

Before the South Dakota Public Utilities Commission  
State of South Dakota

In the Matter of the Application of  
Otter Tail Power Company  
For Authority to Increase Rates for Electric Utility  
Service in South Dakota  
EXHIBIT \_\_\_\_

Docket No. EL10-011

REBUTTAL TESTIMONY AND SCHEDULES OF

**BRYAN D. MORLOCK**

March 28, 2011

## TABLE OF CONTENTS

I.	QUALIFICATIONS .....	1
II.	PURPOSE OF TESTIMONY.....	2
III.	BACKGROUND ON THE LUVERNE WIND FARM.....	3
IV.	COMPARISON OF THE REVENUE REQUIRMENT FOR LUVERNE AND THE COST OF REPLACEMENT POWER. ....	3
V.	THE IRP MANAGER RESOURCE PLANNING SOFTWARE .....	8
VI.	OTP’S USE OF IRP-MANAGER SOFTWARE FOR THE OTP 2006-2020 IRP .....	9
VII.	RESPONSE TO EVANS’ CRITICISMS THAT IRP-MANAGER IS NOT A VALID IRP MODELING SOFTWARE TOOL .....	11
VIII.	RESPONSE TO EVANS’ CLAIM THAT OTP MODELED WIND GENERATION INCORRECTLY IN THE 2006 IRP.....	14
IX.	RESPONSE TO EVANS’ CLAIM THAT THE IRP-MANAGER MODELING IS INVALID BECAUSE IT DOES NOT ACCURACTELY REFLECT OTP’S OPERATIONS.....	17
X.	RESPONSE TO EVANS’ CLAIM THAT OTP DID NOT NEED CAPACITY WHEN ITS IRP IDENTIFIED THE NEED FOR THE LUVERNE PROJECT.....	20
XI.	RESPONSE TO EVANS CLAIM THAT OTP DID NOT ADEQUATELY CONSIDER WIND INTEGRATION COSTS. ....	22
XII.	RESPONSE TO EVANS’ CLAIM THAT OTP DID NOT COMPARE LUVERNE TO ALTERNATIVES.....	26
XIII.	CONCLUSION.....	30

## **ATTACHED SCHEDULES**

- Schedule 1 – Qualifications and experience of Bryan D. Morlock, P.E.
- Schedule 2 – Estimated Luverne revenue requirements versus market price  
(CONFIDENTIAL)
- Schedule 3 – List of regulatory dockets in which IRP-Manager was used
- Schedule 4 – Mr. Evans’ response to IR SD-OTP-18
- Schedule 5 – Mr. Evans’ email on Strategist settings
- Schedule 6 – Mr. Evans’ email on unit commitment
- Schedule 7 – Mr. Evans’ supplemental response to IR SD-OTP-27
- Schedule 8 – Mr. Evans’ response to IR SD-OTP-16
- Schedule 9 – Mr. Evans’ response to IR SD-OTP-17
- Schedule 10 – OTP 2006-2020 load and capability
- Schedule 11 – Mr. Evans’ response to IR SD-OTP-26
- Schedule 12 – Present worth analysis of wind integration costs

1 **I. QUALIFICATIONS**

2  
3 Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.

4 A. Bryan D. Morlock. I am currently a Planning Consultant with Otter Tail Power  
5 Company (Otter Tail or OTP). My address is 215 South Cascade St., Fergus Falls,  
6 MN 56538-0496.

7  
8 Q. CAN YOU PLEASE SUMMARIZE YOUR EDUCATION, QUALIFICATIONS,  
9 AND EXPERIENCE?

10 A. Yes. I am a graduate of the University of North Dakota with Bachelor of Science  
11 degrees in Electrical Engineering and Business Administration. I have been a  
12 registered professional engineer in the State of Minnesota since 1983, license no.  
13 15964. My experience includes over four years of designing, building, and  
14 maintaining distribution and transmission facilities and several years in system  
15 operations where I supervised daily load forecasting and generation scheduling. I  
16 managed the OTP resource planning function for 23 years, including the 2006 – 2020  
17 Integrated Resource Plan (2006-2020 IRP) developed and filed in the State of  
18 Minnesota on June 30, 2005, and eventually approved in January 2009. Further detail  
19 on my background and experience is included in Exhibit \_\_\_\_ (BDM-1), Schedule 1 to  
20 this testimony.

21  
22 Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE SOUTH DAKOTA  
23 PUBLIC UTILITIES COMMISSION (THE COMMISSION)?

24 A. Yes. I presented testimony on behalf of OTP and other co-owners of the Big Stone II  
25 Project in June 2006, for the plant siting permit in Docket No. EL05-022. My  
26 testimony in that docket was based on the results obtained in developing the 2006-  
27 2020 IRP, which included the new wind generation which became the Luverne Wind  
28 Farm (Luverne or Luverne Wind Farm).

29

1 Q. HAVE YOU PROVIDED INFORMATION AND TESTIMONY IN OTHER  
2 JURISDICTIONS REGARDING OTP'S INTEGRATED RESOURCE PLANS, AND  
3 IN PARTICULAR DOCKETS PERTAINING TO OTP'S 2006-2020 IRP AND  
4 LUVERNE?

5 A. Yes. I was involved with all OTP integrated resource plans submitted in the State of  
6 Minnesota in 1992, 1994, 1996, 1999, 2002, and 2005. With respect to the 2006-2020  
7 IRP, I provided testimony in Minnesota in Dockets E017/RP-05-968, the resource  
8 plan docket, and E017/CN-05-619, the Certificate of Need docket for the Big Stone  
9 Plant II project. I testified in North Dakota in Docket PU-06-481, the advance  
10 determination of prudence for the Big Stone Plant II project, which was based on the  
11 results of the 2006 – 2020 IRP. Finally, I was involved in Dockets E017/M-09-883 in  
12 Minnesota and PU-10-18 in North Dakota. These two dockets were the renewable  
13 resource recovery tariff filings for approval to recover the costs of the Luverne Wind  
14 Farm from Minnesota and North Dakota customers.

15  
16 **II. PURPOSE OF TESTIMONY**

17  
18 Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS CASE?

19 A. I will respond to the prefiled testimony of Mr. George W. Evans regarding the  
20 inclusion of the Luverne Wind Farm in this proceeding.

21  
22 My testimony will demonstrate that South Dakota customers would pay much more  
23 for electricity if the Commission were to deny recovery for Luverne and to subject  
24 South Dakota customers to the cost of replacement power. I will compare the revenue  
25 requirements for Luverne to the forecast cost of replacement power. That comparison  
26 demonstrates that replacement power would cost South Dakota customers significantly  
27 more than the cost of Luverne.

28  
29 My testimony will also address Mr. Evans' criticisms of OTP's resource planning. I  
30 will provide testimony demonstrating the validity of OTP's resource planning

1 software and OTP’s modeling for the 2006-2020 IRP specifically, and I will address  
2 the specific criticisms raised in Mr. Evans’ testimony. My review of Mr. Evans’  
3 testimony and conclusions indicates that Mr. Evans has overlooked or misunderstood  
4 some of the information, may not have been aware of other information, and as a  
5 result reached incorrect conclusions regarding OTP’s resource planning activities and  
6 the Luverne Wind Farm specifically.

7  
8 **III. BACKGROUND ON THE LUVERNE WIND FARM**

9  
10 Q. PLEASE PROVIDE SOME BACKGROUND INFORMATION ON LUVERNE  
11 AND THE REVENUE REQUIRMENTS FOR LUVERNE.

