Before The Public Service Commission
Of the State of Montana

DOCKET NO. 2019.09.59

QF-1 Tariff
Update Application

October 2019

NorthWestern Energy
Delivering a Bright Future

October 4, 2019

Mr. Will Rosquist, Administrator
Montana Public Service Commission
1701 Prospect Avenue
Helena, MT 59620-2601

RE: Docket No. 2019.09.059. In the Matter of NorthWestern Energy's QF-1 Tariff Update Application

Dear Mr. Rosquist:

Enclosed for filing are one original and ten copies of NorthWestern Energy's ("NorthWestern") Application for Approval of Changes and Modifications to Schedule No. QF-1.

Included in this submittal are the following:

- Application and proposed QF-1 Tariff
- Prefiled Direct Testimony and Exhibits of Dr. Ben A. Fitch-Fleischmann, Mr. Michael S. Babineaux, Mr. Joseph M. Stimatz, Dr. Brandon K. Mauch, and Ms. Autumn M. Mueller

Three copies of this submittal are being delivered to the Montana Consumer Counsel.

The NorthWestern employee responsible for answering questions concerning this application or for inquiries to the appropriate members of the utility staff is:

Mr. Joe Schwartzenberger
Regulatory Affairs Department
NorthWestern Energy
11 East Park
Butte, MT 59701
joe.schwartzenberger@northwestern.com

NorthWestern's attorney in this matter is:

Ann B. Hill
NorthWestern Energy
208 North Montana, Suite 205
Helena, MT 59601
ann.hill@northwestern.com

NorthWestern requests that the names of Joe Schwartzenberger, Ann Hill, and Tracy Killoy appear on all service lists in this proceeding.

If you have any questions, please call me at (406) 497-3362.

Sincerely,

Joe Schwartzenberger by CRH

Joe Schwartzenberger
Director
Regulatory Affairs

Enclosures

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DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

IN THE MATTER OF NorthWestern	)	REGULATORY DIVISION
Energy's QF-1 Tariff Update Application	)	
	)	DOCKET NO. 2019.09.059

NorthWestern Energy's Application for Approval of Changes and Modifications to Schedule No. QF-1

NorthWestern Energy ("NorthWestern") respectfully submits this Application to the Montana Public Service Commission ("Commission") for approval of **c**hanges and modifications to Schedule No. QF-1 Qualifying Facility Power Purchase ("QF-1 Tariff"). In support thereof, NorthWestern states as follows:

I.

Applicant's full name and address are:

NorthWestern Energy
11 East Park
Butte, MT 59701

II.

The following described tariff sheets are the only electric sheets impacted by the proposals in this Application.

Schedule	Description	Sheet No.
QF-1	Qualifying Facility Power Purchase	74.1 to 74.6
CR-1	Contingency Reserves	85.1

III.

NorthWestern moves for Commission approval of a partial waiver of the application of Administrative Rule of Montana ("ARM") 38.2.1209, which requires an original plus ten copies of all pleadings and documents. If the Commission grants this waiver, NorthWestern will file an original plus ten copies of all testimony, but will only file an original of discovery requests, discovery responses, motions, and other pleadings in this docket.

There is good cause for the Commission to grant this waiver. The Commission has not updated the rule requiring ten copies since 1982. Over the past 37 years, the use of technology has negated the requirement for multiple copies of filings since the Commission now has access to all filings electronically. In addition, the Commission's rules allow for staff to request additional copies as needed. NorthWestern will accommodate requests for copies, but moves for a partial waiver to prevent filing unnecessary copies.

IV.

Attached hereto and incorporated by reference are the following documents:

- Appendix 1 – Proposed QF-1 Tariff
- Prefiled Direct Testimony and Exhibits of Dr. Ben Fitch-Fleischmann, Mr. Michael S. Babineaux, Mr. Joseph M. Stimatz, Dr. Brandon Mauch, and Ms. Autumn Mueller

WHEREFORE, NorthWestern respectfully requests the approval of the proposed QF-1, CR-1, and WI-1 Tariffs.

Respectfully submitted this 4th day of October 2019.

NORTHWESTERN ENERGY

By: Ann B. Hill

Ann B. Hill

Schedule No. QF-1

QUALIFYING FACILITY POWER PURCHASE

APPLICABILITY: Applicable to any Seller with nameplate capacity of 3 MW or less who enters into a Power Purchase Agreement (Agreement) with the Utility for the sale of electric power to the Utility from a Qualifying Facility (QF) as defined under the Rules of the Commission after *<<DATE of Final Order in Docket No. 2019.09.059>>* or who continues to sell electric power to the Utility after expiration of an Agreement entered into before *<<Date of Final Order in Docket No. 2019.09.059>>*.

The Utility shall purchase electrical energy for a term of not less than one month and not more than 15 years.

The QF-1 Tariff rates do not reflect Network Upgrade costs. The Seller is responsible for these costs pursuant to the Special Terms and Conditions in this schedule. Seller must apply for interconnection and enter into the applicable generation interconnection agreement with the Utility in addition to entering into an Agreement under the terms of this Tariff.

RATE OPTIONS: Seller may select from the following two rate options and sub-options: Option 1(a) and (b) and Option 2.

For all Rate Options, refer to Special Terms and Conditions Item 3 Disposition of RECs, Item 4 Ancillary Services, and Item 6 Network Upgrades.

A Seller selecting Option 1 Rates will be paid the Avoided Energy and Capacity Rate which corresponds to their resource type and Agreement length as reflected in Table 1 below, adjusted for Special Terms and Conditions. After the term of an Agreement has expired, and before a new Agreement is executed, the Seller will receive the Option 2 rate, adjusted for Special Terms and Conditions.

The Utility will update the Option 1 Rates every 12 months or when the total installed capacity of resources in the Utility's supply portfolio has changed by more than 40 MW since the previous Option 1 Rate update, whichever is sooner.

(continued)

Schedule No. QF-1

QUALIFYING FACILITY POWER PURCHASE

Option 1(a): Avoided Energy and Capacity Rates:

Option 1 Rates for Energy and Capacity						
	Solar		Wind		Hydro/other	
Contract Length (years)	Off-peak Rate ($/kWh)	On-peak Rate ($/kWh)	Off-peak Rate ($/kWh)	On-peak Rate ($/kWh)	Off-peak Rate ($/kWh)	On-peak Rate ($/kWh)
1	$0.01706	$0.01706	$0.00725	$0.01512	$0.01529	$0.05298
2	$0.01705	$0.01705	$0.00739	$0.01526	$0.01533	$0.05302
3	$0.01703	$0.01703	$0.00753	$0.01540	$0.01537	$0.05307
4	$0.01701	$0.01701	$0.00767	$0.01554	$0.01541	$0.05311
5	$0.01700	$0.01700	$0.00781	$0.01569	$0.01545	$0.05315
6	$0.01698	$0.01698	$0.00795	$0.01583	$0.01549	$0.05319
7	$0.01696	$0.01696	$0.00810	$0.01597	$0.01553	$0.05323
8	$0.01695	$0.01695	$0.00824	$0.01611	$0.01557	$0.05327
9	$0.01693	$0.01693	$0.00838	$0.01625	$0.01561	$0.05331
10	$0.01691	$0.01691	$0.00852	$0.01639	$0.01565	$0.05335
11	$0.01690	$0.01690	$0.00866	$0.01654	$0.01569	$0.05339
12	$0.01688	$0.01688	$0.00880	$0.01668	$0.01573	$0.05343
13	$0.01686	$0.01686	$0.00895	$0.01682	$0.01577	$0.05347
14	$0.01685	$0.01685	$0.00909	$0.01696	$0.01582	$0.05351
15	$0.01683	$0.01683	$0.00923	$0.01710	$0.01586	$0.05355

Payments: Rate x kWh metered during each Off-Peak Hours and On-Peak Hours period.

kWh = Metered kilowatt-hours supplied to the Utility for each Off-Peak Hours and On-Peak Hours period.

(continued)

QUALIFYING FACILITY POWER PURCHASE

Option 1(b): Agreement lengths: 1 month to 18 months – short-term.

RATE:

Energy ($/kWh):

i. Agreement lengths up to 1 year use Year 1 rates from above table.

ii. Agreement lengths 1 year to 18 months use Year 2 rates from above table.

Payments: Hourly Rate x Hourly kWh

kWh = Metered kilowatt hours supplied to the Utility in each hour.

Option 2: Agreement length of up to 15 years.

Rate: This rate is equal to the published Intercontinental Exchange (ICE) Mid-C index price for Heavy Load Hours and Light Load Hours, less $.00162/kWh basis adjustment between Mid-C and Montana, and applied to the Heavy Load and Light Load metered sales and purchases of Seller. Another Mid-C price index may be substituted if necessary, if ICE is no longer available.

Payments: Daily Heavy Load Hour and Light Load Hour Rate x Heavy Load and Light Load kWh

kWh = Metered kilowatt hours supplied to the Utility in each daily Heavy Load and Light Load period.

(continued)

Schedule No. QF-1

QUALIFYING FACILITY POWER PURCHASE

SPECIAL TERMS AND CONDITIONS:

1) Definitions:

A. "Agreement" means the Power Purchase Agreement between Seller and the Utility for a term of not less than one month.

B. Ancillary Services means those services that are necessary to support the transmission of capacity and energy for resources to loads while maintaining reliable operation of the Transmission Providers' Transmission System in accordance with Good Utility Practice. Under NorthWestern's Open Access Transmission Tariff ("OATT"), four ancillary services apply to this tariff:

Schedule 3, Regulation and Frequency Response Service;
Schedule 5, Operating Reserve – Spinning Reserve Service;
Schedule 6, Operating Reserve – Supplemental Reserve Service; and
Schedule 11, Flex Reserve Service (applies only to wind generators).

C. "Commission" means the Montana Public Service Commission.

D. "Contract Length" means the length of a Seller's contract with NorthWestern measured in whole years. For contract terms not in whole years, the length of a Seller's contract will be rounded up to the next whole year for purposes of determining applicable rates.

E. "Good Utility Practice" means any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods, and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act section 215(a)(4).

F. "Heavy Load Hours" means the weekday and Saturday hours ending 7 and through hour ending 22 inclusive, Pacific Prevailing Time, except NERC defined holidays. For purposes of this Tariff, Heavy Load Hours correspond to Peak hours as used on the ICE web site.

(continued)

QUALIFYING FACILITY POWER PURCHASE

G. “Intermittent” means generation resources with variable generation output from hour to hour. Specifically, wind and solar PV are considered to be Intermittent resources.

H. “Light Load Hours” means those hours not included in the definition of Heavy Load Hours. For purposes of this Tariff, Light Load Hours correspond to Off-Peak hours as used on the ICE web site.

I. “Network Upgrades” means additions, modifications, and upgrades to NorthWestern’s transmission system required at or beyond the point at which the Small Generating Facility interconnects with the transmission system to accommodate the interconnection with the Small Generating Facility to NorthWestern’s transmission system. Network Upgrades do not include Distribution Upgrades. Network Upgrades include interconnection Network Upgrades and transmission service Network Upgrades.

J. “Off-Peak Hours” means those hours in the year not included in the definition of On-Peak Hours.

K. “On-Peak Hours” means the Heavy Load hours for the months of January, February, July, August, and December.

L. “Other QF” means QF facilities other than hydroelectric-, wind-, or solar-powered resources.

M. “RECs” means renewable energy credits. One megawatt hour of renewable energy generation gives rise to one REC, and this REC embodies all environmental attributes of that renewable energy generation.

N. “Seller,” for purposes of this schedule, is any individual, partnership, corporation, association, government agency, political subdivision, municipality, or other entity that:

   a. Operates a QF; and

   b. Has entered into an Agreement(s) with the Utility stipulating the terms and conditions of the interconnection and separately the sale of electric power to the Utility.

O. “Transmission Provider” means the public utility (or its Designated Agent) that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides transmission service.

P. “Transmission System” means the facilities owned, controlled, or operated by the Transmission Provider that are used to provide transmission service.

(continued)

Schedule No. QF-1

QUALIFYING FACILITY POWER PURCHASE

Q. "Utility" means NorthWestern Energy.

2) Net Billing Option: If Seller contracts for Net Billing and the Seller's consumption kWh exceeds its production kWh, Seller shall be billed for power supply for the consumption kWh in excess of the production kWh in accordance with the Utility's applicable rate schedule. If Seller's consumption kWh is less than its production kWh, Seller shall receive a power supply payment (credit) for the production kWh in excess of the consumption kWh at the Rates specified above.

3) Disposition of RECs: QFs retain RECs but may still separately attempt to negotiate for the sale of RECs to NWE or other interested parties at any time that an Agreement remains in effect. Any such negotiation occurs separate from the Power Purchase Agreement and does not create a reopener that refreshes the rates in the Agreement.

4) Ancillary Services: Sellers must contractually agree to the provision of ancillary services for the term of the Agreement and may either self-supply these services under terms acceptable to NorthWestern or pay the Utility for these services according to NorthWestern's Open Access Transmission Tariff ("OATT"). Payment to the Utility for selection of service through the OATT, including payment from Sellers who receive an Option 2 Rate upon expiration of an Agreement, will result in a deduction from the total monthly payment made to the QF to reflect the provision of ancillary services.

5) Hourly Metering: Sellers are required to install interval metering capability if necessary to support the Rate Option chosen.

6) Network Upgrades: Any Seller must pay for network upgrade costs, including both generator interconnection and transmission service. Seller represents and warrants that Seller will not seek reimbursement from NorthWestern or the Transmission Provider for Network Upgrades.

SERVICE AND RATES SUBJECT TO COMMISSION JURISDICTION: All rates and service conditions under this Rate Schedule are governed by the rules and regulations of the Public Service Commission of Montana and are subject to revision as the Commission may duly authorize in the exercise of its jurisdiction.

CERTIFICATE OF SERVICE

I hereby certify that the original and 10 copies of NorthWestern Energy's QF-1 Tariff Update Application in Docket No. 2019.09.059 has been hand delivered to the Montana Public Service Commission and three copies to the Montana Consumer Counsel this date. It has also been e-filed on the PSC website and served on the most recent service list by mailing a copy thereof by first class mail, postage prepaid.

Date: October 4, 2019

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Department of Public Service Regulation
Montana Public Service Commission
Docket No. 2019.09.059
QF-1 Tariff Update Application
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF DR. BEN FITCH-FLEISCHMANN

ON BEHALF OF NORTHWESTERN ENERGY

TABLE OF CONTENTS

Exhibits

* Electronic exhibits provided on CD only

Witness Information

Q. Please identify yourself, your employer, and your title.

A. My name is Ben Fitch-Fleischmann. I am NorthWestern Energy's ("NorthWestern") Manager of Energy Supply Planning.

Q. Please describe your relevant experience and education.

A. I have been employed at NorthWestern since September of 2018. I am responsible for managing NorthWestern's team of analysts that conduct integrated supply resource planning and supply portfolio modeling. Before joining NorthWestern, I was a consultant to various stakeholders on energy and regulatory matters, including ratepayer advocates, independent power producers, regulated utilities, private companies, and government agencies such as the Montana Public Service Commission ("Commission"), the U.S. Department of Energy, Department of Labor, and the Environmental Protection Agency.

Prior to my work as a consultant, I was Senior Economist in the Energy Resources and Planning Division of the Oregon Public Utility Commission. I have a Ph.D. in Economics.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. I provide overviews of NorthWestern's application, proposed Electric Tariff Schedule No. QF-1 Qualifying Facility Power Purchase ("QF-1 Tariff") which applies to small Qualifying Facilities ("QF"), and the calculation of avoided costs. I then present NorthWestern's proposal to calculate QF-1 rates considering the four components to an avoided cost calculation: (1) avoided costs of energy, (2) avoided costs of capacity, (3) the costs of integrating the generation resource, and (4) the costs of interconnecting the resource to the system and delivering its generation to load. Finally, I present NorthWestern's proposed changes to several QF-1 Tariff provisions.

Q. What other witnesses provide testimony in support of NorthWestern's application?

A. Mr. Michael S. Babineaux presents testimony on the PowerSimm^{TM} modeling used to develop the avoided energy costs and the Southwest Power Pool's ("SPP") Planning Criteria used to calculate capacity contribution.

Mr. Joseph M. Stimatz provides estimates of the cost of the ancillary services that will be required to integrate small QFs that qualify under the QF-1 Tariff into NorthWestern's system.

Dr. Brandon K. Mauch, of Ascend Analytics, LLC, testifies to the hourly-level calculation used in the PowerSimm™ model to calculate avoided costs of energy to serve load and places the results in the context of current market conditions. Dr. Mauch also testifies to the transparency of the PowerSimm model, including the use of a reduced number of simulations for the QF-1 rate calculations.

Ms. Autumn M. Mueller recommends changes to the QF-1 Tariff to reflect the costs of physically connecting the QF resource to the system and delivering the QF's generation to the utility's load.

<u>Overview of Application</u>

Q. What is the purpose of NorthWestern's application?

A. NorthWestern seeks Commission approval to update the Option 1 rates and certain provisions in the QF-1 Tariff. The changes for which NorthWestern seeks approval are included in a redline version of the QF-1 Tariff attached as Exhibit__(BFF-1).

Regarding the calculation of rates, NorthWestern recommends a change from the proxy methodology the Commission utilized when it approved the QF-1 Tariff rates in 2017 in Docket No. 2016.05.039. Instead of the proxy methodology, NorthWestern recommends calculating avoided cost through 10 simulations of PowerSimm. In addition, rather than applying a

"Conditions 1, 2, and 3" analysis, NorthWestern recommends a calculation directly based on the avoided cost *to serve load*.

To calculate the avoided cost of capacity, NorthWestern proposes to calculate the capacity contribution using the SPP methodology and the capacity cost based on a proxy resource of a 50-megawatt ("MW") Aeroderivative Combustion Turbine ("AERO") located at the Dave Gates Generating Station ("DGGS"). This method has been approved by the Commission in its recent rulings for large QFs. The calculations of the avoided cost of capacity are contained in Exhibit__(BFF-2) and Exhibit__(BFF-3).

NorthWestern also recommends that the QF, rather than NorthWestern's customers, pay for the cost of ancillary services and Network Upgrade costs associated with the QF resource. This is because the need for these services and facilities is caused by the QF, and it is exceedingly unlikely that these services and facilities would provide any benefits other than the delivery of the QF generation to load.

Additional tariff modifications that NorthWestern recommends include:

- Expired contract pricing;
- Option 1 rate updates, and

- Definitions to match NorthWestern's Open Access Transmission Tariff ("OATT").

<u>Overview of the QF-1 Tariff</u>

Q. Please provide an overview of the QF-1 Tariff.

A. The QF-1 Tariff contains the standard rates applicable to QFs with a nameplate capacity of 3 MW or less. A QF may select from two rate options in the tariff. Option 1 includes avoided energy and capacity rates for three resource-specific categories (solar, wind, and hydro/other). Option 2 includes a rate based on the published Intercontinental Exchange ("ICE") Mid-Columbia ("Mid-C") index price. The maximum length of a power purchase agreement ("PPA") under the tariff is 15 years.

