | $5,615 | $300 | $- | $1,305 |
| 2036 | $- | $14,792 | $4,174 | $5,615 | $301 | $- | $1,305 |
| 2037 | $- | $15,158 | $4,259 | $5,615 | $300 | $- | $1,305 |

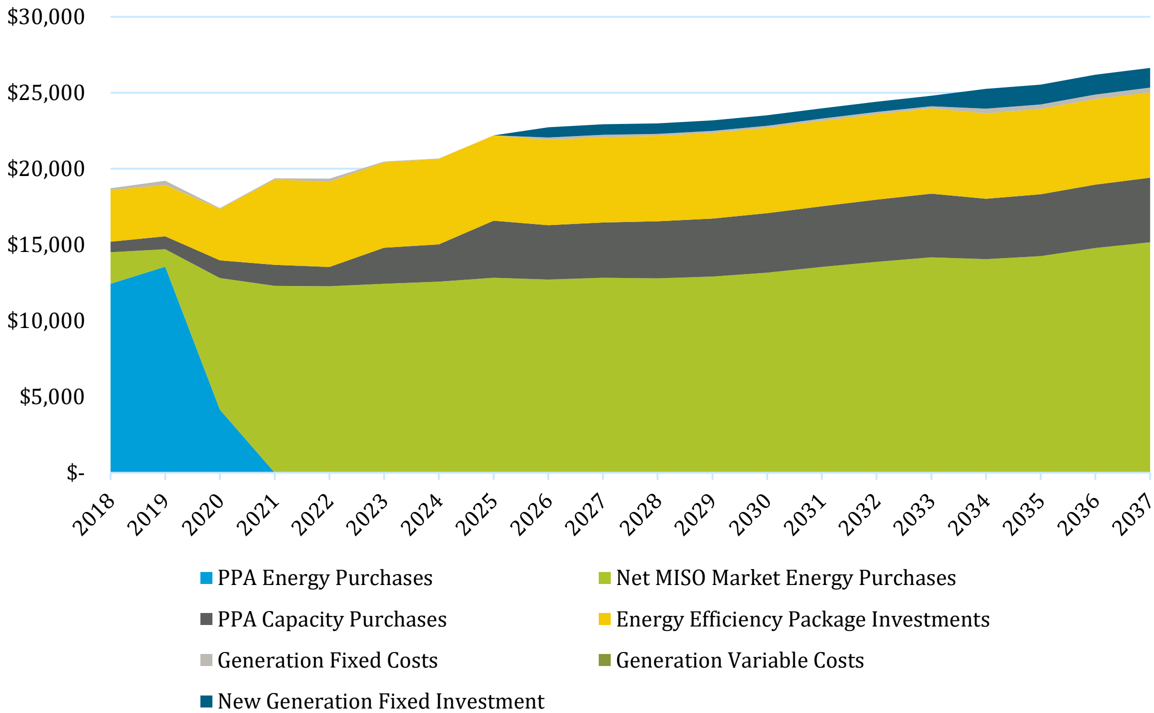



**Figure 9-17 Components of the Emerging Technology at 1.5% Load Growth CPWC**

### 9.1.18 Emerging Technology: 2.5% EWR

In this case, emerging technology is considered at a 2.5 percent energy waste reduction (EWR). UPPCO would continue to rely on the MISO capacity market for an average annual cost of $2.522 million and utilize energy efficiency packages for average annual investment costs of $10.209 million. MISO capacity market costs, oil-fired costs, and PPA capacity costs are also considered. PRM for this case is 8.4 percent with an RPS in 2021 of 17 percent and an EE percentage of 50 percent in 2025. In the emerging technology 1.5 percent load growth case, UPPCO would receive 64.7 percent of energy from owned resources. CPWC for this case is $232.234 million with a rank of 11. The detailed results of this case are shown in Table 9-14. The cost components of the CPWC are represented graphically in Figure 9-14.

**Table 9-18 CPWC for Emerging Technology at 2.5% EWR ($000)**

| YEAR | PPA ENERGY PURCHASE S | NET MISO MARKET ENERGY PURCHASES | PPA CAPACITY PURCHASE S | ENERGY EFFICIENCY PACKAGE INVESTMENT S | GENERATION FIXED COSTS | GENERATIO N VARIABLE COSTS | NEW GENERATION FIXED INVESTMENT |
|---|---|---|---|---|---|---|---|
| 2018 | $12,445 | $1,507 | $700 | $6,277 | $134 | $- | $- |
| 2019 | $13,560 | $332 | $838 | $6,277 | $284 | $- | $- |
| 2020 | $4,150 | $7,293 | $976 | $6,277 | $47 | $- | $- |
| 2021 | $- | $10,417 | $1,090 | $10,903 | $73 | $- | $- |
| 2022 | $- | $9,896 | $893 | $10,903 | $199 | $- | $- |
| 2023 | $- | $9,463 | $1,894 | $10,903 | $58 | $- | $- |
| 2024 | $- | $8,978 | $1,880 | $10,903 | $21 | $- | $- |
| 2025 | $- | $8,550 | $3,076 | $10,903 | $- | $- | $- |
| 2026 | $- | $8,219 | $3,086 | $10,903 | $- | $- | $- |
| 2027 | $- | $7,643 | $3,067 | $10,903 | $- | $- | $- |
| 2028 | $- | $6,983 | $3,056 | $10,903 | $- | $- | $- |
| 2029 | $- | $6,449 | $3,048 | $10,903 | $- | $- | $- |
| 2030 | $- | $6,396 | $3,048 | $10,903 | $- | $- | $- |
| 2031 | $- | $6,429 | $3,048 | $10,903 | $- | $- | $- |
| 2032 | $- | $6,442 | $3,056 | $10,903 | $- | $- | $- |
| 2033 | $- | $6,437 | $3,048 | $10,903 | $- | $- | $- |
| 2034 | $- | $6,394 | $3,048 | $10,903 | $- | $- | $- |
| 2035 | $- | $6,329 | $3,048 | $10,903 | $- | $- | $- |
| 2036 | $- | $6,394 | $3,057 | $10,903 | $- | $- | $- |
| 2037 | $- | $6,391 | $3,048 | $10,903 | $- | $- | $- |

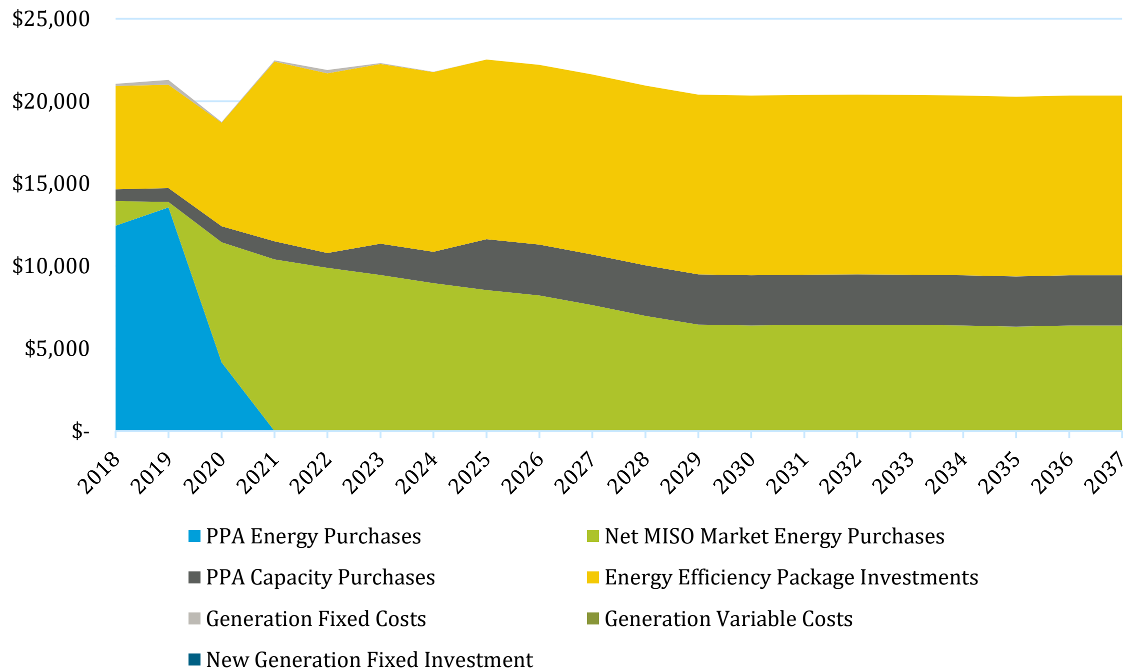



**Figure 9-18 Components of the Emerging Technology at 2.5% EWR CPWC**

### 9.1.19 Emerging Technology: 200% Gas

In this case, emerging technology is considered at a 200 percent gas price. UPPCO would employ a 10 MW solar expansion, 20 MW solar expansion, and 100 MW solar expansion. The 10 MW solar expansion would commence in 2020 with firm capacity of 5 MW in 2020 increased to 40 MW by 2037 with annual average fixed costs of $823,000 and average annual investment costs of $3.886 million. The 20 MW solar expansion would commence in 2025 with firm capacity of 10 MW in 2025 increased to 50 MW by 2037 with annual average fixed costs of $993,000 and average annual investment costs of $4.504 million. The 100 MW solar expansion would commence in 2030 with firm capacity of 150 MW from 2030 onwards with annual average fixed costs of $4.503 million and average annual investment costs of $19.530 million. MISO capacity market costs, oil-fired costs, and PPA capacity costs are also considered. PRM for this case is 213.5 percent with an RPS in 2021 of 21 percent and an EE percentage of 58 percent in 2025. In the emerging technology 200 percent gas price case, UPPCO would be able to receive 128.5 percent of energy from owned resources. CPWC for this case is $284.235 million with a rank of 22. The detailed results of this case are shown in Table 9-15. The cost components of the CPWC are represented graphically in Figure 9-15.

**Table 9-19 CPWC for Emerging Technology at 200% Gas Rate ($000)**

| YEAR | PPA ENERGY PURCHASES | NET MISO MARKET ENERGY PURCHASES | PPA CAPACITY PURCHASES | ENERGY EFFICIENCY PACKAGE INVESTMENTS | GENERATION FIXED COSTS | GENERATION VARIABLE COSTS | NEW GENERATION FIXED INVESTMENT |
|---|---|---|---|---|---|---|---|
| 2018 | $12,445 | $2,989 | $700 | $3,382 | $134 | $- | $- |
| 2019 | $13,560 | $1,405 | $838 | $3,382 | $284 | $- | $- |
| 2020 | $4,150 | $13,802 | $679 | $3,382 | $207 | $- | $735 |
| 2021 | $- | $19,214 | $497 | $5,615 | $393 | $- | $1,461 |
| 2022 | $- | $18,823 | $301 | $5,615 | $519 | $- | $1,461 |
| 2023 | $- | $15,690 | $116 | $5,615 | $1,018 | $- | $4,298 |
| 2024 | $- | $15,362 | $97 | $5,615 | $924 | $- | $4,298 |
| 2025 | $- | $11,690 | $113 | $5,615 | $1,500 | $- | $7,066 |
| 2026 | $- | $9,734 | $- | $5,615 | $1,800 | $- | $8,434 |
| 2027 | $- | $9,232 | $- | $5,615 | $1,800 | $- | $8,434 |
| 2028 | $- | $8,505 | $- | $5,615 | $1,805 | $- | $8,434 |
| 2029 | $- | $7,916 | $- | $5,615 | $1,800 | $- | $8,434 |
| 2030 | $- | $(9,207) | $- | $5,615 | $6,300 | $- | $27,963 |
| 2031 | $- | $(9,414) | $- | $5,615 | $6,300 | $- | $27,963 |
| 2032 | $- | $(9,237) | $- | $5,615 | $6,317 | $- | $27,963 |

| YEAR | PPA ENERGY PURCHASES | NET MISO MARKET ENERGY PURCHASES | PPA CAPACITY PURCHASES | ENERGY EFFICIENCY PACKAGE INVESTMENTS | GENERATION FIXED COSTS | GENERATION VARIABLE COSTS | NEW GENERATION FIXED INVESTMENT |
|---|---|---|---|---|---|---|---|
| 2033 | $- | $(9,066) | $- | $5,615 | $6,300 | $- | $27,963 |
| 2034 | $- | $(9,628) | $- | $5,615 | $6,600 | $- | $29,205 |
| 2035 | $- | $(9,682) | $- | $5,615 | $6,600 | $- | $29,205 |
| 2036 | $- | $(10,468) | $- | $5,615 | $6,768 | $- | $29,811 |
| 2037 | $- | $(10,800) | $- | $5,615 | $7,200 | $- | $31,608 |

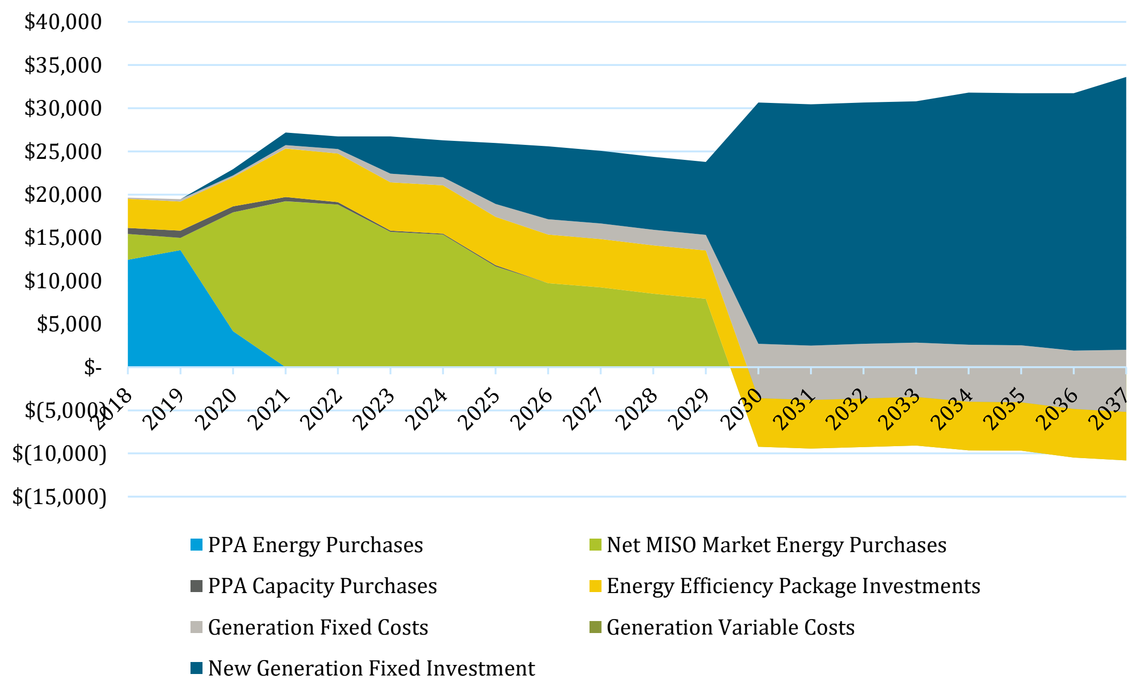



**Figure 9-19 Components of the Emerging Technology at 200% Gas Rate CPWC**

### 9.1.20 Emerging Technology: Base Case

In this case, emerging technology base case is considered. UPPCO would continue to employ the energy efficiency packages at an average annual investment cost $5.280 million and the MISO capacity market at average annual fixed cost of $2.901 million. MISO capacity market costs, oil-fired costs, and PPA capacity costs are also considered. PRM for this case is 8.4 percent with an RPS in 2021 of 17 percent and an EE percentage of 42 percent in 2025. In the emerging technology base case, UPPCO would be able to receive 47.9 percent of energy from owned resources. CPWC for this case is $199.769 million with a rank of 2. The detailed results of this case are shown in Table 9-16. The cost components of the CPWC are represented graphically in Figure 9-16.

**Table 9-20 CPWC for Emerging Technology Base Case ($000)**

| YEAR | PPA ENERGY PURCHASES | NET MISO MARKET ENERGY PURCHASES | PPA CAPACITY PURCHASES | ENERGY EFFICIENCY PACKAGE INVESTMENTS | GENERATION FIXED COSTS | GENERATION VARIABLE COSTS | NEW GENERATION FIXED INVESTMENT |
|---|---|---|---|---|---|---|---|
| 2018 | $12,445 | $1,718 | $700 | $3,382 | $134 | $- | $- |
| 2019 | $13,560 | $784 | $838 | $3,382 | $284 | $- | $- |
| 2020 | $4,150 | $7,967 | $976 | $3,382 | $47 | $- | $- |
| 2021 | $- | $11,302 | $1,090 | $5,615 | $73 | $- | $- |
| 2022 | $- | $11,006 | $893 | $5,615 | $199 | $- | $- |
| 2023 | $- | $10,825 | $1,894 | $5,615 | $58 | $- | $- |
| 2024 | $- | $10,594 | $1,880 | $5,615 | $21 | $- | $- |
| 2025 | $- | $10,446 | $3,076 | $5,615 | $- | $- | $- |
| 2026 | $- | $10,384 | $3,086 | $5,615 | $- | $- | $- |
| 2027 | $- | $10,080 | $3,067 | $5,615 | $- | $- | $- |
| 2028 | $- | $9,665 | $3,056 | $5,615 | $- | $- | $- |
| 2029 | $- | $9,423 | $3,048 | $5,615 | $- | $- | $- |
| 2030 | $- | $9,364 | $3,048 | $5,615 | $- | $- | $- |
| 2031 | $- | $9,405 | $3,048 | $5,615 | $- | $- | $- |
| 2032 | $- | $9,412 | $3,056 | $5,615 | $- | $- | $- |
| 2033 | $- | $9,391 | $3,048 | $5,615 | $- | $- | $- |
| 2034 | $- | $9,361 | $3,048 | $5,615 | $- | $- | $- |
| 2035 | $- | $9,265 | $3,048 | $5,615 | $- | $- | $- |
| 2036 | $- | $9,373 | $3,057 | $5,615 | $- | $- | $- |
| 2037 | $- | $9,377 | $3,048 | $5,615 | $- | $- | $- |

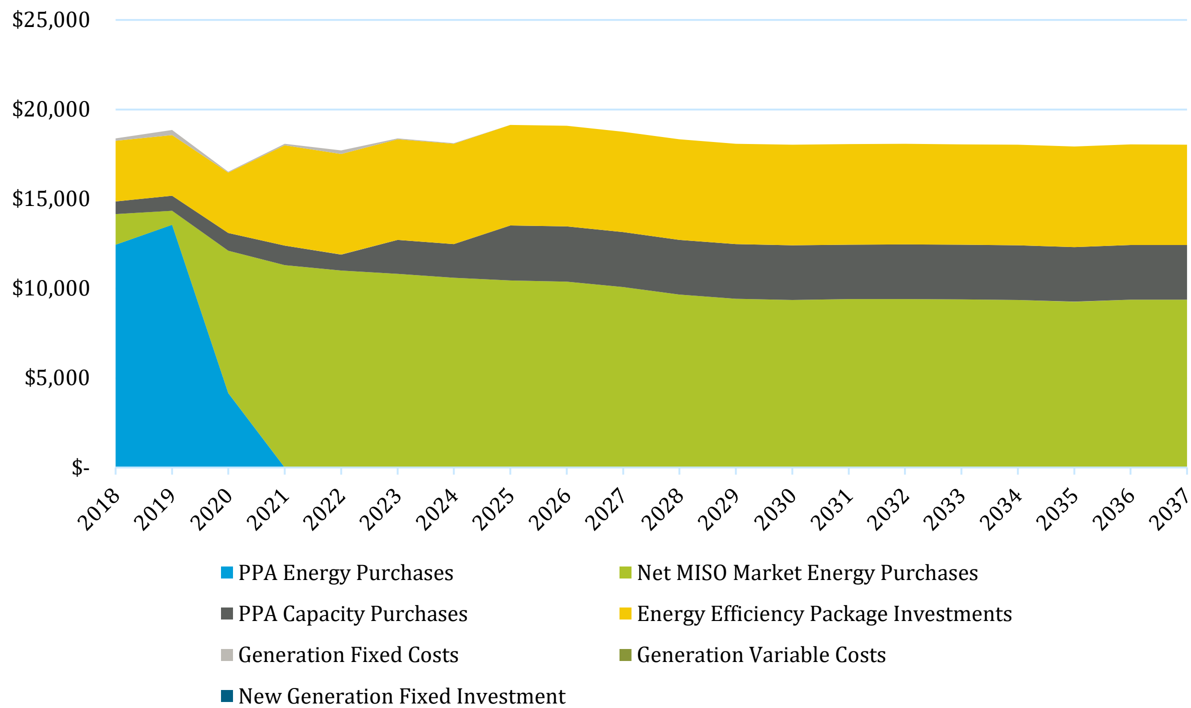



**Figure 9-20 Components of the Emerging Technology Base Case CPWC**

### 9.1.21 Emerging Technology: Base + RPS50

In this case, emerging technology base case plus RPS50 is considered. UPPCO would employ a 10 MW solar expansion and 20 MW solar expansion. The 10 MW solar expansion would commence in 2030 with firm capacity of 5 MW from 2030 onwards with annual average fixed costs of $150,000 and average annual investment costs of $651,000 million. The 20 MW solar expansion would commence in 2030 with firm capacity of 20 MW from 2030 onwards with annual average fixed costs of $600,000 and average annual investment costs of $2.604 million. MISO capacity market costs, oil-fired costs, and PPA capacity costs are also considered. PRM for this case is 8.4 percent with an RPS in 2021 of 17 percent and an EE percentage of 42 percent in 2025. In the emerging technology 200 percent gas price case, UPPCO would be able to receive 59.2 percent of energy from owned resources. CPWC for this case is $200.483 million with a rank of 3. The detailed results of this case are shown in Table 9-17. The cost components of the CPWC are represented graphically in Table 9-17.

**Table 9-21 CPWC for Emerging Technology Base Case plus RPS50 ($000)**

| YEAR | PPA ENERGY PURCHASES | NET MISO MARKET ENERGY PURCHASES | PPA CAPACITY PURCHASES | ENERGY EFFICIENCY PACKAGE INVESTMENTS | GENERATION FIXED COSTS | GENERATION VARIABLE COSTS | NEW GENERATION FIXED INVESTMENT |
|---|---|---|---|---|---|---|---|
| 2018 | $12,445 | $1,718 | $700 | $3,382 | $134 | $- | $- |
| 2019 | $13,560 | $784 | $838 | $3,382 | $284 | $- | $- |
| 2020 | $4,150 | $7,967 | $976 | $3,382 | $47 | $- | $- |
| 2021 | $- | $11,302 | $1,090 | $5,615 | $73 | $- | $- |
| 2022 | $- | $11,006 | $893 | $5,615 | $199 | $- | $- |
| 2023 | $- | $10,825 | $1,894 | $5,615 | $58 | $- | $- |
| 2024 | $- | $10,594 | $1,880 | $5,615 | $21 | $- | $- |
| 2025 | $- | $10,446 | $3,076 | $5,615 | $- | $- | $- |
| 2026 | $- | $10,384 | $3,086 | $5,615 | $- | $- | $- |
| 2027 | $- | $10,080 | $3,067 | $5,615 | $- | $- | $- |
| 2028 | $- | $9,665 | $3,056 | $5,615 | $- | $- | $- |
| 2029 | $- | $9,423 | $3,048 | $5,615 | $- | $- | $- |
| 2030 | $- | $7,117 | $1,567 | $5,615 | $750 | $- | $3,255 |
| 2031 | $- | $7,128 | $1,567 | $5,615 | $750 | $- | $3,255 |
| 2032 | $- | $7,147 | $1,571 | $5,615 | $752 | $- | $3,255 |
| 2033 | $- | $7,149 | $1,567 | $5,615 | $750 | $- | $3,255 |
| 2034 | $- | $7,131 | $1,567 | $5,615 | $750 | $- | $3,255 |
| 2035 | $- | $7,048 | $1,567 | $5,615 | $750 | $- | $3,255 |
| 2036 | $- | $7,086 | $1,571 | $5,615 | $752 | $- | $3,255 |
| 2037 | $- | $7,106 | $1,567 | $5,615 | $750 | $- | $3,255 |

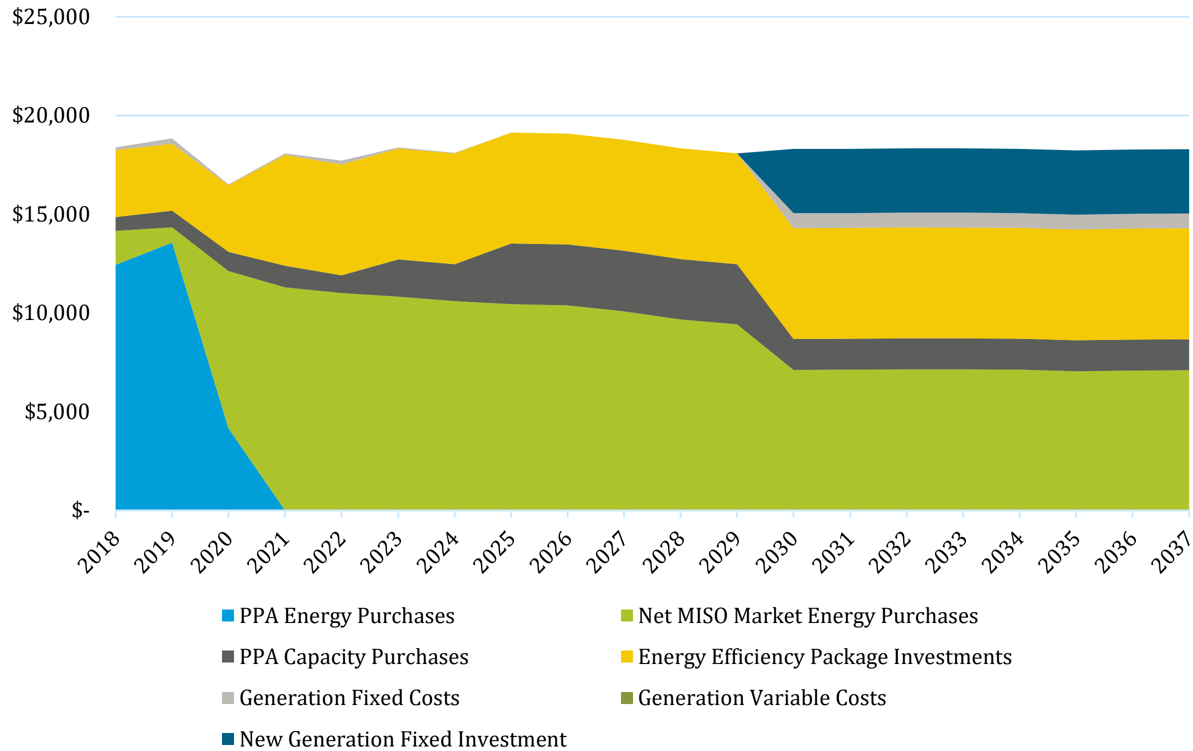



**Figure 9-21 Components of the Emerging Technology Base Case plus RPS50 CPWC**

### 9.1.22 High Market Price: 1.5% Load Growth

In this case, high market price with 1.5 percent load requirement growth is considered. UPPCO would employ a 10 MW solar expansion, 20 MW solar expansion, and 100 MW solar expansion. The 10 MW solar expansion would commence in 2026 with firm capacity of 5 MW in 2020 increased to 10 MW by 2034 with annual average fixed costs of $200,000 and average annual investment costs of $1.370 million. The 20 MW solar expansion would commence in 2035 with firm capacity of 20 MW from 2035 onwards with annual average fixed costs of $600,000 and average annual investment costs of $3.773 million. The 100 MW solar expansion would commence in 2035 with firm capacity of 50 MW from 2035 onwards with annual average fixed costs of $1.502 million and average annual investment costs of $9.433 million. MISO capacity market costs, oil-fired costs, and PPA capacity costs are also considered. PRM for this case is 8.4 percent with an RPS in 2021 of 17 percent and an EE percentage of 38 percent in 2025. In the emerging technology 200 percent gas price case, UPPCO would be able to receive 60.8 percent of energy from owned resources. CPWC for this case is $307.76 million with a rank of 23. The detailed results of this case are shown in Table 9-18. The cost components of the CPWC are represented graphically in Figure 9-18.

**Table 9-22 CPWC for High Market Price with 1.5% Load Growth Case ($000)**

| YEAR | PPA ENERGY PURCHASES | NET MISO MARKET ENERGY PURCHASES | PPA CAPACITY PURCHASES | ENERGY EFFICIENCY PACKAGE INVESTMENTS | GENERATION FIXED COSTS | GENERATION VARIABLE COSTS | NEW GENERATION FIXED INVESTMENT |
|---|---|---|---|---|---|---|---|
| 2018 | $12,445 | $2,312 | $700 | $3,382 | $134 | $- | $- |
| 2019 | $13,560 | $1,417 | $838 | $3,382 | $284 | $- | $- |
| 2020 | $4,150 | $11,723 | $1,494 | $3,382 | $47 | $- | $- |
| 2021 | $- | $17,473 | $1,903 | $5,615 | $73 | $- | $- |
| 2022 | $- | $17,564 | $1,825 | $5,615 | $199 | $- | $- |
| 2023 | $- | $18,208 | $3,555 | $5,615 | $58 | $- | $- |
| 2024 | $- | $18,868 | $3,684 | $5,615 | $21 | $- | $- |
| 2025 | $- | $19,414 | $5,626 | $5,615 | $- | $- | $- |
| 2026 | $- | $19,443 | $5,350 | $5,615 | $150 | $- | $1,052 |
| 2027 | $- | $19,689 | $5,475 | $5,615 | $150 | $- | $1,052 |
| 2028 | $- | $19,842 | $5,617 | $5,615 | $150 | $- | $1,052 |
| 2029 | $- | $20,074 | $5,731 | $5,615 | $150 | $- | $1,052 |
| 2030 | $- | $20,311 | $5,861 | $5,615 | $150 | $- | $1,052 |
| 2031 | $- | $20,863 | $5,994 | $5,615 | $150 | $- | $1,052 |
| 2032 | $- | $21,470 | $6,146 | $5,615 | $150 | $- | $1,052 |
| 2033 | $- | $22,010 | $6,265 | $5,615 | $150 | $- | $1,052 |
| 2034 | $- | $22,137 | $5,960 | $5,615 | $300 | $- | $2,007 |
| 2035 | $- | $12,190 | $1 | $5,615 | $2,400 | $- | $15,212 |
| 2036 | $- | $12,792 | $23 | $5,615 | $2,407 | $- | $15,212 |
| 2037 | $- | $13,536 | $167 | $5,615 | $2,400 | $- | $15,212 |

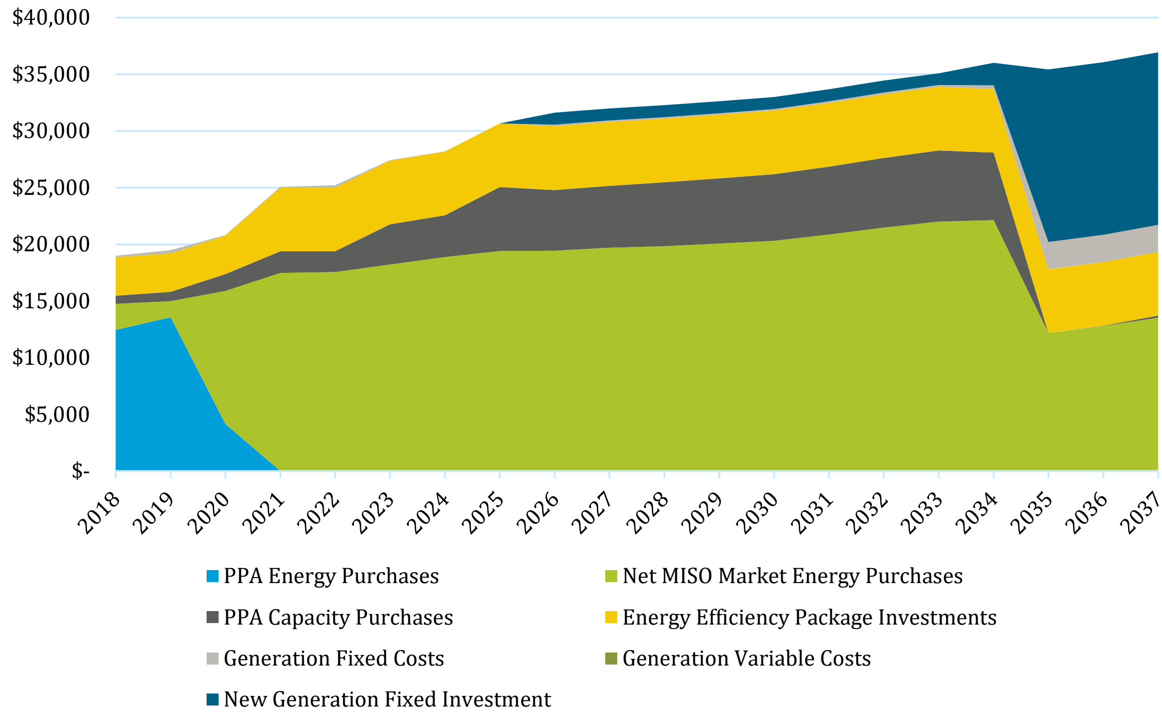



**Figure 9-22 Components of the High Market Price with 1.5% Load Growth CPWC**

### 9.1.23 High Market Price: 150% Gas

In this case, high market price with a 150 percent gas price is considered. UPPCO would employ a 10 MW solar expansion, 20 MW solar expansion, 100 MW solar expansion, and a 20 MW wind expansion. The 10 MW solar expansion would commence in 2024 with firm capacity of 30 MW in 2020 increased to 50 MW from 2025 onwards with annual average fixed costs of $1.501 million and average annual investment costs of $10.720 million. The 20 MW solar expansion would commence in 2037 with firm capacity of 20 MW from 2037 onwards with annual average fixed costs of $600,000 and average annual investment costs of $3.686 million. The 100 MW solar expansion would commence in 2036 with firm capacity of 100 MW from 2036 onwards with annual average fixed costs of $3.004 million and average annual investment costs of $18.647 million. The 20 MW solar expansion would commence in 2033 with firm capacity of 2.1 MW from 2033 increased to 14.6 MW from 2036 onwards with annual average fixed costs of $2.939 million and average annual investment costs of $12.567 million. MISO capacity market costs, oil-fired costs, and PPA capacity costs are also considered. PRM for this case is 153.2 percent with an RPS in 2021 of 17 percent and an EE percentage of 58 percent in 2025. In the high market price with a 150 percent gas price case, UPPCO would be able to receive 176.4 percent of energy from owned resources. CPWC for this case is $314.708 million with a rank of 24. The detailed results of this case are shown in Table 9-19. The cost components of the CPWC are represented graphically in Figure 9-19.

**Table 9-23 CPWC for High Market Price with 150% Gas Rate Case ($000)**

| YEAR | PPA ENERGY PURCHASES | NET MISO MARKET ENERGY PURCHASES | PPA CAPACITY PURCHASES | ENERGY EFFICIENCY PACKAGE INVESTMENTS | GENERATION FIXED COSTS | GENERATION VARIABLE COSTS | NEW GENERATION FIXED INVESTMENT |
|---|---|---|---|---|---|---|---|
| 2018 | $12,445 | $2,557 | $700 | $3,382 | $134 | $- | $- |
| 2019 | $13,560 | $1,311 | $838 | $3,382 | $284 | $- | $- |
| 2020 | $4,150 | $15,412 | $1,189 | $3,382 | $47 | $- | $- |
| 2021 | $- | $23,103 | $1,455 | $5,615 | $73 | $- | $- |
| 2022 | $- | $23,380 | $1,257 | $5,615 | $199 | $- | $- |
| 2023 | $- | $24,008 | $2,840 | $5,615 | $58 | $- | $- |
| 2024 | $- | $18,450 | $146 | $5,615 | $924 | $- | $6,463 |
| 2025 | $- | $14,144 | $170 | $5,615 | $1,500 | $- | $10,720 |
| 2026 | $- | $14,054 | $186 | $5,615 | $1,500 | $- | $10,720 |
| 2027 | $- | $13,511 | $157 | $5,615 | $1,500 | $- | $10,720 |
| 2028 | $- | $12,741 | $129 | $5,615 | $1,504 | $- | $10,720 |
| 2029 | $- | $12,080 | $128 | $5,615 | $1,500 | $- | $10,720 |
| 2030 | $- | $11,925 | $128 | $5,615 | $1,500 | $- | $10,720 |
| 2031 | $- | $11,868 | $128 | $5,615 | $1,500 | $- | $10,720 |
| 2032 | $- | $11,981 | $129 | $5,615 | $1,504 | $- | $10,720 |

| YEAR | PPA ENERGY PURCHASES | NET MISO MARKET ENERGY PURCHASES | PPA CAPACITY PURCHASES | ENERGY EFFICIENCY PACKAGE INVESTMENTS | GENERATION FIXED COSTS | GENERATION VARIABLE COSTS | NEW GENERATION FIXED INVESTMENT |
|---|---|---|---|---|---|---|---|
| 2033 | $- | $7,773 | $- | $5,615 | $2,380 | $- | $14,411 |
| 2034 | $- | $7,865 | $- | $5,615 | $2,380 | $- | $14,411 |
| 2035 | $- | $7,911 | $- | $5,615 | $2,380 | $- | $14,411 |
| 2036 | $- | $(35,595) | $- | $5,615 | $10,549 | $- | $55,248 |
| 2037 | $- | $(36,721) | $- | $5,615 | $11,120 | $- | $58,933 |

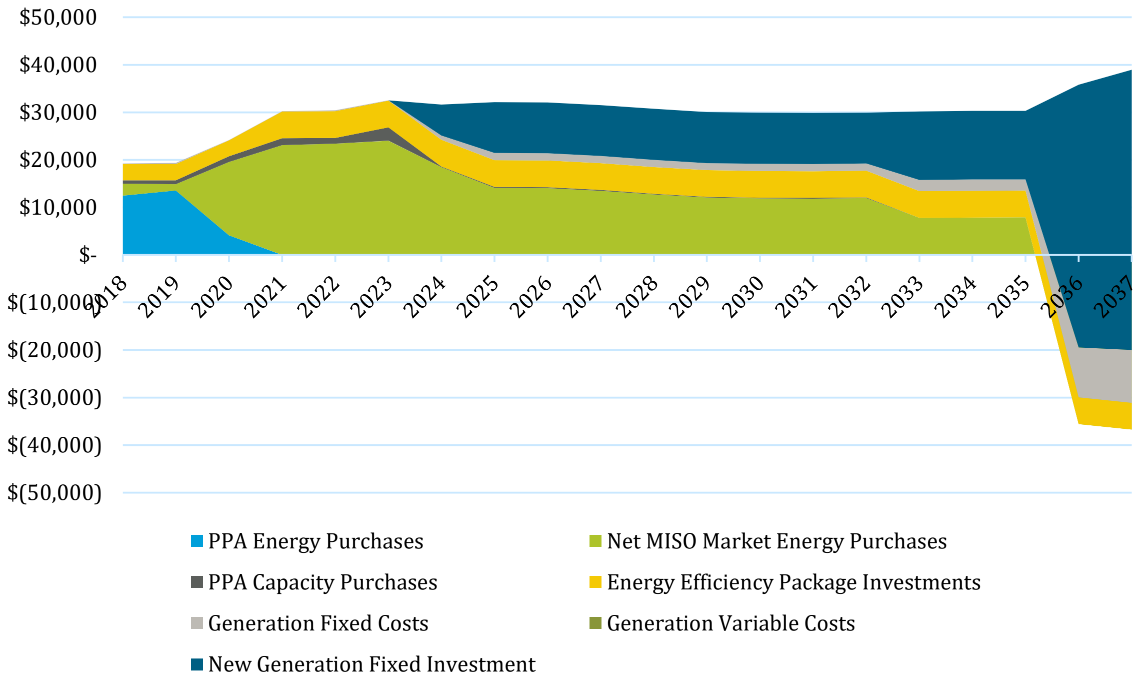



**Figure 9-23 Components of the High Market Price with 150% Gas Rate CPWC**

### 9.1.24 High Market Price: 2.5% EWR

In this case, high market price with 2.5 percent energy waste reduction is considered. UPPCO would employ a 20 MW solar expansion commencing in 2035 with firm capacity of 50 MW from 2035 onwards with fixed annual costs of $1.501 million and annual investment costs of $9.433 million. MISO capacity market costs, oil-fired costs, and PPA capacity costs are also considered. PRM for this case is 8.4 percent with an RPS in 2021 of 18 percent and an EE percentage of 50 percent in 2025. In the high market price with 2.5 percent energy waste reduction case, UPPCO would receive 87.3 percent of energy from owned resources. CPWC for this case is $277.319 million with a rank of 19. The detailed results of this case are shown in Table 9-20. The cost components of the CPWC are represented graphically in Figure 9-20.

**Table 9-24 CPWC for High Market Price with 2.5% EWR Case ($000)**

| YEAR | PPA ENERGY PURCHASES | NET MISO MARKET ENERGY PURCHASES | PPA CAPACITY PURCHASES | ENERGY EFFICIENCY PACKAGE INVESTMENTS | GENERATION FIXED COSTS | GENERATION VARIABLE COSTS | NEW GENERATION FIXED INVESTMENT |
|---|---|---|---|---|---|---|---|
| 2018 | $12,445 | $1,701 | $700 | $6,277 | $134 | $- | $- |
| 2019 | $13,560 | $416 | $838 | $6,277 | $284 | $- | $- |
| 2020 | $4,150 | $9,892 | $1,189 | $6,277 | $47 | $- | $- |
| 2021 | $- | $14,817 | $1,455 | $10,903 | $73 | $- | $- |
| 2022 | $- | $14,183 | $1,257 | $10,903 | $199 | $- | $- |
| 2023 | $- | $13,866 | $2,840 | $10,903 | $58 | $- | $- |
| 2024 | $- | $13,486 | $2,819 | $10,903 | $21 | $- | $- |
| 2025 | $- | $12,957 | $4,614 | $10,903 | $- | $- | $- |
| 2026 | $- | $12,592 | $4,630 | $10,903 | $- | $- | $- |
| 2027 | $- | $11,767 | $4,600 | $10,903 | $- | $- | $- |
| 2028 | $- | $10,862 | $4,585 | $10,903 | $- | $- | $- |
| 2029 | $- | $10,063 | $4,572 | $10,903 | $- | $- | $- |
| 2030 | $- | $9,903 | $4,572 | $10,903 | $- | $- | $- |
| 2031 | $- | $9,942 | $4,572 | $10,903 | $- | $- | $- |
| 2032 | $- | $10,008 | $4,585 | $10,903 | $- | $- | $- |
| 2033 | $- | $10,028 | $4,572 | $10,903 | $- | $- | $- |
| 2034 | $- | $10,115 | $4,572 | $10,903 | $- | $- | $- |
| 2035 | $- | $2,769 | $128 | $10,903 | $1,500 | $- | $9,433 |
| 2036 | $- | $2,684 | $129 | $10,903 | $1,504 | $- | $9,433 |
| 2037 | $- | $2,770 | $129 | $10,903 | $1,500 | $- | $9,433 |

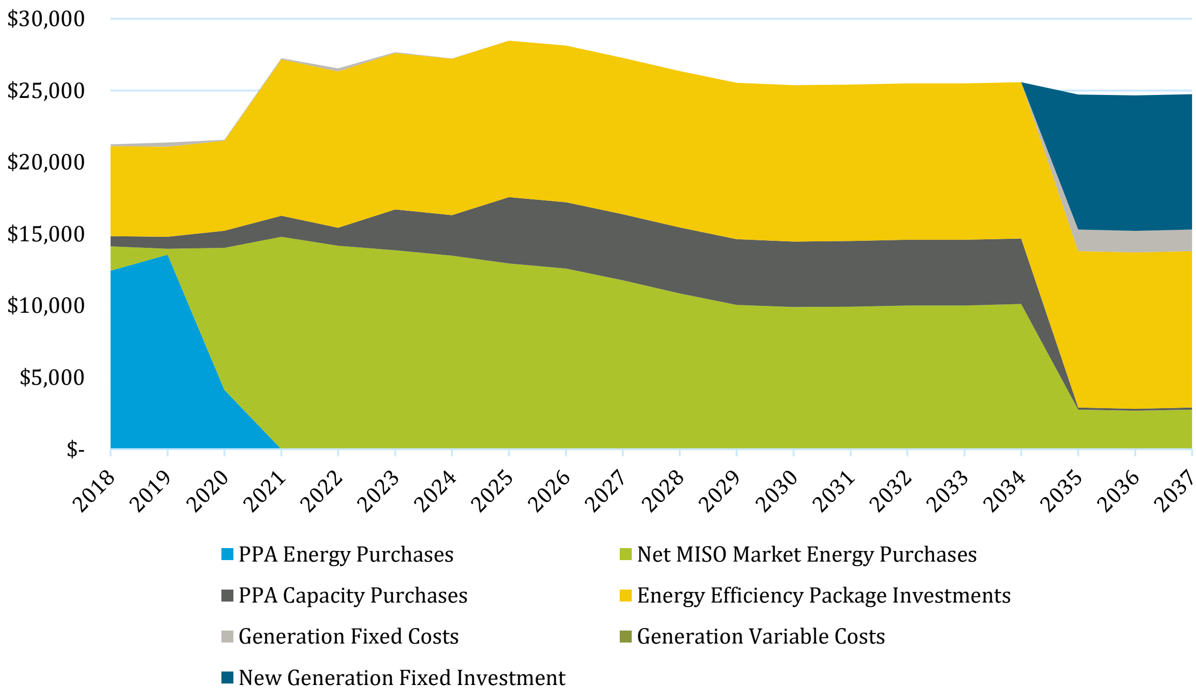



**Figure 9-24 Components of the High Market Price with 2.5% EWR Case CPWC**

### 9.1.25 High Market Price: 50% Gas

In this case, high market price with a 50 percent gas rate is considered. UPPCO would continue to rely on the MISO capacity market for an average annual cost of $3.968 million and utilize energy efficiency packages for average annual investment costs of $5.280 million. Oil-fired costs, and PPA capacity costs are also considered. PRM for this case is 8.4 percent with an RPS in 2021 of 17 percent and an EE percentage of 42 percent in 2025. In the emerging technology 1.5 percent load growth case, UPPCO would receive 47.9 percent of energy from owned resources. CPWC for this case is $186.342 million with a rank of 1. The detailed results of this case are shown in Table 9-21. The cost components of the CPWC are represented graphically in Figure 9-21.

**Table 9-25 CPWC for High Market Price with 50% Gas Rate Case ($000)**

| YEAR | PPA ENERGY PURCHASES | NET MISO MARKET ENERGY PURCHASES | PPA CAPACITY PURCHASES | ENERGY EFFICIENCY PACKAGE INVESTMENTS | GENERATION FIXED COSTS | GENERATION VARIABLE COSTS | NEW GENERATION FIXED INVESTMENT |
|---|---|---|---|---|---|---|---|
| 2018 | $12,445 | $966 | $700 | $3,382 | $134 | $- | $- |
| 2019 | $13,560 | $483 | $838 | $3,382 | $284 | $- | $- |
| 2020 | $4,150 | $5,402 | $1,189 | $3,382 | $47 | $- | $- |
| 2021 | $- | $8,037 | $1,455 | $5,615 | $73 | $- | $- |
| 2022 | $- | $7,886 | $1,257 | $5,615 | $199 | $- | $- |
| 2023 | $- | $7,929 | $2,840 | $5,615 | $58 | $- | $- |
| 2024 | $- | $7,955 | $2,819 | $5,615 | $21 | $- | $- |
| 2025 | $- | $7,912 | $4,614 | $5,615 | $- | $- | $- |
| 2026 | $- | $7,951 | $4,630 | $5,615 | $- | $- | $- |
| 2027 | $- | $7,755 | $4,600 | $5,615 | $- | $- | $- |
| 2028 | $- | $7,512 | $4,585 | $5,615 | $- | $- | $- |
| 2029 | $- | $7,345 | $4,572 | $5,615 | $- | $- | $- |
| 2030 | $- | $7,243 | $4,572 | $5,615 | $- | $- | $- |
| 2031 | $- | $7,267 | $4,572 | $5,615 | $- | $- | $- |
| 2032 | $- | $7,304 | $4,585 | $5,615 | $- | $- | $- |
| 2033 | $- | $7,308 | $4,572 | $5,615 | $- | $- | $- |
| 2034 | $- | $7,398 | $4,572 | $5,615 | $- | $- | $- |
| 2035 | $- | $7,257 | $4,572 | $5,615 | $- | $- | $- |
| 2036 | $- | $7,354 | $4,585 | $5,615 | $- | $- | $- |
| 2037 | $- | $7,401 | $4,572 | $5,615 | $- | $- | $- |

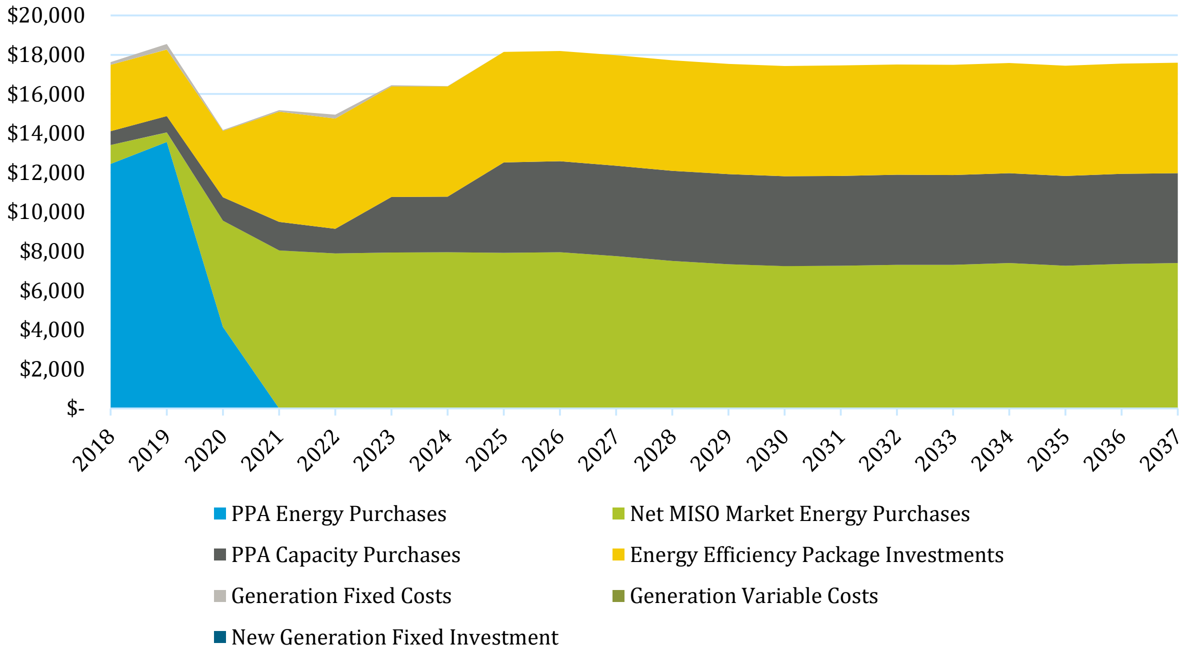



**Figure 9-25 Components of the High Market Price with 50% Gas Rate Case CPWC**

### 9.1.26 High Market Price: Base Case

In this case, the high market base case is considered. UPPCO would employ a 100 MW solar expansion commencing in 2035 with firm capacity of 50 MW from 2035 onwards with fixed annual costs escalate of $1.501 million and annual investment costs escalate of $9.443 million. MISO capacity market costs, oil-fired costs, and PPA capacity costs are also considered. PRM for this case is 8.4 percent with an RPS in 2021 of 17 percent and an EE percentage of 42 percent in 2025. In the emerging technology 1.5 percent load growth case, UPPCO would receive 70.5 percent of energy from owned resources. CPWC for this case is $254.562 million with a rank of 16. The detailed results of this case are shown in Table 9-22. The cost components of the CPWC are represented graphically in Figure 9-22.

**Table 9-26 CPWC for High Market Price Base Case ($000)**

| YEAR | PPA ENERGY PURCHASES | NET MISO MARKET ENERGY PURCHASES | PPA CAPACITY PURCHASES | ENERGY EFFICIENCY PACKAGE INVESTMENTS | GENERATION FIXED COSTS | GENERATION VARIABLE COSTS | NEW GENERATION FIXED INVESTMENT |
|---|---|---|---|---|---|---|---|
| 2018 | $12,445 | $1,932 | $700 | $3,382 | $134 | $- | $- |
| 2019 | $13,560 | $966 | $838 | $3,382 | $284 | $- | $- |
| 2020 | $4,150 | $10,803 | $1,189 | $3,382 | $47 | $- | $- |
| 2021 | $- | $16,074 | $1,455 | $5,615 | $73 | $- | $- |
| 2022 | $- | $15,771 | $1,257 | $5,615 | $199 | $- | $- |
| 2023 | $- | $15,858 | $2,840 | $5,615 | $58 | $- | $- |
| 2024 | $- | $15,909 | $2,819 | $5,615 | $21 | $- | $- |
| 2025 | $- | $15,824 | $4,614 | $5,615 | $- | $- | $- |
| 2026 | $- | $15,901 | $4,630 | $5,615 | $- | $- | $- |
| 2027 | $- | $15,509 | $4,600 | $5,615 | $- | $- | $- |
| 2028 | $- | $15,024 | $4,585 | $5,615 | $- | $- | $- |
| 2029 | $- | $14,690 | $4,572 | $5,615 | $- | $- | $- |
| 2030 | $- | $14,485 | $4,572 | $5,615 | $- | $- | $- |
| 2031 | $- | $14,533 | $4,572 | $5,615 | $- | $- | $- |
| 2032 | $- | $14,607 | $4,585 | $5,615 | $- | $- | $- |
| 2033 | $- | $14,616 | $4,572 | $5,615 | $- | $- | $- |
| 2034 | $- | $14,795 | $4,572 | $5,615 | $- | $- | $- |
| 2035 | $- | $7,355 | $128 | $5,615 | $1,500 | $- | $9,433 |
| 2036 | $- | $7,348 | $129 | $5,615 | $1,504 | $- | $9,433 |
| 2037 | $- | $7,472 | $129 | $5,615 | $1,500 | $- | $9,433 |

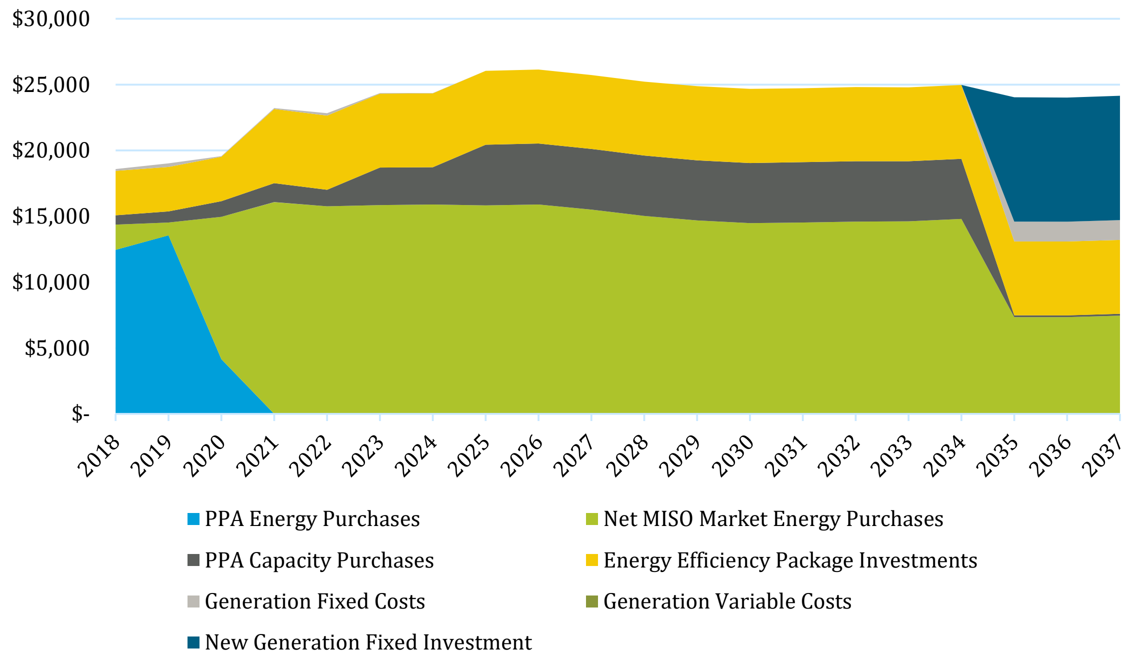



**Figure 9-26 Components of the High Market Price Base Case CPWC**

### 9.1.27 High Market Price: Base + 50% Choice Load

In this case, high market price base case with 50 percent choice load is considered. UPPCO would employ a 20 MW solar expansion and 100 MW solar expansion. The 20 MW solar expansion would commence in 2035 with firm capacity of 10 MW from 2035 onwards with annual average fixed costs of $300,000 and average annual investment costs of $1.887 million. The 100 MW solar expansion would commence in 2035 with firm capacity of 50 MW in 2025 from 2035 onwards with annual average fixed costs of $1.501 million and average annual investment costs of $9.433 million. MISO capacity market costs, oil-fired costs, and PPA capacity costs are also considered. PRM for this case is 10.3 percent with an RPS in 2021 of 16 percent and an EE percentage of 40 percent in 2025. In the high market prices with 50 percent choice load case, UPPCO would be able to receive 69.5 percent percent of energy from owned resources. CPWC for this case is $281.195 million with a rank of 20. The detailed results of this case are shown in Table 9-23. The cost components of the CPWC are represented graphically in Figure 9-23.

