DEPARTMENT OF ENERGY

Western Area Power Administration

Pick-Sloan Missouri Basin Program—Eastern Division—Rate Order No. WAPA–135

AGENCY: Western Area Power Administration, DOE.

ACTION: Notice of Order Concerning Power Rates.

SUMMARY: The Deputy Secretary of Energy confirmed and approved Rate Order No. WAPA–135 and Rate Schedules P–SED–F9 and P–SED–FP9, placing firm power and firm peaking power rates from the Pick-Sloan Missouri Basin Program—Eastern Division (P–SMBP—ED) of the Western Area Power Administration (Western) into effect on an interim basis. The provisional rates will be in effect until the Federal Energy Regulatory Commission (FERC) confirms, approves, and places them into effect on a final basis or until they are replaced by other rates. The provisional rates will provide sufficient revenue to pay all annual costs, including interest expense, and repay power investment and irrigation aid within the allowable periods.

DATES: Rate Schedules P–SED–F9 and P–SED–FP9 will be placed into effect on an interim basis on the first day of the first full billing period beginning on or after January 1, 2008, and will be in effect until FERC confirms, approves, and places the rate schedules in effect on a final basis ending December 31, 2012, or until the rate schedules are superseded.

FOR FURTHER INFORMATION CONTACT: Mr. Robert J. Harris, Regional Manager, Upper Great Plains Region, Western Area Power Administration, 2900 4th Avenue North, Billings, MT 59101–1266, telephone (406) 247–7405, e-mail *rharris@wapa.gov*, or Mr. Jon R. Horst, Rates Manager, Upper Great Plains Region, Western Area Power Administration, 2900 4th Avenue North, Billings, MT 59101–1266, telephone (406) 247–7444, e-mail *horst@wapa.gov*.

SUPPLEMENTARY INFORMATION: The Deputy Secretary of Energy approved existing Rate Schedules P–SED–F8 and P–SED–FP8 for firm and firm peaking electric service on an interim basis on November 9, 2005.[1] The existing rate schedules are effective from January 1, 2006, through December 31, 2010.

The P–SMBP—ED firm power and firm peaking power rates must be increased due to the economic impact of the drought, increased operation and maintenance and other annual expenses, increased investments, and increased interest expense associated with drought induced deficits. Additionally, under Rate Schedules P–SED–F9 and P–SED–FP9, Western will identify its firm electric and firm peaking service revenue requirements using a Base component (Base) and a Drought Adder component (Drought Adder). Under Rate Schedule P–SED–F9, Western will also eliminate the tiered rate in P–SMBP—ED.

The existing firm electric service Rate Schedules P–SED–F8 and P–SED–FP8 are being superseded by Rate Schedules P–SED–F9 and P–SED–FP9. Under current Rate Schedules P–SED–F8 and P–SED–FP8, a two-step method was approved. The composite rate for the second step of Rate Schedules P–SED–F8 and P–SED–FP8, effective on January 1, 2007, is 19.54 mills per kilowatt hour (mills/kWh), the firm energy rate is 11.29 mills/kWh, the firm capacity rate is $4.45 per kilowatt month (kWmonth) and the firm peaking capacity rate is $4.45 per kWmonth. Under Rate Schedule P–SED–F9, the provisional rates for firm electric services will result in a combined composite rate of 24.49 mills/kWh. The energy rate will be 13.99 mills/kWh (a Base component of 8.93 mills/kWh and a Drought Adder component of 5.06 mills/kWh) and the capacity rate will be $5.65 kWmonth (a Base component of $3.65/kWmonth and a Drought Adder component of $2.00/kWmonth). This will result in an increase of 25.3 percent when compared with the existing firm power rate under Rate Schedule P–SED–F8. Under Rate Schedule P–SED–FP9 the provisional

[1] Rate Order No. WAPA–125, November 9, 2005 (70 FR 71280). It was confirmed and approved by FERC on a final basis on June 14, 2006, in Docket No. EF06–5181–000 (115 FERC ¶ 62276).

rates for firm peaking power consist of a capacity charge of $5.10 per kWmonth and an energy charge of 13.99 mills/kWh, effective on January 1, 2008. This will result in an increase of 14.6 percent when compared with the existing firm peaking power rate under Rate Schedule P–SED–FP8.

By Delegation Order No. 00–037.00, effective December 6, 2001, the Secretary of Energy delegated: (1) The authority to develop power and transmission rates to Western's Administrator; (2) the authority to confirm, approve, and place such rates into effect on an interim basis to the Deputy Secretary of Energy; and (3) the authority to confirm, approve, and place into effect on a final basis, to remand or to disapprove such rates to FERC. Existing DOE procedures for public participation in power rate adjustments (10 CFR part 903) were published on September 18, 1985.

Under Delegation Order Nos. 00–037.00 and 00–001.00C, 10 CFR part 903, and 18 CFR part 300, I hereby confirm, approve, and place Rate Order No. WAPA–135, the proposed P–SMBP—ED firm power and firm peaking power rates, into effect on an interim basis. The new Rate Schedules P–SED–F9 and P–SED–FP9 will be promptly submitted to FERC for confirmation and approval on a final basis.

Dated: November 1, 2007.

Clay Sell,

Deputy Secretary of Energy.

