Black Hills Corporation

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April 27, 2011

Advice No. 642

Public Utilities Commission
of the State of Colorado
1560 Broadway
Suite 250
Denver, CO 80202

The accompanying tariff sheets issued by Black Hills/Colorado Electric Utility Company, LP, d/b/a Black Hills Energy ("Black Hills Energy" or the "Company") are sent to you for filing in compliance with the requirements of the Public Utilities Law and the applicable rules of the Public Utilities Commission of the State of Colorado ("Commission"), including Rule 1210, 4 *Code of Colorado Regulations* 723-1. The following sheets are attached:

COLORADO P.U.C. NO. 8

Colorado P.U.C. Sheet Number	Title of Sheet	Cancels Colorado P.U.C. Sheet Number
Second Revised Sheet No. 45	Energy Cost Adjustment, Electric	First Sheet No. 45
First Revised Sheet No. 46	Energy Cost Adjustment (Continued) Electric	Original Sheet No. 46

The purpose of this filing is to amend the Energy Cost Adjustment ("ECA") tariffs and add a mechanism to include Incentive Sharing, defined as net income from energy sales, pursuant to the Settlement Agreement and Commission decisions in the Company's most recent rate case relating to the treatment of off-system sales revenues and expenses. *See*, Decision Nos. R10-0793 and C10-0848, Docket No. 10AL-008E. Black Hills Energy requests that the ECA tariffs attached to this Advice Letter as Appendix A become effective on 30 days' notice by operation of law without hearing and suspension, pursuant to Colo. Rev. Stat. § 40-6-111.

Accompanying this Advice Letter is direct testimony and an exhibit supporting and explaining Black Hills Energy's proposed sharing of energy sales net income with all retail customers as a credit through the ECA mechanism. Energy sales are defined as short-term (generally less than one year) sales of energy to wholesale customers. Energy sales net income represents energy sales revenue minus the related cost of goods sold (generation, purchased power and transmission expense) and operating expenses (generation dispatch personnel and other related costs).

The proposed Incentive Sharing mechanism, on an annual basis, incorporates a $1,000,000 sharing threshold with a dead band equal to half the threshold. Black Hills Energy would retain the first $500,000 of Incentive Sharing. Incentive Sharing above $500,000 to $1,000,000 would be shared 75 percent customers and 25 percent Company, and then Incentive Sharing above $1,000,000 would be shared 55 percent customers and 45 percent Company. Appendix B illustrates this Incentive Sharing mechanism. The customer credit would be applied to the total energy costs, before comparing to the base energy cost to determine the over- or under-recovery of costs for the test period.

Black Hills Energy prefers this straight forward sharing approach as compared to more complex methods involving the separation of generation book and proprietary book margins and unique dead-band and sharing calculations for each of these books. This approach is also consistent with the Black Hills Power Generation Dispatch and Power Marketing Department Administrative Guideline, Policy No. DAG-011, which is provided as Appendix C to this Advice Letter. The Company's proposed mechanism for sharing is easy for customers, regulators and Black Hills employees to understand, thereby minimizing confusion, misunderstanding and calculation errors. This sharing mechanism benefits both the utility as well as the customers, and is the key component to this arrangement. This sharing aligns the interests of the customers and the utility so both should benefit, including the potential reduction in electric costs flowed through the ECA.

Black Hills Energy's intent is to obtain approval of this proposed revision to the ECA tariff, so that it will be effective for the April 1, 2012 filing pursuant to the schedule set forth in Sheet 45 of the ECA tariff. The impact of these changes to the ECA will be applicable to the calendar year of January 1, 2011 to December 31, 2011, and implemented on May 1, 2012 with the filing of the new ECA factor. Due to the timing of the most recent rate case decisions cited above, as compared to the test period definitions in the Energy Cost Adjustment tariff (Sheet No. 45), there would be a one-time adjustment in the October 1, 2011 filing to include the sharing of August, 2010 through December, 2010 energy sales net income as proposed in the ECA.