**Table 9-27 CPWC for High Market Price with 50% Choice Load ($000)**

| YEAR | PPA ENERGY PURCHASES | NET MISO MARKET ENERGY PURCHASES | PPA CAPACITY PURCHASES | ENERGY EFFICIENCY PACKAGE INVESTMENTS | GENERATION FIXED COSTS | GENERATION VARIABLE COSTS | NEW GENERATION FIXED INVESTMENT |
|---|---|---|---|---|---|---|---|
| 2018 | $12,445 | $3,233 | $910 | $3,382 | $134 | $- | $- |
| 2019 | $13,560 | $2,514 | $1,160 | $3,382 | $284 | $- | $- |
| 2020 | $4,150 | $12,510 | $1,782 | $3,382 | $47 | $- | $- |
| 2021 | $- | $17,843 | $2,047 | $5,615 | $73 | $- | $- |
| 2022 | $- | $17,557 | $1,849 | $5,615 | $199 | $- | $- |
| 2023 | $- | $17,720 | $3,433 | $5,615 | $58 | $- | $- |
| 2024 | $- | $17,851 | $3,414 | $5,615 | $21 | $- | $- |
| 2025 | $- | $17,832 | $5,208 | $5,615 | $- | $- | $- |
| 2026 | $- | $17,963 | $5,224 | $5,615 | $- | $- | $- |
| 2027 | $- | $17,605 | $5,195 | $5,615 | $- | $- | $- |
| 2028 | $- | $17,146 | $5,181 | $5,615 | $- | $- | $- |
| 2029 | $- | $16,846 | $5,166 | $5,615 | $- | $- | $- |
| 2030 | $- | $16,619 | $5,166 | $5,615 | $- | $- | $- |
| 2031 | $- | $16,672 | $5,165 | $5,615 | $- | $- | $- |
| 2032 | $- | $16,753 | $5,179 | $5,615 | $- | $- | $- |
| 2033 | $- | $16,762 | $5,165 | $5,615 | $- | $- | $- |
| 2034 | $- | $16,979 | $5,164 | $5,615 | $- | $- | $- |
| 2035 | $- | $8,062 | $- | $5,615 | $1,800 | $- | $11,319 |
| 2036 | $- | $8,057 | $- | $5,615 | $1,805 | $- | $11,319 |
| 2037 | $- | $8,195 | $- | $5,615 | $1,800 | $- | $11,319 |

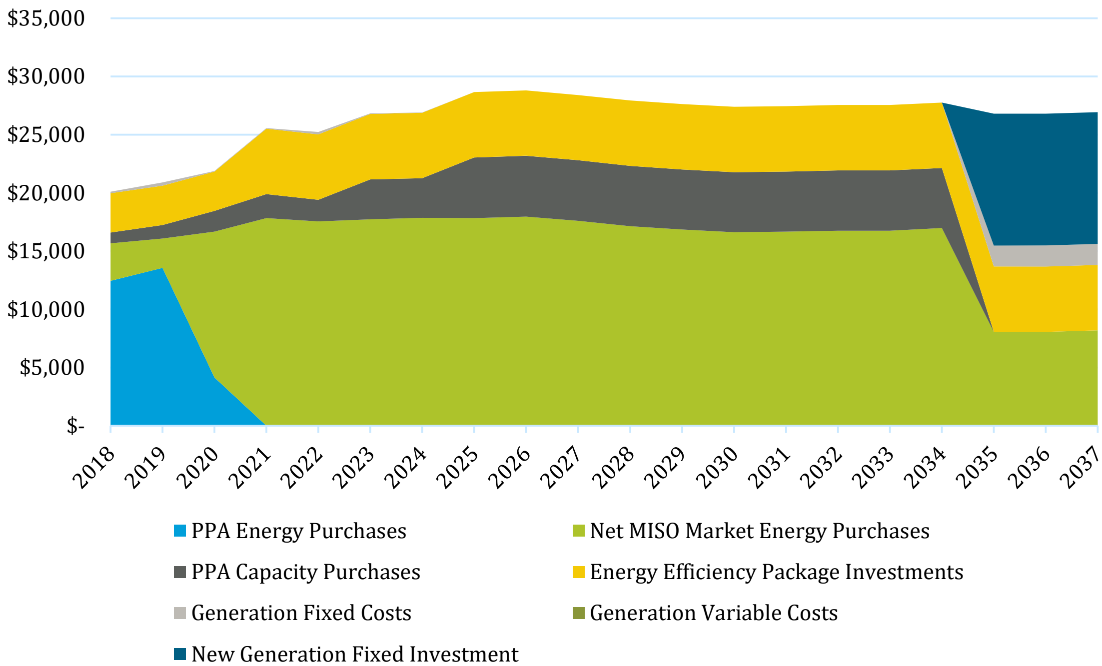



**Figure 9-27 Components of the High Market Price with 50% Choice Load Case CPWC**

### 9.1.28 High Market Price: Base + RPS50

In this case, high market price base case with RPS50 is considered. UPPCO would employ a 10 MW solar expansion and 20 MW solar expansion. The 10 MW solar expansion would commence in 2030 with firm capacity of 25 MW increased to 30 MW from 2035 onwards with annual average fixed costs of $807,000 and average annual investment costs of $5.366 million. The 20 MW solar expansion would commence in 2035 with firm capacity of 20 MW from 2035 onwards with annual average fixed costs of $600,000 and average annual investment costs of $3.773 million. MISO capacity market costs, oil-fired costs, and PPA capacity costs are also considered. PRM for this case is 10.3 percent with an RPS in 2021 of 17 percent and an EE percentage of 42 percent in 2025. In the high market price base case with RPS50 case, UPPCO would be able to receive 70.5 percent of energy from owned resources. CPWC for this case is $254.769 million with a rank of 17. The detailed results of this case are shown in Table 9-24. The cost components of the CPWC are represented graphically in Figure 9-24.

**Table 9-28 CPWC for High Market Price Base plus RPS50 ($000)**

| YEAR | PPA ENERGY PURCHASES | NET MISO MARKET ENERGY PURCHASES | PPA CAPACITY PURCHASES | ENERGY EFFICIENCY PACKAGE INVESTMENTS | GENERATION FIXED COSTS | GENERATION VARIABLE COSTS | NEW GENERATION FIXED INVESTMENT |
|---|---|---|---|---|---|---|---|
| 2018 | $12,445 | $1,932 | $700 | $3,382 | $134 | $- | $- |
| 2019 | $13,560 | $966 | $838 | $3,382 | $284 | $- | $- |
| 2020 | $4,150 | $10,803 | $1,189 | $3,382 | $47 | $- | $- |
| 2021 | $- | $16,074 | $1,455 | $5,615 | $73 | $- | $- |
| 2022 | $- | $15,771 | $1,257 | $5,615 | $199 | $- | $- |
| 2023 | $- | $15,858 | $2,840 | $5,615 | $58 | $- | $- |
| 2024 | $- | $15,909 | $2,819 | $5,615 | $21 | $- | $- |
| 2025 | $- | $15,824 | $4,614 | $5,615 | $- | $- | $- |
| 2026 | $- | $15,901 | $4,630 | $5,615 | $- | $- | $- |
| 2027 | $- | $15,509 | $4,600 | $5,615 | $- | $- | $- |
| 2028 | $- | $15,024 | $4,585 | $5,615 | $- | $- | $- |
| 2029 | $- | $14,690 | $4,572 | $5,615 | $- | $- | $- |
| 2030 | $- | $10,953 | $2,350 | $5,615 | $750 | $- | $5,012 |
| 2031 | $- | $10,959 | $2,350 | $5,615 | $750 | $- | $5,012 |
| 2032 | $- | $11,043 | $2,357 | $5,615 | $752 | $- | $5,012 |
| 2033 | $- | $11,079 | $2,350 | $5,615 | $750 | $- | $5,012 |
| 2034 | $- | $11,199 | $2,350 | $5,615 | $750 | $- | $5,012 |
| 2035 | $- | $7,355 | $128 | $5,615 | $1,500 | $- | $9,728 |
| 2036 | $- | $7,348 | $129 | $5,615 | $1,504 | $- | $9,728 |
| 2037 | $- | $7,472 | $129 | $5,615 | $1,500 | $- | $9,728 |

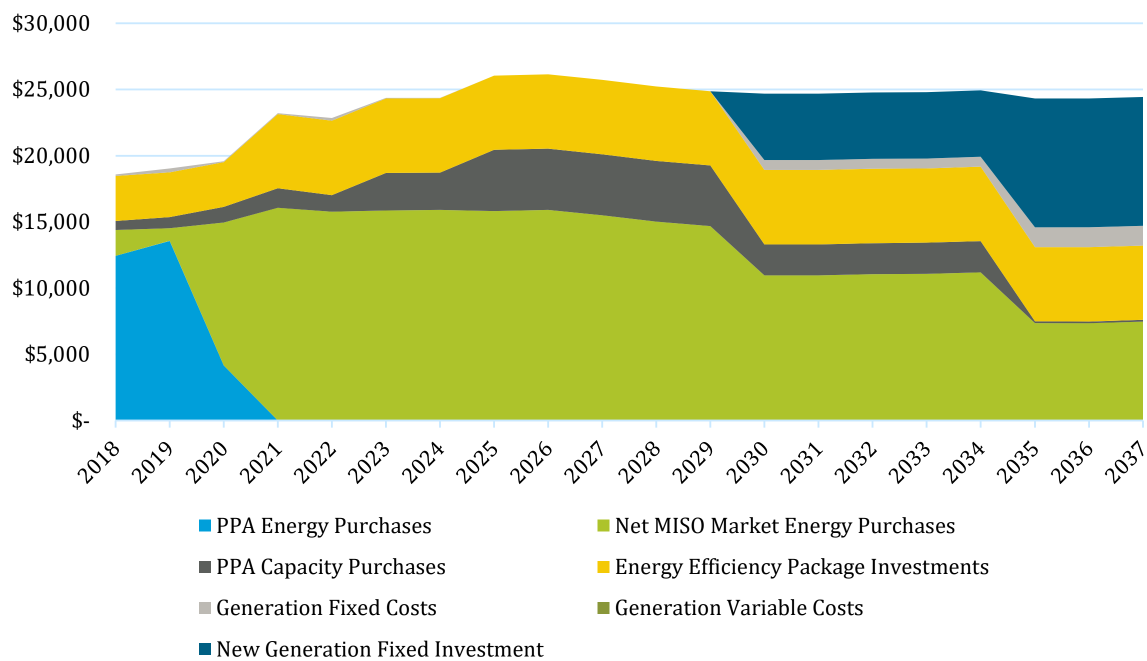



**Figure 9-28 Components of the High Market Price Base plus RPS50 CPWC**

### 9.1.29 High Market Price: Grid Defection

In this case, high market price with grid defection is considered. UPPCO would employ a 10 MW solar expansion and 20 MW solar expansion. The 10 MW solar expansion would commence in 2035 with firm capacity of 5 MW from 2035 onwards with annual average fixed costs of $150,000 and average annual investment costs of $943,000. The 20 MW solar expansion would commence in 2035 with firm capacity of 40 MW from 2035 onwards with annual average fixed costs of $1.201 million and average annual investment costs of $7.546 million. MISO capacity market costs, oil-fired costs, and PPA capacity costs are also considered. PRM for this case is 8.4 percent with an RPS in 2021 of 18 percent and an EE percentage of 43 percent in 2025. In the high market price with grid defection case, UPPCO would be able to receive 73.5 percent of energy from owned resources. CPWC for this case is $244.250 million with a rank of 15. The detailed results of this case are shown in Table 9-25. The cost components of the CPWC are represented graphically in Figure 9-25.

**Table 9-29 CPWC for High Market Price with Grid Defection ($000)**

| YEAR | PPA ENERGY PURCHASES | NET MISO MARKET ENERGY PURCHASES | PPA CAPACITY PURCHASES | ENERGY EFFICIENCY PACKAGE INVESTMENTS | GENERATION FIXED COSTS | GENERATION VARIABLE COSTS | NEW GENERATION FIXED INVESTMENT |
|---|---|---|---|---|---|---|---|
| 2018 | $12,445 | $1,977 | $700 | $3,382 | $134 | $- | $- |
| 2019 | $13,560 | $617 | $838 | $3,382 | $284 | $- | $- |
| 2020 | $4,150 | $10,394 | $1,052 | $3,382 | $47 | $- | $- |
| 2021 | $- | $15,626 | $1,312 | $5,615 | $73 | $- | $- |
| 2022 | $- | $15,222 | $1,083 | $5,615 | $199 | $- | $- |
| 2023 | $- | $15,262 | $2,659 | $5,615 | $58 | $- | $- |
| 2024 | $- | $15,264 | $2,631 | $5,615 | $21 | $- | $- |
| 2025 | $- | $15,133 | $4,420 | $5,615 | $- | $- | $- |
| 2026 | $- | $15,170 | $4,430 | $5,615 | $- | $- | $- |
| 2027 | $- | $14,745 | $4,395 | $5,615 | $- | $- | $- |
| 2028 | $- | $14,228 | $4,372 | $5,615 | $- | $- | $- |
| 2029 | $- | $13,750 | $4,326 | $5,615 | $- | $- | $- |
| 2030 | $- | $13,426 | $4,292 | $5,615 | $- | $- | $- |
| 2031 | $- | $13,344 | $4,259 | $5,615 | $- | $- | $- |
| 2032 | $- | $13,286 | $4,236 | $5,615 | $- | $- | $- |
| 2033 | $- | $13,166 | $4,191 | $5,615 | $- | $- | $- |
| 2034 | $- | $13,190 | $4,157 | $5,615 | $- | $- | $- |
| 2035 | $- | $6,373 | $125 | $5,615 | $1,350 | $- | $8,489 |
| 2036 | $- | $6,226 | $92 | $5,615 | $1,354 | $- | $8,489 |
| 2037 | $- | $6,211 | $59 | $5,615 | $1,350 | $- | $8,489 |

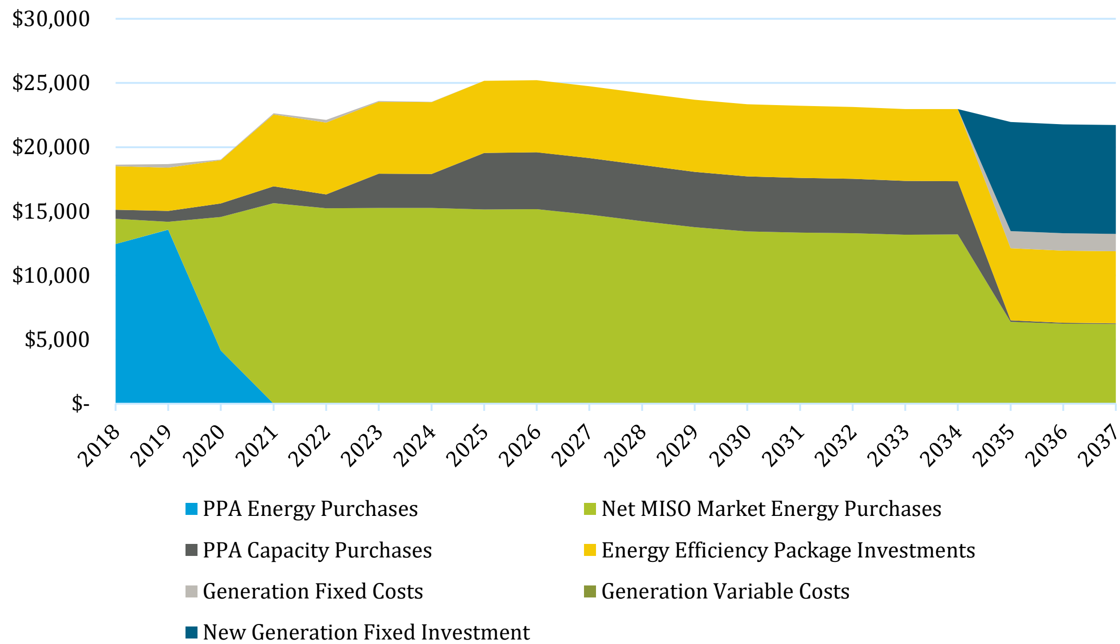



**Figure 9-29 Components of the High Market Price with Grid Defection Case CPWC**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **2036** | $- | $(263.7) | $86 | $5,615 | $0 | $9,931 | $- |
| **2037** | $- | $(157.3) | $86 | $5,615 | $0 | $9,931 | $- |

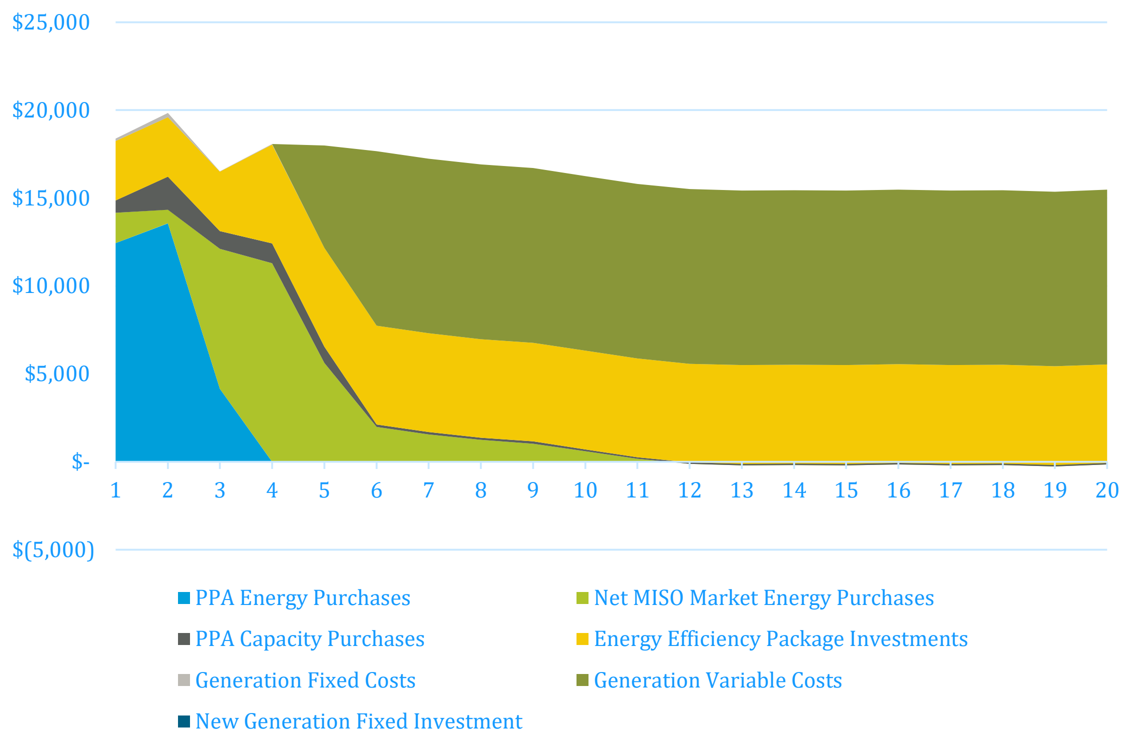



**Figure 9-30 Components of BAU Solar PPA 125 PCA CPWC**

## 9.2 PREFERRED CASE ALTERNATIVE

### 9.2.1 BAU Solar PPA 125 + RICE PCA

Through an iterative process of reviewing each of the above cases' results as further described in Sections 10 and 11, Black & Veatch ultimately selected a PCA that combines two of the previously discussed scenarios, the BAU Solar PPA 125 and the RICE 2022 cases, in order to form the Solar PPA 125 + RICE PCA. While the BAU Solar PPA 125 scenario resulted in the lowest CPWC of all evaluated scenarios and reduced overall UPPCO exposure to the MISO market, Black & Veatch believes that the additional energy source variety and firm, quickly dispatchable generation from a 20 MW RICE unit would be a favorable tradeoff for a relatively higher CWPC than the BAU Solar PPA 125 without a RICE. Adding the marginal CPWC costs from the BAU RICE 2022 scenario to the BAU Solar PPA

125 scenario results in a hybrid CPWC of $195,054 million, which is approximately 4.6 percent higher than the BAU Solar PPA 125 scenario, and ranks third overall among selectable scenarios.

In the PCA, Black & Veatch would expect UPPCO to be able to receive 95% or more of its energy from owned resources, materially similar to the BAU Solar PPA 125 Scenario, but with the added system reliability of a RICE unit.

# 10.0 IRP Recommendation

Black & Veatch's IRP recommendation is derived from further analysis of the top five CPWP ranked selectable cases (e.g. ignoring those cases such as high market or gas price conditions) as shown in Table 10-1. Assessments of net value, resources utilized, fuel prices, energy market prices, and capital costs have been compared among the five cases to reach a recommended solution.

## 10.1 OVERVIEW

Black & Veatch has considered the following cases to be compared to the BAU:

- BAU Solar PPA 125
- BAU Solar PPA 75
- BAU Solar PPA 125 + RICE PCA
- BAU Solar PPA 20
- BAU 50% Self-Supply

The CPWC, CPWC ranking, levelized cost, and levelized cost delta of the five cases are summarized and compared to the BAU Base Case in Table 10-1 and Figure 10-1.

**Table 10-1 CPWC and Levelized Cost of the Top Five Selectable Cases**

| CASE | CPWC ($000) | RANK (CPWC) | LEVELIZED COST ($/MWH) | LEVELIZED COST DELTA (%) |
|---|---|---|---|---|
| BAU Base Case | 202,182 | 9 | $33.34 | - |
| BAU Solar PPA 125 | 186,563 | 2 | $30.76 | -8% |
| BAU Solar PPA 75 | 193,904 | 3 | $31.97 | -4% |
| BAU Solar PPA 125 + RICE | 195,054 | 4 | $32.16 | -4% |
| BAU Solar PPA 20 | 200,558 | 8 | $33.07 | -1% |
| BAU 50% Self Supply | 206,117 | 11 | $33.98 | 2% |

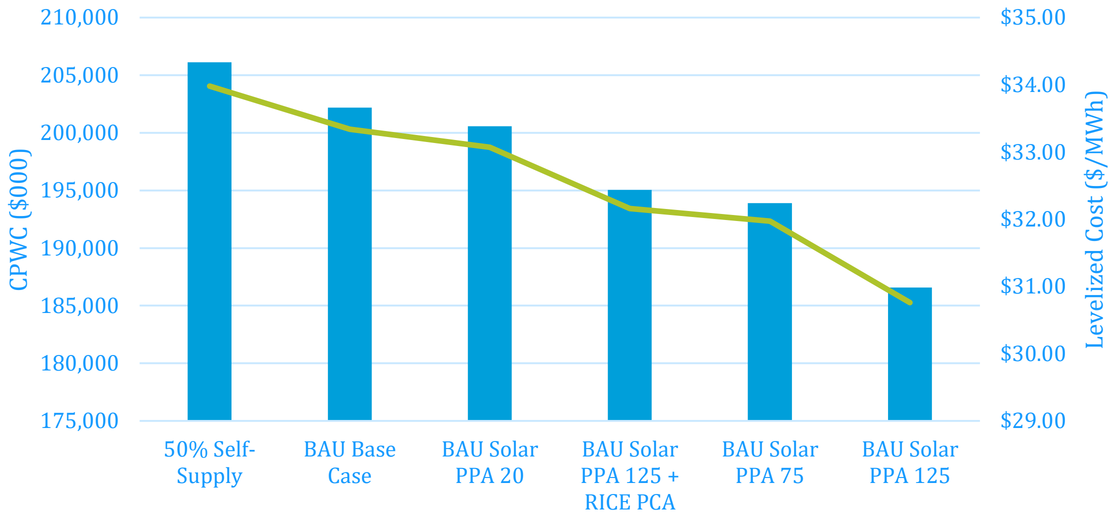



**Figure 10-1 CPWC and Levelized Cost Delta of the Top Six Cases ($000)**

Though the scenarios are ranked in ascending order of their CPWC, the lowest cost scenario may not be the best option for UPPCO. A scenario with a higher CPWC may be a better fit for UPPCO's system compared to a scenario with a lower CPWC depending upon multiple aspects, both on a qualitative and quantitative basis.

In the subsequent portions of this section, Black & Veatch discusses the various key variables that impact the CPWC of each of these scenarios and analyzes them to understand how their variability can affect UPPCO's system costs and risks before recommending the best fit scenario for UPPCO.

## 10.2 ANALYSIS OF KEY VARIABLES

### 10.2.1 Capacity Resources

One of the key parameters in a long-term planning scenario is the total generating resource mix of the system during the entire study period. The resource mix helps to identify the different categories of resources in a system. Typically, one would like to have a balanced mix of resources of different technologies using different types of fuel. This helps to reduce exposure to risks associated with a particular technology or fuel type. By having a balanced mix of resources, the risk associated with fuel costs, fuel supply disruption and technology risks can be avoided.

Figure 10-2 shows the technology mix of resources (both existing and future) in each of the six scenarios in 2037, the final year of the study period. All the six scenarios add similar amount of capacity resources during the study period. However, the High Market Price 50% Gas scenario, which is the scenario with the lowest CPWC is very heavily dependent on capacity purchases from the MISO regional capacity market. Similarly, the BAU Base case is also heavily dependent on the capacity purchases from the MISO capacity market and no other new resources are added. In comparison, the other cases have the more diversified portfolio of assets, with the BAU Solar PPA

125 PCA scenario having the most diverse portfolio of resources comprising of existing hydro and oil-fired resources as well as new renewable and thermal resources.

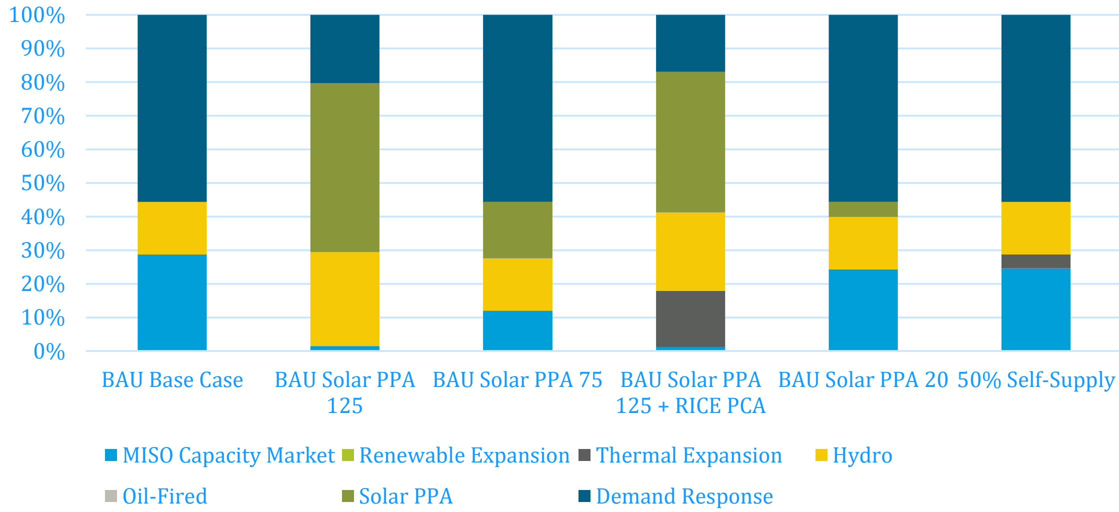



**Figure 10-2 Firm Capacity Breakdown and Comparison of Top Five Cases**

Black & Veatch is of the opinion that from a capacity resource mix the BAU Solar PPA 125 + RICE PCA case is the most diverse and therefore the least risky case amongst the six cases being discussed here. It relies least on buying capacity from the regional MISO capacity market. The capacity market price used in the model is based on the capacity prices forecast developed by Aces Marketing. Black & Veatch notes that though UPPCO territory falls within MISO Zone 2 region, the bilateral capacity prices at which UPPCO currently buys capacity is lower than the MISO zonal capacity clearing price.

Thus, from a resource mix standpoint, the BAU Solar PPA 125 + RICE PCA case is an ideal and robust option as it is the most varied.

### 10.2.2 Market Prices

As discussed above, capacity purchases through bilateral PPAs from the MISO regional capacity market have a significant impact on the CPWC. A projection of annual market purchase costs for each scenario evaluated is shown in Figure 10-4. Black & Veatch notes that the capacity purchase cost as shown in the figure below is based on current forecast of capacity prices.

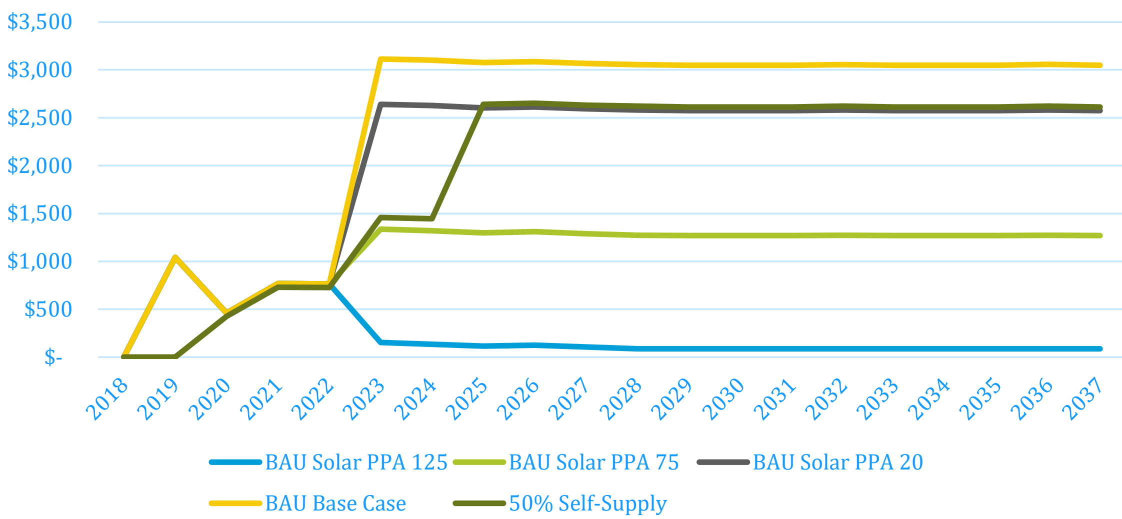



**Figure 10-3 Annual Fixed MISO Capacity Market Cost ($000)**

UPPCO has historically seen capacity prices to be more volatile and more expensive in their region in Upper Michigan, compared to rest of MISO in general, so reducing market capacity purchases and thereby market purchase cost will help mitigate risks associated with capacity price volatility. As such the BAU Solar PPA 125 + RICE PCA, which would be capable of achieving materially similar levels of reduced market reliance as shown by the BAU Solar PPA 125 scenario shown below in Figures 10-5 and 10-6, which reduces market reliance much more than the other low CPWC scenarios, and therefore seems to be the most appropriate option for UPPCO to mitigate this risk.

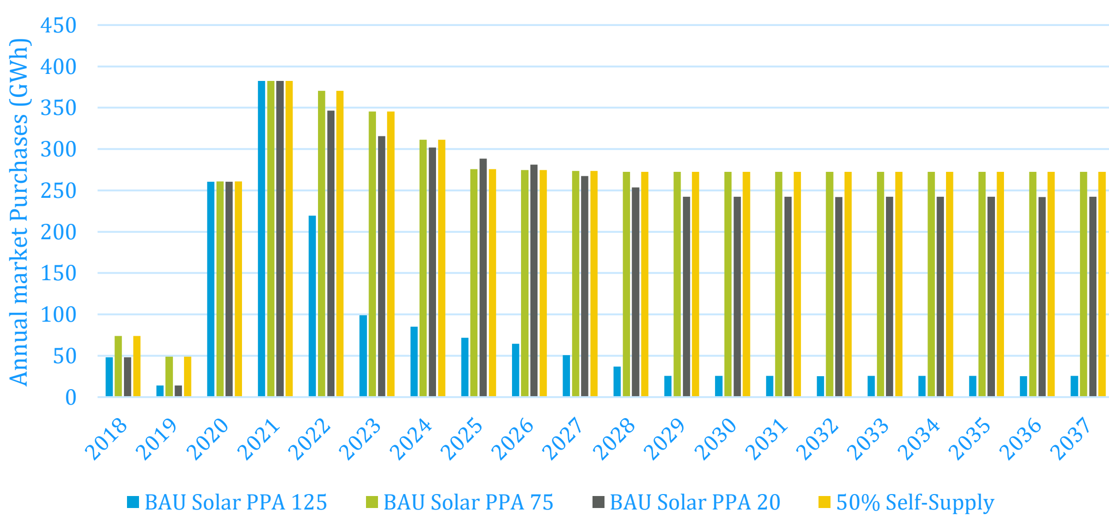



**Figure 10-4 Annual Market Purchases of Top Cases (GWh)**

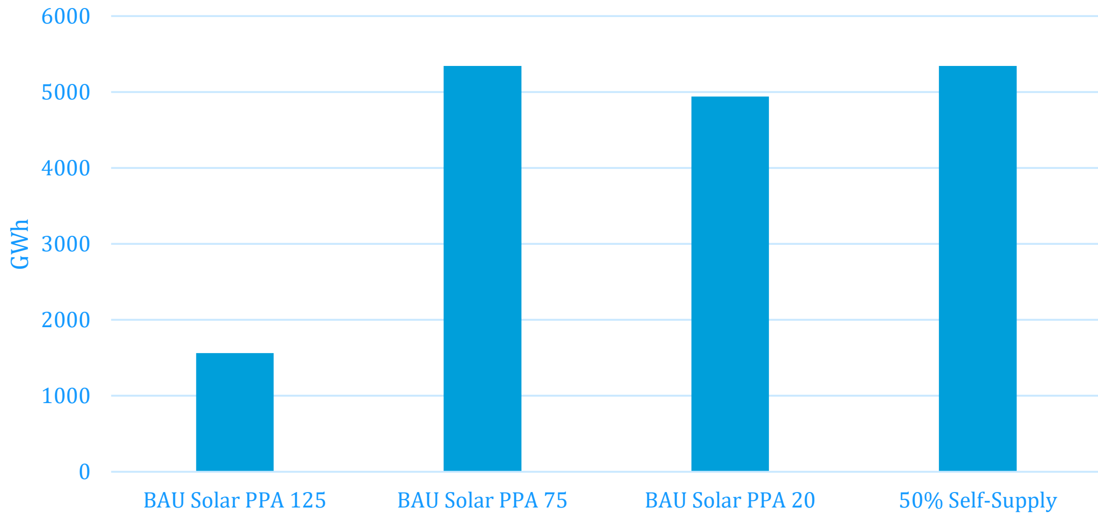



**Figure 10-5 Cumulative Market Purchases over 20-Year Period (GWh)**

Another key aspect to consider is the energy purchases made from the regional MISO energy market. The regional energy prices were developed by Black & Veatch as part of the Energy Market Perspective and is heavily dependent upon the regional gas price forecast. As coal plants are being retired and replaced by gas power generation and renewable generation, the energy prices in the region are expected to be heavily dependent on the gas prices in the future. Due to the volatility of gas prices, the regional energy prices will likely be volatile as well. Therefore, for planning purposes, UPPCO (with its high exposure to the gas market) needs to consider this volatility risk and try to mitigate it by reducing the dependence on energy purchases from the regional energy market. Figure above covers the market purchases for each case considered.

It is desirable to not be heavily dependent on market purchases. Black & Veatch believes that the BAU Solar PPA 125 + RICE PCA case has relatively lower dependence on the market purchases, which is desirable and mitigates undue exposure to volatile gas markets.

### 10.2.3 Investment Costs

Another key factor to analyze is capital cost investment. Typically, capital cost investment helps to build up generating assets in the utility portfolio. Owning generating assets help utilities by giving them the flexibility to generate energy based on need and energy market economics. While upfront capital costs are high, it allows the utility to generate electricity without paying additional capacity charges once the capital investment is paid off. It also helps to mitigate risks associated with buying capacity and energy from the regional markets, which can be volatile and unpredictable. Further capital investments help to build up assets as opposed to paying for capacity charges for purchasing capacity through bilateral PPAs. Considering the above factors, one needs to assess the importance of the capital investment in a utilities system in order to understand the best planning option for the utility

In Figure 10-7, it is observed that each of the solar PPA scenarios tie for the lowest overall investment cost, as they do not rely on building out owned assets. Conversely, the BAU Solar PPA 125 + RICE PCE has the higher capital cost investments.

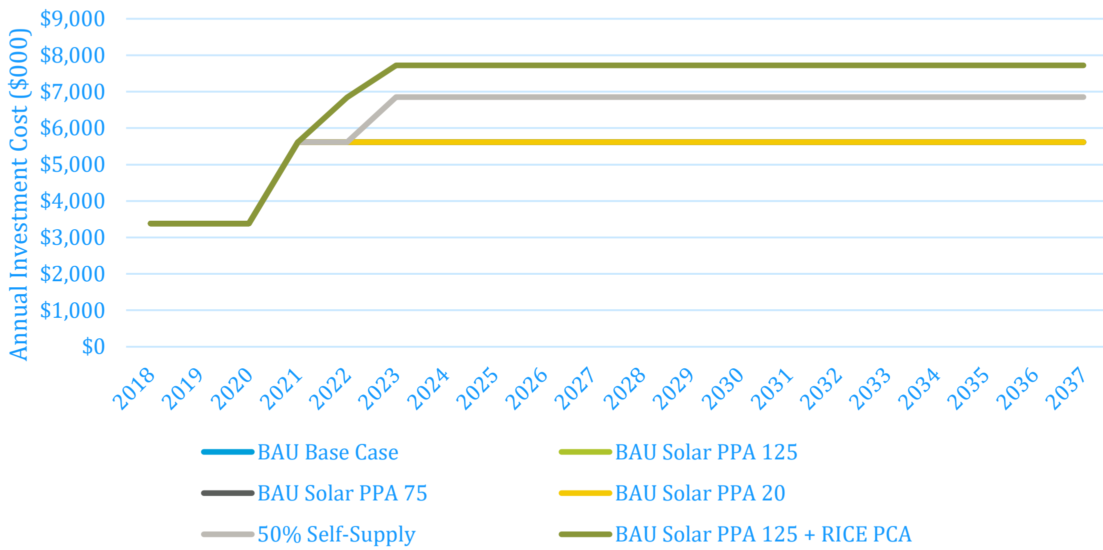



**Figure 10-6 Total Annual Investment Costs of Top Cases**

UPPCO's current generation resources comprises of old hydro and oil units which are becoming increasingly expensive and difficult to operate. So, it is likely an ideal time for UPPCO to add new owned resources, in addition to PPA energy. This would help to mitigate the risk of aging infrastructure and help to minimize the dependence on the MISO regional capacity market. Considering the above, Black & Veatch is of the opinion that the BAU Solar PPA 125 + RICE PCA case is the most favorable scenario for UPPCO's customers as it helps to build up its generating resource infrastructure. It is also favorable for UPPCO's customers as it helps to build up a diverse portfolio of renewable and thermal energy.

## 10.2.4 Conclusion

Based on the above analysis, Black & Veatch is of the opinion that BAU Solar PPA 125 + RICE PCA case is the most favorable case for UPPCO's system.

# 11.0 Risk Analysis

## 11.1 SENSITIVITY ANALYSIS

In addition to the base scenarios described in Section 9.0, Black & Veatch, along with UPPCO identified key risk areas that may have an impact on some of the key scenarios evaluated for the IRP and performed various sensitivity analyses. For the sensitivity analysis, the following five cases were selected:

- BAU Base + 1.5% Load Growth
- BAU 200% Gas
- BAU All Simple Cycle
- BAU Base
- BAU Solar PPA 125 PCA

For the sensitivity analyses, Black & Veatch kept the expansion plan for each of the above scenarios the same as the corresponding base scenario expansion plan, so a proper comparison of CPWC of the sensitivity cases can be made with that of the corresponding base scenario.

The following sensitivities were assessed for each of the cases listed above:

- Change in Capital Cost for new generating resources: The capital cost for the new generating resources as assumed in the base scenarios were increased and decreased by 20 percent to assess the impact of the variability of the assumed capital cost of the new generating resources. For each scenario, two (2) different sensitivity runs for each of the five (5) cases selected above were made for this sensitivity analysis.
- Change in Capacity Factor for new solar projects: The capacity factor assumed in the base scenario is 14 percent. However as solar resources are intermittent, in reality, the actual capacity factor of solar projects may vary which can significantly impact UPPCO's system cost. To assess the risks due to variability of solar generation, Black & Veatch performed sensitivity analyses on the capacity factor of new solar resources by increasing and decreasing the proposed capacity factor by a total of 4 percent in 2 percent blocks, i.e., assuming 10, 12, 16 and 18 percent capacity factors for the solar resources. Altogether four (4) runs were done for this sensitivity scenario for each of the five cases selected above.
- Change in market-based Capacity Prices: UPPCO historically have experienced low capacity prices through bilateral capacity PPAs which far exceeded the market clearing capacity price in the MISO region. UPPCO is located in Zone 2 of the MISO region. However due to their geographic location and current transmission constraints with rest of MISO Zone 2, UPPCO has had to pay a high premium on capacity prices through bilateral PPAs. In discussions with UPPCO, Black & Veatch understands that this uncertainty poses a potential risk for them and so Black & Veatch performed two (2) sensitivities for each of the above scenarios by increasing the base scenario market capacity prices by 50 percent and 100 percent. In addition, Black & Veatch also performed a downside sensitivity scenario for all the above cases where the market capacity price was decreased by 50 percent from the base scenario assumptions.

### 11.1.1 CPWC and Levelized Cost Comparison

The details of the scenario analysis outputs are shared in Section 9. Tables 11-1 and 11-2 show the comparison of the CPWC and system levelized. The tables show impact of the Cases to the CPWC and the Levelized Cost in $/MWh.

**Table 11-1 CPWC Comparison of the Base Scenarios and their Sensitivities**

| CPWC ($000S) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | BAU SOLAR PPA 125 PCA | | BAU 1.5% LOAD GROWTH | | BAU 200% GAS | | BAU ALL SIMPLE CYCLE | | BAU BASE | |
| SENSITIVITY | $000 | CHANGE FROM BASE SCENARIO | $000 | CHANGE FROM BASE SCENARIO | $000 | CHANGE FROM BASE SCENARIO | $000 | CHANGE FROM BASE SCENARIO | $000 | CHANGE FROM BASE SCENARIO |
| Base Scenario | $186,563 | | $237,545 | | $283,961 | | $263,057 | | $199,769 | |
| Capital Cost (+ 20%) | $185,147 | -1% | $238,746 | 1% | $286,135 | 1% | $278,726 | 6% | $199,769 | 0% |
| Capital Cost (- 20%) | $185,657 | 0% | $236,343 | -1% | $281,787 | -1% | $247,389 | -6% | $199,769 | 0% |
| Solar Capacity Factor (10%) | $186,166 | 0% | $238,288 | 0% | $286,892 | 1% | $263,057 | 0% | $199,769 | 0% |
| Solar Capacity Factor (12%) | $187,149 | 0% | $237,911 | 0% | $285,405 | 1% | $263,057 | 0% | $199,769 | 0% |
| Solar Capacity Factor (16%) | $189,813 | 2% | $237,172 | 0% | $282,493 | -1% | $263,057 | 0% | $199,769 | 0% |
| Solar Capacity Factor (18%) | $188,188 | 1% | $236,807 | 0% | $281,054 | -1% | $263,057 | 0% | $199,769 | 0% |
| Market Capacity Price (+100%) | $184,938 | -1% | $263,532 | 11% | $300,797 | 6% | $263,057 | 0% | $219,979 | 10% |
| Market Capacity Price (+50%) | $186,563 | | $250,538 | 5% | $292,379 | 3% | $263,057 | 0% | $209,874 | 5% |
| Market Capacity Price (-50%) | $185,147 | -1% | $224,551 | -5% | $275,543 | -3% | $263,057 | 0% | $189,664 | -5% |

**Table 11-2 Levelized Cost Comparison of the Base Scenarios and their Sensitivities**

| LEVELIZED COST, $/MWH | | | | | |
|---|---|---|---|---|---|
| SENSITIVITY | BAU SOLAR PPA 125 PCA | BAU 1.5% LOAD GROWTH | BAU 200% GAS | BAU ALL SIMPLE CYCLE | BAU BASE |
| Base Scenario | $31 | $34 | $47 | $43 | $33 |
| Capital Cost (+ 20%) | $31 | $34 | $47 | $46 | $33 |
| Capital Cost (- 20%) | $31 | $34 | $46 | $41 | $33 |
| Solar Capacity Factor (10%) | $31 | $34 | $47 | $43 | $33 |
| Solar Capacity Factor (12%) | $31 | $34 | $47 | $43 | $33 |
| Solar Capacity Factor (16%) | $31 | $34 | $47 | $43 | $33 |
| Solar Capacity Factor (18%) | $31 | $34 | $46 | $43 | $33 |
| Market Capacity Price (+100%) | $31 | $38 | $50 | $43 | $36 |
| Market Capacity Price (+50%) | $31 | $36 | $48 | $43 | $35 |
| Market Capacity Price (-50%) | $31 | $32 | $45 | $43 | $31 |

As seen in the tables above, changes in market capacity prices has the most impact on the each of the cases. The increase in capacity prices by 100 percent had the most upside impact to the CPWC and levelized cost and the decrease in capacity prices by 50 percent had the most downside impact to the cases. The other sensitivity scenarios have a lesser impact on the base scenario CPWC and levelized cost.

For the different cases, the BAU Solar PPA 125 PCA had the least variation to CPWC where the value varied between +6 percent and -3 percent for the different scenarios. The BAU case do not have any variations for the capital cost and solar resources capacity factor sensitivity cases as no new resources are added in that case.

### 11.1.2 Conclusion

Based on the above sensitivity analyses, it is understood that Solar PPA 125 PCA case has the least variation across all scenarios amongst all the five cases evaluated, and has a lower CPWC than the BAU base case ($186,563 million compared to $199. 769 million) under the base scenario assumptions The Solar PPA 125 PCA also does not heavily rely on the MISO energy and capacity market to fulfill the requirements of UPPCO's system, which reduces risk for UPPCO as the market capacity price variation. This market variation has the greatest impact on the system CPWC and the variability in CPWC is the highest for the BAU case under those circumstances. As such Black & Veatch is of the opinion that BAY Solar PPA 125 PCA case poses the least risk in terms of variation in CPWC and levelized costs.

## 11.2 STOCHASTIC ANALYSIS ON NATURAL GAS PRICES

In addition to the above sensitivity analyses, Black & Veatch also performed a stochastic analysis on natural gas prices to assess the impact of gas price variations on the CPWC of UPPCO's system. This was done on each of the following (4) base scenarios:

- BAU Base + 1.5% Load Growth
- BAU All Simple Cycle
- BAU Base
- BAU SolarPPA 125 PCA

Black & Veatch notes that the stochastic analysis was done for all the cases on which sensitivity analysis was done except for the BAU 200% Gas case. This is because the gas price in that case has already been doubled compared to the gas prices in the base case which is by itself a very high and extremely unlikely situation and any stochastic analysis on the high gas prices will therefore likely be redundant.

The approach for the stochastic analysis and the distribution of the CPWC costs for the different base scenarios are explained in detail in the following sections.

### 11.2.1 Approach

Black & Veatch utilized daily historical Henry Hub gas prices to develop a realistic historical distribution and randomly selected 50 price scenarios from 2019 through 2038 to understand the impact of Henry Hub prices on the conclusions of the planning study. For each randomly selected price scenario, Black & Veatch utilized a Monte-Carlo simulation approach assuming that natural gas price will follow a mean-reverting price were the mean itself evolves stochastically. Black & Veatch's Base Case utilized the 2018 EIA AEO price as the ultimate mean where prices would converge to in the long-term, and developed the random price scenarios off this mean price trajectory. The Monte-Carlo simulation assumes two types of uncertainties:

- **Forecast uncertainty.** All assumptions on the underlying fundamental factors, such as gas demand, gas supply curves from different basins, LNG export terminal location and volume, and pipeline exports to Mexico which determine the trajectory of the long-term forecast have inherent uncertainties associated with them. Intuitively, this uncertainty grows with the forecast period since there is more uncertainty associated assumptions further into the future than in the near term.
- **Short-term volatility**. Factors that will impact the market only for a short period of time, such as extreme weather, supply disruptions will likely to have an impact determining what the actual price would have been.

Black & Veatch estimated the forecast uncertainty component based on its our views regarding the development trend of the fundamental market drivers and their potential impact on price paths. The short-term volatility is estimated from historical gas price, weather, consumption and production data.

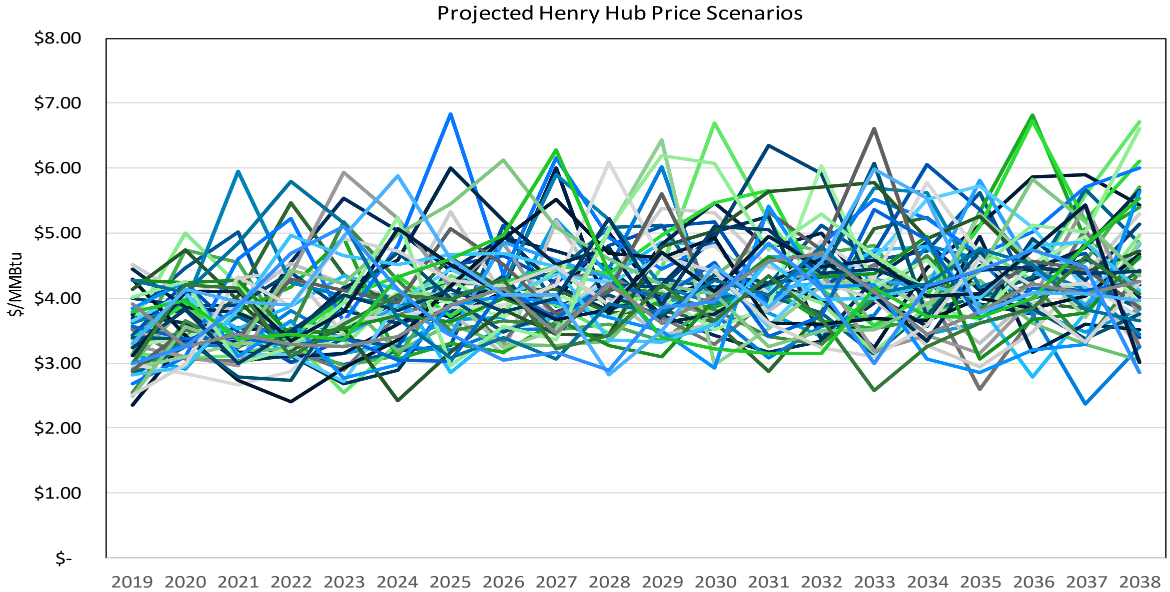



**Figure 11-1 Projected Henry Hub Prices**

As shown in Figure 11-1, projected Henry Hub prices for each random scenario can move appreciably from year to year over the 20-year analysis period. Black & Veatch developed the projected monthly prices for PLEXOS based on the annual price simulations seen in Figure 11-1 and utilized a monthly price shape based on historical EIA data. The monthly gas price projections for each of the fifty draws are provided in Appendix A.

Variances in gas prices in each draw will chance the dispatch cost of gas-fired units (both in the UPPCO system and the MISO market), and will subsequently alter the merit order of resources dispatched by PLEXOS to meet UPPCOs energy demand. These changes will ultimately drive up or down the total cost to serve UPPCO's demand, and this the CPWC. Each draw will result in its own CPWC, and for each case Black & Veatch can evaluate both the mean and distribution of resulting CPWCs to understand the expected value for each case, as well as its pricing subjectivity (and therefore risk) tied to gas prices as illustrated in the following subsection.

### 11.2.2 Results

Table 11-3 shows the key metrics of the stochastic analysis for each of the five cases. Figures 11-2 through Figure 11-6 shows the distribution of the CPWC of UPPCO's system for the five different cases due to the variation of the natural gas prices.

**Table 11-3 Summary of CPWC For the Four Scenarios**

| | BAU 1.5% LOAD GROWTH | BAU BASE | BAU ALL SIMPLE CYCLE | BAU SOLAR PPA 125 PCA |
|---|---|---|---|---|
| Number of Draws | 50 | 50 | 50 | 50 |
| Mean | 236,944 | 199,240 | 262,523 | 186,165 |
| | | | | |
| Median | 236,112 | 198,795 | 262,030 | 185,971 |
| Standard Deviation | 7,107 | 5,721 | 5,228 | 2,618 |
| Minimum | 224,695 | 189,257 | 253,402 | 180,758 |
| Maximum | 258,125 | 215,804 | 277,429 | 192,970 |
| Confidence Level (95.0%) | 2,020 | 1,626 | 1,486 | 1,075 |

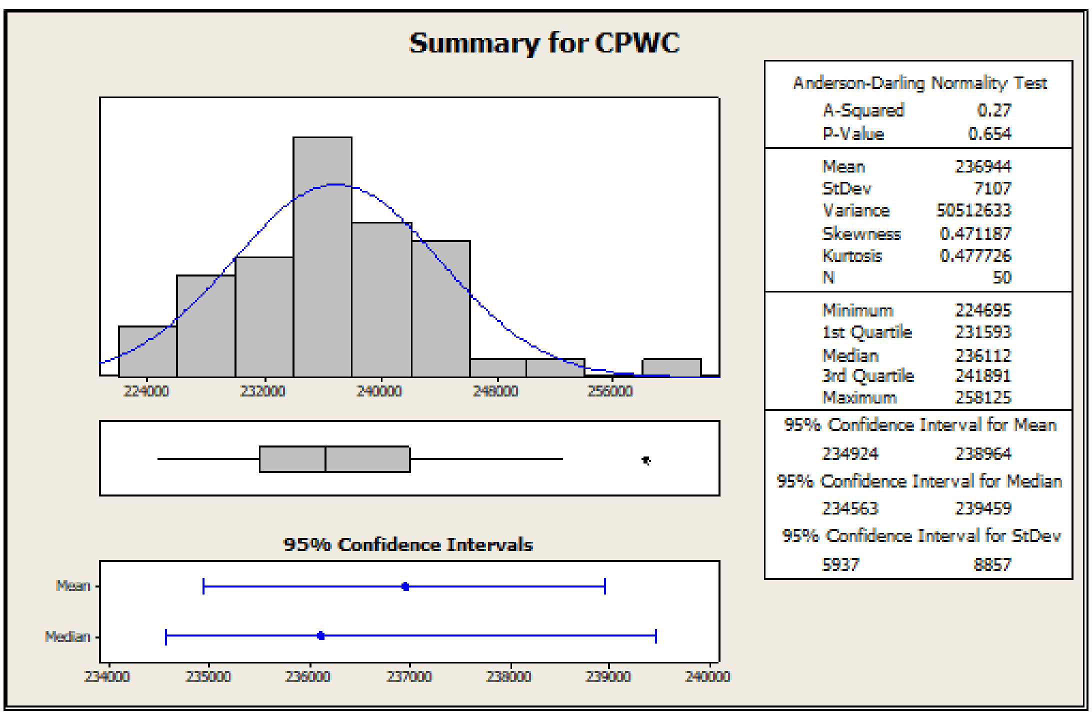



**Figure 11-2 CPWC Summary for BAU 1.5% Load Growth**

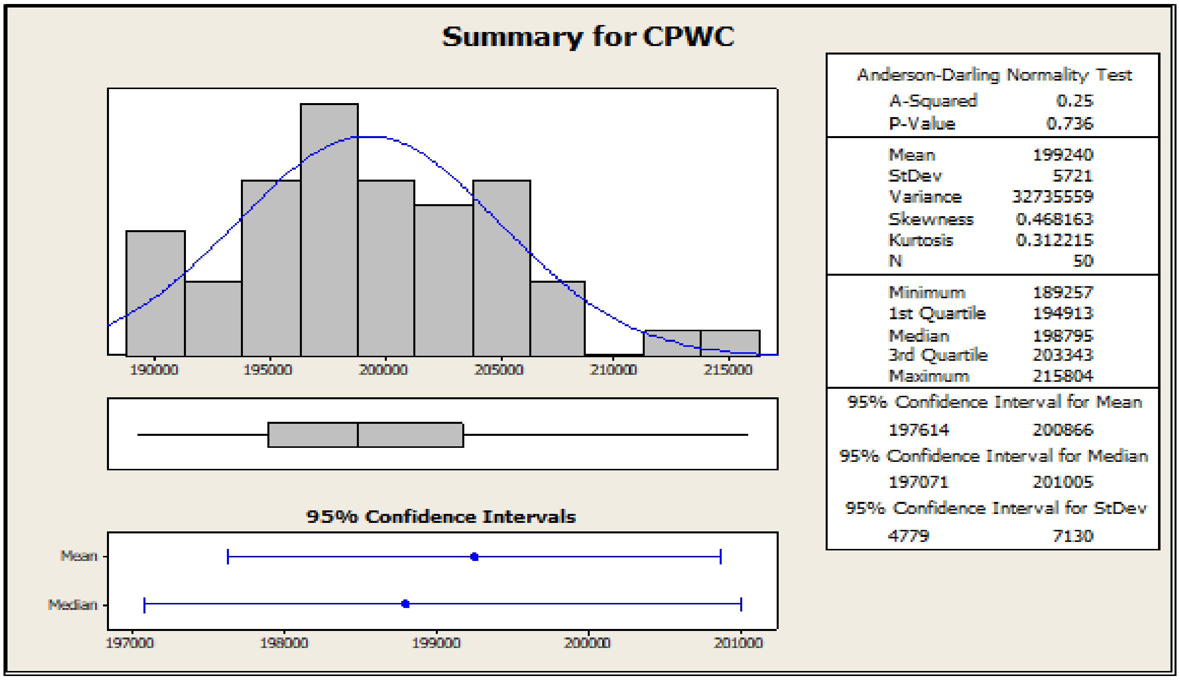



**Figure 11-3 CPWC Summary for BAU Base**

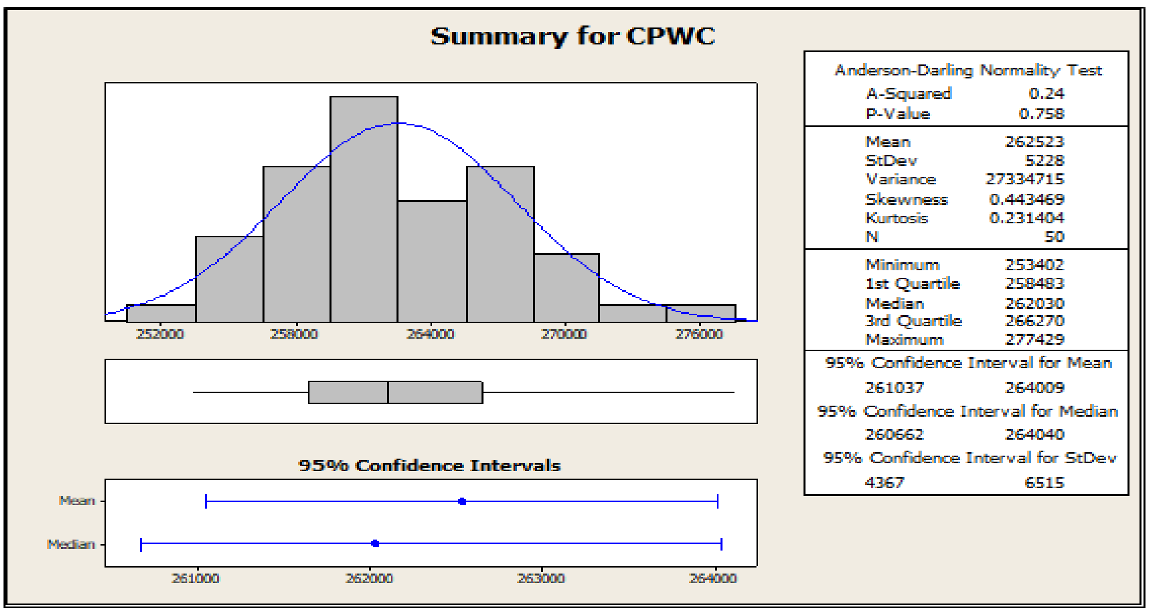



**Figure 11-4 CPWC Summary for BAU All Simple Cycle**

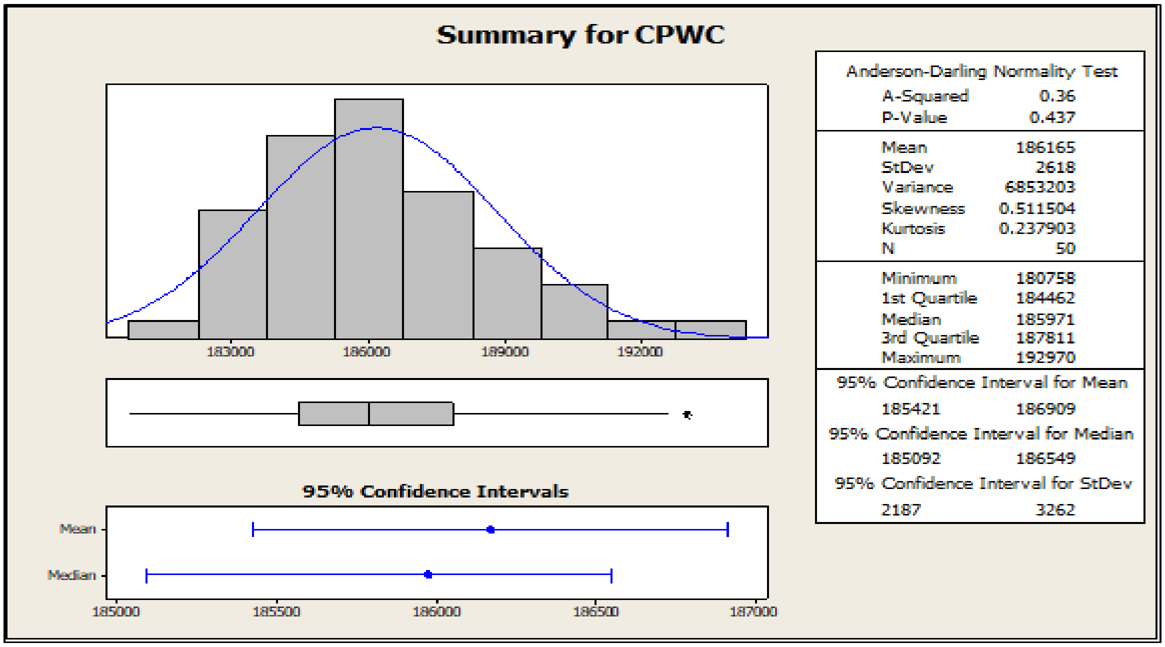



**Figure 11-5 CPWC Summary for BAU Solar PPA 125 PCA**

Based on the above analysis and the distribution results shown in Table 11-1, it is noted that the BAU Solar PPA 125 PCA Case and has the lowest CPWC in the base scenario and also has the lowest standard deviation of the system CPWC for the 50 draws of natural gas price forecast. This indicates that the BAU Solar PPA 125 PCA Case presents the minimum risk for UPPCO considering gas price volatility over the entire study period. This is primarily because this scenario has a balanced portfolio of new generating resources. In this scenario, UPPCO is planning on having a combination of solar and natural gas based resources in its generation mix. While solar resources are generally cheaper and economically more stable generating resources from a cost stand point compared to conventional natural gas based generating resources, they are however intermittent resources and their generation cannot always be predicted accurately thereby bringing in uncertainty around the actual available generation over a sustained period. Natural gas based resources like the RICE units on the other hand have a volatile generation cost as they are dependent on the volatile natural gas prices, but their generation is very stable and there is less uncertainty around their energy generation compared to solar resources. Therefore, by opting for a generation mix that includes both solar and gas based resources, UPPCO is balancing its risk exposure to gas price volatility as well as ensuring that it has access to non-intermittent generating resources to help mitigate any risks associated with intermittent generating resources. This is reflected by the fact that this scenario offers both the lowest CPWC and the lowest standard deviation based on the gas price stochastic analysis. Further, the RICE units will be built further down the study period, which will provide UPPCO with the option of re-evaluating the resource during the next IRP study before taking a firm decision on building the unit. As such, Black & Veatch is of the opinion that the 50% Self-Supply PCA case presents the minimum risk to UPPCO for the different sensitivities analyzed as part of this study.

