

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

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Chair
Commissioner
Commissioner
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In the Matter of the 2006-2020
Resource Plan of Missouri Basin
Municipal Power Agency d/b/a
Missouri River Energy Services

DATE: September 7, 2006
Docket No. ET10/RP-05-1102

**ADDENDUM TO
MRES
2006-2020 RESOURCE PLAN**

PUBLIC DOCUMENT – TRADE SECRET DATA HAS BEEN EXCISED

Introduction

Missouri Basin Municipal Power Agency d/b/a Missouri River Energy Services (MRES), as agent for Western Minnesota Municipal Power Agency (Western Minnesota), submits to the Minnesota Public Utilities Commission (Commission) this Addendum to the MRES 2006-2020 Resource Plan (Addendum). The purpose of this Addendum is to inform the Commission and interested parties of the results of our evaluation of whether or how cost changes in the proposed Big Stone Plant Unit II (BSP II) resource will affect either the Base Case or Preferred Alternative, identified in the Supplement to the Missouri River Energy Services 2006-2020 Resource Plan (Supplement), dated May 8, 2006. MRES submits this information to provide a complete picture of the current state of its resource planning analyses.

The increases in capital costs for the BSP II Project, as well as generation resources in general, have had no material affect on the resource selection results for MRES and its members. New analysis based on increased cost information continues to demonstrate that despite these increased costs, it remains prudent for MRES to participate in the proposed BSP II Project to meet anticipated need. Based on the information submitted here, the entirety of the record, and the recommendation of the Department of Commerce (Department), MRES respectfully requests that the Commission issue an advisory order to accept and affirm the MRES Resource Plan, as amended.

Background¹

In the Supplemental Comments of the Minnesota Department of Commerce, dated July 20, 2006, the Department reported on its thorough analysis of the MRES Supplement, provided recommendations for future resource planning processes (which MRES accepted) and recommended the Commission accept the MRES 2006-2020 Resource Plan. At about that same time, MRES, as a participant in the BSP II Project, was made aware of new project cost estimates that reflected a higher capital cost for the plant than was used by MRES in its resource planning process.

Based on this new information and the fact that the Commission required Otter Tail Power Company to provide additional analysis in its resource plan based on the new BSP II information, MRES requested that the Commission defer action on its resource plan until such time as MRES could also analyze the information, particularly through its capacity expansion modeling.

In the Supplement, the Base Case scenario placed no limits on any resource when calculating the least-cost plan. That is, no minimum amount of wind was “forced” into the Base Case model. Also in the Supplement, a Preferred Alternative was modeled in the same way as the Base Case scenario, except BSP II was limited to a maximum of 110 MW, and 40 MW of wind was forced into the model to represent the compliance with the Minnesota Renewable Energy Objective (REO).

MRES has now completed its additional analyses based on the revised project cost estimates to determine whether those changes in the BSP II resource, as well as corresponding capital cost increases associated with alternative, viable forms of generation, will affect either the Base Case or Preferred Alternative identified in the Supplement. The Supplement contained analysis based on alternative commercial operation dates for BSP II of 2011, 2012, 2013 and 2014. For purposes of this Addendum, our new analysis is limited to commercial operation dates of 2011 and 2012.

This Addendum provides information on the new analysis, including the data points that were changed in constructing the inputs to the revised scenarios, and the outcome of the new capacity expansion analysis utilizing the Strategist[®] software modeling tool. As detailed below, because the Strategist capacity expansion modeling continues to select BSP II in both the Base Case and Preferred Case when the BSP II resource was available in 2011 and in 2012, the additional modeling demonstrates that, although BSP II costs have risen (as have other alternative generation costs), BSP II remains a cost-effective, optimal resource to meet growing customer need. The additional analysis also confirms that it remains prudent for MRES to participate in the proposed BSP II Project, in combination with a mix of conservation, renewable resources, and gas peaking investments, to meet member anticipated needs.

¹ For complete details of the procedural background in this matter, please refer to the MRES Reply to Supplemental Comments of the Department of Commerce, dated August 3, 2006, pages 1-2.

Additional Scenario Modeling

As with the Supplement, MRES utilized Strategist capacity expansion software in the re-analysis of the Base Case and Preferred Alternative. The analysis of each included an evaluation based on the availability of BSP II in 2011 (Addendum – 2011) and in 2012 (Addendum – 2012). This Addendum analysis included the same types of resources used throughout this 2006-2020 resource planning process, and used updated information on the costs for each of those resources, primarily to reflect higher capital costs experienced industry-wide for new generation resources. The only additional resource added in the Addendum was unaccredited wind, in addition to accredited wind, as explained below. All other data and assumptions used in the MRES resource planning process remained the same as those used in the Supplement, except where otherwise stated.