Department of Energy, Deputy Secretary

[Rate Order No. WAPA–135]

In the matter of: Western Area Power Administration Rate Adjustment for the Pick-Sloan Missouri Basin Program—Eastern Division

Order Confirming, Approving, and Placing the Pick-Sloan Missouri Basin Program—Eastern Division Firm Power and Firm Peaking Power Service Rates Into Effect on an Interim Basis

These rates for the Pick-Sloan Missouri Basin Program—Eastern Division were established in accordance with section 302 of the Department of Energy (DOE) Organization Act (42 U.S.C. 7152). This Act transferred to and vested in the Secretary of Energy the power marketing functions of the Secretary of the Department of the Interior and the Bureau of Reclamation under the Reclamation Act of 1902 (ch. 1093, 32 Stat. 388), as amended and supplemented by subsequent laws, particularly section 9(c) of the Reclamation Project Act of 1939 (43 U.S.C. 485h(c)) and section 5 of the Flood Control Act of 1944 (16 U.S.C. 825s) and other Acts that specifically apply to the project involved.

By Delegation Order No. 00–037.00, effective December 6, 2001, the Secretary of Energy delegated: (1) The authority to develop power and transmission rates to Western's Administrator; (2) the authority to confirm, approve, and place such rates into effect on an interim basis to the Deputy Secretary of Energy; and (3) the authority to confirm, approve, and place into effect on a final basis, to remand or to disapprove such rates to FERC. Existing DOE procedures for public participation in power rate adjustments (10 CFR part 903) were published on September 18, 1985.

Acronyms and Definitions

As used in this Rate Order, the following acronyms and definitions apply:

Administrator: The Administrator of the Western Area Power Administration.

Base: Revenue requirement component of the power rate including annual operation and maintenance expenses, investment repayment and associated interest, normal timing power purchases, and transmission costs.

Capacity: The electric capability of a generator, transformer, transmission circuit, or other equipment. It is expressed in kilowatts.

Capacity Charge: The rate which sets forth the charges for capacity. It is expressed in dollars per kWmonth.

Composite Rate: The rate for commercial firm power which is the total annual revenue requirement for capacity and energy divided by the total annual energy sales. It is expressed in mills per kilowatthour and used for comparison purposes.

Corps: United States Army Corps of Engineers.

CROD: Contract rate of delivery. The maximum amount of capacity made available to a preference customer for a period specified under a contract.

Customer: An entity with a contract that is receiving service from Western's Upper Great Plains Region.

Deficits: Deferred or unrecovered annual expenses.

DOE: United States Department of Energy.

DOE Order RA 6120.2: An order outlining power marketing administration financial reporting and rate-making procedures.

Drought Adder: Formula based revenue requirement component including costs associated with the drought.

Energy: Measured in terms of the work it is capable of doing over a period of time. It is expressed in kilowatthours.

Energy Charge: The rate which sets forth the charges for energy. It is expressed in mills per kilowatthour and applied to each kilowatthour delivered to each customer.

FERC: Federal Energy Regulatory Commission.

Firm: A type of product and/or service available at the time requested by the customer.

FRN: **Federal Register** notice.

Fry-Ark: Fryingpan-Arkansas Project.

FY: Fiscal year; October 1 to September 30.

kW: Kilowatt—the electrical unit of capacity that equals 1,000 watts.

kWh: Kilowatthour—the electrical unit of energy that equals 1,000 watts in 1 hour.

kWmonth: Kilowattmonth—the electrical unit of the monthly amount of capacity.

LAP: Loveland Area Projects.

Load Factor: The ratio of average load in kW supplied during a designated period to the peak or maximum load in kW occurring in that period.

mills/kWh: Mills per kilowatthour—the unit of charge for energy (equal to one tenth of a cent or one thousandth of a dollar.)

MW: Megawatt—the electrical unit of capacity that equals 1 million watts or 1,000 kilowatts.

NEPA: National Environmental Policy Act of 1969 (42 U.S.C. 4321, *et seq.*).

Non-timing Power Purchases: Power purchases that are not related to operational constraints such as management of endangered species, species habitat, water quality, navigation, control area purposes, etc.

O&M: Operation and Maintenance.

P–SMBP: The Pick-Sloan Missouri Basin Program.

P–SMBP—ED: Pick-Sloan Missouri Basin Program—Eastern Division.

P–SMBP—WD: Pick-Sloan Missouri Basin Program—Western Division.

Power: Capacity and energy.

Power Factor: The ratio of real to apparent power at any given point and time in an electrical circuit. Generally it is expressed as a percentage ratio.

Preference: The requirements of Reclamation Law which provide that preference in the sale of Federal power shall be given to municipalities and other public corporations or agencies and also to cooperatives and other nonprofit organizations financed in whole or in part by loans made under the Rural Electrification Act of 1936 (Reclamation Project Act of 1939, section 9(c), 43 U.S.C. 485h(c)).

Provisional Rate: A rate which has been confirmed, approved and placed into

effect on an interim basis by the Deputy Secretary.

PRS: Power Repayment Study.

Rate Brochure: A June 2007 document explaining the rationale and background for the rate proposal contained in this Rate Order.

Reclamation: United States Department of the Interior, Bureau of Reclamation.

Reclamation Law: A series of Federal laws. Viewed as a whole, these laws create the originating framework under which Western markets power.

Revenue Requirement: The revenue required to recover annual expenses (such as O&M, purchase power, transmission service expenses, interest and deferred expenses) and repay Federal investments and other assigned costs.

RMR: The Rocky Mountain Customer Service Region of Western.

Timing Power Purchases: Power purchases that are due to operational constraints (e.g. management of endangered species, species habitat, water quality, navigation, control area purposes, etc.) and not associated with the drought.