# 12.0 Retail Rate Impact

As a regulated utility, the costs UPPCO incurs in generating, procuring, and distributing the energy to meet its system native load is passed on to its customers and ratepayers through UPPCO's rate base, therefore a primary objective of an IRP study is to evaluate the impact that a potential scenario will have on retail electricity rates.

Black & Veatch's IRP modeling outputs levelized and year 1 power generation and procurement costs for each generation scenario as discussed in Section 1.0. Using standard cost-of-service methodology, UPPCO may allocate these power costs and PSCR savings that are applicable to all customers on a projected $/kWh of consumption basis. The exceptions to this are RTMP sales to Verso, as these are based on real time pricing of power taken directly from the MISO market, and sales to industrial interruptible customers who are separate from the retail rate base; because UPPCO can remove projected load to these interruptible customers from its MISO capacity requirements, these customers do not have any large capacity-related charges applied to them, whether purchased in the market or whether self-owned and recovered in revenue requirements.

Along with this IRP Report, Black & Veatch has provided to UPPCO all supporting documentation required to determine the total power costs associated with each scenario, which UPPCO may utilize to develop anticipated rate impact associated with those scenarios. However, Black & Veatch notes that these IRP results only provide the costs associated with power generation. Ultimately, retail rates will also be impacted by other costs, such as transmission, operations and maintenance, and corporate SG&A costs, which are not part of this IRP scope. Accordingly, UPPCO is evaluating these costs separately in order to build a comprehensive rate model inclusive of this IRP.

# Appendix A. Regional Model Methodology and Approach

## A.1 PLEXOS MODEL

### A.1.1 Overview

Two commercial software models were utilized to support the analysis, PROMOD® and PLEXOS®, which are licensed by Black & Veatch from ABB/Ventyx and Energy Exemplar, respectfully. A model of the MISO market (MISO Model) was developed using PROMOD to simulate an hourly forecast of wholesale energy and capacity prices over the 20-year planning horizon of the IRP. The regional price forecast is used to establish prices at which UPPCO can sell into or purchase electricity from the MISO market over the study horizon. A model of the UPPCO system was also developed in PLEXOS to support the evaluation of the least cost expansion plan (UPPCO System Model). The UPPCO System Model incorporates specific generation parameters for existing UPPCO units and existing PPAs. Market prices from the MISO Model were used as inputs to determine the costs and revenue associated with serving load and selling power into the MISO market.

PLEXOS was selected for the evaluation of the least cost expansion plan due to its ability to simulate long-term resource expansion analysis based on a detailed representation of utility load shape(s), granular representation of generator operating characteristics and cost, and customizable constraints on system planning requirements and/or system operation. Examples of constraints or criteria that can be included in the model include a system planning reserve margin and target levels of renewable energy. Using such constraints and input data such as UPPCO's load forecast for energy and peak demand, PLEXOS determines the least cost expansion plan by assessing all possible combinations of expansion options for the time period under evaluation and selecting the plan that has the lowest costs, accounting for lifecycle investment costs, fuel costs, and fixed and variable operations and maintenance (O&M) costs.

### A.1.2 Key Model Inputs and Assumptions

#### A.1.2.1 WACC

The WACC assumed in Black & Veatch's modeling and CPWC calculations is 7.467, as directed by UPPCO.

#### A.1.2.2 Inflation Rate

The inflation rate as directed by UPPCO is 2.565 percent, with a base year of 2017.

### A.1.2.3 Capital Cost Assumptions

**Non-Emerging Technology**

| YEAR | BIOMASS | SOLAR PV 100 MW | SOLAR PV 20 MW | SOLAR PV 2 MW | WIND 100 MW | WIND 100 MW | WIND 20 MW | LI-ION (30 MIN) | LI-ION (4 HOUR) |
|---|---|---|---|---|---|---|---|---|---|
| 2020 | 4,484 | 1,242 | 1,242 | 2,128 | 2,014 | 2,014 | 2,014 | 1,062 | 2,035 |
| 2021 | 4,475 | 1,227 | 1,227 | 2,102 | 2,014 | 2,015 | 2,015 | 1,019 | 1,954 |
| 2022 | 4,466 | 1,212 | 1,212 | 2,128 | 2,014 | 2,016 | 2,016 | 978 | 1,875 |
| 2023 | 4,458 | 1,198 | 1,198 | 2,128 | 2,014 | 2,017 | 2,017 | 969 | 1,857 |
| 2024 | 4,449 | 1,183 | 1,183 | 2,128 | 2,014 | 2,018 | 2,018 | 959 | 1,838 |
| 2025 | 4,440 | 1,169 | 1,169 | 2,102 | 2,015 | 2,019 | 2,019 | 949 | 1,820 |
| 2026 | 4,431 | 1,155 | 1,155 | 2,077 | 2,016 | 2,020 | 2,020 | 940 | 1,801 |
| 2027 | 4,422 | 1,141 | 1,141 | 2,052 | 2,017 | 2,021 | 2,021 | 930 | 1,783 |
| 2028 | 4,413 | 1,128 | 1,128 | 2,028 | 2,018 | 2,022 | 2,022 | 921 | 1,766 |
| 2029 | 4,404 | 1,114 | 1,114 | 2,003 | 2,019 | 2,023 | 2,023 | 912 | 1,748 |
| 2030 | 4,396 | 1,101 | 1,101 | 1,979 | 2,020 | 2,024 | 2,024 | 903 | 1,730 |
| 2031 | 4,387 | 1,088 | 1,088 | 1,956 | 2,021 | 2,025 | 2,025 | 894 | 1,713 |
| 2032 | 4,378 | 1,074 | 1,074 | 1,932 | 2,022 | 2,026 | 2,026 | 885 | 1,696 |
| 2033 | 4,369 | 1,062 | 1,062 | 1,909 | 2,023 | 2,027 | 2,027 | 876 | 1,679 |
| 2034 | 4,360 | 1,049 | 1,049 | 1,886 | 2,024 | 2,028 | 2,028 | 867 | 1,662 |
| 2035 | 4,352 | 1,036 | 1,036 | 1,863 | 2,025 | 2,029 | 2,029 | 859 | 1,646 |
| 2036 | 4,343 | 1,024 | 1,024 | 1,841 | 2,026 | 2,031 | 2,031 | 850 | 1,629 |
| 2037 | 4,334 | 1,012 | 1,012 | 1,819 | 2,027 | 2,032 | 2,032 | 842 | 1,613 |

*All values are in $000's.

## Emerging Technology – Costs Reduced by 35% Year Over Year

| YEAR | SOLAR PV 100 MW | SOLAR PV 20 MW | SOLAR PV 2 MW | LI-ION (30 MIN) | LI-ION (4-HOUR) |
|---|---|---|---|---|---|
| 2020 | 807 | 807 | 1,383 | 690 | 1,323 |
| 2021 | 798 | 798 | 1,367 | 662 | 1,270 |
| 2022 | 788 | 788 | 1,383 | 636 | 1,219 |
| 2023 | 779 | 779 | 1,383 | 630 | 1,207 |
| 2024 | 769 | 769 | 1,383 | 623 | 1,195 |
| 2025 | 760 | 760 | 1,367 | 617 | 1,183 |
| 2026 | 751 | 751 | 1,350 | 611 | 1,171 |
| 2027 | 742 | 742 | 1,334 | 605 | 1,159 |
| 2028 | 733 | 733 | 1,318 | 599 | 1,148 |
| 2029 | 724 | 724 | 1,302 | 593 | 1,136 |
| 2030 | 715 | 715 | 1,287 | 587 | 1,125 |
| 2031 | 707 | 707 | 1,271 | 581 | 1,114 |
| 2032 | 698 | 698 | 1,256 | 575 | 1,102 |
| 2033 | 690 | 690 | 1,241 | 569 | 1,091 |
| 2034 | 682 | 682 | 1,226 | 564 | 1,080 |
| 2035 | 674 | 674 | 1,211 | 558 | 1,070 |
| 2036 | 665 | 665 | 1,197 | 553 | 1,059 |
| 2037 | 658 | 658 | 1,182 | 547 | 1,048 |

*All values are in $000's.

### A.1.2.4 O&M Costs

| TECHNOLOGY | FOM CHARGE ($/KW/YR) |
|---|---|
| Solar PV 100-MW Site (2020 Build) | $12 |
| Solar PV 100-MW Site (2024 Build) | $10 |
| RICE Wartsila 16V34SG | $14 |
| RICE Wartsila 18V50SG | $18 |
| RICE Wartsila 20V34SG | $14 |
| RICE Wartsila 9L34SG | $14 |
| SCGT GE LM6000 SP | $14 |
| Wind 100-MW Site (2022 Build) | $48 |
| Wind 100-MW Site (2025 Build) | $47 |
| Wind 100-MW Site (2028 Build) | $46 |
| Wind 100-MW Site (2031 Build) | $45 |
| Wind 100-MW Site (2033 Build) | $44 |
| Wind 100-MW Site (2036 Build) | $43 |
| Measure Group A (1 percent Savings) | $1,273 |
| Measure Group B (1.5 percent Savings) | $1,191 |
| Measure Group C (2.5 percent Savings) | $1,125 |
| Li-Ion (30 Min) | $8 |
| Li-Ion (4-hour) | $8 |
| Wind 20-MW Site (2020 Build) | $49 |
| Wind 20-MW Site (2022 Build) | $48 |
| Wind 20-MW Site (2025 Build) | $47 |
| Wind 20-MW Site (2028 Build) | $46 |
| Wind 20-MW Site (2031 Build) | $45 |
| Wind 20-MW Site (2033 Build) | $44 |
| Wind 20-MW Site (2036 Build) | $43 |
| Generic Biomass | $108 |
| Solar PV 20-MW Site (2020 Build) | $12 |
| Solar PV 20-MW Site (2024 Build) | $10 |
| Solar PV 2-MW Site (2020 Build) | $12 |
| Solar PV 2-MW Site (2026 Build) | $10 |

### A.1.2.5 Key Capital Cost Assumptions Rationale

Black & Veatch held discussions with Shaw and UPPCO to determine the most appropriate capital cost assumptions for the potential new assets. The capital cost assumptions used as well as the reasoning behind the assumptions are explained in this section.

**Wind – ELCC Capacity & Power Generation Capacity Factor**

Black & Veatch utilized the December 2017 MISO Planning Year 2018-2019 Wind Capacity Credit Report to determine the value of the capacity credit for wind assets. As seen in the figure below, there are large differences between the local resource zones (LRZ). Areas such as Zone 1, which include high wind energy states like North Dakota, has an ELCC percentage at 18.3 percent, moving the average upwards. Black & Veatch has decided that the lower figure of 10.4 percent which corresponds with Zone 2 as more appropriate.


| Local Resource Zone | Local Balancing Authorities |
|---|---|
| 1 | DPC, GRE, MDU, MP, NSP, OTP, SMP |
| 2 | ALTE, MGE, MIUP, UPPC, WEC, WPS |
| 3 | ALTW, MEC, MPW |
| 4 | AMIL, CWLP, SIPC |
| 5 | AMMO, CWLD |
| 6 | BREC, CIN, HE, IPL, NIPSCO, SIGE |
| 7 | CONS, DECO |
| 8 | EAI |
| 9 | CLEC, EES, LAFA, LAGN, LEPA |
| 10 | EMBA, SME |

| Metric | MISO | Zone 1 | Zone 2 | Zone 3 | Zone 4 and Zone 5 | Zone 6 | Zone 7 | Zone 8 | Zone 9 | Zone 10 |
|---|---|---|---|---|---|---|---|---|---|---|
| Registered Max (MW) | 16,761 | 4,779 | 734 | 8,450 | 644 | 282 | 1,872 | 0 | 0 | 0 |
| UCAP (MW) | 2,548 | 873 | 76 | 1,310 | 58 | 21 | 210 | 0 | 0 | 0 |
| ELCC % | 15.2% | 18.3% | 10.4% | 15.5% | 9.0% | 7.4% | 11.2% | 0.0% | 0.0% | 0.0% |
| Wind CPNode Count | 207 | 72 | 11 | 86 | 8 | 4 | 26 | 0 | 0 | 0 |

To determine the best capacity factor, Black & Veatch observed comparable wind projects in the Upper Peninsula region. There is currently only one wind project in the Upper Peninsula known as the Garden Wind Farm which is located on the Garden peninsula just east of Escanaba. This 28 MW project (14 Gamesa turbines x 2 MW) was built in 2012, is owned by Heritage Wind Energy, and sells its renewable power to DTE and Consumers Energy. The actual capacity factor for this project was 32.5 percent in 2016 and 33.5 percent in 2015. For the PLEXOS model, Black & Veatch assumed a starting capacity factor of 34 percent and factored in an average of 20 years of degradation to reach a capacity factor of 32.3 percent. This 32.3 percent figure was used as the capacity for new wind unit additions.

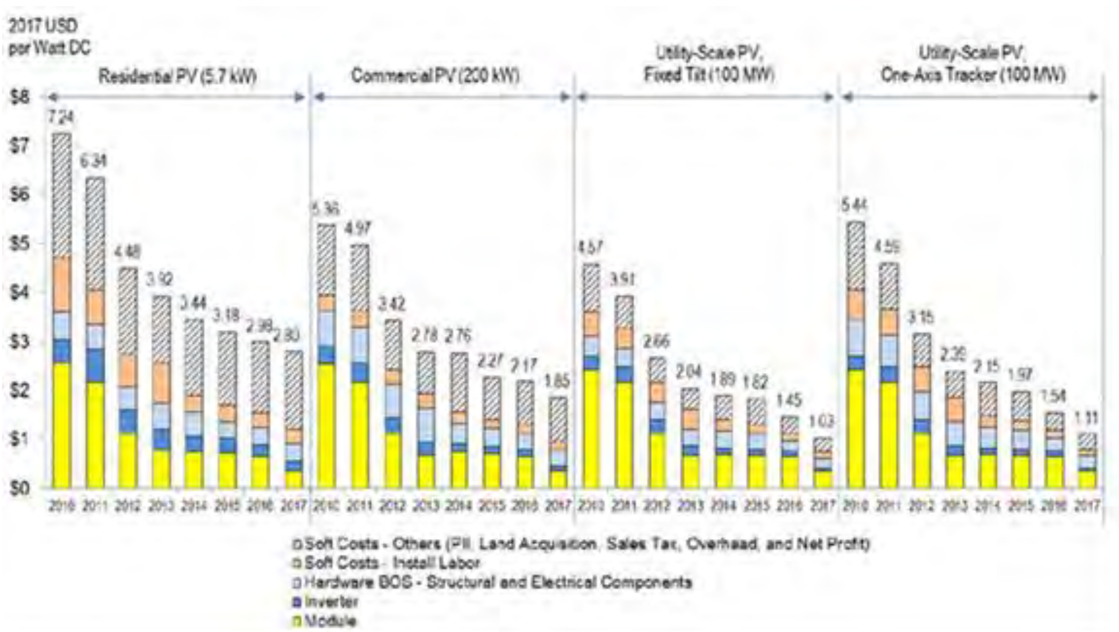
## Solar – O&M Costs

Black & Veatch, upon discussion with Shaw, decided to use solar O&M cost assumptions that are consistent with NREL, Lazard, and others, as well as recent MPSC filings.

| TECHNOLOGY | FO&M CHARGE ($/KW/YR) |
|---|---|
| Solar PV (2020 Build) | $12 |
| Solar PV (2024 Build) | $10 |

## Solar – Capital Costs

As seen in comparable projects, the recently introduced solar module tariffs have not had the significant cost increase impact that was expected, and manufacturers might simply be accepting compressed margins for the time being to maintain sales volumes. As seen in the figure below, cost reductions have been steadily coming from all areas of EPC and owner's costs, not just module price reductions, and NREL is projecting this trend to continue. From 2013-2016, even though utility scale module prices were flat, all-in capex still declined 29 percent. Therefore, Black & Veatch has used the $1,242/kW starting point (based on the MI actual EPC data + 20 percent owner's cost) and then used the same 1.2 percent price decrease that NREL uses for its mid case ($1,148 in 2018 down to $850 in 2037), but have the 1.2 percent decline start in 2019 onwards.



# A.2 PLEXOS OPTIMIZATION

## A.2.1 Modeling Assumptions and Constraints

## A.2.2 Optimization Cases

# Appendix B. Principal Considerations and Assumptions

## B.1 MICHIGAN IRP MODELING INPUT ASSUMPTIONS & SOURCES

### B.1.1 Model Region

Market price forecasting assumes MISO LRZ Zone 2

| Local Resource Zone | Local Balancing Authorities |
|---|---|
| 1 | DPC, GRE, MDU, MP, NSP, OTP, SMP |
| 2 | ALTE, MGE, MIUP, UPPC, WEC, WPS |
| 3 | ALTW, MEC, MPW |
| 4 | AMIL, CWLP, SIPC |
| 5 | AMMO, CWLD |
| 6 | BREC, CIN, HE, IPL, NIPSCO, SIGE |
| 7 | CONS, DECO |
| 8 | EAI |
| 9 | CLEC, EES, LAFA, LAGN, LEPA |
| 10 | EMBA, SME |

### B.1.2 Economic Indicators and Financial Assumptions

| TAX RATES | NEW | OLD |
|---|---|---|
| MI | 6% | 6% |
| Federal | 21% | 35% |
| Portion of Fed Deductible From State | 0% | 0% |
| Tax Rate | 26% | 39% |

| UPPCO | TOTAL | PERCENT OF CAPITAL | PRE-TAX COST | POST-TAX COST (2017 LAW) | POST-TAX COST (2018 LAW) |
|---|---|---|---|---|---|
| Long-term Debt | 108,200,000 | 44.70% | 4.88% | 2.980% | 3.622% |
| Adjusted Common Equity | 133,871,512 | 55.30% | 10.00% | 10% | 10% |
| Total Capital | 242,071,512 | | 7.71% | 6.862% | 7.149% |

| | COST | AFTER TAX COST | SHARE | WACC |
|---|---|---|---|---|
| Equity | 10% | 10% | 55% | 5.50% |
| Long-term Debt | 4.36% | 3% | 41% | 1.09% |
| Revolving Debt | 2.50% | 2% | 4% | 0.06% |
| WACC | | | | 6.65% |
| Effective Tax Rate | 38.90% | | | |
| *Assumptions used in modeling completed 1/04/18. | | | | |

| PARAMETER | VALUE |
|---|---|
| WACC | 7.467% |
| Inflation Rate | 2.57% |
| Basis Year for Values | $2017 (real) |
| *Assumptions after 4/12/18. | |

### B.1.3 Load Forecast

| Year | Base Case Forecast | | 1.5% Load Growth (High Growth Case) | | | | -0.5% Load Growth (Grid Defection Case) | | |
|---|---|---|---|---|---|---|---|---|---|
| | Energy Forecast (MWh, Before EWR) | Peak Demand (MW) | 1.5% Growth Rate | Energy (MWh) | Peak Demand (MW) | Load Factor | Energy (MWh) | Peak Demand (MW) | Load Factor |
| 2017 | 558,357.53 | 87.9 | 1 | 558,357.53 | 87.9 | 0.73 | 558,357.53 | 87.9 | 0.73 |
| 2018 | 554,079.01 | 87.2 | 1.015 | 566,732.89 | 89.2 | 0.73 | 555,579.63 | 87.4 | 0.73 |
| 2019 | 562,599.83 | 88.5 | 1.030 | 575,233.89 | 90.5 | 0.73 | 552,815.55 | 87.0 | 0.73 |
| 2020 | 560,478.57 | 88.2 | 1.046 | 583,862.39 | 91.9 | 0.73 | 550,065.23 | 86.6 | 0.73 |
| 2021 | 558,306.18 | 87.9 | 1.061 | 592,620.33 | 93.3 | 0.73 | 547,328.59 | 86.1 | 0.73 |
| 2022 | 557,946.46 | 87.8 | 1.077 | 601,509.64 | 94.7 | 0.73 | 544,605.56 | 85.7 | 0.73 |
| 2023 | 555,773.78 | 87.5 | 1.093 | 610,532.28 | 96.1 | 0.73 | 541,896.08 | 85.3 | 0.73 |
| 2024 | 553,601.74 | 87.1 | 1.11 | 619,690.26 | 97.5 | 0.73 | 539,200.08 | 84.9 | 0.73 |
| 2025 | 551,429.11 | 86.8 | 1.126 | 628,985.62 | 99.0 | 0.73 | 536,517.49 | 84.4 | 0.73 |
| 2026 | 549,236.69 | 86.4 | 1.143 | 638,420.40 | 100.5 | 0.73 | 533,848.25 | 84.0 | 0.73 |
| 2027 | 547,024.45 | 86.1 | 1.161 | 647,996.71 | 102.0 | 0.73 | 531,192.29 | 83.6 | 0.73 |
| 2028 | 544,829.34 | 85.8 | 1.178 | 657,716.66 | 103.5 | 0.73 | 528,549.54 | 83.2 | 0.73 |
| 2029 | 544,829.34 | 85.8 | 1.196 | 667,582.41 | 105.1 | 0.73 | 525,919.94 | 82.8 | 0.73 |
| 2030 | 544,829.34 | 85.8 | 1.214 | 677,596.15 | 106.6 | 0.73 | 523,303.42 | 82.4 | 0.73 |
| 2031 | 544,829.34 | 85.8 | 1.232 | 687,760.09 | 108.2 | 0.73 | 520,699.92 | 82.0 | 0.73 |
| 2032 | 544,829.34 | 85.8 | 1.25 | 698,076.49 | 109.9 | 0.73 | 518,109.38 | 81.5 | 0.73 |
| 2033 | 544,829.34 | 85.8 | 1.269 | 708,547.64 | 111.5 | 0.73 | 515,531.72 | 81.1 | 0.73 |
| 2034 | 544,829.34 | 85.8 | 1.288 | 719,175.85 | 113.2 | 0.73 | 512,966.88 | 80.7 | 0.73 |
| 2035 | 544,829.34 | 85.8 | 1.307 | 729,963.49 | 114.9 | 0.73 | 510,414.81 | 80.3 | 0.73 |
| 2036 | 544,829.34 | 85.8 | 1.327 | 740,912.94 | 116.6 | 0.73 | 507,875.43 | 79.9 | 0.73 |
| 2037 | 544,829.34 | 85.8 | 1.347 | 752,026.63 | 118.4 | 0.73 | 505,348.69 | 79.5 | 0.73 |
| 2038 | 544,829.34 | 85.8 | 1.367 | 763,307.03 | 120.1 | 0.73 | 502,834.52 | 79.1 | 0.73 |

| BASE CASE ENERGY AND PEAK FORECAST (AND EWR TARGET) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| YEAR | Total With RTMP (MWH) | RTMP LOAD (MWH) | BASE FORECAST (BEFORE EWR) | EWR TARGET (%) | EWR (1%) (MWH) | CUMULATIVE EWR (MWH) | PEAK DEMAND (MW) | LOAD FACTOR (%) |
| 2017 | 751,005 | 192,647 | 558,358 | 1% | 7,510 | 82,867 | 87.9 | 73% |
| 2018 | 746,726 | 192,647 | 554,079 | 1% | 7,510 | 90,377 | 86.5 | 73% |
| 2019 | 755,247 | 192,647 | 562,600 | 1% | 7,467 | 97,844 | 85.6 | 75% |
| 2020 | 753,126 | 192,647 | 560,479 | 1% | 7,552 | 105,396 | 84.7 | 76% |
| 2021 | 750,953 | 192,647 | 558,306 | 1% | 7,531 | 112,928 | 83.8 | 76% |
| 2022 | 750,594 | 192,647 | 557,946 | 1% | 6,008 | 118,935 | 82.9 | 77% |
| 2023 | 748,421 | 192,647 | 555,774 | 1% | 4,504 | 123,439 | 82.0 | 77% |
| 2024 | 746,249 | 192,647 | 553,602 | 0% | 2,994 | 126,432 | 81.1 | 78% |
| 2025 | 744,076 | 192,647 | 551,429 | 0% | 1,492 | 127,925 | 80.2 | 78% |
| 2026 | 741,884 | 192,647 | 549,237 | 0% | 744 | 128,669 | 79.3 | 79% |
| 2027 | 739,672 | 192,647 | 547,024 | 0% | 742 | 129,411 | 78.4 | 80% |
| 2028 | 737,476 | 192,647 | 544,829 | 0% | 0 | 129,411 | 78.4 | 80% |
| 2029 | 737,476 | 192,647 | 544,829 | 0% | 0 | 129,411 | 78.4 | 80% |
| 2030 | 737,476 | 192,647 | 544,829 | 0% | 0 | 129,411 | 78.4 | 80% |
| 2031 | 737,476 | 192,647 | 544,829 | 0% | 0 | 129,411 | 78.4 | 80% |
| 2032 | 737,476 | 192,647 | 544,829 | 0% | 0 | 129,411 | 78.4 | 80% |
| 2033 | 737,476 | 192,647 | 544,829 | 0% | 0 | 129,411 | 78.4 | 80% |
| 2034 | 737,476 | 192,647 | 544,829 | 0% | 0 | 129,411 | 78.4 | 80% |
| 2035 | 737,476 | 192,647 | 544,829 | 0% | 0 | 129,411 | 78.4 | 80% |
| 2036 | 737,476 | 192,647 | 544,829 | 0% | 0 | 129,411 | 78.4 | 80% |
| 2037 | 737,476 | 192,647 | 544,829 | 0% | 0 | 129,411 | 78.4 | 80% |
| 2038 | 737,476 | 192,647 | 544,829 | 0% | 0 | 129,411 | 78.4 | 80% |

### B.1.4 Unit Retirements

No UPPCO-owned unit retirements were assumed in the planning period of this IRP.

### B.1.5 Natural Gas Prices

| YEAR | ANNUAL AVERAGE (BAU CASE) (MMBTU) |
|---|---|
| 2018 | $3.52 |
| 2019 | $3.95 |
| 2020 | $4.46 |
| 2021 | $4.58 |
| 2022 | $4.78 |
| 2023 | $5.05 |
| 2024 | $5.31 |
| 2025 | $5.61 |
| 2026 | $5.80 |
| 2027 | $6.01 |
| 2028 | $6.19 |
| 2029 | $6.43 |
| 2030 | $6.60 |

These prices used for:

- Business-as-usual case
- Emerging Technologies case
- These prices x 2 used for:
- Business-as-usual - 200% gas price
- Emerging Tech - 200% gas price

| YEAR | ANNUAL AVG (LOW OGRT CASE) (MMBTU) |
|---|---|
| 2018 | $3.93 |
| 2019 | $4.83 |
| 2020 | $5.94 |
| 2021 | $6.39 |
| 2022 | $6.86 |
| 2023 | $7.42 |
| 2024 | $8.00 |
| 2025 | $8.54 |
| 2026 | $8.94 |
| 2027 | $9.32 |
| 2028 | $9.70 |
| 2029 | $10.12 |
| 2030 | $10.31 |

These prices used for:

- High Market Price Variant case
- These prices x 1.5 used for:
- High Market Price - 150% gas price
- This price x .5 is used for cases:
- High Market Price - 50% gas price

### B.1.6 Coal Prices

Coal price forecasting was not utilized in this IRP.

### B.1.7 Fuel Oil Prices

Fuel oil price forecasting was not utilized in this IRP.

### B.1.8 Wholesale Electric Prices

| YEAR | BASE CASE WHOLESALE MARKET PRICE | | |
|---|---|---|---|
| | ON-PEAK | AVERAGE | OFF PEAK |
| 2018 | $28.86 | $25.58 | $27.14 |
| 2019 | $30.90 | $27.26 | $28.99 |
| 2020 | $30.70 | $27.12 | $28.83 |
| 2021 | $30.13 | $26.84 | $28.41 |
| 2022 | $30.23 | $26.97 | $28.52 |
| 2023 | $30.86 | $27.50 | $29.10 |
| 2024 | $31.37 | $28.00 | $29.61 |
| 2025 | $32.12 | $28.74 | $30.35 |
| 2026 | $32.65 | $29.13 | $30.80 |
| 2027 | $32.99 | $29.48 | $31.16 |
| 2028 | $33.06 | $29.56 | $31.22 |
| 2029 | $33.48 | $30.00 | $31.67 |
| 2030 | $33.39 | $29.98 | $31.61 |
| 2031 | $33.44 | $30.10 | $31.69 |
| 2032 | $33.31 | $30.09 | $31.62 |
| 2033 | $33.23 | $30.11 | $31.61 |
| 2034 | $33.35 | $30.21 | $31.70 |
| 2035 | $32.96 | $30.01 | $31.43 |
| 2036 | $33.63 | $30.51 | $31.98 |
| 2037 | $33.57 | $30.50 | $31.97 |

| YEAR | HIGH WHOLESALE MARKET PRICE | | |
|---|---|---|---|
| | ON-PEAK | AVERAGE | OFF PEAK |
| 2018 | $43.44 | $34.81 | $39.08 |
| 2019 | $54.25 | $43.44 | $48.79 |
| 2020 | $61.42 | $49.51 | $55.42 |
| 2021 | $63.28 | $52.70 | $57.94 |
| 2022 | $65.49 | $55.63 | $60.50 |
| 2023 | $69.42 | $59.70 | $64.49 |
| 2024 | $73.10 | $63.54 | $68.29 |
| 2025 | $76.54 | $66.55 | $71.51 |
| 2026 | $78.79 | $68.89 | $73.78 |
| 2027 | $80.50 | $70.43 | $75.42 |
| 2028 | $81.59 | $71.60 | $76.52 |
| 2029 | $83.20 | $73.42 | $78.28 |
| 2030 | $82.58 | $73.25 | $77.87 |
| 2031 | $82.60 | $73.47 | $77.99 |
| 2032 | $82.42 | $73.74 | $78.04 |
| 2033 | $82.56 | $74.65 | $78.57 |
| 2034 | $84.34 | $76.33 | $80.29 |
| 2035 | $84.81 | $77.45 | $81.13 |
| 2036 | $87.22 | $79.59 | $83.33 |
| 2037 | $87.29 | $80.08 | $83.65 |

### B.1.9 EWR Savings

Actual EWR savings, in MWh, as reported in EWR Annual Reports, 2010-2016.

| ACTUAL EWR SAVINGS (2009-2016) | |
|---|---|
| 2009 | 0 |
| 2010 | 6,357 |
| 2011 | 7,749 |
| 2012 | 9,494 |
| 2013 | 11,196 |
| 2014 | 10,514 |
| 2015 | 19,393 |
| 2016 | 10,653 |
| 2017 | 7,510 |

### B.1.10 EWR Costs

| MEASURE GROUP | YEAR | INCREMENTAL ANNUAL SAVINGS (MWH) | | | | PEAK CONTRIBUTION (MW) | ANNUAL PROGRAM COST ($) |
|---|---|---|---|---|---|---|---|
| | | ON-PEAK WINTER | OFF-PEAK WINTER | ON-PEAK SUMMER | OFF-PEAK SUMMER | | |
| A | 1 | 2487.739 | 2592.266 | 1243.87 | 1306.586 | 1.021 | $2,000,768 |
| A | 2 | 2487.739 | 2592.266 | 1243.87 | 1306.586 | 1.021 | $2,052,088 |
| A | 3 | 2487.739 | 2592.266 | 1243.87 | 1306.586 | 1.021 | $2,104,724 |
| A | 4 | 2487.739 | 2592.266 | 1243.87 | 1306.586 | 1.021 | $2,158,710 |
| A | 5 | 2487.739 | 2592.266 | 1243.87 | 1306.586 | 1.021 | $2,214,081 |
| A | 6 | 2487.739 | 2592.266 | 1243.87 | 1306.586 | 1.021 | $2,270,872 |
| A | 7 | 2487.739 | 2592.266 | 1243.87 | 1306.586 | 1.021 | $2,329,120 |
| A | 8 | 2487.739 | 2592.266 | 1243.87 | 1306.586 | 1.021 | $2,388,862 |
| A | 9 | 2487.739 | 2592.266 | 1243.87 | 1306.586 | 1.021 | $2,450,136 |
| A | 10 | 2487.739 | 2592.266 | 1243.87 | 1306.586 | 1.021 | $2,512,982 |
| A | 11 | 2487.739 | 2592.266 | 1243.87 | 1306.586 | 1.021 | $2,577,440 |
| A | 12 | 2487.739 | 2592.266 | 1243.87 | 1306.586 | 1.021 | $2,643,551 |
| A | 13 | 2487.739 | 2592.266 | 1243.87 | 1306.586 | 1.021 | $2,711,358 |
| A | 14 | 2487.739 | 2592.266 | 1243.87 | 1306.586 | 1.021 | $2,780,904 |
| A | 15 | 2487.739 | 2592.266 | 1243.87 | 1306.586 | 1.021 | $2,852,234 |
| A | 16 | 2487.739 | 2592.266 | 1243.87 | 1306.586 | 1.021 | $2,925,394 |
| A | 17 | 2487.739 | 2592.266 | 1243.87 | 1306.586 | 1.021 | $3,000,430 |

| MEASURE GROUP | YEAR | INCREMENTAL ANNUAL SAVINGS (MWH) | | | | PEAK CONTRIBUTION (MW) | ANNUAL PROGRAM COST ($) |
|---|---|---|---|---|---|---|---|
| | | ON-PEAK WINTER | OFF-PEAK WINTER | ON-PEAK SUMMER | OFF-PEAK SUMMER | | |
| A | 18 | 2487.739 | 2592.266 | 1243.87 | 1306.586 | 1.021 | $3,077,391 |
| A | 19 | 2487.739 | 2592.266 | 1243.87 | 1306.586 | 1.021 | $3,156,326 |
| A | 20 | 2487.739 | 2592.266 | 1243.87 | 1306.586 | 1.021 | $3,237,286 |
| B | 1 | 3731.609 | 3888.399 | 1865.804 | 1959.878 | 1.55 | $2,807,697 |
| B | 2 | 3731.609 | 3888.399 | 1865.804 | 1959.878 | 1.55 | $2,879,714 |
| B | 3 | 3731.609 | 3888.399 | 1865.804 | 1959.878 | 1.55 | $2,953,579 |
| B | 4 | 3731.609 | 3888.399 | 1865.804 | 1959.878 | 1.55 | $3,029,338 |
| B | 5 | 3731.609 | 3888.399 | 1865.804 | 1959.878 | 1.55 | $3,107,041 |
| B | 6 | 3731.609 | 3888.399 | 1865.804 | 1959.878 | 1.55 | $3,186,737 |
| B | 7 | 3731.609 | 3888.399 | 1865.804 | 1959.878 | 1.55 | $3,268,477 |
| B | 8 | 3731.609 | 3888.399 | 1865.804 | 1959.878 | 1.55 | $3,352,313 |
| B | 9 | 3731.609 | 3888.399 | 1865.804 | 1959.878 | 1.55 | $3,438,300 |
| B | 10 | 3731.609 | 3888.399 | 1865.804 | 1959.878 | 1.55 | $3,526,492 |
| B | 11 | 3731.609 | 3888.399 | 1865.804 | 1959.878 | 1.55 | $3,616,947 |
| B | 12 | 3731.609 | 3888.399 | 1865.804 | 1959.878 | 1.55 | $3,709,722 |
| B | 13 | 3731.609 | 3888.399 | 1865.804 | 1959.878 | 1.55 | $3,804,876 |
| B | 14 | 3731.609 | 3888.399 | 1865.804 | 1959.878 | 1.55 | $3,902,471 |
| B | 15 | 3731.609 | 3888.399 | 1865.804 | 1959.878 | 1.55 | $4,002,569 |
| B | 16 | 3731.609 | 3888.399 | 1865.804 | 1959.878 | 1.55 | $4,105,235 |

| MEASURE GROUP | YEAR | INCREMENTAL ANNUAL SAVINGS (MWH) | | | | PEAK CONTRIBUTION (MW) | ANNUAL PROGRAM COST ($) |
|---|---|---|---|---|---|---|---|
| | | ON-PEAK WINTER | OFF-PEAK WINTER | ON-PEAK SUMMER | OFF-PEAK SUMMER | | |
| B | 17 | 3731.609 | 3888.399 | 1865.804 | 1959.878 | 1.55 | $4,210,534 |
| B | 18 | 3731.609 | 3888.399 | 1865.804 | 1959.878 | 1.55 | $4,318,534 |
| B | 19 | 3731.609 | 3888.399 | 1865.804 | 1959.878 | 1.55 | $4,429,304 |
| B | 20 | 3731.609 | 3888.399 | 1865.804 | 1959.878 | 1.55 | $4,542,916 |
| C | 1 | 6219.348 | 6480.665 | 3109.674 | 3266.464 | 2.609 | $4,421,554 |
| C | 2 | 6219.348 | 6480.665 | 3109.674 | 3266.464 | 2.609 | $4,534,967 |
| C | 3 | 6219.348 | 6480.665 | 3109.674 | 3266.464 | 2.609 | $4,651,289 |
| C | 4 | 6219.348 | 6480.665 | 3109.674 | 3266.464 | 2.609 | $4,770,595 |
| C | 5 | 6219.348 | 6480.665 | 3109.674 | 3266.464 | 2.609 | $4,892,961 |
| C | 6 | 6219.348 | 6480.665 | 3109.674 | 3266.464 | 2.609 | $5,018,465 |
| C | 7 | 6219.348 | 6480.665 | 3109.674 | 3266.464 | 2.609 | $5,147,189 |
| C | 8 | 6219.348 | 6480.665 | 3109.674 | 3266.464 | 2.609 | $5,279,214 |
| C | 9 | 6219.348 | 6480.665 | 3109.674 | 3266.464 | 2.609 | $5,414,626 |
| C | 10 | 6219.348 | 6480.665 | 3109.674 | 3266.464 | 2.609 | $5,553,511 |
| C | 11 | 6219.348 | 6480.665 | 3109.674 | 3266.464 | 2.609 | $5,695,959 |
| C | 12 | 6219.348 | 6480.665 | 3109.674 | 3266.464 | 2.609 | $5,842,060 |
| C | 13 | 6219.348 | 6480.665 | 3109.674 | 3266.464 | 2.609 | $5,991,909 |
| C | 14 | 6219.348 | 6480.665 | 3109.674 | 3266.464 | 2.609 | $6,145,601 |
| C | 15 | 6219.348 | 6480.665 | 3109.674 | 3266.464 | 2.609 | $6,303,236 |

| MEASURE GROUP | YEAR | INCREMENTAL ANNUAL SAVINGS (MWH) | | | | PEAK CONTRIBUTION (MW) | ANNUAL PROGRAM COST ($) |
|---|---|---|---|---|---|---|---|
| | | ON-PEAK WINTER | OFF-PEAK WINTER | ON-PEAK SUMMER | OFF-PEAK SUMMER | | |
| C | 16 | 6219.348 | 6480.665 | 3109.674 | 3266.464 | 2.609 | $6,464,914 |
| C | 17 | 6219.348 | 6480.665 | 3109.674 | 3266.464 | 2.609 | $6,630,739 |
| C | 18 | 6219.348 | 6480.665 | 3109.674 | 3266.464 | 2.609 | $6,800,817 |
| C | 19 | 6219.348 | 6480.665 | 3109.674 | 3266.464 | 2.609 | $6,975,258 |
| C | 20 | 6219.348 | 6480.665 | 3109.674 | 3266.464 | 2.609 | $7,154,173 |

### B.1.11 DR Costs

Demand response costs are not applicable to this IRP.

### B.1.12 DR Savings

Demand response costs are not applicable to this IRP.

### B.1.13 Renewable Capacity Factor

### B.1.14 Renewable Capital Costs and Fixed O&M

**Solar**

| SOLAR PV TECHNOLOGY DESCRIPTION | ESTIMATE BASE YEAR | CAPACITY (MW) | CAPACITY FACTOR | CONSTRUCTION COSTS ($/KW) | FIXED O&M ($/KW-YR) | FINANCING YEARS |
|---|---|---|---|---|---|---|
| Utility-Scale, Crystalline, Tracking | 2017 | 100 | 20% | $1,730 | 14.4 | 20 |
| Utility-Scale, Crystalline, Tracking | 2020 | 100 | 20% | $1,490 | 13.2 | 20 |
| Utility-Scale, Crystalline, Tracking | 2021 | 100 | 20% | $1,470 | 13.2 | 20 |
| Utility-Scale, Crystalline, Tracking | 2026 | 100 | 20% | $1,370 | 12 | 20 |
| Utility-Scale, Crystalline, Tracking | 2017 | 20 | 20% | $1,910 | 15.84 | 20 |
| Utility-Scale, Crystalline, Tracking | 2020 | 20 | 20% | $1,640 | 14.52 | 20 |
| Utility-Scale, Crystalline, Tracking | 2021 | 20 | 20% | $1,620 | 14.52 | 20 |
| Utility-Scale, Crystalline, Tracking | 2026 | 20 | 20% | $1,500 | 13.2 | 20 |
| Community-Scale, Crystalline, Fixed | 2017 | 2 | 15% | $2,950 | 19.2 | 20 |
| Community-Scale, Crystalline, Fixed | 2020 | 2 | 15% | $2,530 | 14.4 | 20 |
| Community-Scale, Crystalline, Fixed | 2021 | 2 | 15% | $2,440 | 14.4 | 20 |
| Community-Scale, Crystalline, Fixed | 2026 | 2 | 15% | $1,970 | 9.6 | 20 |

**Wind**

| WIND TECHNOLOGY DESCRIPTION | CAPACITY (MW) | CAPACITY FACTOR | CONSTRUCTION COSTS ($/KW) | FIXED O&M ($/KW-YR) |
|---|---|---|---|---|
| Wind On-Shore | 100 | 34% | $1,971 | 50 |
| Wind On-Shore | 20 | 34% | $2,180 | 55 |

### B.1.15 Other Emerging Alternatives

**Li-ion Battery Storage**

| ENERGY STORAGE TECHNOLOGY DESCRIPTION | CONSTRUCTION COSTS ($/KW) | FIXED O&M ($/KW-YR) | NON-FUEL VARIABLE O&M | EFOR (%) | POH (HRS/YR) |
|---|---|---|---|---|---|
| Energy Storage - Batteries: Li-Ion (30 Minute Duration) | $1,200 | $8 | $2 | 1% | 88 |

Upper Peninsula Power Company

# Stakeholder Outreach

January 2018

*Powering our communities since 1884*

# UPPCO History

1884 – Peninsula Electric Light and Power Company was formed (aka Houghton County Electric Light Company)

1947 – Upper Peninsula Power Company was formed through the merger of Houghton County Electric Light Company, Copper District Power Company and Iron Range Light and Power

1998 – UPPCO was acquired by Wisconsin Public Service Resources Corporation (Integrys)

August 2014 – UPPCO began the process of returning to its roots as a stand-alone, U.P. based utility

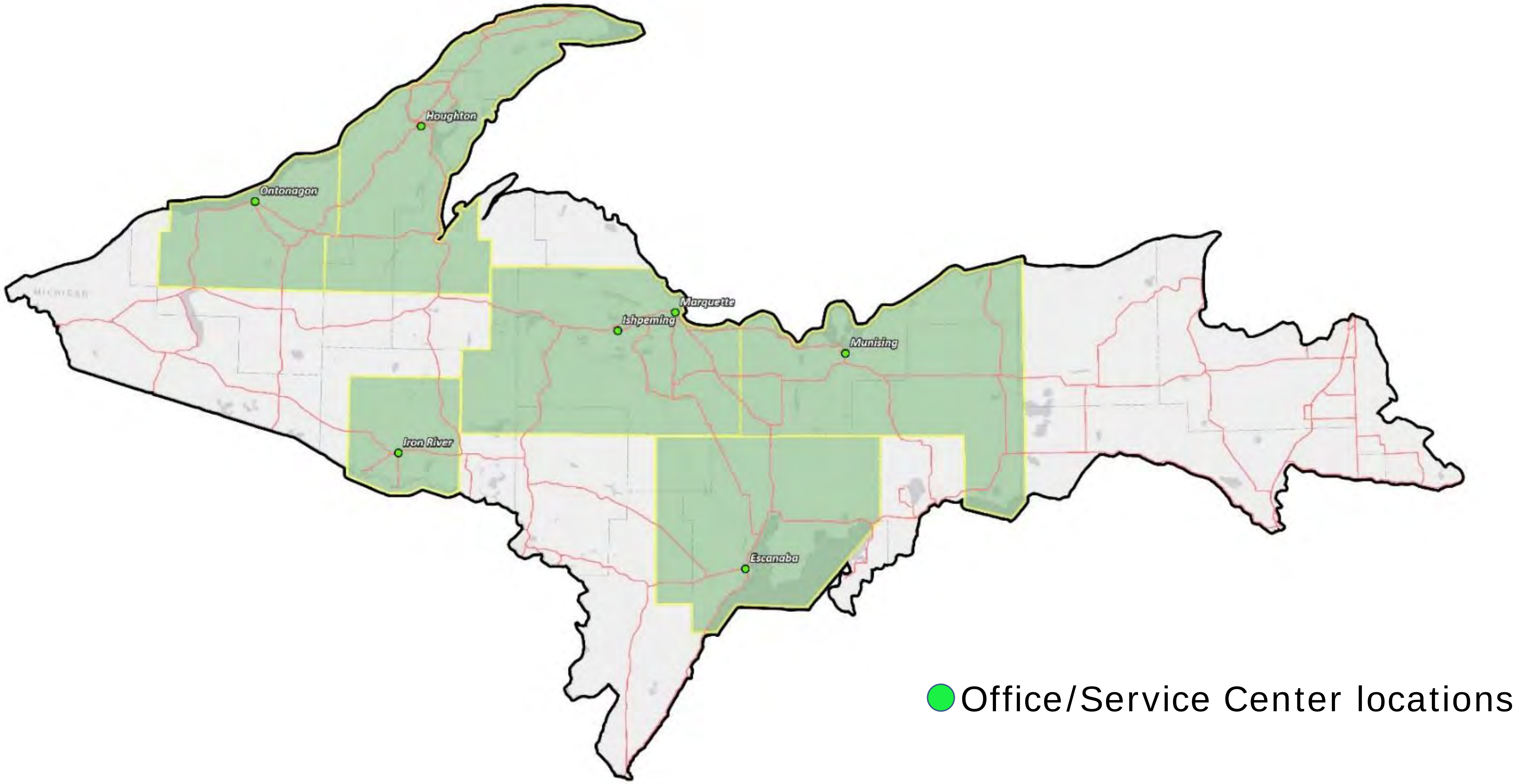
February 2017 – UPPCO returned to a fully independent, U.P. based electric utility

# Company Overview

- UPPCO provides safe and reliable energy to ~52,000 customers in 10 U.P. counties
- UPPCO's service territory covers 4,460 square miles
- UPPCO serves approximately 12 customers per square mile
- UPPCO owns 4,469 miles of distribution lines and 58 substations

UPPCO®

# Service Territory



# Transition Update

- Fully independent from Integrys in February 2017
- Current Employee Count: 173
  - 121 at acquisition in August 2014
  - 52 employees added during the transition period
- Functions moved back to the U.P.:

| | |
|---|---|
| Accounting | Procurement |
| Finance | Legal |
| Engineering | Information Technology |
| Safety | Generation Engineering |
| Human Resources | Regulatory Affairs |
| System Operations | Communications |
| Customer Service | Executive |

UPPCO®

# Community Involvement

- Consistently donates over $100,000 on an annual basis to support our local communities
- Employees contribute to United Way Campaigns
  - 2017 contributions with company match exceeded $40,000
- UPPCO/Michigan Tech Collaboration
  - Senior Design team is evaluating potential expansion at Prickett and Victoria hydrogeneration facilities
  - Student team is evaluating the feasibility of a Community Solar project through the Alternative Energy Enterprise
- Industry Partner in the Line-Technician program at Sawyer
- Industry Partner in the Power-Technician program at the Jacobetti Center

# What is an Integrated Resource Plan?

- What is an Integrated Resource Plan (IRP)?
  - An IRP is a process that a utility uses to evaluate how it will best serve its customers' future power needs
  - As part of this process, and through predictive modeling, UPPCO will evaluate several resource alternatives to develop a plan that meets our customers' future power needs
- Why perform an IRP at this time?
  - As a stand-alone, U.P. based utility, UPPCO recognizes the value of planning for its future power needs
  - UPPCO is developing its IRP and is actively seeking stakeholder feedback as part of the process

UPPCO ®

# IRP Stakeholder Forums

- “Open House” setting where customers and stakeholders can speak to UPPCO staff to obtain information on various topics:
  - Customer Service
  - Energy Waste Reduction (EWR)
  - Generation Fleet
  - Regulatory/Integrated Resource Planning
  - Path-to-Ground safety demonstration

# Questions Resolved through the IRP

- How much generation will UPPCO need to meet the future needs of its customers?
- When should existing generation be retired?
- When will additional generation resources be required?
- How much generation Capacity should be company-owned?
- How much Energy should be produced by company-owned generation?

# Questions Resolved through the IRP

- What opportunities and risks need to be managed to ensure long-term price stability for UPPCO customers?
- What types of resources will safely, reliably and economically meet the future needs of the customers?
- What renewable energy resources (hydro, solar, wind, biomass, storage, etc.) should be included for the future?

# Regulatory Outlook

- Energy Waste Reduction Plan (pending)
- Renewable Energy Plan (targeting January 2018)
- Integrated Resource Plan (targeting Q2 2018)
- Current business drivers being monitored:
  - Reduction in sales volumes
  - General inflation and capital investments
  - Deployment of Advanced Metering Infrastructure (AMI)
  - Operating and Maintenance reductions through various management initiatives
  - Changes to federal tax laws

# 2018 Rate Reductions

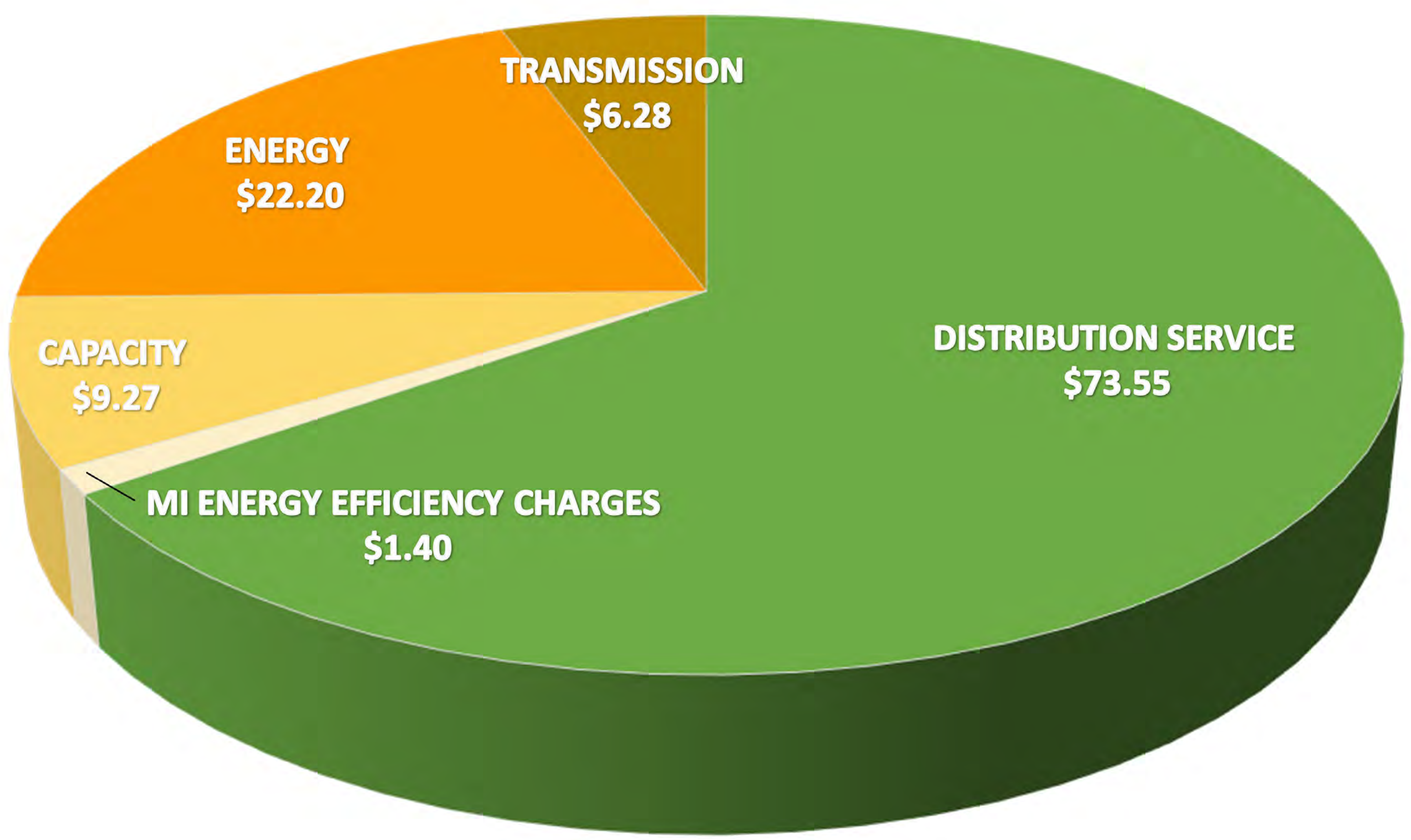
**Typical Monthly Bill**

| Customer Class | | Typical Usage (kWh) | Typical Demand (kW) | Jan-17 | Jan-18 | Reduction |
|---|---|---|---|---|---|---|
| Residential | A1 | 500 | N/A | $120 | $113 | -6% |
| Small Commercial | C1 | 1,500 | N/A | $268 | $233 | -13% |
| Medium Commercial | P1 | 14,000 | 40 | $1,987 | $1,689 | -15% |
| Large Industrial | CPU | 400,000 | 1,000 | $44,915 | $34,323 | -24% |

- Rate reductions are due to renegotiated Power Supply contracts, changes to UPPCO's Energy Waste Reduction (EWR) program (MPSC Order anticipated in February) and the Federal Energy Regulatory Commission's recent decision in the Presque Isle SSR complaint

- Additional reductions may result from the recent passage of the new federal tax law

# Breakdown of a Residential Bill




| Breakdown of your UPPCO Bill | | |
|---|---|---|
| Distribution | | Cost of "delivering" power to your meter through UPPCO-owned utility assets (poles, wires, transformers, substations, vehicles and equipment, personnel, service centers, etc.) |
| MI Energy Efficiency Charges | | Cost of UPPCO's energy efficiency program |
| Power Supply Charges | Capacity (MW) | Capacity is the amount of generation the company has available to serve load and is measured in megawatts (MW). It represents UPPCO's ability to generate electricity, as needed. |
| Power Supply Charges | Energy (MWh) | Energy is the amount (volume) of electricity that customers use over time. It is measured in megawatt-hours (MWh). |
| Power Supply Charges | Transmission | Cost of moving electricity from generation resources to distribution substations located throughout the region. |

Represents 500 kWh usage for a monthly bill total of $112.70

# Understanding a Residential Bill

Historical monthly energy usage.

This area is the budget billing summary.

Budget balance after payment of current bill.

Important bill messages located here.