Cost assumptions for all resources were revised where necessary to reflect the widespread cost increases that are affecting the entire generation sector, including significant changes in availability and cost of materials, labor, and specialized manufacturing capacity. Changes between the data used in preparing the Supplement and the data used in completing the analysis for this Addendum are detailed below. All cost values are in 2011 dollars, escalated annually.

Base Load/BSP II: Pulverized Coal (PC) [**TRADE SECRET DATA HAS BEEN EXCISED**]

- Source – Updated design and cost data was provided by Project consultants and participants.

Base Load: Integrated Gasification Combined Cycle (IGCC)

- Capital Costs – Previous capital costs were \$1816/kW for generation plus \$155/kW for transmission. New capital costs are \$2294/kW for generation plus \$369/kW for transmission.
- Fuel Cost – Fuel cost was changed to be identical to the new fuel cost values for BSP II.
- Source – Capital costs for IGCC were assumed to increase by the same proportion as BSP II.

Peaking: Simple-Cycle Combustion Turbine (CT), LM 6000

- Capital Costs – Previous capital costs were \$683/kW for generation with no additional cost for transmission. New capital costs are \$1182/kW for generation plus \$92/kW for transmission.

- Source – MRES used the actual costs for construction, expansion, and operation of Western Minnesota’s Exira Station as the basis for updating CT Capital Cost data.

Peaking: Natural Gas Combined Cycle² (NGCC), LM 6000

- Typical size – NGCC was modeled as a 130 MW unit, modeled in 13 MW increments.
- Capital Costs – Previous capital costs were \$1156/kW for generation with no additional cost for transmission. New capital costs are \$1876/kW for generation plus \$92/kW for transmission.
- Source – MRES used a two-part process to obtain the updated cost information for NGCC, breaking the analysis into the two processes. Given a nominal 130 MW unit size, 100 MW of output is assumed to be derived from an LM 6000 CT. For this 100 MW portion, it was assumed that the cost would increase at the same rate as CT units, as identified previously based on actual experience with Exira Station. The remaining 30 MW of the 130 MW nominal unit is assumed to be the heat recovery component. It is assumed that this portion would increase at a lesser rate; therefore, the BSP II capital cost increase ratio was used to estimate the capital cost increase for this portion of the NGCC peaking resource.

Renewable: Wind Turbines (Accredited):

- Accredited Wind was used as a resource in the Supplement to model new wind capacity, with the assumption that the addition of any new wind resources would also require additional transmission capacity. Accreditation of these resources was assumed, with a summer peak accreditation of 15% of the nameplate rating of the wind units.
- Capital Costs – Previous capital costs were \$1230/kW for generation with no additional cost for transmission. New capital costs are \$1738/kW for generation plus \$369/kW for transmission.
- Source – MRES updated its costs based on recent bids, negotiations with developers, and the contractual arrangements that were recently completed for the construction of the Western Minnesota Marshall Wind Project.

Renewable: Wind Turbines (Unaccredited):

- Unaccredited Wind was used as a resource for the Addendum to model new wind capacity, because MRES anticipates the ability to add at least 40 MW of new wind resources, and obtain transmission access, at existing generation sites without increasing transmission capacity. However, it would be unable to accredit those wind units without increasing transmission capacity.
- Capital Costs – Previous capital costs were \$1230/kW for generation with no additional cost for transmission. New capital costs are \$1738/kW for generation with no addition cost for transmission.

² The Supplement analysis also included an evaluation of natural gas combined cycle (NGCC) units. However, because our modeling did not select NGCC, this resource was not detailed in the MRES May 8, 2006 filing. The information was, however, provided subsequently to the Department as part of the information exchange between the parties, and was included as a basis for the Department’s recommendation in its July 20, 2006 Comments.

- Source – MRES developed costs for unaccredited wind based on recent bids, negotiations with developers, and the contractual arrangements that were recently completed for the construction of the Western Minnesota Marshall Wind Project.

Renewable: Demand Side Management (DSM):

- No changes. MRES did not update any DSM cost information. The implementation costs were assumed to remain as modeled in the Supplement.

Results of Analyses

In the analyses conducted for this Addendum, MRES studied the two primary cases from its Supplement, i.e., the Base Case and the Preferred Alternative. Each case was optimized assuming no surplus sales from the generating resources. Then, once the optimal resource mix for each case was established, the actual net costs were calculated with surplus sales enabled. The results of each case are presented with surplus sales revenue included in the calculated results; however, surplus sales were not included when identifying the optimal resource mix.

Capacity expansion analysis was performed for each of these two scenarios, assuming a 2011 commercial operation date for BSP II (the date used in the Resource Plan and the Supplement). It was also performed assuming a 2012 commercial operation date. In essence, the Addendum analysis changed two assumptions from the Supplement: first, to reflect the higher costs of resource acquisition and use the 2011 commercial operation date of BSP II; and second, to both reflect the higher resource acquisition costs and to use the 2012 commercial operation date.