UGPR: The Upper Great Plains Customer Service Region of Western.

Western: United States Department of Energy, Western Area Power Administration.

Effective Date

The new provisional rates will take effect on the first day of the first full billing period beginning on or after January 1, 2008, and will remain in effect until December 31, 2012, pending approval by FERC on a final basis.

Public Notice and Comment

Western followed the Procedures for Public Participation in Power and Transmission Rate Adjustments and Extensions, 10 CFR part 903, in developing these rates. The steps Western took to involve interested parties in the rate process were:

1. The proposed rate adjustment process began March 15, 2007, when Western's UGPR mailed a notice announcing informal customer meetings to all P–SMBP—ED preference customers and interested parties. The informal meetings were held on April 9, 2007, in Denver, Colorado, and on April 10, 2007, in Sioux Falls, South Dakota. At these informal meetings, Western explained the rationale for the rate adjustment, presented rate designs and methodologies, and answered questions.

2. An FRN was published on May 31, 2007 (72 FR 30372), that announced the proposed rates for P–SMBP—ED, began a public consultation and comment period, and announced the public information and public comment forums.

3. On June 1, 2007, Western's UGPR mailed letters to all P–SMBP—ED preference customers and interested parties transmitting the FRN published on May 31, 2007.

4. On June 18, 2007, beginning at 10 a.m. (MDT), Western held a public information forum at the Radisson Stapleton Plaza in Denver, Colorado. On June 19, 2007, beginning at 9 a.m. (CDT), a second public information forum was held at the Holiday Inn in Sioux Falls, South Dakota. Western provided detailed explanations of the proposed rates for P–SMBP—ED, and a list of issues that could change the proposed rates. Western also answered questions and gave notice that more information was available in the rate brochure.

5. On July 23, 2007, beginning at 10 a.m. (MDT), Western held a public comment forum at the Radisson Stapleton Plaza in Denver, Colorado, to give the public an opportunity to comment for the record. No oral or written comments were received at this forum. On July 24, 2007, beginning at 9 a.m. (CDT), a second public comment forum was held at the Holiday Inn in Sioux Falls, South Dakota, to give the public an opportunity to comment for the record. No oral or written comments were received at this forum.

6. Western's UGPR provided a Web site with all of the letters, time frames, dates and locations of forums, documents discussed at the information meetings, FRNs, rate brochure, and all other information about this rate process for easy customer access. The Web site is located at *http://www.wapa.gov/ugp/rates/2008FirmRateAdjust*.

7. Western received 25 comment letters during the consultation and comment period, which ended August 29, 2007. All formally submitted comments have been considered in preparing this Rate Order.

Comments

Written comments were received from the following organizations:

City of Gering, Nebraska.
City of Wisner, Nebraska.
Central Power Electric Cooperative, Inc., North Dakota.
Corn Belt Power Cooperative, Iowa.
East River Electric Power Cooperative, South Dakota.
Federated Rural Electric, Minnesota.
Heartland Consumers Power District, South Dakota.
Lincoln Electric System, Nebraska.
Lower Yellowstone Rural Electric Cooperative, Montana.
Lyon-Lincoln Electric Cooperative, Minnesota.
Marshall Municipal Utilities, Minnesota.
Mid-West Electric Consumers Association, Colorado.
Minnkota Power Cooperative, Inc., North Dakota.
Montana Electric Cooperatives' Association, Montana.
Municipal Energy Agency of Nebraska, Nebraska.
Nebraska Public Power District, Nebraska.
Northwest Iowa Power Cooperative, Iowa.
Renville Sibley Cooperative Power Association, Minnesota.
Rosebud Electric Cooperative, South Dakota.
Sioux Valley Energy, South Dakota.
Sisseton-Wahpeton Oyate, Lake Traverse Reservation, South Dakota.
South Dakota Rural Electric Association, South Dakota.
Town of Julesburg, Colorado.
Verendrye Electric Cooperative, North Dakota.
Woodbury Rural Electric Cooperative, Iowa.

Project Description

The P–SMBP was authorized by Congress in section 9 of the Flood Control Act of December 22, 1944, commonly referred to as the 1944 Flood Control Act. This multipurpose program provides flood control, irrigation, navigation, recreation, preservation and enhancement of fish and wildlife, and power generation. Multipurpose projects have been developed on the Missouri River and its tributaries in Colorado, Montana, Nebraska, North Dakota, South Dakota and Wyoming.

In addition to the multipurpose water projects authorized by section 9 of the Flood Control Act of 1944, certain other existing projects have been integrated with the P–SMBP for power marketing, operation and repayment purposes. The Colorado-Big Thompson, Kendrick, and Shoshone Projects were combined with the P–SMBP in 1954, followed by the North Platte Project in 1959. These projects are referred to as the "Integrated Projects" of the P–SMBP.

The Flood Control Act of 1944 also authorized the inclusion of the Fort Peck Project with the P–SMBP for operation and repayment purposes. The Riverton Project was integrated with the P–SMBP in 1954, and in 1970 was reauthorized as a unit of P–SMBP.

