Service Date: October 19, 2011

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

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IN THE MATTER OF the NorthWestern Energy's Application for Approval of Avoided Cost Tariff for New Qualifying Facilities	) REGULATORY DIVISION)) DOCKET NO. D2010.7.77) ORDER NO. 7108e

FINAL ORDER

Appearances

FOR THE APPLICANT:

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FOR THE INTERVENORS:

Montana Consumer Counsel

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Montana Small Independent Renewable Generators

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BEFORE:

TRAVIS KAVULLA, Chairman
GAIL GUTSCHE, Vice Chair
W.A. GALLAGHER, Commissioner
BRAD MOLNAR, Commissioner
JOHN VINCENT, Commissioner

COMMISSION STAFF:

Sarah Norcott, Attorney
Will Rosquist, Chief, Economics and Rate Design Bureau

BACKGROUND

1. In 1978, Congress enacted a National Energy Act to conserve domestic oil and natural gas resources, increase the efficiency and reduce the cost of electric generating facilities, and reduce the nation's dependence on foreign energy sources. The National Energy Act consisted of five energy-related laws including the Public Utility Regulatory Policies Act (PURPA). Section 210 of PURPA encourages cogeneration and small power production by requiring electric utilities to buy energy and capacity from qualifying facilities (QFs) at prices reflecting the incremental cost to an electric utility of alternative electric power.[1/] PURPA requires the Federal Energy Regulatory Commission (FERC) to adopt rules to implement the law. In 1980 FERC defined the electric utility costs that are the basis for energy and capacity payments to QFs in Title 18 of the Code of Federal Regulations (CFR), Section 292.

2. In 1981, the Montana Legislature also enacted a PURPA-related law (see § 69-3-601 et seq., Montana Code Annotated (MCA)).[2/] That law entitles QFs to contract for the sale of electricity to public utilities regulated by the Montana Public Service Commission (PSC or Commission). When a QF and a public utility are unable to agree on contract terms, including price, Montana law requires the Commission to determine the contract terms, including prices based on the public utility's avoided costs.

3. Montana's PURPA-related law also authorizes the Commission to adopt rules. The Commission's rules adopt FERC rules by reference and define the obligations of QFs and public utilities (see Administrative Rules of Montana (ARM) 38.5.1901 et seq.). Commission rules require utilities to offer standard rates to QFs, but limit availability of long-term standard rates to QFs 10 MWs and smaller. QFs larger than 10 MW must successfully compete in a utility's resource solicitation process to receive long-term contracts, but between competitive solicitations QFs larger than 10 MW may sell power to a utility at standard or negotiated short-term rates. During the 1980s, the Commission processed three broad-reaching QF dockets aimed at defining QF policies and setting standard rates.[3/]

4. The Commission last reviewed NWE's standard avoided cost rates in Docket No.

[1/] 16 U.S.C. Chapter 12, Subchapter II, Section 824a-3

[2/] The 2003 Montana legislature repealed these statutes "on occurrence of contingency" and upon the effective date of PURPA's repeal (see HB 417, § 69-3-601(4)).

[3/] See Docket Nos. 81.2.15, 83.1.2, and 84.10.64

D2008.12.146, Order No. 6973d. In that order, the Commission adopted multiple standard rate options that reflected the host of uncertainties facing NWE and its customers at that time. Each rate option reflected a different method for estimating avoided costs and, accordingly, required QFs to confront the same set of risks and uncertainties facing NWE and its ratepayers in terms of long-term resource planning and acquisition decisions. See Order 6973d, ¶ 132. The Commission found that these rate options offered QFs nondiscriminatory opportunities to serve a portion of NWE's retail supply obligation at avoided cost-based prices that were consistent with Commission and FERC rules implementing PURPA. *Id*. The standard rate options the PSC approved in Order No. 6973d were:

Option 1(a)
Duration: 19 mos. - 25 yrs.
Rate: \$0.09941 /kWh in heavy load hours
\$0.05115 /kWh in light load hours

Option 1(b)
Duration: 1 mo. - 18 mos.
Rate: \$0.05115 /kWh

Option 1(c) (wind only)
Duration 19 mos. - 25 yrs.
Rate: \$0.05283 /kWh

Option 1 adjustments & conditions
1. Contingency reserves - QF opts to self-supply or purchase from NWE. Purchase rate based on CU4 reserve cost applied to QF technology
2. RECs - non CO2-emitting QFs may retain or convey RECs to NWE. If QF conveys RECs to NWE, rates are adjusted to reflect future CO2 emissions costs NWE incurs for CU4.
3. Wind integration - QF opts to self-supply or purchase integration service from NWE. Purchase rate is annually adjusted based on actual cost

Option 2(a)
Duration: Up to 25 yrs.
Rate: Highest-cost 25 MWh Mid-C purchase each hour less \$1.00/MWh

Option 2(b)
Duration Up to 25 yrs.
Rate: ICE Mid-C index price in on/off peak periods less \$1.00/MWh

Option 2 adjustments & conditions
1. Contingency reserves - QF opts to self-supply or purchase from NWE
2. RECs - QFs retain RECs
3. Wind integration - QF opts to self-supply or purchase integration service from NWE. Purchase rate is annually adjusted based on actual cost

Option 3 (wind only)
Duration 25 yrs.
Rate: \$0.06921 /kWh

Option 3 adjustments & conditions
1. RECs - QF conveys RECs to NWE

5. Option 1 rates reflected an avoided cost method that used a projection of Colstrip Unit 4 (CU4) per unit revenue requirements. As a recent, market-based resource acquisition, the Commission determined that CU4 was a reasonable proxy for the cost of base load power products NWE could avoid with future long-term QF power purchases, and it pointed to several other recent NWE market purchases at similar prices. The Commission approved NWE's proposal to classify the CU4-based total avoided costs into energy and capacity cost components.

QFs were paid avoided energy and capacity costs for power delivered in heavy load hours during December, January, February, July, and August (see footnote 6 for an explanation of heavy load hours). QFs were paid only avoided energy costs in all other hours. The energy-only avoided cost also applied to all QF power deliveries if the contract is 18 months or less. Option 1 also included a fixed, wind specific rate based on avoided energy costs and an assumption that a wind QF provides a capacity contribution equal to 15% of its nameplate capacity. As shown above, Option 1 rates were subject to several adjustments for contingency reserves, renewable energy credits (RECs) and wind integration.

6. Option 2 rates reflected NWE's hourly incremental costs derived from either actual NWE purchases or a wholesale market price index. In Order No. 6973d, the Commission found that these rates satisfy PSC and FERC rules requiring utilities to offer QFs the option of rates based on avoided costs calculated at the time of delivery.[4/] Option 2 rates were also available to QFs larger than 10 MW between competitive solicitations. As with Option 1 rates, Option 2 rates were subject to several adjustments for contingency reserves, RECs, and wind integration.

7. When the PSC issued Order 6973d, 85% of the capacity in NWE's QF queue was wind capacity. NWE's 2007 electricity supply resource procurement plan (2007 Plan) identified three preferred resource acquisition strategies, each of which included 150 MW of additional wind capacity and in August, 2009, NWE issued a request for information on renewable resources with the intent of acquiring additional resources, likely wind. Given these circumstances, the Commission considered it important to set a reasonable, nondiscriminatory, standard avoided cost rate for wind QFs reflective of the costs NWE would otherwise incur to acquire alternative wind resources. The result was the Option 3 rate. It reflected the wind resource costs NWE assumed in its 2007 Plan, a method supported by QF intervenors in Docket No. D2008.12.146, but with an assumed higher capacity factor for Montana wind resources (38%) than that recommended by the QF intervenors (30%). Option 3 was a simple, fixed, avoided cost-based rate that required no adjustments. QFs were required to convey all RECs to NWE. In return, QFs received a rate that encapsulates a balancing of a range of economic forecasts and risk factors embodied in NWE's 2007 Plan. Option 3 required no adjustment for

[4/] See 18 CFR § 292.304(d) and ARM 38.5.1905(3).

wind integration costs because the Commission assumed these would be the same for alternative wind capacity avoided by acquiring QF wind capacity instead.

PROCEDURAL HISTORY

8. NWE filed its application in this proceeding on July 30, 2010. On August 4, 2010, the PSC issued a Notice of Application and Intervention Deadline.

9. On September 3, 2010, the PSC issued Procedural Order 7108 establishing deadlines for discovery, intervenor, rebuttal, cross intervenor, and additional issues testimony, and a tentative hearing date of February 16, 2011.

10. On October 28, 2010, the PSC granted intervention to Montana Consumer Counsel (MCC), Montana Small Independent Renewable Generators (MSIRG), and United Materials of Great Falls, Inc. The PSC denied a late-filed motion for intervention by Sagebrush Energy, LLC on October 26, 2010.

11. Staff, on behalf of the PSC, and intervenors engaged in discovery throughout the proceeding, according to the terms of Procedural Order 7108, as modified by Notice of Commission Action dated October 28, 2010. The PSC resolved a discovery dispute in a Notice of Commission Action dated October 26, 2010.