Q. When did the Commission last approve changes to the QF-1 Tariff?

A. The current rate structure is the result of the Commission's Final Order No. 7500c and Order on Reconsideration No. 7500d from Docket No. 2016.05.039. Order No. 7500c included a requirement that NorthWestern update the Option 1(a) QF-1 Tariff rates every August and February to reflect a 15-day average of forward prices beginning July 1 and January 1. The updates also reflect escalation rates taken from the most recent Energy Information Administration's (EIA) *Annual Energy Outlook* (AEO). As a result, NorthWestern has made five biannual Option 1(a) rate updates thus far: in August 2017, in February and August 2018, and in

February and August 2019. On September 4, 2019, the August 2019 updated rates were approved.

Order on Reconsideration No. 7500d provided for a maximum 15-year contract length and approved certain tariff language changes. The Commission approved these changes to NorthWestern's tariff effective January 2, 2018.

Q. Is the current rate structure still in effect?

A. Yes**.** Although the Eighth Judicial District Court modified the Commission's decisions from Docket No. 2016.05.039, the Montana Supreme Court stayed the District Court's decision pending judicial review. The Supreme Court has not yet issued a decision.

Q. What is the basis for the rates in the current QF-1 Tariff?

A. As required by the Public Utility Regulatory Policies Act of 1978 ("PURPA"), the rates are based on NorthWestern's avoided costs. The Commission approved the current QF-1 rates based on the proxy method. The proxy method assumes that the QF will allow the utility to delay or avoid its next planned generation unit. That avoided unit served as a proxy for both the avoided cost of energy and the avoided cost of capacity. This approach does not require the use of a production cost model, such as PowerSimm. The Commission explained that it approved the proxy method for the benefits it provides in terms of simplicity and transparency.

Q. Is the proxy method a reasonable method for calculating avoided cost in this docket?

A. No. Unlike previous plans, NorthWestern's 2019 Electricity Supply Resource Procurement Plan ("2019 Plan") does not identify a need for future resources whose costs could reasonably serve as proxy values for the costs that a QF could allow NorthWestern to avoid. In this filing, NorthWestern instead proposes to use the same modeling methods it uses for calculating the avoided costs for large QFs and for portfolio modeling in its 2019 Plan, with the exception that NorthWestern proposes to improve the transparency of these methods by reducing the number of simulations (from 100 to 10) when applying them to the QF-1 calculations.

Q. Why is it important for the Commission to approve accurate QF-1 Tariff rates?

A. Montana's "Mini-PURPA" contains a statutory preference for long-term contracts. The current QF-1 Tariff provides QF developers with the option of a 15-year standard offer contract. If the rates in the tariff overstate avoided costs, or if there are numerous QF-1 contracts entered into without an update to the rates, NorthWestern's customers will significantly overpay developers for the QF power. Conversely, if the rates in the tariff understate avoided costs, PURPA's goals of encouraging QF development will be undermined.

Overview of Avoided Costs

Q. What does PURPA specify about the avoided cost rates that a QF is entitled to receive?

A. PURPA requires that the rates a QF receives as payment from the utility for the costs of energy and capacity that the QF's generation allows the utility to avoid must leave the utility's customers indifferent. To ensure that the utility's customers are indifferent, any costs imposed by the QF on the utility's system (e.g., costs required to physically connect the QF resource to the system, or to deliver the QF's energy to the utility's load, or to balance the QF's generation) must be accounted for in the avoided cost rate.

PURPA also requires that avoided cost rates be based on the costs *to serve load* that the utility would otherwise incur but for the generation from the QF. Thus, while PURPA requires the utility to purchase all energy and capacity that the QF wishes to sell, the Federal Energy Regulatory Commission ("FERC") has explained that "the purchase rate should only include payment for energy or capacity *which the utility can use to meet its total system load*" [emphasis added] and FERC states clearly that its "rules impose no requirement on the purchasing utility to deliver unusable energy or capacity to another utility for subsequent sale" (Small Power Production and Cogeneration Facilities; Regulations Implementing Section

210 of the Public Utility Regulation Policies Act of 1978, 45 Fed. Reg. 12,214, 12,216 (Feb. 25, 1980)).

Q. Please explain the main components of an avoided cost calculation.

A. There are four main components to an avoided cost calculation: (1) avoided costs of energy, (2) avoided costs of capacity, (3) the costs of integrating the generation resource, and (4) the costs of interconnecting the resource to the system and delivering its generation to load. The first two categories result from the PURPA requirement that electric utilities purchase any (1) energy and (2) capacity that a QF desires to sell to the utility. The third and fourth categories result from the facts that adding a generation resource affects the costs of balancing the system and there are costs associated with physically interconnecting the resource to the system. There also may be further costs necessary to deliver the generation to load.

Q. What are the costs of energy that QF generation allows the utility to avoid?

A. These costs are the variable costs NorthWestern is able to avoid by substituting the energy provided by a QF for energy NorthWestern would otherwise use to serve its load, which energy NorthWestern either generates from resources in its portfolio or acquires through market purchases.

Q. Please explain the significance of the term "costs to serve load."

A. NorthWestern recommends a calculation based explicitly on the *costs to serve load* that the QF generation allows NorthWestern to avoid. This means QF generation that cannot be used to serve NorthWestern's load does not allow NorthWestern to avoid any costs. The Commission has in the past ordered that NorthWestern value such energy at market prices, under the assumption that NorthWestern could easily and without cost sell any and all QF generation into the market on behalf of the QF, collect payment on behalf of the QF, and then transfer the sales revenue to the QF.

This assumption is flawed. NorthWestern cannot sell QF generation as the Commission suggests without imposing costs on its customers and increasingly putting its customers at risk. This is because NorthWestern does not have firm transmission rights to the Mid-C market, because transmission is often congested, and because market prices are expected to be negative with increasing frequency.

NorthWestern's proposal is in accordance with PURPA's clear direction that the "rules impose no requirement on the purchasing utility to deliver unusable energy or capacity to another utility for subsequent sale" and that "the purchase rate should only include payment for energy or capacity *which the utility can use to meet its total system load*" [emphasis added].

(Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulation Policies Act of 1978, 45 Fed. Reg. 12,214, 12,216 (Feb. 25, 1980)).

Q. Are there any general references or benchmarks that can be used to assess the reasonableness of an avoided cost of energy?

A. Yes. An avoided cost of energy should never exceed the forecast market prices. The market price represents the upper bound on a reasonable avoided cost because the economic dispatch of a utility's resources dictates that a dispatchable resource should never generate when it is out of the money (i.e., when its variable costs exceed the market price). A second reasonableness check for an avoided cost calculation is to compare it to the levelized cost of building a new, comparable resource. For example, the avoided cost for a wind resource should not exceed the levelized payment for a similar resource that could be procured through a competitive solicitation. The public results of such solicitations are therefore useful benchmarks for the upper bound of a reasonable avoided cost calculation.

Q. Did NorthWestern include a carbon adder when calculating the costs of energy that a QF will allow NorthWestern to avoid?

A. No. NorthWestern is not required to pay any costs for carbon emissions associated with energy it generates and there is thus no such cost that a

QF could allow NorthWestern to avoid. To the extent that carbon costs may be incurred by other parties from whom NorthWestern may purchase energy, those costs would already be included in the purchase price.

Q. What are the costs of capacity that QF generation allows the utility to avoid?

A. These are the costs of acquiring a capacity resource that NorthWestern can avoid because of the capacity that the QF resource will reliably provide. The calculation of avoided capacity costs is complicated by the intermittent availability of wind, solar, and hydro QF generation. Furthermore, unlike energy, capacity is only a useful product inasmuch as it can reliably be counted on and planned for in advance. If it is only known in retrospect that a QF provided capacity, there is no way the utility could have avoided costs associated with that capacity because the utility cannot go backwards in time to change its prior capacity allocation.

Q. What are the costs of integrating QF generation into the utility's system?

A. These costs include the costs of ancillary services which NorthWestern's supply customers bear via NorthWestern's OATT. These are described in the Prefiled Direct Testimony of Joseph M. Stimatz ("Stimatz Direct Testimony").

Q. What are the costs of interconnecting QF generation into the utility's system?

A. The costs of physically connecting the QF resource to the system and delivering the QF's generation to the utility's load include costs of interconnection facilities and transmission service Network Upgrades, if any. These are described in the Prefiled Direct Testimony of Autumn M. Mueller ("Mueller Direct Testimony").

Avoided Cost of Energy

Q. What method does NorthWestern use for calculating the avoided cost of energy?

A. NorthWestern uses the PowerSimm modeling software to simulate future weather conditions and hourly-level customer loads, market prices, and generation from wind, solar, and hydro resources. The modeling software then simulates the economic dispatch of NorthWestern's dispatchable resources and makes market purchases, if necessary, to serve its load. The model then compares the *costs of serving load* with and without the QF resource.

In this comparison, QF generation that occurs when NorthWestern's supply portfolio is short (i.e., there is not enough generation to meet load) is valued at the market price. When NorthWestern is not short and the marginal load-serving resource is dispatchable and can be backed down, QF generation is valued at the variable costs of that generator (because the QF generation allows NorthWestern to avoid those variable costs). When NorthWestern's generation from resources with variable costs of $0 (such as other QFs or hydro) plus must-take or must-run resources (such as other QFs or thermal resources with minimum-run requirements) is greater than NorthWestern's loads, additional generation from a new QF cannot be used to serve NorthWestern's load and is therefore valued at zero. It is possible, and NorthWestern believes increasingly likely, that additional generation in this situation will actually impose costs on NorthWestern if the additional power cannot be delivered for off-system sales, or requires costly curtailment of other resources, or occurs when prices are negative.

NorthWestern is working to develop a "curtailment stack" to incorporate into the model so that it can accurately account for curtailment costs that are required in this situation.

Q. Does this method reflect Conditions 1, 2, and 3[1]?

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[1] The conditions previously used were: Condition 1 – when load exceeds generation from NorthWestern's supply portfolio (QF generation has been valued at market price); Condition 2 – generation exceeds load and market price exceeds the economic dispatch of the lowest-cost dispatchable resource in the portfolio (QF generation has been valued at the variable cost of the highest-cost economically dispatched resource generating in the hour, even though this resource was not serving load); and Condition 3 – when generation exceeds load and the market price is below the variable cost of the portfolio's lowest-cost dispatchable resource (NorthWestern believes QF generation in this situation should be valued at $0, though others have argued that this energy should be valued at market price.).

A. No. NorthWestern recommends a method directly based on the hourly avoided cost to serve load, instead of a method using monthly-level calculations and Conditions 1, 2, and 3 analysis, to more accurately reflect the costs of serving load that a QF allows NorthWestern to avoid.

Q. Why did NorthWestern use a modified peaker methodology, instead of the proxy method the Commission previously approved for QF-1 rates?

A. The proxy method previously approved by the Commission for calculating the costs of energy that a small QF would allow NorthWestern to avoid was based on the assumption that NorthWestern would have a future need for resources whose costs could reasonably be used as proxies for QF-1 avoided costs. NorthWestern's 2019 Plan does not identify a need for any such resources. The proposed method is more complex than the previous method but NorthWestern has taken steps to ensure that it is transparent for small QF developers. The proposed method is entirely consistent with how NorthWestern modeled resource portfolios in the 2019 Plan and how it calculates avoided costs for large QFs.

Q. Is NorthWestern's method of calculating the avoided cost of energy transparent?

A. Yes. It is relatively easy to review the data files for 10 simulations. In addition, Dr. Mauch has provided a graphical illustration of the values of all the key variables for each of the 131,400 hours (15 years times 8760 hours per year) in one simulation. This provides a clear and understandable way to review the mechanics of the calculation, including the generation and dispatch of all resources in NorthWestern's supply portfolio.

Q. Why do you recommend an hourly-level calculation instead of a monthly-level calculation?

A. As the quantity of variable energy resources on the power grid continues to grow and increases the hourly and sub-hourly volatility of prices, it is increasingly important to analyze the system at a fine temporal granularity (i.e. hourly rather than monthly). NorthWestern will soon join the Western Energy Imbalance Market, which sends price signals at a 5-minute frequency. In this environment, a monthly-level calculation is too coarse. The monthly-level calculation relies on aggregating and averaging values at the monthly level before determining their avoided cost value and this is less accurate than the hourly-level assignment of avoided costs. In addition, hourly-level calculations more accurately reflect the costs associated with increased needs for ancillary services required to integrate QFs into the portfolio.

The reason that the hourly calculation is more accurate can be seen in the following example. Consider a utility with one dispatchable resource whose variable cost is $15/megawatt-hour ("MWh"). In the hourly calculation, if the market price in any given hour is cheaper than the utility's dispatch cost, then the QF generation in that hour would be valued at the market price. This is because the market provides the cheapest source of power and the QF generation allows the utility to avoid buying power at the market price. When the market price is higher than the utility's dispatch cost, then the utility runs its resource (because it is cheaper than the market) and QF generation in this hour would allow the utility to avoid the resource's variable cost, which in this example is $15/MWh. Note that in the monthly calculation the prices are first averaged across all hours *before* making this comparison between the market price and resource's dispatch costs.[2]

Now consider two possible months that are identical in all ways except for the hourly market price of electricity. In Month A, the price for electricity is identical in every hour and equal to $18/MWh (the average price is thus $18). In this month the results of the hourly and monthly calculations would be the same. This is because the hourly calculation would assign an avoided cost in every hour of $15 (the utility's dispatch cost), while the monthly model would compare the average price of $18 to the dispatch cost of $15 and also assign an avoided cost of $15.

[2] This is a simplified explanation. In actuality, the averages are calculated separately for the light-load and heavy-load periods within a month.

In Month B, the price for electricity is equal to $18/MWh in all hours except 10. In these 10 hours, the price is $5. The average price in Month B is thus $17.91.[3] The monthly calculation would see that this value is above the utility's dispatch cost of $15 and thus assign an avoided cost for all QF generation in this month of $15, just as it did for Month A. However, in the hourly model, the avoided cost in the 10 cheap hours would be $5 (i.e., the market price in those hours), while the hours when the market price is $18 would have an avoided cost of $15. In this case, the average avoided cost for the month using the hourly model would be $14.86. This is different from the value calculated with the monthly model and it shows how the coarseness of the monthly model—which coarseness results from using a monthly average price rather than hourly prices—can result in a less accurate avoided cost calculation. In this example the monthly calculation over-estimated the avoided cost, but the results would be in the opposite direction if the example used 10 "outlier" hours with prices above the average rather than below the average.

Q. What inputs and assumptions did NorthWestern use to calculate the avoided cost of energy?

A. NorthWestern used the following inputs for the PowerSimm simulations:

- Historical weather, commodity prices (electricity, coal, and natural gas), loads, and generation from NorthWestern's supply resources.

[3] For a month with 730 hours, the calculation is [720 hours * $15/hr + 10 hours * $5/hr] / 730 hours = $14.86 per hour.

- Forecasts of future loads.
- Forward price projections based on the ICE forward curves from the first 15 trading days each of the preceding two quarters (in this case, 2019 Quarter 2 and 2019 Quarter 3).
- A market price forecast that projects lower prices at Mid-C due to the high level of renewables expected to come online over the next decade as multiple states in the WECC increase their mandates for renewable energy. We also provide calculations based on an increasing power price forecast.
- A 15-year contract term with a Commercial Operation Date of October 1, 2020.
- Transmission basis differentials relative to Mid-C prices of -$8.00 for sales throughout the 15-year term and for purchases of $0.00 before the closure of Colstrip Units 1 and 2 on December 31, 2019 and +$2.00 thereafter.

Q. Why did NorthWestern average forward ICE curves?

A. The purpose of averaging multiple forward curves is to reduce the possibility that short-term volatility will inappropriately influence the calculations and to be consistent with NorthWestern's methods of projecting prices in other applications, such as resource planning and avoided cost calculations for large QFs. (NorthWestern uses an average of multiple forward curves for large QFs to prevent the QF developer from strategically selecting a day with a particularly high forward curve).

Q. Did NorthWestern calculate an avoided cost of energy for each resource type?

A. Yes, NorthWestern calculated avoided energy costs separately for wind, solar, and hydro/other. The calculations for wind and solar were based on the generation profiles from existing resources, which were selected based on their capacity factors falling in the middle range of the existing solar and wind resources on NorthWestern's system. The calculation for the hydro/other resource was based on a flat production profile (1 MW around the clock).

Q. What information did you use to calculate the recommended transmission basis differentials?

A. The following table shows the transmission basis that NorthWestern has experienced for both purchases and sales at Mid-C for the 24-month period ending June 2019. NorthWestern's avoided cost modeling is based on a sales differential of -$8.00, which is reasonably close to the average value of negative $9.18 as shown in the table (inclusive of line losses and transmission costs). The average basis for NorthWestern's purchases over the period shown in the table was negative $1.19. NorthWestern estimates that this will increase when Colstrip Units 1 and 2 close (because NorthWestern will have to purchase energy from Mid-C more often as a result of the reduction in on-system energy available after the closure of Colstrip 1 & 2). Some of the Mid-C parties from whom NorthWestern purchases energy have transmission costs, which result in a price premium, while others do not. The recommended value of $0.00 until Colstrip 1 & 2 close is consistent with the current data. The recommended value of positive $2.00 after Colstrip 1 & 2 close is based on the judgment of NorthWestern's power marketing department. NorthWestern does not have a forecast study of this value nor the data to conduct such a study, as the implications on transmission availability and costs that will result from the closure of Colstrip 1 & 2 are uncertain.

