Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2011.5.41
Spion Kop Wind Generation
NorthWestern Energy

PREFILED DIRECT TESTIMONY OF

TODD A. GULDSETH

ON BEHALF OF NORTHWESTERN ENERGY

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Witness Information

Q. **Please state your name and business address.**

A. My name is Todd A. Guldseth. My business address is 40 East Broadway, Butte Montana, 59701.

Q. **By whom are you employed and in what capacity?**

A. I am employed by NorthWestern Energy ("NWE" or "NorthWestern") as a Planner in Energy Supply.

Q. **Please summarize your education and employment experience.**

A. I graduated from Montana Tech in 1990 with a B.S. Degree in Business Administration, and from the University of Montana in 1992 with a Masters in Business Administration. In September 2005, I earned the right to use the Chartered Financial Analyst designation.

I joined NorthWestern Energy in July 2003 as a Financial Analyst in the Financial Planning and Analysis Group. In November 2008, I moved to the Energy Supply Group as a Planner, where my duties include assisting in the development of the biennial resource procurement plan, analyzing potential energy resources for addition to the supply portfolio, and modeling the impact of variables such as variations in load, resource stack, and other items that could affect the supply portfolio.

Purpose of Testimony

Q. What is the primary purpose of your testimony?

A. My testimony addresses:

1. The impact of the Spion Kop Wind Generation Project ("Spion Kop") on the cost of NorthWestern's supply portfolio;
2. Spion Kop's cost and value in comparison to alternative energy resources; and
3. The consistency of the 2009 Request For Information ("RFI), and consequently the Spion Kop acquisition, with the conclusions and action plans outlined in NWE's 2007 and 2009 Resource Procurement Plans ("RPP"), and § 69-8-419, MCA.

Impact of Spion Kop on Supply Portfolio Cost

Q. Please explain the impact of the acquisition of Spion Kop on the cost of NorthWestern's supply portfolio.

A. Because the Spion Kop cost of service has no variable components that will be tracked, the Spion Kop fixed cost of service, or revenue requirement, will be added into the generation asset mix already established under the Electricity Supply Service umbrella. Colstrip Unit 4 and the Dave Gates Generating Station at Mill Creek ("DGGS") are also included among these generation assets. The following table illustrates the total electric supply rate with and without the impact of Spion Kop's fixed cost of service:

Illustrative Average Supply Rate Comparison With & Without Spion Kop Based on May 2011 - April 2012 Electric Tracker Filing			
Electric Supply Rates: ($/MWh)	May 2011 Forecast	2013 Spion Kop	2014 Spion Kop
Market Purchases & Other Supply Costs	$37.59	$36.89	$36.89
Colstrip Unit 4 Fixed	$12.67	$12.67	$12.67
Colstrip Unit 4 Variable	$3.61	$3.61	$3.61
Dave Gates Generation Station Fixed	$4.58	$4.58	$4.58
Dave Gates Generation Station Variable	$1.83	$1.86	$1.86
Spion Kop Fixed Cost of Service	n/a	$1.18	$1.61
Energy Supply Total:	$60.28	$60.78	$61.21
$ Difference from May 2011 Forecast:		*$0.50*	*$0.93*
% Difference from May 2011 Forecast:		*0.8%*	*1.5%*

Comparing the May 2011 tracker costs without Spion Kop to the May 2011 tracker costs including Spion Kop, market purchase costs decrease by an estimated $0.70/MWh as a result of Spion Kop's energy production. Colstrip Unit 4 fixed and variable costs, and DGGS fixed costs are not impacted by the addition of Spion Kop. Variable costs at the DGGS increase $0.03/MWh due to the increased production necessary to serve the incremental 7 to 8 MW of regulation required to support integration of Spion Kop on the transmission system as described in the Prefiled Direct Testimony of Mike Cashell. The new DGGS variable cost rate of $1.86/MWh reflects increased fuel expense partially offset by increased energy revenue credits, as discussed below. Finally, Spion Kop's fixed cost of service is layered in. The total Spion Kop fixed cost revenue requirement as well as an explanation of the difference in Spion Kop's revenue requirement between 2013 and 2014 due to bonus depreciation is discussed in the Prefiled Direct Testimony of Pat DiFronzo. Note that unlike Colstrip Unit 4 and the DGGS, Spion Kop does not include a variable cost component. This is because its fuel, wind, does not incur a cost and all operating and maintenance expenses are included in the fixed cost of service.