12 A. Background information on Luverne and the test year revenue requirement impacts of  
13 Luverne were included in the prefiled Direct Testimonies of Mr. Thomas R. Brause,  
14 Mr. Peter J. Beithon, and Mr. Kyle Sem. Since those testimonies were filed, the  
15 Commission has approved the agreement between OTP and Staff as to what the  
16 revenue requirement for the project will be if the Commission approves rate recovery  
17 for the project (“The Approved Stipulation,” approved in the Commission’s March 14,  
18 2011 ORDER APPROVING THE JOINT MOTION FOR APPROVAL OF THE  
19 SETTLEMENT STIPULATION in this case). In addition to approving the agreement  
20 between OTP and Staff with respect to the revenue requirements for Luverne, the  
21 Commission also approved in that same order the methodology for calculating the cost  
22 of replacement power for the output of Luverne that would not be allocated to South  
23 Dakota if the Commission were to disallow rate recovery for Luverne.

24  
25 **IV. COMPARISON OF THE REVENUE REQUIRMENT FOR**  
26 **LUVERNE AND THE COST OF REPLACEMENT POWER.**

27  
28 Q. HAS OTP PERFORMED A COMPARISON OF WHAT OTP’S SOUTH DAKOTA  
29 CUSTOMERS WOULD EXPECT TO PAY FOR LUVERNE’S REVENUE

1 REQUIREMENT AND WHAT THEY WOULD PAY FOR REPLACEMENT  
2 ENERGY?

3 A. Yes. We calculated the revenue requirement that our South Dakota customers would  
4 pay over the life of Luverne (based on the Approved Stipulation) and compared that  
5 with what our customers would be expected to pay for replacement energy over the  
6 same period (also based on the Approved Stipulation).

7  
8 Q. WHAT WERE THE RESULTS OF THAT COMPARISON?

9 A. The results show that our South Dakota customers would pay significantly more for  
10 replacement energy than they would for the revenue requirements of Luverne. The  
11 comparison is illustrated in the graph included as Exhibit \_\_\_ (BDM-2), Schedule 2.  
12 The graph incorporates price data that is a confidential commercial product and  
13 therefore has been excluded from the public version of my testimony.

14  
15 Q. WHAT WERE THE ASSUMPTIONS USED IN ARRIVING AT THE ANNUAL  
16 REVENUE REQUIRMENTS AND THE ANNUAL MARKET ENERGY COSTS  
17 FOR THE COMPARISON?

18 A. As I mentioned, we began with the agreed upon revenue requirement for Luverne and  
19 agreed upon cost of replacement energy included in the Approved Stipulation. Going  
20 forward, the annual revenue requirement for Luverne is then calculated for each year  
21 during its expected life, including annually updated depreciation and other predictable  
22 cost changes. The rate of return and jurisdictional allocators are held constant over the  
23 period. Those components will change each time rates are reset over the period, but  
24 because we cannot predict what those changes might be, we maintain them at their  
25 current levels. Of course, the rates paid by South Dakota customers will change only  
26 when OTP has a general rate case, but the effects of the annual reductions of the  
27 revenue requirements benefit customers even between rate cases because it  
28 counteracts increases in other expenses thereby diminishing the need for rate  
29 increases.

30

1 For the projection of replacement energy costs, we use the energy price forecast  
2 commercially marketed by Woods Mackenzie. That forecast is the December 2009  
3 edition when the economy and energy prices were at their very lowest, and therefore,  
4 the forecasted replacement energy costs reflected are conservative. We updated the  
5 costs for 2011 and 2012 using the actual costs incurred from 2010, because we do not  
6 expect energy prices to drop in that timeframe. In fact, we expect the energy costs to  
7 be higher than 2010 in those years, so the use of 2010 actuals for 2011 and 2012  
8 should be a conservative estimate for purposes of this comparison. The calculation  
9 reflects that the kWh of Replacement Power will match the total kWh of Luverne  
10 output. This approach to Replacement Power was taken in the Approved Stipulation  
11 because South Dakota customers benefit from Luverne's output both for serving retail  
12 needs (in some hours) and in the production of asset based margins (in other hours)  
13 which are reflected as a credit to customers in the FCA. The Replacement Power  
14 calculation reflects that if Luverne is not approved for rate recovery, a replacement is  
15 necessary for the energy to serve retail load and for the energy sold to produce the  
16 asset based margins.

17  
18 Q. WHAT CONCLUSIONS DO YOU REACH FROM THIS COMPARISON?

19 A. This comparison demonstrates that OTP's South Dakota customers would pay much  
20 less for Luverne's revenue requirements than they would for replacement energy.  
21 That makes sense when one considers that the revenue requirements for Luverne will  
22 decline over the period, and the cost of replacement energy will increase. The graph  
23 illustrates that point. This point can also be illustrated by comparing the levelized  
24 revenue requirement of Luverne to the levelized cost of replacement energy. Luverne  
25 has a levelized cost for OTP's South Dakota customers of just \$32. Replacement  
26 energy over the same period would have a levelized cost of \$65. In other words,  
27 OTP's South Dakota customers should expect to pay more than double for  
28 replacement power if Luverne is not approved for rate recovery.

29



1 Q. YOU SAY THAT YOU CALCULATE THE LEVELIZED REVENUE  
2 REQUIREMENT FOR LUVERNE AS \$32. WHY IS THIS AMOUNT LOWER  
3 THAN THE \$37 LEVELIZED COST REFERENCED IN THE IRP PORTIONS OF  
4 TESTIMONY?

5 A. The amount is lower because Luverne has been in service for almost two years, and it  
6 is only being included in OTP's rates in this case. The Rate Base amount used in the  
7 revenue requirement calculation for Luverne in the Approved Stipulation reflects the  
8 depreciation that has occurred over that time. That means that South Dakota  
9 customers have not been charged anything for the output of Luverne since it became  
10 operational, and the resulting levelized cost of the project for South Dakota customers  
11 is less than the total levelized cost of the project.  
12

13 Q. IN ADDITION TO SAVINGS ON THE COSTS OF ENERGY, ARE THERE ANY  
14 OTHER SAVINGS THAT SOUTH DAKOTA CUSTOMERS WOULD REALIZE  
15 FROM LUVERNE IF IT IS APPROVED FOR RATE RECOVERY?

16 A. Yes. The comparison of the revenue requirement to the cost of replacement power  
17 does not include additional benefits that South Dakota customers will receive from  
18 Luverne if it is approved for rate recovery, such as: (i) the value of the renewable  
19 energy credits that can be sold (currently selling for about \$1 per MWh and expected  
20 to increase as the renewable energy mandates of other states kick in at higher and  
21 higher levels); and (ii) the capacity value for Luverne (MISO has given Luverne an  
22 accreditation of 25 percent of nameplate due to Luverne's very high capacity factors).  
23 OTP currently purchases capacity from the market, so the Luverne Wind Farm  
24 capacity has reduced the amount of capacity that OTP needs to purchase.  
25

26 Q. ARE THERE REASONS WHY LUVERNE'S REVENUE REQUIREMENTS ARE SO  
27 MUCH LOWER THAN FORECASTED MARKET ENERGY PRICES?

28 A. There are several reasons that are contributing to this difference. Luverne was  
29 constructed at very low cost. Because OTP has historically had reasonable cost  
30 recovery mechanisms in its three states, OTP was able to finance Luverne at a time

1 (during 2009) when almost no one else could get financing for infrastructure projects.  
2 This timing allowed OTP to procure the components for constructing Luverne at the  
3 very lowest possible cost. OTP also secured a federal grant for Luverne, made  
4 available through the American Recovery and Reinvestment Act, that reduced  
5 Luverne's capital costs by 30 percent. That grant was recognized as an up-front  
6 reduction to the amount of this investment included in rate base. The siting of  
7 Luverne also has advantages that further reduce the cost of this generation. OTP  
8 receives an investment tax credit from North Dakota, because Luverne is located in  
9 that state, and OTP has reflected the value of that credit in the revenue requirement in  
10 all of its service territory, including South Dakota. In addition, the specific site of  
11 Luverne (near Lake Ashtabula) has some of the most consistent wind in the region,  
12 resulting in very high capacity factors, reducing the per MWh cost. Further, Luverne  
13 had very low transmission interconnection costs because of its proximity to existing  
14 transmission facilities. All these factors have contributed to the very low cost of  
15 Luverne. In fact, the cost of Luverne is even lower than the Ashtabula project, which  
16 was constructed by OTP in 2008, and for which rate recovery was approved by the  
17 Commission in OTP's last rate case.