Table 1. Mid-C Price Basis (Differential) for NWE Sales and Purchases

Month	Powerdex Index[1]	NWE Purchase Price	Basis		Powerdex Index[2]	NWE Sales Price	Basis
Jul-17	$ 27.35	$ 27.65	$ 0.30		$ 23.97	$ 21.91	$ (2.07)
Aug-17	$ 38.65	$ 34.60	$ (4.06)		$ 35.51	$ 32.52	$ (2.99)
Sep-17	$ 31.46	$ 29.04	$ (2.42)		$ 24.17	$ 22.45	$ (1.73)
Oct-17	$ 24.86	$ 25.60	$ 0.74		$ 23.32	$ 22.48	$ (0.84)
Nov-17	$ 25.34	$ 25.03	$ (0.31)		$ 21.54	$ 20.26	$ (1.27)
Dec-17	$ 27.41	$ 27.42	$ 0.01		$ 24.46	$ 21.95	$ (2.51)
Jan-18	$ 23.84	$ 24.59	$ 0.75		$ 19.40	$ 18.68	$ (0.73)
Feb-18	$ 15.58	$ 16.17	$ 0.58		$ 18.54	$ 18.96	$ 0.42
Mar-18	$ 19.09	$ 18.64	$ (0.45)		$ 17.10	$ 16.61	$ (0.49)
Apr-18	$ 14.80	$ 14.29	$ (0.50)		$ 15.64	$ 15.79	$ 0.16
May-18	$ 8.06	$ 7.75	$ (0.31)		$ 13.64	$ 15.75	$ 2.11
Jun-18	$ 11.42	$ 12.69	$ 1.27		$ 14.81	$ 15.10	$ 0.29
Jul-18	$ 47.04	$ 46.09	$ (0.95)		$ 31.31	$ 27.48	$ (3.83)
Aug-18	$ 69.61	$ 73.66	$ 4.05		$ 38.34	$ 34.61	$ (3.73)
Sep-18	$ 26.19	$ 24.59	$ (1.60)		$ 25.98	$ 24.60	$ (1.38)
Oct-18	$ 39.39	$ 37.79	$ (1.60)		$ 39.74	$ 36.61	$ (3.13)
Nov-18	$ 49.06	$ 45.50	$ (3.56)		$ 47.84	$ 43.13	$ (4.71)
Dec-18	$ 45.60	$ 38.01	$ (7.59)		$ 43.53	$ 40.15	$ (3.38)
Jan-19	$ 35.07	$ 29.61	$ (5.46)		$ 32.62	$ 30.34	$ (2.28)
Feb-19	$ 71.38	$ 70.93	$ (0.45)		$ 67.36	$ 63.24	$ (4.12)
Mar-19	$ 45.76	$ 40.90	$ (4.86)		$ 43.15	$ 35.86	$ (7.29)
Apr-19	$ 13.39	$ 13.05	$ (0.34)		$ 14.84	$ 14.83	$ (0.02)
May-19	$ 12.03	$ 12.44	$ 0.41		$ 14.10	$ 14.12	$ 0.02
Jun-19	$ 16.70	$ 14.57	$ (2.13)		$ 22.00	$ 20.74	$ (1.27)
July '17 - June '19	$ 30.79	$ 29.61	$ (1.19)		$ 28.04	$ 26.17	$ (1.86)
					PTP Transmission Cost		$ (6.53)
					Transmission Losses		$ (0.79)
					Total Basis		$ (9.18)

[1] Index average in the hours where NWE had purchases

[2] Index average in the hours where NWE had sales

Q. What are the avoided costs of energy that NorthWestern recommends?

A. Using the methods described above and as described in the Mauch Direct Testimony, NorthWestern calculated the following avoided costs to serve load for QF energy for a 15-year levelized contract. See Exhibit__(BFF-4), Exhibit__(BFF-5), and Exhibit__(BFF-6). These are the costs that NorthWestern recommends:

Avoided Cost of Energy - Hourly Calculation	Wind	Solar	Hydro/other
Levelized value for 15-year contract	$9.23	$16.83	$15.86

I have also levelized the avoided cost results over a 1-year period, and then scaled them in 1-year increments to create the following rate schedule, expressed in $/kilowatt-hour ("kWh"), for the QF-1 Tariff. The on-peak rate includes an adder for the avoided cost of capacity. The calculation of this value is described further below.

Table 2. Option 1 Rates

Option 1 Rates for Energy and Capacity						
	Solar		Wind		Hydro/other	
Contract Length (years)	Off-peak Rate ($/kWh)	On-peak Rate ($/kWh)	Off-peak Rate ($/kWh)	On-peak Rate ($/kWh)	Off-peak Rate ($/kWh)	On-peak Rate ($/kWh)
1	$0.01706	$0.01706	$0.00725	$0.01512	$0.01529	$0.05298
2	$0.01705	$0.01705	$0.00739	$0.01526	$0.01533	$0.05302
3	$0.01703	$0.01703	$0.00753	$0.01540	$0.01537	$0.05307
4	$0.01701	$0.01701	$0.00767	$0.01554	$0.01541	$0.05311
5	$0.01700	$0.01700	$0.00781	$0.01569	$0.01545	$0.05315
6	$0.01698	$0.01698	$0.00795	$0.01583	$0.01549	$0.05319
7	$0.01696	$0.01696	$0.00810	$0.01597	$0.01553	$0.05323
8	$0.01695	$0.01695	$0.00824	$0.01611	$0.01557	$0.05327
9	$0.01693	$0.01693	$0.00838	$0.01625	$0.01561	$0.05331
10	$0.01691	$0.01691	$0.00852	$0.01639	$0.01565	$0.05335
11	$0.01690	$0.01690	$0.00866	$0.01654	$0.01569	$0.05339
12	$0.01688	$0.01688	$0.00880	$0.01668	$0.01573	$0.05343
13	$0.01686	$0.01686	$0.00895	$0.01682	$0.01577	$0.05347
14	$0.01685	$0.01685	$0.00909	$0.01696	$0.01582	$0.05351
15	$0.01683	$0.01683	$0.00923	$0.01710	$0.01586	$0.05355

Q. Did NorthWestern make any other calculations of the avoided costs of energy?

A. Yes. The Prefiled Direct Testimony of Michael S. Babineaux ("Babineaux Direct Testimony") provides the results of the monthly-level calculations with the Conditions 1, 2, and 3 analysis. NorthWestern presented these results for purposes of comparison, but because these calculations do not accurately reflect the cost of serving load that a QF would allow NorthWestern to avoid (described above), NorthWestern does not recommend them.

<u>Avoided Cost of Capacity</u>

Q. How does NorthWestern calculate the avoided cost of capacity?

A. NorthWestern uses the costs of a 50-MW AERO unit located at DGGS as a proxy of the potential least-cost candidate resource that could be acquired to provide capacity. An AERO unit is the appropriate proxy resource because it is a pure capacity resource. In other words, it most closely represents the characteristics of the capacity that the QF is helping NorthWestern to avoid. It would not be appropriate to use costs from a more flexible capacity resource in this case because the QF does not allow NorthWestern to avoid such costs. Furthermore, using AERO technology to determine avoided capacity costs is consistent with the Commission's recent Order No. 7661c for the Grizzly Wind, LLC and Black Bear Wind, LLC projects and also with Order No. 7628b for the previous Caithness Beaver Creek ("CBC") proceeding in Docket No. 2018.08.052 ("CBC Order"). The characteristics of the DGGS location that affect the costs of acquiring this proxy resource, including costs of interconnection, and transmission service network upgrades, are described in the Mueller Direct Testimony and are included in the calculation of avoided capacity costs. See Exhibit__(BFF-3) for the inclusions of these costs in the calculation of the avoided cost of capacity.

Q. Did NorthWestern calculate an avoided cost of capacity for each resource type?

A. No. The avoided cost of capacity is based on the costs of the capacity unit that NorthWestern can theoretically avoid, which value is then applied to the capacity contribution of a QF resource. NorthWestern calculates the cost of the proxy capacity resource and then levelizes this value over 30 years (to get the value in $/year) and then divides this value by the capacity of the proxy resource (i.e., 50 MW), which results in an annual value expressed in dollars per megawatt of capacity (i.e., $/MW-year).

Q. What is the cost of capacity that a QF could allow NorthWestern to avoid?

A. I have calculated this value, based on the costs of the proxy capacity resource discussed above, as a total of $176,444 per MW-year. This is the sum of $160,521 per MW-year of capital costs plus $15,923 per MW-year of fixed costs for operations and maintenance. These calculations are contained in Exhibit__(BFF-2) and Exhibit__(BFF-3). To determine the avoided cost of capacity for a particular QF resource, this total value is then multiplied by the capacity contribution of a QF resource, which is the amount of capacity (in MW) that a QF resource allows NorthWestern to avoid.

Q. Did NorthWestern calculate the capacity contribution separately for each resource type?

A. Yes. NorthWestern has calculated the capacity contribution separately for each fuel type because the QF resources are variable energy resources and their production shape varies with fuel type (i.e., wind, solar, or hydro). These calculations were completed using historical generation data from existing wind and hydro resources in NorthWestern's portfolio and with solar data from the National Renewable Energy Laboratory (because NorthWestern does not have any solar resources on its system with three years of historical data, as required for the SPP method). The Babineaux Direct Testimony describes these calculations and presents the results.

Q. What capacity contribution does NorthWestern propose for calculating avoided costs for the QF-1 Tariff?

A. NorthWestern recommends using the average capacity value for each resource type based on the existing resources in NorthWestern's portfolio. The individual capacity contribution for each of these resources is calculated using the SPP tool and is presented in the Babineaux Direct Testimony. The average values are:

- 2.22% for wind
- 0.00% for solar
- 18.96% for hydro/other

Q. How does NorthWestern incorporate these values into the avoided cost rates?

A. For each resource type, NorthWestern multiplies the capacity contribution percentage by the avoided cost of capacity (in $/MW) to determine the annual value of the capacity that would be provided by a 3-MW resource of each type. This value is then divided by the expected on-peak generation, producing an avoided cost of capacity on a $/MWh basis which is added to the avoided cost of energy and paid to the QF for its on-peak generation.[4] The calculation of the on-peak generation is contained in Exhibit__(MSB-2). The following table illustrates these calculations and shows the avoided cost of capacity rate that NorthWestern recommends for each fuel type. The recommended values for solar, wind, and

[4] On-peak hours are heavy-load hours occurring in December, January, February, July, and August. Heavy-load hours are hours ending 7am-11pm Pacific Prevailing Time excluding Sundays and NERC-defined holidays.

hydro/other are $0.00, $7.87, and $37.69, respectively. The value of $0 for solar results from the fact that the SPP method calculates a capacity value of 0.00% based on historical solar generation data from the current sites of solar resources in NorthWestern's portfolio.

Table 3. Avoided Cost of Capacity

	Avoided Cost of Capacity for 3 MW resource				
		Solar	Wind	Hydro/Other	Source
A	Capacity Contribution (%)	0.00%	2.22%	18.96%	MSB-2
B	Capacity Contribution for 3 MW resource (MW)	0.00	0.07	0.57	=A*3MW
C	Avoided Capacity Rate ($/MW-year)	$176,444.28	$176,444.28	$176,444.28	BFF-2
D	Avoided Capacity Cost ($/yr)	$ -	$ 11,751.19	$100,344.05	B*C
E	Capacity Factor of Proxy Resource	16.33%	25.29%	42.34%	MSB-2
F	Expected Annual Energy	4292	6646	11126	=E*3MW*8760
G	Percentage of energy that is On-Peak	30.62%	22.46%	23.93%	MSB-2 & MSB-3
H	Annual on-peak energy for 3 MW resource (MWh)	1314.0	1492.5	2662.0	=F*G
I	**On-Peak adder ($/MWh)**	**$ -**	**$ 7.87**	**$ 37.69**	=D/H

<u>Ancillary Services</u>

Q. How does NorthWestern calculate the cost of integrating QF generation into its system?

A. NorthWestern recommends using the rates from its current OATT to determine the cost of integrating QF generation into its system. These rates are the costs that NorthWestern's supply customers bear for integrating variable energy resources. The Stimatz Direct Testimony explains this in detail. For purposes of illustration I have converted these values into rates on a $/MWh basis as shown in the table below. However, consistent with the OATT, these charges are billed monthly on the basis of dollars per kW-month. In other words, they are based on a resource's capacity, not its generation. This is described in the OATT and the Stimatz Direct Testimony.

Table 4. Ancillary Service Charges on $/MWh basis

	Ancillary Service Charges	Solar	Wind	Hydro/Other	Source
J	Annual Cost for 3 MW Project	$ 66,069	$ 151,358	$ 19,152	JMS
K	Capacity Factor	16.33%	25.29%	42.34%	MSB-2
L	Annual Energy for 3 MW project	4292	6646	11126	=K*3MW*8760
M	**Charge per MWh**	**$ 15.40**	**$ 22.77**	**$ 1.72**	=J/L

Q. Can you summarize all of the results you have presented for a 15-year contract?

A. Yes, the following table incorporates all of the components described above, but does not include costs for Network Upgrades (these are described further below). Note that the OATT assigns charges for ancillary services on the basis of a resource’s capacity, not its generation. The rates for ancillaries expressed below in $/MWh are only provided to facilitate comparisons.

Table 5. Avoided Costs for 15-year contract, excluding Network Upgrades

	Avoided Cost of Capacity for 3 MW resource	Solar	Wind	Hydro/Other	Source
A	Capacity Contribution (%)	0.00%	2.22%	18.96%	MSB-2
B	Capacity Contribution for 3 MW resource (MW)	0.00	0.07	0.57	=A*3MW
C	Avoided Capacity Rate ($/MW-year)	$176,444.28	$176,444.28	$176,444.28	BFF-2
D	Avoided Capacity Cost ($/yr)	$ -	$ 11,751.19	$100,344.05	B*C
E	Capacity Factor of Proxy Resource	16.33%	25.29%	42.34%	MSB-2
F	Expected Annual Energy	4292	6646	11126	=E*3MW*8760
G	Percentage of energy that is On-Peak	30.62%	22.46%	23.93%	MSB-2 & MSB-3
H	Annual on-peak energy for 3 MW resource (MWh)	1314.0	1492.5	2662.0	=F*G
I	**On-Peak adder ($/MWh)**	**$ -**	**$ 7.87**	**$ 37.69**	=D/H

	Ancillary Service Charges	Solar	Wind	Hydro/Other	Source
J	Annual Cost for 3 MW Project	$ 66,069	$ 151,358	$ 19,152	JMS
K	Capacity Factor	16.33%	25.29%	42.34%	MSB-2
L	Annual Energy for 3 MW project	4292	6646	11126	=K*3MW*8760
M	**Charge per MWh**	**$ 15.40**	**$ 22.77**	**$ 1.72**	=J/L

	Summary of All-in 15-year Rates	Solar	Wind	Hydro/Other	
	Avoided cost of energy (15 yr, declining IMHR)	$ 16.83	$ 9.23	$ 15.86	
N	15-yr contract Off-Peak rate	$ 16.83	$ 9.23	$ 15.86	
O	15-yr contract On-Peak rate	$ 16.83	$ 17.10	$ 53.55	=N+I
	Rate including Ancillary Charges ($/MWh)				
P	15-yr Off-Peak	**$ 1.43**	**$ (13.54)**	**$ 14.14**	=N-M
Q	15-yr On-Peak	**$ 1.43**	**$ (5.67)**	**$ 51.83**	=O-M

Note that the charges for ancillary services are displayed above for informational purposes. Actual charges would be assigned on the basis of the resource's capacity, consistent with NorthWestern's OATT.

<u>Network Upgrades</u>

Q. What are the costs of interconnecting QF generation into the system and delivering the generation to NorthWestern's load?

A. These costs, which include interconnection Network Upgrades as well as Network Upgrades for transmission service, are described in the Mueller Direct Testimony. Because these facilities exist only to deliver the QF generation to load, and because their construction creates costs that NorthWestern's customers would not incur but for the existence of the QF resource, the QF should be responsible for paying these costs.

Q. Do QFs help NorthWestern avoid Network Upgrade costs NorthWestern would incur if it added another resource, instead of the QF, to the system?

A. This is conceptually possible but highly unlikely in the current situation because the DGGS site could currently accommodate the addition of a capacity resource with minimal or no Network Upgrade costs. The Mueller Direct Testimony discusses this.

<u>Miscellaneous Tariff Changes</u>

Q. Does NorthWestern propose changes to the QF-1 Tariff other than changes to the rates?

A. Yes. NorthWestern proposes several modifications to facilitate the administration of QF-1 contracts. NorthWestern also proposes modifications to the current bi-annual update of QF-1 rates that provide a schedule for updates that balances the need to maintain rates that accurately reflect actual avoided costs with reducing the administrative burden of filing frequent updates. The proposed changes are:

1. After the term of a QF-1 contract has expired, NorthWestern proposes that the QF receive by default the Option 2 rate. Currently, if a contract expires and the QF has not entered into a subsequent contract, there is nothing that defines how or whether the QF should continue to be compensated. Using the Option 2 rate, which is a market index rate, is a simple and fair default option, which the QF can opt out of simply by entering into a new contract at the then-current Option 1 rates.
2. NorthWestern proposes that QF-1 rates be updated every 12 months or when the total installed capacity of resources in NorthWestern's supply portfolio has changed by more than 40 MW since the previous QF-1 rate update, whichever is sooner. This method for updating QF-1 rates will ensure that they are never based on pricing information that is more than 12 months old while also ensuring that rates are updated when changes occur in the supply portfolio that are large enough to reasonably expect that they would have a non-negligible impact on NorthWestern's avoided costs.
3. NorthWestern proposes to include and change definitions to match our OATT.

These changes are shown in a redline version of the QF-1 Tariff in Exhibit__(BFF-1).

Q. Does this conclude your testimony?

A. Yes.

ELECTRIC TARIFF

NorthWestern Energy

	11th ~~10th~~	Revised	Sheet No.	74.1
Canceling	10th ~~9th~~	Revised	Sheet No.	74.1

Schedule No. QF-1

QUALIFYING FACILITY POWER PURCHASE

APPLICABILITY: Applicable to any Seller with nameplate capacity of 3 MW or less who enters into a Power Purchase Agreement (Agreement) with the Utility for the sale of electric power to the Utility from a Qualifying Facility (QF) as defined under the Rules of the Commission after <<*DATE of Final Order in Docket No. 2019.09.059*>> or who continues to sell electric power to the Utility after expiration of an Agreement entered into before <<*Date of Final Order in Docket No. 2019.09.059*>>.

The Utility shall purchase electrical energy for a term of not less than one month and not more than 15 years.

The QF-1 Tariff rates do not reflect Network Upgrade costs. The Seller is responsible for these costs pursuant to the Special Terms and Conditions in this schedule. Seller must apply for interconnection and enter into the applicable generation interconnection agreement with the Utility ~~addressing those items~~ in addition to entering into an Agreement under the terms of this Tariff.

RATE OPTIONS: Seller may select from the following two rate options and sub-options: Option 1(a) and (b) and Option 2.

For all Rate Options, refer to Special Terms and Conditions Item 3 Disposition of RECs, Item 4 Ancillary Services~~Wind Integration~~, and Item ~~5~~6 Network Upgrades~~Contingency Reserves~~.

~~The selected rate will be adjusted by the value of Contingency Reserves per the current Contingency Reserves Tariff CR-1. Subsequent to this adjustment, QFs must either self-provide or purchase Contingency Reserves as described in Item 5 under Special Terms and Conditions.~~

~~QFs~~ A Seller selecting Option 1 Rates will be paid the Avoided Energy and Capacity Rate which corresponds to their resource type and Agreement length as reflected in Table 1 below, adjusted for Special Terms and Conditions. —After the term of an Agreement has expired, and before a new Agreement is executed, the Seller will receive the Option 2 rate, adjusted for Special Terms and Conditions.

The Utility will update the Option 1 Rates every 12 months or when the total installed capacity of resources in the Utility's supply portfolio has changed by more than 40 MW since the previous Option 1 Rate update, whichever is sooner.