Upper Peninsula Power Company

**Contact us:**
www.uppco.com
customerservice@uppco.com
800-582-7680 7AM-6PM Eastern Time - Mon-Fri
**Payments:** PO Box 60055, Prescott AZ 86304-6055

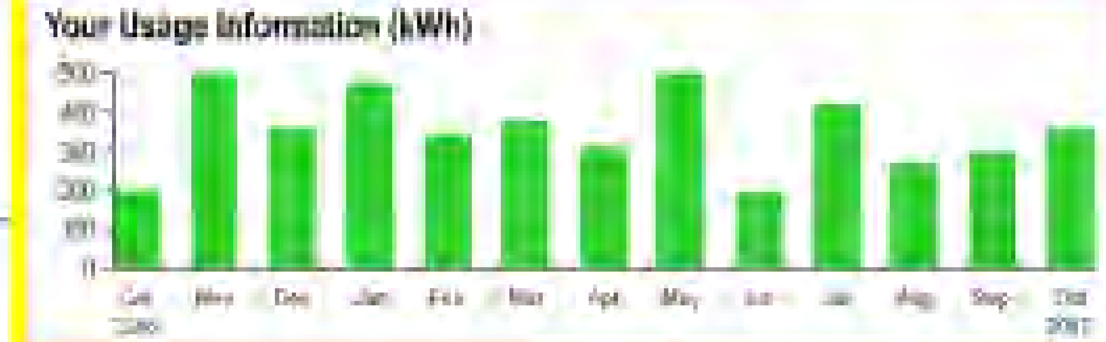
**Service Address:**
John Doe
1234 Jones Street
Ishpeming, MI 49849

**Amount to be withdrawn on 01/10/2018 $70.00**

Page 1 of 2

| Account No | Transfer Date | Transfer Amount |
|---|---|---|
| DDDDDDDDD | 01/10/2018 | $70.00 |

**Your Usage Information (kWh)**



| Comparison | Days | kWh | Avg kWh / Day |
|---|---|---|---|
| Current Bill Period | 41 | 500 | 12.2 |
| Same Period Last Year | - | - | - |

| **Budget Summary Month 00** | | |
|---|---|---|
| Total Current Charges | $ | 124.12 |
| **Budget Amount Billed** | $ | 70.00 |
| Difference | $ | 54.12 |
| Budget Correction | $ | 0.00 |
| Previous Budget Balance | $ | 0.00 |
| **New Budget Balance** | $ | 54.12 |

After paying this bill, you have used more energy than you have paid for.

| **Your Account Summary** | | |
|---|---|---|
| **Previous Charges** | | |
| Amount of your Last Bill | $ | 0.00 |
| Payment Received | $ | 0.00 |
| **Past Due Amount** | $ | **0.00** |
| **Current Charges** | | |
| Electric Charges | $ | 70.00 |
| **Total Current Charge** | $ | 70.00 |
| **Total** *(includes current and past due charges)* | $ | **70.00** |

**Important Messages:**
- Energy Use information is based on an estimated meter reading. Your actual use may be different.
- You have a credit balance on your account. We will reduce your next bill total by this amount.
- Spread your energy costs over 12 months by enrolling in Budget Billing. Enroll online at uppco.com or by calling 800-562-7680.

This customer is on autopay using the new UPPCO Online Portal.

This area is the current billing summary.

***UPPCO Online Portal***

**Manage your account ANYTIME, ANYWHERE from ANY DEVICE.**

- Sign up for e-Bill paperless billing
- Schedule electronic payments
- Report an outage
- View energy consumption

**Become a *new* portal user today** at www.uppco.com

## Front of Bill

# Understanding a Residential Bill

UPPCO
Upper Peninsula Power Company

Page 2 of 2

| Account No | Date Due | Amount Due |
|---|---|---|
| 000000000 | 01/10/2018 | $70.00 |

| Rate Description | Meter Number | Start Date Read | End Date Read | Constant | Kilowatt Hours (kWh) | Meter Read Type | Next Meter Read Date |
|---|---|---|---|---|---|---|---|
| Residential Service A-1 | 00000000 | 01/10 42208 | 02/19 42708 | 1 | 500 | Actual | 03/19/2018 |

| Electric Charge Details (41 days) | Charge |
|---|---|
| **Distribution Service** | |
| Service Charge (41 Days at $0.4932) | 20.22 |
| Energy Charge (500 kWh at $0.10904) | 54.52 |
| **Power Supply Service** | |
| Energy Charge (500 kWh at $0.10023) | 50.12 |
| **Others** | |
| MI Energy Efficiency Charges (500 kWh at $0.0051) | 2.56 |
| Power Supply Cost Recovery (500 kWh at $0.02474CR) | 12.37CR |
| Rate Realignment Adjustment (500 kWh at $0.0062) | 3.10 |
| Low Income Energy Assistance Fund (1 at $0.93) | 1.25 |
| Sales Tax (4% of $118.14) | 4.73 |
| **Total Electric Charges** | **$124.12** |

**Energy Charge** - The charges for generating or purchasing electricity for customers. It includes an Energy Charge.
**Low Income Energy Assistance Fund** - This charge is to support the state Low Income Energy Assistance Fund (LIEAF).
**MI Energy Efficiency Charges** - A fee that funds a state-required energy efficiency program.
**Power Supply Cost Recovery** - A charge or credit that's applied when our actual cost to produce or purchase electricity is higher or lower than what was projected in your rates.
**Rate Realignment Adjustment** - Required by Michigan law to make rates reflect the actual cost of providing electric service.
**Service Charge** - A daily charge that helps cover the fixed costs of providing service to customers. This includes equipment, billing and programs.

**MI Energy Efficiency** is the cost of UPPCO's Energy Waste Reduction (EWR) program. This program offers rebate incentives on energy saving products and services. Learn more at: www.efficiencyunited.com

**Power Supply Cost Recovery** (PSCR) charges represent the increase or decrease in actual Power Supply costs versus projected costs. In 2018, UPPCO is forecasting a decrease of approximately $5.5 million which will result in greater savings for the customer.

**Low Income Energy Assistance Fund** (LIEAF) provides energy assistance and self-sufficiency services to low-income households in Michigan.

## Back of Bill

UPPCO®

# Energy Waste Reduction

## Energy Waste Reduction

### Home energy use breakdown

| Device | Energy used |
|---|---|
| Heating System | 26 percent |
| Cooling System | 17 percent |
| Appliances | 14 percent |
| Water Heater | 13 percent |
| Lighting | 10 percent |
| Electronics | 7 percent |
| Other | 13 percent |

### Lightbulb efficiency comparison

Least efficient — Most efficient

Bulb Type

| | Incandescent | Halogen | CFL | LED |
|---|---|---|---|---|
| | Energy Used | | | |
| Bright 450 Lumens | 40w $9.86yr | 29w $7.14/yr | 11w $2.71/yr | 6w $1.48/yr |
| 800 Lumens | 60w $14.78/yr | 43w $10.59/yr | 13w $3.20/yr | 9w $2.22/yr |
| 1100 Lumens | 75w $18.48/yr | 53w $13.06/yr | 20w $4.93/yr | 12w $2.96/yr |
| Brightest 1600 Lumens | 100w $24.64/yr | 72w $17.74/yr | 23w $5.67/yr | 14w $3.45/yr |
| Longevity | 1 Year | 1-3 Year | 6-10 Year | 15-20 Year |

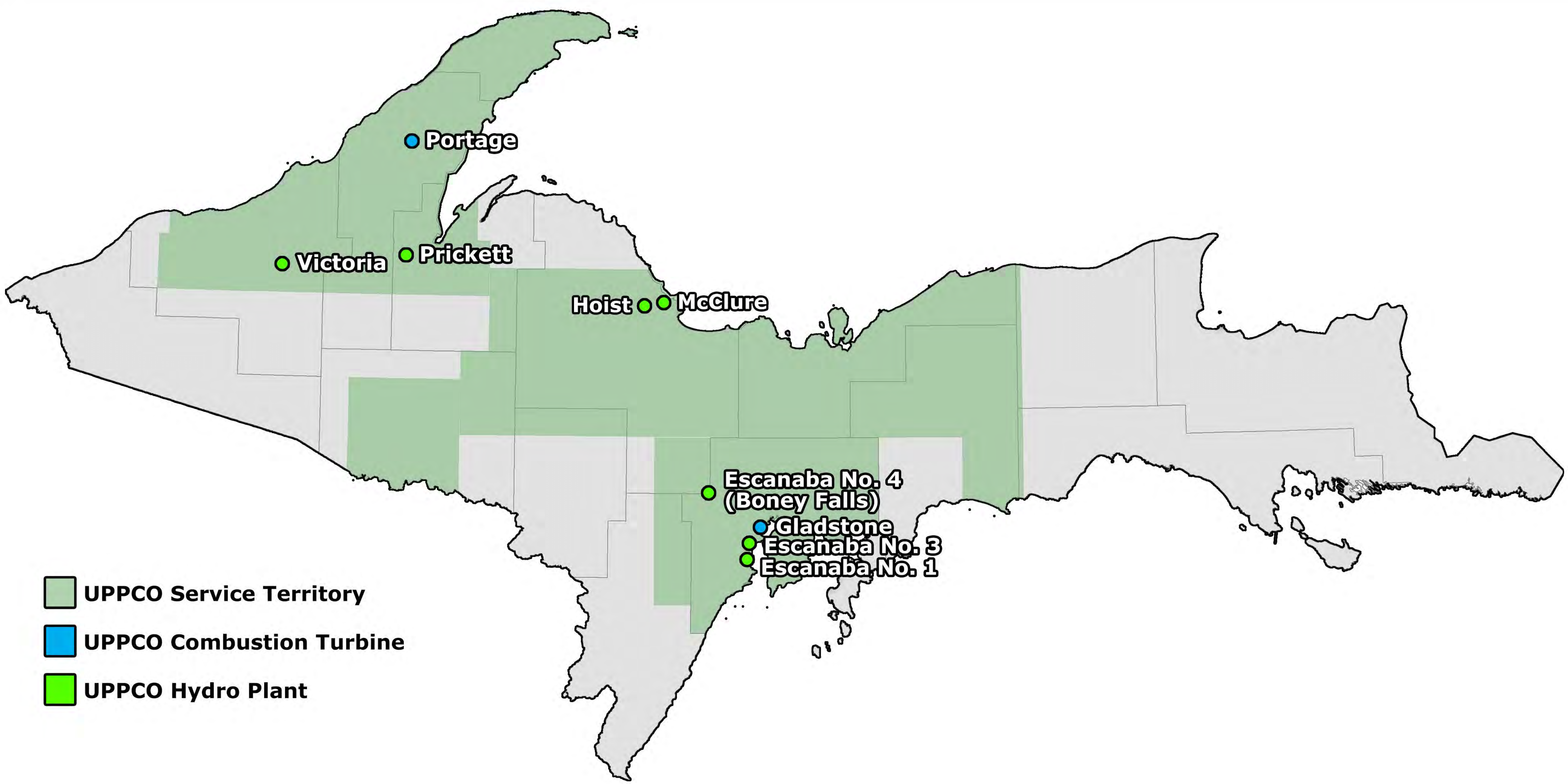
Estimated energy cost per year is based on three hours of use per day at Upper Peninsula Power Company's A-1 Residential Rate of 22.5 cents per kWh in an average single family home using an average of 500 kWh per month.

# Generation Fleet

| Station | Type | Units | Date Built | Capacity (kW) |
|---|---|---|---|---|
| Hoist | Hydroelectric | 2 | 1916 | 3,400 |
| McClure | Hydroelectric | 2 | 1919 | 8,480 |
| Prickett | Hydroelectric | 2 | 1931 | 2,000 |
| Victoria | Hydroelectric | 2 | 1930 | 12,200 |
| Boney Falls | Hydroelectric | 3 | 1921 | 4,100 |
| Escanaba 3 | Hydroelectric | 2 | 1914 | 2,500 |
| Escanaba 1 | Hydroelectric | 3 | 1907/1920 | 1,600 |
| Gladstone | Combustion Turbine | 1 | 1975/1987 | 22,567* |
| Portage | Combustion Turbine | 1 | 1971 | 23,800* |

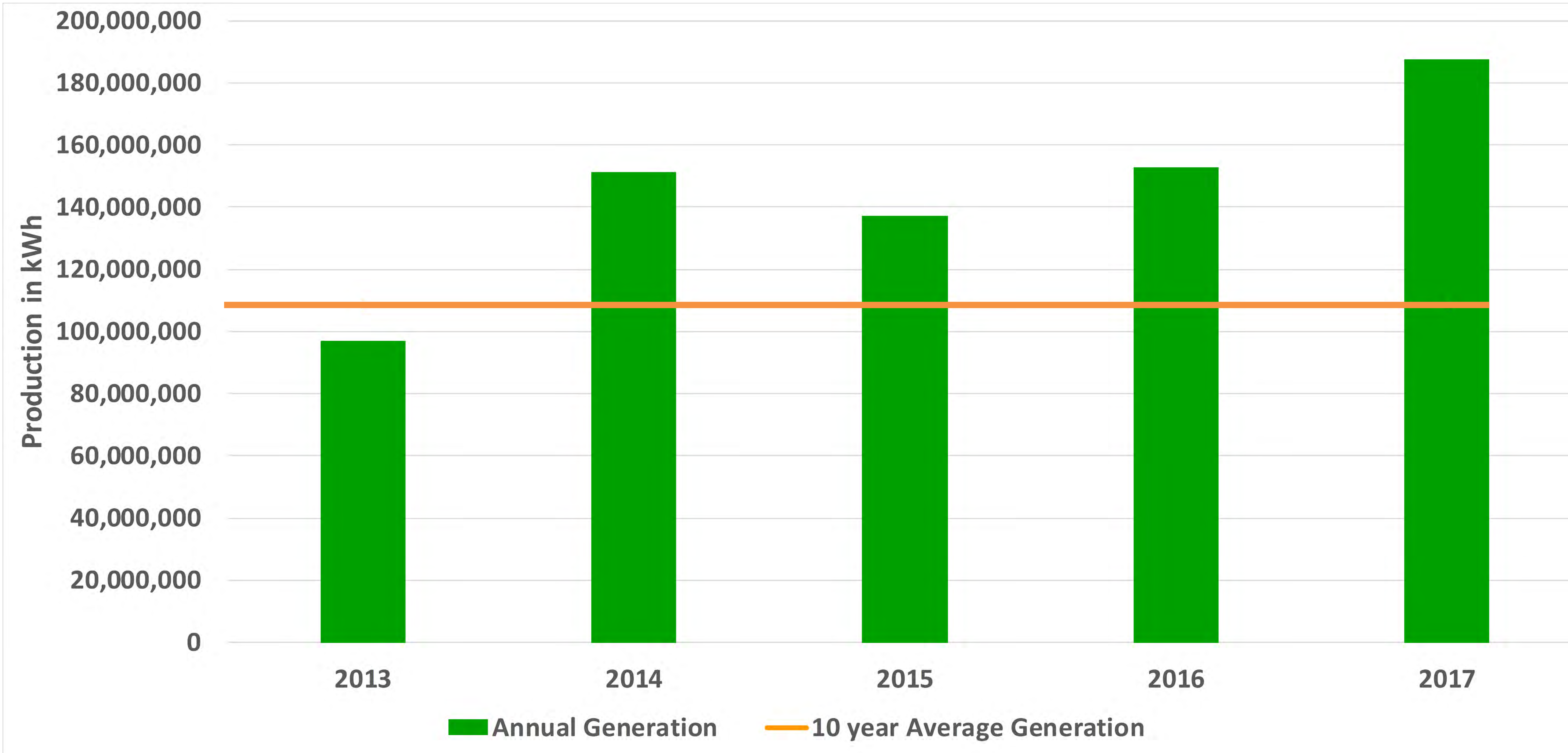
- UPPCO owned generation provides approximately 18% of annual energy requirement
- Additional generation resources being evaluated via the Integrated Resource Plan
- * Denotes reported winter capacity

# Generation Fleet




UPPCO®

# 2017 Strong Hydro Performance




2017 represents an increase of ~75% over the 10 year average

**Upper Peninsula Power Company**
Integrated Resource Plan Survey

**Upper Peninsula Power Company (UPPCO) is seeking customer and stakeholder feedback on its Integrated Resource Plan or IRP. The IRP will help determine where our energy will come from in the future. We greatly value your feedback and opinions!**

1. Which one of the following applies?

- ◯ I am a Residential customer of UPPCO
- ◯ I am a Commerical customer of UPPCO
- ◯ I am an Industrial customer of UPPCO
- ◯ I am not an UPPCO customer

2. UPPCO is committed to engaging its customers and stakeholders throughout the IRP process. How important is being able to participate in UPPCO's IRP process?

- ◯ Very Important
- ◯ Moderately Important
- ◯ Not Important

3. What are the most effective ways of communicating with you regarding news and future events? (Check all that apply)

- ☐ UPPCO Website
- ☐ Newspaper
- ☐ Radio
- ☐ Television
- ☐ Billing Insert
- ☐ Social Media
- ☐ Email

Other (please specify)

☐

4. In order of importance, please rank where you feel your energy should come from in the future.
(1 = most important and 6 = least important).

- Renewable sources (hydro, solar, wind, biomass)
- Coal-fired generators
- Natural gas-fired generators
- Nuclear power
- A balance portfolio of energy resources
- Lowest cost

5. In order of importance, please rank the following renewable energy resources:
(1 = most important and 5 = least important).

- Hydroelectric
- Solar
- Wind
- Biomass
- Lowest cost

6. When considering your experience with your utility, please rank the following in order of importance:
(1 = most important and 5 = least important).

- Use of "Smart Meters" to better manage my energy consumption
- Reliability (keeping the lights on)
- Cost of providing utility service
- Ability to use Internet based tools to manage my account
- Local presence (UP-based)

7. UPPCO currently purchases approximately 80% of the energy that is required to meet its customers' needs from the wholesale energy market. Future energy prices in the wholesale market may fluctuate over time. How important is it that UPPCO owns sufficient generation to provide long-term price stability?

- ◯ Very Important
- ◯ Moderately Important
- ◯ Not Important

8. The state has mandated 15% of the energy that is required to serve the customers' needs must come from renewable sources by the year 2021. How strongly do you agree or disagree that UPPCO should exceed the state mandate of 15%?

- ◯ Strongly agree
- ◯ Agree
- ◯ Neither agree nor disagree
- ◯ Disagree
- ◯ Strongly disagree

9. The state has set an annual Energy Efficiency/Energy Waste Reduction goal of 1% through the year 2021. How strongly do you agree or disagree that UPPCO should exceed this goal?

- ◯ Strongly agree
- ◯ Agree
- ◯ Neither agree nor disagree
- ◯ Disagree
- ◯ Strongly disagree

10. How strongly do you agree or disagree that UPPCO should rely on generation resources that are located in the Upper Peninsula for meeting your future energy needs?

- ◯ Strongly agree
- ◯ Agree
- ◯ Neither agree nor disagree
- ◯ Disagree
- ◯ Strongly disagree

11. How strongly do you agree or disagree that UPPCO should take proactive measures to protect its customers from unexpected costs like those that resulted from generation retirements?

- ◯ Strongly agree
- ◯ Agree
- ◯ Neither agree nor disagree
- ◯ Disagree
- ◯ Strongly disagree

12. Address (OPTIONAL)

**Name**

**Company**

**Address**

**Address 2**

**City/Town**

**State/Province**

**ZIP/Postal Code**

**Country**

**Email Address**

**Phone Number**

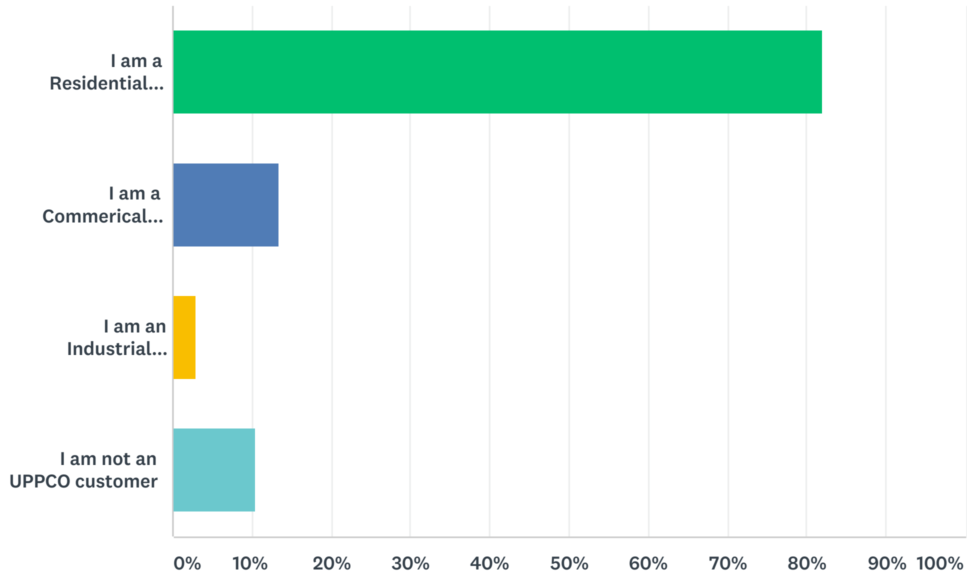
13. Do you have any other comments, questions, or concerns relating to UPPCO's Integrated Resource Plan?

**Upper Peninsula Power Company (UPPCO) values your feedback and your participation in our Integrated Resource Planning process. Additional information is available at: https://www.uppco.com/home/irp/.**

Copy of Upper Peninsula Power Company Integrated Resource Plan Survey

# Q1 Which one of the following applies?

Answered: 67 Skipped: 0

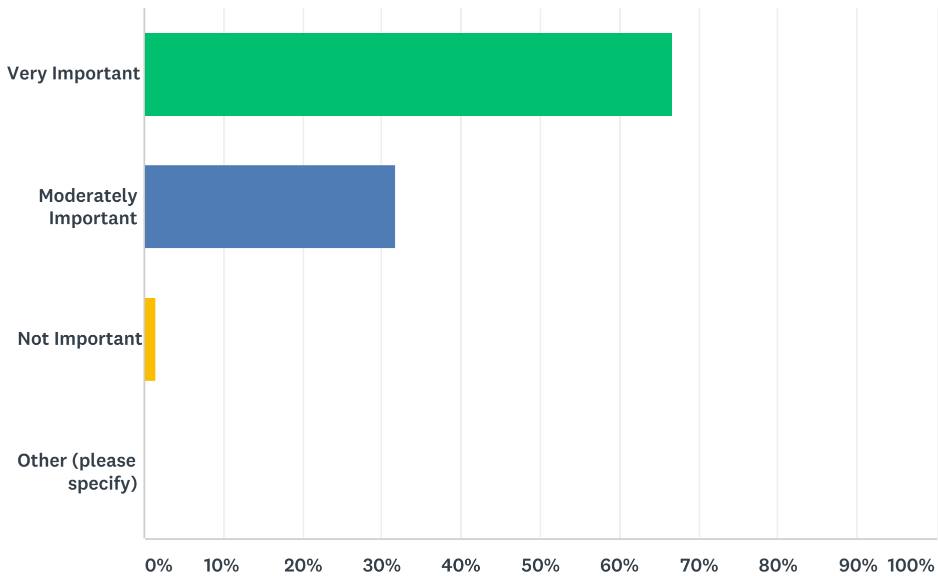



| ANSWER CHOICES | RESPONSES | |
|---|---|---|
| I am a Residential customer of UPPCO | 82.09% | 55 |
| I am a Commerical customer of UPPCO | 13.43% | 9 |
| I am an Industrial customer of UPPCO | 2.99% | 2 |
| I am not an UPPCO customer | 10.45% | 7 |
| Total Respondents: 67 | | |

Copy of Upper Peninsula Power Company Integrated Resource Plan Survey

# Q2 UPPCO is committed to engaging its customers and stakeholders throughout the IRP process. How important is being able to participate in UPPCO's IRP process?

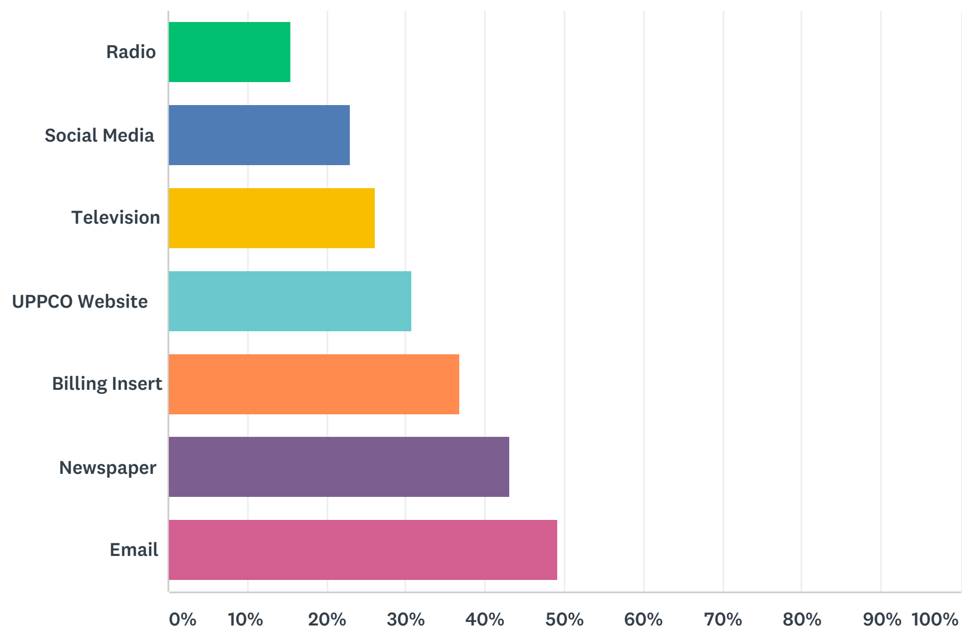
Answered: 66 Skipped: 1




| ANSWER CHOICES | RESPONSES | |
|---|---|---|
| Very Important | 66.67% | 44 |
| Moderately Important | 31.82% | 21 |
| Not Important | 1.52% | 1 |
| Other (please specify) | 0.00% | 0 |
| TOTAL | | 66 |

## Q3 What are the most effective ways of communicating with you regarding news and future events?(Check all that apply)

Answered: 65 Skipped: 2




| ANSWER CHOICES | RESPONSES | |
|---|---|---|
| Radio | 15.38% | 10 |
| Social Media | 23.08% | 15 |
| Television | 26.15% | 17 |
| UPPCO Website | 30.77% | 20 |
| Billing Insert | 36.92% | 24 |
| Newspaper | 43.08% | 28 |
| Email | 49.23% | 32 |
| Total Respondents: 65 | | |

# Q4 In order of importance, please rank where you feel your energy should come from in the future.(1 = most important and 6 = least important).

Answered: 64 Skipped: 3

| ANSWER CHOICES | RESPONSES | |
|---|---|---|
| Renewable sources (hydro, solar, wind, biomass) | 93.75% | 60 |
| Coal-fired generators | 87.50% | 56 |
| Natural gas-fired generators | 90.63% | 58 |
| Nuclear power | 85.94% | 55 |
| A balance portfolio of energy resources | 95.31% | 61 |
| Lowest cost | 92.19% | 59 |

# Q5 In order of importance, please rank the following renewable energy resources:(1 = most important and 5 = least important).

Answered: 62 Skipped: 5

| ANSWER CHOICES | RESPONSES | |
|---|---|---|
| Hydroelectric | 98.39% | 61 |
| Solar | 96.77% | 60 |
| Wind | 96.77% | 60 |
| Biomass | 95.16% | 59 |
| Lowest cost | 93.55% | 58 |

Copy of Upper Peninsula Power Company Integrated Resource Plan Survey

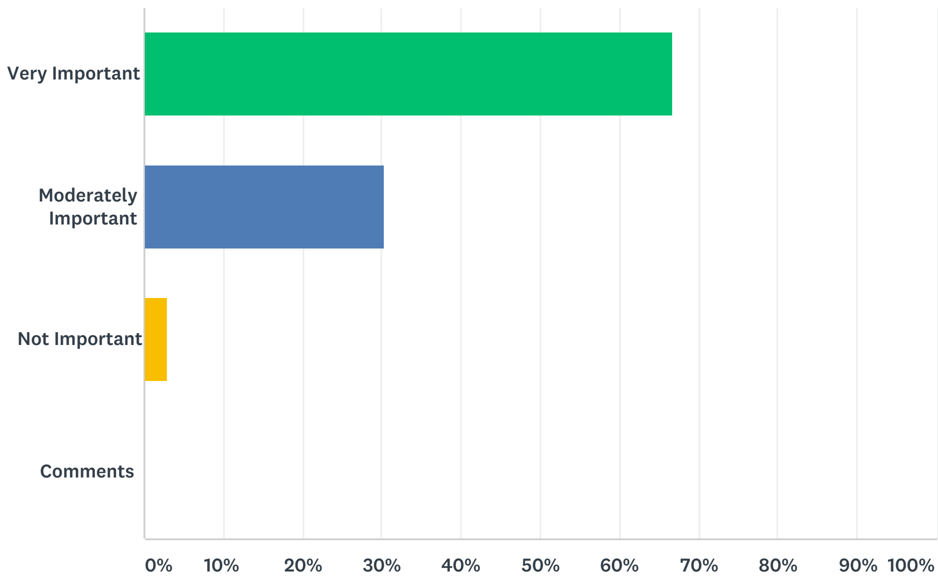
# Q6 In order of importance, please rank the following factors:(1 = most important and 5 = least important).

Answered: 63 Skipped: 4

| ANSWER CHOICES | RESPONSES | |
|---|---|---|
| Use of "Smart Meters" | 96.83% | 61 |
| Reliability | 100.00% | 63 |
| Cost of Service | 96.83% | 61 |
| Ability to use Internet based tools to manage my account | 95.24% | 60 |
| Local presence (UP-based) | 98.41% | 62 |

# Q7 UPPCO currently purchases approximately 80% of the energy that is required to meet its customers' needs from the wholesale energy market. Future energy prices in the wholesale market may fluctuate over time. How important is it that UPPCO owns sufficient generation to provide long-term price stability?

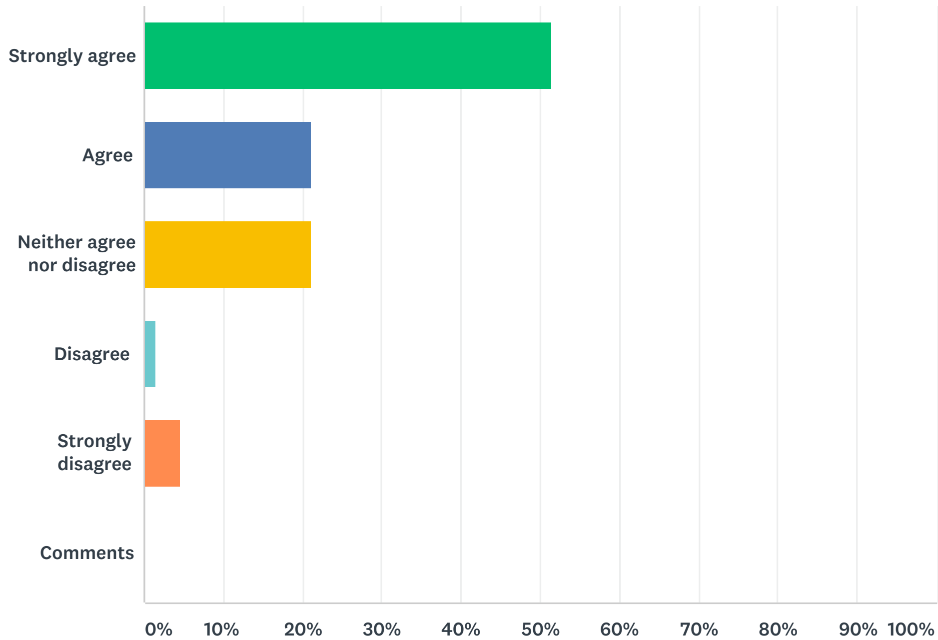
Answered: 66 Skipped: 1




| ANSWER CHOICES | RESPONSES | |
|---|---|---|
| Very Important | 66.67% | 44 |
| Moderately Important | 30.30% | 20 |
| Not Important | 3.03% | 2 |
| Comments | 0.00% | 0 |
| TOTAL | | 66 |

# Q8 The state has mandated 15% of the energy that is required to serve the customers' needs must come from renewable sources by the year 2021. How strongly do you agree or disagree that UPPCO should exceed the state mandate of 15%?

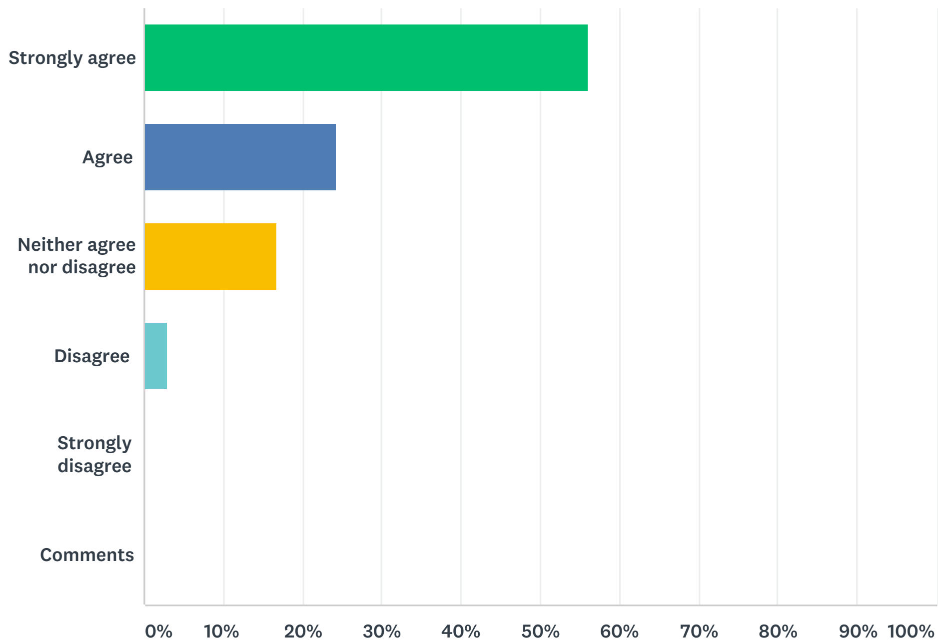
Answered: 66 Skipped: 1




| ANSWER CHOICES | RESPONSES | |
|---|---|---|
| Strongly agree | 51.52% | 34 |
| Agree | 21.21% | 14 |
| Neither agree nor disagree | 21.21% | 14 |
| Disagree | 1.52% | 1 |
| Strongly disagree | 4.55% | 3 |
| Comments | 0.00% | 0 |
| TOTAL | | 66 |

# Q9 The state has set an annual Energy Efficiency/Energy Waste Reduction goal of 1% through the year 2021. How strongly do you agree or disagree that UPPCO should exceed this goal?

Answered: 66 Skipped: 1

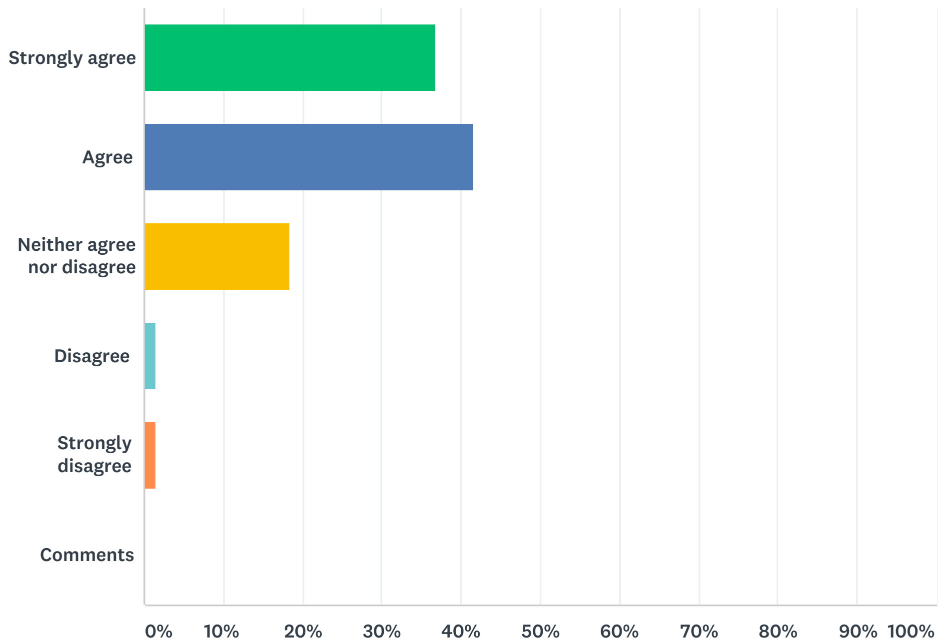



| ANSWER CHOICES | RESPONSES | |
|---|---|---|
| Strongly agree | 56.06% | 37 |
| Agree | 24.24% | 16 |
| Neither agree nor disagree | 16.67% | 11 |
| Disagree | 3.03% | 2 |
| Strongly disagree | 0.00% | 0 |
| Comments | 0.00% | 0 |
| TOTAL | | 66 |

Copy of Upper Peninsula Power Company Integrated Resource Plan Survey

## Q10 How strongly do you agree or disagree that UPPCO should rely on generation resources that are located in the Upper Peninsula for meeting your future energy needs?

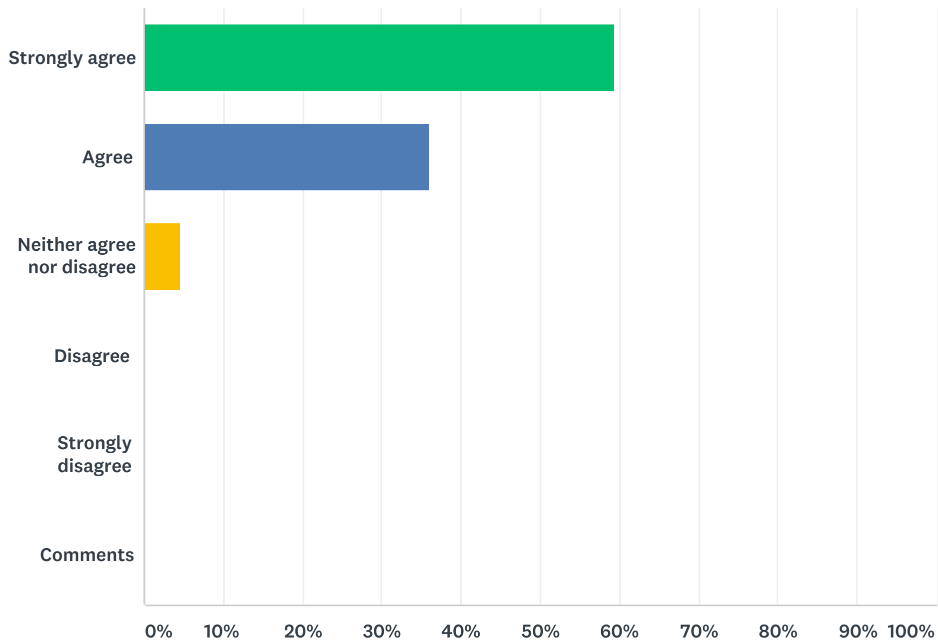
Answered: 65 Skipped: 2




| ANSWER CHOICES | RESPONSES | |
|---|---|---|
| Strongly agree | 36.92% | 24 |
| Agree | 41.54% | 27 |
| Neither agree nor disagree | 18.46% | 12 |
| Disagree | 1.54% | 1 |
| Strongly disagree | 1.54% | 1 |
| Comments | 0.00% | 0 |
| TOTAL | | 65 |

# Q11 How strongly do you agree or disagree that UPPCO should take proactive measures to protect its customers from unexpected costs like those that resulted from generation retirements?

Answered: 64 Skipped: 3




| ANSWER CHOICES | RESPONSES | |
|---|---|---|
| Strongly agree | 59.38% | 38 |
| Agree | 35.94% | 23 |
| Neither agree nor disagree | 4.69% | 3 |
| Disagree | 0.00% | 0 |
| Strongly disagree | 0.00% | 0 |
| Comments | 0.00% | 0 |
| TOTAL | | 64 |

# Q12 Address (OPTIONAL)

Answered: 40 Skipped: 27

| ANSWER CHOICES | RESPONSES | |
|---|---|---|
| Name | 95.00% | 38 |
| Company | 37.50% | 15 |
| Address | 82.50% | 33 |
| Address 2 | 7.50% | 3 |
| City/Town | 80.00% | 32 |
| State/Province | 65.00% | 26 |
| ZIP/Postal Code | 80.00% | 32 |
| Country | 22.50% | 9 |
| Email Address | 65.00% | 26 |
| Phone Number | 60.00% | 24 |

## Q13 Do you have any other comments, questions, or concerns relating to UPPCO's Integrated Resource Plan?

Answered: 19 Skipped: 48

Upper Peninsula Power Company

# Customer Update

## Fall 2018

*Powering our communities since 1884*

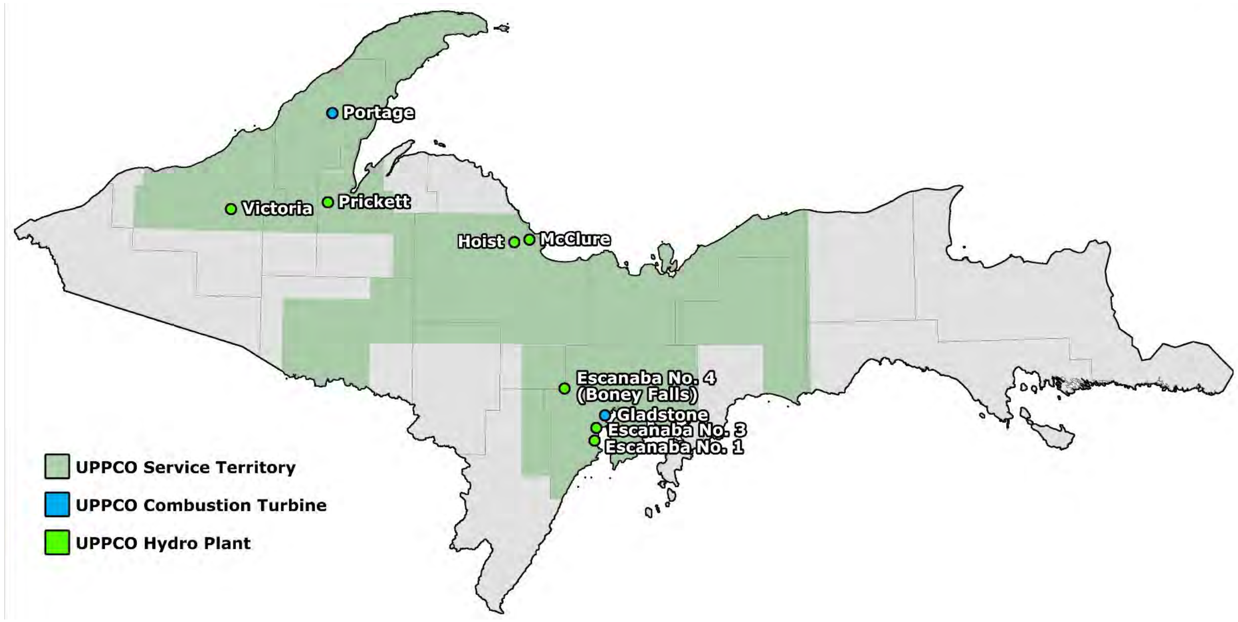
# Overview

Integrated Resource Plan Update

Power Supply Cost Recovery Update

Tax Cuts and Jobs Act/Rate Case Briefing

# UPPCO Generation Fleet



# UPPCO Generation Fleet

| Station | Type | Units | Date Built | Capacity (kW) |
|---|---|---|---|---|
| Hoist | Hydroelectric | 2 | 1916 | 3,400 |
| McClure | Hydroelectric | 2 | 1919 | 8,480 |
| Prickett | Hydroelectric | 2 | 1931 | 2,000 |
| Victoria | Hydroelectric | 2 | 1930 | 12,200 |
| Boney Falls | Hydroelectric | 3 | 1921 | 4,100 |
| Escanaba 3 | Hydroelectric | 2 | 1914 | 2,500 |
| Escanaba 1 | Hydroelectric | 3 | 1907/1920 | 1,600 |
| Gladstone | Combustion Turbine | 1 | 1975/1987 | 22,567* |
| Portage | Combustion Turbine | 1 | 1971 | 23,800* |

# Integrated Resource Plan

- An Integrated Resource Plan or "IRP" is the process a utility uses to determine the *Best Value Plan* for meeting the needs of its customers

- UPPCO started the IRP process in January 2018 by engaging its customers, seeking their input and feedback

# Questions Resolved through the IRP

- How much generation is needed to meet the future demand of its customers?
- When should existing generation be retired?
- When should new generation be constructed?
- How much Capacity should be company-owned?
- How much Energy should be produced by company-owned generation?
- Where should new generation be added to enhance the grid's Reliability?

# Integrated Resource Plan

- Predictive modeling was used to evaluate and compare *plausible* alternatives that:
  - Ensure adequate generation resources – *Capacity* – capable of producing the energy our customers' will require in the future (20 year study horizon)
  - Utilize clean, renewable energy resources – *Renewables* – that meet or exceed the state's requirements
  - Adopt a diversified strategy for delivering the *Energy* our customers' will consume during the next 5 years
  - Establish a resource plan that compliments and enhances Grid Resiliency and Reliability

# Integrated Resource Plan

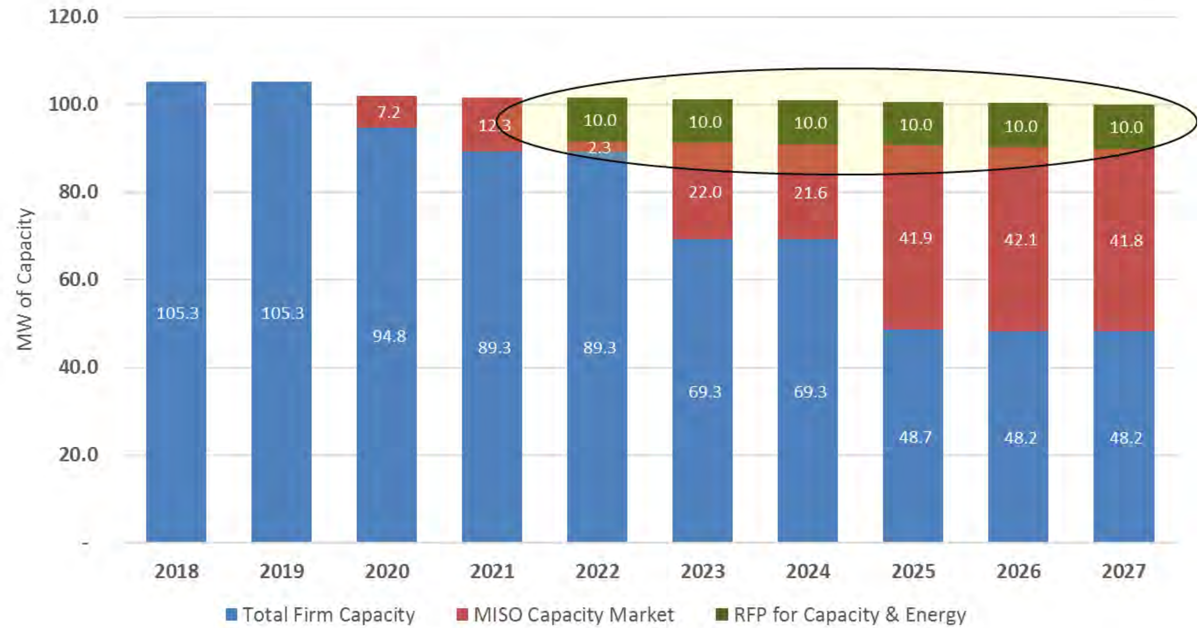
Key Modeling Assumptions

- Retirement of Gladstone Combustion Turbine (-20 MW)
  - December 2019
- Increase in company owned generation Capacity (20 MW)
  - Q2 2020
- Retirement of Portage Combustion Turbine (-20 MW)
  - May 2024

Modeling Results: 2022 Planning Horizon

- Forecasting a Capacity deficit of ~20MW
- 19% of the energy being consumed by our customers will be sourced as Renewable Energy

# IRP – Capacity Position 2018-2027



# IRP – Request for Proposals

- UPPCO issued a Request for Proposals or “RFP” in September 2018 for procurement of ~20 MW of new solar photovoltaic (PV) generating Capacity
- Commercial Operation Date (COD) of Q2 2022
- The additional Capacity is to be located in Michigan’s Upper Peninsula
- May be a single 20 MW facility or multiple facilities of lower capacity

# IRP – What's Next

- UPPCO's Integrated Resource Plan will be filed with the Michigan Public Service Commission on, or about December 15, 2018

- The Commission has 300 days to consider the Company's proposal and stakeholder/intervenor input and issue its Order in the case

# Integrated Resource Plan

For more information:

https://www.uppco.com/home/irp/

We value your feedback and input!

Email: IRP@uppco.com

# PSCR Update

| ANTICIPATED ADJUSTMENTS TO POWER SUPPLY COST RECOVERY FACTOR | | | |
|---|---|---|---|
| MONTH | YEAR | RATE | DRIVER |
| October | 2018 | ($0.030) | -- |
| November | 2018 | ($0.034) | Increased Hydro production, reduced market purchases |
| December | 2018 | ($0.034) | -- |
| January | 2019 | ($0.016) | Presque Isle SSR refund complete |
| February | 2019 | ($0.016) | -- |
| March | 2019 | ($0.016) | -- |
| April | 2019 | ($0.016) | -- |
| May | 2019 | ($0.016) | -- |
| June | 2019 | ($0.016) | -- |
| July | 2019 | ($0.016) | -- |
| August | 2019 | $0.000 | Reset due to outcome in Rate Case |

# Regulatory Update

- UPPCO submitted a comprehensive, multifaceted filing with the Michigan Public Service Commission on September 21, 2018 (Case No. U-20276)

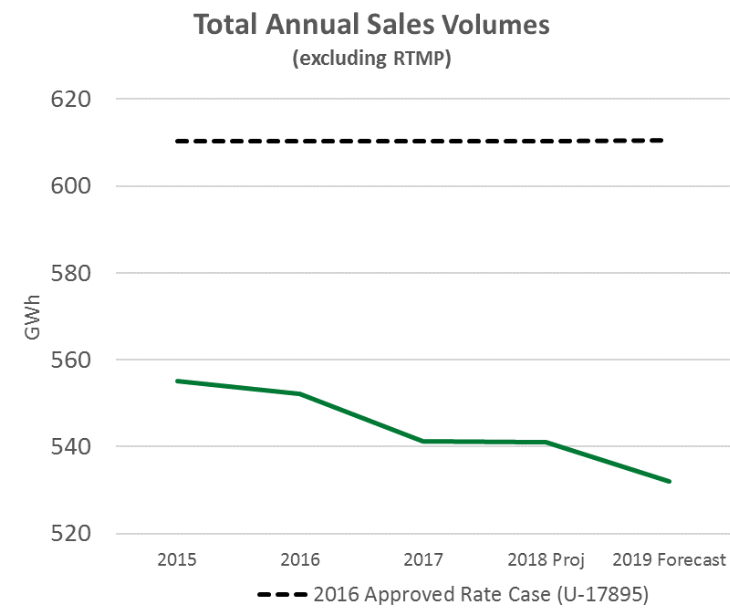
- The filing addresses various issues, including the need to adjust rates to reflect and recover the true cost of providing electric service to all customer classes

- The filing utilizes an updated Cost of Service Study and 2017 “Test” and 2019 “Projected” benchmarks

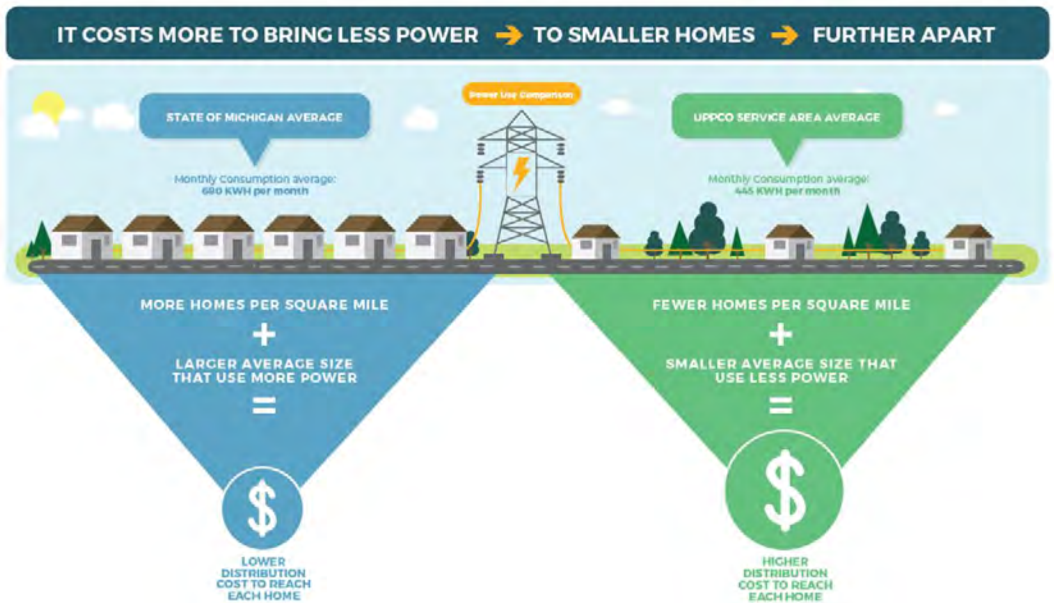
# Key Drivers

- Investments being made to improve upon reliability and provide better customer service
- Investments being made in the *UPPCO Smart Energy*™ advanced metering solution (AMI)
- Impact of the Tax Cuts and Jobs Act of 2017
- Evolving customer usage trends (declining sales)

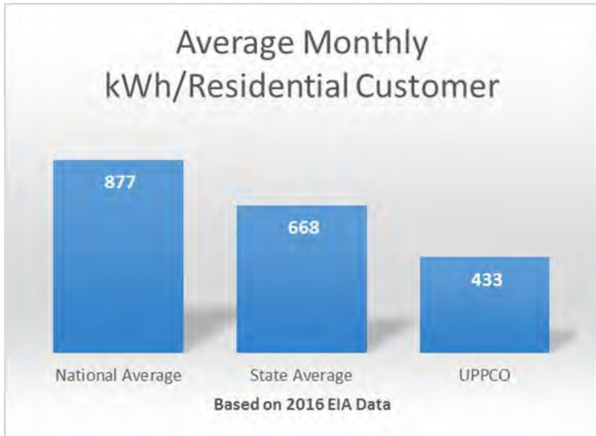
# Customer Usage Trends

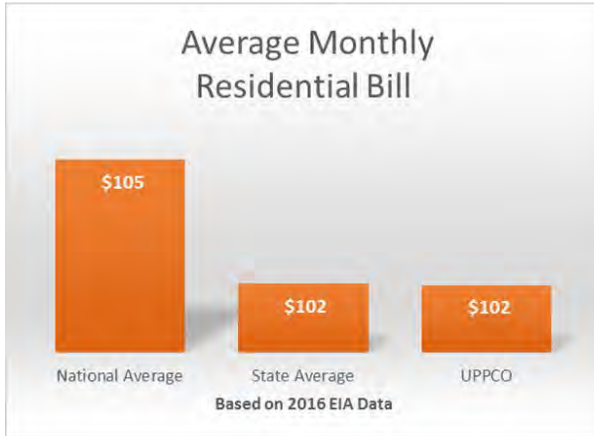


# How do we compare?



# How do we compare?



# How will the case impact customers?

- Returns the full benefit of the Tax Cuts and Jobs Act of 2017 to customers
- Resets the Power Supply Cost Recovery factor to reflect current market conditions
- Adjusts the rates being charged to all customer classes to reflect the true cost of service

# How will the case impact customers?

- Establishes a new Distributed Generation tariff, as required under the 2016 energy laws
- Eliminates the fees that are currently assessed whenever a residential/small commercial customer utilizes a credit/debit card to pay their bill utilizing UPPCO’s Online Portal
- Better customer service through the *UPPCO Smart Energy*™ advanced metering solution (AMI)

# Key Takeaway

The proposed rates reflect the true cost of providing service to each customer class

# MPSC Rate Comparison Data

**COMPARISON OF AVERAGE RATES (IN CENTS PER kWh)**
**FOR MPSC-REGULATED ELECTRIC UTILITIES IN MICHIGAN**
**October 1, 2018**

| | RESIDENTIAL | | | SMALL COMMERCIAL | | LARGE COMMERCIAL | | | INDUSTRIAL | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *kW* | | | | 5 | 25 | 100 | 100 | 100 | 1,000 | 10,000 | 50,000 |
| *kWh* | 250 | 500 | 1,000 | 1,000 | 5,000 | 21,600 | 28,800 | 36,000 | 432,000 | 4,320,000 | 21,600,000 |
| ***INVESTOR OWNED*** | | | | | | | | | | | |
| ALPENA POWER | 14.14 | 12.95 | 12.36 | 13.10 | 12.25 | 12.29 | 10.95 | 10.00 | 8.45 | 6.29 | 6.26 |
| CONSUMERS ENERGY | 17.12 | 15.53 | 14.74 | 15.17 | 13.54 | 14.70 | 13.28 | 12.42 | 9.78 | 7.69 | 7.03 |
| DTE ELECTRIC | 17.06 | 15.37 | 15.27 | 13.47 | 12.35 | 11.59 | 11.53 | 11.62 | 8.03 | 7.29 | 7.04 |
| AEP (I&M) COMBINED | 17.43 | 15.19 | 14.07 | 0.00 | 16.85 | 14.83 | 13.57 | 12.81 | 10.06 | 8.81 | 10.80 |
| NORTHERN STATES POWER | 14.62 | 12.63 | 11.64 | 11.66 | 10.45 | 11.57 | 10.40 | 9.70 | 9.24 | 9.14 | 9.13 |
| UPPER PENINSULA POWER | 24.52 | 21.33 | 19.74 | 14.96 | 13.25 | 13.25 | 11.65 | 10.68 | 6.65 | 5.97 | 5.15 |
| UPPER PENINSULA POWER IRON RIVER | 23.67 | 20.48 | 19.75 | 14.96 | 13.25 | 13.25 | 11.65 | 10.68 | 6.65 | 5.97 | 5.15 |
| UMERC (FORMERLY WEPCO) | 16.63 | 14.42 | 13.32 | 15.32 | 13.04 | 12.67 | 12.62 | 11.09 | 9.70 | 9.26 | 6.91 |
| UMERC (FORMERLY WPSC) | 14.85 | 12.45 | 11.25 | 12.52 | 10.25 | 10.23 | 10.14 | 10.08 | 8.54 | 8.11 | 7.52 |
| *AVERAGE INVESTOR OWNED* | 17.78 | 15.60 | 14.68 | 12.35 | 12.80 | 12.71 | 11.75 | 11.01 | 8.56 | 7.61 | 7.22 |

Source: Michigan Public Service Commission Utility Rate Books
Compiled by the Regulated Energy Division

# Benefits of AMI

- Utilizes new infrastructure, state-of-the-art technology and smart meters to modernize the power grid
- Eliminates bi-monthly meter reads and reliance on estimated usage for monthly billing statements
- Increased reliability through better detection of outages and deployment of crews and resources
- Meter installations to begin during the spring of 2019

# Key Takeaway

Provides the necessary resources to eliminate bi-monthly meter reading through deployment of Advanced Metering Infrastructure (AMI)