18  
19 Q. IS YOUR COMPARISON OF THE COST OF LUVERNE TO THE COST OF  
20 REPLACEMENT POWER INTENDED TO REBUT MR. EVANS' TESTIMONY?

21 A. It is to the extent that Mr. Evans is advocating against rate recovery for Luverne.  
22 However, as Mr. Patrylak and I both explain, Mr. Evans' testimony is aimed at  
23 criticizing what OTP did in and around 2006 in putting together the OTP 2006-2020  
24 IRP, which is in large part beside the point as we stand here in 2011 and ask the  
25 question whether the Commission wants a share of Luverne to be used for service to  
26 OTP's South Dakota customers. That question should first be answered based upon  
27 what options OTP and the Commission have today.

28  
29 That having been said, OTP has a strong interest in demonstrating to the Commission  
30 that it has been and continues to do excellent work in its integrated resource planning

1 activities. I believe I have demonstrated that over my tenure at OTP and in the  
2 proceedings I have been part of, such as the Big Stone II Siting proceeding. I am,  
3 therefore, providing additional testimony to rebut Mr. Evans' specific criticisms of  
4 OTP's integrated resource planning work. Mr. Patrylak also provides testimony to  
5 demonstrate that our integrated resource planning work has been consistent with  
6 industry standards.

7  
8 **V. THE IRP MANAGER RESOURCE PLANNING SOFTWARE**

9  
10 Q. CAN YOU PROVIDE A HISTORICAL SUMMARY OF THE SOFTWARE  
11 PACKAGE USED BY OTP TO DEVELOP THE 2006 – 2020 INTEGRATED  
12 RESOURCE PLAN?

13 A. Yes. OTP has used a software package called "IRP Manager" for its integrated  
14 resource planning, including the OTP 2006-2020 IRP. The concept for IRP Manager  
15 originated with the Electric Power Research Institute (EPRI) in the early 1980s. EPRI  
16 contracted with a California company, Decision Focus Inc., to develop a software  
17 program, which became known as the Load Management Strategy Testing Model  
18 (LMSTM). The intent behind LMSTM was to incorporate the ability to model  
19 conservation programs and load management programs in the same platform as  
20 supply-side resources. OTP was particularly interested in the software program  
21 because OTP had aggressively pursued load management to control peak demands and  
22 was implementing conservation programs. The first use of LMSTM at OTP was in  
23 1987. To further develop LMSTM as a commercial product, a company named  
24 Electric Power Software, later renamed EPS Solutions (EPS), was created as a spinoff  
25 from Decision Focus in 1988.

26  
27 Because of OTP's expertise in load management, EPS approached OTP about  
28 participating in further development of the model. This effort resulted in a greatly  
29 refined software package that included integrating the FIN financial model into  
30 LMSTM. FIN was a financial modeling package geared toward regulated utility

1 financial analysis, developed and marketed by M.S. Gerber and Associates of  
2 Columbus, Ohio.

3  
4 In the early 1990s, the LMSTM model was rewritten to a PC-based platform and  
5 renamed IRP-Manager. Throughout the 1990s, IRP-Manager was in significant use by  
6 utilities, both in the U.S. and internationally. EPS also developed and marketed other  
7 utility specific software packages. In late 2001, EPS was purchased by Itron and  
8 support for the IRP-Manager was dropped by Itron. OTP continued to maintain and  
9 use IRP-Manager and make additional changes by contracting with the original  
10 software developers from EPS.

11  
12 Q. DO YOU HAVE KNOWLEDGE OF OTHER USERS OF IRP-MANAGER?

13 A. Yes. According to Mr. Steven Bubb, who was CEO of EPS, between 25 and 50  
14 entities were using IRP-Manager when it was commercially available. These entities  
15 included utilities, state regulatory agencies, and research institutions.

16  
17 **VI. OTP'S USE OF IRP-MANAGER SOFTWARE FOR THE OTP**  
18 **2006-2020 IRP**  
19

20 Q. WHEN DID OTP BEGIN WORK ON THE OTP 2006-2020 IRP?

21 A. The development of an IRP takes many months of preparation and analysis. OTP was  
22 required to file the IRP in Minnesota by July 1, 2005, so work actually began in 2004.

23  
24 Q. DID OTP CONSIDER USING OTHER RESOURCE PLANNING SOFTWARE?

25 A. Yes. Because IRP-Manager was no longer commercially available and no longer  
26 generally supported by its developer, OTP was beginning discussions with software  
27 developers and vendors of other resource planning packages to replace IRP-Manager,  
28 but OTP had not yet received bids and selected a replacement product at that time. A  
29 new product would have required the construction of a complete new database and  
30 software testing, as well as training, and there wasn't sufficient time available prior to  
31 the filing date.

1 Q. WAS IRP-MANAGER AN OBSOLETE MODEL AT THAT TIME (2004)?  
2 A. In terms of functionality and developing a resource plan IRP-Manager was not  
3 obsolete. As I previously mentioned, OTP had hired the software developers to make  
4 updates to IRP-Manager. But because the IRP-Manager was no longer being made  
5 available from its developer, it was not being updated by the developer and therefore  
6 there were some aspects of IRP-Manager that were not current. Those aspects only  
7 affected the speed of the IRP-Manager and its ability to be operated using a Windows  
8 based operating system. IRP Manager was incapable of utilizing the higher speeds  
9 and memory capability of newer PCs, thus full model execution time was 5 – 7 days.  
10 IRP-Manager was also not able to take advantage of the features of the Windows  
11 operating system, and data input was very labor intensive.  
12  
13 Q. DID ANY OF THESE LIMITATIONS AFFECT THE ACCURACY OR VALIDITY  
14 OF IRP-MANAGER?  
15 A. No. While these limitations could create inconvenience for me and my colleagues,  
16 they did not affect the accuracy or the validity of IRP-Manager. As further explained  
17 by Mr. Patrylak, there were advantages to IRP-Manager compared to other software  
18 options that were commercially available in that timeframe.  
19  
20 Q. IS OTP STILL USING IRP-MANAGER?  
21 A. Yes, but only on a limited basis to verify results from the 2006 – 2020 IRP or to  
22 extract data to respond to information requests. OTP began the process of migrating  
23 the development of new resource plans to Strategist in 2007. The Strategist model  
24 was used by OTP in the development of its most recent 2011-2025 resource plan in  
25 Docket No. E-017/RP-10-623.  
26  
27 Q. WHAT HAS BEEN YOUR EXPERIENCE IN COMPARING STRATEGIST TO  
28 IRP-MANAGER?  
29 A. Overall, Strategist provides us the ability to run more scenarios in a shorter period of  
30 time. Strategist executes much faster than IRP-Manager and some of the data input

1 can be accomplished by cutting and pasting from Excel spreadsheets. It improves  
2 productivity. In terms of functionality, there are a few differences. Both models use  
3 essentially the same data, but in different formats in many cases. IRP-Manager  
4 provided some output functions and analysis capabilities not present in Strategist,  
5 especially in processing marginal unit and marginal cost data for rate development.  
6 IRP-Manager also has a much better financial modeling capability.

7  
8 Q. ARE THERE ANY DIFFERENCES IN THE MODELING OF WIND  
9 GENERATION BETWEEN STRATEGIST AND IRP-MANAGER?

10 A. None that we have noted. Ventyx, the vendor of the Strategist software, was hired to  
11 assist OTP in establishing a base case in Strategist. Ventyx developed the wind  
12 generation modeling in essentially the same manner that OTP had used in IRP-  
13 Manager.