(continued)

Schedule No. QF-1

QUALIFYING FACILITY POWER PURCHASE

Option 1(a): Avoided Energy and Capacity Rates:

Option 1 Rates for Energy and Capacity						
	Solar		Wind		Hydro/other	
Contract Length (years)	Off-peak Rate ($/kWh)	On-peak Rate ($/kWh)	Off-peak Rate ($/kWh)	On-peak Rate ($/kWh)	Off-peak Rate ($/kWh)	On-peak Rate ($/kWh)
1	$0.01706	$0.01706	$0.00725	$0.01512	$0.01529	$0.05298
2	$0.01705	$0.01705	$0.00739	$0.01526	$0.01533	$0.05302
3	$0.01703	$0.01703	$0.00753	$0.01540	$0.01537	$0.05307
4	$0.01701	$0.01701	$0.00767	$0.01554	$0.01541	$0.05311
5	$0.01700	$0.01700	$0.00781	$0.01569	$0.01545	$0.05315
6	$0.01698	$0.01698	$0.00795	$0.01583	$0.01549	$0.05319
7	$0.01696	$0.01696	$0.00810	$0.01597	$0.01553	$0.05323
8	$0.01695	$0.01695	$0.00824	$0.01611	$0.01557	$0.05327
9	$0.01693	$0.01693	$0.00838	$0.01625	$0.01561	$0.05331
10	$0.01691	$0.01691	$0.00852	$0.01639	$0.01565	$0.05335
11	$0.01690	$0.01690	$0.00866	$0.01654	$0.01569	$0.05339
12	$0.01688	$0.01688	$0.00880	$0.01668	$0.01573	$0.05343
13	$0.01686	$0.01686	$0.00895	$0.01682	$0.01577	$0.05347
14	$0.01685	$0.01685	$0.00909	$0.01696	$0.01582	$0.05351
15	$0.01683	$0.01683	$0.00923	$0.01710	$0.01586	$0.05355

~~Option 1 Rates for Energy and Capacity~~						
-	~~Solar~~		~~Wind~~		~~Hydro/other~~	
~~Contract Length (years)~~	~~Off-peak Rate ($/kWh)~~	~~On-peak Rate ($/kWh)~~	~~Off-peak Rate ($/kWh)~~	~~On-peak Rate ($/kWh)~~	~~Off-peak Rate ($/kWh)~~	~~On-peak Rate ($/kWh)~~
~~1~~	~~$0.03342~~	~~$0.04248~~	~~$0.03079~~	~~$0.03844~~	~~$0.03063~~	~~$0.08728~~
~~2~~	~~$0.03099~~	~~$0.04005~~	~~$0.02886~~	~~$0.03652~~	~~$0.02873~~	~~$0.08542~~
~~3~~	~~$0.03011~~	~~$0.03917~~	~~$0.02811~~	~~$0.03578~~	~~$0.02799~~	~~$0.08471~~
~~4~~	~~$0.03100~~	~~$0.04007~~	~~$0.02890~~	~~$0.03657~~	~~$0.02877~~	~~$0.08552~~

(continued)

ELECTRIC TARIFF

NorthWestern Energy

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Schedule No. QF-1

QUALIFYING FACILITY POWER PURCHASE

~~5~~	~~$0.03178~~	~~$0.04086~~	~~$0.02966~~	~~$0.03734~~	~~$0.02954~~	~~$0.08631~~
~~6~~	~~$0.03263~~	~~$0.04171~~	~~$0.03049~~	~~$0.03817~~	~~$0.03036~~	~~$0.08716~~
~~7~~	~~$0.03359~~	~~$0.04268~~	~~$0.03141~~	~~$0.03909~~	~~$0.03128~~	~~$0.08811~~
~~8~~	~~$0.03365~~	~~$0.04274~~	~~$0.03170~~	~~$0.03938~~	~~$0.03158~~	~~$0.08844~~
~~9~~	~~$0.03376~~	~~$0.04286~~	~~$0.03201~~	~~$0.03969~~	~~$0.03190~~	~~$0.08879~~
~~10~~	~~$0.03391~~	~~$0.04301~~	~~$0.03231~~	~~$0.04000~~	~~$0.03221~~	~~$0.08913~~
~~11~~	~~$0.03408~~	~~$0.04319~~	~~$0.03263~~	~~$0.04032~~	~~$0.03254~~	~~$0.08948~~
~~12~~	~~$0.03426~~	~~$0.04336~~	~~$0.03293~~	~~$0.04063~~	~~$0.03285~~	~~$0.08982~~
~~13~~	~~$0.03445~~	~~$0.04356~~	~~$0.03323~~	~~$0.04094~~	~~$0.03316~~	~~$0.09016~~
~~14~~	~~$0.03464~~	~~$0.04376~~	~~$0.03352~~	~~$0.04122~~	~~$0.03345~~	~~$0.09047~~
~~15~~	~~$0.03486~~	~~$0.04398~~	~~$0.03383~~	~~$0.04154~~	~~$0.03377~~	~~$0.09082~~

Payments: Rate x kWh metered during each Off-Peak Hours and On-Peak Hours period.

kWh = Metered kilowatt-hours supplied to the Utility for each Off-Peak Hours and On-Peak Hours period.

(continued)

Schedule No. QF-1

QUALIFYING FACILITY POWER PURCHASE

Option 1(b): Agreement lengths: 1 month to 18 months – short-term.

RATE:

Energy ($/kWh):

i. Agreement lengths up to 1 year use Year 1 rates from above table.

ii. Agreement lengths 1 year to 18 months use Year 2 rates from above table.

Payments: Hourly Rate x Hourly kWh

kWh = Metered kilowatt hours supplied to the Utility in each hour.

Option 2: Agreement length of up to ~~25~~ 15 years.

Rate: This rate is equal to the published Intercontinental Exchange (ICE) Mid-C index price for Heavy Load Hours and Light Load Hours, less $.00162/kWh basis adjustment between Mid-C and Montana, and applied to the Heavy Load and Light Load metered sales and purchases of Seller. Another Mid-C price index may be substituted if necessary, if ICE is no longer available.

Payments: Daily Heavy Load Hour and Light Load Hour Rate x Heavy Load and Light Load kWh

kWh = Metered kilowatt hours supplied to the Utility in each daily Heavy Load and Light Load period.

(continued)

Schedule No. QF-1

QUALIFYING FACILITY POWER PURCHASE

SPECIAL TERMS AND CONDITIONS:

1) Definitions:

A. "Agreement" means the Power Purchase Agreement between Seller and the Utility for a term of not less than one month.

B. Ancillary Services means those services that are necessary to support the transmission of capacity and energy for resources to loads while maintaining reliable operation of the Transmission Providers' Transmission System in accordance with Good Utility Practice. Under NorthWestern's Open Access Transmission Tariff ("OATT"), four ancillary services apply to this tariff:

Schedule 3, Regulation and Frequency Response Service;
Schedule 5, Operating Reserve – Spinning Reserve Service;
Schedule 6, Operating Reserve – Supplemental Reserve Service; and
Schedule 11, Flex Reserve Service (applies only to wind generators).

~~B.~~C. "Commission" means the Montana Public Service Commission.

~~C. "Contingency Reserves" are an amount of spinning and nonspinning reserves (at least half must be spinning reserve) sufficient to meet the North American Electric Reliability Council (NERC) Disturbance Control Standard BAL-002 consistent with Western Electric Coordinating Council and Northwest Power Pool requirements.~~

D. "Contract Length" means the length of a Seller's contract with NorthWestern measured in whole years. For contract terms not in whole years, the length of a Seller's contract will be rounded up to the next whole year for purposes of determining applicable rates.

E. "Good Utility Practice"~~:~~ means- ~~A~~any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods, and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act section 215(a)(4).

(continued)

ELECTRIC TARIFF

NorthWestern Energy

	3rd ~~2nd~~	Revised	Sheet No.	74.4
Canceling	2nd ~~1st~~	Revised	Sheet No.	74.4

Schedule No. QF-1

QUALIFYING FACILITY POWER PURCHASE

~~E.~~F. “Heavy Load Hours” means the weekday and Saturday hours ending 7 and through hour ending 22 inclusive, Pacific Prevailing Time, except NERC defined holidays. For purposes of this Tariff, Heavy Load Hours correspond to Peak hours as used on the ICE web site.

(continued)

ELECTRIC TARIFF

NorthWestern Energy

	~~3rd~~ 4th	Revised	Sheet No.	74.5
Canceling	~~2nd~~ 3rd	Revised	Sheet No.	74.5

Schedule No. QF-1

QUALIFYING FACILITY POWER PURCHASE

~~F.~~G. “Intermittent” means generation resources with variable generation output from hour to hour. Specifically, wind and solar PV are considered to be Intermittent resources.

~~G.~~H. “Light Load Hours” means those hours not included in the definition of Heavy Load Hours. For purposes of this Tariff, Light Load Hours correspond to Off-Peak hours as used on the ICE web site.

~~H.~~I. “Network Upgrades” means additions, modifications, and upgrades to NorthWestern’s transmission system required at or beyond the point at which the Small Generating Facility interconnects with the transmission system to accommodate the interconnection with the Small Generating Facility to NorthWestern’s transmission system. Network Upgrades do not include Distribution Upgrades. Network Upgrades include interconnection Network Upgrades and transmission service Network Upgrades.

~~I.~~J. “Off-Peak Hours” means those hours in the year not included in the definition of On-Peak Hours.

~~J.~~K. “On-Peak Hours” means the Heavy Load hours for the months of January, February, July, August, and December.

~~K.~~L. “Other QF” means QF facilities other than hydroelectric-, wind-, or solar-~~-~~powered resources.

~~L.~~M. “RECs” means renewable energy credits. One megawatt hour of renewable energy generation gives rise to one REC, and this REC embodies all environmental attributes of that renewable energy generation.

~~M. “Regulating Reserve” is spinning reserve immediately responsive to Automatic Generation Control (AGC) to provide sufficient regulating margin to allow the Balancing Authority to meet NERC’s Control Performance Criteria (BAL-001).~~

N. “Seller,” for purposes of this schedule, is any individual, partnership, corporation, association, government agency, political subdivision, municipality, or other entity that:

a. Operates a QF; and

b. Has entered into an Agreement(s) with the Utility stipulating the terms and conditions of the interconnection and separately the sale of electric power to the Utility.

(continued)

Schedule No. QF-1

QUALIFYING FACILITY POWER PURCHASE

O. "Transmission Provider"~~:~~ means- ~~T~~the public utility (or its Designated Agent) that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides transmission service.

P. "Transmission System"~~: T~~means the facilities owned, controlled, or operated by the Transmission Provider that are used to provide transmission service.

(continued)

Schedule No. QF-1

QUALIFYING FACILITY POWER PURCHASE

~~O~~Q. "Utility" means NorthWestern Energy.

~~P. "Wind Integration Services" means those services necessary to integrate wind generation into the Utility's electric transmission and/or distribution system(s) in a manner such that all operational and reliability criteria are met. Wind Integration Services include, but are not limited to, Regulating Reserves, imbalance service, and scheduling.~~

~~1)~~ 2) Net Billing Option: If Seller contracts for Net Billing and the Seller's consumption kWh exceeds its production kWh, Seller shall be billed for power supply for the consumption kWh in excess of the production kWh in accordance with the Utility's applicable rate schedule. If Seller's consumption kWh is less than its production kWh, Seller shall receive a power supply payment (credit) for the production kWh in excess of the consumption kWh at the Rates specified above.

~~2)~~ 3) Disposition of RECs: QFs retain RECs but may still separately attempt to negotiate for the sale of RECs to NWE or other interested parties at any time that an Agreement remains in effect. Any such negotiation occurs separate from the Power Purchase Agreement and does not create a reopener that refreshes the rates in the Agreement.

4) Ancillary Services: Sellers must contractually agree to the provision of ancillary services for the term of the Agreement and may either self-supply these services under terms acceptable to NorthWestern or pay the Utility for these services according to NorthWestern's Open Access Transmission Tariff ("OATT"). Payment to the Utility for selection of service through the OATT, including payment from- Sellers who receive an Option 2 Rate upon expiration of an Agreement, will result in a deduction from the total monthly payment made to the QF to reflect the provision of ancillary services.

~~Wind Integration: Sellers of Wind Energy must contractually agree to the provision of wind integration services for the term of the Agreement and may either self-supply sufficient within-hour regulating reserves under terms acceptable to NorthWestern or pay the Utility for these services according to the Wind Integration Tariff (WI-1).NorthWestern's Open). Payment to the Utility for selection of service through WI-1 will result in a deduction from the total monthly payment made to the QF to reflect the provision of integration services.~~

~~3) Contingency Reserves: QFs must either self-supply contingency reserves, or purchase the needed reserves from NorthWestern at the rate as specified according to the Contingency Reserves Tariff (CR-1). If the QF purchases reserves from NorthWestern, the CR-1 rate for the appropriate resource type will be deducted from the total monthly payment made to the QF to reflect the provision of contingency reserves.~~

5) Hourly Metering: Sellers are required to install interval metering capability if necessary to support the Rate Option chosen.

Schedule No. QF-1

QUALIFYING FACILITY POWER PURCHASE

6) Network Upgrades: Any Seller must pay for network upgrade costs, including both generator interconnection and transmission service. -Seller represents and warrants that Seller will not seek reimbursement from NorthWestern or the Transmission Provider for Network Upgrades.

SERVICE AND RATES SUBJECT TO COMMISSION JURISDICTION: All rates and service conditions under this Rate Schedule are governed by the rules and regulations of the Public Service Commission of Montana and are subject to revision as the Commission may duly authorize in the exercise of its jurisdiction.

Department of Public Service Regulation
Montana Public Service Commission
Docket No. 2019.09.059
QF-1 Tariff Update Application
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF DR. BRANDON K. MAUCH

ON BEHALF OF NORTHWESTERN ENERGY

TABLE OF CONTENTS

* Electronic exhibits provided on CD only

1: Witness Information

Q. Please state your name, occupation, and address.

A. My name is Brandon K. Mauch. I am a Senior Energy Analyst at Ascend Analytics, LLC ("Ascend"). I work at our headquarters located at 1877 Broadway Street, Suite 706, Boulder, CO 80302. We have additional offices at 222 E. Main, Suite 201, Bozeman, MT 59715 and 440 Grand Avenue, Suite 360, Oakland, CA 94610.

Q. Please summarize your educational and professional background.

A. I have worked in the electric utility industry for the past seven years. In my current position, I support utilities in long-term resource planning and asset valuation. I have been in this role for over a year.

Previously, I worked for CLEAResult Consulting where I designed and managed energy efficiency programs for utility customers. I worked directly with utility staff, commercial and industrial customers, and contractors to develop solutions that saved electric and gas consumption in cost effective ways.

Prior to that, I worked as a utility regulation engineer for the Iowa Utilities Board where I provided analysis for rate cases and represented the Board in the Mid-Continent Independent System Operator stakeholder processes.

I hold a Ph.D. in Engineering and Public Policy from Carnegie Mellon University, a MS in Mechanical Engineering from the University of Wisconsin, and a BS in Mechanical Engineering from the University of Kansas. My CV is attached as Exhibit__(BKM-1).

Q. Have you previously testified before the Montana Public Service Commission?

A. No.

2: Overview of Testimony

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of NorthWestern Energy ("NorthWestern").

Q. What is the purpose of your testimony?

A. My testimony supports NorthWestern's avoided cost calculations for its Electric Tariff Schedule No. QF-1 ("QF-1 Tariff"). Specifically, I provide an overview of PowerSimm™ modeling and explain that the use of 10, rather than 100, simulations for purposes of the QF-1 Tariff results in analytically robust calculations. I also explain Ascend's expectation that prices at the Mid-Columbia ("Mid-C") trading hub will decline over the next 15 years due to the rapid growth of renewable generation, which will diminish the role of natural gas in setting the price of power.

3: Overview of PowerSimm

Q. What is PowerSimm?

A. PowerSimm is an analytical software package that combines market dynamics with physical characteristics in power system modeling. PowerSimm creates multiple simulations of weather, load, renewable generation, and market prices. The simulations flow into a dispatch model where the physical parameters of the power system (generators, transmission, ancillary services, etc.) are used to simulate the operation of the power system over a range of future states.

Q. What do you mean by "simulation"?

A. In the PowerSimm modeling construct, a simulation represents a possible future path for weather, renewables, load, and market prices. Collectively, these simulations capture a range of possible future outcomes. PowerSimm starts with weather simulations which drive the load, renewables, and market price simulations.

Q. How does PowerSimm simulate weather, renewables, load, and prices?

A. All simulated values in PowerSimm are derived from historical data measured hourly and spanning at least a year, preferably longer. Weather simulations are based on historical data pulled from weather stations in the respective territory. Using the weather history, PowerSimm estimates seasonal patterns in the data along with the random variations therein. This information is used to produce future simulations of weather with the same underlying seasonal patterns and random variations for realistic weather outcomes.

Renewable generation (wind, solar, and hydro) simulations use weather as a dependent variable. The statistical models used for renewables simulations maintain historical correlations in the weather and renewable data for each renewable generation item in the model. We use monthly forecasts of energy generation for all wind, solar, and hydro items to scale the simulations to align with the forecasted values. For a given month, the hourly simulated values over all hours and simulations in the month must average to the forecasted value while holding all simulated values under the maximum capacity of the item. The results are realistic future simulations of renewable resources based on historical data covering a range of potential weather patterns.

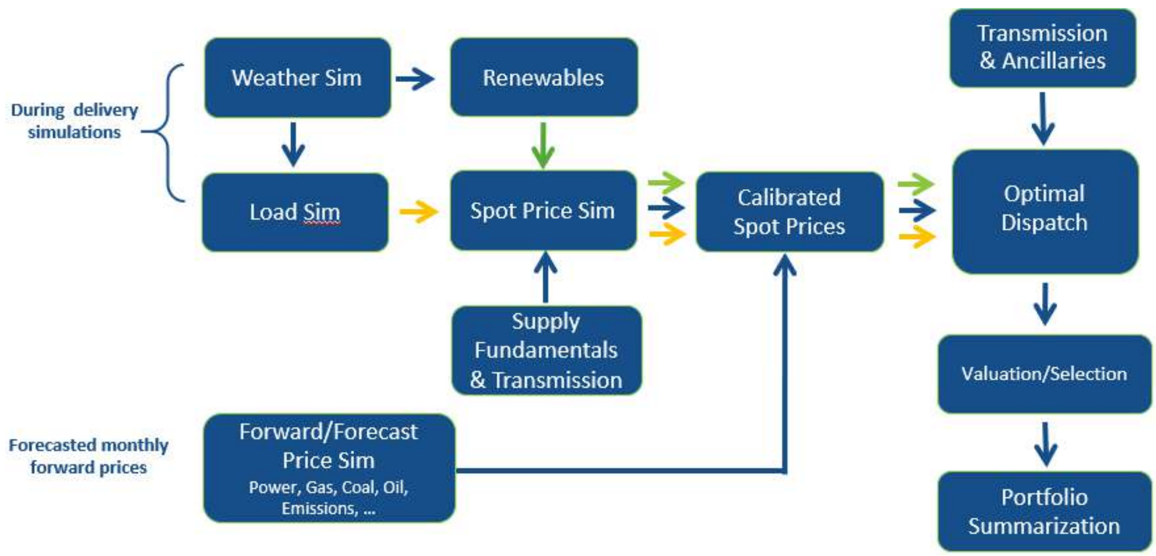
Customer demand for electricity (load) is also dependent on weather. Extremely cold days cause high levels of electric heat and often lead to the highest levels of peak demand in NorthWestern's territory. Hot days, likewise, cause customers to use more air conditioning. In determining the relationship between load and weather, PowerSimm estimates correlations between weather and load and a "break point" in how temperatures affect load. The break point is defined as the temperature at which load is the minimum value. Temperatures hotter or colder than the break point will create higher load levels in NorthWestern's territory. Load simulations exhibit similar patterns as the historical data and, like renewable items, the load simulations are scaled to match forecasted values on average.