12. On November 10, 2010, MCC and MSIRG filed testimony in response to NWE's application.

13. On December 23, 2010, NWE filed rebuttal testimony and MSIRG filed cross-intervenor testimony.

14. Due to discovery disputes, in February of 2011, the Commission issued a Notice of Commission Action vacating the hearing date and authorizing staff to set a new hearing date.

15. A properly noticed public hearing was held July 6-7, 2011, in Helena. At the completion of the hearing, the parties participated in post hearing briefing which was completed by August 31, 2011.

SUMMARY OF TESTIMONY

NorthWestern Energy direct testimony

Mark Stauffer

16. Mr. Stauffer, a Senior Analyst in NWE's Energy Supply department, prefiled testimony updating NWE's tariff schedule QF-1 based on the Company's 2009 electricity supply resource procurement plan (2009 Plan), pursuant to PSC Order No. 6973d. He also testified on the proper treatment of marginal transmission costs associated with new QFs.

17. Stauffer testified that NWE's QF-1 Option 1 rate proposals are based on the three preferred resource portfolios the Company selected in its 2009 Plan. Each of these portfolios acquire some type of natural gas fired resource in 2015, either a combustion turbine or combined cycle combustion turbine. They also acquire 25 MW of biomass in 2020. Because NWE has not determined which natural gas technology it will acquire, Stauffer computed avoided costs based on a weighted average of all fixed and variable costs associated with all marginal resources in the three preferred portfolios. The result is a total 20-year levelized per-unit avoided cost of $.07265/kWh. Stauffer classified this total per-unit avoided cost into energy- and capacity-related cost components using the same method the Commission approved in Order No. 6973d.[5/] Consistent with the current QF-1 Option 1(a) rates, the capacity-related cost is allocated to heavy load hours in December, January, February, July, and August.[6/] In all other hours the rate reflects only energy-related avoided costs. Stauffer's proposed Option 1 rates are:

Option 1 (a)	Heavy Load Hours	$0.09865/kWh
	Light Load Hours	$0.06477/kWh
Option 1(b)	$0.06477/kWh	
Option 1(c)	$0.06595/kWh	

[5/] The method the PSC approved in Order 6973d, Docket D2008.12.146, uses the annualized capital and fixed O&M costs of a frame single cycle combustion turbine as the cost of capacity ($/KW). The capacity cost is converted into a cost per kWh by dividing it by the total hours per year and is then subtracted from the total per kWh avoided cost to derive an energy-only avoided cost. The capacity cost per KW is then divided by the on-peak hours to derive a per kWh value of capacity that is added to the energy avoided cost to derive the total on-peak avoided cost (consisting of both energy and capacity costs). See Order 6973d, ¶¶ 5-14, 134.

[6/] NWE's QF-1 tariff schedule defines Heavy Load Hours to be the hour ending 07:00 through the hour ending 22:00 Pacific prevailing time, Monday through Saturday (except holidays), in the months December through February, July, and August. Light Load Hours are those hours not included in the definition of Heavy Load Hours.

18. Stauffer proposed updating the Option 3 wind rate based on the expected cost of new wind generation included in the 2009 Plan, \$0.06842/kWh. He explained that this rate is close to the current Option 3 rate of \$0.06921/kWh because the economic recession has prevented prices for wind turbines and other components from increasing. Stauffer provided a complete copy of tariff schedule QF-1, reflecting his proposed rates, in Exhibit NWE-2 at (MAS-1).[7/]

19. Stauffer also addressed the Commission's recent determination that a particular QF would not be required to pay for certain transmission system upgrades associated with its project.[8/] According to Stauffer, the interconnection costs associated with that particular QF would increase the total cost of power by almost 50%, making it more expensive than other resources available to NWE.[9/] Stauffer concluded that if the Commission's decision in that case becomes policy for other QF projects, consumers will not be indifferent to QF resources and QF development decisions will occur without proper consideration of transmission costs, including alternatives to transmission system upgrades.

<u>Carolyn Loos</u>

20. Ms. Loos, NWE's Director, Business Performance & Analysis, prefiled testimony responding to Order No. 7068b, Docket No. D2010.2.18, order paragraph 5, which states:

> The PSC directs NWE to thoroughly address the merits of applying FERC's [Small Generator Interconnection Agreement (SGIA)] interconnection approach to QF resource acquisition in its next QF-1 tariff filing. NWE should contrast FERC's SGIA approach with the approach outlined in PSC rules in terms of economic efficiency and customer impacts.

21. Loos testified that an SGIA is the final interconnection agreement for generating facilities smaller than 20 MW and it includes the terms and conditions transmission providers and generators must adhere to after a generator becomes commercial. According to Loos,

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[7/] In RDR PSC-005 Stauffer stated that NWE did not propose to update the wind integration tariff because final cost information is not available to support such an update.

[8/] See *In the Matter of the Petition of Kenfield Wind Park I, LLC and KWP-LC7, LLC to set Terms and Conditions for Qualifying Small Power Production Facility Pursuant to § 69-3-603, MCA*, Docket No. D2010.2.18.

[9/] In RDR PSC-004 Stauffer acknowledged that neither NWE nor bidders responding to the Company's RFI have analyzed the cost of system upgrades for those RFI projects.

FERC's SGIA interconnection approach should be applied to QFs in order to maintain orderliness, comparability, consistency, fairness, and economic efficiency. She asserted that the FERC's SGIA interconnection approach is an established and well-defined approach that has been vetted through years of application, whereas a separate approach for QFs could lead to conflicts and discrimination. She said the SGIA approach treats all generators the same so, for example, similar generators would face comparable economic consequences for interconnecting in a congested area. She added that studying QF projects together with other existing and proposed generation projects ensures an accurate assessment of transmission system reliability and an economically efficient solution to any reliability issues caused by a new generation project(s).

22. Loos stated that using the SGIA approach would not constrain the PSC in setting avoided cost-based QF rates or determining from whom transmission costs caused by QFs would be recovered, i.e., from the QF, NWE's retail customers, or a combination of both. She said that PSC rules and orders address QF interconnection requirements, but added that NWE seeks an affirmative PSC determination that QFs must follow the SGIA approach.[10/]

23. Loos explained the various studies NWE conducts at various stages of the interconnection process and how the SGIA assigns cost responsibility for various types of interconnection costs. She testified that under the SGIA approach, an interconnecting electric generator must initially fund any transmission system upgrades needed to accommodate the generation, but that the generator receives a full refund, with interest, of the amount paid to NWE for system upgrades through credits to FERC-jurisdictional transmission service rates. She asserted that the SGIA approach is consistent with PSC rules governing QF interconnection and PSC Order 7068b because it requires the interconnecting generator to reimburse the utility for interconnection costs.

24. According to Loos, FERC Order No. 2006 requires NWE to study generators smaller than 20 MW under an Energy Resource Interconnection Service (ERIS) arrangement. ERIS is a lower level interconnection service that allows the generator to obtain transmission

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[10/] ARM 38.5.1904(2) makes a QF responsible for all interconnection costs associated with its project. QF-related interconnection costs are limited to those in excess of the corresponding costs which the utility would have incurred if it had not engaged in interconnected operations with the QF but instead generated an equivalent amount of electricity itself or purchased an equivalent amount of energy or capacity from other sources. See PSC Order No. 7068b and ARM 38.5.1901(2)(d). ARM 38.5.1901(2)(d), which mirrors a FERC rule, 18 CFR § 292.101, states that interconnection costs do not include any costs included in the calculation of avoided costs.

service only when transmission capacity is available. Small generators may request to be studied under a Network Resource Interconnection Service (NRIS) arrangement, which would guarantee sufficient transmission capacity to provide transmission service at all times (i.e, firm service), but to do so the small generator must execute a Large Generator Interconnection Agreement (LGIA). Loos recommended applying these same procedures to QF generators.

Montana Small Independent Renewable Generators response testimony

Richard Lauckhart

25. Mr. Lauckhart is a managing director in the enterprise management solutions division of Black & Veatch. He prefiled testimony on behalf of MSIRG addressing wind capacity factors, availability of the Option 3 rate, and NWE's approach to studying QF-related transmission system impacts.

26. According to Lauckhart, because NWE's 2009 Plan acquires new wind resources, the avoided cost rate for wind QFs should be based on the cost of building and owning a wind plant. Lauckhart explained that the per-unit cost of wind depends on a project's capacity factor – the ratio of energy produced to what could be produced if the plant ran at full capacity continuously. He said gross capacity factor is measured at the generator and net capacity factor is measured at the point where a project's energy is delivered to NWE's transmission grid. He asserted that the net capacity factor for a wind project is typically 87% of gross capacity factor due to various energy losses.

27. Lauckhart contended that not many wind projects can be built in Montana with net capacity factors over 40%. He submitted a map of Montana, published in 2010, showing average wind speeds at 80 meters. He testified that except for a few areas the map indicates that the best average annual wind speeds range from 8.0-8.5 meters/second (m/sec). According to Lauckhart, based on a Wind Logic report, an average annual wind speed of 8.28 m/sec is equivalent to a net capacity factor of 34.8% and a gross capacity factor of 40% (see DR PSC-010(c)). Lauckhart stated that NWE does not own transmission in many areas where the map shows wind speeds of 8.28 m/sec or higher. On that basis, he concluded that a 34.8% net capacity factor is representative of areas where NWE has transmission lines.