Q. Please explain how Spion Kop impacts the supply portfolio's cost of regulation.

A. As explained above, 7 to 8 MW of incremental regulation will be required by Spion Kop and will be provided by the DGGS. As a result of the increased regulation need, production at DGGS will increase by an estimated 2 Average Megawatts ("MWa") requiring an additional 137,983 Dkt of natural gas. Assuming an average price of $4.6034/Dkt for natural gas, the increased annual fuel expense equals $635,194. Energy revenue credits will also increase as a result of the increased production at the plant. Assuming the 2 MWa can be valued at $25.93/MWh (Mid-C price of $32.93/MWh minus a Mid-C to Montana market discount of $7.00/MWh) for each hour of the year (8,760), the increased energy revenue credit equals $454,207. The increase in fuel expense offset by the increase in energy revenue credit results in a net annual DGGS variable cost increase of $180,987. Dividing this net annual increase by the forecasted sales volumes for May 2011 – April 2012 (5,916,672 MWh) results in the $0.03/MWh DGGS Variable Cost rate increase reflected in the table above.

Comparison to Alternative Resources

Q. As a general matter, how does NorthWestern compare the relative costs and benefits of alternative energy resources?

A. Many things need to be considered when evaluating resources. These resource parameters include:

- How well the resource meets the energy and capacity needs of the utility;
- The risks associated with managing the resource, such as fuel supply risk or transmission availability;
- The costs of the resource, including integration costs, transmission costs and other indirect costs of the project;
- The environmental attributes of the resource, including whether the resource meets the eligibility criteria for renewable resources in the state of Montana; and
- Whether the resource contributes to fuel and resource type diversity in the supply portfolio.

NorthWestern employs a variety of processes to ensure proper consideration of each of these factors for all possible resources. These include needs assessments for the portfolio, consultation with the Electric Technical Advisory Committee ("ETAC"), the development and use of the biennial RPPs, and the use of broad market solicitations such as the 2009 RFI in resource procurement processes.

Q. Do the costs of Spion Kop compare favorably to other alternatives?

A. Yes. The levelized cost of Spion Kop in comparison to the levelized cost of alternative energy resources is summarized in the following table. The alternative resources chosen for comparison include: (1&2) entering into market contracts and buying market renewable energy credits ("RECs") to meet the Renewable Portfolio Standard ("RPS"), (3&4) entering into market contracts but not buying market RECs and not meeting RPS, (5) entering into Qualifying Facility ("QF") contracts, (6) the generic wind pricing incorporated in the 2009 RPP, and (7) the next lowest priced power purchase agreement ("PPA") of the proposals that made the final four in the 2009 RFI.

Total Cost of Alternative Energy Resources (All 25-year levelized $/MWh except Hypothetical Wind and 2009 RFI PPA are 20-year)					
Resource Type	Energy	RECs	Sub-Total Energy + RECs	Integration	Total Comparative Cost
1. Market + RECs	$83.89	$7.48	$91.37	$0.00	$91.37
2. Sensitivity Market Scenario + RECs	$68.04	$7.48	$75.52	$0.00	$75.52
3. Market Only	$83.89	$0.00	$83.89	$0.00	$83.89
4. Sensitivity Market Scenario Only	$68.04	$0.00	$68.04	$0.00	$68.04
5. QF-1 Option 3: Wind Only Rate	$61.73	$7.48	$69.21	$14.99	$84.20
6. Hypothetical Wind in 2009 RPP	$59.34	$7.48	$66.82	$14.99	$81.82
7. 2009 RFI Second Lowest PPA	$57.40	$7.48	$64.88	$14.99	$79.87
8. Spion Kop Wind Project	$46.29	$7.48	$53.78	$14.99	$68.77

1. 25- year flat energy rate based on 2009 RPP Base Case Delay Carbon market price forecast - carbon penalty begins 2017 This is a buy market energy and market RECs scenario to satisfy RPS.
2. 25-year flat energy sensitivity scenario based on 2009 RPP Base Case Delay Carbon market price forecast revised with November 2010 forward electric and gas prices. This is a buy market energy and market RECs scenario to satisfy RPS.
3. 25- year flat energy rate based on 2009 RPP Base Case Delay Carbon market price forecast - carbon penalty begins 2017 RECs are not purchased and RPS is not achieved.
4. 25-year flat energy sensitivity scenario based on 2009 RPP Base Case Delay Carbon market price forecast revised with November 2010 forward electric and gas prices. RECs are not purchased and RPS is not achieved.
5. Current QF-1 Tariff Option 3 rate of $59.21, set by the PSC and based on the 2007 RPP, includes energy and RECs. This rate is currently the subject of an open PSC proceeding.
6. Pricing for Hypothetical Wind included in 2009 RPP was based on PPA pricing information obtained in the 2009 RFI.
7. Levelized PPA price of second lowest proposal submitted in 2009 RFI. $64.88 includes energy and RECs.
8. Spion Kop levelized rate of $53.78 includes energy and RECs.