# For Additional Information

Dan Crane, Senior Account Executive
dcrane@uppco.com
(906) 483-4507

David Puskala, Account Executive
dpuskala@uppco.com
(906) 485-2427

| | Dec. 20th Order in MPSC Case No. U-18461 | IRP Report Section |
|---|---|---|
| **1** | **Executive Summary** | Section 1.0 |
| 1 a | Summary of IRP time frame | Section 1.2 |
| 1 b | Introduction to UPPCo | Section 1.1 |
| **2** | **Table of Contents** | Will include |
| **3** | **Table of Figures** | Will include (both tables and figures) |
| **4** | **Introduction** | varies - see below |
| 4 a | Description of existing energy system | Section 3.0 |
| 4 b | Statement of power need | Section 6.0 |
| 4 c | Fuel/energy/capacity forecast | Section 4.0 |
| 4 d | Market & regulatory environment | Section 2.2 |
| 4 e | IRP Planning Process | Section 2.1 |
| 4 f | Stakeholder Report | Section 2.4 |
| **5** | **Analytical Approach** | varies - see below |
| 5 a | Modeling process | Section 2.1, Appendix A |
| 5 b | Risk analysis approach | Section 11.1 |
| 5 c | Identification of risk variables | Section 11.2 |
| **6** | **IRP Scenarios and Sensitivities** | varies - see below |
| 6 a | Description of scenarios | Section 9.0 |
| 6 b | Michigan established scenarios | Section 9.x |
| **7** | **Supply side resources** | Section 9.x |
| 7 a | Overview | Section 7.1 |
| 7 b | Fossil fuel | Section 7.2 |
| 7 c | Nuclear | Section 7.2 |
| 7 d | Hydroelectric | Section 7.2 |
| 7 e | Renewable | Section 7.2 |
| 7 f | Energy storage | Section 7.4 |
| 7 g | PPA | Section 3.3 |
| 7 h | RTO capacity credits | Section 7.2 |
| 7 i | Spot market purchases | Section 3.3 |
| **8** | **Deman side resources** | varies - see below |
| 8 a | Projected demand-side resources | Section 5.0 |
| **9** | **Renewables and Portfolio Standards** | varies - see below |
| 9 a | How UPPCo will meet renewable standards | Section 6.2 |
| 9 b | MWh renewable energy calc clarification | Section 6.2 |
| 9 c | Incremental cost of compliance | Section 9.x |
| 9 d | How plan is consistent with MI 35% by 2025 | Section 6.2 |
| 9 e | Customer-initiated renewable energy | Section 6.2 |
| 9 f | How UPPCO will meet customer-initiated demand | Section 6.2 |
| **10** | **Peak demand and energy forecasts** | varies - see below |
| 10 a | Forcast of peak demand | Section 4.1 |
| 10 b | Subsections (methods, assumptions) | Sections 4.2 and 4.3 |
| **11** | **Capacity & Reliability Requirements** | Section 6.3 |
| **12** | **Transmission Analysis** | varies - see below |
| 12 a | New generation interconnection | Section 8.1 |
| 12 b | Efforts to engage RTOs | Section 8.1 |
| 12 c | Current transmission system | Section 3.4 |
| 12 d | IRP effects on RTOs | Section 8.1 |
| 12 e | RTO transmission changes that could imapct IRP | Section 8.1 |

| | Dec. 20th Order in MPSC Case No. U-18461 | IRP Report Section |
|---|---|---|
| **13** | **Fuel** | varies - see below |
| 13 a | Overview | Section 3.1.1 |
| 13 b | Natural Gas forecast (w/ scenarios) | Section 9.x |
| 13 c | Oil forecast (w/ scenarios) | Section 9.x |
| 13 d | Coal forecast (w/ scenarios) | Section 9.x |
| 13 e | Delivered natural gas prices | Section 9.x |
| 13 f | Delivered oil prices | Section 9.x |
| 13 g | Delivered coal prices | Section 9.x |
| 13 h | Projected annual fuel costs | Section 10.2 |
| 13 i | Long term contracts | Section 3.1.1 |
| **14** | **Resource Screen** | varies - see below |
| 14 a | Existing and planned generation | Section 3.1.1 |
| 14 b | New build | Appendix B.2.10 |
| 14 c | Distributed generation | Appendix B.2.10 |
| 14 d | Market capacity purchases | Appendix B.2.10 |
| 14 e | Long term PPAs | Appendix B.2.10 |
| 14 f | Transmission resources | Appendix B.2.10 |
| **15** | **Modeling Results** | varies - see below |
| 15 a | IRP portfolio design strategy | Section 10.1 |
| 15 b | Scenario and sensitivity results | Section 9 |
| 15 c | BAU portfolios | Section 9.x |
| 15 d | Analysis of IRP results | Section 10.2 |
| 15 e | Risk assessment of each scenario | Section 11 |
| **16** | **Proposed course of action** | Section 10.1 |
| 16 a | Type of generation proposed in IRP plan | Section 10 |
| 16 b | Plans for meeting capacity needs | Section 10 |
| 16 c | Projected long term gas contracts | Section 10 |
| 16 d | Meeting regulations | Section 10 |
| **17** | **Rate Impact and Financial Information** | Section 12 (UPPCo) |
| 17 a | Revenue requirement | Section 12 (UPPCo) |
| 17 b | Rate base | Section 12 (UPPCo) |
| 17 c | Plant in-service capital accounts | Section 12 (UPPCo) |
| 17 d | Non-fuel, FOM accounbts | Section 12 (UPPCo) |
| 17 e | Non-fuel, VOM accounts | Section 12 (UPPCo) |
| 17 f | Fuel accounts | Section 12 (UPPCo) |
| 17 g | Emmissions costs | Section 12 (UPPCo) |
| 17 h | Effluent additive costs | Section 12 (UPPCo) |
| 17 i | Projected change in generation plant-in-service | Section 12 (UPPCo) |
| **18** | **Environmental** | varies - see below |
| 18 a | All applicable environmental regulations | Section 2.2 |
| 18 b | Capital costs for environmental compliance | Appendix B.2.4 |
| 18 c | Annual emmision projections (proposed IRP) | Section 9.x |
| 18 d | Annual emmision projections (scenarios) | Section 9.x |
| **19** | **Exhibits and Workpapers** | varies - see below |
| 19 a | Workpapers used in developing IRP | N/A |
| 19 b | Modelling input/output files | Appendix A.1.2 |
| 19 c | Cost data/estimates used in IRP | Appendices A & B, various |

| | Dec. 20th Order in MPSC Case No. U-18461 | IRP Report Section |
|---|---|---|
| 19 d | Desctription of proposed alternatives | Appendix A.2.2 |
| 19 e | Differences in IRP/cost recovery proceeding costs | Appendix A.2.1 |
| 19 f | Energy, capacity, fuel cost forecast justification | Appendix B.1.5-B.1.7, B.1.15 |
| 19 g | Environmental complinace strategy | Appendix B.2.4 |
| 19 h | Estimated annual emissions | Section 9.x |
| 19 i | Comparison of scenario carbon emissions | Appendix B.2.4 |
| 19 j | Assumed facility retirement dates | Appendix B.1.4, B.2.13 |
| 19 k | Cost estiamte of all alternative proposals | Section 9.x |
| 19 l | Electricity market forecasts utilized | Appendix B.1.15 |
| 19 m | Other documents underlying the IRP process | Appendices A & B, various |

**CONFIDENTIAL**

Exhibit A-7 (GRH-7)

PPA FCM

**CONFIDENTIAL**

Exhibit A-8 (GRH-8)

Summary Inputs and Outputs

# **CONFIDENTIAL**

## Exhibit A-9 (GRH-9)

## Revenue Requirements Summary

Phase 1: RICE 2022

| | | a | b | c | | d | e | f | g | h | i |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Initial Investment | | | | Tax Depreciation | | | | Deferre |
| Line | | | Capital Investment | Book Depreciation | PTC $ | Tax Depreciation Rate | Tax Depreciation | ITC Adj Tax Depreciation | Accumulated Tax Depreciation | Temporary Timing Difference | Deferred Taxes |
| 1 | 0 | 2018 | - | - | - | - | - | - | - | - | - |
| 2 | 0 | 2019 | - | - | - | - | - | - | - | - | - |
| 3 | 0 | 2020 | - | - | - | - | - | - | - | - | - |
| 4 | 0 | 2021 | - | - | - | - | - | - | - | - | - |
| 5 | 1 | 2022 | 26,834,500 | 670,863 | - | 0.03750 | (1,006,294) | - | (1,006,294) | (335,431) | (86,340) |
| 6 | 2 | 2023 | - | 894,483 | - | 0.07219 | (1,937,183) | - | (2,943,476) | (1,042,699) | (268,391) |
| 7 | 3 | 2024 | | 894,483 | - | 0.06677 | (1,791,740) | - | (4,735,216) | (897,256) | (230,954) |
| 8 | 4 | 2025 | | 894,483 | - | 0.06177 | (1,657,567) | - | (6,392,783) | (763,084) | (196,418) |
| 9 | 5 | 2026 | | 894,483 | - | 0.05713 | (1,533,055) | - | (7,925,838) | (638,572) | (164,368) |
| 10 | 6 | 2027 | | 894,483 | - | 0.05285 | (1,418,203) | - | (9,344,041) | (523,720) | (134,806) |
| 11 | 7 | 2028 | | 894,483 | - | 0.04888 | (1,311,670) | - | (10,655,712) | (417,187) | (107,384) |
| 12 | 8 | 2029 | | 894,483 | - | 0.04522 | (1,213,456) | - | (11,869,168) | (318,973) | (82,104) |
| 13 | 9 | 2030 | | 894,483 | - | 0.04462 | (1,197,355) | - | (13,066,523) | (302,872) | (77,959) |
| 14 | 10 | 2031 | | 894,483 | - | 0.04461 | (1,197,087) | - | (14,263,610) | (302,604) | (77,890) |
| 15 | 11 | 2032 | | 894,483 | - | 0.04462 | (1,197,355) | - | (15,460,966) | (302,872) | (77,959) |
| 16 | 12 | 2033 | | 894,483 | - | 0.04461 | (1,197,087) | - | (16,658,053) | (302,604) | (77,890) |
| 17 | 13 | 2034 | | 894,483 | - | 0.04462 | (1,197,355) | - | (17,855,408) | (302,872) | (77,959) |
| 18 | 14 | 2035 | | 894,483 | - | 0.04461 | (1,197,087) | - | (19,052,495) | (302,604) | (77,890) |
| 19 | 15 | 2036 | | 894,483 | - | 0.04462 | (1,197,355) | - | (20,249,850) | (302,872) | (77,959) |
| 20 | 16 | 2037 | | 894,483 | - | 0.04461 | (1,197,087) | - | (21,446,937) | (302,604) | (77,890) |
| 21 | 17 | 2038 | | 894,483 | - | 0.04462 | (1,197,355) | - | (22,644,293) | (302,872) | (77,959) |
| 22 | 18 | 2039 | | 894,483 | - | 0.04461 | (1,197,087) | - | (23,841,380) | (302,604) | (77,890) |
| 23 | 19 | 2040 | | 894,483 | - | 0.04462 | (1,197,355) | - | (25,038,735) | (302,872) | (77,959) |
| 24 | 20 | 2041 | | 894,483 | - | 0.04461 | (1,197,087) | - | (26,235,822) | (302,604) | (77,890) |
| 25 | 21 | 2042 | | 894,483 | - | 0.02231 | (598,678) | - | (26,834,500) | 295,806 | 76,140 |
| 26 | 22 | 2043 | | 894,483 | - | - | - | - | (26,834,500) | 894,483 | 230,240 |
| 27 | 23 | 2044 | | 894,483 | - | - | - | - | (26,834,500) | 894,483 | 230,240 |
| 28 | 24 | 2045 | | 894,483 | - | - | - | - | (26,834,500) | 894,483 | 230,240 |
| 29 | 25 | 2046 | | 894,483 | - | - | - | - | (26,834,500) | 894,483 | 230,240 |
| 30 | 26 | 2047 | | 894,483 | - | - | - | - | (26,834,500) | 894,483 | 230,240 |
| 31 | 27 | 2048 | | 894,483 | - | - | - | - | (26,834,500) | 894,483 | 230,240 |
| 32 | 28 | 2049 | | 894,483 | - | - | - | - | (26,834,500) | 894,483 | 230,240 |
| 33 | 29 | 2050 | | 894,483 | - | - | - | - | (26,834,500) | 894,483 | 230,240 |
| 34 | 30 | 2051 | | 894,483 | - | - | - | - | (26,834,500) | 894,483 | 230,240 |
| 35 | 31 | 2052 | | 223,621 | - | - | - | - | (26,834,500) | 223,621 | 57,560 |

| | Phase 1: RICE 2022 | a | j | k | l | m | n | o | p | q | r |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | d Taxes | | | | Rate Base | | | | Return or |
| Line | | | Total Timing Difference | Accumulated Deferred Taxes | Cumulative Book Value | Accumulated Deferred Income Taxes | Accumulated Book Depreciation | Accumulated Def ITC | Rate Base Dec 31 | 13 Mo. Rolling Average | Debt Portion Before Tax |
| 1 | 0 | 2018 | - | - | - | - | - | - | - | - | - |
| 2 | 0 | 2019 | - | - | - | - | - | - | - | - | - |
| 3 | 0 | 2020 | - | - | - | - | - | - | - | - | - |
| 4 | 0 | 2021 | - | - | - | - | - | - | - | - | - |
| 5 | 1 | 2022 | (335,431) | (86,340) | 26,834,500 | (86,340) | (670,863) | - | 26,077,297 | 13,038,649 | 280,593 |
| 6 | 2 | 2023 | (1,378,130) | (354,731) | 26,834,500 | (354,731) | (1,565,346) | - | 24,914,423 | 25,495,860 | 548,673 |
| 7 | 3 | 2024 | (2,275,387) | (585,685) | 26,834,500 | (585,685) | (2,459,829) | - | 23,788,986 | 24,351,705 | 524,051 |
| 8 | 4 | 2025 | (3,038,470) | (782,102) | 26,834,500 | (782,102) | (3,354,313) | - | 22,698,085 | 23,243,536 | 500,203 |
| 9 | 5 | 2026 | (3,677,042) | (946,471) | 26,834,500 | (946,471) | (4,248,796) | - | 21,639,234 | 22,168,659 | 477,071 |
| 10 | 6 | 2027 | (4,200,762) | (1,081,276) | 26,834,500 | (1,081,276) | (5,143,279) | - | 20,609,945 | 21,124,589 | 454,603 |
| 11 | 7 | 2028 | (4,617,949) | (1,188,660) | 26,834,500 | (1,188,660) | (6,037,763) | - | 19,608,077 | 20,109,011 | 432,748 |
| 12 | 8 | 2029 | (4,936,922) | (1,270,764) | 26,834,500 | (1,270,764) | (6,932,246) | - | 18,631,490 | 19,119,784 | 411,459 |
| 13 | 9 | 2030 | (5,239,794) | (1,348,723) | 26,834,500 | (1,348,723) | (7,826,729) | - | 17,659,048 | 18,145,269 | 390,488 |
| 14 | 10 | 2031 | (5,542,398) | (1,426,613) | 26,834,500 | (1,426,613) | (8,721,213) | - | 16,686,674 | 17,172,861 | 369,561 |
| 15 | 11 | 2032 | (5,845,270) | (1,504,572) | 26,834,500 | (1,504,572) | (9,615,696) | - | 15,714,232 | 16,200,453 | 348,635 |
| 16 | 12 | 2033 | (6,147,873) | (1,582,463) | 26,834,500 | (1,582,463) | (10,510,179) | - | 14,741,858 | 15,228,045 | 327,709 |
| 17 | 13 | 2034 | (6,450,745) | (1,660,422) | 26,834,500 | (1,660,422) | (11,404,663) | - | 13,769,416 | 14,255,637 | 306,783 |
| 18 | 14 | 2035 | (6,753,349) | (1,738,312) | 26,834,500 | (1,738,312) | (12,299,146) | - | 12,797,042 | 13,283,229 | 285,856 |
| 19 | 15 | 2036 | (7,056,221) | (1,816,271) | 26,834,500 | (1,816,271) | (13,193,629) | - | 11,824,599 | 12,310,821 | 264,930 |
| 20 | 16 | 2037 | (7,358,825) | (1,894,162) | 26,834,500 | (1,894,162) | (14,088,113) | - | 10,852,226 | 11,338,413 | 244,004 |
| 21 | 17 | 2038 | (7,661,697) | (1,972,121) | 26,834,500 | (1,972,121) | (14,982,596) | - | 9,879,783 | 10,366,005 | 223,077 |
| 22 | 18 | 2039 | (7,964,301) | (2,050,011) | 26,834,500 | (2,050,011) | (15,877,079) | - | 8,907,410 | 9,393,597 | 202,151 |
| 23 | 19 | 2040 | (8,267,173) | (2,127,970) | 26,834,500 | (2,127,970) | (16,771,563) | - | 7,934,967 | 8,421,189 | 181,225 |
| 24 | 20 | 2041 | (8,569,776) | (2,205,860) | 26,834,500 | (2,205,860) | (17,666,046) | - | 6,962,594 | 7,448,780 | 160,298 |
| 25 | 21 | 2042 | (8,273,971) | (2,129,720) | 26,834,500 | (2,129,720) | (18,560,529) | - | 6,144,251 | 6,553,422 | 141,030 |
| 26 | 22 | 2043 | (7,379,488) | (1,899,480) | 26,834,500 | (1,899,480) | (19,455,013) | - | 5,480,007 | 5,812,129 | 125,078 |
| 27 | 23 | 2044 | (6,485,004) | (1,669,240) | 26,834,500 | (1,669,240) | (20,349,496) | - | 4,815,764 | 5,147,886 | 110,783 |
| 28 | 24 | 2045 | (5,590,521) | (1,439,000) | 26,834,500 | (1,439,000) | (21,243,979) | - | 4,151,521 | 4,483,642 | 96,488 |
| 29 | 25 | 2046 | (4,696,038) | (1,208,760) | 26,834,500 | (1,208,760) | (22,138,463) | - | 3,487,277 | 3,819,399 | 82,194 |
| 30 | 26 | 2047 | (3,801,554) | (978,520) | 26,834,500 | (978,520) | (23,032,946) | - | 2,823,034 | 3,155,156 | 67,899 |
| 31 | 27 | 2048 | (2,907,071) | (748,280) | 26,834,500 | (748,280) | (23,927,429) | - | 2,158,791 | 2,490,912 | 53,605 |
| 32 | 28 | 2049 | (2,012,588) | (518,040) | 26,834,500 | (518,040) | (24,821,913) | - | 1,494,547 | 1,826,669 | 39,310 |
| 33 | 29 | 2050 | (1,118,104) | (287,800) | 26,834,500 | (287,800) | (25,716,396) | - | 830,304 | 1,162,426 | 25,016 |
| 34 | 30 | 2051 | (223,621) | (57,560) | 26,834,500 | (57,560) | (26,610,879) | - | 166,061 | 498,182 | 10,721 |
| 35 | 31 | 2052 | - | - | 26,834,500 | - | (26,834,500) | - | - | 83,030 | 1,787 |

Phase 1: RICE 2022

| Line | | a | s | t | u | v | w | x | y | z |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | Rate Base | Nominal Revenue Requirement | | | | | | |
| | | | **Common Portion After Tax** | **Return on Rate Base** | **Book Depreciation** | **Income Tax** | **Renewable Tax Credit** | **Variable O&M** | **Fixed O&M** | **Property Tax** |
| 1 | 0 | 2018 | - | - | - | - | - | - | - | - |
| 2 | 0 | 2019 | - | - | - | - | - | - | - | - |
| 3 | 0 | 2020 | - | - | - | - | - | - | - | - |
| 4 | 0 | 2021 | - | - | - | - | - | - | - | - |
| 5 | 1 | 2022 | 705,816 | 986,409 | 670,863 | 244,650 | - | 1,223,858 | 284,077 | 654,091 |
| 6 | 2 | 2023 | 1,380,158 | 1,928,831 | 894,483 | 478,390 | - | 1,673,748 | 388,503 | 631,729 |
| 7 | 3 | 2024 | 1,318,222 | 1,842,273 | 894,483 | 456,922 | - | 1,716,763 | 398,488 | 609,367 |
| 8 | 4 | 2025 | 1,258,234 | 1,758,437 | 894,483 | 436,129 | - | 1,760,884 | 408,729 | 587,005 |
| 9 | 5 | 2026 | 1,200,048 | 1,677,119 | 894,483 | 415,961 | - | 1,806,139 | 419,233 | 564,643 |
| 10 | 6 | 2027 | 1,143,530 | 1,598,133 | 894,483 | 396,370 | - | 1,852,556 | 430,007 | 542,281 |
| 11 | 7 | 2028 | 1,088,554 | 1,521,301 | 894,483 | 377,315 | - | 1,900,167 | 441,059 | 519,918 |
| 12 | 8 | 2029 | 1,035,004 | 1,446,464 | 894,483 | 358,753 | - | 1,949,001 | 452,394 | 497,556 |
| 13 | 9 | 2030 | 982,251 | 1,372,739 | 894,483 | 340,468 | - | 1,999,091 | 464,020 | 475,194 |
| 14 | 10 | 2031 | 929,612 | 1,299,174 | 894,483 | 322,222 | - | 2,050,467 | 475,946 | 452,832 |
| 15 | 11 | 2032 | 876,973 | 1,225,608 | 894,483 | 303,976 | - | 2,103,164 | 488,177 | 430,470 |
| 16 | 12 | 2033 | 824,334 | 1,152,043 | 894,483 | 285,731 | - | 2,157,216 | 500,724 | 408,108 |
| 17 | 13 | 2034 | 771,695 | 1,078,478 | 894,483 | 267,485 | - | 2,212,656 | 513,592 | 385,746 |
| 18 | 14 | 2035 | 719,056 | 1,004,912 | 894,483 | 249,239 | - | 2,269,521 | 526,791 | 363,384 |
| 19 | 15 | 2036 | 666,417 | 931,347 | 894,483 | 230,994 | - | 2,327,848 | 540,330 | 341,022 |
| 20 | 16 | 2037 | 613,778 | 857,782 | 894,483 | 212,748 | - | 2,387,674 | 554,216 | 318,660 |
| 21 | 17 | 2038 | 561,139 | 784,216 | 894,483 | 194,502 | - | 2,449,037 | 568,460 | 296,298 |
| 22 | 18 | 2039 | 508,500 | 710,651 | 894,483 | 176,256 | - | 2,511,977 | 583,069 | 273,936 |
| 23 | 19 | 2040 | 455,861 | 637,086 | 894,483 | 158,011 | - | 2,576,535 | 598,054 | 251,573 |
| 24 | 20 | 2041 | 403,222 | 563,521 | 894,483 | 139,765 | - | 2,642,752 | 613,424 | 229,211 |
| 25 | 21 | 2042 | 354,754 | 495,784 | 894,483 | 122,965 | - | 2,710,671 | 629,189 | 206,849 |
| 26 | 22 | 2043 | 314,626 | 439,703 | 894,483 | 109,056 | - | 2,780,335 | 645,359 | 184,487 |
| 27 | 23 | 2044 | 278,669 | 389,452 | 894,483 | 96,592 | - | 2,851,789 | 661,945 | 162,125 |
| 28 | 24 | 2045 | 242,711 | 339,200 | 894,483 | 84,129 | - | 2,925,080 | 678,957 | 139,763 |
| 29 | 25 | 2046 | 206,754 | 288,948 | 894,483 | 71,665 | - | 3,000,255 | 696,406 | 117,401 |
| 30 | 26 | 2047 | 170,797 | 238,696 | 894,483 | 59,202 | - | 3,077,362 | 714,304 | 95,039 |
| 31 | 27 | 2048 | 134,840 | 188,444 | 894,483 | 46,738 | - | 3,156,450 | 732,661 | 72,677 |
| 32 | 28 | 2049 | 98,882 | 138,192 | 894,483 | 34,275 | - | 3,237,571 | 751,491 | 50,315 |
| 33 | 29 | 2050 | 62,925 | 87,941 | 894,483 | 21,811 | - | 3,320,776 | 770,804 | 27,953 |
| 34 | 30 | 2051 | 26,968 | 37,689 | 894,483 | 9,348 | - | 3,406,120 | 790,614 | 5,591 |
| 35 | 31 | 2052 | 4,495 | 6,281 | 223,621 | 1,558 | - | 873,414 | 202,733 | - |

| | Phase 1: RICE 2022 | a | aa | ab | ac | ad | ae | af | ag | ah | ai |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Line | | | Total Revenue Requirement | Discount Factor | Present Value Revenue Requirement | Accumulated Present Value | Average LMP U-18094 | 10 Year Average Generation | Energy Cost Savings | Capacity Value | Avoided PS $/MW-year |
| 1 | 0 | 2018 | - | 1.00 | - | - | 36.81 | **32,762** | 1,205,997 | **18.70** | 59,250 |
| 2 | 0 | 2019 | - | 0.93 | - | - | 36.26 | 32,762 | 1,187,854 | 18.70 | 59,250 |
| 3 | 0 | 2020 | - | 0.87 | - | - | 36.02 | 32,762 | 1,180,246 | 18.70 | 59,250 |
| 4 | 0 | 2021 | - | 0.81 | - | - | 38.88 | 32,762 | 1,273,897 | 18.70 | 59,250 |
| 5 | 1 | 2022 | 4,063,947 | 0.75 | 3,046,111 | 3,046,111 | 38.93 | 32,762 | 1,275,514 | 18.70 | 59,250 |
| 6 | 2 | 2023 | 5,995,685 | 0.70 | 4,181,536 | 7,227,647 | 39.09 | 32,762 | 1,280,564 | 18.70 | 59,250 |
| 7 | 3 | 2024 | 5,918,296 | 0.65 | 3,840,548 | 11,068,195 | 39.34 | 32,762 | 1,288,972 | 18.70 | 59,250 |
| 8 | 4 | 2025 | 5,845,666 | 0.60 | 3,529,636 | 14,597,831 | 48.15 | 32,762 | 1,577,535 | 18.70 | 59,250 |
| 9 | 5 | 2026 | 5,777,578 | 0.56 | 3,245,945 | 17,843,776 | 48.43 | 32,762 | 1,586,686 | 18.70 | 59,250 |
| 10 | 6 | 2027 | 5,713,831 | 0.52 | 2,986,910 | 20,830,685 | 48.64 | 32,762 | 1,593,664 | 18.70 | 59,250 |
| 11 | 7 | 2028 | 5,654,243 | 0.49 | 2,750,228 | 23,580,913 | 49.04 | 32,762 | 1,606,822 | 18.70 | 59,250 |
| 12 | 8 | 2029 | 5,598,652 | 0.45 | 2,533,827 | 26,114,740 | 49.44 | 32,762 | 1,619,863 | 18.70 | 59,250 |
| 13 | 9 | 2030 | 5,545,995 | 0.42 | 2,335,460 | 28,450,201 | 49.65 | 32,762 | 1,626,616 | 18.70 | 59,250 |
| 14 | 10 | 2031 | 5,495,124 | 0.39 | 2,153,128 | 30,603,329 | 50.01 | 32,762 | 1,638,424 | 18.70 | 59,250 |
| 15 | 11 | 2032 | 5,445,880 | 0.36 | 1,985,454 | 32,588,783 | 50.11 | 32,762 | 1,641,867 | 18.70 | 59,250 |
| 16 | 12 | 2033 | 5,398,304 | 0.34 | 1,831,254 | 34,420,037 | 50.02 | 32,762 | 1,638,760 | 18.70 | 59,250 |
| 17 | 13 | 2034 | 5,352,440 | 0.32 | 1,689,439 | 36,109,476 | 49.93 | 32,762 | 1,635,803 | 18.70 | 59,250 |
| 18 | 14 | 2035 | 5,308,332 | 0.29 | 1,559,007 | 37,668,483 | 50.24 | 32,762 | 1,646,075 | 18.70 | 59,250 |
| 19 | 15 | 2036 | 5,266,024 | 0.27 | 1,439,038 | 39,107,522 | 50.55 | 32,762 | 1,656,079 | 18.70 | 59,250 |
| 20 | 16 | 2037 | 5,225,563 | 0.25 | 1,328,685 | 40,436,206 | 50.85 | 32,762 | 1,666,016 | 18.70 | 59,250 |
| 21 | 17 | 2038 | 5,186,996 | 0.24 | 1,227,169 | 41,663,375 | *51.68* | 32,762 | 1,693,152 | 18.70 | 59,250 |
| 22 | 18 | 2039 | 5,150,373 | 0.22 | 1,133,774 | 42,797,149 | *52.60* | 32,762 | 1,723,425 | 18.70 | 59,250 |
| 23 | 19 | 2040 | 5,115,742 | 0.20 | 1,047,842 | 43,844,991 | *53.61* | 32,762 | 1,756,360 | 18.70 | 59,250 |
| 24 | 20 | 2041 | 5,083,156 | 0.19 | 968,769 | 44,813,759 | *54.48* | 32,762 | 1,784,791 | 18.70 | 59,250 |
| 25 | 21 | 2042 | 5,059,941 | 0.18 | 897,287 | 45,711,046 | *55.40* | 32,762 | 1,815,025 | 18.70 | 59,250 |
| 26 | 22 | 2043 | 5,053,424 | 0.17 | 833,818 | 46,544,864 | *56.37* | 32,762 | 1,846,956 | 18.70 | 59,250 |
| 27 | 23 | 2044 | 5,056,387 | 0.15 | 776,292 | 47,321,156 | *57.40* | 32,762 | 1,880,474 | 18.70 | 59,250 |
| 28 | 24 | 2045 | 5,061,612 | 0.14 | 723,058 | 48,044,214 | *57.90* | 32,762 | 1,897,063 | 18.70 | 59,250 |
| 29 | 25 | 2046 | 5,069,159 | 0.13 | 673,782 | 48,717,996 | *58.42* | 32,762 | 1,914,085 | 18.70 | 59,250 |
| 30 | 26 | 2047 | 5,079,085 | 0.12 | 628,158 | 49,346,154 | *58.96* | 32,762 | 1,931,699 | 18.70 | 59,250 |
| 31 | 27 | 2048 | 5,091,454 | 0.12 | 585,901 | 49,932,055 | *59.51* | 32,762 | 1,949,567 | 18.70 | 59,250 |
| 32 | 28 | 2049 | 5,106,327 | 0.11 | 546,752 | 50,478,807 | *60.06* | 32,762 | 1,967,710 | 18.70 | 59,250 |
| 33 | 29 | 2050 | 5,123,768 | 0.10 | 510,471 | 50,989,278 | *60.63* | 32,762 | 1,986,529 | 18.70 | 59,250 |
| 34 | 30 | 2051 | 5,143,844 | 0.09 | 476,835 | 51,466,113 | *61.22* | 32,762 | 2,005,757 | 18.70 | *59,250* |
| 35 | 31 | 2052 | 1,307,608 | 0.09 | 112,787 | 51,578,900 | *61.84* | 32,762 | 2,025,934 | 18.70 | *59,250* |

Phase 1: RICE 2022

| | | a | aj | ak | al | am | an | ao | ap | aq |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | CR Costs | | | | | | | |
| Line | | | Capacity Cost Savings | RECs | Value of RECs | REC Savings | Total PSCR Savings | PSCR Savings | Present Value PSCR Savings | Accumulated Present Value |
| 1 | 0 | 2018 | 1,107,975 | **32,762** | - | - | 2,313,972 | - | - | - |
| 2 | 0 | 2019 | 1,107,975 | 32,762 | - | - | 2,295,829 | - | - | - |
| 3 | 0 | 2020 | 1,107,975 | 32,762 | - | - | 2,288,221 | - | - | - |
| 4 | 0 | 2021 | 1,107,975 | 32,762 | - | - | 2,381,872 | - | - | - |
| 5 | 1 | 2022 | 1,107,975 | 32,762 | - | - | 2,383,489 | (2,383,489) | (1,786,532) | (1,786,532) |
| 6 | 2 | 2023 | 1,107,975 | 32,762 | - | - | 2,388,539 | (2,388,539) | (1,665,825) | (3,452,357) |
| 7 | 3 | 2024 | 1,107,975 | 32,762 | - | - | 2,396,947 | (2,396,947) | (1,555,446) | (5,007,803) |
| 8 | 4 | 2025 | 1,107,975 | 32,762 | - | - | 2,685,510 | (2,685,510) | (1,621,521) | (6,629,324) |
| 9 | 5 | 2026 | 1,107,975 | 32,762 | - | - | 2,694,661 | (2,694,661) | (1,513,908) | (8,143,232) |
| 10 | 6 | 2027 | 1,107,975 | 32,762 | - | - | 2,701,639 | (2,701,639) | (1,412,284) | (9,555,516) |
| 11 | 7 | 2028 | 1,107,975 | 32,762 | - | - | 2,714,797 | (2,714,797) | (1,320,479) | (10,875,995) |
| 12 | 8 | 2029 | 1,107,975 | 32,762 | - | - | 2,727,838 | (2,727,838) | (1,234,560) | (12,110,555) |
| 13 | 9 | 2030 | 1,107,975 | 32,762 | - | - | 2,734,591 | (2,734,591) | (1,151,557) | (13,262,112) |
| 14 | 10 | 2031 | 1,107,975 | 32,762 | - | - | 2,746,399 | (2,746,399) | (1,076,108) | (14,338,220) |
| 15 | 11 | 2032 | 1,107,975 | 32,762 | - | - | 2,749,842 | (2,749,842) | (1,002,535) | (15,340,755) |
| 16 | 12 | 2033 | 1,107,975 | 32,762 | - | - | 2,746,735 | (2,746,735) | (931,768) | (16,272,524) |
| 17 | 13 | 2034 | 1,107,975 | 32,762 | - | - | 2,743,778 | (2,743,778) | (866,043) | (17,138,567) |
| 18 | 14 | 2035 | 1,107,975 | 32,762 | - | - | 2,754,050 | (2,754,050) | (808,839) | (17,947,405) |
| 19 | 15 | 2036 | 1,107,975 | 32,762 | - | - | 2,764,054 | (2,764,054) | (755,329) | (18,702,734) |
| 20 | 16 | 2037 | 1,107,975 | 32,762 | - | - | 2,773,991 | (2,773,991) | (705,333) | (19,408,067) |
| 21 | 17 | 2038 | 1,107,975 | 32,762 | - | - | 2,801,127 | (2,801,127) | (662,706) | (20,070,773) |
| 22 | 18 | 2039 | 1,107,975 | 32,762 | - | - | 2,831,400 | (2,831,400) | (623,288) | (20,694,062) |
| 23 | 19 | 2040 | 1,107,975 | 32,762 | - | - | 2,864,335 | (2,864,335) | (586,693) | (21,280,755) |
| 24 | 20 | 2041 | 1,107,975 | 32,762 | - | - | 2,892,766 | (2,892,766) | (551,315) | (21,832,070) |
| 25 | 21 | 2042 | 1,107,975 | 32,762 | - | - | 2,923,000 | (2,923,000) | (518,340) | (22,350,410) |
| 26 | 22 | 2043 | 1,107,975 | 32,762 | - | - | 2,954,931 | (2,954,931) | (487,565) | (22,837,975) |
| 27 | 23 | 2044 | 1,107,975 | 32,762 | - | - | 2,988,449 | (2,988,449) | (458,808) | (23,296,783) |
| 28 | 24 | 2045 | 1,107,975 | 32,762 | - | - | 3,005,038 | (3,005,038) | (429,274) | (23,726,056) |
| 29 | 25 | 2046 | 1,107,975 | 32,762 | - | - | 3,022,060 | (3,022,060) | (401,686) | (24,127,742) |
| 30 | 26 | 2047 | 1,107,975 | 32,762 | - | - | 3,039,674 | (3,039,674) | (375,933) | (24,503,675) |
| 31 | 27 | 2048 | 1,107,975 | 32,762 | - | - | 3,057,542 | (3,057,542) | (351,848) | (24,855,523) |
| 32 | 28 | 2049 | 1,107,975 | 32,762 | - | - | 3,075,685 | (3,075,685) | (329,324) | (25,184,847) |
| 33 | 29 | 2050 | 1,107,975 | 32,762 | - | - | 3,094,504 | (3,094,504) | (308,299) | (25,493,146) |
| 34 | 30 | 2051 | 1,107,975 | 32,762 | - | - | 3,113,732 | (3,113,732) | (288,644) | (25,781,790) |
| 35 | 31 | 2052 | 1,107,975 | 32,762 | - | - | 3,133,909 | (3,133,909) | (270,313) | (26,052,103) |

Phase 1: RICE 2022

| Line | a | | ar<br>Net Revenue Requirement | as<br>Present Value Net Revenue Requirement | at<br>Accumulated Present Value |
|---|---|---|---|---|---|
| 1 | 0 | 2018 | - | - | - |
| 2 | 0 | 2019 | - | - | - |
| 3 | 0 | 2020 | - | - | - |
| 4 | 0 | 2021 | - | - | - |
| 5 | 1 | 2022 | 1,680,458 | 1,259,579 | 1,259,579 |
| 6 | 2 | 2023 | 3,607,146 | 2,515,711 | 3,775,290 |
| 7 | 3 | 2024 | 3,521,349 | 2,285,102 | 6,060,392 |
| 8 | 4 | 2025 | 3,160,157 | 1,908,115 | 7,968,507 |
| 9 | 5 | 2026 | 3,082,917 | 1,732,037 | 9,700,544 |
| 10 | 6 | 2027 | 3,012,191 | 1,574,626 | 11,275,169 |
| 11 | 7 | 2028 | 2,939,446 | 1,429,749 | 12,704,918 |
| 12 | 8 | 2029 | 2,870,814 | 1,299,268 | 14,004,185 |
| 13 | 9 | 2030 | 2,811,405 | 1,183,904 | 15,188,089 |
| 14 | 10 | 2031 | 2,748,725 | 1,077,020 | 16,265,109 |
| 15 | 11 | 2032 | 2,696,038 | 982,919 | 17,248,028 |
| 16 | 12 | 2033 | 2,651,569 | 899,486 | 18,147,514 |
| 17 | 13 | 2034 | 2,608,662 | 823,396 | 18,970,909 |
| 18 | 14 | 2035 | 2,554,282 | 750,169 | 19,721,078 |
| 19 | 15 | 2036 | 2,501,970 | 683,709 | 20,404,787 |
| 20 | 16 | 2037 | 2,451,572 | 623,352 | 21,028,139 |
| 21 | 17 | 2038 | 2,385,870 | 564,462 | 21,592,602 |
| 22 | 18 | 2039 | 2,318,972 | 510,485 | 22,103,087 |
| 23 | 19 | 2040 | 2,251,408 | 461,149 | 22,564,236 |
| 24 | 20 | 2041 | 2,190,390 | 417,453 | 22,981,690 |
| 25 | 21 | 2042 | 2,136,942 | 378,947 | 23,360,637 |
| 26 | 22 | 2043 | 2,098,492 | 346,252 | 23,706,889 |
| 27 | 23 | 2044 | 2,067,938 | 317,484 | 24,024,373 |
| 28 | 24 | 2045 | 2,056,574 | 293,784 | 24,318,158 |
| 29 | 25 | 2046 | 2,047,098 | 272,096 | 24,590,254 |
| 30 | 26 | 2047 | 2,039,411 | 252,225 | 24,842,479 |
| 31 | 27 | 2048 | 2,033,912 | 234,053 | 25,076,532 |
| 32 | 28 | 2049 | 2,030,642 | 217,428 | 25,293,960 |
| 33 | 29 | 2050 | 2,029,264 | 202,171 | 25,496,131 |
| 34 | 30 | 2051 | 2,030,112 | 188,192 | 25,684,323 |
| 35 | 31 | 2052 | (1,826,301) | (157,526) | 25,526,797 |

**CONFIDENTIAL**

# Exhibit A-11 (GRH-11)

# Solar PPA Revenue Requirement

| Line | Phase 4: HYDRO | a | b | c | d | e | f | g | h | i |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | Initial Investment | | | Tax Depreciation | | | | Deferre |
| | | | Capital Investment | Book Depreciation | Tax Depreciation Rate | Tax Depreciation | ITC Adj Tax Depreciation | Accumulated Tax Depreciation | Temporary Timing Difference | Deferred Taxes |
| 1 | 0 | 2018 | - | - | - | - | - | - | - | - |
| 2 | 1 | 2019 | 0 | 0 | 1.00000 | (0) | - | (0) | (0) | (0) |
| 3 | 2 | 2020 | - | 0 | - | - | - | (0) | 0 | 0 |
| 4 | 3 | 2021 | - | 0 | - | - | - | (0) | 0 | 0 |
| 5 | 4 | 2022 | - | 0 | - | - | - | (0) | 0 | 0 |
| 6 | 5 | 2023 | - | 0 | - | - | - | (0) | 0 | 0 |
| 7 | 6 | 2024 | | 0 | - | - | - | (0) | 0 | 0 |
| 8 | 7 | 2025 | | 0 | - | - | - | (0) | 0 | 0 |
| 9 | 8 | 2026 | | 0 | - | - | - | (0) | 0 | 0 |
| 10 | 9 | 2027 | | 0 | - | - | - | (0) | 0 | 0 |
| 11 | 10 | 2028 | | 0 | - | - | - | (0) | 0 | 0 |
| 12 | 11 | 2029 | | 0 | - | - | - | (0) | 0 | 0 |
| 13 | 12 | 2030 | | 0 | - | - | - | (0) | 0 | 0 |
| 14 | 13 | 2031 | | 0 | - | - | - | (0) | 0 | 0 |
| 15 | 14 | 2032 | | 0 | - | - | - | (0) | 0 | 0 |
| 16 | 15 | 2033 | | 0 | - | - | - | (0) | 0 | 0 |
| 17 | 16 | 2034 | | 0 | - | - | - | (0) | 0 | 0 |
| 18 | 17 | 2035 | | 0 | - | - | - | (0) | 0 | 0 |
| 19 | 18 | 2036 | | 0 | - | - | - | (0) | 0 | 0 |
| 20 | 19 | 2037 | | 0 | - | - | - | (0) | 0 | 0 |
| 21 | 20 | 2038 | | 0 | - | - | - | (0) | 0 | 0 |
| 22 | 21 | 2039 | | 0 | - | - | - | (0) | 0 | 0 |
| 23 | 22 | 2040 | | 0 | - | - | - | (0) | 0 | 0 |
| 24 | 23 | 2041 | | 0 | - | - | - | (0) | 0 | 0 |
| 25 | 24 | 2042 | | 0 | - | - | - | (0) | 0 | 0 |
| 26 | 25 | 2043 | | 0 | - | - | - | (0) | 0 | 0 |

Phase 4: HYDRO

| | a | j | k | l | m | n | o | p | q |
|---|---|---|---|---|---|---|---|---|---|
| | | d Taxes | | | | Rate Base | | | |
| | | Total Timing Difference | Accumulated Deferred Taxes | Cumulative Book Value | Accumulated Deferred Income Taxes | Accumulated Book Depreciation | Accumulated Def ITC | Rate Base Dec 31 | 13 Mo. Rolling Average |
| 0 | 2018 | - | - | - | - | - | - | - | - |
| 1 | 2019 | (0) | (0) | 0 | (0) | (0) | - | 0 | 0 |
| 2 | 2020 | (0) | (0) | 0 | (0) | (0) | - | 0 | 0 |
| 3 | 2021 | (0) | (0) | 0 | (0) | (0) | - | 0 | 0 |
| 4 | 2022 | (0) | (0) | 0 | (0) | (0) | - | 0 | 0 |
| 5 | 2023 | (0) | (0) | 0 | (0) | (0) | - | 0 | 0 |
| 6 | 2024 | (0) | (0) | 0 | (0) | (0) | - | 0 | 0 |
| 7 | 2025 | (0) | (0) | 0 | (0) | (0) | - | 0 | 0 |
| 8 | 2026 | (0) | (0) | 0 | (0) | (0) | - | 0 | 0 |
| 9 | 2027 | (0) | (0) | 0 | (0) | (0) | - | 0 | 0 |
| 10 | 2028 | (0) | (0) | 0 | (0) | (0) | - | 0 | 0 |
| 11 | 2029 | (0) | (0) | 0 | (0) | (0) | - | 0 | 0 |
| 12 | 2030 | (0) | (0) | 0 | (0) | (0) | - | 0 | 0 |
| 13 | 2031 | (0) | (0) | 0 | (0) | (0) | - | 0 | 0 |
| 14 | 2032 | (0) | (0) | 0 | (0) | (0) | - | 0 | 0 |
| 15 | 2033 | (0) | (0) | 0 | (0) | (0) | - | 0 | 0 |
| 16 | 2034 | (0) | (0) | 0 | (0) | (0) | - | 0 | 0 |
| 17 | 2035 | (0) | (0) | 0 | (0) | (0) | - | 0 | 0 |
| 18 | 2036 | (0) | (0) | 0 | (0) | (0) | - | 0 | 0 |
| 19 | 2037 | (0) | (0) | 0 | (0) | (0) | - | 0 | 0 |
| 20 | 2038 | (0) | (0) | 0 | (0) | (0) | - | 0 | 0 |
| 21 | 2039 | (0) | (0) | 0 | (0) | (0) | - | 0 | 0 |
| 22 | 2040 | (0) | (0) | 0 | (0) | (0) | - | 0 | 0 |
| 23 | 2041 | (0) | (0) | 0 | (0) | (0) | - | 0 | 0 |
| 24 | 2042 | (0) | (0) | 0 | (0) | (0) | - | 0 | 0 |
| 25 | 2043 | (0) | (0) | 0 | (0) | (0) | - | 0 | 0 |

Phase 4: HYDRO

| | a | r | s | t | u | v | w | x | y |
|---|---|---|---|---|---|---|---|---|---|
| | | **Return on Rate Base** | | | | | **Nominal Revenue Requirement** | | |
| | | **Debt Portion Before Tax** | **Common Portion After Tax** | **Return on Rate Base** | **Book Depreciation** | **Income Tax** | **Renewable Tax Credit** | **Variable O&M** | **Fixed O&M** |
| 0 | 2018 | - | - | - | - | - | - | - | - |
| 1 | 2019 | 0 | 0 | 0 | 0 | 0 | - | - | - |
| 2 | 2020 | 0 | 0 | 0 | 0 | 0 | - | - | - |
| 3 | 2021 | 0 | 0 | 0 | 0 | 0 | - | - | - |
| 4 | 2022 | 0 | 0 | 0 | 0 | 0 | - | - | - |
| 5 | 2023 | 0 | 0 | 0 | 0 | 0 | - | - | - |
| 6 | 2024 | 0 | 0 | 0 | 0 | 0 | - | - | - |
| 7 | 2025 | 0 | 0 | 0 | 0 | 0 | - | - | - |
| 8 | 2026 | 0 | 0 | 0 | 0 | 0 | - | - | - |
| 9 | 2027 | 0 | 0 | 0 | 0 | 0 | - | - | - |
| 10 | 2028 | 0 | 0 | 0 | 0 | 0 | - | - | - |
| 11 | 2029 | 0 | 0 | 0 | 0 | 0 | - | - | - |
| 12 | 2030 | 0 | 0 | 0 | 0 | 0 | - | - | - |
| 13 | 2031 | 0 | 0 | 0 | 0 | 0 | - | - | - |
| 14 | 2032 | 0 | 0 | 0 | 0 | 0 | - | - | - |
| 15 | 2033 | 0 | 0 | 0 | 0 | 0 | - | - | - |
| 16 | 2034 | 0 | 0 | 0 | 0 | 0 | - | - | - |
| 17 | 2035 | 0 | 0 | 0 | 0 | 0 | - | - | - |
| 18 | 2036 | 0 | 0 | 0 | 0 | 0 | - | - | - |
| 19 | 2037 | 0 | 0 | 0 | 0 | 0 | - | - | - |
| 20 | 2038 | 0 | 0 | 0 | 0 | 0 | - | - | - |
| 21 | 2039 | 0 | 0 | 0 | 0 | 0 | - | - | - |
| 22 | 2040 | 0 | 0 | 0 | 0 | 0 | - | - | - |
| 23 | 2041 | 0 | 0 | 0 | 0 | 0 | - | - | - |
| 24 | 2042 | 0 | 0 | 0 | 0 | 0 | - | - | - |
| 25 | 2043 | 0 | 0 | 0 | 0 | 0 | - | - | - |

Phase 4: HYDRO

| | a | z | aa | ab | ac | ad | | ae | af | ag |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Property Tax | Total Revenue Requirement | Discount Factor | Present Value Revenue Requirement | Accumulated Present Value | | Average LMP U-18094 | 10 Year Average Generation | Energy Cost Savings |
| 0 | 2018 | - | - | 1.00 | - | - | | - | - | - |
| 1 | 2019 | 0 | 0 | 0.93 | 0 | 0 | | - | - | - |
| 2 | 2020 | 0 | 0 | 0.87 | 0 | 0 | | - | - | - |
| 3 | 2021 | 0 | 0 | 0.81 | 0 | 0 | | - | - | - |
| 4 | 2022 | 0 | 0 | 0.75 | 0 | | | - | - | - |
| 5 | 2023 | 0 | 0 | 0.70 | 0 | | | - | - | - |
| 6 | 2024 | 0 | 0 | 0.65 | 0 | | | - | - | - |
| 7 | 2025 | 0 | 0 | 0.60 | 0 | | | - | - | - |
| 8 | 2026 | 0 | 0 | 0.56 | 0 | | | - | - | - |
| 9 | 2027 | 0 | 0 | 0.52 | 0 | | | - | - | - |
| 10 | 2028 | 0 | 0 | 0.49 | 0 | | | - | - | - |
| 11 | 2029 | 0 | 0 | 0.45 | 0 | | | - | - | - |
| 12 | 2030 | 0 | 0 | 0.42 | 0 | | | - | - | - |
| 13 | 2031 | 0 | 0 | 0.39 | 0 | | | - | - | - |
| 14 | 2032 | 0 | 0 | 0.36 | 0 | | | - | - | - |
| 15 | 2033 | 0 | 0 | 0.34 | 0 | | | - | - | - |
| 16 | 2034 | 0 | 0 | 0.32 | 0 | | | - | - | - |
| 17 | 2035 | 0 | 0 | 0.29 | 0 | | | - | - | - |
| 18 | 2036 | 0 | 0 | 0.27 | 0 | | | - | - | - |
| 19 | 2037 | 0 | 0 | 0.25 | 0 | | | - | - | - |
| 20 | 2038 | 0 | 0 | 0.24 | 0 | | | - | - | - |
| 21 | 2039 | 0 | 0 | 0.22 | 0 | | | - | - | - |
| 22 | 2040 | 0 | 0 | 0.20 | 0 | | | - | - | - |
| 23 | 2041 | 0 | 0 | 0.19 | 0 | 0 | | - | - | - |
| 24 | 2042 | 0 | 0 | 0.18 | 0 | 0 | | - | - | - |
| 25 | 2043 | 0 | 0 | 0.17 | 0 | 0 | | - | - | - |

| Phase 4: HYDRO | a | ah | ai | aj | ak | al | am | an | ao |
|---|---|---|---|---|---|---|---|---|---|
| | | Avoided PSCR Costs | | | | | | | |
| | | **Capacity Value** | **$/MW-year** | **Capacity Cost Savings** | **RECs** | **Value of RECs** | **REC Savings** | **Total PSCR Savings** | **PSCR Savings** |
| 0 | 2018 | **7.68** | 59,250 | 455,040 | **-** | **-** | - | 455,040 | - |
| 1 | 2019 | 7.68 | 59,250 | 455,040 | - | - | - | 455,040 | (455,040) |
| 2 | 2020 | 7.68 | 59,250 | 455,040 | - | - | - | 455,040 | (455,040) |
| 3 | 2021 | 7.68 | 59,250 | 455,040 | - | - | - | 455,040 | (455,040) |
| 4 | 2022 | 7.68 | 59,250 | 455,040 | - | - | - | 455,040 | (455,040) |
| 5 | 2023 | 7.68 | 59,250 | 455,040 | - | - | - | 455,040 | (455,040) |
| 6 | 2024 | 7.68 | 59,250 | 455,040 | - | - | - | 455,040 | (455,040) |
| 7 | 2025 | 7.68 | 59,250 | 455,040 | - | - | - | 455,040 | (455,040) |
| 8 | 2026 | 7.68 | 59,250 | 455,040 | - | - | - | 455,040 | (455,040) |
| 9 | 2027 | 7.68 | 59,250 | 455,040 | - | - | - | 455,040 | (455,040) |
| 10 | 2028 | 7.68 | 59,250 | 455,040 | - | - | - | 455,040 | (455,040) |
| 11 | 2029 | 7.68 | 59,250 | 455,040 | - | - | - | 455,040 | (455,040) |
| 12 | 2030 | 7.68 | 59,250 | 455,040 | - | - | - | 455,040 | (455,040) |
| 13 | 2031 | 7.68 | 59,250 | 455,040 | - | - | - | 455,040 | (455,040) |
| 14 | 2032 | 7.68 | 59,250 | 455,040 | - | - | - | 455,040 | (455,040) |
| 15 | 2033 | 7.68 | 59,250 | 455,040 | - | - | - | 455,040 | (455,040) |
| 16 | 2034 | 7.68 | 59,250 | 455,040 | - | - | - | 455,040 | (455,040) |
| 17 | 2035 | 7.68 | 59,250 | 455,040 | - | - | - | 455,040 | (455,040) |
| 18 | 2036 | 7.68 | 59,250 | 455,040 | - | - | - | 455,040 | (455,040) |
| 19 | 2037 | 7.68 | 59,250 | 455,040 | - | - | - | 455,040 | (455,040) |
| 20 | 2038 | 7.68 | 59,250 | 455,040 | - | - | - | 455,040 | (455,040) |
| 21 | 2039 | 7.68 | 59,250 | 455,040 | - | - | - | 455,040 | (455,040) |
| 22 | 2040 | 7.68 | 59,250 | 455,040 | - | - | - | 455,040 | (455,040) |
| 23 | 2041 | 7.68 | 59,250 | 455,040 | - | - | - | 455,040 | (455,040) |
| 24 | 2042 | 7.68 | 59,250 | 455,040 | - | - | - | 455,040 | (455,040) |
| 25 | 2043 | 7.68 | 59,250 | 455,040 | - | - | - | 455,040 | (455,040) |

Hydro Capacity Revenue Requirement



Phase 4: HYDRO

| | a | ap | aq | ar | as | at |
|---|---|---|---|---|---|---|
| | | **Present Value PSCR Savings** | **Accumulated Present Value** | **Net Revenue Requirement** | **Present Value Net Revenue Requirement** | **Accumulated Present Value** |
| 0 | 2018 | - | - | - | - | - |
| 1 | 2019 | (423,398) | (423,398) | (455,040) | (423,398) | (423,398) |
| 2 | 2020 | (393,957) | (817,355) | (455,040) | (393,957) | (817,355) |
| 3 | 2021 | (366,562) | (1,183,917) | (455,040) | (366,562) | (1,183,917) |
| 4 | 2022 | (341,073) | (1,524,990) | (455,040) | (341,073) | (1,524,990) |
| 5 | 2023 | (317,356) | (1,842,346) | (455,040) | (317,356) | (1,842,346) |
| 6 | 2024 | (295,288) | (2,137,634) | (455,040) | (295,288) | (2,137,634) |
| 7 | 2025 | (274,755) | (2,412,389) | (455,040) | (274,755) | (2,412,389) |
| 8 | 2026 | (255,649) | (2,668,039) | (455,040) | (255,649) | (2,668,039) |
| 9 | 2027 | (237,873) | (2,905,911) | (455,040) | (237,873) | (2,905,911) |
| 10 | 2028 | (221,332) | (3,127,243) | (455,040) | (221,332) | (3,127,243) |
| 11 | 2029 | (205,941) | (3,333,184) | (455,040) | (205,941) | (3,333,184) |
| 12 | 2030 | (191,621) | (3,524,805) | (455,040) | (191,621) | (3,524,805) |
| 13 | 2031 | (178,296) | (3,703,101) | (455,040) | (178,296) | (3,703,101) |
| 14 | 2032 | (165,898) | (3,868,999) | (455,040) | (165,898) | (3,868,999) |
| 15 | 2033 | (154,362) | (4,023,361) | (455,040) | (154,362) | (4,023,361) |
| 16 | 2034 | (143,628) | (4,166,990) | (455,040) | (143,628) | (4,166,990) |
| 17 | 2035 | (133,641) | (4,300,631) | (455,040) | (133,641) | (4,300,631) |
| 18 | 2036 | (124,348) | (4,424,979) | (455,040) | (124,348) | (4,424,979) |
| 19 | 2037 | (115,701) | (4,540,680) | (455,040) | (115,701) | (4,540,680) |
| 20 | 2038 | (107,656) | (4,648,336) | (455,040) | (107,656) | (4,648,336) |
| 21 | 2039 | (100,170) | (4,748,506) | (455,040) | (100,170) | (4,748,506) |
| 22 | 2040 | (93,204) | (4,841,710) | (455,040) | (93,204) | (4,841,710) |
| 23 | 2041 | (86,723) | (4,928,434) | (455,040) | (86,723) | (4,928,434) |
| 24 | 2042 | (80,693) | (5,009,127) | (455,040) | (80,693) | (5,009,127) |
| 25 | 2043 | (75,082) | (5,084,208) | (455,040) | (75,082) | (5,084,208) |

**STATE OF MICHIGAN**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

*** * * * ***

| | | |
|---|---|---|
| In the matter of the application of | ) | |
| **UPPER PENINSULA POWER COMPANY** | ) | |
| for approval of its integrated resource plan | ) | Case No. U-20350 |
| pursuant to MCL 460.6t and for other relief. | ) | |

**DIRECT TESTIMONY AND EXHIBITS OF**

**ERIC W. STOCKING**

**FOR**

**UPPER PENINSULA POWER COMPANY**

**February 12, 2019**

Q. Please state your name, business address, and the name of your employer for the record.

A. My name is Eric W. Stocking. My business address is 1002 Harbor Hills Drive, Marquette, Michigan 49855. I am employed by Upper Peninsula Power Company ("UPPCO" or the "Company").

Q. Please describe your job responsibilities.

A. I am UPPCO's Rate Analyst within the Regulatory Affairs department. My responsibilities in this role include analytical support of a wide variety of issues touching several aspects of UPPCO's business, including power supply, resource planning, wholesale power purchasing strategy, cost of service and rate design, sales and peak demand forecasting, and Renewable Portfolio Standard ("RPS") compliance analysis.

Q. Briefly describe your educational background and applicable professional experience.

A. I graduated from Michigan State University in 2009 with a Bachelor of Science in Economics. In February 2010, I entered into employment with the Michigan Public Service Commission ("MPSC") Staff as an Economic Analyst in the Generation and Certificate with responsibilities related to generation resource adequacy, load forecasting, integrated resource planning, capacity expansion modeling, and utility capital investment related to compliance with Federal and State air quality regulations. In the Fall of 2016, I took on the role of Economic Specialist in the Resource Adequacy and Retail Choice area of the MPSC staff, where I played an active role in the implementation of several aspects of PA 341 & 342 of 2016, including the State Reliability Mechanism and Integrated Resource Planning. In November of 2017, I left my employment with the MPSC Staff and moved into my current role at UPPCO.