Market price simulations are more complex than the weather, load, and renewable simulations. Spot prices for natural gas, power, and coal are simulated using a system of equations that include stochastic components of the prices as well as correlations between time periods (e.g. correlation between power prices in June and power prices in July) and between commodities (e.g. correlation between power and gas). Monthly price forecasts are used to scale the simulations so that average values of monthly spot prices across all simulations equal the forecasted monthly prices.

Spot price simulations are calibrated to ensure realistic results that match expected correlations, volatility, and daily profiles. This process involves additional scaling of values while maintaining monthly averages to match forecasted values.

Figure 1 shows the simulation process in graphical form. After PowerSimm creates the load, renewables, and price simulations, these values are used in the dispatch module along with physical parameters describing the generation, transmission, and ancillary requirements of the power system.

Figure 1: PowerSimm flow chart



PowerSimm results are summarized over all simulations to get an expected value for the variables of interest over a range of potential outcomes (e.g. generation costs, market sales, revenue, etc.). The result for an avoided cost is determined over multiple, realistic simulations of the NorthWestern system.

<u>4: Avoided Cost Calculation</u>

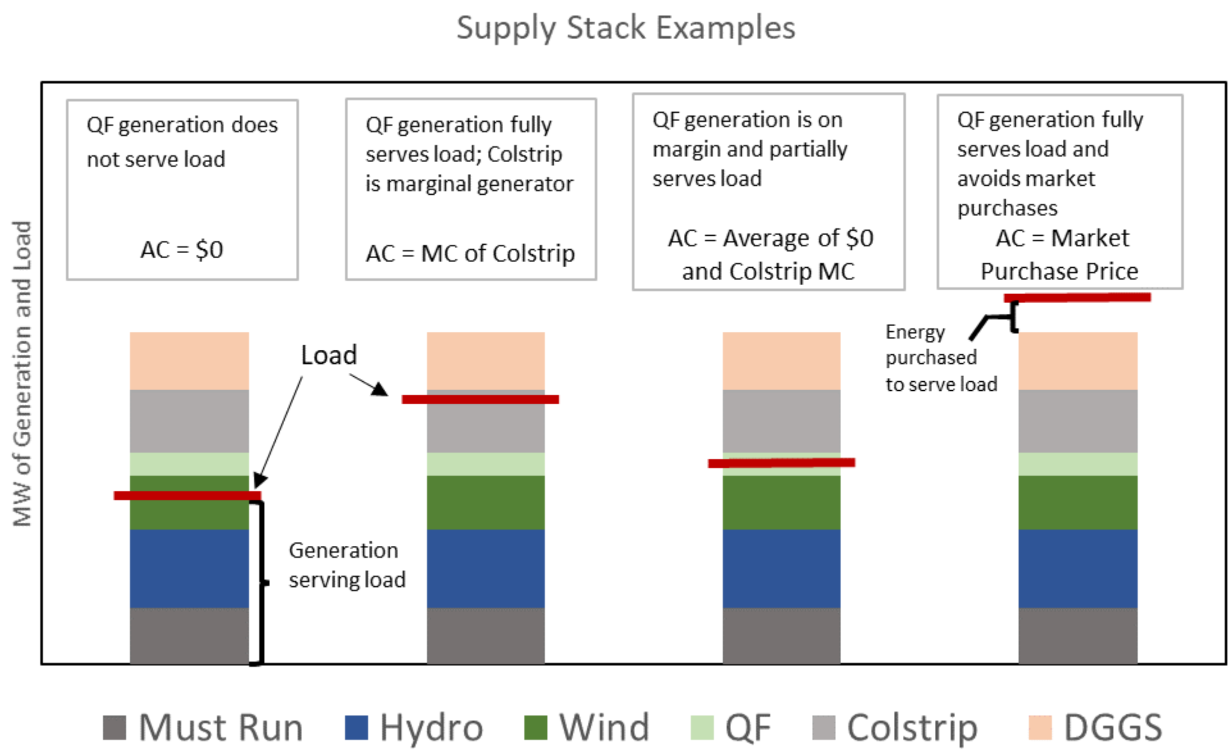
Q. How was PowerSimm used to determine the avoided cost for the QF-1 Tariff rates?

A. NorthWestern’s system was modeled in PowerSimm with 10 simulations. In each simulation, the hourly generation and hourly load was used to determine the marginal cost to serve the customer load. This means that the generation output of the thermal generators determined in the dispatch module was used with the simulated values of wind, solar, and hydro generation to determine if NorthWestern’s load is fully served by NorthWestern’s resources or if market purchases are also used to satisfy the customer load.

During simulated hours where NorthWestern relied on market purchases, the avoided cost of the Qualifying Facility (“QF”) was set at the price of the market purchases (simulated value of Mid-C plus the $2 differential). This is reasonable because the QF allowed NorthWestern to avoid market purchases that would have otherwise been needed to serve customers.

In the simulated hours where NorthWestern’s load was fully served without market purchases, I calculated the avoided cost by determining the cost of the generator that is supplying the last megawatt (“MW”) for customer load. In doing so, I allocated the lowest-cost generation to the customer load and continued adding the next lowest-cost resource until customer load was met. For instance, consider Figure 2 below which shows four scenarios of customer load at an hour where Colstrip and the Dave Gates Generating Station (“DGGS”) are generating due to high market prices. If the QF generation is above the load line, the QF is not contributing to load and has an avoided cost of $0. If some or all of the QF generation is below the customer load in the supply stack, then the avoided cost is greater than zero. The Exhibit__(BKM-2a – f) files contain additional details on the hourly avoided cost results.

Figure 2: Avoided cost calculations from the supply stack



Q. How many simulations does NorthWestern typically use in its PowerSimm models?

A. NorthWestern uses 100 simulations in PowerSimm models to estimate avoided costs for large QFs and for its electricity supply resource procurement plans. In general, more simulations will give a more stable and accurate result. When using 100 simulations, NorthWestern is ensuring that a model run multiple times will provide nearly the same result.

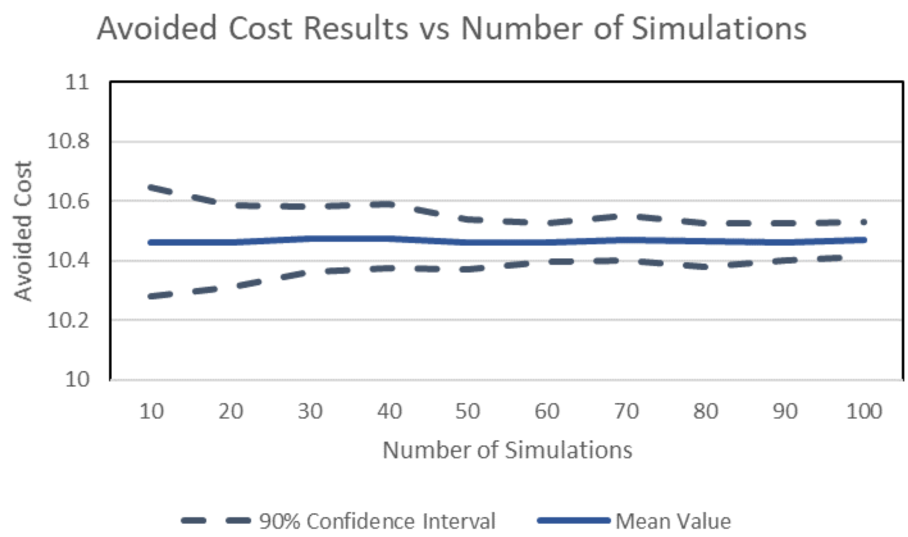
Q. Did you use 100 simulations for this analysis?

A. No. I used 10 simulations for this analysis.

Q. Why did you run the model with 10 simulations for QF-1 Tariff avoided costs?

A. I have reviewed the avoided costs for small QFs that are three MW and smaller using various numbers of simulations. For these small QFs, the avoided cost result can vary only slightly more with 10 simulations compared to 100 simulations. Figure 3 shows the mean value with the 90% confidence interval for an avoided cost calculation with simulations ranging from 10 to 100. In my opinion this is an acceptable amount of variance around the average value. Essentially, this analysis means that the true avoided cost is within 1.8% of the model results when using 10 simulations. This compares to a potential error of plus or minus 0.6% if 100 simulations are used. In fact, for reasons I will get into later, these are conservative estimates of the confidence interval. The actual levels are likely smaller.

Figure 3: Mean Avoided Cost and 90% Confidence Interval for Studies with Simulations Ranging from 10 to 100



This analysis was conducted using an approach known in statistics as bootstrapping. I ran a study using 500 simulations and sampled a portion of the 500 simulations to recalculate the avoided cost with a sample size of 10 simulations, 20 simulations, 30 simulations, and so on until I reached 100 simulations. For each sample size, the avoided cost was calculated 100 times. For example, I pulled 10 simulations from the set of 500 and calculated an avoided cost. I replaced those 10 samples and grabbed another 10 samples to calculate another avoided cost. This process repeated until I had 100 avoided cost results based on 10 simulations. I then moved to sample sizes of 20 simulations and calculated avoided costs 100 times.

The purpose of calculating the avoided cost over and over is to determine how much the result changes when the underlying simulations change.

As expected, results based on 100 simulations vary over a smaller range compared to the result based on 10 simulations. Therefore, the confidence interval gets smaller when more simulations are used to generate an avoided cost result. Please see Exhibit__(BKM-3) for further details.

Q. Have you confirmed this analysis with additional studies?

A. Yes, I ran a series of 10-simulation studies and observed the avoided cost results. With 10 new studies, the avoided cost varied by 1.7% over the 10 results. These results are expected to be a bit closer together due to the way simulations for prices, load, and renewables are scaled to align with forecasted values. In the bootstrap analysis, the samples were selected such that prices scaled to match the forecasted prices. The bootstrap analysis was not able to match all forecasts for load, renewable generation, etc., so the range of results ended up being a bit larger compared to running a number of studies and analyzing the results.

5: Market Price Forecasts

Q. What is your forecast for the power price at Mid-C?

A. Ascend projects power prices at Mid-C to increase over the next five years based on the forward market values and then decline over time to $22 per megawatt-hour ("MWh") around-the-clock in 2035. The average Mid-C price during heavy load hours is projected to be $26.87/MWh in 2035 while the average price during light load hours is projected to be $16.40/MWh during the same year.

Q. Why will power prices at Mid-C decline over time?

A. Prices will decline due to a large increase in the amount of renewable energy expected to come online over the next 15 years. Policies in Washington, California, Colorado, New Mexico, and Nevada will put a large portion of the supply in the Western Electricity Coordinating Council ("WECC") region on a roadmap to 100% renewables by 2045. Currently, the WECC generates 38% of its energy from renewables and hydro. The transition from 38% to roughly 90% by 2040 will cause disruptive change to power markets.

As states move closer to a 100% goal for renewables, the amount of time that natural gas is on the margin will decrease. Power prices are determined by the variable cost of generation on the margin, or the last generator needed to supply customer load. If the marginal generator is wind, solar, or hydro, the marginal cost, and the price of power, will be at or very close to zero. Another way to look at this is that the price of energy will be lower as utilities strive to procure more and more energy resources from low-cost renewables.

In California, we are already seeing many hours where solar and wind are pushing natural gas off the margin, leading to the so-called "duck curve" where power prices are diminished during summer afternoons due to a high level of renewables generation on the grid.[1]

Q. Have you reviewed other forecasts of power prices at Mid-C?

A. Yes. Of the utilities in the Pacific Northwest that I reviewed, Puget Sound Energy ("PSE") and Avista stand out since they released updated price forecasts at Mid-C this year. PSE's current power price projection estimates the price at Mid-C to be $31 per MWh in 2035 which was presented at the Technical Advisory Council meeting in September[2]. In its Technical Advisory Council meeting in May 2019, PSE's presentation of the updated price forecast stated that, "The increase in zero variable cost renewable resources is causing power prices to decrease. *It is expected that the power prices will decrease even more* once the updated clean energy laws are added for NV, NM and WA."[3] [emphasis added] When those clean energy laws were added to the modeling, the power price forecast for Mid-C in 2035 dropped from $40 to $31 per MWh.

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[1] Many articles exist regarding the California Duck Curve. An example is found at: https://www.greentechmedia.com/articles/read/the-california-duck-curve-is-real-and-bigger-than-expected#gs.76bhv2

[2] The Presentation for PSE's TAG #8 on September 19, 2019 is found at: https://oohpseirp.blob.core.windows.net/media/Default/19_Sept_TAG_8/02_IRP_TAG_Meeting_8_Slide_Deck_FINAL.pdf

[3] The Presentation for PSE's TAG #6 on May 29, 2019 is found at: https://oohpseirp.blob.core.windows.net/media/Default/29_May_TAG_6/02_IRP_052919_TAG_Meeting_6_Slide_Deck_FINAL.pdf

In the Avista price forecast for Mid-C, the estimated price in 2035 is $33/MWh. It should be noted that Avista's price forecast included carbon prices from states that have carbon pricing policies.

The price forecasts from Avista and PSE are relevant because they were completed after the policy announcements in the WECC states that will increase renewables and decrease power prices. Other resource plans in the Pacific Northwest were assembled prior to the recent clean energy mandates in the WECC so they contain prices forecasts that do not include these ambitious renewable goals.

Q. Are there studies that support the thesis that prices will decrease if renewables continue to increase?

A. Yes, a recent analysis from the National Economics Research Associates[4] (NERA) showed that wind generation in the Electric Reliability Council of Texas ("ERCOT") region depresses wholesale prices by $1.45/MWh to $4.45/MWh for every 1,000 MW of wind generation in a real-time settlement interval. Additionally, researchers at the Lawrence Berkeley National Laboratory ("LBNL") evaluated the impact of renewables on market prices and found that in a high renewables future there is "a general decrease in average annual hourly wholesale energy prices with more VRE [Variable Renewable Energy] penetration, increased price

[4] Chen-Hao Tsai and Derya Eryilmaz; "Effect of wind generation on ERCOT nodal prices"; Energy Economics, 76 (208) 21-33.

volatility and frequency of very low-priced hours, and changing diurnal price patterns."[5] Finally, The Energy Institute at Haas[6] (of the University of California at Berkeley) analyzed data from the California Independent System Operator (CAISO) and determined that dramatic increases in California's solar renewable energy has led to "a substantial decline in daily average prices," and threatens to undermine the economic viability of traditional baseload generation technologies.

Q. Does this end your testimony?

A. Yes.

[5] Joachim Seel, Andrew Mills, Ryan Wiser; "Impacts of High Variable Renewable Energy Futures on Wholesale Electricity Prices, and on Electric-Sector Decision Making"; LBNL, May 2018.

[6] James Bushnell and Kevin Novak; "Setting with the Sun: The impacts of renewable energy on wholesale power markets"; Energy Institute WP 292; August 2018.

Brandon Keith Mauch, Ph.D.

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PROFESSIONAL EXPERIENCE

Ascend Analytics, Boulder, CO
Senior Energy Analyst — August 2018 - Present

- Performed analysis for utility clients using production cost models and statistical analysis for resource planning, RFP evaluations, Loss of Load Probability analysis, avoided cost calculations
- Provide software training and technical support to client users of PowerSimm

CLEAResult Consulting, Des Moines, IA
Senior Program Manager — August 2015 – August 2018

- Leveraged technical experience and industry knowledge to provide demand side management program design and operations support
- Directed a team of energy specialist in implementing utility energy efficiency programs for commercial customers
- Provided analytical oversite used for tracking performance and driving decision making

Policy, Design and Evaluation Analyst — May 2014 – August 2015

- Developed analytic models to forecast energy savings and spending for demand side management programs
- Consulted with utility clients on energy efficiency program design including rebate amounts, savings algorithms, and measurement and evaluation
- Performed risk assessments on programs to assist in meeting targets

Iowa Utilities Board, Des Moines, IA
Utility Regulation Engineer — October 2012 – May 2014

- Produced statistical and economic analysis for decision makers in various regulatory proceedings (rate cases, outage reports, requests for information)
- Represented Iowa interests in regional energy policy issues through MISO including transmission planning, reliability assessments and electric markets
- Reviewed utility resource plans and financial analysis

Carnegie Mellon Electricity Industry Center, Carnegie Mellon University, Pittsburgh, PA
Research Assistant — August 2008 – October 2012

- Research focused on the integration of large-scale wind energy in electric grids
- Created statistical models to analyze wind and electric load data
- Presented results at conferences and in peer-reviewed journals
- Taught an undergraduate course on engineering and public policy analysis

Robert Bosch Research and Technology Center, Pittsburgh, PA
Energy Research Intern — May – August 2011

- Researched policies and markets for distributed generation and renewable energy
- Collaborated with engineering team in the development of a control algorithm for minimizing energy costs in commercial buildings

U. S. Department of State, Foreign Service
Security Engineer January 2003 – August 2008

- Managed technical security projects at U.S. Government facilities
- Conducted annual technical security assessments of government buildings
- Assigned to Washington, D.C., Dakar, Senegal and Belgrade, Serbia with extensive travel throughout West Africa and Eastern Europe

Tumaini University, Iringa, Tanzania
Lecturer January 2002 – January 2003

- Developed and taught courses on computer applications
- Assisted the department head with integrating computer knowledge into curriculums

U.S. Peace Corps, Tanzania
Math and Physics Teacher October 1998 – December 2001

- Taught math and physics at a girls' high school in northern Tanzania
- Organized sports events, field trips and annual school climbs up Mt. Kilimanjaro

EDUCATION

Carnegie Mellon University	Ph.D. - Engineering and Public Policy	December 2012
University of Wisconsin	M.S. - Mechanical Engineering	August 1998
University of Kansas	B.S. - Mechanical Engineering	May 1996

SKILLS

Statistics; Engineering and Economic Analysis; Public Policy; Project Management
Computer: Matlab, SAS, Power BI, MS Office with VBA applications
Language: French (conversant), Swahili (proficient)

PUBLICATIONS

- Horowitz, S., **Mauch, B.**, Sowell, F., Forecasting for direct load control in energy markets, Applied Energy, 2014
- **Mauch, B**., Apt, J., Carvalho, P., Jaramillo, P., What day-ahead reserves are needed in electric grids with high levels of wind power?, Environmental Research Letters, 2013
- **Mauch, B**., Carvalho, P., Apt, J., Small, M., An effective method to model wind power forecast uncertainty, Energy Systems, 2013
- **Mauch, B**., Apt, J., Carvalho, P., Can a Wind Farm with CAES Survive in the day-ahead market?, Energy Policy, 2012

REFEREE AND REVIEWER

I review papers for journals and conferences a few times per year. These include the Journal of Energy Engineering, Engineering Management, Journal of Renewable and Sustainable Energy, Power Systems Computation Conference.