28. Lauckhart questioned whether Judith Gap represents a typical Montana wind project and whether Judith Gap in fact has a 40% or better net capacity factor. He noted that

prior to construction Judith Gap was expected to achieve a net capacity factor of 37%, and that the actual net capacity factor for the twelve months ending June 30, 2010 was 36.23%.[11/] He also testified that measured energy from Judith Gap has exceeded its nameplate capacity, implying that the project's nameplate capacity may be understated or measurement errors have occurred.

29. Lauckhart also questioned the veracity of various NWE capacity factor estimates derived from its Request for Information (RFI). He noted that the RFI did not require binding bids and that bidders' capacity factor claims were dubious. He asserted that in some cases bidders confused net and gross capacity factor, developed their own capacity factor estimates instead of providing independent assessments, relied on higher-cost, unapproved, low-speed turbines, and used incomplete wind regime studies. He concluded that the net capacity factor estimates provided in the RFI bids were not guaranteed and advised against relying on them.

30. Lauckhart proposed an Option 3 rate based on adjusting NWE's proposed $0.06842/kWh rate to reflect a 34.8% net capacity factor rather than NWE's assumed 40% capacity factor. The result is $0.07864/kWh [$0.06842 * (40.0/34.8)]. He asserted that this rate would not expose ratepayers to significant risk because the tariff limits the amount of QF power acquired at the standard rate to 50 MW – if the $0.07864/kWh rate attracts too much interest, the PSC can revisit the rate once NWE has acquired 50 MW of QF power. Lauckhart also recommended making the Option 3 rate available to small hydro resources but with a $0.015/kWh adder that reflects avoidance of the wind integration costs estimated in NWE Exhibit NWE-2 at (MAS-4).

31. Lauckhart contended that NWE's transmission system impact studies should focus on the resources used to meet native load when analyzing QF impacts. He said that when adding a QF to existing resources to analyze the QF's impact, NWE should remove a resource that is not under NWE ownership or control from the set of resources used to serve native load in order to achieve load-resource balance. According to Lauckhart, adding the QF allows NWE to avoid using the removed resource to meet its load. He said that if more than one resource can be removed, NWE should remove the one most beneficial to the QF's impact on the system.

[11/] In data request response PSC-011, Lauckhart reports that Judith Gap's net capacity factor for the three years from 2006-2008 exceeded 40%.

32. Lauckhart testified that QFs should not be responsible for the transmission system upgrade costs. Rather, he asserted that any transmission system upgrade costs attributable to QFs should be considered costs necessary to allow the QFs to serve native load and should be borne by native load customers. He contended that this approach would not violate FERC cost allocation policies. He also asserted that this approach would be consistent with NWE's treatment of its own Mill Creek generating station. He said NWE's ratepayers are responsible for transmission system upgrades required for Mill Creek because Mill Creek is a network resource. Similarly, he asserted, QFs are network resources.

Montana Consumer Counsel response testimony

Dr. John Wilson

33. Dr. Wilson, president of J.W. Wilson & Associates, Inc, prefiled testimony on behalf of MCC asserting that the avoided costs NWE submitted in its application in this case do not reflect the Company's current electric generation cost expectations. He said electric generation cost forecasts, especially for natural gas generating resources which figure prominently in NWE's avoided cost estimates, have declined substantially since NWE developed its 2009 Plan. He noted that the January 2011 natural gas price in the forecast underlying NWE's avoided cost estimates was $6.67/MMBtu while on the date of his response testimony the AECO forecast for January 2011 was $3.84/MMBtu. He contended future periods are similarly lower than the forecasts embedded in NWE's avoided cost estimates. For example, AECO forecast prices for January 2012 and 2013 were $4.49/MMBtu and $4.96/MMBtu, respectively. The prices embedded in NWE's avoided cost estimates for the same months are $6.85/MMBtu and $6.91/MMBtu.

34. As further evidence that NWE's avoided cost estimates are likely too high, Wilson pointed to a decline in projected wholesale electric power purchase prices. He testified that the market purchase prices shown in NWE's recent electricity supply tracker filing, Docket D2010.5.50, declined from $49.38/MWh in 2008-09 to $31.46/MWh in 2009-10. He said NWE's 2009 forecast of market purchase prices for the period 2010-2014 started at about $46.00/MWh and increased to $60.53/MWh, substantially higher than both current prices and NWE's 2010 forecasts. Wilson also questioned NWE's inclusion of high cost biomass and gas-fired peaker capacity in the mix of resources used to estimate avoided costs.

35. Wilson took no position on NWE's rate proposals for Option 1(a) heavy load hours and Option 3. He contended that NWE's proposal to increase rates for Option 1(a) light load hours, Option 1(b), and Option 1(c) by 25% is not warranted given declines in wholesale electricity market costs and natural gas costs that have occurred in the last year.

NorthWestern Energy rebuttal testimony

Mark Stauffer

36. Mr. Stauffer's rebuttal testimony addressed Dr. Wilson's testimony on natural gas prices. Stauffer agreed with Wilson that natural gas prices appear to have fundamentally decreased.

37. In his direct testimony Stauffer used NWE's 2009 Plan natural gas price forecast to estimate the power market prices and gas generator costs that underlie his proposed QF-1 Option 1 rates. In rebuttal testimony he updated the proposed QF-1 rates based on NWE's current expectations for future natural gas prices, which he said is the forecast in the Company's 2010 natural gas procurement plan. That forecast, which represents a reduction from $7.39/Dkt to $5.34/Dkt on a 20 year (2010-2029) levelized basis, reduced Stauffer's QF-1 Option 1 avoided cost rates as shown in Table 1.

Table 1. Comparison of NWE QF-1 rate proposals – direct and rebuttal testimony

	Option 1(a)		Option 1(b)	Option 1(c)
	Heavy load ($/kWh)	Light Load ($/kWh)	All hours ($/kWh)	Wind only ($/kWh)
Stauffer direct testimony	$0.06477	$0.09865	$0.06477	$0.06595
Stauffer rebuttal testimony	$0.04807	$0.08195	$0.04807	$0.04925
Unit change	($0.01670)	($0.01670)	($0.01670)	($0.01670)
Percent change	-25.78%	-16.93%	-25.78%	-25.32%

38. Stauffer testified that using an updated natural gas forecast rather than the forecast from the Company's 2009 Plan comports with a consumer indifference objective. He asserted that forecast gas prices reflect the effects of recession-induced demand suppression and an increase in recoverable proven reserves. He advised the Commission to consider the increase in

proven reserves in setting long-term QF-1 rates. He added that the PSC should consider updating the natural gas forecast between electric procurement plans for the purpose of determining QF-1 rates.

John Leland

39. Mr. Leland is NWE's Manager of Regional Systems Planning and Engineering. His rebuttal testimony addressed MSIRG witness Lauckhart's direct testimony on transmission system impact studies. Leland contended that Lauckhart did not accurately define QF resources and incorrectly described system impact studies.

40. Lauckhart testified that, "QF projects by definition are projects that meet the native load of NorthWestern." Ex. MSIRG-2, p. 11. Leland countered that Lauckhart's definition matches neither FERC nor PSC definitions.[12/] He added that, with respect to meeting native load, ARM 38.5.1902(5) requires, "[a] long-term contract for purchases and sales of energy and capacity between a utility and a qualifying facility greater than 10 MW in size shall be contingent on selection of the qualifying facility by a utility through an all-source competitive solicitation…" He noted that long-term standard rates are available for smaller projects.

41. Leland reiterated NWE witness Loos's testimony that, in terms of the generation interconnection process, NWE proposed to study QFs as requiring Energy Resource Interconnection Service, not as requiring Network Resource Interconnection Service. Leland explained that the ERIS study process defines only the direct costs of interconnecting the QF to NWE's transmission grid system, not the costs for transmission upgrades that might be needed to provide reliable transmission of the QF's power to load. He further explained that FERC Order 2006 addressed ERIS transmission system impact studies for small, non-QF generators up to 20 MW and that the ordered procedures are known as small generator interconnection procedures (SGIP). FERC Order 2003 addressed NRIS transmission system impact studies associated with large generator interconnection procedures (LGIP). Leland said both FERC orders are relevant to its QF proposals in this case.

42. Leland indicated that once the generation interconnection process is complete, QFs must follow the transmission service process to actually move power across NWE's

[12/] Mr. Leland points to http://www.ferc.gov/help/glossary.asp#q and ARM 38.5.1901 for the FERC and PSC definitions, respectively.

transmission system to load. NWE determines any costs associated with providing transmission service (moving generation to load) through System Impact Studies and Transmission Service Facility Studies. He testified that a QF has two options if it wants a firm right to move its power through or across NWE's transmission system: it can apply for point-to-point service, or its network customer can designate the QF as a network resource.[13/] NWE's FERC-jurisdictional open access transmission tariff (OATT) contains point-to-point service procedures. A QF's network customer can designate the QF a network resource by attesting that the QF and the network customer have executed a contract. NWE then determines whether studies are needed to provide the transmission service – system impact and facility studies ensure transmission system reliability with the QF connected to the system. These studies model a connected QF generating at full capacity in order to identify operating conditions that will cause transmission performance to violate reliability standards. Identified conditions may require mitigation before the QF is connected.