Q. Have you previously testified before the MPSC?

A. Yes. I have provided testimony in several cases before the Commission, on behalf of UPPCO as well as the MPSC Staff.

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

A. The purpose of my testimony is to present UPPCO's analysis and discussion regarding the following topics:

1. The development of the Company's electric sales and peak demand forecast for the IRP analysis period of 2019 – 2037.
2. UPPCO's Current Power Supply Procurement Strategy, Resource Adequacy, and Risk Mitigation.
3. PURPA Avoided Cost Review.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring the following Exhibits:

Exhibit A-13 (EWS-1) Resource Adequacy Template

Exhibit A-14 (EWS-2) Parallel Generation – Purchase by UPPCO PG-4

Exhibit A-15 (EWS-3) Capacity Contract

Exhibit A-16 (EWS-4) LMP Forecast

Exhibit A-17 (EWS-5) ATC Reliability Memorandum

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

A. Yes, they were.

## 1. Sales and Peak Demand Forecast

Q. Please explain how the Company's long-term sales forecast was developed for use in this IRP.

A. Given recent actions taken to combine the Integrated and Iron River systems into combined tariff units, both systems were forecasted in tandem. The Residential forecast utilizes two regression models, a monthly customer count projection and a monthly use-per-customer model. Both models include seasonal customers and sales. The historical period utilized as a basis for the projection is January 1, 2013 through December 31, 2017. The customer count projection is based on a regression analysis of the historical monthly trend in the number of residential customers. The use-per-customer forecast is based on a regression model, utilizing seasonal, weather related, and autoregressive variables to project average residential customer usage.

The Commercial forecast utilizes two regression models, a customer model and a use-per-customer model. The models use historical data from January 2013 – December 2017, and exclude Company use sales. The customer forecast is based on a regression analysis of the historical monthly trend in the number of commercial customers within the service territory, excluding those served by an Alternative Energy Supplier ("AES"). The use-per-customer model is based on a regression model, utilizing seasonal, weather-related, and autoregressive variables to project average commercial customer usage.

The Industrial forecast utilizes a use-per-customer regression model. The model uses historical data from January 2013 – December 2017. The customer forecast is based on the historical trend in the number of commercial customers within the service territory, excluding those served by an AES. The use-per-customer model is based on a regression model, utilizing seasonal, weather-related, Producer Price Index, and autoregressive variables to project average commercial customer usage.

Company Use is based on a regression model utilizing historical Company Use sales as a percentage of total sales.

Given the Company's intent to embark on a large-scale replacement of its existing Sodium Vapor and Metal Halide lighting fixtures to LED, I determined that it was not reasonable to project future lighting sales based on a regression analysis of relatively static historical usage levels. At its most basic level, total lighting sales can be approximated as a function of the following:

- Total number of lighting fixtures deployed, by type and wattage.
- Total wattage consumed by each fixture type, per hour.
- Lighting burn rate in hours, by month per year.

By applying the detailed fixture replacement plan that is set to commence over the next three years, I developed a year-over-year savings profile and applied it to known actual 2017 lighting sales volumes. This savings profile is applied for each of the three years in which UPPCO intends to undertake this large-scale conversion to LED public lighting, and reflects the savings that will ultimately be realized by this customer class. Upon completion of the LED fixture replacement program, lighting sales are expected to remain static throughout the forecast period.

Q. Are the effects of Energy Waste Reduction ("EWR") included in the sales forecast presented here?

A. No. For the purposes of establishing the sales projections in this IRP proceeding, the Company added back historical kWh savings attributable to its EWR program. The regression models were run on this adjusted data set, such that the future trend does not include the discrete effects of historical EWR savings on total energy sales.

Q. Please explain the basis for the Company's treatment of EWR in this IRP filing.

A. Given the desire for UPPCO and other parties to utilize the IRP proceedings as a venue to evaluate the economic benefit of EWR in relation to all other resource alternatives, it is necessary to isolate EWR savings from future sales projections.  Neglecting to account for EWR savings in this manner will skew the future total requirements forecast utilized in IRP analyses, such that some level of EWR savings will be assumed without accounting for the cost to administer and implement the program.

Q. Please explain how the demand forecast was developed for the 2019 test year.

A. Peak demand is forecasted using a regression analysis of historical peak kilowatt ("kW") to monthly kilowatt-hour ("kWh") sales, along with weather and seasonal explanatory variables.

Q. What weather and temperature assumptions were made in the development of the Company's sales and peak demand projection?

A. UPPCO used a 10-year average of actual monthly weather observations at KI Sawyer International Airport, as reported by the National Oceanic and Atmospheric Administration ("NOAA") between the years of 2007 – 2018 as the basis for assumed future weather characteristics utilized in the forecast.

Q. Please summarize the results of these efforts.

A. An annual summary of the energy and firm peak demand requirements for the UPPCO system is provided below.  Once again, the sales volumes here are intended to encompass the total sales volumes that would have otherwise occurred absent any EWR program savings.  Within the context of the IRP modeling performed by Black & Veatch, EWR savings are accounted for through additions to the total resource portfolio.

**Figure 1**

| Year | Base Case Forecast: Energy Forecast (MWh, Before EWR) | Base Case Forecast: Peak Demand (MW) | 1.5% Load Growth (High Growth Case): Energy Forecast (MWh, Before EWR) | 1.5% Load Growth (High Growth Case): Peak Demand (MW) | -1.5% Load Growth (Grid Defection Case): Energy Forecast (MWh, Before EWR) | -1.5% Load Growth (Grid Defection Case): Peak Demand (MW) |
|---|---|---|---|---|---|---|
| **2018** | 554,079.01 | 86.47 | 566,732.89 | 89.20 | 550,105.94 | 86.58 |
| **2019** | 562,599.83 | 85.57 | 575,233.88 | 90.54 | 541,976.30 | 85.30 |
| **2020** | 560,478.57 | 84.67 | 583,862.39 | 91.90 | 533,966.79 | 84.04 |
| **2021** | 558,306.18 | 83.78 | 592,620.33 | 93.27 | 526,075.66 | 82.80 |
| **2022** | 557,946.46 | 82.89 | 601,509.63 | 94.67 | 518,301.14 | 81.58 |
| **2023** | 555,773.78 | 81.99 | 610,532.28 | 96.09 | 510,641.52 | 80.37 |
| **2024** | 553,601.74 | 81.10 | 619,690.26 | 97.53 | 503,095.09 | 79.18 |
| **2025** | 551,429.11 | 80.21 | 628,985.61 | 99.00 | 495,660.19 | 78.01 |
| **2026** | 549,236.69 | 79.32 | 638,420.40 | 100.48 | 488,335.16 | 76.86 |
| **2027** | 547,024.45 | 78.42 | 647,996.70 | 101.99 | 481,118.39 | 75.72 |
| **2028** | 544,829.34 | 78.42 | 657,716.65 | 103.52 | 474,008.26 | 74.61 |
| **2029** | 544,829.34 | 78.42 | 667,582.40 | 105.07 | 467,003.22 | 73.50 |
| **2030** | 544,829.34 | 78.42 | 677,596.14 | 106.65 | 460,101.69 | 72.42 |
| **2031** | 544,829.34 | 78.42 | 687,760.08 | 108.25 | 453,302.16 | 71.35 |
| **2032** | 544,829.34 | 78.42 | 698,076.48 | 109.87 | 446,603.11 | 70.29 |
| **2033** | 544,829.34 | 78.42 | 708,547.63 | 111.52 | 440,003.06 | 69.25 |
| **2034** | 544,829.34 | 78.42 | 719,175.85 | 113.19 | 433,500.56 | 68.23 |
| **2035** | 544,829.34 | 78.42 | 729,963.48 | 114.89 | 427,094.14 | 67.22 |
| **2036** | 544,829.34 | 78.42 | 740,912.94 | 116.61 | 420,782.41 | 66.23 |
| **2037** | 544,829.34 | 78.42 | 752,026.63 | 118.36 | 414,563.95 | 65.25 |
| **2038** | 544,829.34 | 78.42 | 763,307.03 | 120.14 | 408,437.39 | 64.28 |

2. **<u>UPPCO's Current Power Supply Procurement Strategy, Resource Adequacy, and Portfolio Risk Mitigation.</u>**

Q. Please describe the resources currently available to the Company for the generation of energy ultimately delivered to retail customers.

A. UPPCO owns four small hydroelectric plants that are utilized for PSCR purposes. These units constitute a total net capability of about 16 MW. All plants operate with limited capability to store water. In a normal year, these plants may operate at approximately a 50% utilization factor. Since hydro is currently UPPCO's resource with the lowest variable operation and maintenance cost, its operation is used to minimize costs from other supply resources. In addition, the Company owns two oil-fired combustion turbine units. These units are rarely dispatched economically, and therefore provide little to no energy value for customers. However, these units have historically provided a significant portion of the capacity that UPPCO relies upon to meet its resource adequacy requirements, both in terms of MISO Module E and State Reliability Mechanism ("SRM") requirements.

Q. Are there any fundamental changes to the Company's current resource portfolio that are reflected in this IRP submittal?

A. Yes. As discussed further by Company Witness David Tripp, the Company has experienced mechanical issues at each of its two, 40+ year old oil-fired combustion turbine units within the last 8 months. While the decision was made to repair the identified mechanical deficiency for the Gladstone unit, returning it to service in early 2019, the fate of the Portage unit is less certain. Given the extensive nature of the mechanical failure at the Portage facility, at this time the Company expects to retire the Portage facility in 2019. Repair investigations and discussions with the Company's insurance carrier are ongoing as of the date of this filing.

Additionally, and also explained by Company Witness Tripp in further detail, the Company recently undertook a project at its Hoist and McClure hydroelectric units, whereby the Company estimates that it will gain the benefit of an additional 7.6 Zonal Resource Credits ("ZRC") of capacity, at essentially zero cost to its ratepayers. The Hoist and McClure project is viewed by the Company as a key portion of its multi-faceted, diverse resource portfolio approach, whereby in addition to evaluating a wide spectrum of resource alternatives to meets its total obligations, UPPCO is also looking to optimize the assets that it currently owns to maximize customer benefit.

Q. On average, what percentage of total energy requirements are provided by Company-owned generation facilities.

A. Output from the Company's four hydroelectric units comprises approximately 20% of the energy that is ultimately delivered to retail customers, not inclusive of sales to the RTMP rate class. RTMP sales are purchased solely on the MISO real-time market, per the tariff definition.

Q. How does the Company currently procure the remaining 80% of its total energy requirements?

A. The Company currently procures the remaining 80% of the energy that it ultimately delivers to its retail customers through two long-term power purchase agreements with U.P. Hydro, LLC., various short-term fixed price market contracts, and purchases from the MISO day-ahead and real-time energy markets.

Q. Please describe the power purchase agreements with U.P. Hydro, LLC.

A. On July 8, 2010, UPPCO closed on the sale of its Au Train hydroelectric project with U.P. Hydro, LLC. Additionally, on February 2, 2011, UPPCO closed on the sale of its Cataract hydroelectric facility with U.P. Hydro, LLC. UPPCO signed the PPAs with U.P. Hydro for all output of the Au Train and Cataract facilities, for a term of ten (10) years from the commencement of commercial operation for each facility. Under the terms of these PPAs, UPPCO retained the rights to the Renewable Energy Credits ("RECs"), which UPPCO will use to meet its renewable energy standard. For the 2019 calendar year, the energy and renewable attributes of the Au Train and Cataract hydroelectric facilities are priced at \$80.89 and \$78.54 per MWh, respectively, escalating by at least 3.0 percent each year. This contract allows UPPCO to hedge a small portion of its power supply portfolio into the future, while contributing to its ability to continue to be in compliance with the renewable energy standard. The terms for these two long-term PPA's expire in 2020 and 2025 for Au Train and Cataract, respectively.

Q. Why are the existing ten-year PPAs with U.P. Hydro LLC reasonable and prudent?

A. The longer term PPAs with U.P. Hydro LLC are reasonable and prudent for the following reasons:

1) The PPAs enabled the Au Train and Cataract Sales Agreements to be completed, avoiding other higher cost options to upgrade or abandon the two facilities.

2) The PPA purchase price for renewable energy was reasonable at the time it was signed relative to market prices for renewable energy and the related RECs that help meet UPPCO's renewable energy requirements over the lives of the agreements.

3) The PPAs add price certainty to a portion of UPPCO's power supply resources on a longer-term basis.

Q. Does UPPCO expect to renew the long-term PPA's with U.P. Hydro, LLC.?

A. Based upon the current contract rates, UPPCO does not anticipate a renewal of the U.P. Hydro, LLC. PPA's, as the contract pricing exceeds the cost of procuring energy and capacity from several alternatives.

Q. Please describe the "various short-term fixed price market contracts" currently utilized to procure a portion of the Company's total energy requirements.

A. Through a blind, reverse auction process administered by a third party, UPPCO currently looks to hedge a significant portion of its expected total PSCR energy requirement with firm, fixed price contracts over the following three years. By staggering several short-term contracts, in various amounts and timeframes over some future time period, UPPCO manages its significant market exposure by "locking-in" prices for a known amount of MWh. This entire strategy hinges on the plan to purchase small amounts of energy over the near-term, thereby mitigating risk of being forced into purchasing hedge products when the market does not bear favorable prices.

Q. Why does UPPCO purchase energy via short-term energy supply agreements versus simply purchasing from the MISO market?

A. UPPCO's participation in the MISO market subjects it to price risk due to fluctuations in the energy market. In order to reduce UPPCO customers' exposure to energy price fluctuations to an acceptable level, UPPCO purchases a certain amount of its energy requirements at fixed prices for a specific term.

Q. How does UPPCO determine the amount of energy that it will purchase under short-term contracts?

A. UPPCO employs a diverse portfolio approach, whereby a portion of UPPCO's power supply is served by the following: (1) Company-owned generation, (2) long term power purchase agreements, (3) short term power purchase agreements, and (4) purchases made in the MISO market. Forecasted sales, excluding RTMP sales, are broken down into hourly load profiles based on historic customer usage patterns. By definition, RTMP sales are purchased based on the actual LMP, therefore, UPPCO does not take these sales into consideration when looking to define the quantity of energy that should be purchased via short term agreements. Owned generation, based on historic hourly generation curves, and long-term power purchase agreements are then utilized to serve the hourly forecasted sales. The quantity of short-term power purchased is determined by attempting to minimize the amount of energy subject to daily or hourly price volatility, while taking advantage of currently low forward energy prices for UPPCO customers. Purchasing too much energy exposes UPPCO to making sales to the MISO market during times of low demand and potentially low prices that could result in sales at a loss. Purchasing too little energy exposes UPPCO to purchasing from the MISO market during times of high demand and potentially high prices. UPPCO reviews the level of energy requirements exposed to the market price volatility to identify an amount of purchases that may be warranted. If there is an exposure that warrants locking in pricing with a short-term purchase, UPPCO evaluates the current market conditions to determine if the expected price of the energy purchase is in a range that would result in a reduction in the overall volatility of the PSCR costs as a whole.

Q. Do the short-term contract purchases guarantee the lowest overall power supply cost for UPPCO's customers?

A. No, but neither would purchasing all of UPPCO's energy requirements from the MISO market. Actual market prices may be higher or lower than fixed price short-term purchases; however, fixed price purchases create price certainty by reducing the exposure to potentially volatile market prices. UPPCO's proposed Solar PPA and RICE build accomplish a similar objective to historic short-term contract purchases, namely providing UPPCO customers with a hedge against uncertain future market volatility.

Q. What factors could cause MISO market prices to increase significantly?

A. Suppliers to the MISO market could experience higher market prices for natural gas and/or coal used as fuel for generation, which could cause the market prices for power to be significantly higher than forecasted. Planned or unplanned outages of low-cost generation, generating unit retirements, or transmission outages in the MISO market could also significantly increase market prices for power. With these considerations, UPPCO currently chooses to limit its exposure to the MISO market with fixed price short-term purchases.

Q. Please provide a breakdown of the average market hedge value provided by each of the Company's current sources of electric energy, as a percentage of total non-RTMP energy requirements.

A. Company-owned hydroelectric generation plus long-term PPA's with U.P. Hydro LLC. constitute 20% of total energy requirements, assuming 10-year average generation figures. UPPCO typically plans to purchase short-term fixed price wholesale contracts to encompass an additional 70-75% hedge against market volatility, leaving 5-10% of the Company's total non-RTMP energy requirement exposed to the day-ahead and real-time MISO energy markets.

Q. Are the Company's short-term contracts completely isolated from market volatility?

A. No. Several factors can affect the future energy contract prices yielded by a reverse auction process.

Q. What factors could cause volatility in the bid prices received in a reverse auction for energy products?

A. Many of the same factors that drive volatility in the day-ahead and real-time MISO energy markets can cause the bid prices received through an auction prices to be higher than expected. Short and long-term natural gas price expectations, emerging market conditions, generating unit retirements, transmission outages, and even the date of the auction can all have an effect on the prices ultimately received. While the Company plans its auctions strategically to minimize the uncertainty surrounding many of these factors, the effects of these and other market conditions are largely outside of UPPCO's control.

Q. What level of market exposure do UPPCO customers bear for market capacity purchases?

A. Due to the requirements inherent within the State Reliability Mechanism ("SRM"), Michigan utilities are required to demonstrate that they own or have contractual rights to sufficient capacity resources to meet their need four years into the future. As such, UPPCO entered into a contract with Wisconsin Power and Light (WP&L) to purchase 25MWs of capacity through the 2019/20 planning year. With the termination of the WPS Corp contract in 2017, UPPCO forecasted that it would need approximately 25 MWs of additional capacity to comply with the MISO resource adequacy and SRM requirements in planning years 2018/19 and 2019/20. Similarly, UPPCO has entered into a contract with Dairyland Power Cooperative ("Dairyland") to purchase 20MWs of capacity in planning years 2020/21 and 2021/22.

In light of the likely retirement of the Portage facility, as well as uncertainty related to the continued operation of the 40+ year old Gladstone facility, UPPCO customers could be exposed to capacity market volatility for up to 56 Zonal Resource Credits ("ZRC") in the coming years. The expiration of the U.P. Hydro, LLC PPA's constitute an additional future capacity need of 1 ZRC.

Q. What factors could cause volatility in the capacity market?

A. Several factors can influence the price obtained for future capacity contracts, aside from normal market fluctuations. Zonal resource adequacy projections, such as the annual OMS-MISO Resource Adequacy survey can often provide an outlook on the relative scarcity of capacity resources that could be available in a given year. If a particular zone is expected to be deficient in relation to its zonal Planning Reserve Margin Requirement ("PRMR") or its Local Clearing Requirement ("LCR"), then one could expect to pay a premium for any capacity contract. The potential for a locational requirement that is tied to the SRM requirements of a particular zone would likely yield a premium to be paid for any capacity contract, due to an increased demand for a discrete amount of resources, at least until such time that additional generating resources can be built.

Q. What is the resource adequacy outlook for Local Resource Zone ("LRZ") 2, as published in the 2018 OMS-MISO Survey?

A. For planning year 2019, the survey results indicate that LRZ 2 is expected to have 100-200MW of surplus capacity in excess of the amount needed to satisfy its 1 day in 10-year loss of load expectation requirements. In planning year 2023, LRZ 2 is expected to be between 100 MW short and 400 MW long on its capacity requirements, depending on whether currently planned resource additions come to fruition as scheduled.

Q. Please describe the Company's Preferred Course of Action ("PCA").

A. UPPCO looks to hedge its customers against future market volatility, and replace the capacity lost by the retirement of its two oil-fired combustion turbine units with a Solar PPA (125 MW), a new RICE unit (up to 20 MW), additional capacity resources from its existing Hoist and McClure hydroelectric generating facilities, and Energy Waste Reduction. UPPCO asserts that by implementing its multi-faceted resource portfolio approach, its customers will receive reliable, low-cost energy that is adequately hedged against future market price volatility. UPPCO's PCA is explained by Company Witness Gradon Haehnel.

Q. Please generally describe the benefits of the Solar PPA and the RICE build, in terms of economic benefit in relation to the Company's current avoided cost, and market risk mitigation.

A. The Solar PPA replaces a significant portion of the short-term market energy purchases that UPPCO would otherwise procure on an annual basis at some unknown future rate, at an economically beneficial fixed price for 25 years. As such, the Solar PPA provides a significant hedge against on-peak day-ahead market pricing, which would typically command a pricing premium against off-peak or nighttime contracts.

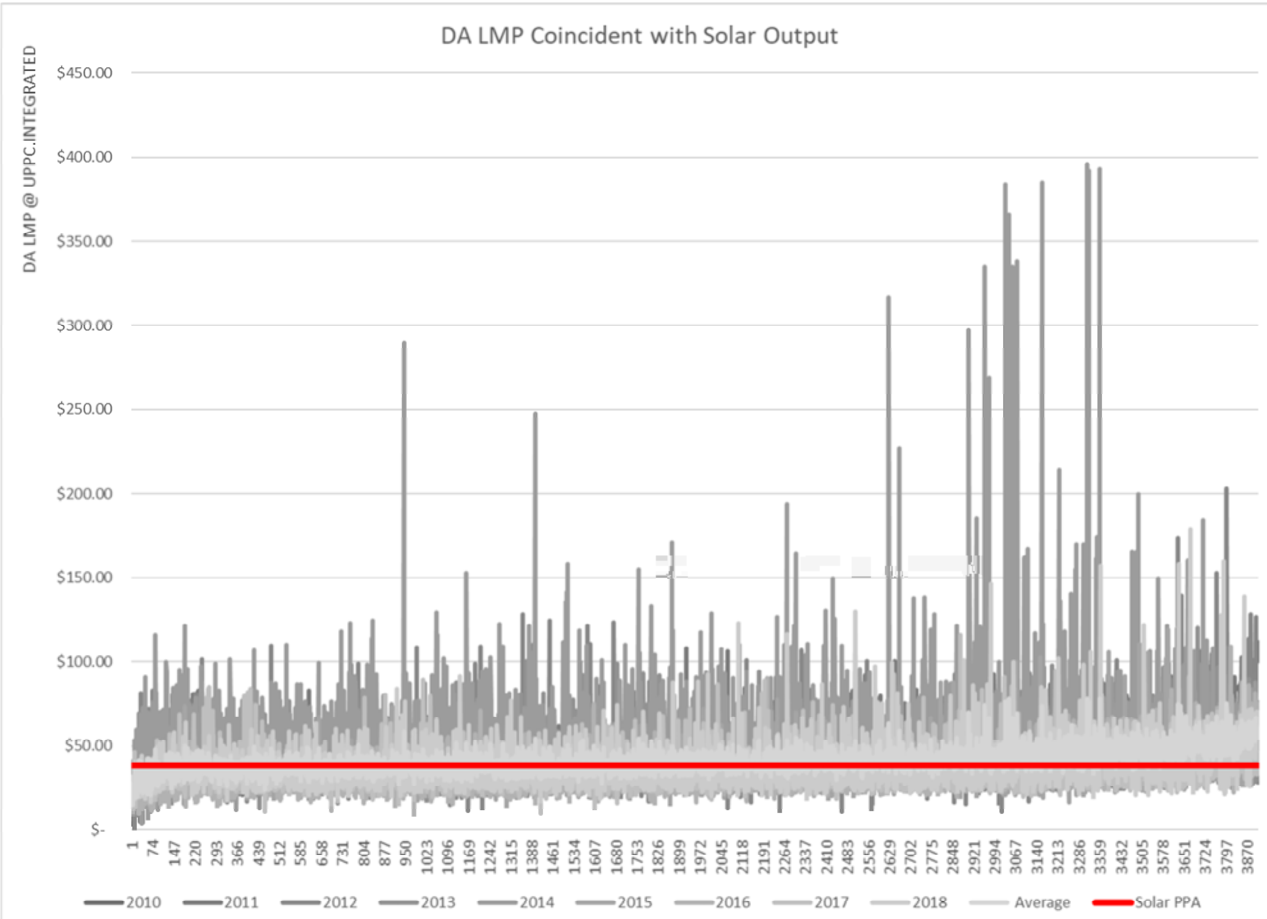
The proposed RICE build also provides a hedge against future market volatility, in that it isolates UPPCO's customers from incremental market purchases at times of high LMP. As discussed previously, several factors can contribute to elevated day-ahead or real-time LMP's that are largely outside of the Company's control. Additionally, the proposed RICE build also provides for increased operational flexibility of the transmission system, such that thermal loading and voltage profiles can be more effectively managed.

Q. What other benefit does the Solar PPA provide UPPCO, other than future price certainty?

A. Currently, UPPCO is highly dependent on market energy purchases. As such, any fluctuation in that market pricing, regardless of whether the energy is acquired through reverse auction or from the Day-Ahead or Real-Time market, will yield a proportionate impact on the PSCR costs to UPPCO customers. The Company is continually looking to isolate its customers from the effects of unfavorable pricing conditions.

Hourly solar generation profiles often align closely with market pricing trends. As such, the Company's proposal to enter into a long-term, fixed price PPA for a solar facility will tend to isolate the Company from the necessity of buying a significant amount of energy from, potentially, unfavorable spot-market energy prices. Figure 2 below provides an annual summary of the average hourly LMP that is coincident with energy production from the proposed solar facility, in relation to the known Solar PPA rate. These values are based on actual, Day-Ahead LMP values for the UPPC.INTEGRATED pricing node.

**Figure 2**




Q. Are there any hours in Figure 2 that are less-costly than the Solar PPA?

A. Yes. Similar to the previous discussion of the hedge value obtained from short-term, fixed price energy contracts, this strategy does not guarantee that spot-market energy prices will be higher than the cost of the Solar PPA; however, this strategy will bolster future price certainty by reducing the exposure to potentially volatile market prices. Furthermore, the correlation between expected solar output and elevated market energy prices (as seen in Chart 2) provides a reasonable expectation that the Solar PPA will serve to mitigate future market price uncertainty.

Q. Has the Company included, as a part of its IRP filing, an analysis of the risks associated with various future outcomes, and commodity pricing?

A. Yes. Section 11 of the B&V Report, included as Exhibit A-1 (GRH-1) provides a summary of the sensitivity analyses performed, as well as a stochastic risk assessment of the future disposition of natural gas commodity pricing.

Q. Are there any other benefits to the proposed Solar PPA?

A. Yes. Over time, and as energy storage technology becomes more prevalent and economic at the utility scale, this technology provides significant additional benefit to a large solar application. UPPCO sees its PCA in this IRP as expandable, whereby in future proceedings the Company will look to closely evaluate the economics of storage and other emerging technologies, in an effort to further leverage the many benefits of solar energy. Recently, Michigan Technological University and the City of Negaunee announced that they are collaborating on a pilot study to determine if abandoned mines can be profitably converted into utility-scale batteries (hydroelectric pumped-storage), thereby storing energy for retail customers. This is but one example of the impending change in the national energy landscape, which could yield long-term, positive benefits to utility customers.

Q. Does the proposed RICE build offer any market hedge value to UPPCO customers?

A. Yes. As stated previously, natural gas pricing and market energy pricing are generally thought of to be highly correlated. Therefore, any natural gas-fired generating unit will not provide a complete hedge against energy market pricing. However, as evidenced by recent approvals to build new natural gas-fired, dispatchable generating resources in Michigan as well as elsewhere in the MISO footprint, these resources provide necessary redundant capacity to the growing volume of renewable energy generating facilities in MISO. The hedge value provided by RICE, or other natural gas-fired dispatchable resources, is a hedge against the factors that cause market price volatility <u>other</u> than natural gas prices.

The characteristics of a natural gas-fired RICE unit complement a resource portfolio that is increasingly saturated with renewable generation. Dispatchable units with expedient start-up times and quick ramping rates allow system operators to closely match the total system demand to the amount of resources that available to meet this demand, thereby reducing the potential for large variability in LMP pricing.

Q. What amount of ZRC's would UPPCO expect to obtain through the Solar PPA to meet its resource adequacy requirements?

A. The regional average effective load carrying capability ("ELCC") for solar facilities is 50%. Simply put, until such time that a particular solar facility has sufficient data to measure its average contribution to the MISO coincident peak, it is assumed that the facility will be at 50% output at the peak hour. Therefore, for the full 125MW solar PPA, UPPCO assumes that it will be credited with 62.5 ZRC for the first three years. Once the Solar facility has been in service long enough to utilize actual hourly output to determine its ELCC, the Company expects this value to decline slightly, due to the latitude of the project in relation to the rest of the MISO footprint.

Q. What amount of ZRC's would UPPCO expect to obtain through the RICE project to meet its resource adequacy requirements?

A. UPPCO would expect that the ZRC's attributed to a modern, efficient natural gas-fired RICE unit to approach the unit's nameplate capability, of up to 20 MW.

Q. Please provide a resource adequacy outlook, incorporating all aspects of the Company's IRP as filed.

A. Please see Exhibit A-13 (EWS-1) Resource Adequacy Template.

Q. As illustrated in Exhibit A-13 (EWS-1), why does UPPCO plan to maintain a capacity surplus throughout the timeframe evaluated by this IRP?

A. The reason for this is a product of the disparity between UPPCO's energy and capacity market exposure. Due to the large amount of the Company's peak demand requirements that are satisfied through demand response resources, UPPCO's overall capacity deficit is significantly less than its energy deficit. Moreover, due to the competitive pricing that resulted from the Company's RFP processes, UPPCO is looking to provide a long-term, low cost hedge against energy and capacity market volatility to the benefit of its PSCR customers. In order to take advantage of the significant amount of economic energy market hedge presented by the Solar PPA, UPPCO finds itself with an outlook including a capacity surplus. In any given year, excess capacity can be sold through contract or offered into the MISO Planning Resource Auction, providing additional benefit to UPPCO's PSCR customers.

Q. Are there any other benefits associated with the proposed RICE build?

A. Yes. Following the April 1, 2018 anchor strike that impacted ATC's inter-peninsular submarine cables at the Straits of Mackinac, MISO sought stakeholder input while deliberating MTEP 2018 ID No. 15145 (Mackinac – McGulpin 138kV Cable Replacement project). During these deliberations, ATC informed stakeholders of certain risks attributable to the loss of the remaining 138kV submarine circuit under several North American Electric Reliability Council (NERC) Transmission System Planning Performance (TPL) requirements. UPPCO believes the RICE project helps mitigate certain contingent loss-of-load risks that were articulated by ATC during the MTEP 2018 process.

Additionally, MISO commissioned its Michigan Exploratory Transmission study on August 17, 2016, at the request of Governor Rick Snyder and the Michigan Agency for Energy. The study was completed to conduct a near and long-term regional evaluation of potential production cost savings, reliability and resource adequacy benefits of adding additional transmission and generation resources in the eastern portion of Michigan's Upper Peninsula and norther Lower Peninsula. This indicative study concluded, in part, that dispatchable, natural gas-fired generating resources located in the region would provide reliability benefits that were comparable to the transmission alternatives that were studied.

Q. Why is UPPCO targeting ________________ for the location of its proposed RICE facility?

A. ________________ provides a unique opportunity to construct new dispatchable, natural gas-fired generating resources at the southeast corner of UPPCO's service territory, leveraging existing natural gas supply infrastructure, 69kV and 138kV electric transmission infrastructure, and vacant land. Additionally, this locale presents considerable opportunity for expansion by UPPCO or through collaboration with other Load Serving Entities (LSEs) or Independent Power Producers (IPPs) to effectively mitigate reliability issues (voltage and/or thermal) that may exist in the central and eastern Upper Peninsula.

Q. What reliability issues are mitigated by the RICE facility?

A. UPPCO's proposed dispatchable RICE generating unit provides voltage and local reliability support and greater operational flexibility alleviating potential voltage excursions and thermal loadings attributable to the limitations of the existing electric transmission infrastructure that currently serves the area.

Q. Has the Company had any discussions with ATC or MISO related to the proposed RICE build at ________________?

A. UPPCO has discussed the RICE project with ATC and MISO and participated in a Generation Information Ad Hoc Information Session.

Q. Has ATC made any comments with respect to UPPCO's proposed RICE project?

A. Yes. Please refer to Exhibit A-17 (EWS-5).

Q. Please briefly summarize the reliability benefit that is provided by the RICE build.

A. Interconnecting new dispatchable generation to the existing 69kV "Inland Line" in the vicinity of ________ provides greater operational flexibility, mitigates thermal loadings and voltage excursions and reduces system losses attributable to the lower operating voltages. Furthermore, this project could be expanded in the future creating additional benefits attributable to new generation capacity in the central and eastern portions of Michigan's Upper Peninsula.

3. **<u>PURPA Avoided Cost</u>**

Q. Why is UPPCO addressing the issue of PURPA avoided costs in its IRP filing?

A. Pursuant to the Order issued on September 28, 2017 in Case No. U-18094, UPPCO was scheduled to file its next PURPA review application by February 1, 2019. After discussions with Staff, as well as considering the Commission's words in its October 5, 2018 Order in Case No. U-20095 UPPCO filed a motion to extend the filing deadline for its PURPA review to accommodate its inclusion in the IRP filing. The Commission approved the Company's motion in its Order on February 7, 2019 in Case No. U-18094.

Q. What is the definition of "avoided cost" in the context of PURPA?

A. PURPA Regulations (18 CFR 292.101(b)(6)) define avoided costs as the following:

"Avoided costs means the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself ***or purchase*** from another source." [emphasis added].

Q. Based on this definition of avoided costs, how should the Commission determine UPPCO's avoided costs?

A. According to the definition of avoided costs above, and consistent with the Commission's directive in its previous PURPA avoided cost review, UPPCO's avoided capacity cost should be set at a level equal to the Company's contracted capacity price at the time the PURPA contract is entered into, with an adjustment for effective load carrying capability applied to the qualifying facility ("QF"). For energy payments, UPPCO's avoided cost should be based on the actual LMP at the time of delivery, or based on forecasted LMP, at the option of the QF. This calculation is the most efficient means to derive the true cost of the incremental energy and capacity that UPPCO would look to purchase to satisfy its total energy requirements, until such time that the Company's resource portfolio becomes substantially different than it is today. Since the Federal Energy Regulatory Commission ("FERC") acknowledges that the avoided costs can be based on the utility's costs to self-generate with incremental resources, or purchase from another source, it is appropriate to align the avoided cost set in this proceeding with the expected cost of the incremental energy and capacity that would be purchased by UPPCO, but for the purchase from the QF.

Q. Please describe the Company's current capacity contracts.

A. As evidenced by Exhibit A-15 (EWS-3), the Company has currently contracted with Dairyland Power Cooperative to provide 20 MW of capacity in planning years 2020/21 and 2021/22 at a cost of $15,000/MW-year and $20,000/MW-year, respectively

Q. What is UPPCO's proposal regarding the capacity payment to QF's.

A. Consistent with the outcome in Case No. U-18094, UPPCO proposes that capacity payments under the standard offer contract should be the avoided capacity cost should be equal to the contracted capacity cost in the year that the PURPA contract is entered into, adjusted for the effective load carrying capability that is applied to the QF. If the Commission determines that UPPCO has satisfied its requirement to demonstrate that it has adequate capacity to serve its requirements over a 10-year planning horizon, then the Company should not be obligated to purchase capacity from the QF.

Q. What is UPPCO's proposal for the proposed capacity cap on the QF standard offer?

A. UPPCO's proposal is to set the QF standard offer cap at 500 kW. This is consistent with other Michigan utilities of comparable size as UPPCO.

Q. What is UPPCO's proposal regarding energy payment to QF's.

A. Consistent with the outcome of U-18094, energy payments should be based on the hourly LMP at the time of delivery, or based on forecasted LMP, at the option of the QF. Similarly, the Standard Offer contract terms for five, 10, 15, and 20 years, at the option of the QF, should be based on the average forecasted LMP for each time horizon, respectively.

Q. Has UPPCO submitted a 20-year forecast of LMP's to use as a basis for the avoided energy cost?

A. Yes. Please see Exhibit A-16 (EWS-4).

Q. Is this LMP forecast the equal to the base assumptions utilized in the production-cost and capacity expansion modeling efforts performed by B&V, as described by Exhibit A-1 (GRH-1)?

A. Yes.

Q. How was this LMP Forecast derived?

A. The LMP forecast was developed utilizing the PROMOD IV cost model. As stated in section 2.1 of Exhibit A-1 (GRH-1):

"Black & Veatch utilizes a fundamental market model and key assumptions of energy efficiency trends, fuel price forecast, reliability concerns, emission prices, and other sensitivities, to forecast future wholesale market prices. The fundamental market model is created by using the PROMOD IV cost model, which allows Black & Veatch to look at hourly production costs to project costs to meet power supply needs, which includes assumptions on long-term planning for hourly loads, economically dispatching units based on hour generation output and costs, and chronological constraints, such as ramp rates."

Q. Does the LMP forecast provided here constitute a reasonable expectation of future average LMP prices?

A. Yes.

Q. Is the avoided energy payment methodology proposed by UPPCO in this proceeding consistent with the outcome of the last case?

A. Yes. As evidenced by the discussion of the Company's current reliance on purchased capacity and energy, it is clear that UPPCO's circumstances related to true avoided costs are largely similar to those that existed at the time of the Commission's September 28, 2017 Order in Case No. U-18094. Further, UPPCO contends that the biennial review schedule of PURPA avoided costs is intended o closely align PURPA avoided cost rates with the actual costs experienced by a Company at that point in time, thereby allowing for timely calibration of the avoided cost to changing market conditions, changes in the utilities resource portfolio, and any other potentially unexpected circumstances.

Q. Are you proposing any tariff changes based on UPPCO's proposed avoided cost rates as discussed above?

A. Yes. UPPCO is proposing to modify its existing Parallel Generation-Purchase Tariff as presented in Exhibit A-14 (EWS-2) to be consistent with the positions taken by the Company in this proceeding.

Q. Does this proposed tariff meet the Federal Energy Regulatory Commission's requirements to comply with the Public Utilities Regulatory Policies Act?

A. Yes. The Parallel Generation-Purchase Tariff allows a QF to sell energy and capacity to UPPCO at non-discriminatory rates that are set through a competitive bidding process, to interconnect with UPPCO and operate in parallel with established standards and other generating resource. The PG-4 tariff also provides the standard offer tariff avoided cost rates at which UPPCO would pay the QF for delivered energy and capacity.

Q. Does this complete your direct testimony?

A. Yes, it does.

**Planning Reserve Margin Requirements and Planning Resources to be Acquired (ZRC)**

| | (a) | (b) | (c) | (d) | (e) | (e) | (e) | (e) | (e) | (e) | (e) | (e) | (e) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Line** | | **PY 2019-2020** | **PY 2020-2021** | **PY 2021-2022** | **PY 2022-2023** | **PY 2023-2024** | **PY 2024-2025** | **PY 2025-2026** | **PY 2026-2027** | **PY 2027-2028** | **PY 2028-2029** | **PY 2029-2030** | **PY 2030-2031** |
| 1 | Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW (from Ex. 1) | 133.2 | 133.2 | 133.2 | 133.2 | 133.2 | 133.2 | 133.2 | 133.2 | 133.2 | 133.2 | 133.2 | 133.2 |
| 2 | Internal Demand Response Programs that are applied as an adjustment to the Peak forecast, MW | - | - | - | - | - | - | - | - | - | - | - | - |
| 3 | Adjusted Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW (line 1 - line 2) | 133.2 | 133.2 | 133.2 | 133.2 | 133.2 | 133.2 | 133.2 | 133.2 | 133.2 | 133.2 | 133.2 | 133.2 |
| 4 | Load Diversity Factor coincident to MISO, %. | 86.04% | 86.04% | 86.04% | 86.04% | 86.04% | 86.04% | 86.04% | 86.04% | 86.04% | 86.04% | 86.04% | 86.04% |
| 5 | Adjusted Forecasted Bundled (or AES) Coincident Peak Demand, MW (line 3 x line 4) | 115 | 115 | 115 | 115 | 115 | 115 | 115 | 115 | 115 | 115 | 115 | 115 |
| 6 | Transmission Losses, % | 1.40% | 1.40% | 1.40% | 1.40% | 1.40% | 1.40% | 1.40% | 1.40% | 1.40% | 1.40% | 1.40% | 1.40% |
| 7 | Planning Reserve Margin % UCAP Basis | 7.90% | 8.00% | 8.00% | 8.10% | 8.10% | 8.10% | 8.10% | 8.10% | 8.10% | 8.10% | 8.10% | 8.10% |
| 8 | Total Planning Reserve Margin Requirement, ZRC ((line 5) x (1 + line 6) x (1 + line 7)) | 125 | 125 | 125 | 126 | 126 | 126 | 126 | 126 | 126 | 126 | 126 | 126 |
| 9 | Company Owned, In-State, Non-Intermittent, ZRC | 17 | 17 | 17 | 35 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 |
| 10 | Company Owned, Out-of-State, Non-Intermittent, ZRC | - | - | - | - | - | - | - | - | - | - | - | - |
| 11 | Company Owned, In-State, Non-Intermittent (BTMG), ZRC | - | - | - | - | - | - | - | - | - | - | - | - |
| 12 | Company Owned, Out-of-State, Non-Intermittent (BTMG), ZRC | - | - | - | - | - | - | - | - | - | - | - | - |
| 13 | Company Owned, In-State, Intermittent, ZRC | 16 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 |
| 14 | Company Owned, Out-of-State, Intermittent, ZRC | - | - | - | - | - | - | - | - | - | - | - | - |
| 15 | Company Owned, In-State, Intermittent (BTMG), ZRC | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 16 | Company Owned, Out-of-State, Intermittent (BTMG), ZRC | - | - | - | - | - | - | - | - | - | - | - | - |
| 17 | Total Company Owned Generation, ZRC (sum of lines 9-16) | 33 | 39 | 39 | 57 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 |
| 18 | Total Load Modifying Resources, Treated as Capacity, ZRC (from Ex. 4) | 59 | 59 | 59 | 59 | 59 | 59 | 59 | 59 | 59 | 59 | 59 | 59 |
| 19 | PPA, In-State, Non-Intermittent, ZRC | - | - | - | - | - | - | - | - | - | - | - | - |
| 20 | PPA, Out-of-State, Non-Intermittent, ZRC | - | - | - | - | - | - | - | - | - | - | - | - |
| 21 | PPA, In-State, Non-Intermittent (BTMG), ZRC | - | - | - | - | - | - | - | - | - | - | - | - |
| 22 | PPA, Out-of-State, Non-Intermittent (BTMG), ZRC | - | - | - | - | - | - | - | - | - | - | - | - |
| 23 | PPA, In-State, Intermittent, ZRC | - | - | - | - | - | - | - | - | - | - | - | - |
| 24 | PPA, Out-of-State, Intermittent, ZRC | - | - | - | - | - | - | - | - | - | - | - | - |
| 25 | PPA, In-State, Intermittent (BTMG), ZRC | - | - | - | - | - | - | - | - | - | - | - | - |
| 26 | PPA, Out-of-State, Intermittent (BTMG), ZRC | - | - | - | - | - | - | - | - | - | - | - | - |
| 27 | Other Forward Capacity Contract, ZRC - In-State | 1 | 1 | 1 | 63 | 62 | 62 | 50 | 50 | 50 | 50 | 50 | 50 |
| 28 | Other Forward Capacity Contract, ZRC - Out-of-State | 25 | 20 | 20 | - | - | - | - | - | - | - | - | - |
| 29 | Total PPA, ZRC (sum of lines 19-28) | 26 | 21 | 21 | 63 | 62 | 62 | 50 | 50 | 50 | 50 | 50 | 50 |
| 30 | Total Planning Resources, ZRC (line 17 + line 18 + line 29) | 119 | 119 | 119 | 179 | 162 | 162 | 150 | 150 | 150 | 150 | 150 | 150 |
| 31 | UCAP Surplus/(Shortfall), MW (line 30 - line 8) | (7) | (6) | (6) | 53 | 36 | 36 | 24 | 24 | 24 | 24 | 24 | 24 |

## Demand Response - Capacity Resources

| ( a ) | ( b ) Demand Response Program Name | ( c ) Demand Response Program (MW) | ( d ) Credit Transmission Losses and PRM $_{UCAP}$ | ( e ) Total ZRC per Program Name |
|---|---|---|---|---|
| **PY 2019-UCAP** | CP-U with Interruptible Rider | 19.3 | 1.956 | 21.3 |
| | Real Time Market Pricing Tariff | 34.4 | 3.486 | 37.9 |
| | | | | - |
| | | | | - |
| | | | | - |
| | | | | - |
| | | | | - |
| | | | | - |
| | | | | - |
| **Total Demand Response - Capacity Resources PY 2019-2020 (ZRC)** | | | | 59.1 |
| **PY 2020-UCAP** | CP-U with Interruptible Rider | 19.3 | 1.956 | 21.3 |
| | Real Time Market Pricing Tariff | 34.4 | 3.486 | 37.9 |
| | | | | - |
| | | | | - |
| | | | | - |
| | | | | - |
| | | | | - |
| | | | | - |
| | | | | - |
| **Total Demand Response - Capacity Resources PY 2020-2021 (ZRC)** | | | | 59.1 |
| **PY 2021-UCAP** | CP-U with Interruptible Rider | 19.3 | 1.956 | 21.3 |
| | Real Time Market Pricing Tariff | 34.4 | 3.486 | 37.9 |
| | | | | - |
| | | | | - |
| | | | | - |
| | | | | - |
| | | | | - |
| | | | | - |
| | | | | - |
| **Total Demand Response - Capacity Resources PY 2021-2022 (ZRC)** | | | | 59.1 |
| **PY 2022-UCAP** | CP-U with Interruptible Rider | 19.3 | 1.956 | 21.3 |
| | Real Time Market Pricing Tariff | 34.4 | 3.486 | 37.9 |
| | | | | - |
| | | | | - |
| | | | | - |
| | | | | - |
| | | | | - |
| | | | | - |
| | | | | - |
| **Total Demand Response - Capacity Resources PY 2022-2023 (ZRC)** | | | | 59.1 |

## Company Owned Electric Generation Resources

| | ( a ) | ( b ) | ( c ) | ( m ) | ( n ) | ( o ) | ( p ) | ( q ) | ( r ) | ( s ) | ( t ) | ( u ) | ( v ) | ( w ) | ( x ) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Fuel or | Location of Resource: | | | | | | UCAP MW (ZRC) | | | | | | |
| Line | Electric Generation Unit Name | Renewable Type | LRZ 1, LRZ 2, LRZ 7, PJM, Other | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| 1 | Portage CT | Fuel Oil | LRZ 2 | - | - | - | - | - | - | - | - | - | - | - | - |
| 2 | Gladstone CT | Fuel Oil | LRZ 2 | 16.6 | 16.6 | 16.6 | 16.6 | - | - | - | - | - | - | - | - |
| 3 | Victoria Hydro | Hydro | LRZ 2 | 10.9 | 10.9 | 10.9 | 10.9 | 10.9 | 10.9 | 10.9 | 10.9 | 10.9 | 10.9 | 10.9 | 10.9 |
| 4 | McClure Hydro | Hydro | LRZ 2 | 3.6 | 7.8 | 7.8 | 7.8 | 7.8 | 7.8 | 7.8 | 7.8 | 7.8 | 7.8 | 7.8 | 7.8 |
| 5 | Prickett Hydro | Hydro | LRZ 2 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 |
| 6 | Hoist Hydro | Hydro | LRZ 2 | 1.4 | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 |
| 7 | New RICE | Natural Gas | LRZ 2 | | | | 18.0 | 18.0 | 18.0 | 18.0 | 18.0 | 18.0 | 18.0 | 18.0 | 18.0 |
| 8 | | | | - | - | - | | | | | | | | | |
| 9 | | | | | | | | | | | | | | | |
| 10 | | | | | | | | | | | | | | | |
| 65 | | | | 17 | 17 | 17 | 35 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 |
| 66 | | | | - | - | - | - | - | - | - | - | - | - | - | - |
| 67 | | | | - | - | - | - | - | - | - | - | - | - | - | - |
| 68 | | | | - | - | - | - | - | - | - | - | - | - | - | - |
| 69 | | | | 16 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 |
| 70 | | | | - | - | - | - | - | - | - | - | - | - | - | - |
| 71 | | | | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 72 | | | | - | - | - | - | - | - | - | - | - | - | - | - |
| 73 | | | | 33 | 39 | 39 | 57 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 |
| | | | | - | - | - | - | - | - | - | - | - | - | - | - |

**Generation Resources Under PPA or Other Capacity Contract**

| | ( a ) | ( b ) | ( c ) | ( d ) | ( e ) | ( f ) | ( g ) | ( h ) | ( i ) | ( n ) | ( o ) | ( p ) | ( q ) | ( q ) | ( r ) | ( s ) | ( t ) | ( u ) | ( v ) | ( w ) | ( x ) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Fuel or | Specify: | Located in | Intermittent | PA 295 | BTMG | PURPA | Other Bilateral | UCAP MW Contracted (ZRC) | | | | | | | | | | | |
| Line | Electric Generator Name | Renewable Type | LRZ 1, LRZ 2, LRZ 7, PJM, Other | Michigan Y/N | Resource (Y/N) | Y/N | Y/N | Y/N | PPA Y/N | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| 1 | 2018/19-2019/20 ZRC Purchase | N/A | LRZ 2 | N | N | N | N | N | Y | 25 | 0 | 0 | 0 | | | | | | | | |
| 2 | 2020/21-2021/22 ZRC Purchase | N/A | LRZ 2 | N | N | N | N | N | Y | | 20 | 20 | 0 | | | | | | | | |
| 3 | Autrain Hydro | Hydro | LRZ 2 | Y | Y | Y | Y | N | Y | 1 | 0 | 0 | 0 | | | | | | | | |
| 4 | Cataract Hydro | Hydro | LRZ 2 | Y | Y | Y | Y | N | Y | 1 | 1 | 1 | 1 | | | | | | | | |
| 5 | Solar PPA | Solar | LRZ 2 | Y | Y | Y | N | N | Y | 0 | 0 | 0 | 62 | 62.0 | 62.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 |
| 6 | | | | | | | | | | | | | | | | | | | | | |
| 7 | | | | | | | | | | | | | | | | | | | | | |
| 8 | | | | | | | | | | | | | | | | | | | | | |
| 9 | | | | | | | | | | | | | | | | | | | | | |
| 10 | | | | | | | | | | | | | | | | | | | | | |
| 11 | | | | | | | | | | | | | | | | | | | | | |
| 12 | | | | | | | | | PPA, In-State, Non-Intermittent, ZRC | - | - | - | - | - | - | - | - | - | - | - | - |
| 13 | | | | | | | | | PPA, Out-of-State, Non-Intermittent, ZRC | - | - | - | - | - | - | - | - | - | - | - | - |
| 14 | | | | | | | | | PPA, In-State, Non-Intermittent (BTMG), ZRC | - | - | - | - | - | - | - | - | - | - | - | - |
| 15 | | | | | | | | | PPA, Out-of-State, Non-Intermittent (BTMG), ZRC | - | - | - | - | - | - | - | - | - | - | - | - |
| 16 | | | | | | | | | PPA, In-State, Intermittent, ZRC | - | - | - | - | - | - | - | - | - | - | - | - |
| 17 | | | | | | | | | PPA, Out-of-State, Intermittent, ZRC | - | - | - | - | - | - | - | - | - | - | - | - |
| 18 | | | | | | | | | PPA, In-State, Intermittent (BTMG), ZRC | - | - | - | - | - | - | - | - | - | - | - | - |
| 19 | | | | | | | | | PPA, Out-of-State, Intermittent (BTMG), ZRC | - | - | - | - | - | - | - | - | - | - | - | - |
| 20 | | | | | | | | | Other Forward Capacity Contract, ZRC - In-State | 1.4 | 0.5 | 0.5 | 62.5 | 62.0 | 62.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 |
| 21 | | | | | | | | | Other Forward Capacity Contract, ZRC - Out-of-State | 25 | 20 | 20 | - | - | - | - | - | - | - | - | - |
| 22 | | | | | | | | | Total PPA, ZRC (sum of lines 1-64) | 26.4 | 20.5 | 20.5 | 62.5 | 62.0 | 62.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 |
| 23 | | | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | CHECK | - | - | - | - | - | - | - | - | - | - | - | - |

UPPER PENINSULA POWER COMPANY

MPSC Vol No 8-ELECTRIC — 8th Revised Sheet No. D-72.70
Replaces 7th Revised Sheet No. D-72.70

**D2. Parallel Generation – Purchase by UPPCO** **PG-4**

EFFECTIVE IN
All territory served.

AVAILABILITY
To customers contracting for electric service who satisfy the requirements of "qualifying facility" status under Part 292 of the Federal Energy Regulatory Commission's regulations under the Public Utility Regulatory Policies Act of 1978, generating electrical energy with total customer owned generating capacity of 1 MW AC or less, and desiring to sell electrical energy to the Company. To qualify for this service, a seller shall execute a standard Power Purchase Agreement with the Company. Customers with generation capacity greater than 1 MW may negotiate with the Company for rates other than specified in this rate schedule. Customers with generation capacity of 150 KW or less have the option of selling energy to the Company under the Pg-2 tariff or the Pg-1M tariff for customers with generator ratings that do not exceed 20 KW. Customers may take service under PG-3 if the requirements are met for methane digesters.

Service hereunder shall be restricted to the Company's purchase of energy or energy and capacity from the seller's generating facilities up to the Contract Capacity specified in the Power Purchase Agreement which may be operated in parallel with the Company's system. Power delivered to the Company shall not offset or be substituted for power contracted for, or which may be contracted for, under any other schedule of the Company. If a seller requires supplemental, back-up, or standby services, the seller shall enter into a separate service agreement with the Company in accordance with the Company's applicable electric rates and Service Regulations approved by the Michigan Public Service Commission.

MONTHLY RATES
Customer Charge:
For total customer owned generating capacity of under 200 KW: Standard applicable rate schedule Customer Charge.

For total customer owned generating capacity of 200 KW and greater:

| | Secondary | Primary | Transmission |
|---|---|---|---|
| Monthly: | $250.00 | $325.00 | $750.00 |
| Daily: | $8.2192 | $10.6849 | $24.6575 |

Charges for Deliveries from Company
Deliveries from the Company to the customer shall be billed in accordance with the standard applicable rate schedules of the Company.

Energy and Capacity Rate

Energy – For all energy supplied by the customer, the customer shall receive an energy payment equal to one of the rate options below, as selected by the customer and applicable for the term of the special offer contract:

Continued to Sheet No. D-72.71

Issued: XX-XX-XXXX
By G R Haehnel
Director of Regulatory Affairs
Marquette, Michigan

Effective for Service
On and After: XX-XX-XX
Issued Under Auth. of
Mich Public Serv Comm
Dated: XX-XX-XX
In Case No: U-20350

UPPER PENINSULA POWER COMPANY

MPSC Vol No 8-ELECTRIC

2nd Revised Sheet No. D-72.71
Replaces 1st Revised Sheet No. D-72.71

**D2. Parallel Generation – Purchase by UPPCO** **PG-4**

Continued from Sheet No. D-72.70

| **Rate Option** | **Energy Rate $/kWh** |
|---|---|
| 1. As Available Rate | Actual MISO Day Ahead Locational Marginal Price (LMP) at the Company’s UPPC.INTEGRATED load node, adjusted to reflect reduced line losses according to the distribution line voltage level at the project interconnection point, less the Administrative Fee of $0.001/kWh. |

| | |
|---|---|
| 2. LMP Energy Rate Forecast* | MISO Real Time Locational Marginal Price (LMP) at the Company’s UPPCO.INTEGRATED load node, adjusted to reflect reduced line losses according to the distribution line voltage level at the project interconnection point, less the Administrative Fee of $0.001/kWh. |

| Contract Term | 5 Years | | 10 Years | | 15 Years | | 20 Years | |
|---|---|---|---|---|---|---|---|---|
| | On-Peak | Off-Peak | On-Peak | Off-Peak | On-Peak | Off-Peak | On-Peak | Off-Peak |
| | $.03050~~4422~~ | $.02670~~3127~~ | $.03093~~4729~~ | $.02764~~3374~~ | $.03185~~4948~~ | $.02877~~3549~~ | $.03371~~5057~~ | $.03067~~3636~~ |

Capacity –
Capacity value for intermittent resources is based on MISO zonal resource credits (ZRCs). Capacity value paid to QFs does not depend on whether the Company actually obtains ZRCs for such capacity, only that the Company could obtain ZRCs for the QF capacity. Capacity value paid to a QF is in units of $/ZRC-Month. MISO ZRCs are equal to the project’s nameplate capacity (in MW AC) modified by the MISO effective load carrying capacity (ELCC) calculation.

The MISO ELCC calculation method shall be set for the term of the QF contract according to the MISO Business Practices Manual (BPM) calculation method effective at the time of the QF contract execution.

The currently effective ELCC calculation is provided in MISO BPM-011-r16 § 4.2.3, which recognizes capacity based on accumulated, historical performance.

The current resource planning period is the planning year which runs from June 1st of each year through May 31st of the following year. If no historical generation data is available for the first year of generation a QF shall be assigned the MISO class average capacity credits by technology.

Payments shall be reduced by any applicable monthly Interconnection Cost.

Capacity Payment

| **Year** | **Capacity Payment** |
|---|---|
| 2019~~2017~~ | $3,000/ZRC-Month~~$2,100/ZRC-Month~~ |
| 2020~~18~~ | $~~2,500~~1,250/ZRC-Month |
| 2021~~18~~ and After | $1,667~~3,000~~/ZRC-Month |

Continued to Sheet No. D-72.72

Issued: XX-XX-XXXX
By G R Haehnel
Director of Regulatory Affairs
Marquette, Michigan

Effective for Service
On and After: XX-XX-XX
Issued Under Auth. of
Mich Public Serv Comm

Dated: XX-XX-XX
In Case No: U-20350

UPPER PENINSULA POWER COMPANY

MPSC Vol No 8-ELECTRIC

2nd Revised Sheet No. D-72.72
Replaces 1st Revised Sheet No. D-72.72

**D2. Parallel Generation – Purchase by UPPCO** **PG-4**

Continued from Sheet No. D-72.71

Renewable Premium: At the Company's sole discretion, a premium to be paid on a per kWh basis may be applied to generators that generate a renewable credit that is transferred to the Company. Customers retain the right to refuse a renewable premium and keep the renewable credits or tags. Premiums are to be set when the contract is signed and will not change during the contract period.

Distribution Loss Factors: The following factors shall be applied to the on-peak and off-peak energy factors and capacity payments to reflect system losses:

| | |
|---|---|
| Customers metered at a transmission voltage of 50,000 volts or higher: | 1.0350 |
| Customers metered at a primary voltage of 4,160 volts – 50,000 volts: | 1.0550 |
| Customers metered at a secondary voltage of less than 4,160 volts: | 1.0322 |

ON-PEAK HOURS

Hours Ending 0800 through 2300 Eastern Prevailing Time Monday through Friday excluding NERC holidays.

OFF-PEAK HOURS
All hours not listed as on-peak hours.

HOLIDAYS
The days of the year which are considered holidays are: New Year's Day, Memorial Day, Fourth of July, Labor Day, Thanksgiving Day, Christmas Day.

MINIMUM CHARGE
The monthly minimum charge shall be the customer charge.

