Service Date: July 19, 1982

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

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IN THE MATTER of Avoided Cost Based Rates for Public Utility Purchases from Qualifying Cogenerators and Small Power Producers.)	UTILITY DIVISION DOCKET NO. 81.2.15 ORDER NO. 4865c

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ORDER ON MONTANA POWER COMPANY'S
MOTION FOR RECONSIDERATION AND
FOR A STAY OF ORDER NO. 4865b

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FINDINGS OF FACT

BACKGROUND

1. Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) required the Federal Energy Regulatory Commission (FERC), as well as state regulatory authorities, to prescribe rules to encourage cogeneration and small power production (COG/SPP) including rules requiring electric utilities to purchase electric power from cogeneration and small power production facilities.

2. On May 4, 1981 the Commission adopted final rules governing purchases and sales between public utilities and qualifying small power production facilities.

3. The Commission's rules (ARM 38.5.1901 through 38.5.1908), pursuant to FERC regulations, provide the general obligations of the COG/SPP and the regulated electric utilities.

4. The Commission initiated Docket No. 81.2.15 on February 24, 1981. On January 4, 1982, the Commission issued Order No. 4865 setting forth the Commission's initial findings in this Docket.

5. On January 22, 1982, the three applicable electric utilities -- Montana-Dakota Utilities (MDU), Montana Power Company (MPC) and Pacific Power and Light (PP&L) each filed Petitions for Reconsideration and/or Clarification. On February 18, 1982, the Commission issued Order No. 4865a which addresses the Petitions.

6. By March 5, 1982, the utilities had submitted their original compliance tariffs. On March 12, 1982, the Commission had a working session where it approved on an interim basis the utilities' complying tariffs.

7. On June 21, 1982, the Commission issued Order No. 4865b; this order established final avoided cost tariffs for the three electric utilities.

8. On July 8, 1982, MPC filed a Motion For Reconsideration And For A Stay Of Order No. 4865b. The following findings contain the Commission's responses to the Company's requests in this Motion.

9. The fundamental issue in MPC's Motion is the methodology that should be used to compute variable "a", the annualized capital cost of a baseload generating plant. The Company's first three requests in Sections I and II and the fifth request in Section IV of the Company's Motion concern the issue.

10. These four requests, dealing with the appropriate method of computing variable "a", will be addressed first. The Company's remaining requests, which deal specifically with the resulting calculations, will be addressed individually.

11. The Company makes the following request:

> MPC requests the PSC reconsider the Order No. 4865b criticism of the MPC methodology utilized in calculating the February 25, 1982 COG/SPP Compliance tariffs and recognize the validity of the arguments for this methodology as they have previously been presented...
>
> MPC believes that if avoided cost is defined as the cost which leaves ratepayers unaffected by the purchase from a COG/SPP, and that if Colstrip #3 and #4 are to be the basis for determining avoided cost as required by Order No. 4865, then the actual expected cost of Colstrip #3 and #4 must be used. (Motion, pp. 3 & 4).

12. Although MPC is correct to equate avoided cost with "the cost which leaves ratepayers unaffected," the Commission maintains that the nominal historical cost stream (including AFUDC) associated with Colstrip #3 and #4 does not meet this criterion.

13. The ratepayer, in contract year 1982, is offered, at the margin, electricity generated by 1) traditional sources or

2) COG/SPP. The utility's cost of COG/SPP production is set, by definition, at the cost avoided in avoiding procurement of additional increments of traditional generation. The Commission has established (Order Nos. 4865 and 4865b) that the proper approach to arriving at the costs of "additional increments of traditional generation" in 1982 is to utilize the Colstrip project as a source of cost data. However, these historical cost data (including nominal AFUDC) must be converted into 1982 dollars by (de-)escalating the historical cost stream. Any value less (greater) than this value produces an avoided cost rate less (greater) than that associated with the increment of traditional generation and leaves the ratepayer affected -- the utility procures more (less) relatively higher (lower) cost increments of traditional generation than would otherwise be the case.

14. The Commission is resolute in its interpretation of avoided costs. As a result, the Commission finds the Company's method used in computing variable "a" to be incorrect. The Company's four requests centering around the methodology used to compute variable "a" (discussed in Finding No. 9 above) are denied.

15. In Section III of the Company's Motion, the Company requests the Commission to reconsider Finding of Fact Nos. 19 through 24, and accept the validity of MPC's methodology. MPC bases this request on the fact that it used the same analytic

method to compute the annualized cost of a combustion turbine (CT), as it did with Colstrip #3 and #4. The Commission acknowledges this inconsistency, but chooses not to request the Company to recompute the CT cost (variable b). The affect of this inconsistency is slight: 1) the ratio of long term energy to long term capacity is slightly altered and 2) the short term rate is slightly lower, apparently, than it would be otherwise. In the Company's next annual filing of proposed avoided cost tariffs (See Finding No. 36 of Order No. 4865), it will have an opportunity to correct this methodclogical inconsistency.