Statistical Analysis of PowerSimm Simulations

NorthWestern's avoided cost calculations for Qualifying Facilities (QFs) greater than 3 MW use 100 simulations in the PowerSimm model. This is appropriate for a larger facility that will have a big impact on NorthWestern's operating costs. However, for small QFs the need for 100 simulations in the PowerSimm model is less. Further, the models become more transparent with less simulations because it becomes possible to share all results in a meaningful manner using Excel.

In order to justify the reduction of simulations, Ascend Analytics performed a statistical analysis of a large avoided cost study based on 500 simulations. The QF in the study is a 3 MW wind farm. The objective of this analysis was to determine the confidence interval for avoided cost calculations that are based on a range of simulation numbers. Ascend employed a bootstrap method using the following steps.

1. Calculated the average hourly Mid-C price for each of the 500 simulations covering 15 years
2. Sort the simulations by average Mid-C price from lowest to highest
3. Place the sorted simulations into groups of 50 so that the first group contains the 50 lowest Mid-C values and the last group contains the 50 highest Mid-C values. The purpose of grouping the simulations is to allow for stratified samples that ensure the average Mid-C value for smaller samples of simulations will remain close to the overall average Mid-C price over all 500 samples.
4. Grab 10 simulations, one from each group in step 3. Note that in step 3 the simulations were organized into 10 groups.
5. Calculate an avoided cost with a weighted average across the 10 simulations. Hourly avoided costs are averaged over months where they are levelized across 15 years.
6. Repeat steps 4 and 5 200 times.
7. Repeat steps 4 through 6 with 20 simulations, 30 simulations, 40 simulations and so on up to 100 simulations.

Table 1: Analysis of avoided cost results based on 10 to 100 simulations

Number of Simulations	95th Percentile Avoided Cost	Mean Avoided Cost	5th Percentile Avoided Cost	90% Confidence Interval	Percent Difference 95th and Mean
10	10.65	10.46	10.28	0.37	1.8%
20	10.59	10.46	10.31	0.28	1.2%
30	10.58	10.48	10.36	0.22	1.0%
40	10.59	10.47	10.38	0.22	1.1%
50	10.54	10.46	10.37	0.17	0.8%
60	10.53	10.46	10.40	0.13	0.6%
70	10.55	10.47	10.40	0.15	0.7%
80	10.52	10.47	10.38	0.15	0.5%
90	10.53	10.46	10.40	0.12	0.6%
100	10.53	10.47	10.42	0.11	0.6%

The results in table show that when 10 simulations are used to calculate the avoided cost, the result is likely within 1.8% of the true value. Moving up to 100 simulations reduces the uncertainty to the point where the result is within 0.6% of the true value. Note the results in Table 1 were obtained from avoided cost models with a 3 MW QF. These results do not necessarily hold for a large QF.

PowerSimm scales simulations of load, renewables, and prices so that the monthly average values match the forecasts. For example, if the generation from a wind farm is projected to be 10,000 MWh in the month of January 2020, then the average monthly value over all simulations will equal 10,000 MWh for January 2020. Some simulations will have higher values and some simulations will have lower values, but all simulations are scaled until the average value equals the forecast. In the bootstrap method used for the analysis described earlier, Ascend grouped the simulations so the average monthly prices over all simulations closely matched the forecasted values. However, the renewable generation forecasts and load forecasts were not considered in the analysis. Thus, the bootstrap results should be viewed as an upper bound for the 90% confidence interval for a given number of simulations. Ascend followed up the bootstrap analysis with a series of studies, each using 10 simulations to determine an avoided cost.

Table 2: Avoided Cost calculations for 10 separate PowerSimm studies using 10 simulations each

Study	Avoided Cost
1	8.51
2	8.50
3	8.48
4	8.41
5	8.51
6	8.48
7	8.48
8	8.32
9	8.50
10	8.43
Average	8.46
Range	0.19
Percent Difference between Max and Mean	0.57%
Percent Difference between Mean and Min	1.7%

A sample of ten studies is not enough for a full statistical analysis, but this shows that the actual spread in avoided cost results with 10 simulations is likely to be smaller than what the bootstrap analysis would suggest.

Department of Public Service Regulation
Montana Public Service Commission
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PREFILED DIRECT TESTIMONY

OF JOSEPH M. STIMATZ

ON BEHALF OF NORTHWESTERN ENERGY

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Witness Information

Q. Please identify yourself, your employer, and your job title.

A. My name is Joseph (Joe) M. Stimatz. I am NorthWestern Energy's ("NorthWestern") Manager of Asset Optimization in the Energy Supply group.

Q. Please provide a description of your relevant employment experience and other professional qualifications.

A. I have over 20 years of experience in the areas of electricity and natural gas trading and marketing, hedging strategy, and asset valuation. I joined NorthWestern in March of 2011 and lead NorthWestern's electric resource optimization efforts. Prior to joining NorthWestern, I co-founded Highland Energy, an energy trading firm that participated in electricity markets throughout the Western Electricity Coordinating Council region. I also worked for Montana Power Trading & Marketing Company and PPL Energy Plus in various positions related to trading, marketing, and portfolio management. I hold a Bachelor's degree in Finance, a Master's in Business Administration, and Chartered Financial Analyst designation.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide estimates of the cost of the ancillary services that are required to integrate Qualifying Facilities ("QF") that are eligible for the standard rates in NorthWestern's Electric Tariff Schedule No. QF-1 ("QF-1 Tariff"). I propose using the ancillary service schedules and corresponding rates from NorthWestern's Open Access Transmission Tariff ("OATT") which the Federal Energy Regulatory Commission ("FERC") has approved on an interim basis, for the amount and cost of these ancillary services.

Ancillary Services

Q. What are ancillary services?

A. Ancillary services are those that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the system. NorthWestern's witness, Dr. Ben Fitch-Fleischmann, explains that the cost of ancillary services, which reflects the cost of integrating the QF on NorthWestern's system, is a component of an avoided cost calculation.

Q. What ancillary services have you identified that will be needed to support the projects eligible for the QF-1 Tariff?

A. Under NorthWestern's OATT, there are four ancillary services that apply to small QFs. These services are:

Schedule 3, Regulation and Frequency Response Service;

Schedule 5, Operating Reserve – Spinning Reserve Service;

Schedule 6, Operating Reserve – Supplemental Reserve Service; and

Schedule 11, Flex Reserve Service.

Q. What is Regulation and Frequency Response Service?

A. This service provides for the second-to-second and minute-to-minute balancing of the resources and load on NorthWestern's system and is required to maintain the frequency of the grid in compliance with the North American Electric Reliability Corporation ("NERC") Standard BAL-001-2, Real Power Balancing Control Performance.

Q. What is Operating Reserve – Spinning Reserve Service?

A. This service is required by NERC Standard BAL-002-WECC 2a. It must be provided from resources that are online and responsive to frequency drops on the system. This service provides an immediate response to a contingency event on the system and must be fully deployable within ten minutes.

Q. What is Operating Reserve – Supplemental Reserve Service?

A. This service is also required by BAL-002-WECC 2a to respond to contingency events. It can be provided from resources that are offline, but it must be fully deployable within ten minutes.

Q. What is Flex Reserve Service?

A. Flex Reserve Service is necessary for NorthWestern to respond to sudden, large drops in wind power production. This service is deployable in a slightly longer time horizon (up to 30 minutes). Flex Reserve Service applies only to wind generators.

Q. How does using the rates from the OATT as the basis for the cost of ancillary services differ from previous QF-1 Tariffs?

A. NorthWestern previously used the CR-1 and WI-1 tariffs for ancillary service charges for QFs.

Q. Why is NorthWestern now proposing to apply its OATT ancillary service rates to the projects eligible for QF-1 Tariff rates?

A. There are several reasons. First, the application of the OATT rates ensures fair and reasonable treatment for QFs. The OATT rates ensure that small QFs are treated neither more favorably nor less favorably than any similar generator on NorthWestern's system. They will be subject to the same FERC-approved rates as other generators.

Second, the OATT rates are tied directly to the cost of the generating resources that NorthWestern uses to supply the services. In previous QF dockets, NorthWestern proposed different methods of estimating the cost to provide the services. This approach eliminates the need to use estimates of future costs.

Third, the WI-1 tariff applied only to wind projects. Solar projects, and to a lesser extent, hydro projects, cause integration costs on NorthWestern's system as well. Ancillary service charges for those resources that reflect the cost of integration are appropriate.

Finally, the situation has changed considerably since the WI-1 Tariff was implemented. At that time, the only wind generator larger than 10 MW on NorthWestern's system was the 135-MW Judith Gap project, and as a result, the Montana Public Service Commission chose to implement a zonal integration rate based on a QF's proximity to Judith Gap. The situation is much different now. In addition to Judith Gap, NorthWestern's system now includes an 80-MW facility, a 40-MW facility, and two 25-MW facilities. Another 80-MW facility will be online before the end of the year. Because of this, a zonal rate based on proximity to Judith Gap no longer makes sense.

Q. Under this approach, would NorthWestern fix the cost of ancillary services for the term of the Power Purchase Agreement ("PPA") with the QF?

A. No. Rates in the PPA will change as the rates in the OATT change. The QF will pay the current OATT rates for the ancillary services for the periods they are provided. This is entirely consistent with how all OATT customers, including third-party generators, are charged, whether they are serving on-system loads or selling their output off-system. This would include any change from interim to final OATT rates.

Q. How will NorthWestern implement changing rates?

A. As part of the normal invoicing and payment process under a PPA with a QF, NorthWestern will deduct the appropriate charges from the monthly payment to the QF based on the ancillary service rates that are in effect at that time. If FERC approves a change to the rates, the QF will be charged the new rates. This process will remain in effect for the term of the PPA, with the monthly charge for ancillary services reflecting the current OATT rates at that time.

Q. Can you provide an estimate of the total annual cost of ancillary services for a QF project?

A. The cost of ancillary services will depend on the type of resource. Wind and solar projects will be charged the Variable Energy Resource ("VER") rate for Schedule 3, while hydro projects will be charged the non-VER rate. All types of generation will pay the same rate for Schedules 5 and 6. Only wind resources will be charged for Schedule 11 service. The table below shows the current interim rates for each of these services and the corresponding annual cost for a 3-MW project.

	Rate ($/kW-month)			Annual Cost (3 MW Project)		
	Wind	Solar	Hydro	Wind	Solar	Hydro
Schedule 3	$ 1.415	$ 1.415	$ 0.112	$ 50,949	$ 50,949	$ 4,032
Schedule 5	$ 0.219	$ 0.219	$ 0.219	$ 7,878	$ 7,878	$ 7,878
Schedule 6	$ 0.201	$ 0.201	$ 0.201	$ 7,242	$ 7,242	$ 7,242
Schedule 11	$ 2.369	NA	NA	$ 85,289		
Total	$ 4.204	$ 1.835	$ 0.532	$ 151,358	$ 66,069	$ 19,152

Q. Will the changes to ancillary services apply to existing QF power purchase agreements?

A. No. These changes will only apply to new and renewal QFs. They will not apply to existing contracts. To reflect this distinction, NorthWestern proposes minor changes to the CR-1 Tariff and the WI-1 Tariff. Redlines of these proposed changes are provided as Exhibit__(JMS-1) and Exhibit__(JMS-2).

Q. Does this conclude your testimony?

A. Yes.

ELECTRIC TARIFF

NorthWestern Energy

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Canceling	2nd~~1st~~	Revised	Sheet No.	85.1

Schedule No. CR-1

CONTINGENCY RESERVES

APPLICABILITY: Applicable to any Qualifying Facility (QF) with nameplate capacity of 10 MW or less who ~~enters~~ entered into a Power Purchase Agreement (Agreement) with the Utility for the sale of electric power to the Utility from a QF as defined under the Rules of the Commission before *<<DATE of Final Order in Docket No. 2019.09.059>*.~~, or to QFs with a nameplate capacity greater than 10MW that are paid according to the QF-1 Tariff under the short-term purchase options.~~

The Utility shall offer contingency reserve services to a Seller for the full reserve requirement of the QF. Sellers choosing Rate Option 1 ~~or 2(a)~~ will receive a positive rate adjustment equal to the value of Contingency Reserves that is the basis of the Contingency Reserve rate included in this tariff.

Subsequent to this adjustment, QFs must either purchase Contingency Reserves pursuant to this tariff or self provide Contingency Reserves. Self provided Contingency Reserves must be approved by NorthWestern.

For Sellers who ~~choose~~ chose a market-based QF-1 rate Option 2~~(b)~~, the cost of Contingency Reserves is already included in the rate. Such sellers will not receive the rate adjustment but will be required to purchase Contingency Reserves or to self provide them pursuant to this tariff.

RATE:

The rate for the 2012 Calendar Year and until subsequently updated is:

$10.10/MWh

An amount equal to the above rate, multiplied by the reserve requirement as specified in the table below for specific resource types, will be subtracted from the Agreement total monthly payment that NWE makes to the QF should the QF opt to purchase Contingency Reserves from NWE.

Reserve Requirement for All Resources:
3% of Actual Hourly Integrated Generation ($0.303/MWh); plus 3% of hourly integrated load served by that generation (equal to the Actual Hourly Integrated Generation) ($0.303/MWh)

These requirements are based upon applicable Western Electricity Coordinating Council (WECC) and Northwest Power Pool (NWPP) requirements and therefore are subject to change in the future and such changes shall be applicable at that time.

-continued-

Schedule No. CR-1

CONTINGENCY RESERVES

SPECIAL TERMS AND CONDITIONS:

1) Definitions:

A. "Agreement" means the Power Purchase Agreement between Seller and the Utility for a term of not less than one month.

B. "Calendar Year" means a twelve-month period beginning on January 1 of any year.

C. "Commission" means the Montana Public Service Commission.

D. "Contingency Reserves" are an amount of reserves sufficient to meet the regional Reliability Control Standard BAL-002-WECC-2, consistent with Western Electricity Coordinating Council and Northwest Power Pool requirements.

E. "Actual Hourly Integrated Generation" means the actual amount of generation integrated over each hour by the QF.

F. "Seller," for purposes of this schedule, is any individual, partnership, corporation, association, government agency, political subdivision, municipality or other entity that:

1. Operates a QF; and

2. Has entered into an agreement with the Utility stipulating the terms and conditions of both the interconnection and sale of electric power to the Utility.

G. "Utility" means NorthWestern Energy or NWE.

SERVICE AND RATES SUBJECT TO COMMISSION JURISDICTION: All rates and service conditions under this Rate Schedule are governed by the rules and regulations of the Public Service Commission of Montana and are subject to revision as the Commission may duly authorize in the exercise of its jurisdiction.

ELECTRIC TARIFF

NorthWestern Energy

	3rd~~2nd~~	Revised	Sheet No.	80.1
Canceling	2nd~~1st~~	Revised	Sheet No.	80.1

Schedule No. WI-1

WIND INTEGRATION

APPLICABILITY: Applicable to any Wind Generator who enter~~s~~ed into an Agreement with the Utility for the sale of electric power to the Utility under Schedule No. QF-1 before *<<DATE of Final Order in Docket No. 2019.09.059>*. Utility-provided Wind Integration Services shall be for the full generation output of the Wind Generator purchasing this service.

For QFs who do not choose Self-Supplied Wind Integration Service, an amount equal to the applicable rate, multiplied by the QF's nameplate capacity in kW, will be subtracted from the Agreement total monthly payments that the Utility makes to the QF under the Agreement. The Utility shall have no obligation to provide Wind Integration Service to Wind Generators who select Self-Supplied Wind Integration Service.

RATE:

Option 1: Zonal Rate: Agreement lengths: 1 month to 18 months - short-term.

1(a) - Zone 1: Applicable to Wind Generators located less than 25 miles from the Judith Gap wind project.

$1.19/kW/mo

1(b) - Zone 2: Applicable to Wind Generators located equal to or more than 25 miles and equal to or less than 60 miles from the Judith Gap wind project.

$0.44/kW/mo

1(c) - Zone 3: Applicable to Wind Generators located more than 60 miles from the Judith Gap wind project.

$0.16/kW/mo

Option 2: Zonal Rate: Agreement Lengths: 19 months to 25 years – long-term.

2(a) - Zone 1: Applicable to Wind Generators located less than 25 miles from the Judith Gap wind project.

$1.92/kW/mo

2(b) - Zone 2: Applicable to Wind Generators located equal to or more than 25 miles and equal to or less than 60 miles from the Judith Gap wind project.

$0.71/kW/mo

2(c) - Zone 3: Applicable to Wind Generators located more than 60 miles from the Judith Gap wind project.

$0.26/kW/mo

(Continued)

Schedule No. WI-1

WIND INTEGRATION

SPECIAL TERMS AND CONDITIONS:

1) Definitions:

A. “Agreement” means the Power Purchase Agreement between Seller and the Utility for a term of not less than one month.

B. “Commission” means the Montana Public Service Commission.

C. “Regulating Reserves” is spinning reserve immediately responsive to Automatic Generation Control (AGC) to provide sufficient regulating margin to allow the Balancing Authority to meet North American Electric Reliability Council (NERC) Control Performance Criteria (BAL-001).

D. “Self Supplied” means a Wind Generator that self-provides Wind Integration Services or contracts for Wind Integration Services from a third party.

E. “Utility” means NorthWestern Energy or NWE.

F. “Wind Generator,” for purposes of this schedule, is any individual, partnership, corporation, association, government agency, political subdivision, municipality or other entity that:

1. Operates a QF Wind facility;

2. Has entered into agreements with the Utility stipulating the terms and conditions of both the interconnection and sale of electric power to the Utility;

G. “Wind Integration Services” means those services necessary to integrate wind generation into the Utility’s electric transmission and/or distribution system(s) in a manner such that all operational and reliability criteria are met. Wind Integration Services include, but are not limited to, Regulating Reserves, imbalance service, and scheduling.

SERVICE AND RATES SUBJECT TO COMMISSION JURISDICTION: All rates and service conditions under this Rate Schedule are governed by the rules and regulations of the Public Service Commission of Montana and are subject to revision as the Commission may duly authorize in the exercise of its jurisdiction.

Department of Public Service Regulation
Montana Public Service Commission
Docket No. 2019.09.059
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NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF AUTUMN M. MUELLER

ON BEHALF OF NORTHWESTERN ENERGY

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* Provided on CD and uploaded to PSC EDDI system

Witness Information

Q. Please provide your name, employer, and title.

A. I am Autumn M. Mueller, NorthWestern Energy's ("NorthWestern") Coordinator of Generator and Transmission Interconnection in the Electric Transmission System Planning Department.

Q. Please describe your relevant experience and training.

A. I have worked in the utility industry for 23 years, with 17 of those years in transmission. In my current position in the Electric Transmission Planning Department, I oversee the interconnection process for all customers seeking interconnection to NorthWestern's system. I completed an Electric and Gas Transmission System Operations apprenticeship with NorthWestern where I received North American Electric Reliability Corporation System Operations Certification and Montana Department of Transportation Gas Operations Certification.