43. Leland disputed Lauckhart's testimony that in studying a QF's impact on transmission, NWE should remove selected resources from the power flow model in order to favor the QF. He asserted that although NWE does remove resources to solve the model, selectively removing resources that provide QF-friendly results would prevent NWE from accurately assessing system reliability. NWE must be able to observe the modeled system under all contingencies in order to ensure transmission system reliability under expected operating conditions.

44. Finally, Leland testified that Lauckhart incorrectly characterized NWE's transmission system load components. He said NWE's retail Energy Supply load is about 1,150 MW, not 1,800 MW. He added that NWE does not control how PPL dispatches its resources to meet its commitment with NWE's Energy Supply function, and that the Mill Creek Generating Station is not an energy resource that serves Energy Supply load, but a regulating resource for all loads and resources.

[13/] With respect to application of the standard avoided cost rates the QF's network customer is NWE's electricity supply function. See RDR PSC-020(c).

Montana Small Independent Renewable Generators cross-intervenor testimony

Richard Lauckhart

45. Mr. Lauckhart submitted cross-intervenor testimony addressing MCC witness Wilson's prefiled response testimony. Wilson concluded that NWE likely overstated the avoided cost of acquiring QF resources. Lauckhart countered that Dr. Wilson failed to provide sufficient evidence to support his claim, and failed to address the probability of a carbon adder.

46. With regard to the Option 3 wind rate, Lauckhart contended that Wilson provided no estimates of the cost to build and operate wind plants, or expected capacity factors for NWE's Montana service territory. Lauckhart said NWE's recent memorandum of understanding (MOU) with Compass Wind (regarding the Spion Kop project) is an example of a project that could be used to determine an avoided cost for Option 3. He calculated an avoided cost from information in DR MSIRG-003(a) and Exhibit NWE-2 at (MAS-2) that exceeded the $0.07864/kWh estimate he offered in his response testimony.

47. Lauckhart opposed updating natural gas costs when estimating the Option 1 rate. He asserted that no party that submitted comments on NWE's 2009 Plan (see Docket No. N2010.6.57) suggested that the natural gas price forecast was too high. He added that if the PSC had wanted to review that natural gas price forecast in this proceeding it should have identified the issue at the beginning of the proceeding, or as an additional issue pursuant to its Procedural Order No. 7108.

48. Lauckhart contended that avoided costs must reflect NWE's 2009 Plan. He acknowledged that natural gas prices are difficult to forecast but asserted that changing the avoided cost of gas generation every time a futures strip price changes would be unworkable. He questioned whether futures prices, such as Wilson's November 2010 forward strip, provide any useful information regarding future prices because so little volume is traded in later periods covered by the strip. He said a forecast should consider prices derived from a fundamentals-based model of supply and demand and that Wilson did not provide any fundamental gas price forecasts.

49. Lauckhart observed that Wilson did not address the likelihood of a carbon emissions price in his analysis of NWE's avoided cost calculations. He asserted that a carbon emissions price would increase the cost of gas fired generation and spot market prices. He noted

Wilson's acknowledgment in DR MSIRG-021(d) that it would likely be prudent to anticipate continuing changes regarding carbon emissions pricing policy.

50. Lauckhart concluded that the PSC should give no weight to Wilson's testimony.

FINDINGS OF FACT, ANALYSIS, AND COMMISSION DECISIONS

Tariff Option 1

51. The Commission last updated the Option 1 rates in Docket No. D2008.12.146, Order No. 6973d. In that case, NWE proposed, and the PSC approved, a total avoided cost based on a levelized projection of annual costs for NWE's share of CU4, which the Commission had authorized NWE to acquire in Docket No. D2008.6.69. The Commission classified the total avoided cost into energy-related and capacity-related cost components. The capacity-related component was based on the fixed costs (capital and fixed O&M) of a frame simple cycle combustion turbine (SCCT). The energy-related component was derived by subtracting the capacity-related component from the total avoided cost. The Commission found that the CU4 purchase was "a reasonable proxy for the cost of base load market products that NWE could avoid with future QF power purchases." Order 6973d, p. 57. Previously, the Commission used the cost of planned coal-fired generators, classified as energy- and capacity-related costs, to set avoided cost-based rates for Montana Power Company, PacifiCorp and Montana-Dakota Utilities in Docket No. 81.2.15, Order 4865, and Docket No. 83.1.2, Order 5017. (See also Ex. NWE-1, p. 3, in Docket No. D2008.12.146)

52. In this case, NWE proposed setting the Option 1 rates based on GenTrader®-modeled marginal resource costs from the three preferred resource portfolios in its 2009 resource plan. Ex. NWE-2, pp. 3-4. NWE's witness Stauffer testified that NWE blended the marginal resource costs from the preferred portfolios, including wholesale market purchases, because each of the preferred portfolios relies on a different gas-fired plant design. He asserted that since the Company has not committed to a particular plant design, avoided costs should reflect an average. *Id*. NWE did not include marginal wind resource costs in the blended marginal costs because Option 1 reflects base load resource costs and wind costs are captured in Option 3. Tr. pp. 69-70.

53. MCC and MSIRG did not contest NWE's method for setting Option 1 rates, i.e., blending the cost of marginal resources in the 2009 resource plan's preferred portfolios. MCC's

witness Wilson testified that NWE's method "does a reasonably good job," although he questioned whether the calculation should include high-operating-cost biomass and gas peaker units that do not reflect costs avoided by typical QFs. Ex. MCC-1, pp. 8-9, Tr. pp. 244-246. MSIRG's witness Lauckhart objected to deviating from the 2009 resource plan's natural gas price forecast, asserting that avoided costs must be based on that plan and that NWE's updated natural gas price forecast is not a legitimate, fundamentals-based forecast. Ex. MSIRG-3, pp. 4-5, Tr. pp. 379-380. MSIRG also argued in its post-hearing answer brief that the PSC's rules require it to set avoided costs based on NWE's most recent resource plan and that NWE inappropriately introduced a new natural gas price forecast in this docket. MSIRG Br. pp. 9-10, 14, 25. In contrast, MCC maintained that the PSC's rules do not prevent it from considering current cost information or require it to consider only the cost information in a resource plan. MCC Br. p. 3. NWE asserted that the rules pertaining to when utilities should file resource plans and update QF rates imply that new QF-1 tariff rates should primarily reflect NWE's previously filed resource plan, but that nothing in Montana law precludes the PSC from considering new data if a fundamental change has occurred. NWE Reply Br. p 3.

54. NWE's proposed method of estimating avoided costs for Option 1 is sensitive to natural gas price expectations because it relies on natural gas plants and a wholesale electricity price forecast derived from a natural gas price forecast. Given this, the Commission must resolve the following issues in setting the Option 1 rate:

A. Do Commission rules require it to use the natural gas price forecast embedded in NWE's 2009 resource plan to set the Option 1 rates?
B. Is the 2010 natural gas price forecast NWE proposed in its rebuttal testimony reasonable and, if not, is there a reasonable alternative?
C. If the Commission adopts an alternative to NWE's natural gas price forecast, how should it use that forecast to estimate NWE's avoided costs?

The following sections analyze each of these issues.

<u>A. Do Commission rules require it to use the natural gas price forecast embedded in NWE's 2009 resource plan to set the Option 1 rates?</u>

55. Following Order No. 6973d in NWE's last QF-1 avoided cost docket, D2008.12.146, MSIRG filed a Motion for Reconsideration arguing, in part, that the Commission

erred in basing the Option 1 rates on CU4 costs because CU4 was not specifically included in NWE's 2007 resource plan and because the Montana Supreme Court had determined in *Whitehall Wind, LLC. v. Montana Public Service Commission* that avoided costs must be based on a utility's least cost plan. (See MSIRG Motion for Reconsideration at p. 2 in D2008.12.146). MSIRG asserted that this requirement stems from ARM 38.5.1902(5), which states:

> [t]he utility shall recompute the short-term and long-term standard tariffed avoided cost rates following public review and comment on each least cost plan filing, ARM 38.5.2001 through 38.5.2012. The recomputed avoided cost rates should reflect any amendments to the plan due to the comments of the commission and the public.

The Commission denied MSIRG's Motion for Reconsideration. Order 6973e. MSIRG makes a similar (if not the same) argument in this case.

56. The Commission finds that nothing in the Supreme Court decision requires the PSC to rely solely on cost data in NWE's 2009 resource procurement plan. The Montana Supreme Court found that "under both state and federal law, rates for purchases from qualifying facilities must be reasonable and based on <u>current avoided least cost resource data</u>." *Whitehall Wind, LLC. v. Montana Public Service Commission*, 2010 MT 2,¶21, 355 Mont. 15, 223 P.3d 907(emphasis added). The Supreme Court decision does not force the PSC to obtain current cost data solely from utility resource procurement plans. These plans contain relevant data, and that is why the PSC requires utilities to update their QF rates shortly after filing their resource plans. But the PSC is free to obtain current avoided cost data using other methods too, including contested cases. Although ARM 38.5.1902(5) directs utilities to re-compute avoided cost rates based on the results of their most recent resource plans, it does not obligate the Commission to automatically approve those rates. If the more current, more accurate and/or more complete avoided cost information becomes available in a subsequent contested avoided cost rate-setting docket, the Commission can and should use that information to set rates.