16. MPC requests that the Commission also reconsider the use of PP&L's escalation/de-escalation factors in Schedule B of Order No. 4865b, and allow the Company an opportunity to "utilize its own factors..." This request is denied. In the Company's next annual filing (June 1, 1983) the Company will have an opportunity to propose its own factors.

17. The Company provides two requests regarding the "ten percent adder" used in Schedule B of Order No. 4865b. Firstly, the Company questions the use of the factor which appears to escalate 1982 dollars into 1983 dollars and, secondly, the Company questions the magnitude (10%) of the adder in light of current estimates of 1982 inflation.

18. The Commission denies the requests. The 10 percent factor is used to convert December 31, 1981 dollars into

December 31, 1982 dollars. The latter date is midway through the July 1, 1982/June 30, 1983 contract year and consequently best serves as an estimate of contract year dollars. Regarding the second request, the Commission finds the issue relatively diminutive. The Company will have the opportunity to refine the factor in its next annual filing.

19. The Company's request to correct the arithmetic error in Schedule B of Order No. 4865b for the year 1976, is granted. The correct value is $3,755. The Company's complying submittal of tariff pages should reflect this correction.

20. In Section V of the Company's Motion, it is requested that the Commission stay the effectiveness of Order No. 4865b "until this Motion for Reconsideration is considered and these issues resolved." In the above findings, the issues are resolved and there exists no need to stay the effectiveness of Order No. 4865b. The Company's request is denied. The complying tariff pages shall be submitted within five working days of the date of this Order and will be effective upon approval.

CONCLUSIONS OF LAW

1. Montana Power Company is a public utility within the meaning of Montana law, Sections 69-3-101 and 69-3-601(3), MCA.

2. The Commission properly exercises jurisdiction over the rates and terms and conditions for the purchase of electricity by

public utilities from qualified cogenerators and small power producers. Sections 69-3-102, 69-3-103 and 69-3-603, MCA. Section 210, Pub. L. 97-617, 92 Stat. 3119 (1978).

3. The rates the Commission has directed the utilities to file are just and reasonable to Montana ratepayers as they reflect each utility's avoided energy and capacity costs.

4. The objective of encouraging cogeneration and small power production is promoted by the rates and terms and conditions established by this order.

ORDER

The Montana Power Company is to submit avoided cost tariffs within 5 working days of the date of this order; these tariffs will become effective upon approval.

DONE IN OPEN SESSION this 19 day of July, 1982, by a vote of 5 - 0 .

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION.

GORDON E. BOLLINGER, Chairman

JOHN B. DRISCOLL, Commissioner

HOWARD L. ELLIS, Commissioner

CLYDE JARVIS, Commissioner

THOMAS J. SCHNEIDER, Commissioner

ATTEST:

Madeline L. Cottrill
Commission Secretary

(SEAL)

NOTE: You may be entitled to judicial review of the final decision in this matter. If no Motion for Reconsideration is filed, judicial review may be obtained by filing a petition for review within thirty (30) days from the service of this order. If a Motion for Reconsideration is filed, a Commission order is final for purpose of appeal upon the entry of a ruling on that motion, or upon the passage of ten (10) days following the filing of that motion. cf. the Montana Administrative Procedure Act, esp. Sec. 2-4-702, MCA; and Commission Rules of Practice and Procedure, esp. 38.2.4806 ARM.

APPENDIX A

SUMMARY OF STANDARD TARIFF RATE SCHEDULES

At the option of the QF, energy and capacity is to be purchased at either 1) the Short-Term Schedule or 2) the Long-Term Schedule.

1) The Short-Term Schedule

- Availability: available to all QFs willing and able to sign the standard contract.

- Rates: all energy and capacity purchased is to be priced, at the option of the QF, at a) the Annual Average Rate or b) the Time Differentiated Rate.

  a) Annual Average Rate

     - X ¢/KWH for all KWH purchased, where X equals the annual average projection of short run incremental energy costs plus the aggregate capacity payment.

  b) Time Differentiated Rate (initially, at the option of the utility)

     - X_t ¢/KWH for all KWH purchased during time period t, where X equals the projection of short run incremental energy costs during each time period t plus the aggregate capacity payment allocated to each time period t based on hourly loss of load probability.

2) The Long-Term Schedule

- Availability: available to all QFs willing and able to sign the standard contract and a performance contract of duration not less than four years.