Purpose of Testimony

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

A. The purpose of my testimony is to provide information regarding the costs of upgrades associated with interconnecting small generating facilities to the system and Transmission Service necessary to deliver the energy produced by the small generating facility to NorthWestern's load. I recommend changes to NorthWestern's Schedule No. QF-1 ("QF-1 Tariff") to allow NorthWestern to recover the costs of any Network Upgrades triggered by QF projects.

Interconnection Procedures

Q. Does NorthWestern follow standardized procedures in responding to QFs seeking interconnection on NorthWestern's system?

A. Yes. We follow the standard procedures in our Federal Energy Regulatory Commission ("FERC") Open Access Transmission Tariff ("OATT"). Specifically regarding QFs that qualify for QF-1 Tariff rates, the Montana Public Service Commission approved NorthWestern following NorthWestern's Small Generator Interconnection Procedures ("SGIP") in Order No. 7108e, ¶ 85, Docket No. 2010.07.077.

NorthWestern follows these procedures for processing requests from small generators to interconnect to both the transmission and distribution systems. Pursuant to these procedures, NorthWestern and the QF enter into a Small Generator Interconnection Agreement ("SGIA"). The SGIP is Attachment N of NorthWestern's FERC tariff. I have attached both the SGIP and the SGIA as Exhibit__(AMM-1). Because the SGIP references the Large Generator Interconnection Procedures ("LGIP"), I have attached the LGIP as Exhibit__(AMM-2).

Q. Please provide an overview of the SGIP.

A. Prior to submitting a formal interconnection request, a QF has the option to request a pre-application report that provides information about the line or substation to which they are seeking potential interconnection. Once NorthWestern receives a formal interconnection request from the QF, NorthWestern initiates the study process. There are three levels of study:

1. Feasibility Study – A high-level look at the system is performed and a high-level, non-binding estimate of interconnection costs is provided to the customer. The QF has the option to bypass this study and go directly to the System Impact Study.
2. System Impact Study – A detailed study is performed to determine what upgrades will be needed to interconnect the project. A report is provided to the QF that includes the upgrades needed and a non-binding good faith estimate of costs for interconnection.
3. Facilities Study – This study specifies the estimated cost of equipment, engineering, procurement, and construction work needed to implement the upgrades identified in the System Impact Study.

Upon completion of study work, the QF is issued a draft SGIA. NorthWestern works with the QF to establish a milestone schedule for construction of the project. Once NorthWestern and the QF execute the SGIA, the project advances to construction.

Interconnection Cost Responsibility

Q. Do QFs pay for system upgrades associated with generator interconnection?

A. Currently, QFs pay for Distribution Upgrades and Transmission Provider Interconnection Facilities, but not interconnection Network Upgrades. In accordance with Article 5 of the SGIA, interconnection customers are responsible for Distribution Upgrades and Transmission Provider Interconnection Facilities costs.

Article 5 of the SGIA also requires interconnection customers to fund all interconnection-related Network Upgrades up front and then be reimbursed for them on a dollar-for-dollar basis, based on their Transmission Service usage, but that is not how the process works for QFs.

Since QFs do not pay Transmission Service rates, there is no available mechanism through which NorthWestern can refund Network Upgrade costs. Instead, NorthWestern pays QFs back for their interconnection-related Network Upgrade costs and then adds those costs to its rate base. As a result, NorthWestern's non-QF customers become responsible for the interconnection-related Network Upgrade costs that the QFs impose on NorthWestern's system.

Q. Could small QF projects trigger significant interconnection-related Network Upgrades?

A. Yes. The interconnection of new generation in certain areas of NorthWestern's system could cause system overloads that could require very costly mitigation.

Interconnection to NorthWestern's distribution system is typically less expensive than interconnection to the transmission system. NorthWestern has SGIAs with several QFs interconnecting to the distribution system that will require no Network Upgrades. But that is not always the case. NorthWestern currently has a signed SGIA for one project on the distribution system that will require $584,000 in interconnection-related Network Upgrades.

Interconnection to the transmission system could trigger the need for Network Upgrades that could cost millions of dollars.

Q. Can NorthWestern deny a QF's request to interconnect at a certain point of interconnection?

A. No. QFs select the point of interconnection for their projects. Even if the point of interconnection selected by a customer would require significant upgrades, NorthWestern cannot deny interconnection.

Q. Does NorthWestern's QF-1 Tariff include rates for interconnection-related Network Upgrade costs?

A. No. The QF-1 Tariff rates do not allow NorthWestern to recover interconnection-related Network Upgrade costs. Although the QF pays for these costs up front, NorthWestern is required to pay for these costs through a refund to the QF.

<u>Transmission Service Cost Responsibility</u>

Q. Who pays for system upgrades associated with Transmission Service?

A. Under the current process, NorthWestern is required to fund these upgrades and then adds the costs to its rate base. As a result, NorthWestern's non-QF customers also become responsible for any Transmission Service-related Network Upgrade costs that the QF imposes on NorthWestern's system.

Again, since the QF does not pay Transmission Service rates, there is no Transmission Service usage to offset the investment that is made by NorthWestern to fund the transmission Network Upgrade costs.

Q. Could small QF projects trigger significant Transmission Service Network Upgrades?

A. Yes. Transmission Service associated with designating these QF projects could cause system overloads that could require very costly mitigation.

Q. Does NorthWestern's QF-1 Tariff include rates for Transmission Service related Network Upgrade costs?

A. No. The QF-1 Tariff rates do not allow NorthWestern to recover Transmission Service-related Network Upgrade costs.

Q. What change do you recommend to the QF-1 Tariff?

A. I recommend a change to NorthWestern's QF-1 Tariff that requires the QF to pay for Network Upgrades associated with both interconnection and Transmission Service. I recommend adding language to the tariff that states that the Seller is responsible for these costs pursuant to the Special Terms and Conditions in the QF-1 Tariff. These changes, including a definition of Network Upgrades, are included in Exhibit__(BFF-1) attached to the Prefiled Direct Testimony of Dr. Ben Fitch-Fleischmann ("Fitch-Fleischmann Direct Testimony").

Dave Gates Generating Station

Q. Are you familiar with the study work performed under NorthWestern Supply's LGIA for DGGS?

A. Yes.

Q. Please provide an overview of the interconnection under the LGIA for DGGS.

A. NorthWestern has an LGIA for 213 megawatts ("MW") at DGGS. NorthWestern currently has 150 MW constructed and online. NorthWestern maintains rights to add additional generation up to the full 213 MW of generation granted under the LGIA. The Fitch-Fleischmann Direct Testimony includes further discussion of DGGS and its use as a proxy resource.

Q. Have the interconnection upgrades identified in the DGGS LGIA been constructed?

A. Yes. NorthWestern completed all of the Network Upgrades and Transmission Provider Interconnection Facilities required under the LGIA. These include the Network Upgrades and the Transmission Provider Interconnection Facilities for the full 213 MW approved in the LGIA.

Q. Would any additional upgrades be needed to add to the existing 150 MW of generation at the facility?

A. As mentioned above, all of the Network Upgrades and Transmission Provider Interconnection Facilities upgrades are complete. No further transmission system upgrades are needed. The only upgrades that would be necessary to add generation at DGGS are Interconnection Customer Interconnection Facilities, which are defined as all facilities and equipment that are located between the Generating Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Generating Facility to the Transmission Providers Transmission System.

Q. **Do you have an estimate of the costs for the Interconnection Customer Interconnection Facilities necessary to add the 63 MW of additional generation at DGGS?**

A. NorthWestern obtained an estimate in 2017 for these upgrades from HDR Engineering, an outside consultant. The estimated cost of the Interconnection Customer Interconnection Facilities associated with the build out of DGGS is $1,500,000. Pertinent pages from this report are provided as Exhibit__(AMM-3) to my testimony.

Q. **What type of interconnection service does DGGS have under the LGIA?**

A. Network Resource Interconnection Service (“NRIS”).

Q. **What does NRIS mean?**

A. FERC defines NRIS as “an Interconnection Service that allows the Interconnection Customer to integrate its Large Generating Facility with the Transmission Provider’s Transmission System (1) in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an RTO or ISO market based congestion management, in the same manner as Network Resources. Network Resource Interconnection in and of itself does not convey transmission service."

Q. Has DGGS secured Transmission Service for the 213 MW of generation under the LGIA?

A. No. NorthWestern only has Transmission Service for the generation that is constructed and online.

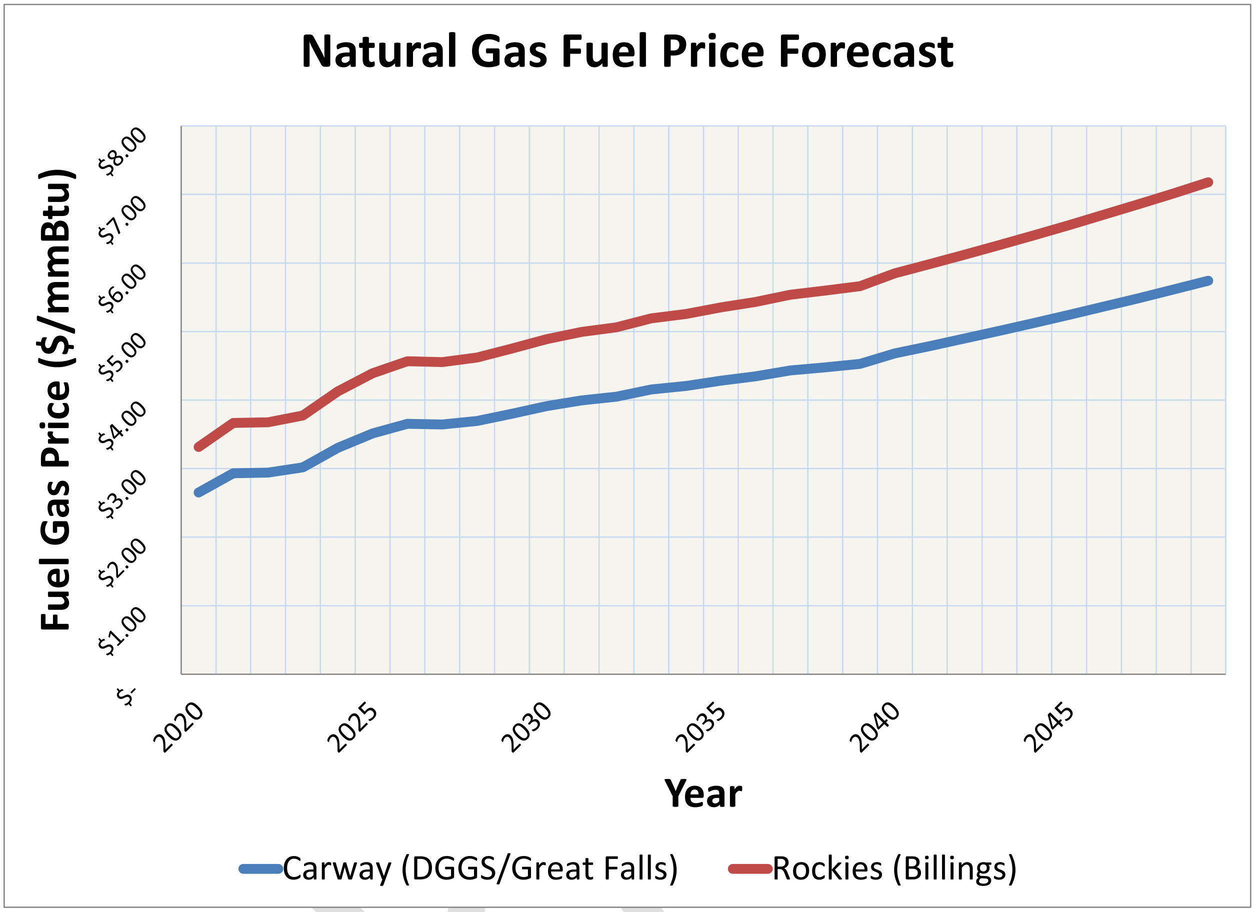
Q. Would upgrades be required if additional Transmission Service is requested for DGGS?

A. DGGS was studied for NRIS interconnection. At this time, there have been no system changes or additional projects interconnected in this area since DGGS was constructed. If Transmission Service was requested today, there would be no additional upgrades required to grant Transmission Service for the full 213 MW. There are currently no projects in NorthWestern's interconnection queue that would impact Transmission Service for DGGS.

Q. Does this conclude your testimony?

A. Yes, it does.

Figure 3.4-1. Assumed Natural Gas Price Fuel Forecast.



Required facilities and associated costs to interconnect to a natural gas pipeline main are also considered. At DGGS, there is an existing 24 inch lateral that delivers gas from the nearby compressor station to the site so an interconnecting radial is not required. However, this analysis does assume that an additional compressor is required to support the additional gas volume required for a new generation facility at DGGS. In general, this is viewed to be a conservative assumption given current compressor station operating mode/capability and based on RICE technology requiring significantly lower fuel gas supply pressures as compared to the existing units at DGGS.

For Great Falls and Billings, it is assumed that a 6 inch radial two miles in length would be required to interconnect to a natural gas main via a gate station (with no compression). For reference, the 24 inch radial to DGGS is approximately 2.5 miles in length. High-level $/mile unit costs were assumed for direct and indirect costs for installing the radial pipeline. Additionally, a typical planning level cost estimate was utilized for the cost of the gate station (provided by NorthWestern).

3.5 ELECTRICAL INTERCONNECTION

Generation additions at any of the sites would be required to complete the Large Generator Interconnect Agreement (LGIA) process, which examines required interconnection facilities and required transmission system/network upgrades associated with the addition. DGGS has an existing LGIA with spare capacity capable of supporting a nominal 55 MW addition. However, the new generators would be subject to a materiality review given that there would be a different number and type of generators as compared to what was contemplated in the initial site LGIA. The alternate sites would require a new LGIA. In general, there is expected to be a schedule and cost advantage associated with DGGS in terms of the interconnection process given that there is an existing LGIA in place with spare capacity. Schedule implications associated with such are discussed further in Section 3.8.

The following Sections discuss potential interconnection and transmission system facilities required to support development at each of the sites.

3.5.1 Interconnection Requirements

The DGGS site is also the site of the existing 230 kV Mill Creek substation, which has a spare 13.8 kV – 230 kV generator step-up (GSU) transformer. As a result, electrical interconnection costs at DGGS are anticipated to be minimal. This evaluation included a high-level assessment of required infrastructure to support interconnection at the Mill Creek substation. Additionally, it is assumed that some existing electric transmission lines would need to be relocated at DGGS to support the addition of the new generating facility. Feedback, in terms of required infrastructure/scope as well as associated costs, was received from NorthWestern.

For the alternate sites, it was assumed that new generation could be sited near existing high voltage transmission facilities, requiring minimal radial transmission line from the generators to the interconnection substation (this analysis did not include any cost adders for the alternate sites for radial transmission line). Additionally, it was assumed that interconnection at the alternate sites could be facilitated by the expansion of an existing 161 kV substation (in lieu of building a new substation). For the alternate sites, an evaluation of required interconnection infrastructure was performed and associated capital costs were estimated based on typical costs observed in the industry.

3.5.2 Transmission System Evaluation

An electric transmission capability analysis was performed for each of the sites under consideration. The electric transmission capability analysis examined the First Contingent Incremental Transfer Capability (FCITC) for each site up to 100 MW (to be conservative). The analysis utilized a combination of Siemens PSS/E and MUST software to determine the FCITC from each site sunk to a remote generator in the control area, which is a common technique for comparative analyses of this type. The FCITC analysis utilized Western Electricity Coordinating Council (WECC) load flow models for the 2021 summer and winter peak cases and considered a distribution factor (DF) cutoff of 1% to identify constraints (which is assumed to be conservative based on NorthWestern transmission analysis methodology). The FCITC analysis evaluated generation added separately at each site and without any additional generation added (e.g. from the current transmission interconnection queue). While FCITC analyses are common for this type of comparative analysis, it

NorthWestern Energy
Montana Generation Site Validation

NPV of Costs Comparison

Year					1	2	3	4	5	6	7	8	9	10
					2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
NG Price Basis														
DGGS / Great Falls (Carway Basis)	$/mmBtu			$ 2.65	$ 2.93	$ 2.94	$ 3.02	$ 3.30	$ 3.51	$ 3.65	$ 3.64	$ 3.70	$ 3.80	$ 3.91
Billings (Rockies/WY Basis)	$/mmBtu			$ 3.31	$ 3.67	$ 3.68	$ 3.77	$ 4.13	$ 4.39	$ 4.57	$ 4.56	$ 4.62	$ 4.75	$ 4.89
DGGS														
Operating Costs		**NPV**												
Fuel Cost	$1,000	**$85,739**			$ 4,844	$ 5,358	$ 5,375	$ 5,516	$ 6,034	$ 6,417	$ 6,678	$ 6,659	$ 6,754	$ 6,946
Ammonia Consumption	$1,000	**$1,746**			$ 103	$ 106	$ 109	$ 112	$ 116	$ 119	$ 123	$ 127	$ 130	$ 134
Incremental Staffing	$1,000	**$0**			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Makeup Power	$1,000	**$2,058**	Annual MWh Δ 3333		$ 121	$ 125	$ 129	$ 133	$ 137	$ 141	$ 145	$ 149	$ 154	$ 158
Total Operating Costs	$1,000	**$89,543**			$ 5,068	$ 5,589	$ 5,613	$ 5,761	$ 6,286	$ 6,677	$ 6,945	$ 6,935	$ 7,038	$ 7,238

Capital Costs		
Natural Gas Gate Station	$1,000	**$2,500**
Natural Gas Radial	$1,000	**$0**
Electrical Interconnection	$1,000	**$1,500**
Transmission System Upgrades	$1,000	**$0**
EPC Cost Adjustment	$1,000	**-$2,500**
Incremental Permitting Allocation	$1,000	**$0**
Incremental Water Infrastructure	$1,000	**$0**
Land Acquisition	$1,000	**$0**
Capacity True-Up	$1,000	**$2,783**
Total Capital	$1,000	**$4,283**
DGGS Total NPV of Costs	**$1,000**	**$93,826**

Department of Public Service Regulation
Montana Public Service Commission
Docket No. 2019.09.059
QF-1 Tariff Update Application
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF MICHAEL S. BABINEAUX

ON BEHALF OF NORTHWESTERN ENERGY

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Exhibits

* Electronic exhibits provided on CD only

Witness Information

Q. Please identify yourself, your employer, and your title.

A. My name is Michael S. Babineaux. I am a Senior Energy Supply Analyst for NorthWestern Energy ("NorthWestern").

Q. Please describe your relevant experience and education.

A. I have been working as an analyst in Energy Supply Planning at NorthWestern for four years. I am responsible for performing avoided energy cost calculations using Ascend Analytics, LLC's ("Ascend") PowerSimm™ model. I also have experience in applying the Southwest Power Pool's ("SPP") Planning Criteria to calculate capacity contribution. I hold Bachelor of Science degrees in both Mathematics and Electrical Engineering.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. I present testimony on the avoided cost of energy calculation process, including the portfolio used, and generation inputs in the PowerSimm modeling. I also discuss the capacity contribution calculation for the QF-1 and other portfolio renewable resources and discuss the SPP's Planning Criteria methodology. Lastly, I explain and present monthly avoided cost of energy results for information use only.