57. MSIRG did not make any new legal arguments in this case. In its view, ARM 38.5.1902(5) requires the PSC to set avoided cost rates based on the utility's most recent resource plan. However, MCC pointed to another rule, ARM 38.5.1905(4), which states:

> [t]he standard rate for purchases from a qualifying facility shall be that rate calculated on the basis of avoided costs to the utility which is determined by the commission to be appropriate for the particular utility after consideration, to the extent practicable, of the avoided cost data submitted to the commission

by the utility and other interested persons.

MCC, correctly, reads ARM 38.5.1902 and 38.5.1905 together to require utilities to provide cost information for use by the PSC in determining avoided costs and setting standard rates and to specify when that cost information should be filed. The Commission's rules do not prevent it from considering the most current cost information or limit it to considering only the cost information in a resource plan, or even information provided by the utility.

B. Is the 2010 natural gas price forecast NWE proposed in its rebuttal testimony reasonable and, if not, is there a reasonable alternative?

58. MCC's witness Wilson testified that the natural gas price expectations embedded in NWE's 2009 resource plan are substantially higher than current expectations. Ex. MCC-1, pp. 6-7. At the hearing he testified that natural gas prices shifted after 2009 as a result of increased supplies from both hydraulic fracturing and conventional drilling and that it would be a mistake to ignore the price shift in this case. Tr. p. 238.

59. In rebuttal testimony, Stauffer agreed that natural gas prices have fundamentally changed since NWE developed the resource plan's forecast in fall 2009, largely due to increased supplies from expanded use of hydraulic fracturing. He proposed replacing the 2009 resource plan's natural gas price forecast with a forecast NWE developed for its December 2010 Natural Gas Default Supply Procurement Plan. Ex. NWE-3, p. 2. That forecast reflects the yearly average of AECO hub settlement prices published by InterContinental Exchange (ICE) for the period December 2010 through March 2014 and 2% annual escalation for the period April 2014 through December 2030. *Id* at MAS-4, pp. 2-3.

60. In response to Wilson, MSIRG's witness Lauckhart questioned whether forward price strips provide useful information since prices for out years in the strips are based on an insufficient number of transactions. He maintained that future price estimates should incorporate a fundamentals-based forecast, which he said reflects physical assumptions about supply and demand. Ex. MSIRG-3, pp. 4-5.

61. Stauffer, Wilson, and Lauckhart all pointed to the U.S. DOE Energy Information Administration (EIA) as an authoritative source of information on the state of natural gas markets. Stauffer relied on natural gas supply, demand, and price data reported by EIA to

support his rebuttal testimony that natural gas prices fundamentally changed after NWE filed its 2009 resource plan. Ex. NWE-3 at MAS-6. At the hearing, Wilson also referred to EIA reports indicating lower natural gas prices. Tr. pp. 236-237, 247-248, 279-280. Lauckhart testified that he agreed with EIA's assessment that proven natural gas reserves have increased and also said he did not dispute EIA's natural gas price forecast. Tr. pp. 381-382. Stauffer agreed that "EIA does a very good fundamental forecast." Tr. p. 54. And when justifying NWE's December 2010 natural gas price forecast, Stauffer again pointed to EIA:

> …I take some comfort from the fact that our forecast, while perhaps simply constructed, does – as I said – the energy – the federal government, EIA, has come up with the 2.3 percent escalator going forward. And we used a 2 percent escalator. So, you know, we're in the ballpark…

Id.

62. The 2.3% escalator Stauffer compared to NWE's 2% escalator comes from EIA's 2011 Annual Energy Outlook (AEO). NWE Late Filed Exhibit No. 1. However, EIA predicts that natural gas prices will increase at a rate of 2.3% per year, from 2009 to 2035, in real terms (not counting inflation), as Figure 86 on p. 2 of the attachment to Late Filed Exhibit No. 1 indicates – the prices shown in Figure 86 are all in 2009 dollars . (See also NWE Reply Br. p. 6) In contrast, NWE predicts that prices will increase at a rate of 2% per year, from 2014 to 2029, in nominal terms (including inflation). Tr. p. 49. Economically, EIA's 2.3% real rate of increase and NWE's 2% nominal rate of increase are not comparable. According to Appendix A Reference Case, Table A1, of EIA's 2011 AEO, EIA predicts that natural gas prices will increase at a rate of 4.1 percent per year, from 2009 to 2035, in nominal terms.[14/] NWE's nominal natural gas price forecast departs significantly from EIA's over the 25-year Option 1 rate period.

In the 2011 AEO, EIA compared its natural gas price forecast to forecasts developed by other industry observers. In addition, Lauckhart provided a graphical representation of his firm's (Black & Veatch) natural gas price forecast in data response PSC-015. The graph below shows how NWE's 2010 natural gas price forecast compares to these other forecasts. Because MSIRG provided only a graph of Black & Veatch's forecast, the Commission quantified relevant Black & Veatch prices through visual inspection of data response PSC-015. Additionally, Black & Veatch's forecast is for natural gas prices at Henry Hub and EIA compared wellhead natural gas

[14/] 4.1% is EIA's reported nominal annual growth in prices for natural gas at Henry Hub, which corresponds to the 2.3% real annual growth in Henry Hub prices shown in the attachment to NWE's Late Filed Exhibit No. 1, p. 2.

prices. In the graph, Black & Veatch's Henry Hub prices are adjusted downward using the difference between EIA's Henry Hub and wellhead natural gas prices. Also NWE's nominal prices are converted to real 2009 prices using NWE's assumed 2% annual inflation factor. Table 2 shows the prices plotted in the graph.

Industry forecasts of natural gas prices for selected years

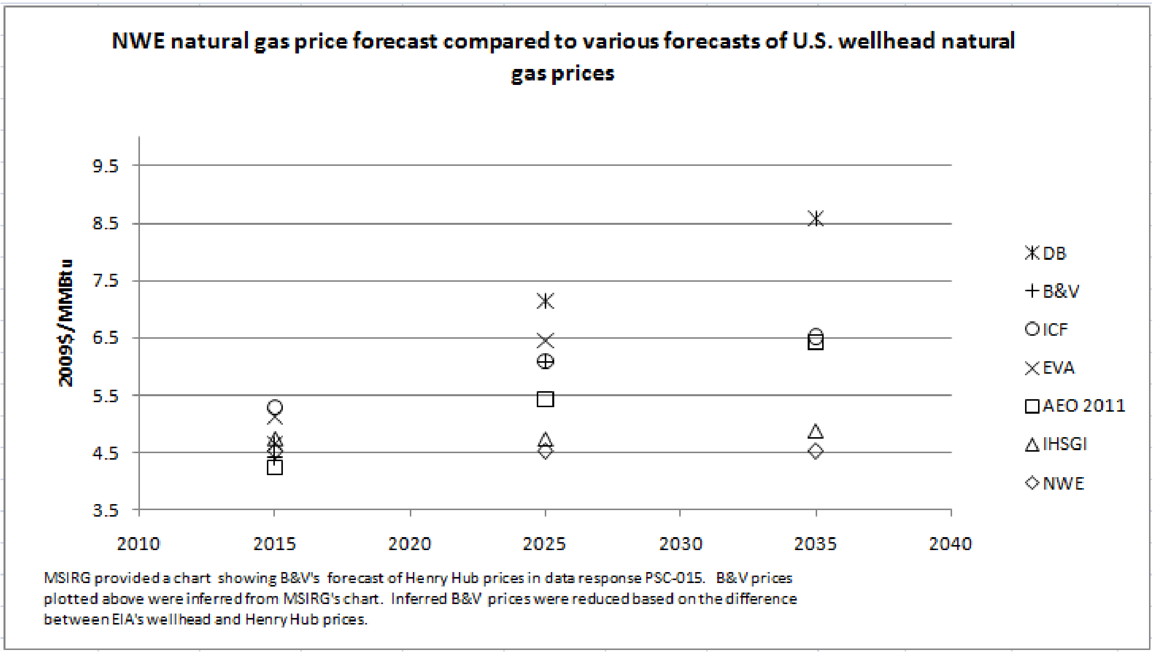

Table 2. Industry forecasts of natural gas prices for selected years ($2009/MMBtu)

	NWE	AEO 2011	IHSGI	EVA	DB	ICF	B&V
2015	4.53	4.24	4.74	5.13	4.66	5.29	4.42
2025	4.53	5.43	4.73	6.46	7.15	6.10	6.09
2035	4.53	6.42	4.88		8.59	6.52	

63. Clearly, expectations vary within the industry regarding future natural gas prices. NWE's forecast appears to define the low end of the range of expectations for later years in the forecast period. When asked at the hearing why NWE did not use EIA's natural gas price forecast, Stauffer referred to the Company's desire to use consistent information and the expertise of Company personnel regarding pipeline constraints and drilling activity. Tr. p. 55. However, the record indicates that to the extent NWE checked its forecast against EIA's, it might have misinterpreted EIA's predicted annual growth in natural gas prices and failed to realize how

much lower its forecast is compared to EIA's. If NWE knew that its forecast diverges from most other industry forecasts, it did not attempt to explain or justify that divergence.