- Rates: all energy and contracted capacity is to be priced, at the option of the QF, at a) the Annual Average Rate or b) the Time Differentiated Rate.

  a) Annual Average Rate

i) Energy Payment

- X ¢/KWH for all KWH purchased, where X equals the annualized unit cost of owning and operating a baseload plant, less the annualized unit cost of owning a combustion turbine.

ii) Capacity Payment

- Y \$/KW(cf) for all contracted KW, where Y equals the annualized unit cost of a combustion turbine (from 2ai, above) and CF represents the negotiated expected or demonstrated QF plant capacity factor.

b) Time Differentiated Rate (initially, at the option of the utility)

i) Energy Payment

- X_t ¢/KWH for all KWH purchased during each time period t where X represents the annualized unit cost of owning and operating a baseload plant less the annualized unit cost of a combustion turbine, differentiated by time period t to reflect short run incremental energy cost variation.

ii) Capacity Payment

- Y_t \$/KW for all contracted KW delivered during each time period t, where Y equals the annualized unit cost of combustion turbine (from 2bi, above) differentiated by time period t to reflect the relative probability of capacity shortage in time period t.

APPENDIX B

SUMMARY OF SPECIFIC DIRECTION IN COSTING

- All values are to be inflated/discounted to reflect constant contract year dollars.
- Inflation is to reflect industry specific, regionalized real cost indices.
- Discounting is to reflect standard (e.g. DRI) projections of national general inflation.
- Variables and formulae are defined and an example provided, below.

Definition of Variables

λ = system lambda[1] (¢/KWH)

a = baseload capital cost[2] ($/KW)

b = combustion turbine capital cost[3] ($/KW)

c = baseload annual carrying charge[4] (%)

d = combustion turbine carrying charge[4] (%)

e = baseload fixed O&M[5] ($/KW)

f = combustion turbine fixed O&M[5] ($/KW)

g = line loss factor [6] (%)

h = coal cost[7] ($/ton)

i = coal fuel content[7] (BTU/lb)

j = baseload plant heat rate[8] (BTU/KWH)

k = baseload variable O&M[5] (¢/KWH)

cf = QF capacity factor[9] (KWH/KW)

1 Short run incremental energy cost via production modeling of economic dispatch. To include variable O&M and revenue requirement associated with working capital and fuel inventory.

2 Actual baseload capital cost estimates to be supported by actual engineering cost study. The capital cost estimates are to be exhaustive and detailed by component. Rather than list the components, the Commission refers you to Appendix A

of EPRI's "Coal-Fired Power Plant Capital Cost Estimates" (Bechtel Power Corporation, May, 1981, report #EPRI PE-1865). Cost estimates will be reviewed with necessary adjustment made as deemed appropriate.

3 Actual combustion turbine capital cost estimate supported by actual engineering cost study, if available, or consistent with industry estimates. Treatment must be equally exhaustive and detailed by component.

4 Annual carrying charges supported by calculations of incremental cost of capital; 35 year book life assigned to base-load plants, 25 for combustion turbines.

5 Appendix A of the EPRI report cited above provides the minimum components to be considered. Includes working capital and variable costs associated with SO_2 removal.

6 Initially, equal to 8.3% applied to all energy. Eventually, shall reflect utility specific actual analysis and, in the case of time differentiation, allocated to rating periods commensurate with analysis results.

7 Coal cost and fuel content are to reflect actual contract year purchase contracts. Coal cost is to include a separate component reflecting transportation costs.

8 Plant heat rate is to reflect actual plant heat rate at expected operating load.

9 QF capacity factor is to represent expected performance, initially, and demonstrated performance after first contract year.

Rate Schedule Formulae

short-term energy =

$$\lambda g + \frac{(bd + f).425}{(8760)(.85).85}$$

long-term energy =

$$\left(\frac{(ac + e) - (bd + f)}{(8760).70}\right)g + \frac{hj}{i} + k$$

long-term capacity =

$$\frac{(bd + f)cf}{.85}$$

Example Rate Calculation[10]

λ =	2.50 ¢/KWH	g =	8.3%
a =	1200 \$/KW	h =	10.0 \$/ton
b =	300 \$/KW	i =	9,000 BTU/lb
c =	16%	j =	11,000 BTU/KWH
d =	17%	k =	.3 ¢/KWH
e =	20 \$/KW	cf =	.65 KWH/KW
f =	10 \$/KW		

$$\therefore \quad \underline{\text{short-term energy}} = .0250\ (1.083) + \frac{(300(.17) + 10).425}{8760(.85)(.85)}$$

$$= .0271 + .0041$$
$$= .0312 \text{ \$/KWH}$$

$$\underline{\text{long-term energy}} =$$

$$\left(\frac{(1200(.16) + 20) - (300(.17) + 10)}{8760(.70)}\right) 1.083 + \frac{(10(11,000))}{(2000(9000))} + .003$$

$$= .0266 + .0091$$
$$= .0357 \text{ \$/KWH}$$

$$\underline{\text{long-term capacity}} = \frac{(300(.17) + 10)(.65)}{(.85)}$$

$$= 46.65 \text{ \$/KW-YR}$$

10 These values are generally representative of those submitted by intervening parties in this proceeding. Although they are provided for illustrative purposes, they also serve as indicators of what the Commission has found to be reasonable.