The analyses evaluated the effects of higher costs in detail over the 2006-2020 planning horizon, and estimated the benefits of each resulting resource mix for the first 30 years beyond 2020.

Base Case

In the Supplement, the Base Case Scenario was the optimal plan. The result of the Base Case in the Supplement demonstrated a total cost of \$559.8 million. This value includes all production costs for existing and future resources, plus capital costs for all new resources. Emissions costs, market energy purchase costs, and market energy sales revenues were also included.

For this Addendum, MRES again ran Strategist to determine the optimal Base Case, first using the higher resource acquisition cost and assuming BSP II continues to become available in 2011 (Addendum Base - 2011), and then using the higher resource acquisition cost and assuming a 2012 commercial operation date for the BSP II resource (Addendum Base - 2012). In completing the updated cost Base Case analysis for 2011, the Addendum analysis demonstrated a

total cost of \$610.4 million (in 2005 dollars). In evaluating the effect of a 2012 commercial operation date, the analysis resulted in a total cost of \$609.7 million (in 2005 dollars).

Table 1, below, is a summary comparison of the results of the Base Case. It compares the updated results of the Base Case reported in the Supplement, with those from this Addendum, using the updated cost with BSP II remaining available in 2011(Addendum Base – 2011) and using a higher cost and assuming a 2012 commercial operation date (Addendum Base – 2012).

Table 1: Base Case Scenario Comparisons						
	Supplement		Addendum Base-2011		Addendum Base-2012	
Cost (2005 \$)	\$559.8 million		\$610.4 million		\$609.7 million	
Cost above Base Case (2005 \$)			\$50.6 million (+9.04%)		\$ 49.9 million (+8.91%)	
Year	Unit	MW	Unit	MW	Unit	MW
2011	BSP II	155	BSP II	125	-	-
2012	-	-	-	-	BSP II	140
2017	-	-	CT	15	CT	-
2019	-	-	CT	15	CT	15
2009-2020	DSM	7.07/yr (total 84.9)	DSM	7.07/yr (total 84.9)	DSM	7.07/yr (total 84.9)

In the Addendum, as in all of its resource planning exercises, MRES identifies the Base Case as the outcome produced by the capacity expansion analysis that results in the least cost, optimal plan. MRES structures the parameters of the Strategist program for this scenario to allow it to freely select resources without any artificial constraints.

The revised Base Case analysis of Addendum Base – 2011 demonstrates that Strategist continues to identify BSP II and DSM as the optimal resources to meet the forecasted needs of MRES members, as in the Supplement, despite a higher cost of \$610.4 million. The revised analysis selected 125 MW of BSP II in 2011, rather than the somewhat larger amount of 155 MW in 2011 identified in the Supplement. Additionally, it selected two combustion turbine (CT) units (in 2017 and 2019) for a combined 30 MW to replace the same amount of BSP II that was displaced in this revised analysis.

Although the costs of BSP II have increased, the costs of several other alternative resource types used in the MRES model have also increased. Thus the optimal amount of BSP II is lower than in the previous study, but not by a material amount. The total cost of the optimal plan is higher because costs have increased essentially across the board for new resource options.

Likewise, the capacity expansion analysis of the Addendum Base – 2012 scenario continues to identify BSP II as the least cost option. The results of the Strategist modeling demonstrate that a 2012 commercial operation date makes it slightly more cost-effective to meet growing needs with BSP II project. The result of modeling BSP II in 2012 identifies the optimal amount of BSP II at 140 MW, eliminates a CT unit in 2017, and adds a 15 MW CT unit in 2019.

The results of the Addendum analysis is that under either the Addendum Base – 2011 or the Addendum Base – 2012, BSP II continues to be identified as a least cost resource in an amount from 125 MW to 140 MW. This is consistent with the amount to which MRES has agreed to participate in the project. It is significant, then, that the revised modeling still selected BSP II in an amount that exceeds the MRES ownership commitment. MRES submits that this demonstrates that despite the increase in capital costs, BSP II remains an optimal resource choice in the overall MRES resource mix.

Preferred Alternative

MRES also used the higher cost figures to re-evaluate the Preferred Alternative reported in the Supplement. As identified in the Supplement, the Preferred Alternative “forced” the selection of the renewable resources needed to meet the Minnesota REO, and limited BSP II to the 110 MW amount to which MRES is contractually obligated and entitled. Strategist was free to select the type and timing of additional resources, given these two parameters. The Supplement results indicated that the Preferred Alternative has a \$10.7 million cost above the Base Case Plan in 2005 dollars (+1.9%). In addition to the renewable resources and BSP II, the capacity expansion modeling also selected DSM and CT units as part of the Preferred Alternative.