Avoided Cost of Energy

Q. How did NorthWestern calculate an avoided cost of energy for QF-1 projects?

A. NorthWestern used PowerSimm to model the generation of the QF-1 and other renewable resources in the portfolio, load, market prices, and the operation of dispatchable resources. All three QF-1 resource types were modeled using the same set of weather simulations. PowerSimm calculates the hourly dispatch of NorthWestern's supply portfolio by performing 10 simulations for every hour of the maximum 15-year contract period in the QF-1 Tariff as described in the Prefiled Direct Testimony of Dr. Brandon K. Mauch ("Mauch Direct Testimony"). Subsequently, hourly modeling results were used to calculate the avoided costs of energy to serve load as described in the Prefiled Direct Testimony of Dr. Ben Fitch-Fleischmann ("Fitch-Fleischmann Direct Testimony").

Q. What PowerSimm inputs did NorthWestern use for renewable generation?

A. Renewable generation units include the solar, wind, and hydroelectric resources that 1) have filed a petition with the Montana Public Service Commission ("Commission") claiming to have established a legally enforceable obligation (and have not withdrawn or otherwise terminated that claim), 2) have contracted with NorthWestern, or 3) are owned by NorthWestern. Each renewable asset is defined by its actual historical or calculated hourly production profile and its monthly peak and total generation forecast. The hourly generation provides a correlation with weather that shapes the daily production profile throughout the simulation. The monthly energy forecasts are the average of the historical monthly generation.

Q. What did NorthWestern use to represent the historical generation profile of each QF-1 resource for modeling purposes?

A. For the QF-1 wind resource definition, NorthWestern used the generation profile from an existing wind resource, Musselshell 2, scaled down from 10 megawatts ("MW") to 3 MW. This resource was chosen because it had a capacity factor that was in the middle of the distribution for NorthWestern's wind resources. Black Eagle Solar, an existing 3-MW solar resource, was chosen similarly to represent QF-1 solar generation based on capacity factor. For the hydro/other rate, NorthWestern used a flat 1-MW generation profile, i.e., 1 MW in all hours. The monthly forecasts were created from these historical generation profiles similar to other renewable generation.

Q. What PowerSimm inputs did NorthWestern use for thermal generation?

A. The thermal generation units included in this calculation are the thermal generation resources that are in NorthWestern's supply portfolio:

NorthWestern's share of Colstrip (which includes a share of Colstrip Unit 4 and a reciprocal sharing agreement that includes a share of Colstrip Unit 3), Dave Gates Generating Station, and Basin Creek. The thermal generation units' resource definition consists of startup costs, ramp rates, outage history, heat rates, emissions, and fuel delivery costs. The unique operating characteristics and costs of each thermal resource are reflected through the parameters that are defined in PowerSimm allowing the model to accurately dispatch or utilize such resources.

Colstrip Energy Limited Partnership ("CELP") and Yellowstone Energy Limited Partnership ("YELP") are non-dispatchable thermal generation assets also included in NorthWestern's portfolio.

The table below lists all the generation assets input into the model as part of the base portfolio.

		Capacity (MW)
Thermal	Colstrip	222
	DGGS	150
	Basin Creek	52
	CELP	42
	YELP	65
Hydro	Thompson Falls	94
	Madison	8
	Hauser	17
	Holter	52
	Black Eagle	21
	Rainbow	64
	Cochrane	62
	Ryan	68
	Morony	49
	Mystic	12
	Turnbull	13
	Tiber	8
	Small Hydro	16
Wind	Judith Gap	135
	Spion Kop	40
	Gordon Butte	10
	Musselshell I	10
	Musselshell II	10
	Fairfield Wind	10
	Two Dot Wind Farm	10
	Greenfield	25
	Big Timber	25
	Stillwater	80
	South Peak	80
	71 Ranch	3
	DA Wind	3
	Oversight	3
	Grizzly Wind	80
	Black Bear Wind	80
	Caithness Beaver Creek II	60
	Caithness Beaver Creek III	60
	Con Ed Teton Wind	80
	Con Ed Pondera Wind	80
	Small Wind	13
Solar	Green Meadow Solar	3
	South Mills Solar	3
	River Bend Solar	2
	Great Divide Solar	3
	Magpie Solar	3
	Black Eagle Solar	3
	MTSUN	80
	Meadowlark Solar	20
Total Supply		2,028

Q. After modeling results are used to create a stream of hourly avoided energy costs, how is the levelized payment over the contract period derived?

A. The levelized payment is determined by calculating a net present value of the stream of hourly total avoided costs. This uses NorthWestern's current weighted average cost of capital ("WACC") to discount over the contract period. The levelized avoided cost is determined by calculating a constant payment over the contract period equal to this net present value using the WACC.

Capacity Contribution

Q. Please describe the method used for calculating the capacity contribution for each type of resource.

A. To calculate the capacity contribution, NorthWestern used the methodology adopted by the SPP. For the purposes of resource adequacy planning, SPP requires that wind and solar resources be treated differently during their first three years of operation than after the first three years. The Planning Criteria (Revision 1.9, published 6/20/2019) requires that for facilities in commercial operation for three years or less, the most recent three years of data be included in the calculation. During the first three years, the default net planning capability ("NPC") percentage for wind is 5%, and the default is 10% for solar. For facilities in operation for more than three years, the Planning Criteria requires that the NPC, or capacity contribution, is calculated by finding the top 3% of peak load hours during the annual peak load month of each year within the period of study and taking the amount of generation exceeded 60% of the time within those hours throughout the period of study. The Planning Criteria methodology is provided as Exhibit__(MSB-1).

Q. What tool did you use to perform the SPP NPC calculation?

A. NorthWestern received an Excel workbook that SPP recommended be used to perform and submit the values of the NPC calculation.

Q. What were the results of the capacity contribution calculations for wind, solar, and hydro resources?

A. Calculations were performed on each of the actively generating wind and hydro resources in NorthWestern's portfolio for the period 2009-2018 that contain at least three years of data, starting with the first full year of data, which meets the SPP NPC methodology requirements. However, the existing solar resources have less than two years of actual data. For each solar resource location, solar generation data from the National Renewable Energy Laboratory's ("NREL") System Advisory Model ("SAM") was used. NREL SAM data was available through 2017, so NorthWestern used 2008-2017 data for all solar locations.

The results of the capacity contribution calculations for each of the wind, solar, and hydro facilities as well as the averages are shown in the table below. The most recent year's capacity factor is also included for informational purposes. The workbook containing this table data as well as the percentages of On-Peak and Off-Peak generation, referenced in Fitch-Fleischmann Direct Testimony, is provided as Exhibit__(MSB-2).

Type	Resource	Nameplate Capacity (MW)	Capacity Contribution (MW)	Capacity Contribution (%)	Most Recent Year Capacity Factor (%)
Solar	Black Eagle	3	0	0%	17%
	Great Divide	3	0	0%	17%
	Green Meadow	3	0	0%	18%
	Magpie	3	0	0%	16%
	River Bend	2	0	0%	15%
	South Mills	3	0	0%	16%
Wind	Cycle Horseshoe Bend	9	0	0%	28%
	Fairfield	10	0.4	4%	32%
	Gordon Butte	9.6	0.6	6%	46%
	Judith Gap	135	6.8	5%	36%
	Martinsdale	0.75	0	0%	19%
	Martinsdale South	2	0	0%	0%
	Moe	0.45	0	0%	7%
	Musselshell	10	0.2	2%	24%
	Musselshell Two	10	0.3	3%	29%
	Sheep Valley	0.46	0	0%	15%
	Spion Kop	40	1.5	4%	36%
	Two Dot	11.28	0.3	3%	32%
Hydro	Barney Creek	0.06	0	0%	17%
	Boulder Hydro Limited Partnership	0.51	0.1	20%	33%
	Broadwater Dam	10	2.6	26%	34%
	Cascade Creek	0.07	0	0%	30%
	Flint Creek Hydroelectric	2	1	50%	87%
	Jenni (Hanover Hydro)	0.24	0	0%	13%
	Lower South Fork	0.46	0	0%	22%
	Pine Creek	0.3	0	0%	53%
	Pony Generating Station	0.4	0.1	25%	40%
	Ross Creek Hydro	0.45	0.2	44%	70%
	South Dry Creek	1.2	0	0%	52%
	Strawberry Creek	0.19	0.1	53%	61%
	Tiber Montana	7.5	5	67%	75%
	Turnbull Hydro	13	0	0%	28%
	Wisconsin Creek	0.55	0	0%	19%
Owned Hydro	Black Eagle	21	13	62%	75%
	Cochrane	62	26	42%	60%
	Hauser	17	14	82%	79%
	Holter	53	31	58%	74%
	Madison	8	7	88%	89%
	Morony	49	26	53%	75%
	Mystic	12	7	58%	58%
	Rainbow	64	36.4	57%	71%
	Ryan	68	44	65%	79%
	Thompson Falls	94	41	44%	56%

NorthWestern recommends using the average capacity contribution of all resources with the same type to represent the capacity contribution for a new QF-1, with the exception of excluding the owned hydro resources from this average as their operation and annual profile are very different from typical small hydro QF-1 facilities. The average values are shown in the table below.

Averages	Capacity Factor	Capacity Contribution
Solar	16.33%	0.00%
Wind	25.29%	2.22%
Hydro/Other*	42.34%	18.96%

*Excludes NWE-owned hydros

Informational Avoided Cost of Energy Comparison

Q. Did NorthWestern calculate an avoided cost of energy using a monthly calculation under Conditions 1, 2, and 3?

A. Yes. NorthWestern recommends a method directly based on the hourly avoided cost to serve load. However, for comparison purposes only, NorthWestern also estimated avoided energy costs based on a monthly calculation under Conditions 1, 2, and 3[1] (with Condition 3 evaluated at the market sales price), using forward power price curves with Energy Information Administration ("EIA") escalation without the declining heat rate. NorthWestern does not recommend the use of these values for the avoided cost of energy. These calculations do not assign an avoided cost to each hour based on conditions during the hour, such as market prices, QF-1 generation, portfolio net position, and the marginal resource serving load. Instead, they are calculated based on the value of offset sales and

[1] The Conditions 1, 2, and 3 evaluation is described in Fitch-Fleischmann Direct Testimony.

offset purchases due to QF-1 generation within each monthly heavy load and light load block of hours. The assignment of an avoided cost for market sales volumes, either as Condition 2 or Condition 3, is made once for the entire block. Furthermore, the value is based only on an average price within those blocks. The calculation process is described below.

For each block, the mean market sales price and purchase price ($/megawatt-hour ("MWh")) are calculated based on the Mid-Columbia On-Peak or Off-Peak price with basis differential adjustments as described in the Fitch-Fleischmann Direct Testimony. The offset market sales volume (MWh) is calculated as the difference in spot sales between the QF-1 portfolio and the base portfolio. This volume is multiplied by the mean market sales price (Condition 3) or the highest-cost dispatchable unit's variable cost ($/MWh) below the market sales price (Condition 2) to find an avoided cost of offset generation (sales) ($). Offset market purchase volumes are calculated similarly and multiplied by the mean market purchase price to calculate an avoided cost of offset purchases ($). Heavy load and light load block avoided cost values are combined into monthly totals for offset generation and offset purchases, and these are further aggregated into a monthly avoided cost ($) which is divided by the monthly generation to get a monthly avoided cost per unit of energy ($/MWh) for the QF-1 informational avoided cost of energy calculation.

Q. What were the resulting monthly avoided energy costs?

A. For information purposes, the monthly calculation results are presented for levelized around-the-clock rates ($/MWh) below using Conditions 1, 2, and 3 with Condition 3 at Market Sales Price, EIA escalation without Declining Heat Rate, Commercial Operation Date of October 1, 2020, and a 15-year term. The workbooks used to calculate these monthly results for QF-1 solar, wind, and hydro/other are included as Exhibit__(MSB-3), Exhibit__(MSB-4), and Exhibit__(MSB-5) respectively.

Avoided Cost of Energy - Monthly Calculation	Wind	Solar	Hydro/other
Levelized value for 15-year contract	$31.39	$36.78	$34.37

Q. Does this conclude your testimony?

A. Yes, it does.

SPP Southwest Power Pool

SPP PLANNING CRITERIA

Revision 1.9

Maintained by:

TRANSMISSION WORKING GROUP
SYSTEM PROTECTION AND CONTROLS WORKING GROUP
SUPPLY ADEQUACY WORKING GROUP

Published on 6/20/2019

design temperatures, although there is considerable variability in this relationship from location to location." In older Handbooks, the minimum dry-bulb temperature for winter testing and net generating capacity shall be taken as that which is equaled or exceeded 99% of the total hours during the months of December through February (per Handbook definition) for the plant's geographical location. The wet-bulb temperature is not significant for the winter rating and can be disregarded.

8) Standard barometric pressure for a plant site shall be determined for each plant elevation from the equation provided in Section 9.
9) For those units using a lake or river as a source of condenser cooling water, the summer standard inlet temperature is the highest water inlet temperature during the month concurrent with the member's peak load of the year, averaged over the past ten years.
10) Ambient wet-bulb temperature and condenser cooling water temperature are generally not significant factors in adjusting cold weather capability of generating units. Shall special situations arise in which these temperatures are required, reasonable estimates for temperatures occurring coincidentally with the winter rating dry-bulb temperature as defined in the Criteria shall be used.

7.1.6.1 Net Generating Capacity Adjustments

1) The rated net capability of a unit may be above or below the actual tested net generation as a result of adjustments for Net generating capacity Conditions, with the exception of units with winter season net generating capacity greater than their summer net generating capacity. For these units, the winter season rated net capability shall be no greater than the actual tested net generation. No net generating capacity adjustment for ambient conditions shall be made.
2) Seasonal net capability shall not be reduced to provide regulating margin or spinning reserve. It shall reflect operation at the power factor level at which the generating equipment is normally expected to be operated over the daily peak load period.
3) Extended capability of a unit or plant obtained through bypassing of feed-water heaters, by utilizing other than normal steam conditions, by abnormal operation of auxiliaries in steam plants, or by abnormal operation of combustion turbines or diesel units may be included in the seasonal net capability if the following conditions are met; a) the extended capability based on such conditions shall be available for a period of not less than four continuous hours when needed and meets the other restrictions, and b) appropriate procedures have been established so that this capability shall be available promptly when requested by the system operator.
4) The seasonal net capability established for nuclear units shall be determined taking into consideration the fuel management program and any restrictions imposed by governmental agencies.
5) The seasonal net capability established for hydroelectric plants, including pumped storage projects, shall be determined taking into consideration the reservoir storage program and any restrictions imposed by governmental agencies and shall be based on median hydro conditions.
6) The seasonal net capability established for run-of-the-river hydroelectric plants shall be determined using historical hydrological data on a monthly basis.

7) The recommended methodology to evaluate the net planning capability established for wind or solar facilities shall be determined on a monthly basis, as stated below. If a member's desire to use a more restrictive methodology to evaluate the net capability of wind or solar they may do so, however net capability determined by the alternative methodology employed cannot credit the wind or solar with a capability greater than determined with the methodology stated below:

8) Assemble all available hourly net power output (MWH) data measured at the system interconnection point.

   (a) Select the hourly net power output values occurring during the top 3% of load hours for the SPP Load Serving Entity for each month of each year for the evaluation period.

   (b) Select the hourly net power output value that can be expected from the facility 60% of the time or greater. For example, for a 5 year period with the 110 hourly net power output values ranked from highest to lowest, the capacity of the facility will be the MW value in the 65th data point.

   (c) A seasonal or annual net capability may be determined by selecting the appropriate monthly MW values corresponding to the Load Serving Entity's peak load month of the season of interest (e.g., 22 hours for a typical 30 day month and110 hours for a 5 year period).

   (d) Facilities in commercial operation 3 years or less:

      (i) The data must include the most recent 3 years.

      (ii) Values may be calculated from wind or solar data, if measured MW values are not yet available. Wind data correlated with a reference tower beyond fifty miles is subject to Supply Adequacy Working Group approval. Solar data correlated with a reference measuring device beyond two hundred miles is subject to Supply Adequacy Working Group approval. For calculated values, at least one year must be based on site specific data.

      (iii) If the Load Serving Entity chooses not to perform the net capability calculations as described above during the first 3 years of commercial operation, the Load Serving Entity may submit 5% for wind facilities and 10% for solar facilities of the site facility's nameplate rating.

   (e) Facilities in commercial operation 4 years and greater

      (i) The data must include all available data up to the most recent 10 years of commercial operation.

      (ii) Only metered hourly net power output (MWH) data may be used.

      (iii) After three years of commercial operations, if the Load Serving Entity does not perform or provide the net capability calculations to SPP as described above, then the net capability for the resource will be 0 MW

(f) The net capability calculation shall be updated at least once every three years.

7.1.7 FUEL SUPPLY

Assurance of having desired generating capacity depends, in part, on the availability of an adequate and reliable fuel supply. Where contractual or physical arrangements permit curtailment or interruption of the normal fuel supply, sufficient quantities of standby fuel shall be provided. Due to the dependence of hydroelectric plants on seasonal water flows, this factor shall be taken into consideration when calculating capacity for reserve margin requirements.

7.2 RATING OF TRANSMISSION FACILITIES

All SPP transmission system equipment shall have a Normal Rating and Emergency Rating. Each SPP member shall establish the Normal Rating and Emergency Rating for their equipment owned under the SPP OATT. All Normal and Emergency Ratings shall respect the most-limiting maximum and minimum voltage, current, frequency, real and reactive power flows under steady state, short-circuit and transient conditions for components that comprise the transmission equipment.

SPP members may use circuit ratings higher than these minimums described in Section 7.2 based upon variables in their respective ratings methodology (i.e. wind speed, etc.). For certain equipment, (switches, wave traps, current transformers and circuit breakers), the Normal and Emergency Ratings are identical.

7.2.1 POWER TRANSFORMER

Power transformer ratings are discussed in ANSI/IEEE C5791, IEEE Guide for Loading Mineral-Oil-Immersed Power Transformers. Every transformer has a distinct temperature rise capability used in setting its nameplate rating (either 55°C or 65°C). These temperature rise amounts reflect the average winding temperature rise over ambient that a transformer may operate on a continuous basis and still provide normal life expectancy.

7.2.1.1 Normal Rating

The normal circuit rating for power transformers shall be its highest nameplate rating. The nameplate rating shall include the effects of forced cooling equipment if it is available. For multi-rated transformer (OA/FA, OA/FA/FA, OA/FOA/FOA, OA/FA/FOA) with all or part of forced cooling inoperative, nameplate rating used is based upon the maximum cooling available for operation. Normal life expectancy will occur with a transformer operated at continuous nameplate rating.

7.2.1.2 Emergency Rating

When operated for one or more load cycles above nameplate rating, the transformer insulation deteriorates at a faster rate than normal. The emergency circuit rating for power transformers shall be a minimum of 100% of its highest nameplate rating. Member systems may use a higher emergency rating if they are willing to experience more transformer loss-of-life.