The P–SMBP is administered by two regions. The UGPR with a regional office in Billings, Montana, markets power from the Eastern Division of P–SMBP, and the RMR with a regional

office in Loveland, Colorado, markets the Western Division power of P–SMBP. The UGPR markets power in western Iowa, western Minnesota, Montana east of the Continental Divide, North Dakota, South Dakota, and the eastern two-thirds of Nebraska. The RMR markets P–SMBP—WD power, which in combination with Fry-Ark power is known as LAP power, in northeastern Colorado, east of the Continental Divide in Wyoming, west of the 101st meridian in Nebraska, and most of Kansas. The P–SMBP power is marketed to approximately 300 firm power customers by the UGPR and approximately 40 firm power customers by the RMR.

Power Repayment Study—Firm Power Rate

Western prepares a PRS each FY to determine if revenues will be sufficient to repay, within the required time, all costs assigned to the P–SMBP. Repayment criteria are based on law, policies including DOE Order RA 6120.2, and authorizing legislation. To meet cost recovery criteria outlined in DOE Order RA 6120.2, a revised study and rate adjustment has been developed to demonstrate that sufficient revenues will be collected under proposed rates to meet future obligations.

Under this adjustment, payments toward irrigation assistance and capital debt are necessary before deficits are completely repaid. Traditionally, prepayment of irrigation assistance or capital is only done in the absence of deficits. However, if all revenue were applied toward deficits prior to making any payments for irrigation and other capital requirements, an extraordinarily large rate increase to meet single-year repayment obligations would be required. Once these single-year repayment obligations were satisfied, another rate adjustment would be necessary to decrease the rates. While repayment of capital debt and irrigation assistance prior to complete repayment of deficits is not typical, the approach approved within this Rate Order is well within the bounds of the discretion allowed under DOE Order RA 6120.2.

Under the adjustment in power rate schedules P–SED–F9 and P–SED–FP9, Western will repay deficits and also make previously planned payments for irrigation assistance and other investments that are due within the required repayment period. Prepaying irrigation and capital investments has been part of the P–SMBP repayment plans and approved rate adjustments for the past 20 years. Prepayment is an integral part of the long-term plan for the project and has provided rate stability for consumers while meeting Federal repayment obligations. Modest irrigation and investment payments for a brief period of 2 to 3 years will reduce the single-year revenue requirement for irrigation assistance and hold increases to the "lowest possible rates to consumers consistent with sound business principles," as outlined in section 5 of the Flood Control Act of 1944.

Existing and Provisional Rates

A comparison of the existing and provisional firm power and firm peaking power rates follow:

Comparison of Existing and Provisional Rates

PICK-SLOAN MISSOURI BASIN PROGRAM—EASTERN DIVISION

Firm electric service	Existing rates effective January 1, 2007	Provisional rates effective January 1, 2008	Percent change
P–SMBP—ED Revenue Requirement	$189.9 million	$235.9 million	24.2
P–SMBP—ED Composite Rate	19.54 mills/kWh	24.49 mills/kWh	25.3
Firm Capacity	$4.45/kWmonth	$5.65/kWmonth	27.0
Firm Energy	11.29 mills/kWh	13.99 mills/kWh	23.9
Tiered > 60 Percent Load Factor	5.21 mills/kWh	Eliminated	N/A
Firm Peaking Capacity	$4.45/kWmonth	$5.10/kWmonth	14.6
Firm Peaking Energy [1]	11.29 mills/kWh	13.99 mills/kWh	23.9

[1] Firm Peaking Energy is normally returned. This rate will be assessed in the event Firm Peaking Energy is not returned.

Western Division

The LAP rate is designed to recover the P–SMBP—WD revenue requirement for the P–SMBP and the revenue requirement for Fry-Ark. The adjustment to the LAP rate is a separate formal rate process which is documented in Rate Order No. WAPA–134. Rate Order No. WAPA–134 is also scheduled to go into effect on the first day of the first full billing period beginning on January 1, 2008.

Certification of Rates

Western's Administrator certified that the provisional rates for P–SMBP—ED firm power and firm peaking power rates are the lowest possible rates consistent with sound business principles. The provisional rates were developed following administrative policies and applicable laws.

P–SMBP—ED Firm Power Rate Discussion

According to Reclamation Law, Western must establish power rates sufficient to recover operation, maintenance, purchased power and interest expenses, and repay power investment and irrigation aid.

The P–SMBP—ED firm power and firm peaking power rates must be increased due to the economic impact of the drought, increased O&M and other annual expenses, increased investments, and increased interest expense associated with deficits.

The existing rates for P–SMBP—ED firm power and firm peaking power under Rate Schedules P–SED–F8 and P–SED–FP8 expire December 31, 2010. Effective January 1, 2008, Rate Schedules P–SED–F8 and P–SED–FP8 will be superseded by the new rates in Rate Schedule P–SED–F9 and Rate Schedule P–SED–FP9. The provisional rates under P–SED–F9 for firm power consist of a capacity charge of $5.65/kWmonth, and an energy charge of 13.99 mills/kWh. The provisional rates under P–SED–FP9 for firm peaking power consist of a capacity of $5.10/kWmonth, and an energy charge of 13.99 mills/kWh. These rates are comprised of Base and Drought Adder components.

Additionally, under Rate Schedules P–SED–F9 and P–SED–FP9, Western will identify its firm and firm peaking electric service revenue requirements using Base and Drought Adder components. The Base is a revenue requirement that includes annual O&M expenses, investment repayment and associated interest, normal timing power purchases, and transmission costs. Normal timing power purchases are purchases due to operational constraints (e.g., management of endangered species habitat, water

quality, navigation, control area purposes, etc.) and are not associated with the current drought in the region. The Base revenue requirement may not be adjusted without Western going through a public process to do so.