Please send copies of all notice, pleading, correspondence, and other documents regarding this filing to the undersigned and to:

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This filing will be noticed pursuant to the requirements of the Colorado Public Utilities Law. Black Hills Energy requests that the tariff sheets accompanying this Advice Letter become effective on 30 days notice on May 28, 2011.

Sincerely,

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BLACK HILLS/COLORADO ELECTRIC UTILITY COMPANY, LP
d/b/a BLACK HILLS ENERGY
105 South Victoria
Pueblo, Colorado 81003

ENERGY COST ADJUSTMENT
ELECTRIC

DEFINITIONS

Test Period: The test period will be actual costs incurred during the period of March through August and September through February. The filing date for the March through August test period will be October 1 and for the September through February test period will be April 1. The recovery period will be 30 days from the filing date and be effective for the next six months.

Recovery Period: The billing months during which the Cost Adjustment Factor (CAF) for the previous Test Period is applied to retail customer billings on a per kilowatt-hour (kWh) basis.

Costs: Costs eligible for Energy Cost Adjustment (ECA) will be the Company's total book costs for fuel consumed in Company generating units and purchased power energy charges. Costs do not include purchased power demand charges.

APPLICATION

The price per kWh of electricity sold will be adjusted subject to application of the ECA mechanism and approval by the Public Utilities Commission. The price will reflect test period costs above or below base costs specified on Sheet No. 46 for:

(1) fuel consumed in Company electric generating plants, plus

(2) purchased energy (excluding demand), minus C

(3) half of the prior calendar year Incentive Sharing (IS), defined as N
energy sales net income, with sharing 75% customers and N
25% Company for IS above $500,000 to $1,000,000 and 55% customers N
and 45% Company for IS above $1,000,000, plus or minus N

ENERGY COST ADJUSTMENT (CONTINUED)
ELECTRIC

an adjustment for recovery period sales variation. This is based on the difference between the value of [(F + P - ($0.02239 x test period sales))] minus [(CAF x Actual Recovery Period kWh sales)±C] during the recovery period. This amount will be collected during the next recovery period.

(4) Interest-Deferred electric energy costs shall be determined monthly. The resulting amount, whether negative or positive will be accumulated for the same test period. In addition, interest at a rate equal to the interest rate paid on customer deposits will be applied to the deferred electric energy costs on an average monthly basis and will be accumulated for the same test period. If the accumulated interest is negative it shall be included in the determination of the ECA. If the interest is positive, it shall be excluded from the determination of the ECA. The accumulated interest shall be included in the determination of the ECA.

The ECA will be the sum of (1), (2), (3), and (4). The Cost Adjustment Factor is the result of dividing the ECA by test period kWh sales, rounded to the nearest $.00000. The formula and components are displayed below. C

$$ECA = ([(F + P - IS - B)] \pm C) \pm I$$ C

The Cost Adjustment Factor (CAF) is as follows:

$$CAF = \frac{ECA}{S}$$

Where:

F = Actual cost of fuel
P = Actual cost of purchased energy
IS = Incentive Sharing collectively defined as energy sales net income N
B = Base cost of fuel and purchased power energy = S x $0.02239
C = Under/over recovery from prior period
S = Total system sales (kWh)
I = Interest

APPLICABLE BASE COST

Company generated energy and purchased energy per kWh sold, $0.02239.

Advice Letter No. 642	Decision or Authority No. C08-0204	
Signature of Issuing Officer	Issue Date April 27, 2011	
Title Manager – Colorado Electric Regulatory Affairs Black Hills Corporation	Effective Date May 28, 2011	

Appendix B

Black Hills Energy - Colorado Electric
Energy Cost Adjustment - Sharing Methodology
Dead Band equals One Half Threshold to Threshold
BHCOE Keeps One Half of Threshold