14  
15 **VII. RESPONSE TO EVANS' CRITICISMS THAT IRP-MANAGER IS**  
16 **NOT A VALID IRP MODELING SOFTWARE TOOL**  
17

18 Q. MR. EVANS CLAIMS THAT IRP-MANAGER IS NOT A VALID IRP MODELING  
19 SOFTWARE TOOL. HAS OTP USED THE IRP-MANAGER MODEL AND  
20 ANALYSIS IN MANY DOCKETS?

21 A. Yes. Exhibit \_\_\_ (BDM-3), Schedule 3 contains a list of dockets in which IRP-  
22 Manager was a significant component of the testimony and/or regulatory review. In  
23 addition, IRP-Manager was used to develop the marginal cost data used in formulating  
24 and updating numerous small power producer tariffs in South Dakota, Minnesota, and  
25 North Dakota.

26  
27 Q. DO YOU BELIEVE THAT MR. EVANS HAS A CLEAR UNDERSTANDING OF  
28 THE IRP-MANAGER PLANNING MODEL?

29 A. No, I do not.  
30

1 Q. CAN YOU PROVIDE EXAMPLES OF WHY YOU FEEL THAT MR. EVANS  
2 DOES NOT UNDERSTAND IRP-MANAGER?

3 A. Yes. In Mr. Evans' testimony on page 5, beginning at line 36, he discusses the FIRM  
4 setting used to identify the wind resource in IRP-Manager. Mr. Evans included a copy  
5 of the IRP-Manager Handbook page relative to this setting as Exhibit GWE-6.

6 Quoting from the Handbook:

7

8 *A firm contract may be either a purchase or a sale. If a purchase, the*  
9 *utility pays at the variable cost and the busbar load is reduced each*  
10 *hour based on load shape(s) as entered by the User. If the interchange*  
11 *is a sale, the utility receives revenue and the busbar load is increased*  
12 *based on the load shapes(s). The revenue appears as a negative cost*  
13 *on the financial statements."*

14

15 The FIRM designation, as applied to wind generation, is simply telling IRP-Manager  
16 that it cannot refuse to take the wind generation, and that the costs are equal to the  
17 variable cost times the number of MWh. Since wind is serving part of the load, that  
18 means all of the rest of the generation resources only have to serve what is left of the  
19 load, from an economic dispatch perspective. If you are receiving wind generation  
20 from the wind, the rest of the generation resources need to back down to make room  
21 for the wind generation. This is exactly the same method used by the Strategist model,  
22 which Mr. Evans' says can model wind correctly.

23

24 In contrast to the limited meaning of FIRM in the IRP-Manager Handbook, Mr.  
25 Evans' response to IR SD-OTP-18, included as Exhibit \_\_\_(BDM-4), Schedule 4,  
26 states:

27

28 *In IRP-Manager, wind is considered a firm resource that reduces*  
29 *customer load. That is, the wind energy is completely dependable and*  
30 *the dispatchable resources only need to cover the customer load reduced*  
*by the wind generation and the reserve requirements necessary for the*

1           *customer load reduced by the wind generation. This technique is*  
2           *completely incorrect. In actual practice, not only do the dispatchable*  
3           *resources have to cover the customer load not reduced by the wind*  
4           *generation, they must also cover the possibility that the wind generation*  
5           *will not materialize and the reserve requirements of the customer load*  
6           *plus the wind generation. (Emphasis added.)*

7  
8           Mr. Evans is mistaken on this point. IRP-Manager calculates the reserve requirements  
9           based on the entire load that is served by any resource, wind or otherwise. IRP-  
10          Manager does not consider wind generation as a firm resource that is completely  
11          dependable and dispatchable from a capacity planning perspective. As I previously  
12          stated, IRP-Manager will back down other resources to the extent necessary to make  
13          room for the wind generation. Those resources are therefore available to increase  
14          generation if the wind generation does not take place.

15  
16          Mr. Evans' testimony with respect to capacity need, beginning at line 34 on page 4,  
17          claims that OTP installed the Luverne Wind Farm solely as an attempt to lower costs  
18          and not for capacity. In fact, IRP-Manager conducts a two-phase approach to its  
19          analysis. The first phase is to look at cost-effectiveness of a potential resource to see  
20          if it is cost-effective to add the resource based on the savings that would be realized by  
21          adding the resource. Cost-effectiveness takes into account the value of the energy  
22          savings, the value of the capacity provided, and the value of all other saved costs  
23          including variable O&M on other generating units. The second phase of IRP-Manager  
24          analysis is to look at any remaining capacity needs after the cost-effectiveness  
25          evaluation. The Luverne Wind Farm provides energy, capacity, and savings at other  
26          resources. Mr. Evans seems to believe that wind generation was not really needed  
27          because it was selected in the cost-effectiveness portion of the IRP-Manager  
28          evaluation. To the contrary, wind generation was the most cost-effective alternative  
29          available. If IRP-Manager had not selected wind generation in the cost-effectiveness  
30          evaluation, it would have been selected as the lowest cost capacity alternative in the



1 capacity expansion portion of the IRP-Manager analysis. Since OTP was at least 50  
2 MW capacity deficit in 2008, the capacity from wind generation was needed.

3  
4 **VIII. RESPONSE TO EVANS' CLAIM THAT OTP MODELED WIND**  
5 **GENERATION INCORRECTLY IN THE 2006 IRP.**  
6

7 Q. MR. EVANS HAS TESTIFIED THAT OTP MODELED WIND GENERATION  
8 INCORRECTLY IN IRP-MANAGER AS A FIRM RESOURCE AND THAT  
9 STRATEGIST IS CAPABLE OF CORRECTLY MODELING WIND  
10 GENERATION. DID YOU ASK MR. EVANS TO EXPLAIN HOW THE  
11 MODELING OF WIND GENERATION SHOULD HAVE BEEN DONE?

12 A. Yes. In a response dated January 25, 2011 (included as Exhibit \_\_\_ (BDM-5),  
13 Schedule 5), Mr. Evans responded and cited two Strategist settings that would treat  
14 wind generation as non-firm.

15  
16 The first setting determines whether the resource is a part of the model's unit  
17 commitment decision process, that is, whether to start or stop units for load serving  
18 purposes. Mr. Evans indicated in an email dated November 15, 2010 (Exhibit \_\_\_  
19 (BDM-6), Schedule 6), his belief that wind generation should not be considered as part  
20 of the decision process of whether to cycle generation off-line. In IRP-Manager, all of  
21 OTP's generation, except peaking generation, is modeled as MUST-RUN generation,  
22 meaning the model cannot cycle the generation off-line. Peaking generation is  
23 normally off-line, so IRP-Manager will behave exactly the same as Strategist on this  
24 item. In real operation, OTP does not pre-commit peaking facilities to operate just in  
25 case the wind doesn't blow. These are quick start units (10-minute start-up) that can  
26 be called upon if needed.

27  
28 The second setting cited by Mr. Evans determines whether the wind generation  
29 contributes to the utility's capacity reserve margin requirements. The rules for  
30 capacity contribution are established by the regional entities, and both the Mid-  
31 Continent Areamerica Power Pool (MAPP) and the Midwest Independent

1 Transmission System Operator (MISO) provide for wind generation capacity to count  
2 toward the reserve margin on a limited basis. In IRP-Manager, there is a REPORTED  
3 CAPACITY setting that tells the model how much capacity credit toward the reserve  
4 margin should be applied. OTP used this setting to correctly incorporate the capacity  
5 credit. While Mr. Evans' believes that wind should not have a capacity credit, the  
6 rules that OTP must follow provide for a partial capacity credit for wind.

7  
8 Q. DID OTP MODEL WIND GENERATION AS A FIRM RESOURCE AS CLAIMED  
9 BY MR. EVANS?