Total comparative cost variables include energy, RECs, and integration. The energy cost component consists of the cost of energy plus a carbon penalty adder in the market purchase comparisons (1-4), and the cost of energy only in the renewable comparisons (5-7). NorthWestern believes that carbon legislation in some form will exist in the future and has included a carbon penalty in the market forecasts beginning in 2017 and escalating over the 25-year forecast period. The REC price is equal to the 20-year levelized price of RECs utilized in the 2009 RPP. Although NorthWestern does not possess significant REC market experience on which to base the 2009 RPP REC forecast, using it does provide consistency with how NorthWestern has conducted its resource planning and resource comparisons in recent years, and the forecast is in a reasonable range relative to the $10/MWh penalty NorthWestern would incur for failing to meet RPS requirements. The wind integration rate of $14.99/MWh is equal to the 20-year levelized integration rate based on DGGS costs and utilized in the 2009 RPP. Wind integration costs are not included in any of the renewable resource PPA or acquisition rates, including Spion Kop, but they have been added so that the total costs of renewable energy are reflected in the table.

Comparisons 1 and 2 are market based alternatives that assume RECs will also be purchased on the open market in order to satisfy RPS requirements. Comparison 1 is based on the 2009 RPP Base Case market price forecast and includes the carbon penalty described above, and Comparison 2 is a sensitivity scenario performed on the 2009 RPP Base Case market price forecast using November 2010 forward electric and natural gas prices. These two comparisons are somewhat imperfect because they are not valid alternatives due to the unlikelihood of being able to sign a 25-year market contract and the current illiquid REC market; however, they do give an idea of how Spion Kop compares to the market over the long-term.

Comparisons 3 and 4 are equal to Comparisons 1 and 2 respectively, but without REC purchases. As a result, RPS requirements are not met in these two comparisons. As with Comparisons 1 and 2, these two comparisons are somewhat imperfect due to the unlikelihood of being able to sign a 25-year market contract; however, they provide a range that helps complete the required analysis pursuant to §69-3-2007, MCA, the cost cap statute, which is discussed further below.

Comparison 5 is the current QF-1 Option 3, wind-only rate of $69.21/MWh. This rate was set by the Montana Public Service Commission ("Commission") based on the 2007 RPP and includes energy and RECs. Integration costs have been added to reflect the total cost of the resource.

Comparison 6 is the generic wind pricing used in the 2009 RPP and is based on PPA information obtained in the 2009 RFI. Again, the PPA pricing included energy and RECs but not integration costs, so they have been added to reflect the total cost of the resource.

Comparison 7 reflects the second lowest PPA offer of the four finalists in the 2009 RFI. The PPA rate of $64.88/MWh includes energy and RECs, and integration costs have been added to reflect the total cost of the resource.

Spion Kop's levelized price is $53.78/MWh and includes energy and RECs, and integration costs have been added to reflect the total cost of the resource. The levelized price is based on the stream of annual unit prices computed for the 25-year estimated life of the project. The unit prices are *computed by dividing the projected revenue requirement for each year by the* estimated annual production of 138,000 MWh described in the Prefiled Direct Testimony of Steve Jones. The 25-year revenue requirement worksheet deriving the levelized price is attached in Exhibit_(TAG-01).

To summarize the alternative resource comparison table, Spion Kop has a lower total cost than six of the seven alternatives and is very close to the lowest cost resource. Comparison 4, which is the 25-year Sensitivity Market Scenario without RECs resource, is the lowest cost alternative by \$0.73/MWh but does not achieve compliance with the RPS and is not readily available for a term of 25 years in the current electric market environment. But, as discussed above, Comparisons 3 and 4 provide a cost range that helps satisfy the requirements in §69-3-2007, MCA, which provides that a utility is "not obligated" to take electricity from an eligible renewable resource unless the eligible renewable resource has "demonstrated through a competitive bidding process that the total cost of electricity from that eligible resource, including the associated cost of ancillary services ... is less than or equal to bids for the equivalent quantity of power over the equivalent contract term from other electricity suppliers." NorthWestern believes that these requirements have been satisfied via comparisons of total costs, including ancillary costs, to several alternative resource options including two that are energy-only and do not achieve RPS compliance.