The Drought Adder revenue requirement is a formula-based revenue requirement that includes costs attributable to the present drought conditions within the P–SMBP. The Drought Adder includes costs associated with future non-timing power purchases of additional power to firm obligations not covered with available system generation due to the drought, previously incurred deficits due to purchased power debt incurred from non-timing power purchases made during this drought, and the interest associated with previously incurred and future drought debt. The Drought Adder is designed to repay drought debt within 10 years of the year the debt was incurred. Adjustments to the Drought Adder of less than or equal to the equivalent of 2 mills/kWh to the PRS composite rate will be made by customer notification of a revised rate schedule with a January implementation date.

The annual revenue requirement calculation can be summarized by the following formula: Annual Revenue Requirement = Base Revenue Requirement + Drought Adder Revenue Requirement. Under this provisional rate, the P–SMBP—ED annual revenue requirement equals $245.2 million and is comprised of a Base revenue requirement of $157.2 million plus a Drought Adder revenue requirement of $88.0 million. Both the Base and the Drought Adder recover portions of the firm power revenue requirement, which when combined with the firm peaking power revenue requirement equals the P–SMBP—ED annual revenue requirement.

Below is a table identifying the rates for the revenue requirement components:

Service	Base component	Drought adder component	Rates
Firm Capacity ($/kWmonth)	$3.65	$2.00	$5.65
Firm Energy (mills/kWh)	8.93	5.06	13.99
Firm Peaking Capacity ($/kWmonth)	$3.25	$1.85	$5.10
Firm Peaking Energy (mills/kWh) [1]	8.93	5.06	13.99

[1] Firm Peaking Energy is normally returned. This rate will be assessed in the event Firm Peaking Energy is not returned.

Western reviews its firm electric service rates annually. Western will review the Base after the annual PRS is completed, generally in the first quarter of the calendar year. If an adjustment to the Base is necessary, Western will initiate a public process pursuant to 10 CFR part 903 prior to making an adjustment.

Western will review the Drought Adder each September to determine if drought costs differ from those projected in the PRS and whether an adjustment to the Drought Adder is necessary. Western will use recent Corps of Engineers and Bureau of Reclamation hydrological estimates and historical data to determine the estimated amounts for future purchase power costs. For any adjustments attributed to drought costs of less than or equal to the equivalent of 2 mills/kWh to the PRS composite rate, Western will notify customers by letter in October of the planned adjustment and implement the adjustment in the following January billing cycle. For the portion of any planned incremental adjustment greater than the equivalent of 2 mills/kWh to the PRS composite rate, Western will engage in a public process pursuant to 10 CFR part 903 prior to implementing that portion of the adjustment. Although decremental adjustments to the Drought Adder may occur, the adjustment cannot result in the Drought Adder being a negative number. Western will conduct a preliminary review of the Drought Adder in early summer and advise customers by letter of any estimated change to the Drought Adder for the following January. Customers will also be notified by letter in October of the final Drought Adder adjustment to be effective with the following January billing period.

Western has also redesigned its revenue recovery methodology for firm peaking service. Under Rate Schedule P–SED–FP9, the firm peaking demand charge is calculated by dividing one-half of the P–SMBP—ED revenue requirement by the sum of the total allocated seasonal CRODs modeled as monthly billing units for both firm electric and firm peaking service.

Statement of Revenue and Related Expenses

The following table provides a summary of projected revenue and expense data for the total P–SMBP, including both the Eastern and Western Divisions, firm electric service revenue requirement through the 5-year rate approval period. The firm power rates for both divisions have been developed with the following revenues and expenses for the P–SMBP:

TOTAL P–SMBP FIRM POWER COMPARISON OF 5-YEAR RATE PERIOD (FY 2008–2012)

	Existing rate ($000)	Proposed rate ($000)	Difference ($000) Total revenues and expenses
Total Revenues	$1,723,061	$2,127,445	$404,384
Revenue Distribution			
Expenses:			
O&M	829,319	910,948	81,629
Purchased Power and Wheeling	84,040	290,654	206,614
Integrated Projects Requirements	0	0	0
Interest	499,116	530,912	31,796
Transmission	58,956	60,856	1,900

TOTAL P–SMBP FIRM POWER COMPARISON OF 5-YEAR RATE PERIOD (FY 2008–2012)—Continued

	Existing rate ($000)	Proposed rate ($000)	Difference ($000) Total revenues and expenses
Total Expenses	1,471,431	1,793,370	321,939
Principal Payments:			
Capitalized Expenses	218,819	127,958	(90,861)
Original Project and Additions	26,392	188,898	162,506
Replacements	2,019	2,219	200
Irrigation	4,400	15,000	10,600
Total Principal Payments	251,630	334,075	82,445
Total Revenue Distribution	1,723,061	2,127,445	404,384

Basis for Rate Development

The existing rates for P–SMBP—ED firm power in Rate Schedule P–SED–F8, which expire December 31, 2010, no longer provide sufficient revenues to pay all annual costs, including interest expense, and repay investment and irrigation aid within the allowable period. The adjusted rates reflect increases due to the economic impact of the drought, increased O&M and other annual expenses, increased investments, and increased interest expense associated with drought deficits. The provisional rates will provide sufficient revenue to pay all annual costs, including interest expense, and repay power investment and irrigation aid within the allowable periods. The provisional rates will take effect on January 1, 2008, to correspond with the start of the calendar year, and will remain in effect on an interim basis, pending FERC's confirmation and approval of them or substitute rates on a final basis, through December 31, 2012.