SERVICE COMPATIBILITY
The customer must generate electric power at the same characteristics, voltage, current and frequency, and number of phases as the customer receives service from the Company and will be subject to the same electric service rules as are the general service customers of the Company.

CONTRACT
The Company will require a contract specifying technical and operating aspects of parallel generation. Customers have the right to appeal to the Michigan Public Service Commission if they believe the contract required by the Company is unreasonable.

EXECUTION OF STANDARD CONTRACT
In Order to execute the Standard Contract, the Seller must complete all of the general project information requested in the applicable Standard Contract. When all information required in the Standard Contract has been received in writing from the Seller, the Company will use best efforts to respond within 15 business days with a draft Standard Contract.

Continued to Sheet D-72.73

Issued: XX-XX-XXXX
By G R Haehnel
Director of Regulatory Affairs

Effective for Service
On and After: XX-XX-XX
Issued Under Auth. of

Marquette, Michigan

Mich Public Serv Comm
Dated: XX-XX-XX
In Case No: U-20350

UPPER PENINSULA POWER COMPANY

MPSC Vol No 8-ELECTRIC

1st Revised Sheet No. D-72.72
Replaces Original Sheet No. D-72.72

**D2. Parallel Generation – Purchase by UPPCO** **PG-4**

Continued from Sheet D-72.72

The Seller may request in writing that the Company prepare a final draft Standard Contract. The Company will use best efforts to respond to the request within 15 business days. In connection with such a request, the Seller must provide the Company with any additional or clarified project information that the Company reasonably determines to be necessary for the preparation of a final draft Standard Contract. When both parties are in full agreement as to all terms and conditions of the draft Standard Contract, the Company will prepare and forward to the Seller a final executable version of the agreement within 15 business days.

PRO-RATION OF DEMAND COST FOR AUTHORIZED MAINTENANCE
For customers billed on rates with demand charges, the demand charges other than "Customer Demand" shall be prorated if the maintenance schedule of the customer owned generation facility has been approved in advance in writing by the Company. Said pro-ration shall be based on the number of authorized days of scheduled maintenance. The customer shall pay the demand rate for the higher than normal demands due to the generation outage only for the days of authorized maintenance.

SPECIAL RULES
1. The Company shall install appropriate metering facilities to record all flows of energy necessary to bill the customer in accordance with the charges and credits of this rate schedule.

2. The customer shall furnish, install, and wire the necessary service entrance equipment, meter sockets, meter enclosure cabinets, or meter connection cabinets that may be required by the Company to properly meter usage and sales to the Company.

3. The requirements for interconnecting a generator with the Company's facilities are contained in the Michigan Public Service Commission's Electric Interconnection Standards Rules (R460.601 – 460.656) and the Company's Michigan Utility Generator Interconnection Requirements, copies of which will be provided to customers upon request. All requirements must be met prior to commencing service.

4. Customer will secure and maintain liability insurance that provides protection against claims for damages resulting from (1) bodily injury, including wrongful death, and (2) property damage arising out of the customer's ownership and/or operation of the facility. The limits of the policy will be at least one million dollars (or the level shown in the Michigan Electric Interconnection and Net Metering Standards, R 460.615 – R 460.628, Rule 624) per occurrence or prove financial responsibility by another method acceptable to and approved in writing by the Company.
The Failure of the customer or the Company to enforce the minimum levels of insurance does not relieve the customer from maintain such levels of insurance or relieve the customer of any liability. The customer will provide the Company with a certificate of insurance containing a minimum 30-day notice of cancellation prior to execution of this agreement.
Each of the parties will indemnify and save harmless the other party against any and all damages to persons or property occasioned, without the negligence of such other party, by the maintenance and operation by such parties of their respective lines and other electrical equipment.

Issued: XX-XX-XXXX
By G R Haehnel
Director of Regulatory Affairs

Effective for Service
On and After: XX-XX-XX
Issued Under Auth. of

Marquette, Michigan

Mich Public Serv Comm
Dated: XX-XX-XX
~~In Case No: U-20350~~

Formatted: Indent: First line: 4.8", Tab stops: -0.5", Left + 0", Left + 0.4", Left + 0.8", Left + 1.2", Left + 1.6", Left + 2", Left + 2.4", Left + 2.8", Left + 3.2", Left + 3.6", Left + Not at 3.65"

**NORTH AMERICAN ENERGY MARKETS ASSOCIATION (NAEMA)
CONFIRMATION LETTER FOR
MISO ZONAL RESOURCE CREDITS**

This confirmation letter ("Written Confirmation"), executed under the Master Agreement as defined below, shall confirm the Transaction agreed to on November 29, 2017 ("Effective Date") between Dairyland Power Cooperative (as "Seller") and Upper Peninsula Power Company (as "Buyer") (collectively, "Parties") regarding the sale/purchase of the Product under the terms and conditions as follows:

**Schedule P Product**:

[X] Other: Capacity, which for the purposes of this Transaction shall mean "Zonal Resource Credits" ("ZRCs") sourced from Local Resource Zone ("LRZ") 2, as such terms are defined in (i) the MidContinent Independent System Operator, Inc. ("MISO") Open Access Transmission, Energy and Operating Reserve Markets Tariff as may be amended from time to time ("MISO Tariff"); and (ii) the MISO Resource Adequacy Business Practices Manual as may be amended from time to time ("RA BPM", or together with the MISO Tariff referred to as the "MISO Rules"). In the event of any inconsistency in the MISO Rules, the MISO Tariff shall govern.

For clarification purposes, the Parties acknowledge that, in accordance with the MISO Rules, one ZRC represents one megawatt ("MW") of Unforced Capacity as defined in the MISO Rules from a Planning Resource(s) that qualifies to satisfy the resource adequacy requirements under Module E-1 of the MISO Tariff.

**Contract Quantity and Contract Price**:

The quantity of ZRCs and the applicable LRZ, as further described in Attachment VV of the MISO Tariff, associated with such ZRCs for each Planning Year (i.e., June 1st of one year through May 31st of the following year) encompassed by this Transaction, and the Contract Price(s) associated therewith shall be as follows:

| Planning Year | Quantity (# of ZRCs) | LRZ | Contract Price ($ per ZRC) | Purchase Price ($) |
|---|---|---|---|---|
| 2020<br>June1, 2020 – May 31, 2021 | 20 MW | 2 | $15,000/MW-year | $300,000.00 |
| 2021<br>June1, 2021 – May 31, 2022 | 20 MW | 2 | $20,000/MW-year | $400,000.00 |

**Special Conditions**:

1. Delivery and Receipt.

The applicable terms and conditions regarding delivery and receipt of the Product shall be as specified below. If no option is selected below, then Option 1 shall apply exclusively.

[ ] **Option 1**: Seller shall accomplish delivery of the full quantity of ZRCs for each applicable Planning Year by submitting the necessary transaction(s) in the Module E Capacity Tracking Tool, or any successor system utilized by MISO for tracking and transferring ZRCs, ("MECT") to electronically transfer such quantity from Seller's MECT account to Buyer's MECT account on or before March 1st immediately prior to the commencement of the applicable Planning Year ("Transfer Deadline"). For example, if the Planning Year listed is 2013/2014, then Seller shall effectuate delivery by submitting the necessary transaction(s) in the MECT to electronically transfer the full quantity of ZRCs for Planning Year 2013/2014 from Seller's MECT account to Buyer's MECT account on or before March 1, 2013. To the extent required, Buyer shall accomplish receipt of the full quantity of ZRCs for each Planning Year by confirming the necessary transaction(s) submitted by Seller. The submitting and confirming of the appropriate transaction(s) in the MECT shall be conducted by the Parties in accordance with the requirements of the MISO Rules and other applicable rules adopted by the MISO regarding the MECT.

In accordance with Section 11.3 of the Tariff, title and risk of loss related to the Product shall transfer from Seller to Buyer when the Product is electronically transferred from Seller's MECT account to Buyer's MECT account in accordance with the requirements specified herein.

[X] **Option 2**: Seller shall accomplish delivery of the quantity of ZRCs for each applicable Planning Year by submitting the necessary transaction(s) in the MISO Module E Capacity Tracking Tool, or any successor system utilized by MISO for tracking and transferring ZRCs, ("MECT") to electronically transfer such quantity from Seller's MECT account to Buyer's MECT account. To the extent required, Buyer shall accomplish receipt of the quantity of ZRCs for each Planning Year by confirming the necessary transaction(s) submitted by Seller. The submitting and confirming of the appropriate transaction(s) in the MECT shall be conducted by the Parties in accordance with the requirements of the MISO Rules and other applicable rules adopted by the MISO regarding the MECT. Seller and Buyer shall accomplish delivery and receipt of the quantity of ZRCs for each applicable Planning Year as follows:

***1. Seller shall accomplish delivery of the Contract Quantity of ZRCs for each respective Planning Year by no later than (i) five (5) Business Days prior to the "Transfer Deadline", such Transfer Deadline being the date by which Fixed Resource Adequacy Plans (as defined in the MISO Rules) must be submitted to MISO for the applicable Planning Year, or (ii) the date on which the MECT becomes available for the submission and confirmation of transactions for the applicable Planning Year.***

In accordance with Section 11.3 of the Tariff, title and risk of loss related to the Product shall transfer from Seller to Buyer when the Product is successfully electronically transferred from Seller's MECT account to Buyer's MECT account in accordance with the requirements specified herein.

2. Payment Terms:

The applicable terms and conditions regarding payment shall be as specified below. If no option is selected below, then Option 1 shall apply exclusively.

[ ] **Option 1:** Within five (5) Business Days after the electronic transfer of the quantity of ZRCs for each applicable Planning Year in the MECT is completed, Seller shall provide Buyer with an invoice for the total amount due for the quantity of ZRC's transferred by Seller to Buyer. Such invoice shall be due and payable by Buyer on or before the fifth (5th) Business Day after Buyer's receipt of such invoice. The Parties acknowledge and agree that the payment terms described herein shall supercede and replace Section 7.1 and the first sentence of Section 7.2 of the Tariff with respect to this Transaction only.

[ ] **Option 2:** The Parties agree that the payment schedule for the Product delivered and received hereunder shall be governed by the terms and conditions of the Tariff.

**[X] Option 3:** The Parties agree that the payment schedule for the Product delivered and received hereunder shall be as follows:

***1. Buyer shall pay for the Product on an annual basis. Buyer shall tender payment to Seller prior to the annual delivery of the Contract Quantity as set forth above.***

The Parties acknowledge and agree that the payment terms described herein shall supercede and replace Section 7.1 of the Tariff with respect to this Transaction only.

3. Failures to Deliver and/or Receive.

(a) Seller's Failure to Deliver. In the event that: (i) Seller fails to deliver all or part of the ZRCs by the Transfer Deadline for the applicable Planning Year, and such failure is not excused by Buyer's failure to perform; (ii) Buyer provides notice of such failure to Seller within at least three (3) Business Days after the applicable Transfer Deadline; and (iii) Seller fails to cure such failure within one (1) Business Day after notice from the Buyer, then Seller shall pay Buyer, within five (5) Business Days of invoice receipt, all Capacity Deficiency Charges assessed to Buyer (either directly or through contractual obligation) attributable to the quantity of ZRCs Seller failed to deliver, not to exceed the calculated equivalent Capacity Deficiency Charges for the applicable LRZ for this Transaction. In addition, (i) if Buyer is assessed a Capacity Deficiency Charge for a deficient number of ZRCs less than the quantity that Seller failed to deliver, then Buyer shall be entitled to the positive difference, if any, obtained by subtracting the Contract Price from the Auction Clearing Price (ACP) for the applicable LRZ for this Transaction, and multiplying such positive difference, if any, by the quantity of ZRCs which Seller failed to deliver, and for which Capacity Deficiency Charges are not attributable and assessed to Buyer; (ii) if Buyer is not assessed a Capacity Deficiency Charge, Buyer shall be entitled to the positive difference, if any, obtained by subtracting the Contract Price from the ACP for the applicable LRZ for this Transaction and multiplying such positive difference, if any, by the quantity of ZRCs which Seller failed to deliver; and (iii) for the number of ZRCs that Seller failed to deliver minus the number of ZRCs attributing to a Capacity Deficiency Charge, if any, Seller shall pay Buyer the Price Differential Credit Adjustment detailed in Special Condition 5.

In the event that: (i) Seller fails to deliver all or part of the Product by the Transfer Deadline for the applicable Planning Year, and such failure is not excused by Buyer's failure to perform; and (ii) Buyer fails to provide notice of such failure to Seller within at least three (3) Business Days after the Transfer Deadline, then Seller shall pay Buyer, within five (5) Business Days of invoice receipt, the positive difference, if any, obtained by subtracting the Contract Price from the ACP for the applicable LRZ for this Transaction and multiplying such positive difference, if any, by the quantity of ZRCs which Seller failed to deliver.
The invoice from Buyer to Seller for any amount owed by Seller to Buyer pursuant to this provision shall include a written statement explaining in reasonable detail the calculation of such amount.

(b) Buyer's Failure to Receive.

In the event that: (i) Buyer fails to receive all or part of the Product by the Transfer Deadline for the applicable Planning Year, and such failure is not excused by Seller's failure to perform; (ii) Seller provides notice of such failure to Buyer within at least three (3) Business Days after the applicable Transfer Deadline; and (iii) Buyer fails to cure such failure within one (1) Business Day after notice from the Seller, then Buyer shall pay Seller, within five (5) Business Days of invoice receipt, an amount equal to the Contract Price multiplied by the quantity of ZRCs which Buyer failed to receive.
In the event that: (i) Buyer fails to receive all or part of the Product by the Transfer Deadline for the applicable Planning Year, and such failure is not excused by Seller's failure to perform; and (ii) Seller fails to provides notice of such failure to Buyer within at least three (3) Business Days after the applicable Transfer Deadline, then Buyer shall pay Seller, within five (5) Business Days of invoice receipt, an amount equal to the positive difference, if any, obtained by subtracting the Sales Price from the Contract Price and multiplying such positive difference, if any, by the quantity of ZRCs which Buyer failed to receive; provided, however, that if Seller, after using commercially reasonable efforts, is unable to resell (including resale through the Planning Resource Auction) all ZRCs which Buyer failed to receive, the Sales Price with respect to such quantity that Seller is unable to resell shall be deemed to be equal to zero (0).

The invoice from Seller to Buyer for any amount owed by Buyer to Seller pursuant to this provision shall include a written statement explaining in reasonable detail the calculation of such amount. The Parties acknowledge and agree that with respect to this Transaction only, the definition of "Sales Price" in the Tariff shall be amended to delete all references to "at the Delivery Point" contained in such definition.

(c) Limitation of Remedies. The Parties acknowledge and agree that the remedies set forth herein regarding failures to deliver/receive shall supercede and replace Sections 5.1 and 5.2 of the Tariff with respect to this Transaction only.

4. Performance Assurance. Performance Assurance shall be as set forth in the Master Agreement.

**[Signature Page Follows]**

This Written Confirmation shall be deemed effective as of the Effective Date, but is subject to and shall only be effective upon the approval of Seller's Board of Directors. This Written Confirmation is being provided pursuant to and in accordance with the North American Energy Markets Association Capacity and Energy Tariff (the "Tariff") (which replaced the Mid-Continent Energy Marketers Association Capacity and Energy Tariff), and the Supplementary Agreement dated November 29, 2017 ("Supplementary Agreement") between the Parties, which constitutes part of and is subject to the terms and provisions of the Tariff (the Tariff and the Supplementary Agreement collectively, the "Master Agreement"). Capitalized Terms used but not defined herein shall have the meanings ascribed to them in the Tariff. If not defined herein or in the Tariff, such capitalized terms shall have the meanings ascribed to such terms in the MISO Rules.

**Seller:**

Dairyland Power Cooperative

By: ______________________

Name: ROBERT M. PALMBERG

Title: VP - STRATEGIC PLANNING

Date: NOVEMBER 30, 2017

**Buyer:**

Upper Peninsula Power Company

By: ______________________

Name: Nicholas Kates

Title: Chief Financial Officer

Date: November 30, 2017

| | | UPPCo | | |
|---|---|---|---|---|
| Year | Date | On-Peak | Off-Peak | Average |
| 2018 | 1/1/2018 | $29.38 | $23.09 | $26.43 |
| 2018 | 2/1/2018 | $29.09 | $23.14 | $26.20 |
| 2018 | 3/1/2018 | $28.54 | $20.98 | $24.66 |
| 2018 | 4/1/2018 | $28.03 | $20.56 | $24.18 |
| 2018 | 5/1/2018 | $28.90 | $19.83 | $24.68 |
| 2018 | 6/1/2018 | $29.85 | $20.91 | $25.75 |
| 2018 | 7/1/2018 | $31.56 | $21.49 | $26.84 |
| 2018 | 8/1/2018 | $31.60 | $21.73 | $27.16 |
| 2018 | 9/1/2018 | $29.30 | $21.17 | $25.14 |
| 2018 | 10/1/2018 | $29.45 | $21.05 | $25.48 |
| 2018 | 11/1/2018 | $29.70 | $22.25 | $26.25 |
| 2018 | 12/1/2018 | $28.97 | $23.09 | $26.04 |
| 2019 | 1/1/2019 | $30.74 | $24.44 | $27.79 |
| 2019 | 2/1/2019 | $30.04 | $24.03 | $27.11 |
| 2019 | 3/1/2019 | $30.01 | $22.45 | $26.11 |
| 2019 | 4/1/2019 | $29.96 | $21.73 | $26.00 |
| 2019 | 5/1/2019 | $30.32 | $21.41 | $26.12 |
| 2019 | 6/1/2019 | $31.92 | $22.80 | $27.58 |
| 2019 | 7/1/2019 | $35.26 | $23.69 | $30.02 |
| 2019 | 8/1/2019 | $35.51 | $24.03 | $30.11 |
| 2019 | 9/1/2019 | $31.56 | $22.45 | $27.01 |
| 2019 | 10/1/2019 | $30.22 | $22.03 | $26.37 |
| 2019 | 11/1/2019 | $31.20 | $23.53 | $27.47 |
| 2019 | 12/1/2019 | $30.52 | $23.94 | $27.26 |
| 2020 | 1/1/2020 | $29.46 | $23.70 | $26.81 |
| 2020 | 2/1/2020 | $29.46 | $22.90 | $26.02 |
| 2020 | 3/1/2020 | $29.60 | $22.48 | $26.02 |
| 2020 | 4/1/2020 | $30.24 | $21.87 | $26.17 |
| 2020 | 5/1/2020 | $30.33 | $22.15 | $26.17 |
| 2020 | 6/1/2020 | $31.61 | $22.49 | $27.44 |
| 2020 | 7/1/2020 | $33.44 | $23.20 | $28.95 |
| 2020 | 8/1/2020 | $34.22 | $23.78 | $29.11 |
| 2020 | 9/1/2020 | $30.84 | $22.00 | $26.49 |
| 2020 | 10/1/2020 | $30.09 | $22.05 | $26.06 |
| 2020 | 11/1/2020 | $30.97 | $22.38 | $26.61 |
| 2020 | 12/1/2020 | $30.04 | $23.42 | $26.92 |
| 2021 | 1/1/2021 | $29.52 | $23.83 | $26.69 |
| 2021 | 2/1/2021 | $29.54 | $23.64 | $26.62 |
| 2021 | 3/1/2021 | $29.20 | $22.06 | $25.69 |
| 2021 | 4/1/2021 | $29.69 | $21.99 | $25.99 |
| 2021 | 5/1/2021 | $30.35 | $21.52 | $25.68 |
| 2021 | 6/1/2021 | $30.78 | $22.11 | $26.91 |
| 2021 | 7/1/2021 | $32.98 | $22.86 | $28.30 |
| 2021 | 8/1/2021 | $32.90 | $23.20 | $28.35 |
| 2021 | 9/1/2021 | $29.83 | $22.01 | $26.08 |
| 2021 | 10/1/2021 | $29.14 | $21.87 | $25.37 |
| 2021 | 11/1/2021 | $31.07 | $22.92 | $27.08 |
| 2021 | 12/1/2021 | $29.79 | $23.41 | $26.75 |
| 2022 | 1/1/2022 | $29.53 | $24.22 | $26.80 |

| | UPPCo | | |
|---|---|---|---|
| Year | On-Peak | Average | Off Peak |
| 2018 | $29.53 | $21.61 | $25.73 |
| 2019 | $31.44 | $23.04 | $27.41 |
| 2020 | $30.86 | $22.70 | $26.90 |
| 2021 | $30.40 | $22.62 | $26.63 |
| 2022 | $30.27 | $23.21 | $26.83 |
| 2023 | $30.37 | $24.26 | $27.37 |
| 2024 | $30.87 | $24.94 | $27.98 |
| 2025 | $31.49 | $25.77 | $28.72 |
| 2026 | $31.94 | $26.48 | $29.31 |
| 2027 | $32.14 | $26.67 | $29.51 |
| 2028 | $32.30 | $26.85 | $29.67 |
| 2029 | $33.14 | $27.69 | $30.54 |
| 2030 | $33.25 | $27.61 | $30.55 |
| 2031 | $34.32 | $28.65 | $31.62 |
| 2032 | $35.39 | $29.76 | $32.71 |
| 2033 | $36.81 | $30.89 | $33.96 |
| 2034 | $37.95 | $31.97 | $35.05 |
| 2035 | $39.05 | $33.03 | $36.14 |
| 2036 | $40.42 | $34.38 | $37.52 |
| 2037 | $42.34 | $35.90 | $39.25 |

| | On-Peak | Off-Peak |
|---|---|---|
| 5-Year | $30.50 | $26.70 |
| 10-Year | $30.93 | $27.64 |
| 15-Year | $31.85 | $28.77 |
| 20-Year | $33.71 | $30.67 |

| | | | | |
|---|---|---|---|---|
| 2022 | 2/1/2022 | $28.96 | $24.07 | $26.58 |
| 2022 | 3/1/2022 | $29.45 | $22.70 | $26.12 |
| 2022 | 4/1/2022 | $30.22 | $22.68 | $26.38 |
| 2022 | 5/1/2022 | $29.37 | $22.13 | $25.72 |
| 2022 | 6/1/2022 | $31.26 | $22.76 | $27.45 |
| 2022 | 7/1/2022 | $33.23 | $23.51 | $28.60 |
| 2022 | 8/1/2022 | $32.84 | $23.50 | $28.64 |
| 2022 | 9/1/2022 | $29.34 | $22.58 | $26.09 |
| 2022 | 10/1/2022 | $29.25 | $22.55 | $25.69 |
| 2022 | 11/1/2022 | $30.05 | $23.51 | $26.83 |
| 2022 | 12/1/2022 | $29.68 | $24.33 | $27.05 |
| 2023 | 1/1/2023 | $28.83 | $25.54 | $27.21 |
| 2023 | 2/1/2023 | $29.12 | $25.24 | $27.22 |
| 2023 | 3/1/2023 | $29.18 | $23.64 | $26.43 |
| 2023 | 4/1/2023 | $30.68 | $23.45 | $26.77 |
| 2023 | 5/1/2023 | $29.08 | $23.14 | $26.18 |
| 2023 | 6/1/2023 | $31.45 | $23.69 | $27.93 |
| 2023 | 7/1/2023 | $34.77 | $24.53 | $29.78 |
| 2023 | 8/1/2023 | $33.79 | $24.29 | $29.40 |
| 2023 | 9/1/2023 | $30.25 | $23.84 | $26.99 |
| 2023 | 10/1/2023 | $29.11 | $23.86 | $26.44 |
| 2023 | 11/1/2023 | $28.84 | $24.69 | $26.82 |
| 2023 | 12/1/2023 | $29.34 | $25.21 | $27.26 |
| 2024 | 1/1/2024 | $28.87 | $26.37 | $27.74 |
| 2024 | 2/1/2024 | $28.69 | $25.18 | $26.99 |
| 2024 | 3/1/2024 | $29.11 | $24.62 | $26.73 |
| 2024 | 4/1/2024 | $31.18 | $24.13 | $27.69 |
| 2024 | 5/1/2024 | $29.18 | $23.98 | $26.73 |
| 2024 | 6/1/2024 | $31.27 | $24.58 | $28.03 |
| 2024 | 7/1/2024 | $36.20 | $25.03 | $31.10 |
| 2024 | 8/1/2024 | $36.91 | $25.23 | $31.26 |
| 2024 | 9/1/2024 | $30.12 | $24.34 | $27.17 |
| 2024 | 10/1/2024 | $28.72 | $24.50 | $26.65 |
| 2024 | 11/1/2024 | $29.78 | $25.42 | $27.55 |
| 2024 | 12/1/2024 | $30.36 | $25.91 | $28.15 |
| 2025 | 1/1/2025 | $30.19 | $27.29 | $28.86 |
| 2025 | 2/1/2025 | $29.34 | $26.79 | $28.16 |
| 2025 | 3/1/2025 | $29.57 | $25.31 | $27.36 |
| 2025 | 4/1/2025 | $31.14 | $24.89 | $28.06 |
| 2025 | 5/1/2025 | $29.15 | $24.62 | $26.93 |
| 2025 | 6/1/2025 | $33.08 | $25.13 | $29.20 |
| 2025 | 7/1/2025 | $37.39 | $25.89 | $32.21 |
| 2025 | 8/1/2025 | $37.62 | $26.34 | $32.08 |
| 2025 | 9/1/2025 | $31.32 | $24.93 | $28.11 |
| 2025 | 10/1/2025 | $28.84 | $25.25 | $27.08 |
| 2025 | 11/1/2025 | $30.08 | $26.12 | $28.05 |
| 2025 | 12/1/2025 | $30.18 | $26.67 | $28.53 |
| 2026 | 1/1/2026 | $30.78 | $27.82 | $29.37 |
| 2026 | 2/1/2026 | $30.46 | $27.41 | $29.03 |
| 2026 | 3/1/2026 | $29.82 | $25.96 | $27.91 |
| 2026 | 4/1/2026 | $30.23 | $25.34 | $27.82 |
| 2026 | 5/1/2026 | $29.66 | $25.34 | $27.46 |

| | | | | |
|---|---|---|---|---|
| 2026 | 6/1/2026 | $33.37 | $25.78 | $29.83 |
| 2026 | 7/1/2026 | $38.33 | $26.78 | $33.20 |
| 2026 | 8/1/2026 | $37.94 | $26.87 | $32.43 |
| 2026 | 9/1/2026 | $31.79 | $25.84 | $28.87 |
| 2026 | 10/1/2026 | $29.45 | $26.26 | $27.88 |
| 2026 | 11/1/2026 | $30.90 | $26.86 | $28.89 |
| 2026 | 12/1/2026 | $30.52 | $27.46 | $29.08 |
| 2027 | 1/1/2027 | $31.76 | $28.64 | $30.23 |
| 2027 | 2/1/2027 | $31.14 | $28.60 | $29.93 |
| 2027 | 3/1/2027 | $30.08 | $26.12 | $28.17 |
| 2027 | 4/1/2027 | $30.03 | $25.59 | $27.89 |
| 2027 | 5/1/2027 | $30.04 | $25.49 | $27.71 |
| 2027 | 6/1/2027 | $33.09 | $25.82 | $29.78 |
| 2027 | 7/1/2027 | $39.31 | $26.86 | $33.45 |
| 2027 | 8/1/2027 | $38.88 | $26.82 | $33.11 |
| 2027 | 9/1/2027 | $31.39 | $25.70 | $28.55 |
| 2027 | 10/1/2027 | $28.79 | $26.05 | $27.40 |
| 2027 | 11/1/2027 | $30.12 | $26.82 | $28.55 |
| 2027 | 12/1/2027 | $31.03 | $27.58 | $29.38 |
| 2028 | 1/1/2028 | $32.20 | $28.92 | $30.53 |
| 2028 | 2/1/2028 | $29.90 | $27.73 | $28.93 |
| 2028 | 3/1/2028 | $29.20 | $26.05 | $27.70 |
| 2028 | 4/1/2028 | $30.03 | $25.56 | $27.62 |
| 2028 | 5/1/2028 | $30.23 | $25.37 | $27.90 |
| 2028 | 6/1/2028 | $34.45 | $26.17 | $30.63 |
| 2028 | 7/1/2028 | $40.40 | $27.26 | $33.91 |
| 2028 | 8/1/2028 | $38.89 | $27.14 | $33.61 |
| 2028 | 9/1/2028 | $31.18 | $26.20 | $28.69 |
| 2028 | 10/1/2028 | $29.40 | $26.31 | $27.88 |
| 2028 | 11/1/2028 | $30.47 | $27.50 | $29.08 |
| 2028 | 12/1/2028 | $31.18 | $27.96 | $29.57 |
| 2029 | 1/1/2029 | $33.21 | $29.95 | $31.71 |
| 2029 | 2/1/2029 | $32.20 | $29.33 | $30.88 |
| 2029 | 3/1/2029 | $30.23 | $26.90 | $28.58 |
| 2029 | 4/1/2029 | $31.15 | $26.40 | $28.72 |
| 2029 | 5/1/2029 | $29.34 | $26.14 | $27.87 |
| 2029 | 6/1/2029 | $34.97 | $27.10 | $31.27 |
| 2029 | 7/1/2029 | $41.19 | $27.68 | $34.73 |
| 2029 | 8/1/2029 | $39.93 | $27.72 | $34.37 |
| 2029 | 9/1/2029 | $32.49 | $27.01 | $29.63 |
| 2029 | 10/1/2029 | $29.61 | $27.15 | $28.49 |
| 2029 | 11/1/2029 | $31.31 | $28.25 | $29.88 |
| 2029 | 12/1/2029 | $32.02 | $28.67 | $30.34 |
| 2030 | 1/1/2030 | $33.14 | $30.22 | $31.78 |
| 2030 | 2/1/2030 | $31.92 | $29.31 | $30.76 |
| 2030 | 3/1/2030 | $29.36 | $26.81 | $28.07 |
| 2030 | 4/1/2030 | $31.33 | $26.24 | $28.83 |
| 2030 | 5/1/2030 | $29.66 | $25.94 | $27.91 |
| 2030 | 6/1/2030 | $35.70 | $26.98 | $31.34 |
| 2030 | 7/1/2030 | $41.52 | $27.58 | $35.15 |
| 2030 | 8/1/2030 | $41.74 | $27.89 | $35.15 |
| 2030 | 9/1/2030 | $32.64 | $26.65 | $29.56 |

| | | | | |
|---|---|---|---|---|
| 2030 | 10/1/2030 | $29.91 | $26.95 | $28.51 |
| 2030 | 11/1/2030 | $30.33 | $28.10 | $29.32 |
| 2030 | 12/1/2030 | $31.77 | $28.65 | $30.20 |
| 2031 | 1/1/2031 | $34.39 | $31.39 | $33.03 |
| 2031 | 2/1/2031 | $32.63 | $30.18 | $31.58 |
| 2031 | 3/1/2031 | $30.63 | $27.75 | $29.15 |
| 2031 | 4/1/2031 | $30.72 | $27.17 | $29.03 |
| 2031 | 5/1/2031 | $30.36 | $26.99 | $28.73 |
| 2031 | 6/1/2031 | $37.96 | $27.96 | $33.11 |
| 2031 | 7/1/2031 | $42.56 | $28.89 | $36.48 |
| 2031 | 8/1/2031 | $42.12 | $29.11 | $35.78 |
| 2031 | 9/1/2031 | $34.69 | $27.71 | $31.23 |
| 2031 | 10/1/2031 | $30.25 | $27.90 | $29.13 |
| 2031 | 11/1/2031 | $31.89 | $28.65 | $30.24 |
| 2031 | 12/1/2031 | $33.70 | $30.07 | $31.95 |
| 2032 | 1/1/2032 | $35.50 | $32.79 | $34.27 |
| 2032 | 2/1/2032 | $33.59 | $31.02 | $32.34 |
| 2032 | 3/1/2032 | $32.75 | $28.98 | $30.99 |
| 2032 | 4/1/2032 | $31.24 | $28.12 | $29.75 |
| 2032 | 5/1/2032 | $32.07 | $28.09 | $30.04 |
| 2032 | 6/1/2032 | $38.32 | $28.93 | $34.03 |
| 2032 | 7/1/2032 | $44.42 | $29.86 | $37.55 |
| 2032 | 8/1/2032 | $44.67 | $30.11 | $37.73 |
| 2032 | 9/1/2032 | $34.24 | $28.85 | $31.63 |
| 2032 | 10/1/2032 | $30.99 | $28.96 | $29.99 |
| 2032 | 11/1/2032 | $32.45 | $29.92 | $31.25 |
| 2032 | 12/1/2032 | $34.40 | $31.43 | $32.93 |
| 2033 | 1/1/2033 | $37.60 | $34.14 | $35.87 |
| 2033 | 2/1/2033 | $35.61 | $33.28 | $34.56 |
| 2033 | 3/1/2033 | $33.14 | $29.67 | $31.49 |
| 2033 | 4/1/2033 | $33.14 | $29.29 | $31.24 |
| 2033 | 5/1/2033 | $32.74 | $28.98 | $30.89 |
| 2033 | 6/1/2033 | $39.17 | $29.64 | $34.72 |
| 2033 | 7/1/2033 | $47.59 | $31.08 | $39.37 |
| 2033 | 8/1/2033 | $45.73 | $30.74 | $38.78 |
| 2033 | 9/1/2033 | $35.37 | $29.92 | $32.75 |
| 2033 | 10/1/2033 | $32.82 | $30.12 | $31.45 |
| 2033 | 11/1/2033 | $33.36 | $30.95 | $32.22 |
| 2033 | 12/1/2033 | $35.52 | $32.81 | $34.20 |
| 2034 | 1/1/2034 | $38.35 | $35.42 | $36.96 |
| 2034 | 2/1/2034 | $36.64 | $34.10 | $35.48 |
| 2034 | 3/1/2034 | $34.46 | $30.82 | $32.76 |
| 2034 | 4/1/2034 | $33.68 | $30.48 | $32.06 |
| 2034 | 5/1/2034 | $33.15 | $30.02 | $31.67 |
| 2034 | 6/1/2034 | $40.08 | $30.78 | $35.70 |
| 2034 | 7/1/2034 | $50.53 | $32.10 | $41.11 |
| 2034 | 8/1/2034 | $46.56 | $32.04 | $39.90 |
| 2034 | 9/1/2034 | $37.17 | $31.32 | $34.22 |
| 2034 | 10/1/2034 | $33.74 | $31.31 | $32.55 |
| 2034 | 11/1/2034 | $35.37 | $32.01 | $33.75 |
| 2034 | 12/1/2034 | $35.70 | $33.20 | $34.47 |
| 2035 | 1/1/2035 | $39.29 | $35.93 | $37.75 |

| | | | | |
|---|---|---|---|---|
| 2035 | 2/1/2035 | $37.15 | $34.71 | $36.07 |
| 2035 | 3/1/2035 | $34.78 | $31.80 | $33.32 |
| 2035 | 4/1/2035 | $34.87 | $31.42 | $33.15 |
| 2035 | 5/1/2035 | $34.42 | $31.32 | $32.98 |
| 2035 | 6/1/2035 | $41.01 | $32.12 | $36.67 |
| 2035 | 7/1/2035 | $52.24 | $33.23 | $42.85 |
| 2035 | 8/1/2035 | $48.05 | $33.15 | $41.15 |
| 2035 | 9/1/2035 | $38.03 | $32.50 | $35.12 |
| 2035 | 10/1/2035 | $35.63 | $32.63 | $34.21 |
| 2035 | 11/1/2035 | $35.99 | $33.24 | $34.68 |
| 2035 | 12/1/2035 | $37.08 | $34.37 | $35.75 |
| 2036 | 1/1/2036 | $40.09 | $36.88 | $38.66 |
| 2036 | 2/1/2036 | $37.22 | $34.93 | $36.23 |
| 2036 | 3/1/2036 | $36.54 | $33.42 | $34.97 |
| 2036 | 4/1/2036 | $36.18 | $32.94 | $34.68 |
| 2036 | 5/1/2036 | $35.79 | $32.67 | $34.31 |
| 2036 | 6/1/2036 | $42.46 | $33.40 | $37.98 |
| 2036 | 7/1/2036 | $52.47 | $35.19 | $44.57 |
| 2036 | 8/1/2036 | $51.55 | $35.12 | $43.22 |
| 2036 | 9/1/2036 | $40.04 | $33.86 | $36.97 |
| 2036 | 10/1/2036 | $36.70 | $33.90 | $35.35 |
| 2036 | 11/1/2036 | $37.17 | $34.37 | $35.76 |
| 2036 | 12/1/2036 | $38.85 | $35.93 | $37.50 |
| 2037 | 1/1/2037 | $41.12 | $38.06 | $39.69 |
| 2037 | 2/1/2037 | $40.10 | $36.96 | $38.67 |
| 2037 | 3/1/2037 | $37.78 | $34.56 | $36.25 |
| 2037 | 4/1/2037 | $38.07 | $34.42 | $36.37 |
| 2037 | 5/1/2037 | $36.93 | $34.01 | $35.44 |
| 2037 | 6/1/2037 | $43.72 | $34.97 | $39.61 |
| 2037 | 7/1/2037 | $55.92 | $36.83 | $47.05 |
| 2037 | 8/1/2037 | $54.68 | $37.01 | $45.74 |
| 2037 | 9/1/2037 | $40.47 | $35.38 | $38.01 |
| 2037 | 10/1/2037 | $38.34 | $35.56 | $36.99 |
| 2037 | 11/1/2037 | $38.76 | $35.61 | $37.25 |
| 2037 | 12/1/2037 | $42.18 | $37.43 | $39.90 |
| 2038 | 1/1/2038 | $43.85 | $39.85 | $41.86 |
| 2038 | 2/1/2038 | $42.31 | $38.80 | $40.64 |
| 2038 | 3/1/2038 | $40.25 | $36.18 | $38.32 |
| 2038 | 4/1/2038 | $38.74 | $35.58 | $37.27 |
| 2038 | 5/1/2038 | $38.18 | $35.39 | $36.77 |
| 2038 | 6/1/2038 | $45.42 | $36.31 | $41.09 |
| 2038 | 7/1/2038 | $57.82 | $38.24 | $48.19 |
| 2038 | 8/1/2038 | $56.19 | $38.17 | $47.31 |
| 2038 | 9/1/2038 | $41.94 | $36.92 | $39.51 |
| 2038 | 10/1/2038 | $39.93 | $37.05 | $38.47 |
| 2038 | 11/1/2038 | $39.67 | $36.78 | $38.29 |
| 2038 | 12/1/2038 | $42.80 | $38.88 | $40.90 |

**CONFIDENTIAL**

Exhibit A-17 (EWS-5)

ATC Reliability Memorandum

**STATE OF MICHIGAN**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

* * * * *

| | | |
|---|---|---|
| In the matter of the application of | ) | |
| **UPPER PENINSULA POWER COMPANY** | ) | |
| for approval of its integrated resource plan | ) | Case No. U-20350 |
| pursuant to MCL 460.6t and for other relief. | ) | |

**DIRECT TESTIMONY OF**

**ANDREW MCNEALLY**

**FOR**

**UPPER PENINSULA POWER COMPANY**

**February 12, 2019**

Q. Please state your name and business address.

A. My name is Andrew McNeally and my business address is 1002 Harbor Hills Drive, Marquette, Michigan 49855.

Q. By whom are you employed and in what capacity?

A. I am employed by Upper Peninsula Power Company (“UPPCO” or the “Company”) as the Energy Efficiency Program Administrator.

Q. Briefly describe your education background and employment history.

A. I earned my Bachelor of Science in Surveying Engineering degree from the University of Maine at Orono in 1993 which included a year-long exchange at the University of Melbourne, Victoria, Australia in 1992. Within the regulated electric utility industry, I began my professional career at Maine Public Service Company, as a Customer Service Representative in 2005. By 2006, I was the sole Energy Management Auditor and primarily responsible for residential and small commercial energy conservation auditing and education, training of energy auditing field service personnel, and responding to customer and Maine Public Utilities Commission (“MPUC”) requests. By 2009, I had transitioned to a Rate and Regulatory Analyst responsible for load settlement, transmission reservations, large customer billing, and governmental agency reporting to the MPUC, Northern Maine Independent System Administrator (“NMISA”), Federal Energy Regulatory Commission (“FERC”) and North American Electric Reliability Corporation (“NERC”). By 2012, Maine Public Service Company had been acquired by Bangor Hydro Electric Company becoming a newly formed regulated transmission and distribution utility in Maine, called Emera Maine. At the newly formed Emera Maine, I assumed the role of Senior Rate Analyst where I was responsible for the annual and triennial Federal transmission rate filings, the transmission Open Access Same-time Information System ("OASIS"), management of the transmission interconnection queue, and providing specific project analytical support for ISO-NE PTO-AC Rates Working Group and development of the Emera Maine heat pump pilot program and electric vehicle assessment. In 2015, I joined Birch Point Software as a Business Analyst where I was responsible for developing custom solutions and web service applications and maintaining and building enterprise software applications. In late 2016, I joined UPPCO as a Business Analyst where I was primarily responsible for budgeting, load settlement, and sales and revenue forecasting. In October 2017, I assumed the role of Energy Efficiency Program Administrator for UPPCO.

Q. Have you previously testified in any regulatory proceedings?

A. Yes. Most recently, I have filed testimony in MPSC Case No. U-18265 and U-20032 concerning the Company's Energy Waste Reduction ("EWR") plans.

Q. What is the purpose of your testimony?

A. I will provide an overview of UPPCO's current EWR plan, discuss UPPCOs transition to an energy reduction target of 1.5% and highlight risks associated with UPPCO's ongoing EWR Plan development.

Q. Are you sponsoring exhibits in support of your testimony?

A. No.

Q. Please identify UPPCO's 2018 and 2019 EWR plan energy savings target approved in Case No. U-18265.

A. PA 295 of 2008, as amended, requires that electric utilities under MPSC rate jurisdiction achieve incremental energy savings of 1.0% per year based upon the utility's previous 3 years' annual retail electricity sales measured in megawatt hours. UPPCO's EWR plan for 2018 and 2019 established an energy savings target of 1.14% of the previous 3 years' annual retail electricity sales measured in megawatt hours. Much of these EWR savings are achieved through programs incentivizing the replacement of incandescent light bulbs with light emitting diode ("LED") light bulbs. UPPCO's current EWR plan is described in Section 5.3 of the Black & Veatch Report (Exhibit A-1 (GRH-1)).

Q. Please identify UPPCO's EWR plan energy savings targets for the 2020 and 2021 EWR plan years.

A. UPPCO will be filing an EWR Plan for the 2020 and 2021 in Case No. U-20368. Pursuant to the statutory goals outlined above, UPPCO will design a plan to, at minimum, meet the statutory requirements. Further, consistent with UPPCO's PCA, as outlined in this IRP filing, UPPCO's plan will include a transition to an incremental energy savings target of 1.5% based on the previous 3 years' annual retail electricity sales in megawatt hours.

Q. Why is UPPCO increasing its EWR plan target from 1.14% to 1.5%?

A. UPPCO experienced great success in 2018, which was the first year in which UPPCO served as the EWR plan administrator. Based upon this success, UPPCO believes additional EWR programs can be implemented to meet the 1.5% target. UPPCO is starting the transition to 1.5% by increasing both residential and commercial measures that qualify for incentives, such as solar water heating under residential and expanding our small business direct install program to include multi-family properties under commercial in 2019. UPPCO understands the value of energy efficiency programs designed for its customers and recognizes the importance of implementing and administering a cost-effective plan. Further, in Section VIII of the Commission's IRP Modeling Parameters under Scenario 1 regarding its "Business as Usual" scenario, the following is stated:

> Not less than 35% of the state's electric needs should be met through a combination of EWR and renewable energy by 2025, as per MCL 460.1001 (3). For all instate electric utilities that are eligible to receive the financial incentive mechanism for exceeding mandated energy saving targets of 1% per year, EWR should be based upon the maximum allowed under the incentive of 1.5% and should be based upon an average cost of MWh saved. The model should include an EWR supply cost curve to project future program expenditures beyond baseline assumptions without any cap. For all other electric utilities, EWR should not exceed the mandated targets for electric energy savings of 1% per year and should be based upon an average cost of MWh saved.

UPPCO developed the EWR supply cost curve by maintaining the 2018-2019 EWR Plan measure mix then scaling incentive amounts and adjusting participation levels to establish average cost to achieve 1.5% energy savings. When making participation level adjustments, UPPCO considered measure cost-effectiveness, life of measure and customer uptake of a measure.

Q. What are some of the current and anticipated challenges to achieving greater energy savings while developing a cost-effective and cost-justified plan?

A. The composition of EWR energy savings measures is changing for electric utilities in both Michigan and across the nation. These challenges include, but are not limited to: i) adoption or repeal of national energy efficiency standards for light bulbs and ii) movement within energy efficiency toward developing programs that achieve "deep energy savings".

Q. How does the adoption or repeal of national energy efficiency standards for light bulbs impact UPPCO?

A. In 2017, the United States Department of Energy ("DOE") established a definition for General Service Lamps ("GSLs") that prohibited the sale of light bulbs by January 1, 2020 that do not meet the standard of producing 45 lumens per watt, which is a standard that only LED bulbs can attain. Currently, the definition of GSLs is the subject of a DOE Notice of Proposed Rulemaking ("NOPR"), which adds uncertainty to energy savings calculations for lighting measures, especially light bulb replacement.

As an example of this uncertainty, an UPPCO residential customer who replaces an incandescent light bulb with an LED light bulb captures an approximate 70% reduction in their energy usage. If the new standard noted above is adopted, that same light bulb replacement may result in little to no energy savings for purposes of the EWR plan. If and when these energy savings standards come to fruition, significant impacts will occur to EWR plan designs and EWR program budgets. Traditionally, residential light bulb programs are cost-effective and relatively easy program to implement to achieve significant energy savings. To the extent these traditional energy savings don't exist at the same cost-effectiveness and to the same breadth, other program measures of equal or approximate cost effectiveness will need to evolve and fill the energy savings gap created by lighting standard changes.

Q. What do you mean by "deep energy savings"?

A. UPPCO is using the term "deep energy savings" as an aggregate term for a variety of energy efficiency measures that are installed and implemented at a single residential or commercial property to capture significant energy savings over a sustained period of time. For residential properties, these energy savings typically include three to seven measures being installed to improve the whole house performance (e.g., energy usage, safety, health, and living comfort), and require coordination with multiple utilities, organizations and contractors to complete the project. For commercial properties, these energy savings, again, include installation of multiple energy efficiency measures with an emphasis of unrelated systems that result in both energy savings (e.g. >30% in New York and California) and annual operating cost savings. Typically, the energy efficiency measures that are implemented to achieve "deep energy savings" are measures that are permanently attached to properties and require higher upfront costs to achieve energy savings immediately and for the long-term. For example, UPPCO is working with the Ontonagon Village Housing Commission and an insulation contractor to reduce air infiltration and increase attic insulation levels in their electrically heated, low-income housing stock. In 2018, seven buildings with a total of 17,600 square feet of floor space were air seals and insulated at a cost of $33,900.00 in incentives. The first-year energy savings is 33,185 kWh with anticipated lifetime savings of 591,838 kWh. UPPCO considers these programs valuable, in-depth programs, but they come with a higher cost to implement and administer.

Q. Are there any other challenges that UPPCO anticipate as it transitions to an EWR energy savings target of 1.5%.

A. UPPCO faces many challenges, as do all other utilities, in designing an EWR plan that is both cost-effective and cost-justified. Some questions that UPPCO is in the process of answering are as follows:

- What is the right mix of energy efficiency measures for UPPCO's customers, both residential and commercial?
- How will customers be impacted by the addition or removal of certain program measures?
- How can the Company improve the cost-effectiveness of its low-income focused programs?
- How can UPPCO offer a better mix of up-stream, mid-stream or down-stream incentives and rebates, from manufacturer to contractor to customer?

- What new technologies will be available in the next 2 to 5 years?

Q. Does UPPCO believe that it can reasonably achieve the goal of increasing EWR savings to 1.5%?

A. Despite the challenges noted above, UPPCO believes that it can reasonably achieve this increased goal. UPPCO will lay out its detailed plan for achieving this goal and its anticipated costs in its next EWR plan case.

Q. Please summarize your testimony.

A. UPPCO is committed to developing a cost-effective and cost-justified EWR plan that provides value to the Company's customers and that is in alignment with the EWR and renewable energy statutes in Michigan. That being said, UPPCO anticipates that as the existing lighting standards change and create diminishing marginal returns for existing EWR plans, newer programs and measures will need to be developed at a pace and on a scale that will supplant this energy savings void on a timely, if not coincident, basis. Moving forward, while programs might still be cost-effective (i.e., creating benefits greater than costs), overall EWR plans may become more expensive. UPPCO is developing an EWR plan that transitions its energy savings target to 1.5%. In doing so, UPPCO will prioritize for customers: 1) program value, 2) program cost-effectiveness and 3) program cost-justification through a deliberate and creative process.

Q. Does this complete your direct testimony?

A. Yes, it does.

**STATE OF MICHIGAN**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

* * * * *

| | | |
|---|---|---|
| In the matter of the application of | ) | |
| **UPPER PENINSULA POWER COMPANY** | ) | |
| for approval of its integrated resource plan | ) | Case No. U-20350 |
| pursuant to MCL 460.6t and for other relief. | ) | |

**DIRECT TESTIMONY AND EXHIBITS OF**

**DAVID R. TRIPP, P.E.**

**FOR**

**UPPER PENINSULA POWER COMPANY**

**February 12, 2019**

Q. Please state your name and business address for the record.

A. My name is David R. Tripp, and my business address is 800 Greenwood St., Ishpeming, Michigan 49849.

Q. By whom are you employed and in what capacity?

A. I am employed by Upper Peninsula Power Company ("UPPCO" or the "Company"), as the Chief Dam Safety / Generation Projects Manager.

Q. Briefly describe your educational background and applicable professional experience.

A. I graduated from Michigan Technological University with a Bachelor of Science in Mechanical Engineering. I am also a licensed Professional Engineer in the state of Michigan. I am currently working towards a master's in business administration through the University of Texas of the Permian Basin and have completed over one half of the required course work, I expect to graduate in December of 2019. I have over fifteen years of engineering and management experience, more than four of which are in managing hydroelectric generation assets, and eleven years in project management mostly in the Iron mining industry which involved managing engineering, design, and construction of large capital projects; these projects include tailings basin construction, process equipment installation and refurbishment, water treatment plant construction, long distance pumping station and pipeline construction.

Q. Have you previously testified before the Michigan Public Service Commission ("MPSC")?

A. No.

Q. What is the purpose of your testimony?

A. I have acted as the project manager for UPPCO regarding the development of its Integrated Resource Plan ("IRP"). The purpose of my testimony is to provide supplemental detail and information related to both the Company's IRP planning process and the development of the Black & Veatch Report, sponsored by Company witness Gradon R. Haehnel as Exhibit A-1 (GRH-

1). Specifically, I will (i) describe the Company's existing and owned generation resources, as well as planning efforts undertaken to increase the benefits of these existing resources, (ii) explain the pre-filing Request for Proposal ("RFP") process that was used to identify potential new power supply resources, as well as the results of the RFP process, and (iii) explain the applicable environmental regulations to and the expected air emissions from the proposed Reciprocating Internal Combustion Engine ("RICE") generating unit portion of the Company's Proposed Course of Action ("PCA").

Q. Have you prepared any exhibits in conjunction with your direct testimony?

A. Yes, I am sponsoring the following exhibits:

- Exhibit A-18 (DRT-1) Solar RFP
- Exhibit A-19 (DRT-2) Solar RFP Final Addendum
- Exhibit A-20 (DRT-3) Solar RFP Evaluation Summary
- Exhibit A-21 (DRT-4) MDEQ Air Permit Analysis

Q. Please provide a summary of UPPCO's existing Generation fleet.

A. UPPCO currently owns two oil fired combustion turbine generating units and 7 hydroelectric generating stations which are powered by stored water at 11 reservoirs. These units currently receive a combined capacity credit from MISO of 44.8 MW, which breaks down per unit follows:

- Portage CT: 14.3 MW
- Gladstone CT: 14.4 MW
- Hoist Hydroelectric Plant: 1.1 MW
- McClure Hydroelectric Plant: 3.3 MW
- Victoria Hydroelectric Plant: 11.3 MW
- Prickett Hydroelectric Plant: 0.4 MW
- Boney Falls (Escanaba Dam #4): No capacity credit given

- Escanaba Dam #3: No capacity credit given
- Escanaba Dam #1: No capacity credit given
- Escanaba Dams 1,3, and 4 do not receive capacity credit because they are directly connected to VERSO paper and are not capable of supplying power to the power grid.

Due to a catastrophic mechanical failure of Portage CT generator, the Portage unit is currently out of service. UPPCO is evaluating options including retirement of the Portage generator and is currently engaged with its insurance provider as part of the evaluation of next steps and alternatives.

Q. Please provide a status update on the Gladstone and Portage CT units and their respective impacts on their condition as modeled in the IRP.

A. The Gladstone CT was originally planned (and is shown in the IRP modeling) to be retired in 2019, while the Portage CT was originally planned to be retired in 2024. Originally, the Gladstone CT retirement date was selected because of a condition that was identified in a borescope inspection conducted in 2018. From a more technical perspective, the hook vane fit was found to be worn and out of tolerance, which is not an uncommon failure point for these machines. Upon inspection, the Gladstone CT was immediately taken out of service due to the potential catastrophic nature of this type of failure occurring. The initial assumption was that the cost of repair would not be warranted based on the age of the unit and this indication was the basis for modeling the UPPCO system with a 2019 retirement date. Further analysis and review of both the condition and the repair costs associated with the Gladstone CT led UPPCO to reinvest and repair the Gladstone CT so it could provide short-term capacity energy value for UPPCO customers until UPPCO's next IRP filing cycle in five years. Correspondingly, repair work was started in November 2018. At this point, however, from a IRP modeling perspective, it was too late to modify the modeling assumptions regarding its original 2019 retirement date.

Just following the start of repair work on the Gladstone CT, the Portage CT experienced a catastrophic failure in the compressor section of the turbine unit on November 28, 2018 and is now non-functional. As previously indicated status of this unit is us under review but UPPCO may retire the Portage CT in 2019. As this unit is a “sister-unit” to the Gladstone CT, the Company recognized that the repair work currently being conducted on the Gladstone unit is only focused on addressing known and major issues. To the Company’s knowledge, The Portage CT failure was not caused by known issues and the subsequent inspections to date have been inconclusive on the cause of the failure, but are ongoing. The Portage CT failure highlights UPPCO’s reliability concern over the age of these generating units. The Gladstone CT, which returned to operation in December 2018, is now slated to be retired in 2022 in conjunction with the expected operational date of the RICE generation solution, as well as the intended effective date of the Solar PPA, as outlined in UPPCO’s PCA.

In summary, as evidenced by the critical repair at Gladstone and the catastrophic mechanical failure at Portage, the Company is concerned about the sustained reliability of these units being able to provide capacity, as well as energy, when dispatched.

Q. Please explain what moving Hoist and McClure hydroelectric plant “in front of the meter” means and what benefit it provides?

A. Hoist and McClure hydroelectric plants are currently “behind the meter” hydroelectric generating plants. The terms “behind” or “in front of the meter” refer to how MISO considers the units in its modeling as part of the greater power grid. For “behind the meter” units, as it relates to the Hoist and McClure , MISO does not value their potential contribution to stabilize the grid beyond their typical generation. Therefore, their capacity value is determined with an averaging calculation of actual generation values. For generating units that are in “front of the meter”, as it relates to the Hoist and McClure situation, MISO considers their ability to be called upon to increase generation and provide a grid stabilizing effect during times of energy need and assigns capacity values based on their maximum 1 hour generating capability. The FERC license for Hoist and McClure generating units allows for generation above normal levels during periods of energy emergency. By moving the Hoist and McClure generating units "in front of the meter" with MISO, UPPCO will be able to report their capacity to MISO at their annual maximum generation instead of an averaged generation. In the case of UPPCO's capacity reported in 2018, the change to "in front of the meter" will increase the reported combined capacity for these two units by 7.6 MW. The required documentation has been filed with MISO on December 5, 2018. UPPCO has received notification from MISO that this move has been accepted and will be recognized and complete as of March 1, 2019.

Q. Please provide a description of the RFP process that is being employed to determine UPPCO's preferred bid and development partner for a solar generating facility for either an EPC build and/or a long-term PPA.

A. UPPCO enlisted the services of WSP, a professional services firm with a worldwide presence, which has experience in both designing solar facilities as wells as conducting solar project bids. WSP has been UPPCO's bid process designer and administrator. All communication with bidders is conducted by and through WSP. The process used has been a multi-step process that started with the development of a bidders list. WSP, through its experience and contacts, developed a core bidders list. To this list, UPPCO added a number of potential bidders that had expressed interest in bidding on solar projects for UPPCO and/or were known to be considering development projects within UPPCO's service territory. WSP developed a Request for Interest ("RFI") issuance to the full bidders list which required bidders to return a statement of interest and a signed non-disclosure agreement prior to being issued the RFP. The issuance of the RFI commenced the RFP process. There was a deadline for return of this RFI documentation to be included on the bidder list.  Most of the parties on the bidders list did return the required information, and those that did not were provided with follow up communication to confirm that they were not interested in bidding.  Following the RFI deadline, and as stated in the RFI documentation, the RFP was issued on September 14, 2018.  See Exhibit A-18 (DRT-1) Solar RFP. The RFP required bidders to provide intermediate financial experience and capability information. These intermediate submittals resulted in some bidders opting to discontinue their participation in the bidding process.  Two organizations approached UPPCO after bid issuance expressing a desire to participate.  UPPCO worked with WSP to get these two bidders caught up and rolled into the bidding process in a manner that was equitable for all parties.  During the process UPPCO did issue an addendum and bid extension, which was required due to a late realization on the impacts of UPPCO's tax position and its inability to utilize the solar Investment Tax Credit ("ITC").  See Exhibit A-19 (DRT-2) Solar RFP Final Addendum.  Bid responses were delivered to WSP on January 4, 2019.  WSP's process for compiling results included bid validation with questions to bidders and bid revisions if necessary, to ensure that bids were comparable.  WSP developed a bid process report and ranking results. See Exhibit A-20 (DRT-3) Solar RFP Evaluation Summary.  UPPCO reviewed the WSP rankings and bid pricing and selected a preferred development partner and/or preferred bid and bidder. UPPCO is currently working through a contract development process to engage with its preferred development partner.

Q. Please provide a description of the RFP that is being followed for the RICE generator.

A. UPPCO is also utilizing WSP as the bid manager for the RICE generator, and the bid process will be similar to the solar bid process.  The RICE bid process, however, was started later than the solar bid process.  RICE generation was added to the IRP recommendation following the failure of the Portage combustion turbine unit on November 28, 2018.  WSP has developed the bidder list and a technical description that has been issued with the request for interest and UPPCO's

Non-disclosure Agreement ("NDA"). Upon receipt of the NDA from interested bidders the detailed bid documents will be issued for bid. WSP will collect bid results and validate the responses. Once the validation process is complete the responses will be ranked based on the bidder's experience and technical solution. Cost comparison will be the final step of evaluation with the bid winner being selected based on an evaluation of bid ranking and cost. UPPCO expects this process to be complete by June 3, 2019. At the conclusion of this process UPPCO will compare the resulting bid prices to the modeling cost assumptions and provide cost updates with in the 150-day cost update window.