Sharing Threshold $ 1,000,000

(75%/25% - 55%/45%)												
A	B	C	D	E	F	G	H	I	J	K	L	M
		Customer			Company					Actual %		
"Incentive Sharing"	Floor (One Half of Threshold)	One Half Threshold to Threshold 75%	Above Threshold 55%	Total Customer	One Half Threshold to Threshold 25%	Above Threshold 45%	Floor (One Half of Threshold)	Total Company	Total	Customer	Company	Total
750,000	500,000	$ 187,500	$ -	$ 187,500	$ 62,500	$ -	$ 500,000	$ 562,500	750,000	25%	75%	100%
850,000	500,000	262,500	-	262,500	87,500	-	500,000	587,500	850,000	31%	69%	100%
950,000	500,000	337,500	-	337,500	112,500	-	500,000	612,500	950,000	36%	64%	100%
1,000,000	500,000	375,000	-	375,000	125,000	-	500,000	625,000	1,000,000	38%	63%	100%
2,000,000	500,000	375,000	550,000	925,000	125,000	450,000	500,000	1,075,000	2,000,000	46%	54%	100%
3,000,000	500,000	375,000	1,100,000	1,475,000	125,000	900,000	500,000	1,525,000	3,000,000	49%	51%	100%
4,000,000	500,000	375,000	1,650,000	2,025,000	125,000	1,350,000	500,000	1,975,000	4,000,000	51%	49%	100%
5,000,000	500,000	375,000	2,200,000	2,575,000	125,000	1,800,000	500,000	2,425,000	5,000,000	52%	49%	100%
6,000,000	500,000	375,000	2,750,000	3,125,000	125,000	2,250,000	500,000	2,875,000	6,000,000	52%	48%	100%
7,000,000	500,000	375,000	3,300,000	3,675,000	125,000	2,700,000	500,000	3,325,000	7,000,000	53%	48%	100%
8,000,000	500,000	375,000	3,850,000	4,225,000	125,000	3,150,000	500,000	3,775,000	8,000,000	53%	47%	100%
9,000,000	500,000	375,000	4,400,000	4,775,000	125,000	3,600,000	500,000	4,225,000	9,000,000	53%	47%	100%
10,000,000	500,000	375,000	4,950,000	5,325,000	125,000	4,050,000	500,000	4,675,000	10,000,000	53%	47%	100%
11,000,000	500,000	375,000	5,500,000	5,875,000	125,000	4,500,000	500,000	5,125,000	11,000,000	53%	47%	100%
12,000,000	500,000	375,000	6,050,000	6,425,000	125,000	4,950,000	500,000	5,575,000	12,000,000	54%	46%	100%

BLACK HILLS POWER
GENERATION DISPATCH AND POWER MARKETING DEPARTMENT ADMINISTRATIVE GUIDELINE

SUBJECT:	DATE ISSUED	POLICY NO.
Margin Calculation Stacking Methodology BHCE	03-03-10	DAG-011
	DATE EFFECTIVE 03-11-11	PAGE NO. Page 1 of 4
Revision Number: 1 02/02/11 2 03/11/11	PREPARED BY D. Batka	APPROVED

1.0 Purpose

To provide information to the department as to how the Native Load and Marketing Margins are calculated on an hourly basis for each day of the year.

2.0 Terminology

Imbalance – A condition in which the generation and demand or interchange schedules do not match.

Margin – how much a company earns taking into consideration the costs that it incurs for serving load and other contractual agreements and/or services.

Merit – numerical value representing a measure of effectiveness, efficiency, performance or other important factor, and ascertained or approximated from analysis, appraisal, or estimation techniques.

Native Load – is defined as the BHCE Total Load less wheeling load (web Trader object).

Reserve – there are several types of reserve capability and capacity that are usually included in consideration of supply of firm power needs. These include: operating reserve, spinning reserve, regulating reserve, contingency reserve, non-spinning reserve, and planning reserve.

Stack – the arrangement of energy purchases and units cost in Merit order by cost. The top of the stack is usually the lowest cost and serves Native Load.

3.0 Reliability

The primary goal of Generation Dispatch and Power Marketing (GDPM) is provide reliable energy to serve the customers of Black Hills Colorado (BHCE). The marketing function will only occur when Native Load is satisfied with reliable resources and will always be conducted in a manner not to degrade the ability to serve Native Load. If it is shown that improper trading activities created a less than reliable Native Load supply, an appropriate credit of the Margin created will be stacked to Native Load.