The P–SMBP—ED provisional firm power rate under rate schedule P–SED–F9 is designed to recover 50 percent of the revenue requirement from the capacity rate and 50 percent from the energy rate. The firm capacity rate of $5.65 per kWmonth is calculated by dividing 50 percent of the total annual revenue by the total firm power billing units (kWmonths) in a year. The firm energy rate of 13.99 mills/kWh is calculated by dividing 50 percent of the total annual revenue requirement by the annual energy sales.

Historically, the P–SMBP—ED firm peaking rate has been equal to the demand charge for the firm power rate. The customer pays the demand rate on their total firm peaking CROD each month rather than firm energy peaking delivered each month. Contract terms vary among firm peaking customers with respect to return of peaking energy. One customer may return all peaking energy, while another peaking customer may pay for 20 to 40 percent of the peaking energy they use and return the rest to Western. When a peaking customer does not return peaking energy, they are billed at the firm energy rate.

Previously, Western used the sum of the metered billing units for firm electric service and the seasonal CROD modeled as monthly billing units for firm peaking service. Western is changing the methodology for the firm peaking rate design to use the sum of the total allocated seasonal CRODs for both firm electric demand and firm peaking demand modeled as billing units. Changing the methodology is consistent with the principle that Western's rate design for firm electric demand and firm peaking demand should be representative of the different products. The firm peaking rate under P–SED–FP9 is $5.10/kWmonth. The revenue requirement for firm peaking demand is calculated by multiplying the firm peaking power billing units per year (4,272,000 kWmonth/year) by the firm peaking demand rate yielding a firm peaking revenue requirement of $21.8 million.

With this rate adjustment, the P–SMBP—ED is also eliminating the tiered rate. The tiered rate charge was implemented in the mid-1970s for loads in excess of 60 percent monthly load factor. Continuing the tiered rate charge discourages load management. Moreover, eliminating the tiered rate from the P–SMBP—ED firm electric service schedule is consistent with the administration of firm electric service rates in the P–SMBP—WD, as well as all other Western regions, which do not assess a tiered rate charge.

Comments

The comments and responses below regarding the firm power and firm peaking power rates are paraphrased for brevity when not affecting the meaning of the statement(s). Direct quotes from comment letters are used for clarification when necessary.

A. *Comment:* Western received numerous comments that strongly supported Western's rate adjustment proposal. These comments support the establishment of a Drought Adder and Base component as it will ensure timely repayment of obligations to the Treasury while insulating the Base from inflation brought about by drought related costs. Comments expressed support for elimination of the tiered rate because it has penalized customers for making efficient use of renewable energy resources that do not contribute to global warming. Comments also supported the redesign of the peaking rate as it better reflects the value and limitations of the peaking product.

Response: Western appreciates customer support received for the rate adjustment proposal, including separation of the annual revenue requirement into a Base component and Drought Adder component, elimination of the tiered rate and redesign of the peaking rate.

B. *Comment:* Western received one comment opposed to the elimination of the tiered rate. "It appears to me to be a push put on by those systems with load management systems. They manage their peaks & thus buy more power in the over 60% load factor range. The systems that do not use load control helped pay for the load control systems of those that do & now they are asking us to pay again."

Response: P–SMBP—ED customers that have load management systems in place have paid for those systems themselves. Western has not recovered costs for load management systems of others nor has Western passed those costs on to customers that do not have load management systems. Western

does not charge a tiered rate in the P–SMBP—WD nor in any other projects marketed by Western. Western endeavors to treat customers fairly and we believe penalizing customers for efficient management is unjust. Furthermore, penalizing customers for managing the load on their power system is unreasonable in an era when use of renewable energy is at the forefront of efficient energy management.

C. *Comment:* Western received one comment opposed to the proposed firm peaking capacity rate and the proposed peaking energy charge. The percentage increase for the firm peaking capacity is only 14.6% compared to the 25.3% increase in firm power. The peaking energy charge of 13.99 mills/kWh seems low.

Response: Those customers who have peaking capacity pay for the service each month of the season for which they have a CROD whether they are allowed to use the capacity under the contract terms or not. Typically, peaking capacity is used one to four times annually by the peaking customers, thus paying monthly for a product they are not allowed to use. Western's new peaking rate is reflective of the peaking customer's historical usage and their impact on drought costs. Western believes we have treated both the firm and firm peaking customers equitably by separating the rate designs of the two products. This separation is demonstrated in the new peaking product rate design which better reflects the value and restrictions of the peaking product.

D. *Comment:* Western received numerous comments encouraging Western to include identification of the portion of the total rate which will be attributed to the Drought Adder and that such amount be identified in terms of both the energy and capacity rates.

Response: Western agrees with this request to identify the portion of the rate attributable to the Drought Adder and has identified both the Base component and Drought Adder component in energy and capacity rates in the firm and firm peaking rate schedules.

E. *Comment:* Western received several comments encouraging Western to keep preference customers informed throughout the year on the progress made in paying down the drought deficits and provide early and timely information to customers on any changes to the Drought Adder so customers can plan accordingly.

Response: Western intends to inform customers annually of the status of the drought costs and the repayment of those costs. It is Western's intention to include the most current hydrological and operations cost data into projections in the PRS as soon as they are available and will notify customers as soon as practical of any changes to the Drought Adder.