10 A. No. Mr. Evans cited the Contract Type entry in IRP-Manager as indicating that OTP  
11 modeled wind generation as a firm resource. The Contract Type entry simply tells  
12 IRP-Manager how it is to handle the energy and the associated cost. The entry used  
13 by OTP was FIRM, which tells IRP-Manager that it must accept the wind generation  
14 and cannot refuse to accept the energy (it is a "must-take" resource). This is the same  
15 treatment OTP gives to its energy purchases, which are generally procured on a take-  
16 or-pay basis. It also tells IRP Manager to calculate the cost based on the variable cost  
17 per megawatt-hour times the number of megawatt-hours of generation. The FIRM  
18 entry also tells IRP Manager that it must back down the load equivalent to the amount  
19 of wind generation prior to determining the dispatch level of the rest of the generation.  
20 This is exactly the way it works in real-life operation. Other generation backs down to  
21 the extent necessary to make room for the wind generation. The model does not cycle  
22 the generation off-line, except for peaking generation, but can only back it down to the  
23 minimum load level. The generation remains on-line ready to pick up load again if the  
24 wind generation drops off.

25  
26 Q. DID MR. EVANS CITE ANYTHING ELSE IN HIS ALLEGATIONS THAT OTP  
27 MODELED WIND GENERATION AS A FIRM RESOURCE?

28 A. In Mr. Evans' response to Information Request SD-OTP-18 (Exhibit \_\_\_\_ (BDM-4),  
29 Schedule 4, he states "*In IRP-Manager, wind is considered a firm resource that*  
30 *reduces customer load. That is, the wind energy is completely dependable and the*

1 dispatchable resources only need to cover the customer load reduced by the wind  
2 generation and the reserve requirements necessary for the customer load reduced by  
3 the wind generation. This technique is completely incorrect. In actual practice, not  
4 only do the dispatchable resources have to cover the customer load not reduced by the  
5 wind generation, they must also cover the possibility that the wind generation will not  
6 materialize and the reserve requirements of the customer load plus the wind  
7 generation.” (Emphasis added.) I believe that Mr. Evans has misunderstood how  
8 IRP-Manager functions. IRP-Manager does subtract the wind generation from the  
9 load, in order to then properly dispatch the rest of the generation on what remains for  
10 load to be served. This is a calculation to determine the fuel and variable costs of  
11 dispatching the other resources to meet the MWh load not being served by the wind  
12 generation. This does not relieve IRP-Manager of having to provide capacity and  
13 associated reserves for 100 percent of the load as Mr. Evans states. The capacity  
14 reserves are calculated based on 100 percent of the reserves, and operating reserves  
15 are set by a MW input number. OTP is not required to carry, and does not carry, 100  
16 percent spinning reserves for wind generation. The Strategist model, that Mr. Evans  
17 suggests can properly model wind, treats purchases and hydro in exactly the same  
18 manner by subtracting it from the load prior to conducting dispatch of other generating  
19 resources.

20  
21 Q. DO YOU BELIEVE THAT MR. EVANS HAS A COMPLETE UNDERSTANDING  
22 OF UTILITY OPERATIONS WITH WIND GENERATION?

23 A. No. Based on his response to IR SD-OTP-18 (Exhibit \_\_\_ (BDM-4), Schedule 4, and  
24 his supplemental response to IR SD-OTP-27 (Exhibit \_\_\_ (BDM-7), Schedule 7, I  
25 believe Mr. Evans is not sufficiently familiar with utility real-time operation of wind  
26 generation and the electric system.

27  
28 Q. CAN YOU PLEASE EXPLAIN?

29 A. In the original response to IR SD-OTP-18 (Exhibit \_\_\_ (BDM-4), Schedule 4,  
30 Mr. Evans states, “*In actual practice, not only do the dispatchable resources have to*

1           *cover the customer load not reduced by the wind generation, they must also cover the*  
2           *possibility that the wind generation will not materialize and the reserve requirements*  
3           *of the customer load plus the wind generation.” And in the supplemental response to*  
4           *IR SD-OTP-27 (Exhibit \_\_\_ (BDM-7), Schedule 7, Mr. Evans states, “However, the*  
5           *intermittent nature of wind can be artificially captured to some extent in IRP-Manager*  
6           *through the following steps: 1. Increase the spinning reserves requirement to include*  
7           *the required back-up for wind resources.”*

8  
9    Q.    DOES MR. EVANS STATEMENT CORRECTLY DESCRIBE UTILITY  
10   OPERATION WITH WIND?

11   A.    No. Utilities do not back up 100 percent of their wind generation with on-line  
12   spinning reserves. There is no requirement to do so, and such excessive spinning  
13   reserves would add significant wasteful and unnecessary expense. The required  
14   backup can be provided by quick start combustion turbines which can be started and  
15   on-line within 10 minutes. Also, in operating the electric system, utilities are not left  
16   blindly trying to guess how much wind generation will be received. Forecasts are  
17   used that provide hourly estimates of the wind generation levels. At that point the  
18   wind generation is variable and utilities can plan on having wind generation within a  
19   reasonable range around the forecast.

20  
21   Q.    WHY IS BEING FAMILIAR WITH UTILITY OPERATIONS IMPORTANT?

22   A.    The whole purpose behind modeling is to reflect real utility operations to the extent  
23   possible within the limits of the model’s capabilities.

24  
25   **IX.    RESPONSE TO EVANS’ CLAIM THAT THE IRP-MANAGER**  
26   **MODELING IS INVALID BECAUSE IT DOES NOT**  
27   **ACCURACTELY REFLECT OTP’S OPERATIONS**

28  
29   Q.    ON PAGE 14 OF HIS TESTIMONY MR. EVANS CLAIMS THAT HE  
30   BENCHMARKED IRP-MANAGER AGAINST ACTUAL OPERATING RESULTS  
31   AND THAT IRP-MANAGER IS NOT REPRESENTATIVE OF OTP’S ACTUAL

1 OPERATIONS, AND THUS THE IRP-MANAGER IS NOT RELIABLE. DO YOU  
2 AGREE WITH HIS ASSESSMENT?

3 A. No, I do not. Mr. Evans did not benchmark IRP-Manager against actual results. Mr.  
4 Evans mismatched a comparison of IRP-Manager modeling *for a typical year* to an  
5 *actual year* of OTP historical operation. You cannot do such a comparison without  
6 accounting for the differences between the actual events and what is being modeled in  
7 a typical year.

8  
9 Q. PLEASE EXPLAIN WHAT YOU MEAN BY A TYPICAL YEAR.

10 A. A resource planning model develops a plan based on a typical year. But a utility never  
11 experiences a typical year. The typical year is developed by putting together twelve  
12 typical months. Each of the twelve months may be from a different year, but each  
13 month should represent the load shapes typically seen in that month. When the base  
14 model is established, the first year is the base year and actual data from the base year  
15 is input into the model and the model benchmarked so that it can replicate the base  
16 year. From that point forward then the model is operating against a typical year. Any  
17 comparison to actual data going forward must account for differences.

18  
19 Q. WHAT KIND OF DIFFERENCES DO YOU MEAN?

20 A. There are differences caused by weather patterns, reliability issues, and generator  
21 outage data, among several other impacts. For example, the OTP load is highly  
22 sensitive to weather patterns. Temperatures that are colder or warmer than typical  
23 have significant impacts on the load shape, and thus the generation levels required to  
24 serve the load. To accurately benchmark a model, you need to input the actual  
25 weather data so that the generation is being properly dispatched to match the actual  
26 load. In Mr. Evans' responses to IR SD-OTP-16 (included as Exhibit \_\_\_ (BDM-8),  
27 Schedule 8) and IR SD-OTP-17(included as Exhibit \_\_\_ (BDM-9), Schedule 9), he  
28 indicated that he did not make any adjustments for actual conditions versus the typical  
29 modeled conditions.