64. Given how readily all of the witnesses pointed to EIA's analyses to support their positions, and since Lauckhart indicated that he would accept EIA's forecast and Stauffer agreed that EIA's forecast is very good, the Commission finds it reasonable to use EIA's 2011 AEO reference case natural gas price forecast in setting Option 1 rates.

C. Determining NWE's avoided costs using EIA's natural gas price forecast

65. The blended marginal costs that are the basis of NWE's initial and rebuttal Option 1 rate proposals reflect outputs from its production cost model, GenTrader®. When NWE recalculated blended marginal costs in its rebuttal testimony it developed a new wholesale electricity market price forecast based on its new natural gas price forecast and re-ran GenTrader® which, in turn, economically dispatched the various gas plants in the preferred resource portfolios and made market purchases with the goal of minimizing total costs. The GenTrader® model established annual revenue requirements and megawatt-hour outputs for each of the marginal resources, from which NWE calculated the blended marginal cost that is the starting point for setting Option 1 rates. Ex. NWE-3, pp. 10-11.

66. Neither the GenTrader® model nor outputs from the GenTrader® model based on EIA's 2011 AEO natural gas price forecast are in the record. However, NWE's 2009 resource plan is in the record and contains detailed cost information for each of the marginal resources in the preferred portfolios. DR MCC-001. That information allows a calculation of avoided costs using the method used to develop the currently-approved Option 1 rates, but substituting NWE's modeled combined cycle gas plant annual costs for CU4's annual costs. NWE's 2009 resource plan described the combined cycle plant as a base load resource and the GenTrader® outputs in Stauffer's blended marginal cost work papers indicate that, as dispatched by GenTrader®, the plant operated at a 90% capacity factor.[15/] This method would also allow use of EIA's natural gas price forecast to estimate an avoided cost. The details of this approach are explained below.

67. Portfolio 27, a preferred portfolio selected in NWE's 2009 resource plan and used in its blended marginal cost calculation, would acquire a 200 MW combined cycle gas plant in

[15/] Annual capacity factors for the combined cycle plant were calculated by dividing the annual MWh output for the plant provided in data response PSC-019b by the product of the plant's capacity (200 MW) and 8,760 hours.

2015. NWE reported that the annual nominal levelized capital cost of this plant was $160/KW-yr in data response MCC-003 (see p. 4). NWE provided the fixed and variable O&M costs and the plant's heat rate in its 2009 resource plan, Volume 1, p. 96. Data response MCC-003 indicates that NWE assumed a 2.5% inflation rate and Stauffer's blended marginal cost work papers show that NWE used an 8.46% cost of capital in its levelization calculation. This information, along with NWE's December 2010 annual natural gas price forecast, allows the Commission to estimate the annual costs of the combined cycle gas plant in Portfolio 27. Table 3 shows these calculations along-side the unit costs from NWE's blended marginal cost work papers. The Commission's estimates deviate from NWE's work papers by about -0.5% for unknown reasons.

Table 3. Calculation of Portfolio 27 combined cycle plant costs

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Levelized capital	Fixed O&M	Total fixed[1]	Variable O&M	Natural gas	Heat rate	Fuel cost[2]	Total unit rate[3]	NWE unit rate[4]	difference
Year	($/KW)	($/KW)	($/KW)	($/kWh)	($/MMBtu)	(Btu/kWh)	($/kWh)	($/kWh)	($/kWh)	($/kWh)
2015	160	14.0	174.3	0.003	5.10	6,916	0.035	0.06051	0.06080	-0.5%
2016	160	14.4	174.6	0.003	5.24	6,916	0.036	0.06160	0.06190	-0.5%
2017	160	14.7	175.0	0.003	5.38	6,916	0.037	0.06269	0.06304	-0.6%
2018	160	15.1	175.4	0.003	5.53	6,916	0.038	0.06386	0.06420	-0.5%
2019	160	15.5	175.7	0.003	5.69	6,916	0.039	0.06510	0.06540	-0.5%
2020	160	15.9	176.1	0.004	5.84	6,916	0.040	0.06627	0.06662	-0.5%
2021	160	16.3	176.5	0.004	6.00	6,916	0.041	0.06752	0.06789	-0.6%
2022	160	16.7	176.9	0.004	6.17	6,916	0.043	0.06883	0.06919	-0.5%
2023	160	17.1	177.3	0.004	6.34	6,916	0.044	0.07016	0.07051	-0.5%
2024	160	17.5	177.8	0.004	6.51	6,916	0.045	0.07148	0.07188	-0.6%
2025	160	18.0	178.2	0.004	6.69	6,916	0.046	0.07288	0.07328	-0.5%
2026	160	18.4	178.7	0.004	6.88	6,916	0.048	0.07435	0.07473	-0.5%
2027	160	18.9	179.1	0.004	7.07	6,916	0.049	0.07583	0.07621	-0.5%
2028	160	19.3	179.6	0.004	7.26	6,916	0.050	0.07731	0.07773	-0.5%
2029	160	19.8	180.1	0.004	7.46	6,916	0.052	0.07886	0.07930	-0.6%

1 (b) + (c)
2 (f)*(g)/10^6
3 (d)/(.9*8760)+(e)+(h)
4 Ex. NWE-3 (MAS-5), data response PSC-019b

68. For the years 2010-2014 NWE's blended marginal cost is simply its forecast of market prices because the other marginal resources do not come on line until 2015 or later. The Commission finds it reasonable to incorporate these market prices into the combined cycle plant-based avoided cost calculation. Since Stauffer testified that calculating nominal levelized avoided costs for 2011 would be appropriate (Tr. p. 72), the Commission finds that the combined cycle plant-based avoided cost calculation should begin with the year 2011 and run through the

year 2035 to capture the full 25 year contract period available under Option 1. This approach blends NWE's forecast of wholesale electricity market prices in the early years with the expected cost of owning and operating a combined cycle gas plant in the later years.

69. The blended market-combined cycle plant approach, with NWE's 2010 natural gas price forecast, produces a 20-year (2010 – 2029) levelized marginal cost of $0.05454/kWh, about 2.5% less than NWE's 20-year levelized blended marginal cost of $0.05595/kWh. Ex. NWE-3 at MAS-5. This result is expected given that the blended market-combined cycle plant approach does not reflect the higher cost gas peaking and biomass plants, the inclusion of which Wilson questioned (see Ex. MCC-1, p 9, Tr. pp. 244-245). Incorporating EIA's natural gas price forecast into the blended market-combined cycle plant approach is straightforward; the gas prices in column (f), Table 3 (above), are replaced with EIA's forecast. A reasonable EIA-based natural gas price forecast results from applying EIA's 4.1% nominal escalation rate starting with NWE's December 2010 natural gas forecast year-15 gas price, as shown in Table 4, and inserting the results into the Table 3 calculation.

Table 4. Developing EIA-based natural gas price forecast

Year	NWE forecast[1]	annual growth	EIA annual growth[2]	EIA forecast
2015	5.10			5.10
2016	5.24	2.75%	4.1%	5.31
2017	5.38	2.67%	4.1%	5.53
2018	5.53	2.79%	4.1%	5.75
2019	5.69	2.89%	4.1%	5.99
2020	5.84	2.64%	4.1%	6.23
2021	6.00	2.74%	4.1%	6.49
2022	6.17	2.83%	4.1%	6.76
2023	6.34	2.76%	4.1%	7.03
2024	6.51	2.68%	4.1%	7.32
2025	6.69	2.76%	4.1%	7.62
2026	6.88	2.84%	4.1%	7.93
2027	7.07	2.76%	4.1%	8.26
2028	7.26	2.69%	4.1%	8.60
2029	7.46	2.75%	4.1%	8.95
2030			4.1%	9.32
2031			4.1%	9.70
2032			4.1%	10.10
2033			4.1%	10.51
2034			4.1%	10.94
2035			4.1%	11.39

1 Data response MCC-006

2 EIA 2011 AEO, Appendix A Reference Case, Table A1

70. The blended market-combined cycle plant approach, with EIA's natural gas price forecast, produces a total, 25-year nominal levelized avoided cost of $0.06291/kWh, about 13% less than what Stauffer proposed in his initial testimony, and about 12% more than what he proposed in his rebuttal testimony. This avoided cost is the starting point for setting Option 1 rates in this Order.

The Commission adopts NWE's method for classifying the total nominal levelized avoided cost as energy- and capacity-related costs, with one exception. NWE's classification used just the annualized capital cost of a frame SCCT as the basis for the capacity value, which Stauffer testified is $69/KW-yr. Ex. NWE-3, p. 5. However, the existing Option 1 rates were calculated using the capital and fixed O&M costs for a frame SCCT. Order 6973d, pp. 4-5. The 2011 – 2035 nominal levelized fixed O&M cost for the frame SCCT modeled in NWE's 2009 resource plan is $5.22/KW-yr.[16/] The total levelized fixed cost for the frame SCCT should be $74.22/KW-yr, or $0.00847/kWh.