F. *Comment:* Many comments supported the increase in rates, recognizing Western's need to generate added revenue in order to meet its operations and repayment obligations due to pressure from the long-term drought affecting the Missouri River Basin.

Response: Western appreciates the customer support it has received for the rate adjustment proposal.

G. *Comment:* Western received one comment that the 25% rate increase for the area utilities should not decrease the Tribal benefits, rather the opposite should happen and Tribal benefits should increase due to the increased value of the hydro resource.

Response: Western does provide bill crediting of the Tribal benefits according to the composite rate for the P–SMBP—ED as provided in the Tribal contracts. Native American contractual arrangements do allow for the composite rate to be modified. Under this rate adjustment, the composite rate for P–SMBP—ED is increasing from 19.54 mills per kWh to 24.49 mills per kWh. Benefits to a Tribe are determined from the difference between the composite rate for Western and the composite rate of the power supplier the Tribe has designated. As Western's composite rate increases, it is likely that the composite rates for the Tribes designated power suppliers will increase as well, although such increase is not within the control of Western. (In addition, this comment pertains to contract administration and is outside the scope of this rate process.)

H. *Comment:* Two comments received expressed appreciation for Western's commitment to supply the full firm power allocation during this drought cycle. However, there is also concern that adequate long term purchase power arrangements have not been pursued by Western, leaving UGPR to continually rely on short-term, spot market energy purchases to meet its shortfall.

Response: Although this comment is not directly related to the proposed rate action and is outside the scope of this rate process, Western is actively addressing these issues as well as other options and evaluating them based on cost and benefit to Western's customers.

I. *Comment:* Commenters state that by relying on non-firm transmission for spot energy purchases, the likelihood of curtailments is increased. It is their understanding that a number of short-term purchases by Western have been curtailed, causing additional drought-related expenses as higher cost energy is generated or purchased to replace the curtailed purchases in real time.

Response: This comment is not directly related to the proposed rate action and is outside the scope of this rate process. However, Western is actively addressing these issues as well as other options and evaluating them based on cost and benefit to Western's customers.

J. *Comment:* Commenters state that one area of controllable cost that causes significant concern is the area of regional transmission. The commenters understand that UGPR is considering the logistics of participating in the Midwest Independent Transmission System Operator (MISO) and its Day Two Markets. Before pursuing such a radical departure from past practice, they suggest a thorough review of costs and benefits to all Western customers. If Western joins MISO, and other area transmission owners that also serve Western customers do not join, there could be significant seams issues. If there are benefits to participating in the Day Two Market, those benefits should flow to all Western customers, not just those that participate in joint dispatching arrangements inside the Integrated System.

Response: This comment is not directly related to the proposed rate action and is outside the scope of this rate process. However, Western is actively addressing these issues as well as other options and evaluating them based on cost and benefit to Western's customers.

Availability of Information

Information about this rate adjustment, including the PRS, comments, letters, memorandums and other supporting material made or kept by Western that was used to develop the provisional rates, is available for public review in the Upper Great Plains Regional Office, Western Area Power Administration, 2900 4th Avenue North, Billings, Montana.

Ratemaking Procedure Requirements

Environmental Compliance

In compliance with the National Environmental Policy Act of 1969 (NEPA) (42 U.S.C. 4321, *et seq.*); the Council on Environmental Quality Regulations for implementing NEPA (40 CFR parts 1500–1508); and DOE NEPA Implementing Procedures and Guidelines (10 CFR part 1021, Subpart D, App. B4.3), Western has determined that this action is categorically excluded

from preparing an environmental assessment or an environmental impact statement.

Determination Under Executive Order 12866

Western has an exemption from centralized regulatory review under Executive Order 12866; accordingly, no clearance of this notice by the Office of Management and Budget is required.

Submission to the Federal Energy Regulatory Commission

The provisional rates herein confirmed, approved, and placed into effect, together with supporting documents, will be submitted to FERC for confirmation and final approval.

Order

In view of the foregoing and under the authority delegated to me, I confirm and approve on an interim basis, effective January 1, 2008, Rate Schedules P–SED–F9 and P–SED–FP9 for the Pick-Sloan Missouri Basin Program—Eastern Division of the Western Area Power Administration. The rate schedules shall remain in effect on an interim basis, pending FERC's confirmation and approval of them or substitute rates on a final basis through December 31, 2012.

Dated: November 1, 2007.

Clay Sell,

Deputy Secretary of Energy.

Rate Schedule P–SED–F9
(Supersedes Schedule P–SED–F8)
Effective January 1, 2008

United States Department of Energy, Western Area Power Administration

Pick-Sloan Missouri Basin Program—Eastern Division, Montana, North Dakota, South Dakota, Minnesota, Iowa, Nebraska

Schedule of Rates for Firm Power Service (Approved Under Rate Order No. WAPA–135)

Effective: The first day of the first full billing period beginning on or after January 1, 2008, through December 31, 2012.

Available: Within the marketing area served by the Eastern Division of the Pick-Sloan Missouri Basin Program.

Applicable: To the power and energy delivered to customers as firm power service.

Character: Alternating current, 60 hertz, three phase, delivered and metered at the voltages and points established by contract.

Monthly Rates:

Demand Charge: $5.65 for each kilowatt per month (kWmonth) of billing demand.

Energy Charge: 13.99 mills per kilowatthour (kWh) for all energy delivered as firm power service.

Billing Demand: The billing demand will be as defined by the power sales contract.