4.0 Interruption of Short-Term Sales

GDPM will curtail all short term non-firm sales prior to interrupting Native Load. In addition, GDPM will not interrupt any Native Load customers in order to make a short term sale.

5.0 Reliability Costs

5.1 Reserves
GDPM recognizes that short term sales could lead to an additional cost incurred from reliability functions for the need of reserve services. These costs include the purchase of energy through the activation of reserves. A sale on margin for a given hour will have a reserve purchase stacked against it if activation occurred.

5.2 WECC Penalties
Penalties payable to WECC, related to reliability polices that are due to short term sales, will be directly assigned to the total Margin.

5.3 Must Run Cost
Units that are placed on-line at the direction of a reliability function will be deemed to serve Native Load. In addition, units required to be in operation to provide reserves or for testing will be deem to serve Native Load. This will be accomplished by moving the must run unit to the top of the Merit stack.

6.0 Purchases of Energy or Capacity

6.1 Long Term Energy
A long term purchase is a transaction generally more than one year and is conducted with the sole purpose of serving Native Load. This type of purchase is made in order to reduce to need for high cost capacity resources, or due to the need for capacity to serve Native Load. Long term purchases will be deemed to serve Native Load and will be placed at the top of Merit stack. Long term purchases that have the ability to be reduced if not needed for Native Load will enter the stack in the order of its energy cost and can be used to serve marketing sales, if excess exists.

6.2 Short Term Energy
A short term purchase is a transaction generally less than one year and is conducted with the purpose of serving Native Load or marketing sales. This type of purchase is made in order to reduce to need for high cost capacity resources, or due to the need for capacity to serve Native Load. The short term purchases will enter the Stack in the order of its energy cost and can be used to serve marketing sales, if excess exists.

6.3 Capacity Energy
A capacity energy purchase is a transaction purchased to cover energy needs for 3 weeks or more with the purpose of serving Native Load

6.4 Off System Purchases
Energy purchases that do not touch the Native Load system will be deemed to serve associated marketing sales.

7.0 Sales

7.1 Long Term Sales
The sale of energy from a BHCE capacity resource generally greater than one year is considered to be long term. This type of sale is stacked against the capacity resource that is in excess.

7.2 Short Term Sales
The sale of energy from a BHCE capacity resource, short term purchase, bundled Renewable Energy Credit, or unbundled Renewable Energy Credit generally less than one year is considered to be short term. This type of energy sale is stacked against energy in Merit order after Native Load requirements have been satisfied.

7.3 Off System Sales
Sales of any length of time that do not touch the Native Load system will be deemed to be served with its associated energy purchases.

8.0 BHCE Native Load and Marketing Margin Calculation

For BHCE, the Native Load and Marketing Margins are calculated based on realized revenue that is actually achieved and can be documented. Native Load obligations, wholesale contracts and other long term power sales contracts will be deemed to be served by the least cost resources.

Resources are stacked in order from least cost resource to most expensive resource based on variable cost of generation or purchase price of energy. Resources are assigned to Native Load and long term contracts in this stacked order for each hour. In this stacking, capacity purchases, must run generation, generation online to supply reserves, and intermittent renewable will go directly to Native Load. Additionally, all physical losses and unit start up charges needed to serve Native Load are charged to Native Load.

Off system sales that do not touch the Native Load system will be deemed to be served with its associated energy purchases.

Native Load is then quantified using the lowest cost first proceeding until filled. Any remaining balance then goes to fill marketing positions.

Marketing margins are calculated as the difference between the sales revenue and the resource cost used to serve the sales. Margins will be calculated by hour and summarized by day, month and quarter. Negative margins will offset positive margins so that total margins reflect actual realized margins.

9.0 Dissemination of Information

Information contained within the Margin report is considered confidential and should be treated as such. The reports are posted on the Marketing log for departmental personnel to view. Additionally, these reports are audited periodically.