Table 5 compares the existing Option 1 rates set in Order 6973d to those NWE proposed in Stauffer's initial and rebuttal testimony and those resulting from the blended market-combined cycle gas plant method that the Commission applies in this Order. In summary, the Commission approves an Option 1(a) on-peak rate of $0.09087/kWh, and an Option 1(a) off-peak rate of $0.05444/kWh. The Option 1(b) short-term rate is the energy-related avoided cost, $0.05444/kWh. The Option 1(c) wind rate that results from the blended market-combined cycle plant avoided cost approach, using NWE's wind capacity credit method, is $0.05571/kWh. However, NWE's method of calculating the wind capacity credit is incorrect. NWE's calculation spreads the wind QF's capacity payment over too much energy, effectively assuming that wind QFs operate continuously at 100% capacity factor.[17/] Since Option 1(c) credits a wind QF a specific quantity of capacity (15% of the QF's nameplate rating), it is not necessary to convert the capacity avoided cost into an energy rate; a one-KW QF should be paid as if it provides .15 KW/yr at a rate of $74.22/KW-yr, or $11.13/yr. NWE's $0.00118/kWh energy rate

[16/] NWE's 2009 resource plan, Volume 1, p. 96, reports FSCCT fixed O&M costs of $4.02/KW-yr in 2009 dollars. These costs were escalated at 2.5% per year through 2035. The nominal levelized cost was then calculated for the period 2011 – 2035 using NWE's assumed 8.46% cost of capital.

[17/] NWE's calculation multiplies the levelized annual combustion turbine capital cost by the assumed 15% capacity contribution from wind QFs, then divides by 8,760 hours per year to derive the $0.00118/kWh capacity credit, which when added to its $0.04807 energy rate equals its Option 1(c) rate, $0.04925/kWh. See Ex. NWE-3 (MAS-5) and data response PSC-019.

would pay this QF, operating at a 37% capacity factor, only $3.82/yr (1 KW*.37*8,760 hrs/yr*$0.00118/kWh). If the $11.13/yr capacity payment due this QF is going to be made based on the QF's energy production, the correct calculation for the capacity credit is: $11.13/yr / (.37*8760) = $0.0343/kWh. Therefore, the Option 1(c) rate should be $0.05787/kWh.

Table 5. Commission-approved Option 1 rates compared to current and proposed

Approved Option 1 rates compared to current and proposed				
	D2008.12.146 ($/kWh)	D2010.7.77 NWE initial ($/kWH)	D2010.7.77 NWE rebuttal ($/kWh)	Market-CCCT standard rate ($/kWh)
Total avoided cost	0.06237	0.07265	0.05595	0.06291
Capacity	0.01122	0.00788	0.00788	0.00847
Energy	0.05115	0.06477	0.04807	0.05444
Capacity allocated to 2037 peak hours	0.04825	0.03387	0.03387	0.03644
1(a) on-peak hours	0.09940	0.09865	0.08195	0.09087
1(a) off-peak hours	0.05115	0.06477	0.04807	0.05444
1(b) short-term energy	0.05115	0.06477	0.04807	0.05444
1(c) wind rate	0.05283	0.06595	0.04925	0.05787

<u>Tariff Option 3</u>

71. The Commission established Option 3 in Docket No. D2008.12.146 after finding that the substantial quantity of new wind capacity included in NWE's 2007 resource plan and its active solicitation of wind resources warranted a non-discriminatory, standard rate option for wind QFs. Order 6973d, p. 61. The Option 3 rate was set to reflect the generic wind resource cost NWE modeled in its 2007 resource plan with a 38% capacity factor. Option 3 removed the uncertainty wind QFs faced under Option 1 regarding future wind integration costs, but obligated QFs to convey all their renewable attributes (renewable energy credits) to NWE for the full contract term. At the time, future wind integration costs were uncertain and the Commission reasoned that whatever those costs turned out to be they would be similar for both new QF wind projects and alternative wind projects NWE might otherwise acquire (whether through rate basing or power purchase agreements). *Id*, p. 62.

72. The Commission adopted Option 3 on the premise that NWE's 2007 resource

plan acquired wind resources as part of a plan to minimize long-term total costs and risks. That premise does not hold in this case because NWE's 2009 plan hard-wired the addition of specific amounts of wind resources, and the timing of the wind resources, in candidate portfolios instead of economically evaluating the cost and risk attributes of wind relative to other resource alternatives. Tr. p. 67 (see reference to DR PSC-020). NWE's planning approach in 2009 ensured that the final resource plans complied with renewable energy standards, but it renders an Option 3 rate based on the plan's modeled wind costs unworkable because those wind costs may not represent economic avoidable costs. In other words, the modeled wind resources represent incremental resource costs that could be avoided by QFs because NWE hard-wired them into its resource plans, not because the wind resources minimize long-term total costs and risks.

73. The Commission also questions whether the other basis for establishing Option 3 in Order 6973d – that NWE was actively soliciting additional wind resources – holds in this case. NWE's 2009 renewable RFI has culminated in its application for approval of the 40 MW Spion Kop project in Docket No. D2011.5.41 and the Company recently acquired 30 MW of new QF wind capacity. DR MSIRG-023, PSC-017 (July 14, 2011 update). Together these wind projects exceed the 50 MW NWE hard-wired into its 2009 resource plan to comply with the renewable energy standards for the 2010 – 2015 period. DR MCC-001, Volume 3, Chapter 4. In short, because the reasons the Commission gave in Order 6973d for establishing Option 3 are not supported by the record in this case, maintaining Option 3 hinges on there being other record-based reasons for doing so.

74. Given statutory renewable energy standards, the costs NWE would incur to comply with those standards but for the purchase from a renewable QF might establish a reasonable avoided cost, and justify Option 3, but not before first showing that such compliance costs do not exceed the cost caps in § 69-3-2007, MCA.[18/] But neither NWE's witness Stauffer, with respect to his initial $0.06842/kWh rate proposal, nor MSIRG's witness Lauckhart, with respect to his $0.07860/kWh rate proposal, measured these rate proposals against the cost caps. Stauffer's rate represents the wind resource cost from NWE's 2009 resource plan, which reflects

[18/] Section 69-3-2007(1) states: "[a] public utility that has restructured pursuant to Title 69, chapter 8, is not obligated to take electricity from an eligible renewable resource unless the eligible renewable resource has demonstrated through a competitive bidding process that the total cost of electricity from that eligible resource, including the associated cost of ancillary services necessary to manage the transmission grid and firm the resource, is less than or equal to bids for the equivalent quantity of power for the equivalent contract term from other electricity suppliers."

the lowest bids submitted in the renewable RFI and which, again, did not compete against other resources for inclusion in the preferred portfolios. Ex. NWE-2, pp. 6-7, DR PSC-020. Lauckhart derived his rate by adjusting Stauffer's rate based on the ratio of NWE's assumed 40% capacity factor to his assumed 34.8% capacity factor. Ex. MSIRG-2, p. 10.

75. Late in this proceeding, NWE provided its application for approval to acquire Spion Kop, in which it compared its estimated $0.05378/kWh levelized Spion Kop cost to alternative resources. DR MSIRG-023 (4th update). At the hearing, NWE suggested that the most up-to-date avoided cost for Option 3 is the estimated Spion Kop costs. Tr. p. 11. During post-hearing briefing, NWE, recognizing the Commission's expressed concerns about basing the avoided costs solely on the unapproved and unexamined Spion Kop agreement, offered three alternative approaches for setting the Option 3 rate. NWE Br. p. 13.

76. Although NWE is attempting in another docket (D2011.5.41) to prove that the Spion Kop project complies with statutory cost caps and contributes to a resource strategy that minimizes long-term total costs and risks (refer to ARM 38.5.8201 *et seq.* and § 69-8-419, MCA), that process is not complete and, as explained above, NWE's 2009 resource plan did not include such a demonstration for any wind resource. Moreover, the record in this case contains unresolved issues regarding the accuracy of NWE's capacity factor estimates, projections of future maintenance costs and capital upgrades, and the availability and effect of bonus depreciation, all of which impact the Spion Kop project's per-kWh cost. Tr. pp. 371-373 Given these uncertainties, and given procedural and due process concerns arising from the fact that the Spion Kop information did not become available until after all opportunities for discovery and pre-filed testimony had passed, the Commission finds that it would be unreasonable to rely on NWE's estimated Spion Kop cost as the basis for an Option 3 rate.

77. Because there is not sufficient evidence in this case to support an Option 3 rate based on the parties' various wind resource cost estimates, NWE must eliminate Option 3 from its tariff. If the Company or another party believes it is in the public interest to include a separate rate option for wind resources, or renewable resources generally, in the QF-1 tariff, it may propose such an option. In its next application to update the QF-1 tariff, NWE must also analyze and update, as appropriate, its wind integration tariff schedule WISC-1 and the value of renewable attributes so the Commission can consider these items when designing prospective standard rates. The Commission encourages NWE to negotiate with renewable QFs seeking

contracts under the standard rate options for the purchase of renewable energy attributes, so long as NWE needs RECs to comply with statutory renewable energy standards.