Charge Components:

Base: A fixed revenue requirement that includes operation and maintenance expense, investments and replacements, interest on investments and replacements, normal timing purchase power costs (purchases due to operational constraints, not associated with drought), and transmission costs. The Base revenue requirement is $157.2 million.

$$\text{Base Demand} = \frac{50\% \times \text{Base Revenue Requirement}}{\text{Firm Metered Billing Units}} = \$3.65/\text{kWmonth}.$$

$$\text{Base Energy} = \frac{50\% \times \text{Base Revenue Requirement}}{\text{Annual Energy}} = 8.93 \text{ mills/kWh}.$$

Drought Adder: A formula-based revenue requirement that includes future purchase power expense excluding timing purchases, previous purchase power drought deficits, and interest on the purchase power drought deficits. For the period beginning January 2008, the Drought Adder revenue requirement is $88 million.

$$\text{Drought Adder Demand} = \frac{50\% \times \text{Drought Adder Revenue Requirement}}{\text{Firm Metered Billing Units}} = \$2.00/\text{kWmonth}.$$

$$\text{Drought Adder Energy} = \frac{50\% \times \text{Drought Adder Revenue Requirement}}{\text{Annual Energy}} = 5.06 \text{ mills/kWh}.$$

Process: Any proposed change to the Base component will require a public process.

The Drought Adder component may be adjusted annually using the above formula for any costs attributed to drought of less than or equal to the equivalent of 2 mills/kWh to the Power Repayment Study (PRS) composite rate. Any planned incremental adjustment to the Drought Adder component greater than the equivalent of 2 mills/kWh to the PRS composite rate will require a public process.

Adjustments:

For Drought Adder: Adjustments pursuant to the Drought Adder component will be documented in a revision to this rate schedule.

For Character and Conditions of Service: Customers who receive deliveries at transmission voltage may in some instances be eligible to receive a 5 percent discount on demand and energy charges when facilities are provided by the customer that results in a sufficient savings to Western to justify the discount. The determination of eligibility for receipt of the voltage discount shall be exclusively vested in Western.

For Billing of Unauthorized Overruns: For each billing period in which there is a contract violation involving an unauthorized overrun of the contractual firm power and/or energy obligations, such overrun shall be billed at 10 times the above rate.

For Power Factor: None. The customer will be required to maintain a power factor at the point of delivery between 95 percent lagging and 95 percent leading.

Rate Schedule P–SED–FP9
(Supersedes Schedule P–SED–FP8)
Effective January 1, 2008

United States Department of Energy, Western Area Power Administration

Pick-Sloan Missouri Basin Program—Eastern Division, Montana, North Dakota, South Dakota, Minnesota, Iowa, Nebraska

Schedule of Rates for Firm Peaking Power Service (Approved Under Rate Order No. WAPA–135)

Effective: The first day of the first full billing period beginning on or after January 1, 2008, through December 31, 2012.

Available: Within the marketing area served by the Eastern Division of the Pick-Sloan Missouri Basin Program, to customers

with generating resources enabling them to use firm peaking power service.

Applicable: To the power sold to customers as firm peaking power service.

Character: Alternating current, 60 hertz, three phase, delivered and metered at the voltages and points established by contract.

Monthly Rates:

Demand Charge: $5.10 for each kilowatt per month (kWmonth) of the effective contract rate of delivery for peaking power or the maximum amount scheduled, whichever is greater.

Energy Charge: 13.99 mills for each kilowatthour (kWh) for all energy scheduled for delivery without return.

Charge Components:

Base: A fixed revenue requirement that includes operation and maintenance expense, investment and replacements, normal timing purchase power costs (purchases due to operational constraints, not associated with drought), and transmission costs. The Base peaking revenue requirement is $13.9 million.

$$\text{Base Demand} = \frac{\text{Base Peaking Demand Revenue Requirement}}{\text{Peaking CROD Billing Units}} = \$3.25/\text{kWmonth}.$$

Energy [1]: = 8.93 mills/kWh.

Drought Adder: A formula-based revenue requirement that includes future purchase power above timing purchases, previous purchase power drought deficits, and interest on the purchase power drought deficits. For the period beginning January 2008, the Drought Adder peaking revenue requirement is $7.9 million.

$$\text{Drought Adder Demand} = \frac{\text{Drought Adder Peaking Demand Revenue Requirement}}{\text{Peaking CROD Billing Units}} = \$1.85/\text{kWmonth}.$$

Energy [1]: = 5.06 mills/kWh.

Process: Any proposed change to the Base component will require a public process.

The Drought Adder component may be adjusted annually using the above formula for any costs attributed to drought of less than or equal to the equivalent of 2 mills/kWh to the Power Repayment Study (PRS) composite rate. Any planned incremental adjustment to the Drought Adder component greater than the equivalent of 2 mills/kWh to the PRS composite rate will require a public process.

Billing Demand: The billing demand will be the greater of: (1) The highest 30-minute integrated demand measured during the month up to, but not in excess of, the delivery obligation under the power sales contract, or (2) the contract rate of delivery.

Adjustments:

For Drought Adder: Adjustments pursuant to the Drought Adder component will be documented in a revision to this rate schedule.

Billing for Unauthorized Overruns: For each billing period in which there is a contract violation involving an unauthorized overrun of the contractual obligation for peaking demand and/or energy, such overrun shall be billed at 10 times the above rate.

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BILLING CODE 6450–01–P

[1] Firm peaking energy is normally returned. This rate will be assessed in the event firm peaking