30

1 Q. HOW DO RELIABILITY ISSUES IMPACT THE RESULTS?

2 A. In running a resource planning model, you are creating a resource plan to serve the  
3 utility load responsibility to its customers. But OTP is a member of a generation pool  
4 and must respond to system emergencies on its own system and the systems of others.  
5 This is especially true for peaking generation that can be called upon to operate for  
6 other utilities. Pool members that lose generating resources due to a sudden forced  
7 outage of a unit or a transmission line have the right to call on OTP's generation for  
8 emergency purposes. A significant amount of the peaking generation operation cited  
9 in Mr. Evans' testimony was called for by other utilities. That operation was to serve  
10 other utilities and they paid for that service. That is not something that is planned for  
11 or included in the economic dispatch of generation contained in the model. Further,  
12 with the startup of the MISO centralized dispatch market in 2005, MISO frequently  
13 called upon the OTP peaking generation to be placed on-line at minimum load as  
14 reliability backup. This service was paid for by MISO, but it severely impacts the  
15 average cost and operating data when trying to compare expected operation with  
16 actual operation.

17  
18 Q. HOW DOES IT IMPACT AVERAGE COST DATA?

19 A. Natural gas and oil-fired combustion turbine peaking generation and baseload  
20 combined cycle generation can be reasonably efficient at full load operation. But this  
21 type of generation also suffers very significant efficiency penalties when operated at  
22 less than full load. The actual performance varies unit by unit, but in some cases it can  
23 take almost as much fuel to operate at low partial load levels as it does at full load.  
24 When MISO called upon OTP's peaking generation to operate at low loads, the  
25 average cost per MWh increased dramatically. And any differences between expected  
26 fuel costs and actual fuel costs are magnified as well. Unless this type of operation is  
27 accounted for in benchmarking, it is a futile exercise to try to benchmark the model  
28 against actual data.

29  
30 Q. HOW DOES GENERATION OUTAGE DATA IMPACT THE RESULTS?

1 A. The planning model will use a long-term average forced outage rate. But the yearly  
2 actual outage data can vary greatly year by year. Again, it is a situation of planning to  
3 a typical year. To benchmark a model against actual data requires consideration of  
4 what actually took place. Mr. Evans' approach would work if the utility's annual  
5 operation went exactly according to plan and expectations, but that does not happen in  
6 the real world.

7  
8 Q WHAT IS THE IMPACT OF THESE ERRORS ON MR. EVAN'S COMMENTS  
9 REGARDING BENCHMARKING?

10 A. Mr. Evans' comments about benchmarking are without merit since he did not account  
11 for differences between what actually happened and what is being modeled.

12

13 **X. RESPONSE TO EVANS' CLAIM THAT OTP DID NOT NEED**  
14 **CAPACITY WHEN ITS IRP IDENTIFIED THE NEED FOR THE**  
15 **LUVERNE PROJECT.**  
16

17 Q. DID OTP HAVE IMMEDIATE CAPACITY AND ENERGY NEEDS WHEN THE  
18 2006 – 2020 RESOURCE PLAN WAS BEING DEVELOPED?

19 A. Yes. Exhibit \_\_\_ (BDM-10), Schedule 10, contains Table III, 2006-2020 Base Case  
20 Planning Scenario Load & Capability Prior to Resource Plan Information. The table  
21 illustrates that OTP expected a 57 MW capacity deficit for Summer Season 2008 and a  
22 50 MW capacity deficit for Winter Season 2008. The expected capacity deficits  
23 increase each year throughout the entire planning period. For energy, the last OTP-  
24 owned baseload generation addition was the acquisition of an additional 28 MW of the  
25 Big Stone Plant in the late 1980s. Since that time, OTP has relied heavily on  
26 purchasing energy from the market to cover load growth. This had proven to be a low  
27 cost strategy as the region was very surplus in baseload energy. By the time of the  
28 2006-2020 IRP, however, the wholesale market was increasingly driven by natural  
29 gas-fueled generation. By 2005, the energy purchased to meet OTP customer load  
30 comprised approximately 36% of total energy requirements. This level of purchased  
31 power exposed OTP and its customers to potential volatile and high energy prices.

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Q. ON PAGE 4 OF HIS TESTIMONY, BEGINNING AT LINE 39, MR. EVANS STATES THAT OTP DID NOT NEED THE LUVERNE WIND FARM CAPACITY AND THAT THE LUVERNE WIND FARM WAS SELECTED BECAUSE IT LOWERED TOTAL OVERALL COSTS AND NOT BECAUSE OF CAPACITY REQUIREMENTS. DO YOU AGREE WITH THIS STATEMENT?

A. No I do not, as it misstates what is really taking place in the resource planning process. IRP-Manager completes a two part process in its evaluation. The first step is to evaluate all potential resources from an economic perspective. Each resource is evaluated independently to determine whether it can lower costs, even if capacity is not needed. If any resources are found to be cost-effective, the most cost-effective resource is implemented and then the cost-effectiveness evaluation is repeated until no more cost-effective resources are found. The model then evaluates whether reserve margin requirements have been met. If they haven't been met, IRP-Manager will implement additional resources, beginning with the resource that provides the lowest total cost, until reserve requirements have been met. Wind generation, including the portion that became the Luverne Wind Farm, was selected in the cost-effectiveness evaluation. That evaluation included the value of the capacity accreditation expected for the wind generation from the regional reliability entity. My point is that while the Luverne Wind Farm was selected in the cost-effectiveness step of the planning process, the reserve margin capacity credit was a part of the evaluation. And OTP needed capacity, as I previously testified.

Q. MR. EVANS' TESTIMONY CONTINUES ON PAGE 5 TO STATE THAT OTP HAS NO NEED FOR THE ADDITIONAL CAPACITY FROM THE LUVERNE WIND FARM AND INCLUDES EXHIBIT GWE-3, AN EMAIL RESPONSE FROM OTP, TO SUPPORT HIS POSITION. DO YOU AGREE WITH THAT STATEMENT?

A. No, I do not. The question Mr. Evans asked of OTP was "*That is, assuming your base plan additions, but without that 40 MW of wind, there is no capacity deficit in future*



1        *years. Am I wrong on this?"* The scenario Mr. Evans was referring to was from an  
2        October 2006 update to the Minnesota Public Utilities Commission. That scenario  
3        was an alternative scenario base case, including the use of the high environmental  
4        externality values as required by Minn. Stat. 216B.2422. Minnesota requires the use  
5        of environmental externalities in resource planning, but OTP does not use them for  
6        planning in North Dakota and South Dakota.

7  
8        When the Minnesota high environmental externality values were incorporated into the  
9        modeling, the model selected an additional 50 MW hydroelectric capacity and energy  
10       purchase from Manitoba Hydro, in order to back down existing fossil fueled  
11       generation to reduce emissions. In that particular alternative Minnesota scenario  
12       (which was not selected as OTP's base resource plan), a capacity deficit would not  
13       occur without the Luverne Wind Farm until 2015.

14  
15       In OTP's base case without environmental externalities, the 50 MW of the Manitoba  
16       Hydro purchase would not be included. But even if the OTP 2006-2020 IRP had  
17       surplus capacity, that does not mean the Luverne Wind Farm should not be added.  
18       One of the features of IRP-Manager is that it will provide the timing and ranking of  
19       when resources were selected in the evaluation process. The wind generation was  
20       selected first, prior to spot market capacity purchases. If the plan called for more  
21       capacity than was needed, it would be logical to reduce or drop the most expensive  
22       capacity resource, not the resource that provides the lowest cost.

23  
24       **XI.    RESPONSE TO EVANS CLAIM THAT OTP DID NOT**  
25       **ADEQUATELY CONSIDER WIND INTEGRATION COSTS.**  
26

27       Q.    ON PAGE 13 OF MR. EVANS' TESTIMONY HE CLAIMS THAT OTP DID NOT  
28       SUFFICIENTLY INCORPORATE THE COSTS OF WIND INTEGRATION IN ITS  
29       MODELING. SPECIFICALLY, MR. EVANS STATES ON PAGE 13, AT LINES  
30       32-35, THAT OTP DOES NOT CLAIM WIND INTEGRATION COSTS WERE  
31       USED IN IRP-MANAGER. DO YOU AGREE?