Transmission system interconnection costs

78. 18 CFR 292.101 of FERC's rules implementing PURPA, defines interconnection costs as:

> …the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions and administrative costs incurred by the electric utility directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a qualifying facility, to the extent such costs are in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations, but instead generated an equivalent amount of electric energy itself or purchased an equivalent amount of electric energy or capacity from other sources. Interconnection costs do not include any costs included in the calculation of avoided costs.

ARM 38.5.1901 of the PSC's QF rules contains the same definition of interconnection costs. Both FERC's and the PSC's rules make QFs responsible for the interconnection costs associated with their projects. 18 CFR 292.306 states:

> a) *Obligation to pay*. Each qualifying facility shall be obligated to pay any interconnection costs which the state regulatory authority (with respect to any electric utility over which it has ratemaking authority) or non regulated electric utility may assess against the qualifying facility on a nondiscriminatory basis with respect to other customers with similar load characteristics.
> b) *Reimbursement of interconnection costs*. Each state regulatory authority (with respect to any electric utility over which it has ratemaking authority) and non regulated electric utility shall determine the manner for payments of interconnection costs, which may include reimbursement over a reasonable period of time.

ARM 38.5.1904 states:

> (2) A qualifying facility shall be fully responsible for interconnection costs and shall:
> …
> (c) Reimburse the utility for special or additional interconnection facilities, including control or protective devices, time of delivery metering, and reinforcement of the utility's system

> to receive or continue to receive the power delivered under contract. Such reimbursement may be accomplished by means of amortization over a reasonable period of time within the term of the contract and such costs must be reasonable according to industry standards.
> (3) Interconnection costs undertaken by the utility shall be reimbursed by the qualifying facility on a nondiscriminatory basis with respect to other customers with similar load characteristics.

79. In Docket No. 83.1.2, Order No. 5017, the Commission determined that QFs are responsible for all costs up to the point of interconnection, where a QF interconnects with the utility's existing grid system. Order 5017, pp. 32-33, 35-36. The Commission ordered that "upgrades required for interconnection to the utility grid system, at the time that the QF interconnects, shall be the cost burden of the QF. Later upgrades to maintain reliable and dependable service are solely the utility's responsibility." *Id*. The Commission found that there should be a sharing of interconnection costs between initial QFs and subsequent QFs or customers, but left to utilities the design of such refunds. *Id*.

80. In Docket No. D2010.2.18, Order No. 7068b (the Kenfield case), the Commission ruled on a QF's petition for the rates and conditions of a contract with NWE pursuant to § 69-3-603, MCA. The QF disputed the cost of network upgrades on NWE's side of the transmission system interconnection point that NWE asserted were the QF's responsibility. Order 7068b, p. 21. NWE contended that ARM 38.5.1904 requires QFs to pay for network upgrades. *Id*., p. 22. The Commission found NWE's application of that rule incomplete because it failed to quantify and charge to the QF only those interconnection costs that were in excess of the corresponding costs which NWE otherwise would have incurred for avoidable resource acquisitions or purchases. The Commission directed NWE to address the merits of applying FERC's Small Generator Interconnection approach to QFs in its next QF-1 tariff filing and asked NWE to contrast FERC's approach with the approach required by Commission rules in terms of economic efficiency and customer impacts. *Id*., p. 24.

81. FERC's Orders 2003 and 2006 govern the process for interconnecting non-QF generators to NWE's system. Ex. NWE-5, p. 9. FERC's Order 2006 defines the interconnection process for generators 20 MW or smaller. Pursuant to Small Generator Interconnection Procedures (SGIP) NWE studies how connecting a new electric generator at a particular place on its transmission system will affect system reliability, given existing generators and other

proposed new generators that may also connect to the system. *Id.*, pp. 4, 7. The SGIP also governs how NWE allocates responsibility for the cost of any system upgrades made to ensure system reliability when the new generator(s) connect to the transmission system. Under the SGIP, a new generator must initially fund any system upgrades for which it is responsible, but NWE refunds the generator with interest over time through transmission service rate credits after the generator is online and taking transmission service. *Id.*, pp. 15-16. This feature of the SGIP makes the generator economically indifferent to the cost of any system upgrades it causes so long as FERC's interest rate equals the generator's borrowing cost. DR PSC-008. In adopting this feature of its generator interconnection policy FERC recognized that it may not be economically efficient:

> …as many point out, providing transmission service credits to an Interconnection Customer for the cost of Network Upgrades that would not be needed but for the interconnection of the new Generating Facility mutes somewhat the Interconnection Customer's incentive to make an efficient siting decision that takes new transmission costs into account, and it provides the Interconnection Customer with what many view as an improper subsidy, particularly when the Interconnection Customer chooses to sell its output off-system.

Order No. 2003, p. 133, ¶ 695. However, in FERC's view, the cost of this potential inefficiency is outweighed by other goals it thinks are achieved with the refund policy: ensuring non-discriminatory access to and pricing for transmission services and enhancing competition in wholesale power markets by promoting construction of new generation. *Id.*, p. 133, ¶ 694.

82. In this case, NWE requested approval to apply FERC's SGIP to QF projects, asserting that applying the same interconnection procedures to QF and non-QF generators is fair, efficient (in a productive sense, see Tr. pp. 332-333), and non-discriminatory. Ex. NWE-5, pp. 4-7. No party objected to NWE's proposal to apply FERC's SGIP to QFs. MSIRG Br. p. 26, NWE Reply Br. p. 17. MSIRG, while agreeing that the SGIP is reasonable, contended that in practice NWE discriminates against QFs, citing differences in how NWE studied the Kenfield Wind project (see Docket No. D2010.2.18) and the Spion Kop project.

83. NWE's witness Stauffer criticized the PSC's decision in Order No. 7068b requiring NWE to pay the network upgrade costs associated with the QF at issue in that case. He contended that the decision, if applied broadly, would remove project location and related system

upgrade costs from the set of variables QFs must consider in determining a project's economic viability. Ex. NWE-2, p. 8. He contended that the approach violates consumer indifference because it would treat two QFs with different transmission upgrade costs the same even though ratepayers are not indifferent between the two. He also asserted that the approach is not consistent with how NWE would evaluate non-QF projects. *Id*., p. 9. However, NWE did not explain how transmission location and system upgrade costs influenced its evaluation of bids in its 2009 RFI, other than to say it generally considered them. DR PSC-002, Tr. pp. 78-80, 195-196. Furthermore, NWE's preferred approach, FERC's SGIP, results in the same economic concerns.

84. In Docket No. D2010.2.18 NWE improperly sought to assign *all* network upgrade costs to the QF instead of the amount of those costs that exceeded what NWE otherwise would incur to connect its avoidable resource. In this case, NWE still has not quantified network upgrade costs for an avoidable resource or proposed some proxy. That is not surprising given that NWE has not refined any of the various possible resource additions it identified in its 2009 resource plan to the point where interconnection costs are quantifiable. Nevertheless, without an estimate of network upgrade costs for NWE's avoidable resources it is not possible to apply ARM 38.5.1904.

85. The Commission approves NWE's request to apply FERC's SGIP to QFs. However, ARM 38.5.1904 and the SGIP are not mutually exclusive and NWE should explore options for applying the PSC's rule in the context of the SGIP because it may provide QFs superior economic incentives regarding project siting and viability and reduce the total cost of service.

CONCLUSIONS OF LAW

1. The Commission has provided adequate and proper public notice of all proceedings, and an opportunity to be heard to all interested parties in this docket. § 69-3-104, MCA.

2. The Commission supervises, regulates, and controls public utilities pursuant to Title 69, Chapter 3, MCA. § 69-3-102, MCA.

3. The Commission implements and enforces the provisions of the Public Utility Regulatory Policies Act. 16 U.S.C. § 824a-3(f).

4. NWE is a public utility subject to the jurisdiction of the Commission. § 69-3-101, MCA.

5. The rates for purchases provided by this order are just and reasonable to the electric consumers of NWE and do not discriminate against QFs. 16 U.S.C. § 824a-3(b).

6. Any conclusions of law that are properly findings of fact are hereby adopted as such.

ORDER

IT IS HEREBY ORDERED that NWE shall comply with the determinations and directives of the PSC set forth in this final order. NWE shall file tariffs reflecting the determinations and directives of this final order.

Done and dated this the 13th day of October 2011 by a vote of 4 to 0, with Commissioner Molnar abstaining.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION

TRAVIS KAVULLA, Chairman

GAIL GUTSCHE, Vice Chair

W. A. GALLAGHER, Commissioner

JOHN VINCENT, Commissioner

ATTEST:

Aleisha Solem
Commission Secretary

(SEAL)

NOTE: Any interested party may request the Commission to reconsider this decision. A motion to reconsider must be filed within ten (10) days. See 38.2.4806, ARM.