Using updated costs, MRES re-analyzed the Preferred Alternative. The Preferred Alternative modeled in this Addendum used slightly different parameters to ensure that it would identify whether BSP II remains a competitive resource. In particular, as with our earlier analysis, the Preferred Alternative scenario was constructed to force in, as a minimum, at least enough renewable resources (i.e., wind) needed to meet the Minnesota REO, but did not restrict the minimum or maximum amount of BSP II. This adjustment was made to ensure that the scenario results would objectively identify whether and, if so, how much of the BSP II resource would be cost-effective, given the higher costs.

Most significantly, under the revised Preferred Alternative analysis, Strategist continues to select BSP II at a level that is greater than the amount that MRES is contractually obligated and entitled. Further, this same analysis was completed using an assumption that BSP II would be commercially available in 2012. The results demonstrate that the capacity expansion analysis continues to identify BSP II as part of the least cost plan.

Table 2, below, is a summary comparison of the various results of the Preferred Alternative analyses. It compares the results of the Preferred Alternative reported in the Supplement, with those from the Addendum, using the updated cost with BSP II remaining

available in 2011(Addendum Preferred – 2011) and using the updated cost and assuming BSP II commercial availability in 2012 (Addendum Preferred – 2012).

Table 2: Preferred Alternative Scenario Comparisons						
	Supplement		Addendum Preferred-2011		Addendum Preferred-2012	
Cost (2005 \$)	\$570.5 million		\$638.4 million		\$637.7 million	
Cost above Preferred Alternative (2005 \$)			\$67.9 million (+11.9%)		\$67.2 million (+11.78%)	
Year	Unit	MW	Unit	MW	Unit	MW
2011	BSP II	110	BSP II	125	-	-
2011	Wind	40 (6 MW Accredited)	Wind	40 (None Accredited)	Wind	40 (None Accredited)
2012	-	-	-	-	BSP II	140
2016	CT	15	-	-	-	-
2017	CT	15	CT	15	CT	-
2019	CT	15	CT	15	CT	15
2009-2020	DSM	7.07/yr (total 84.9)	DSM	7.07/yr (total 84.9)	DSM	7.07/yr (total 84.9)

The re-evaluation of the Preferred Alternative indicates that despite cost increases for BSP II, it remains the optimal resource selected, regardless of whether it is added in 2011 or 2012. This demonstrates that with cost increases applicable to all supply-side resources, BSP II remains the least-cost base load alternative to meet the growing electric energy demand of MRES members and their customers.

Specifically, the Addendum Preferred – 2011 scenario modeling demonstrates that the Preferred Alternative, including BSP II together with DSM, wind and combustion turbines, is the most likely resource mix to achieve the lowest resource cost, while minimizing emission and allowance cost, maintaining resource adequacy, and meeting the Minnesota REO standards. The capacity expansion model also selected proven, reliable types of technology that will provide dependable resources for MRES to serve its member municipal electric utilities.

The Addendum Preferred – 2012 Preferred Alternative scenario modeling results demonstrate a similar outcome. A 2012 commercial operation date for the BSP II resource availability has the effect of eliminating one CT unit, and pushing the date for the only CT unit to 2019. The model continues to identify the same 84.9 MW amount of DSM, added at the rate of 7.07 MW per year, along with 40 MW of unaccredited wind. It also demonstrates that the

selection of BSP II as a major resource is unaffected by a commercial operation date of 2011 in contrast to 2012, as there is no material impact on cost between the two dates.

Conclusion

The increases in capital costs for the BSP II Project, as well as generation resources in general, have had no material affect on the resource selection results for MRES and its members. The MRES capacity expansion modeling in the Supplement demonstrated continued growth in member and customer need, and identified the that the optimal resource acquisitions necessary to meet that need included BSP II in an amount equal to or greater than that which MRES has currently contracted. New analysis based on updated cost information continues to demonstrate that despite these increased costs, it remains prudent for MRES to participate in the proposed BSP II Project to meet anticipated need. BSP II remains part of the least cost resource mix necessary to meet the needs of MRES members, while still being sensitive to keeping customer bills and the utility rates as low as practicable.

The MRES Resource Plan, together with the updated and supplemental information in the record, addresses the requirements of Minn. Stat. § 216B.2422 and related rules, is responsive to the concerns previously raised by the Department and other parties, and should be accepted by the Commission. MRES respectfully requests that the Commission issue an advisory order approving the MRES Resource Plan as amended by the Update, the Supplement, and this Addendum. Last, given the extraordinary effort put forth by MRES, the Department, and all parties, we respectfully ask that this matter be set for final disposition no later than October 19.

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Respectfully submitted,

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