1 A. No, I do not. In March 2006, OTP issued a request-for-proposals for up to 75 MW of  
2 renewable energy. Approximately 45 proposals were received from 28 different  
3 entities. All of the proposals were based on wind generation. In the same time period,  
4 OTP was involved with the State of Minnesota in a wind integration cost study. Mr.  
5 Evans included a presentation of that study as Exhibit GWE-15, which showed the  
6 wind integration costs could vary from \$2.11 to \$4.41 per MWh. As part of its  
7 resource planning process, OTP compared the costs of the wind proposals to the wind  
8 generation costs being modeled in IRP-Manager to determine if the costs being  
9 modeled were sufficient to cover wind integration costs based on the study. OTP  
10 concluded that its modeling costs were sufficient to cover wind integration costs and  
11 the wind generation project costs. OTP did not have a separate line item cost in the  
12 model, but all variable costs per MWh have to be lumped together into a single cost  
13 stream.

14  
15 Q. ON PAGE 13 AT LINE 39 MR. EVANS STATES THAT OTP NEEDED TO  
16 INCREASE THE WIND INTEGRATION COSTS OVER TIME TO COVER  
17 INCREASED WIND GENERATION PENETRATION. DO YOU AGREE?

18 A. No. The Minnesota study results of \$2.11-\$4.41 per MWh already were based on  
19 wind generation penetration levels of 15 percent, 20 percent, and 25 percent. The  
20 increased wind penetration is accounted for.

21  
22 Q. ON PAGE 9 AT LINES 15-18 OF HIS TESTIMONY, MR. EVANS STATES THAT  
23 OTP CLAIMS THAT LUVERNE WILL PROVIDE SAVINGS OF  
24 APPROXIMATELY \$1.63 PER MEGAWATT-HOUR OF WIND GENERATION.  
25 HE STATES THAT THIS IS A SMALL MARGIN OF SAVINGS AND THEN ON  
26 PAGE 13 AT LINES 2-7 OF HIS TESTIMONY CITES THE MINNESOTA WIND  
27 INTEGRATION STUDY THAT DEVELOPED AN ESTIMATED RANGE OF  
28 WIND INTEGRATION COSTS FROM \$2.11 TO \$4.41 PER MEGAWATT-HOUR.  
29 ARE THESE NUMBERS COMPARABLE?

1 A. No, they are not. The \$1.63 per megawatt-hour number was calculated by Mr. Evans.  
2 Exhibit \_\_\_ (BDM-11), Schedule 11, shows his response to IR SD-OTP-26 with the  
3 calculation. It is not comparable to any of the wind integration numbers because  
4 Mr. Evans calculated the number using the entire discounted savings over the resource  
5 plan evaluation period in 2003 dollars.

6

7 Q. DO YOU KNOW WHAT THE COMPARABLE NUMBERS WOULD BE?

8 A. I used the Minnesota wind integration study value range of \$2.11 to \$4.41 per  
9 megawatt-hour and calculated the wind integration costs from 2008 through 2034, the  
10 entire modeling period of the Luverne Wind Farm. Those values were then  
11 discounted back at the same discount rate contained in IRP-Manager to develop a  
12 comparable range value. Putting the wind integration costs on the same 2003 dollar  
13 basis as the savings number calculated by Mr. Evans would provide an average wind  
14 integration cost of \$0.69 to \$1.44 per megawatt-hour. My calculations are shown in  
15 Exhibit \_\_\_ (BDM-12), Schedule 12. But, as I previously testified, OTP had already  
16 included consideration of the wind integration costs in its modeling. My purpose here  
17 is to show that the savings number calculated by Mr. Evans is not relative to any other  
18 cost values contained in his testimony. You cannot ignore the time value of money  
19 when doing these types of comparison.

20

21 Q. ON PAGE 13, AT LINES 19-24, OF HIS TESTIMONY MR. EVANS STATES  
22 THAT WIND INTEGRATION COSTS WILL INCREASE IN FUTURE YEARS.  
23 DO YOU AGREE?

24 A. While some aspects of wind integration costs will increase, other aspects are  
25 decreasing. A tremendous amount of research is being conducted and improvements  
26 are being made in wind generation forecasting. As a result, utilities are able to predict  
27 with much greater accuracy what level of wind generation they will receive in the next  
28 few hours and for the following day. This reduces unit commitment costs and costs  
29 associated with inaccurate energy scheduling. The load balancing function for all of  
30 OTP's wind resources is performed at the MISO level rather than at the OTP level.

1 This reduces the load following costs because the wind generation being balanced is  
2 much more geographically dispersed. This tends to smooth out the variations in total.  
3 Also, all of the MISO area is responding to balance the load and generation which  
4 reduces the variability as well and thus reduces cost. The penetration of wind  
5 generation is much lower at the MISO level and thus the costs are lower. MISO also  
6 does a re-dispatch of resources on 5 minute intervals rather than on hourly intervals,  
7 which helps to ensure the lowest cost generation is being used. Finally, utilities and  
8 the reliability entities are beginning to use wind generation to provide load balancing  
9 on their own. This is accomplished by linking the turbine blade pitch angle to the  
10 imbalance between load and generation. Thus, wind generation can self-provide some  
11 its own regulating reserve. Mr. Evans is correct in that the fuel costs of fossil fueled  
12 generation providing regulation service is likely to increase, but the amount of  
13 regulation per MWh of wind generation is being driven down by improvements in  
14 operations.

15  
16 Q. MR. EVANS CLAIMS THAT OTP DID NOT PERFORM SUFFICIENT  
17 SCENARIO ANALYSIS IN THE DEVELOPMENT OF ITS RESOURCE PLAN. IS  
18 HE CORRECT?

19 A. No. Mr. Evans chose to treat the October 2006 analysis as a stand-alone resource  
20 plan, which is not the case. OTP's initial filing was made to the Minnesota PUC in  
21 mid-2005. The filing included the results of fourteen scenarios. New wind generation  
22 in that filing totaled 110.5 MW. As a result of some potential concerns raised by the  
23 Minnesota Office of Energy Security (OES), several additional scenarios were run in  
24 April 2006. These scenarios proved the OES' concerns were unfounded. In the  
25 development of these scenarios, OTP saw for the first time that IRP-Manager was  
26 selecting 160 to 200 MW of new wind generation, but chose to leave the amount of  
27 wind generation at 110.5 MW. This increase in the amount of wind generation was  
28 the result of four large industrial load additions to the OTP system that were unknown  
29 at the time of filing of the original IRP filing in 2005, but those load additions were  
30 now under construction or committed.

1  
2 In July 2006, the Minnesota PUC ordered additional base case analysis due to rapid  
3 escalation of fuel and construction costs. In August 2006, an 11.5 MW customer-  
4 owned baseload biomass generator shut down permanently. OTP updated its cost  
5 numbers and ran new scenarios that included the base case scenario, a scenario with  
6 the consideration of the MN high environmental externality values, a scenario with the  
7 consideration of a carbon tax, and a scenario that included non-firm wholesale sales.

8  
9 In every one of the scenarios, IRP-Manager was selecting 160 – 200 MW of new wind  
10 generation. Through all of these scenarios, OTP gained experience with what the  
11 results would likely be from various scenarios. The consideration of a carbon tax or  
12 environmental externalities provides much the same result as an increase in fuel costs.  
13 So, over the course of a year and a half or more, OTP had investigated a significant  
14 variety of scenarios. In the fall of 2006, OTP increased the wind generation in its  
15 resource plan to 160 MW, which was the bottom of the range of wind generation  
16 being selected by IRP-Manager across a range of scenarios.