Q. Please provide a summary of how siting for the proposed generation builds were determined.

A. UPPCO enlisted the services of Steigerwaldt Land Services to conduct a land study to identify appropriate properties. UPPCO evaluated properties near 8 substations for both possible solar and RICE generation installation. The winning solar bid offered a PPA from a project already under development; therefore, no solar siting was required. For the RICE generation, UPPCO selected a location near the __________ substation due to its eastern proximity, available electrical transmission connection, proximity to the natural gas transmission system, and available acreage. At this time UPPCO is negotiating with possible land owners cannot disclose the actual parcel location other than stating it is in the vicinity of ___________ substation.

Q. Please provide a summary of the environmental permitting requirements for the recommended RICE generation build.

A. UPPCO's recommended natural gas RICE generator will require an air permit to install to be issued by the Michigan Department of Environment Quality ("MDEQ"). UPPCO has enlisted the services of Mr. Christopher White, of AECOM, to provide the details and analysis of the air permitting process. I am sponsoring Mr. White's report as Exhibit A-21 (DRT-4) MDEQ Air Permit Process Analysis. This report contains (i) an annual projection of emissions from the proposed project, (ii) a discussion of applicable environmental regulations, (iii) a discussion of emission control technologies, and (iv) a proposed timeline for achieving necessary environmental approvals.

Q. Does this complete your Direct Testimony?

A. Yes, it does.

**CONFIDENTIAL**

Exhibit A-18 (DRT-1)

Solar RFP

# <u>CONFIDENTIAL</u>

Exhibit A-19 (DRT-2)

Solar RFP Final Addendum

Solar RFP Evaluation Summary
by WSP

## VALUATION SUMMARY

*Nominal Discount Rate* *7.47%* *annually*
*Real Discount Rate* *5.36%* *annually*

| Rank | Company | Structure | NPV of Project Cost | NPV of Total Production | Real LCOE ($/MWh) | Part I - Rated Score | OPTION | Project Description | Part II Comments |
|---|---|---|---|---|---|---|---|---|---|
| 1 | [redacted] | PPA | [redacted] | [redacted] | [redacted] | 3.45 | Option 2.A | [redacted] Single-Axis Tracker - 20MW to UPPCo out of 125MW build | -No financial information has been provided during the procurement process. [redacted] can provide financial support letters upon shortlisting of its proposal by the Upper Peninsula Power.<br>-EPC cost breakout not provided |
| 2 | [redacted] | PPA | [redacted] | [redacted] | [redacted] | 3.45 | Option 2.A | [redacted] Single-Axis Tracker - 20MW to UPPCo out of 50MW build | -No financial information has been provided during the procurement process. [redacted] can provide financial support letters upon shortlisting of its proposal by the Upper Peninsula Power.<br>-EPC cost breakout not provided |
| 3 | [redacted] | PPA Buyout + O&M | [redacted] | [redacted] | [redacted] | 3.25 | Option 1.B | [redacted] Single-Axis Tracker | EPC cost breakout not provided |
| 4 | [redacted] | PPA | [redacted] | [redacted] | [redacted] | 3.45 | Option 2.A | [redacted] Single-Axis Tracker - 20MW build | -No financial information has been provided during the procurement process. [redacted] can provide financial support letters upon shortlisting of its proposal by the Upper Peninsula Power.<br>-EPC cost breakout not provided |
| 5 | [redacted] | PPA | [redacted] | [redacted] | [redacted] | 3.45 | Option 1.B | [redacted] Single-Axis Tracker | EPC cost breakout not provided |
| 6 | [redacted] | PPA | [redacted] | [redacted] | [redacted] | 3.25 | Option 1.B | [redacted] Single-Axis Tracker | EPC cost breakout not provided |
| 7 | [redacted] | PPA Buyout + O&M | [redacted] | [redacted] | [redacted] | 3.25 | Option 1.B | [redacted] Fixed Tilt | EPC cost breakout not provided |
| 8 | [redacted] | PPA | [redacted] | [redacted] | [redacted] | 3.25 | Option 1.A | [redacted]: Single-Axis Tracker / [redacted] Single-Axis Tracker | EPC cost breakout not provided |
| 9 | [redacted] | PPA | [redacted] | [redacted] | [redacted] | 3.25 | Option 1.B | [redacted] Fixed Tilt | EPC cost breakout not provided |
| 10 | [redacted] | PPA Buyout + O&M | [redacted] | [redacted] | [redacted] | 3.25 | Option 1.A | [redacted]: Single-Axis Tracker / [redacted] Single-Axis Tracker | EPC cost breakout not provided |
| 11 | [redacted] | PPA | [redacted] | [redacted] | [redacted] | 3.25 | Option 1.A | [redacted]: Fixed Tilt / [redacted] Fixed Tilt | EPC cost breakout not provided |
| 12 | [redacted] | PPA | [redacted] | [redacted] | [redacted] | 3.08 | Option 1.B | [redacted] Fixed Tilt | -During the Pre-Qual phase, the Respondent stated that "[redacted] with [redacted] blessing, is currently running a process to find a new investor for our solar projects.There is a small possibility that [redacted] will continue to work with [redacted] on the solar side of our business; however, there is also a strong possibility that [redacted] will begin to work with a new investor for solar in the very near future. As such, it is premature to have any future solar proposals be submitted by [redacted] as the lead." In the Part II Proposal, the Respondent stated "[redacted] financial investor is [redacted] a wholly-owned subsidiary of [redacted] funds all of [redacted] development activity in exchange for a right to own and operate the Projects. Under the credit umbrellas of [redacted] is able to provide balance-sheet financing and avoid the need to source third-party construction financing."<br>[redacted] cost breakout not provided |
| 13 | [redacted] | PPA Buyout + O&M | [redacted] | [redacted] | [redacted] | 3.25 | Option 1.A | [redacted]: Fixed Tilt / [redacted] Fixed Tilt | EPC cost breakout not provided |
| 14 | [redacted] | PPA | [redacted] | [redacted] | [redacted] | 3.45 | Option 1.A | [redacted]: Fixed Tilt / [redacted] Single-Axis Tracker | EPC cost breakout not provided |
| 15 | [redacted] | PPA Buyout + O&M | [redacted] | [redacted] | [redacted] | 3.45 | Option 1.B | [redacted] Single-Axis Tracker | EPC cost breakout not provided |
| 16 | [redacted] | PPA Buyout + O&M | [redacted] | [redacted] | [redacted] | 3.45 | Option 1.A | [redacted]: Fixed Tilt / [redacted] Single-Axis Tracker | EPC cost breakout not provided |
| 17 | [redacted] | PPA | [redacted] | [redacted] | [redacted] | 3.35 | Option 1.A | [redacted]: Single-Axis Tracker / [redacted] Single-Axis Tracker | Only Respondent to provide EPC cost breakout and O&M estimate |
| 18 | [redacted] | PPA Buyout + O&M | [redacted] | [redacted] | [redacted] | 3.35 | Option 1.A | [redacted]: Single-Axis Tracker / [redacted] Single-Axis Tracker | Only Respondent to provide EPC cost breakout and O&M estimate |
| 19 | [redacted] | PPA | [redacted] | [redacted] | [redacted] | 3.35 | Option 1.A | [redacted] Fixed Tilt / [redacted] Single-Axis Tracker | Only Respondent to provide EPC cost breakout and O&M estimate |
| 20 | [redacted] | PPA Buyout + O&M | [redacted] | [redacted] | [redacted] | 3.35 | Option 1.A | [redacted]: Fixed Tilt / [redacted] Single-Axis Tracker | Only Respondent to provide EPC cost breakout and O&M estimate |
| 21 | [redacted] | EPC + O&M | [redacted] | [redacted] | [redacted] | 3.25 | Option 1.B | [redacted] Single-Axis Tracker | EPC cost breakout not provided |
| 22 | [redacted] | EPC + O&M | [redacted] | [redacted] | [redacted] | 3.45 | Option 1.B | [redacted] Single-Axis Tracker | EPC cost breakout not provided |
| 23 | [redacted] | EPC + O&M | [redacted] | [redacted] | [redacted] | 3.25 | Option 1.B | [redacted] Fixed Tilt | EPC cost breakout not provided |
| 24 | [redacted] | EPC + O&M | [redacted] | [redacted] | [redacted] | 3.25 | Option 1.A | [redacted]: Single-Axis Tracker / [redacted] Single-Axis Tracker | EPC cost breakout not provided |
| 25 | [redacted] | EPC + O&M | [redacted] | [redacted] | [redacted] | 3.35 | Option 1.A | [redacted]: Single-Axis Tracker / [redacted] Single-Axis Tracker | Only Respondent to provide EPC cost breakout and O&M estimate |
| 26 | [redacted] | EPC + O&M | [redacted] | [redacted] | [redacted] | 3.35 | Option 1.A | [redacted]: Fixed Tilt / [redacted] Single-Axis Tracker | Only Respondent to provide EPC cost breakout and O&M estimate |

Solar RFP Evaluation Summary
by WSP

## VALUATION SUMMARY

| | | |
|---|---|---|
| *Nominal Discount Rate* | *7.47%* | *annually* |
| *Real Discount Rate* | *5.36%* | *annually* |

| Rank | Company | Structure | NPV of Project Cost | NPV of Total Production | Real LCOE ($/MWh) | Part I - Rated Score | OPTION | Project Description | Part II Comments |
|---|---|---|---|---|---|---|---|---|---|
| 27 | [redacted] | EPC + O&M | [redacted] | [redacted] | [redacted] | 3.45 | Option 1.A | [redacted] Fixed Tilt / [redacted] Single-Axis Tracker | EPC cost breakout not provided |
| 28 | [redacted] | EPC + O&M | [redacted] | [redacted] | [redacted] | 3.25 | Option 1.A | [redacted]: Fixed Tilt / [redacted] Fixed Tilt | EPC cost breakout not provided |
| 29 | [redacted] | PPA Buyout + O&M | [redacted] | [redacted] | [redacted] | 3.00 | Option 1.A | [redacted]: Fixed Tilt / [redacted] Fixed Tilt | EPC cost breakout not provided |
| 30 | [redacted] | PPA | [redacted] | [redacted] | [redacted] | 3.00 | Option 1.A | [redacted]: Fixed Tilt / [redacted] Fixed Tilt | EPC cost breakout not provided |
| Info. not provided | [redacted] | PPA Buyout + O&M | Information Not Prov | [redacted] | Information Not | 3.08 | Option 1.B | [redacted] Fixed Tilt | -The Respondent didn't provide information regarding the PPA Buyout Price at this stage. The company states: "UPPCO may, at its option, elect to purchase the Project from the Project Company after the later of the tax equity flip date and Investment Tax Credit recapture period. The Purchase Price of the Project shall be the greater of the fair market value of the Project or the depreciated book value of the Project, in each case at the time of the sale".<br>-During the Pre-Qual phase, the Respondent stated that "[redacted] with [redacted] blessing, is currently running a process to find a new investor for our solar projects.There is a small possibility that [redacted] will continue to work with [redacted] on the solar side of our business; however, there is also a strong possibility that [redacted] will begin to work with a new investor for solar in the very near future. As such, it is premature to have any future solar proposals be submitted by [redacted] as the lead." In the Part II Proposal, the Respondent stated "[redacted] financial investor is [redacted] . [redacted], a wholly-owned subsidiary of [redacted] funds all of Tradewind's development activity in exchange for a right to own and operate the Projects. Under the credit umbrellas of [redacted] is able to provide balance-sheet financing and avoid the need to source third-party construction financing."<br>-EPC cost breakout not provided |
| N/A | [redacted] | EPC + O&M | N/A | N/A | N/A | N/A | Option 2.A | [redacted] Single-Axis Tracker | -No financial information has been provided during the procurement process. Orion can provide financial support letters upon shortlisting of its proposal by the Upper Peninsula Power.<br>-EPC cost breakout not provided |
| N/A | [redacted] | EPC + O&M | N/A | N/A | N/A | N/A | Option 1.A | [redacted]: Fixed Tilt / [redacted] Fixed Tilt | EPC cost breakout not provided |
| N/A | [redacted] | EPC + O&M | N/A | N/A | N/A | N/A | Option 1.B | [redacted] Fixed Tilt | -During the Pre-Qual phase, the Respondent stated that "[redacted] with [redacted] blessing, is currently running a process to find a new investor for our solar projects.There is a small possibility that [redacted] will continue to work with [redacted] on the solar side of our business; however, there is also a strong possibility that Tradewind will begin to work with a new investor for solar in the very near future. As such, it is premature to have any future solar proposals be submitted by [redacted] as the lead." In the Part II Proposal, the Respondent stated "[redacted] financial investor is [redacted] [redacted], a wholly-owned subsidiary of [redacted] funds all of [redacted] development activity in exchange for a right to own and operate the Projects. Under the credit umbrellas of [redacted] is able to provide balance-sheet financing and avoid the need to source third-party construction financing."<br>-EPC cost breakout not provided |
| N/A | [redacted] | PPA Buyout + O&M | N/A | N/A | N/A | N/A | Option 2.A | [redacted] Single-Axis Tracker | -No financial information has been provided during the procurement process. [redacted] can provide financial support letters upon shortlisting of its proposal by the Upper Peninsula Power.<br>-The Respondent didn't provide information in regards to the PPA Buyout Price. The Respondent stated: [redacted] does not propose a PPA Buyout option at this time as we believe it will impede the ability of the project to secure the lowest cost of long-term financing. In past financings, [redacted] has found "break-up fees" related to early debt pay-off and the "unwinding" of deferred tax liabilities to tax credit investors both impose greater costs than benefits of such an option purchase transaction. Furthermore, Internal Revenue Service rules dictate that a Buyout option must be at Fair Market Value, otherwise the option holder will be considered an owner, for ITC purposes, at initial Commercial Operation. [redacted] has thus focused on RFP Option 2A, where UPPCO purchases a cash equity stake in the project in year 6 from COD equal to 53% of the project. The year by year Equity Purchase Prices, starting in year 6, will be determined in a follow up analysis, should the PPA rate meet UPPCO's shortlisting criteria".<br>-EPC cost breakout not provided |
| Info. not provided | [redacted] | Offered Ownership (as % of total sponsor and tax equity) | 53% stake requested. Information Not Provided for valuation purposes | See values for PPA options | Information Not Provided for valuation purposes | 3.45 | Option 2.A | [redacted] Single-Axis Tracker | -No financial information has been provided during the procurement process. [redacted] can provide financial support letters upon shortlisting of its proposal by the Upper Peninsula Power.<br>-EPC cost breakout not provided |

Solar RFP Evaluation Summary
by WSP

## VALUATION

| Rank | Company | Rated Part I Comments |
|---|---|---|
| 1 | [redacted] | -[redacted] stated that they can provide financial support letters upon shortlisting of its proposal by UPPCO.<br>-[redacted] is in discussions with [redacted] . [redacted] about providing constructions services to the [redacted] Solar project (located near [redacted], Michigan). [redacted] would operate as [redacted] in Michigan's Upper Peninsula.<br>- Doesn't address Commercial Terms in Narrative<br>- Didn't provide a Project Execution Plan |
| 2 | [redacted] | -[redacted] stated that they can provide financial support letters upon shortlisting of its proposal by UPPCO.<br>-[redacted] is in discussions with [redacted] ) about providing constructions services to the [redacted] Solar project (located near [redacted], Michigan). [redacted] would operate as [redacted] in Michigan's Upper Peninsula.<br>- Doesn't address Commercial Terms in Narrative<br>- Didn't provide a Project Execution Plan |
| 3 | [redacted] | - EPC subcontractors not been selected. Once the project details and Scope of Work for the UPPCO project are finalized, [redacted] will conduct a competitive bidding process among our network of Michigan-licensed installation subcontractors. For many of our Midwest projects, [redacted] partnered with [redacted] as the installation subcontractor.<br>-[redacted] is generally comfortable with the overall term sheet provided and would seek clarification on a few points during the negotiation process. |
| 4 | [redacted] | -[redacted] stated that they can provide financial support letters upon shortlisting of its proposal by UPPCO.<br>-[redacted] is in discussions with [redacted] about providing constructions services to the [redacted] Solar project (located near [redacted], Michigan). [redacted] would operate as [redacted] in Michigan's Upper Peninsula.<br>- Doesn't address Commercial Terms in Narrative<br>- Didn't provide a Project Execution Plan |
| 5 | [redacted] | - EPC contractor not selected. For the proposed project, Respondent stated that they would be confident to partner with any of the following EPC contractors as our general contractor For the project: [redacted] among others.<br>-[redacted] provided exceptions to term sheet. |
| 6 | [redacted] | - EPC subcontractors not been selected. Once the project details and Scope of Work for the UPPCO project are finalized, [redacted] will conduct a competitive bidding process among our network of Michigan-licensed installation subcontractors. For many of our Midwest projects, [redacted] partnered with [redacted] as the installation subcontractor.<br>-[redacted] is generally comfortable with the overall term sheet provided and would seek clarification on a few points during the negotiation process. |
| 7 | [redacted] | - EPC subcontractors not been selected. Once the project details and Scope of Work for the UPPCO project are finalized, [redacted] will conduct a competitive bidding process among our network of Michigan-licensed installation subcontractors. For many of our Midwest projects, [redacted] partnered with [redacted] as the installation subcontractor.<br>-[redacted] s generally comfortable with the overall term sheet provided and would seek clarification on a few points during the negotiation process. |
| 8 | [redacted] | - EPC subcontractors not been selected. Once the project details and Scope of Work for the UPPCO project are finalized, [redacted] will conduct a competitive bidding process among our network of Michigan-licensed installation subcontractors. For many of our Midwest projects, [redacted] partnered with [redacted] as the installation subcontractor.<br>-[redacted] s generally comfortable with the overall term sheet provided and would seek clarification on a few points during the negotiation process. |
| 9 | [redacted] | - EPC subcontractors not been selected. Once the project details and Scope of Work for the UPPCO project are finalized, [redacted] will conduct a competitive bidding process among our network of Michigan-licensed installation subcontractors. For many of our Midwest projects, [redacted] partnered with [redacted] as the installation subcontractor.<br>-[redacted] s generally comfortable with the overall term sheet provided and would seek clarification on a few points during the negotiation process. |
| 10 | [redacted] | - EPC subcontractors not been selected. Once the project details and Scope of Work for the UPPCO project are finalized, [redacted] will conduct a competitive bidding process among our network of Michigan-licensed installation subcontractors. For many of our Midwest projects, [redacted] partnered with [redacted] as the installation subcontractor.<br>-[redacted] is generally comfortable with the overall term sheet provided and would seek clarification on a few points during the negotiation process. |
| 11 | [redacted] | - EPC subcontractors not been selected. Once the project details and Scope of Work for the UPPCO project are finalized, [redacted] will conduct a competitive bidding process among our network of Michigan-licensed installation subcontractors. For many of our Midwest projects, [redacted] partnered with [redacted] as the installation subcontractor.<br>-[redacted] s generally comfortable with the overall term sheet provided and would seek clarification on a few points during the negotiation process. |
| 12 | [redacted] | - At this time, an EPC Contractor has not been selected, but potential options include [redacted] .<br>- Respondent stated that a Project Execution Plan, Quality Assurance and Quality Control Plan and Program and Level 2 Project Schedule can be provided upon selection.<br>- Upon project short list, Respondent stated that it can provide a redlined basic term sheet along with a form of PPA consistent with the proposal. |
| 13 | [redacted] | - EPC subcontractors not been selected. Once the project details and Scope of Work for the UPPCO project are finalized, [redacted] will conduct a competitive bidding process among our network of Michigan-licensed installation subcontractors. For many of our Midwest projects, [redacted] partnered with [redacted] as the installation subcontractor.<br>-[redacted] is generally comfortable with the overall term sheet provided and would seek clarification on a few points during the negotiation process. |
| 14 | [redacted] | - EPC contractor not selected. For the proposed project, Respondent stated that they would be confident to partner with any of the following EPC contractors as our general contractor For the project: [redacted] , among others.<br>-[redacted] provided exceptions to term sheet. |
| 15 | [redacted] | - EPC contractor not selected. For the proposed project, Respondent stated that they would be confident to partner with any of the following EPC contractors as our general contractor For the project: [redacted] , among others.<br>-[redacted] provided exceptions to term sheet. |
| 16 | [redacted] | - EPC contractor not selected. For the proposed project, Respondent stated that they would be confident to partner with any of the following EPC contractors as our general contractor For the project: [redacted] among others.<br>-[redacted] provided exceptions to term sheet. |
| 17 | [redacted] | -[redacted] provides in-house EPC services.<br>-[redacted] provided exceptions to term sheet.<br>- Insurance claim: Ontario, New York, solar, photovoltaic project was completed without additional cost to the owner due to the force majeure wind event and without material change to the project schedule. |
| 18 | [redacted] | -[redacted] provides in-house EPC services.<br>-[redacted] provided exceptions to term sheet.<br>- Insurance claim: Ontario, New York, solar, photovoltaic project was completed without additional cost to the owner due to the force majeure wind event and without material change to the project schedule. |
| 19 | [redacted] | -[redacted] provides in-house EPC services.<br>-[redacted] provided exceptions to term sheet.<br>- Insurance claim: Ontario, New York, solar, photovoltaic project was completed without additional cost to the owner due to the force majeure wind event and without material change to the project schedule. |
| 20 | [redacted] | -[redacted] provides in-house EPC services.<br>-[redacted] provided exceptions to term sheet.<br>- Insurance claim: Ontario, New York, solar, photovoltaic project was completed without additional cost to the owner due to the force majeure wind event and without material change to the project schedule. |
| 21 | [redacted] | - EPC subcontractors not been selected. Once the project details and Scope of Work for the UPPCO project are finalized, [redacted] will conduct a competitive bidding process among our network of Michigan-licensed installation subcontractors. For many of our Midwest projects, [redacted] partnered with [redacted] as the installation subcontractor.<br>-[redacted] s generally comfortable with the overall term sheet provided and would seek clarification on a few points during the negotiation process. |
| 22 | [redacted] | - EPC contractor not selected. For the proposed project, Respondent stated that they would be confident to partner with any of the following EPC contractors as our general contractor For the project: [redacted] , among others.<br>-[redacted] provided exceptions to term sheet. |
| 23 | [redacted] | - EPC subcontractors not been selected. Once the project details and Scope of Work for the UPPCO project are finalized, [redacted] will conduct a competitive bidding process among our network of Michigan-licensed installation subcontractors. For many of our Midwest projects, [redacted] partnered with Faith Technologies as the installation subcontractor.<br>-[redacted] is generally comfortable with the overall term sheet provided and would seek clarification on a few points during the negotiation process. |
| 24 | [redacted] | - EPC subcontractors not been selected. Once the project details and Scope of Work for the UPPCO project are finalized, [redacted] will conduct a competitive bidding process among our network of Michigan-licensed installation subcontractors. For many of our Midwest projects, [redacted] partnered with [redacted] as the installation subcontractor.<br>-[redacted] is generally comfortable with the overall term sheet provided and would seek clarification on a few points during the negotiation process. |
| 25 | [redacted] | -[redacted] provides in-house EPC services.<br>-[redacted] provided exceptions to term sheet.<br>- Insurance claim: Ontario, New York, solar, photovoltaic project was completed without additional cost to the owner due to the force majeure wind event and without material change to the project schedule. |
| 26 | [redacted] | -[redacted] provides in-house EPC services.<br>-[redacted] provided exceptions to term sheet.<br>- Insurance claim: Ontario, New York, solar, photovoltaic project was completed without additional cost to the owner due to the force majeure wind event and without material change to the project schedule. |

Solar RFP Evaluation Summary
by WSP

## VALUATION

| Rank | Company | Rated Part I Comments |
|---|---|---|
| 27 | [redacted] | - EPC contractor not selected. For the proposed project, Respondent stated that they would be confident to partner with any of the following EPC contractors as our general contractor For the project: [redacted], among others.<br>-[redacted] provided exceptions to term sheet. |
| 28 | [redacted] | - EPC subcontractors not been selected. Once the project details and Scope of Work for the UPPCO project are finalized, [redacted] will conduct a competitive bidding process among our network of Michigan-licensed installation subcontractors. For many of our Midwest projects, [redacted] partnered with [redacted] as the installation subcontractor.<br>-[redacted] s generally comfortable with the overall term sheet provided and would seek clarification on a few points during the negotiation process. |
| 29 | [redacted] | -[redacted] will partner with [redacted], for this project for EPC. [redacted] is the local branch of [redacted], and was the EPC provider for Michigan's largest solar project, the 47.5MW AC project in Lapeer, MI, for DTE Energy.<br>- Doesn't address Commercial Terms in Narrative |
| 30 | [redacted] | -[redacted] will partner with [redacted], for this project for EPC. [redacted] is the local branch of [redacted], and was the EPC provider for Michigan's largest solar project, the 47.5MW AC project in Lapeer, MI, for DTE Energy.<br>- Doesn't address Commercial Terms in Narrative |
| Info. not provided | [redacted] | - At this time, an EPC Contractor has not been selected, but potential options include [redacted].<br>- Respondent stated that a Project Execution Plan, Quality Assurance and Quality Control Plan and Program and Level 2 Project Schedule can be provided upon selection.<br>- Upon project short list, Respondent stated that it can provide a redlined basic term sheet along with a form of PPA consistent with the proposal. |
| N/A | [redacted] | -[redacted] stated that they can provide financial support letters upon shortlisting of its proposal by UPPCO.<br>-[redacted] is in discussions with [redacted] about providing constructions services to the [redacted] Solar project (located near [redacted] Michigan). IEA would operate as White Construction in Michigan's Upper Peninsula.<br>- Doesn't address Commercial Terms in Narrative<br>- Didn't provide a Project Execution Plan |
| N/A | [redacted] | -[redacted] will partner with [redacted] for this project for EPC. [redacted] is the local branch of [redacted], and was the EPC provider for Michigan's largest solar project, the 47.5MW AC project in Lapeer, MI, for DTE Energy.<br>- Doesn't address Commercial Terms in Narrative |
| N/A | [redacted] | - At this time, an EPC Contractor has not been selected, but potential options include [redacted].<br>- Respondent stated that a Project Execution Plan, Quality Assurance and Quality Control Plan and Program and Level 2 Project Schedule can be provided upon selection.<br>- Upon project short list, Respondent stated that it can provide a redlined basic term sheet along with a form of PPA consistent with the proposal. |
| N/A | [redacted] | -[redacted] stated that they can provide financial support letters upon shortlisting of its proposal by UPPCO.<br>-[redacted] in discussions with [redacted]) about providing constructions services to the [redacted] Solar project (located near [redacted], Michigan). [redacted] in Michigan's Upper Peninsula.<br>- Doesn't address Commercial Terms in Narrative<br>- Didn't provide a Project Execution Plan |
| Info. not provided | [redacted] | -[redacted] stated that they can provide financial support letters upon shortlisting of its proposal by UPPCO.<br>-[redacted] is in discussions with [redacted] about providing constructions services to the [redacted] Solar project (located near [redacted], Michigan). [redacted] would operate as [redacted] in Michigan's Upper Peninsula.<br>- Doesn't address Commercial Terms in Narrative<br>- Didn't provide a Project Execution Plan |

# MICHIGAN AIR PERMIT-TO-INSTALL PERMIT PROCESS ANALYSIS

## PROPOSED [redacted] ELECTRIC GENERATION FACILITY

## PREPARED FOR: UPPER PENINSULA POWER COMPANY

## ISHPEMING, MICHIGAN

***February 2019***

*Prepared by:*

AECOM

800 LaSalle Avenue
Suite 500
Minneapolis, MN 54402

# TABLE OF CONTENTS

# 1 INTRODUCTION

The Upper Peninsula Power Company (UPPCO) is proposing to construct a new electric power generation facility at a site near [redacted], Michigan (Project).

For the purposes of this analysis, AECOM assumed that the Project would include construction of two 13,469 horsepower natural gas fired reciprocating internal combustion engines (RICE) each driving a 9.34 MW electric generator for a total nameplate rating of 18.7 MW. The RICE will be sources of criteria air pollutants, hazardous air pollutants (HAPs) and toxic air contaminants (TACs) as defined by United States Environmental Protection Agency (USEPA) and Michigan Department of Environmental Quality (MDEQ) regulations.

The proposed Project would be required to apply for and receive an air Permit to Install (PTI) prior to beginning actual construction of the facility. Following construction and startup, the Project would also be required to apply for and receive a Renewable Operating Permit (ROP).

The following the following elements are discussed in the following sections:

1) Potential to emit calculations based on published emission factors for natural gas fired RICE;

2) A summary of the federal and state air regulations applicable to the Project;

3) A summary of required pollution control equipment on the RICE;

4) A summary of the air permit needed and the elements required in an air permit application for this installation;

5) A business risk summary related to the air permitting process; and

6) A summary of the potential permitting timeline

# 2 POTENTIAL TO EMIT

The USEPA and MDEQ regulations require that the potential to emit (PTE) for a new or modified facility be calculated to determine what type of air permit, if any, is required. For the Project, AECOM assumed that the Project emission units would consist of two 13,469 horsepower natural gas fired reciprocating internal combustion engines (RICE) each driving a 9.34 MW electric generator for a total nameplate rating of 18.7 MW.

The USEPA and MDEQ regulations require that the PTE be calculated assuming that the units will operate 24 hours per day, 365 days per year (i.e. 8760 hours per year) at their maximum design capacity, unless the Project proposer, UPPCO, accepts federally enforceable limits on the operation of the RICE.

For the purposes of the calculating the PTE for the Project, AECOM assumed that each RICE would operate in startup or shutdown mode for 300 hours per year and run at 100 percent of the rated nameplate capacity for the remaining 8460 hours per year. The hours spent in startup and shutdown mode typically have a higher emission rate (lb/hr) than normal operations, so are included in the PTE calculations.

UPPCO has not chosen the specific manufacturer for the RICE for the Project. Therefore, for the purposes of this analysis, AECOM utilized emission factors from a representative RICE used for the same purpose at other existing facilities. The uncontrolled PTE assumes that no add-on control equipment would be installed on the RICE. The controlled PTE assumes that pollution control equipment including a selective catalytic reduction system would be installed to control emissions of nitrogen oxides ($NO_X$) and an oxidation catalyst would be installed to control emissions of carbon monoxide (CO) and volatile organic compounds (VOCs).

The PTE for the proposed RICE are shown in the Table below.

**Table 1 - [redacted] Project Potential to Emit**

| Regulated Pollutant | Uncontrolled PTE Ton/year | Controlled PTE Ton/year |
|---|---|---|
| Particulate matter less than 2.5 micron ($PM_{2.5}$) | 18.8 | 18.7 |
| Particulate matter less than 10 micron ($PM_{10}$) | 18.8 | 18.7 |
| Nitrogen Oxides ($NO_X$) | 260.1 | 15.3 |
| Sulfur Oxides ($SO_X$) | 0.7 | 0.7 |
| Carbon Monoxide (CO) | 520.3 | 24.3 |
| Volatile Organic Compounds (VOC) | 182.1 | 21.6 |
| Ammonia | 0.0 | 9.0 |
| Carbon Dioxide ($CO_2$) | 73,734 | 73,734 |
| Methane ($CH_4$) | 838 | 349 |

| Regulated Pollutant | Uncontrolled PTE Ton/year | Controlled PTE Ton/year |
|---|---|---|
| Carbon Dioxide Equivalent ($CO_{2e}$) | 94,681 | 82,462 |
| Single Highest Hazardous Air Pollutant (HAP) | 35.4 | 15.4 |
| Total Combined HAP | 48.2 | 21.1 |

# 3 FEDERAL AND STATE REGULATIONS

**FEDERAL REGULATIONS**

Federal regulations for air-emitting processes and equipment are promulgated under the Clean Air Act (CAA). The CAA authorized the development of the Prevention of Significant Deterioration preconstruction permitting rules, detailed in 40 CFR 52.21; New Source Performance Standards (NSPS), detailed in 40 CFR 60; and the National Emission Standards for Hazardous Air Pollutants (NESHAP), detailed in 40 CFR 61 and 40 CFR 63.

Prevention of Significant Deterioration

The Prevention of Significant Deterioration (PSD) regulations apply to new facilities that would be major sources of criteria pollutants in areas that are in attainment for the National Ambient Air Quality Standards (NAAQS). The [redacted] area has been designated as being in attainment for all criteria pollutants. Therefore, the major source thresholds for the Project are shown in the table below.

**Table 2 - PSD Thresholds**

| Pollutant | PSD Threshold Ton/Year |
|---|---|
| $PM_{2.5}$ | 250 |
| $PM_{10}$ | 250 |
| $NO_X$ | 250 |
| $SO_X$ | 250 |
| CO | 250 |
| VOC | 250 |

Proposed new facilities whose PTE exceeds the PSD threshold listed above are required to complete the following analyses as part of the permit application process.

- Best Available Control Technology (BACT) analysis
- NAAQS air quality modeling analysis
- PSD increment air quality modeling analysis
- Class I area increment consumption modeling analysis
- Class I area visibility modeling analysis
- Additional impacts analysis
    - growth analysis (workforce, housing, industry)
    - NAAQS air quality modeling analysis for impacts from growth

- soil and vegetation impact analysis

In addition, up to one year of pre-construction air quality monitoring can be required before the PSD permit application is submitted to the MDEQ.

As shown in Table 1, the uncontrolled emissions from the Project would exceed the PSD thresholds for $NO_X$ and CO. However, USEPA and MDEQ regulations allow a project proposer to presumptively install pollution control equipment to limit emissions to less than the PSD thresholds. Assuming the Project would include the installation of a SCR system and oxidation catalyst, the controlled PTE of the Project would be less than the PSD thresholds and the facility would qualify for a "synthetic" minor PTI. As a synthetic minor source, the Project would not be required to complete the elements of the PSD pre-construction permit application.

National Emission Standard for Hazardous Air Pollutants

The Project RICE will be subject to the National Emission Standards for Hazardous Air Pollutants Program (NESHAPs) for Stationary Reciprocating Internal Combustion Engines (40 CFR 63, Subpart ZZZZ). However, the Project will comply with the requirements of the NESHAP by complying with the requirements of the New Source Performance Standard (NSPS) for Stationary Spark Ignition Internal Combustion Engines (40 CFR 60, Subpart JJJJ) discussed below.

New Source Performance Standards

The Project RICE will be subject to the New Source Performance Standard (NSPS) for Stationary Spark Ignition Internal Combustion Engines (40 CFR 60, Subpart JJJJ). This NSPS sets emission limits for $NO_X$, CO, and VOCs and requires initial and recurring emission performance testing.

**STATE OF MICHIGAN REGULATIONS (PART 55):**

The State of Michigan regulations for air-emitting processes and equipment are promulgated under Part 55 of the Michigan Air Pollution Control Rules (MAPCR).

Rule 201 (Permit-to-Install): Rule 201 spells out the criteria for obtaining a PTI. Per Rule 201, the Project would not qualify for any exemptions and a PTI application would be required to be submitted and a permit issued before construction could begin on the Project.

Rule 224 (T-BACT Requirement): In accordance with R 336.1224 T-BACT requirement for new and modified source of air toxics; exemptions, Subpart 2**,** the requirement for T-BACT in subrule (1) of this rule shall not apply to any of the following:

> R336.1224 Subpart 2(a) – An emission unit or units for which standards have been promulgated under section 112(d) of the clean air act or for which a control technology determination has been made under section 112(g) or 112(j).

The NESHAP for Stationary Reciprocating Internal Combustion Engines applies to the Project RICE, therefore a T-BACT analysis is not required.

Rule 225 (Toxic Air Contaminants)

The Project would need to demonstrate that the emissions from the RICE would meet requirements of Rule 225 for all air toxics.

Rule 241 (Air Quality Modeling Demonstration Requirements

[redacted], Michigan is currently in attainment for the National Ambient Air Quality Standards for all pollutants.

The MDEQ has published an ambient air quality modeling guidance document in support of the requirements of Rule 241. That guidance document indicates that, based on the controlled PTE shown in Table 1, the Project would have to undergo an ambient air quality modeling analysis for $PM_{10}$ and $PM_{2.5}$.

MDEQ Rule 241 specifies that the Project would have to demonstrate compliance with the NAAQS and PSD increment, even though the project would not be subject to PSD pre-construction permitting requirements.

# 4 POLLUTION CONTROL EQUIPMENT

In the absence of voluntary, presumptive installation of pollution control, the Project would trigger a requirement to go through the PSD pre-construction permitting process. The BACT requirement of the PSD process would require the identification and ultimately the installation of pollution control equipment to reduce $NO_X$ and CO emissions.

Currently, SCR and oxidation catalyst are considered to be BACT for natural gas RICE of the size being considered for the Project. Therefore, it is assumed that SCR and oxidation catalyst would be required for each RICE.

# 5 AIR PERMIT APPLICATION SUMMARY

Assuming the Project proposed opts to submit an application for a synthetic minor PTI, the application would need to include the following elements:

- A MDEQ PTI Application form;
- PTE calculations for the Project;
- A compliant ambient air quality analysis for the NAAQS and PSD increment;
- A summary of applicable federal and state regulations.

# 6 BUSINESS RISK SUMMARY

In 2017, the MDEQ issued PTIs for two new natural gas fired electric generating facilities to be constructed in the Upper Peninsula of Michigan. The project proposer for both projects was the Upper Michigan Energy Resources Corporation. The two projects are:

F.D. Kuester Generating Station

Negaunee Township, Michigan

PTI Issued - August 24, 2017

Project Summary - Seven nominally rated 25,828 HP (18,817 kW) natural gas-fueled reciprocating internal combustion engine (RICE) generators with oxidation catalyst and selective catalytic reduction (SCR).

A.J. Mihm Generating Station

Baraga Township, Michigan

PTI Issued - August 24, 2017

Project Summary - Three nominally rated 25,828 HP (18,817 kW) natural gas-fueled reciprocating internal combustion engine (RICE) generators with oxidation catalyst and selective catalytic reduction (SCR).

Given that PTIs were issued in 2017 for two significantly larger electric generating facilities that will utilize a similar RICE technology, there do not appear to be administrative or regulatory prohibitions applicable to the Project, provided that the Project demonstrates compliance with the applicable regulations and PTI requirements.

# 7 PERMIT TO INSTALL TIMELINE

The complete PTI applications for the two Upper Michigan Energy Resources Corporation facilities discussed in Section 6 were received by the MDEQ in April 2017. The PTIs for both facilities were issued in August 2017 for permit issuance timeline of approximately four months.

Timelines in 2018 for similar synthetic minor permits frequently took less than 6 months for processing from the receipt of a complete application to issuance of the final permit.

# APPENDIX A

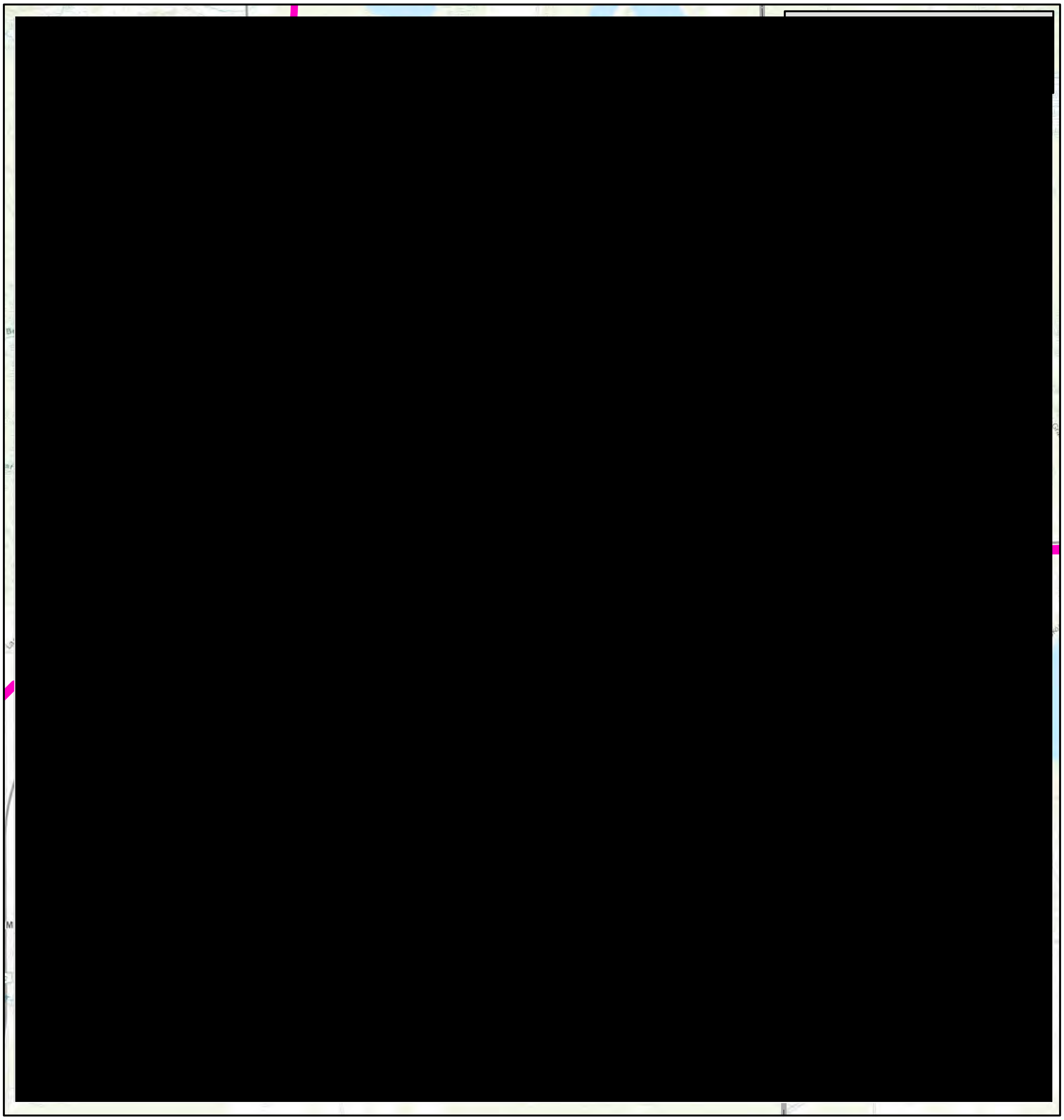
# FACILITY LOCATION MAP

Site Location Map
[redacted] MI

General Location Map

STEIGERWALDT
Your confidence lands here.

January 2019



[redacted]

Map Disclaimer:
This map is intended to provide a visual representation of property and geographic features. It is not a legal survey but a depiction of the property based on reasonably available information suitable for the intended purposes. This map shows the approximate relative location of property boundaries but was not prepared by a professional land surveyor. The use of this map is limited to applications consistent with the intent and accuracy of the map and source data. It may not be sufficient or appropriate for legal, engineering, or surveying purposes. No guarantees or warranties are expressed. This map is not a survey of the actual boundary of any property this map depicts.

# APPENDIX B

# EMISSIONS CALCULATIONS

**Upper Peninsula Power Company**
**Proposed [redacted] Power Facility**
**31-Jan-19**

For the purposes of this evaluation, it was assumed that the facility would consist of two nominal 9.3 MW electric generators powered by natural gas fired, spark ignited reciprocating internal combustion engines. Specifications for a Wartsila 20V34SVG 4 Stroke Lean Burn Natural Gas Reciprocating Engine, for the emission calculations. Review of specifications for a Caterpillar G20CM34 engine show that unit would yield slightly higher annual emissions because it has a slightly higher HP capacity.

| **Performance** | | | |
|---|---|---|---|
| Power output | 9,341 | kWe | Wartsila data |
| Power output | 12,526 | bhpe | Calculated |
| Engine power | 13,469 | hp | assuming 93% enigne power to electricity efficiency |

| **Fuel use** | | | |
|---|---|---|---|
| Heat rate | 7,779 | kJ/kWh | Wartsila data based on LHV |
| Heat rate | 8,192 | Btu HHV/kWe | Calculated |
| Fuel use | 76.52 | MMBtu/hr HHV | Calculated |

**Emisisons before add-on emision controls**
**Emissions at MACT and NSPS Limits (40 CFR Part 63 Subpart ZZZZ and 40 CFR Part 60 Subpart JJJJ)**
**Not including startup and shutdown**

| | | | | | | |
|---|---|---|---|---|---|---|
| NOx | 1.0 | g/hp-hr | 82 | ppmvd at 15% O2 | 0.302 | lb/MMBtu |
| CO | 2.0 | g/hp-hr | 270 | ppmvd at 15% O2 | 0.605 | lb/MMBtu |
| VOC | 0.70 | g/hp-hr | 60 | ppmvd at 15% O2 | 0.077 | lb/MMBtu |
| $PM_{10}/PM_{2.5}$ | 0.0281 | lb/MMBtu | Prevention of Significant Deterioration - Air Construction Permit Application for the Lacey Randall Station - TradeWind energy, Inc., Burns & McDonnell, December 2013 | | | |
| SO2 | 0.001 | lb/MMBtu | | | | |
| $CO_2$ | 110 | lb/MMBtu | | | | |
| $CH_4$ | 1.25 | lb/MMBtu | AP-42, Table 3.2-2. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE LEAN-BURN ENGINES | | | |
| $CO_{2e}$ | 141.25 | lb/MMBtu | | | | |

| | | | PTE Per Unit | | Total Facility | |
|---|---|---|---|---|---|---|
| NOx | 29.69 | lb/hr | 130.1 | tons/year | 260.1 | tons/year |
| CO | 59.39 | lb/hr | 260.1 | tons/year | 520.3 | tons/year |
| VOC | 20.79 | lb/hr | 91.0 | tons/year | 182.1 | tons/year |
| $PM_{10}/PM_{2.5}$ | 2.15 | lb/hr | 9.4 | tons/year | 18.8 | tons/year |
| $SO_2$ | 0.08 | lb/hr | 0.3 | tons/year | 0.7 | tons/year |
| $CO_2$ | 8,417 | lb/hr | 36,867 | tons/year | 73,734 | tons/year |
| $CH_4$ | 96 | lb/hr | 419 | tons/year | 838 | tons/year |
| $CO_{2e}$ | 10,808 | lb/hr | 47,340 | tons/year | 94,681 | tons/year |

**Emissions with an oxidation catalyst and slective catalytic reduction**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| NOx | 0.061 | g/hp-hr | **5.00 (a)** | ppmvd at 15% O2 | 0.0184 | lb/MMBtu | 94% |
| CO | 0.111 | g/hp-hr | **15.00 (a)** | ppmvd at 15% O2 | 0.0336 | lb/MMBtu | 94% |
| VOC | 0.292 | g/hp-hr | **25.00 (a)** | ppmvd at 15% O2 | 0.0320 | lb/MMBtu | 58% |
| $PM_{10}/PM_{2.5}$ | | | | | **0.0281 (a)** | lb/MMBtu | |
| $SO_2$ | | | | | 0.0010 | lb/MMBtu | |
| Ammonia | | | **10.00 (a)** | ppmvd at 15% O2 | 0.0136 | lb/MMBtu | |

(a) Prevention of Significant Deterioration - Air Construction Permit Application for the Lacey Randall Station - TradeWind energy, Inc., Burns & McDonnell, December 2013

| | | | | |
|---|---|---|---|---|
| NOx | 1.41 | lb/hr | 6.2 | tons/year |
| CO | 2.57 | lb/hr | 11.3 | tons/year |
| VOC | 2.45 | lb/hr | 10.7 | tons/year |
| $PM_{10}/PM_{2.5}$ | 2.15 | lb/hr | 9.4 | tons/year |
| $SO_2$ | 0.08 | lb/hr | 0.3 | tons/year |
| Ammonia | 1.04 | lb/hr | 4.6 | tons/year |
| $CO_2$ | 8,417 | lb/hr | 36,867 | tons/year |
| $CH_4$ | 40 | lb/hr | 175 | tons/year |
| $CO_{2e}$ | 9,413 | lb/hr | 41,231 | tons/year |

**Annual Controlled Emisisons with an oxidation catalyst and slective catalytic reduction**

**Routine operation at 100% load**

| | | |
|---|---|---|
| Operating hours | 8,460 | hr/yr |
| NOx | 6.0 | ton/yr |
| CO | 10.9 | ton/yr |
| VOC | 10.4 | ton/yr |
| $PM_{10}/PM_{2.5}$ | 9.1 | ton/yr |
| $SO_2$ | 0.3 | ton/yr |
| Ammonia | 4.4 | ton/yr |

| Startup and shutdown | | | | |
|---|---|---|---|---|
| Number of startups | 300 | per year | | |
| NOx | 1.69 | ton/yr | **11.25 (a)** | lb/event |
| CO | 1.26 | ton/yr | **8.38 (a)** | lb/event |
| VOC | 0.43 | ton/yr | **2.86 (a)** | lb/event |
| $PM_{10}/PM_{2.5}$ | 0.23 | ton/yr | **1.55 (a)** | lb/event |
| $SO_2$ | 0.0035 | ton/yr | **0.023 (a)** | lb/event |
| Ammonia | 0.08 | ton/yr | **0.53 (a)** | lb/event |

(a)Prevention of Significant Deterioration - Air Construction Permit Application for the Lacey Randall Station - TradeWind energy, Inc., Burns & McDonnell, December 2013

| Total Controlled Annual Emissions Per Unit | | | | Total Controlled Annual Facility Emissions | | |
|---|---|---|---|---|---|---|
| NOx | | 7.6 | ton/yr | NOx | 15.3 | ton/yr |
| CO | | 12.1 | ton/yr | CO | 24.3 | ton/yr |
| VOC | | 10.8 | ton/yr | VOC | 21.6 | ton/yr |
| $PM_{10}/PM_{2.5}$ | | 9.3 | ton/yr | $PM_{10}/PM_{2.5}$ | 18.7 | ton/yr |
| $SO_2$ | | 0.3 | ton/yr | SO2 | 0.7 | ton/yr |
| Ammonia | | 4.5 | ton/yr | Ammonia | 9.0 | ton/yr |
| $CO_2$ | | 36867 | tons/year | $CO_2$ | 73734 | ton/yr |
| $CH_4$ | | 175 | tons/year | $CH_4$ | 349 | ton/yr |
| $CO_{2e}$ | | 41231 | tons/year | $CO_{2e}$ | 82462 | ton/yr |

| Hazardous Air Pollutants[1] | | | Total Uncontrolled Annual Emissions Per Unit | | Total Controlled Annual Emissions Per Unit | | Total Annual Facility Emissions |
|---|---|---|---|---|---|---|---|
| | | | lb/hr | ton/yr | lb/hr | ton/yr | ton/yr |
| 1,1,2,2 Tetrachloroethane | 4.00E-05 | lb/MMBtu | 0.003 | 0.013 | 0.001 | 0.006 | 0.01 |
| 1,1,2 Trichloroethane | 3.18E-05 | lb/MMBtu | 0.002 | 0.011 | 0.001 | 0.005 | 0.01 |
| 1,3, Butadiene | 2.67E-04 | lb/MMBtu | 0.020 | 0.089 | 0.009 | 0.039 | 0.08 |
| 1,3 Dichloropropene | 2.64E-05 | lb/MMBtu | 0.002 | 0.009 | 0.001 | 0.004 | 0.01 |
| 2,2,4 Trimethylpentane | 2.50E-04 | lb/MMBtu | 0.019 | 0.084 | 0.008 | 0.037 | 0.07 |
| Acetaldehyde | 8.36E-03 | lb/MMBtu | 0.640 | 2.802 | 0.267 | 1.223 | 2.45 |
| Acrolein | 5.14E-03 | lb/MMBtu | 0.393 | 1.723 | 0.164 | 0.752 | 1.50 |
| Benzene | 4.40E-04 | lb/MMBtu | 0.034 | 0.147 | 0.014 | 0.064 | 0.13 |
| Carbon Tetrachloride | 3.67E-05 | lb/MMBtu | 0.003 | 0.012 | 0.001 | 0.005 | 0.01 |
| Chlorobenzene | 3.04E-05 | lb/MMBtu | 0.002 | 0.010 | 0.001 | 0.004 | 0.01 |
| Chloroform | 2.85E-05 | lb/MMBtu | 0.002 | 0.010 | 0.001 | 0.004 | 0.01 |
| Ethylbenzene | 3.97E-05 | lb/MMBtu | 0.003 | 0.013 | 0.001 | 0.006 | 0.01 |
| Formaldehyde | 5.28E-02 | lb/MMBtu | 4.040 | 17.696 | 1.683 | 7.727 | 15.45 |
| Methanol | 2.50E-03 | lb/MMBtu | 0.191 | 0.838 | 0.080 | 0.366 | 0.73 |
| Methylene Chloride | 2.00E-05 | lb/MMBtu | 0.002 | 0.007 | 0.001 | 0.003 | 0.01 |
| n-Hexane | 1.11E-03 | lb/MMBtu | 0.085 | 0.372 | 0.035 | 0.162 | 0.32 |
| Naphthalene | 7.44E-05 | lb/MMBtu | 0.006 | 0.025 | 0.002 | 0.011 | 0.02 |
| Phenol | 2.40E-05 | lb/MMBtu | 0.002 | 0.008 | 0.001 | 0.004 | 0.01 |
| Styrene | 2.36E-05 | lb/MMBtu | 0.002 | 0.008 | 0.001 | 0.003 | 0.01 |
| Toluene | 4.08E-04 | lb/MMBtu | 0.031 | 0.137 | 0.013 | 0.060 | 0.12 |
| Vinyl Chloride | 1.49E-05 | lb/MMBtu | 0.001 | 0.005 | 0.000 | 0.002 | 0.00 |
| Xylene | 1.84E-04 | lb/MMBtu | 0.014 | 0.062 | 0.006 | 0.027 | 0.05 |
| Polycyclic Compounds | 1.19E-04 | lb/MMBtu | 0.009 | 0.040 | 0.004 | 0.017 | 0.03 |
| **Total** | | | | **24.1** | | **10.5** | **21.06** |

[1]AP-42, Table 3.2-2. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE LEAN-BURN ENGINES

**S T A T E  O F  M I C H I G A N**

**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

*** * * ***

| | | |
|---|---|---|
| In the matter of the application of | ) | |
| **UPPER PENINSULA POWER COMPANY** | ) | Case No. U-20350 |
| for approval of its integrated resource plan | ) | |
| pursuant to MCL 460.6t and for other relief. | ) | |

**PROOF OF SERVICE**

Allison Kellogg, being first duly sworn, deposes and says that on February 12, 2019, she served the ***Redacted Version of Upper Peninsula Power Company's Application and the Testimony and Exhibits of Upper Peninsula Power Company witnesses Gradon R. Haehnel, Andrew McNeally, Eric W. Stocking, and David R. Tripp, P.E.*** upon the parties set forth on the attached Service List via electronic mail.

Allison Kellogg

Subscribed and sworn before me
on this 12th day of February, 2019.

Kimberly S. Fox, Notary Public
State of Michigan, Eaton County
My Commission Expires: July 20, 2023
Acting in Ingham County

**SERVICE LIST**
**Parties to Case #U-20276**

**Michigan Public Service Commission Staff**
Amit T. Singh (P75492)
Daniel E. Sonneveldt (P58222)
Emily A. Jefferson (P81040)
7109 W. Saginaw Hwy., 3rd Floor
Lansing, MI 48917
singha9@michigan.gov
sonneveldtd@michigan.gov
jeffersone1@michigan.gov

**Michigan Attorney General**
Michael E. Moody (P51985)
Public Service Division
7109 W. Saginaw Highway, 3rd Floor
Lansing, MI 48917
moodym2@michigan.gov
ag-enra-spec-lit@michigan.gov

**Citizens Against Rate Excess (CARE)**
John R. Liskey
Constance De Young Groh
John R. Liskey Attorney At Law, PLLC
921 N. Washington Ave.
Lansing MI 48906
john@liskeypllc.com
cdgroh@liskeypllc.com

**Calumet Electronics Corporation**
Michael J. Brown
Carlin Edwards Brown PLLC
6017 W. St. Joseph Highway, Suite 202
Lansing MI 48917
mbrown@cebhlaw.com

**Association of Businesses Advocating Tariff Equity (ABATE)**
Sean P. Gallagher (P73108)
Stephen A. Campbell (P76684)
Clark Hill PLC
212 East César E. Chávez Avenue
Lansing, MI 48906
sgallagher@clarkhill.com
scampbell@clarkhill.com

James Dauphinais
Amanda Alderson
Brubaker & Associates, Inc.
P.O. Box 412000
St. Louis, MO
jdauphinais@consultbai.com
aalderson@consultbai.com

**Energy Michigan**
Laura Chappelle (P42052)
Timothy J. Lundgren (P62807)
Varnum LLP
333 Bridge St., NW
Grand Rapids, MI 49504
lachappelle@varnumlaw.com
tjlundgren@varnumlaw.com

**Verso Corporation**
Timothy J. Lundgren (P62807)
Justin K. Ooms (P82065)
Varnum LLP
333 Bridge St., NW
Grand Rapids, MI 49504
tjlundgren@varnumlaw.com
jkooms@varnumlaw.com

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) 284-8090.

***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 Peninsula Power Company Docket No. U-20350

Please enter my appearance in the above-entitled matter on behalf of:

| |
|---|
| 1. (Name) Upper Peninsula Power Company |
| 2. (Name) |
| 3. (Name) |
| 4. (Name) |
| 5. (Name) |
| 6. (Name) |
| 7. (Name) |

Name Paul M. Collins
Address One Michigan Avenue, Ste. 900

City Lansing State MI
Zip 48933 Phone (517) 483-4954
Email collinsp@millercanfield.com
Date February 12, 2019

☐ I am not an attorney
☑ I am an attorney whose:
Michigan Bar # is P-69719
_____________Bar # is: _____________
( state )

Signature: ______________________

Save Form

EAHR1 - 09/29/2016

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) 284-8090.

***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 Peninsula Power Company Docket No. U-20350

Please enter my appearance in the above-entitled matter on behalf of:

| |
|---|
| 1. (Name)<br>Upper Peninsula Power Company |
| 2. (Name) |
| 3. (Name) |
| 4. (Name) |
| 5. (Name) |
| 6. (Name) |
| 7. (Name) |

Name Sherri A. Wellman

Address One Michigan Avenue, Ste. 900

City Lansing State MI

Zip 48933 Phone (517) 483-4954

Email wellmans@millercanfield.com

Date February 12, 2019

☐ I am not an attorney

☑ I am an attorney whose:

Michigan Bar # is P-38989

_____________ Bar # is: _____________
( state )

Signature: ______________________________

Save Form

EAHR1 - 09/29/2016

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) 284-8090.

***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 Peninsula Power Company Docket No. U-20350

Please enter my appearance in the above-entitled matter on behalf of:

| |
|---|
| 1. (Name) Upper Peninsula Power Company |
| 2. (Name) |
| 3. (Name) |
| 4. (Name) |
| 5. (Name) |
| 6. (Name) |
| 7. (Name) |

Name Matthew S. Carstens

Address One Michigan Avenue, Ste. 900

City Lansing State MI

Zip 48933 Phone (517) 483-4922

Email carstens@millercanfield.com

Date February 12, 2019

☐ I am not an attorney

☑ I am an attorney whose:

Michigan Bar # is P-61070

____________Bar # is: ____________
( state )

Signature: ______________________________

Save Form

EAHR1 - 09/29/2016