17  
18 **XII. RESPONSE TO EVANS' CLAIM THAT OTP DID NOT**  
19 **COMPARE LUVERNE TO ALTERNATIVES.**  
20

21 Q. MR. EVANS CONCLUDES THAT OTP DID NOT COMPARE LUVERNE TO  
22 OTHER ALTERNATIVES. IS THAT A FAIR CONCLUSION?

23 A. No. OTP's analysis provided a comparison of all resource alternatives. Evan's  
24 appears to base his criticism on OTP's practice of reflecting in its modeling the time  
25 frames necessary to permit and construct each resource alternative—and he interprets  
26 this practice as giving resources with shorter lead times (such as wind) an advantage in  
27 the comparison when compared with resources with longer lead times. But this is  
28 incorrect. Reflecting the lead times of resource alternatives does not inappropriately  
29 advantage certain resource types over others, and the lead times for putting resources  
30 into service cannot be ignored in planning.

31

1 The resource planning analysis that resulted in the Luverne Wind Farm was being  
2 completed in 2006. The earliest resource plan approval could have been received was  
3 early in 2007. The time required to obtain construction permits, complete designs,  
4 acquire equipment, and complete construction is then in addition to this timeline. OTP  
5 made available to IRP-Manager resource alternatives in the years in which they  
6 physically could be available. Wind generation was available in 2008 because of its  
7 relatively short permitting and construction requirements. Peaking generation was  
8 made available in 2009 and baseload generation was made available beginning in  
9 2010.

10  
11 OTP also made spot market capacity purchases available to bridge the gaps until  
12 certain resources could be permitted, constructed, and would be available. On page 10  
13 of his testimony Mr. Evans states OTP should have allowed IRP-Manager to select  
14 baseload and peaking generation in 2008. Those scenarios would not have been  
15 physically possible and therefore are not potential resource plans. But as I will explain  
16 below, that doesn't mean that alternative resources were not available for the model to  
17 select if they were part of the least cost plan—the model would have selected these  
18 alternatives if they were part of the least cost plan.

19  
20 Q. WHAT WOULD HAPPEN IF YOU DID ANALYSIS WHERE YOU MADE  
21 PEAKING AND BASELOAD RESOURCES AVAILABLE IN YEARS EARLIER  
22 THAN IT WOULD HAVE BEEN POSSIBLE TO PLACE THOSE RESOURCES  
23 INTO SERVICE?

24 A. If that was how we made resources available in the modeling, we would need to take  
25 into consideration that there would be other costs of implementing the plan, due to the  
26 need to purchase spot market capacity to bridge the intervening time period until such  
27 a resource could be brought on-line in 2009, 2010, or later. If those additional costs  
28 weren't included in the modeling, the results would not be accurate because they  
29 would not include the spot market capacity costs or the increased cost of construction  
30 from real lead times. In fact, the way that we have made resources available

1 appropriately considers these costs to bridge the lead times. If the costs of an  
2 alternative resource, including these bridge costs, had been preferable to including the  
3 wind resources into the plan, the modelling would have done so.

4  
5 Q. SO IRP-MANAGER WAS DOING THIS WEIGHING OF ALTERNATIVES ON  
6 ITS OWN, AND ANY ALTERNATIVE COULD HAVE BEEN SELECTED?

7 A. Yes. If it was the least cost plan, IRP-Manager could have not chosen the wind  
8 generation, and purchased spot market capacity until a resource available at a later  
9 date could be constructed that provided lower costs. In fact, IRP-Manager starts with  
10 a default resource plan consisting of natural gas-fired peaking generation for use in  
11 economic comparisons. Even though OTP did not make peaking generation available  
12 in 2008, IRP-Manager had default peaking generation available that it could pair up  
13 with spot market capacity, or simply use all peaking generation for the resource plan.  
14 IRP-Manager evaluated those possibilities and found them to be more expensive.

15  
16 Q. DID YOU HAVE ANY SUBSEQUENT IRP-MANAGER RUNS TO CHECK  
17 MR. EVANS' POINT?

18 A. Yes. Mr. Evans requested that OTP do an IRP-Manager run, removing the Luverne  
19 Wind Farm and replacing it with a natural gas-fired combustion turbine in 2015.

20  
21 Q. WHAT WERE THE RESULTS OF THE IRP-MANAGER RUN FOR MR. EVANS?

22 A. The results confirmed the resource plan which included the Luverne Wind Farm. The  
23 scenario picked by Mr. Evans had a lifetime cost higher than OTP's resource plan of  
24 \$6 million in 2003 dollars. This was a cost reduction to customers after all other costs  
25 had been paid. To put this in proper context, from a time value of money perspective,  
26 the equivalent 2003 construction cost of the Luverne Wind Farm was about \$42  
27 million using the discount rate that was in IRP-Manager. If we leave the Luverne  
28 Wind Farm construction cost at its \$72 million level in 2009, the associated expected  
29 customer savings are \$10.3 million in 2009\$.

30

1 Q. SO IS THIS WHAT SOUTH DAKOTA CUSTOMERS CAN EXPECT FOR  
2 SAVINGS?

3 A. No. The Luverne Wind Farm began operation in August 2009. Since that time, South  
4 Dakota customers have been receiving the output from the Luverne Wind Farm  
5 without cost since the facility has not been included in base rates. As I previously  
6 testified, the levelized cost to South Dakota customers over the life of the wind farm is  
7 now substantially lower and their savings are substantially higher.

8  
9 Q. ARE THERE OTHER QUALITATIVE CONSIDERATIONS IN THE SELECTION  
10 OF THE LUVERNE WIND FARM?

11 A. Yes, there are. Mr. Evans cited a number of risks relative to load growth, fuel prices,  
12 wind integration costs, etc. And those are valid risks to some degree. There are many  
13 other considerations, most of which have very little downside risk for wind generation  
14 and significant potential upside benefits. Most significant are the environmental risks  
15 for utilities and their customers, and we don't see much potential for environmental  
16 regulation declining in the future.

17  
18 Wind generation has zero emission risk and offsets the use of fossil fuels. There is a  
19 chance we will have some sort of carbon regulation in the future. This could either be  
20 in the form of cap and trade or a carbon tax. The proposals that have been put forth so  
21 far would add costs to utilities and their customers. Wind generation will avoid those  
22 costs and thus the risk exposure of SD customers is reduced. There is also the  
23 potential for a federal Renewable Energy Standard (RES). Should Congress pass an  
24 RES, many believe the federal Production Tax Credit (PTC) will no longer be needed  
25 as a market incentive. In OTP's experience, the PTC reduced the cost of wind  
26 generation by about 33%. North Dakota has some of the best state incentives around,  
27 reducing the cost of wind generation by another 10%. The North Dakota incentives  
28 had sunset clauses. OTP managed to lock in the federal and state incentives by  
29 moving forward with the Luverne Wind Farm when it did. If OTP had not moved  
30 forward with the Luverne Wind Farm and then been forced to add more wind



1 generation at a later date to meet a federal RES, without the incentives, costs would  
2 have been substantially higher.

3  
4 **XIII. CONCLUSION**

5  
6 Q. PLEASE SUMMARIZE YOUR TESTIMONY.

7 The Luverne Wind Farm Costs should be approved for recovery in OTP's South  
8 Dakota rates. South Dakota customers would pay much more for electricity if the  
9 Commission were to deny recovery for Luverne and to subject South Dakota  
10 customers to the cost of replacement power. Also, Mr. Evans' criticisms of OTP's  
11 resource planning are incorrect. OTP's use of IRP Manager and its modeling for the  
12 2006-2020 IRP specifically are valid, and Mr. Evans' testimony and conclusions  
13 indicate that Mr. Evans has overlooked or misunderstood some of the information,  
14 may not have been aware of other information, and as a result reached incorrect  
15 conclusions regarding OTP's resource planning activities and the Luverne Wind Farm  
16 specifically.

17  
18 Q. DOES THIS CONCLUDE YOUR TESTIMONY?

19 A. Yes.