Q. Does Spion Kop possess any non-price benefits or risk mitigation characteristics?

A. Yes. In addition to Spion Kop being in-line with alternative resources from a cost stand-point, it also possesses characteristics that shield it from several potential risks over the long-term. The first risk is the volatility in the power markets to which a supply portfolio is exposed if it relies too heavily on market purchases to fulfill its load serving obligations. Even long-term market contracts, the longest of which normally do not exceed five years, expose a supply portfolio to the risk of renewing those contracts at unknown prices every few years. Although wind energy is variable by nature and exposes a portfolio to short-term market fluctuations to some degree, Spion Kop provides a long-term energy resource at a known price, thereby reducing the overall amount of the portfolio's exposure to volatile power markets.

Second is the risk of green house gas ("GHG") emissions regulation, either by the Environmental Protection Agency ("EPA") or legislated by Congress. While it appears that congressional legislation is on the back-burner for the time being, the EPA is moving forward, albeit slowly, with regulations addressing GHG emissions via the Clean Air Act. If, or when, this happens, thermal generating plants will be impacted while resources that do not emit GHGs will provide price stability to supply portfolios that contain them. To give an idea of the degree of penalty a portfolio may experience by substituting market purchases for wind energy, the levelized difference between the 2009 RPP Base Case Delay Carbon market forecast used in the alternative resource comparison table, which included a carbon penalty beginning in 2017 and was based on the proposed Waxman-Markey legislation, and the no-carbon market forecast used in the 2009 RPP is $11.06/MWh. Multiplying this levelized penalty rate by Spion Kop's expected annual production of 138,000 MWh equals annual carbon risk mitigation of $1.5 million.

Third is volatility in fuel markets such as natural gas and coal. Because wind facilities do not consume any fuel, wind projects are immune to this volatility.

Fourth is protection from having to achieve RPS compliance by transacting in an illiquid REC market. The current REC market has not developed into the type of liquid market in which buyers can be matched with sellers in a timely, efficient manner. And, even if an efficient REC market does develop, neighboring states and California have RPS requirements that substantially exceed Montana's and this could drive strong demand for RECs causing prices to escalate to very high levels. Combined with its current renewable resource portfolio, NorthWestern estimates that the addition of Spion Kop will allow for RPS compliance through 2015; absent Spion Kop, compliance will be in jeopardy as early as the 2013-2014 timeframe (see Exhibit_TAG-(02)).

Lastly, an ownership benefit offered by Spion Kop is mitigation of the risk of an energy or RPS shortfall at the end of its projected life in 25 years. By owning Spion Kop rather than entering into a PPA (which will simply expire in 25 years and expose the supply portfolio to the risks associated with replacing the contract, which could include market price risk, REC price and availability risk, and contract renewal risk), NorthWestern will have the option to continue running the project for the purpose of serving NorthWestern customers if its condition is adequate to do so, recapitalize the project if its condition is inadequate to serve customers, sell the project, or just sell the energy and RECs. Ownership of the project will allow NorthWestern to assess market conditions in 25 years and choose an option that best suits its customers.

Q. Has NorthWestern compared these non-price benefits and risk mitigation characteristics to other resource types?

A. Yes. The following table illustrates some risk areas that various types of resources, both owned and contracted, hedge against. This is not necessarily an all-inclusive list of risks or resource types, but it gives an indication of the advantages different types of resources have relative to various types of risk. It is evident that selecting energy resources of only one or two types can leave a supply portfolio exposed to considerable risk, and that an owned wind resource provides diversity from more traditional thermal resources and market purchase contracts.

Risks Hedged by Various Energy Resource Types						
	Potential Risk					
Resource Type	Long-term Power Market Exposure	Short-term Power Market Exposure	Environ-mental Regulation	Fuel Price Volatility	Contract Renewal	Operating
Wind (owned)	X		X	X	X	X*
Wind (contract)	X		X	X		X
Thermal (owned)	X	X			X	
Thermal (contract)	X	X				X
Market (contract)		X		X		X

*Spion Kop has an effective 10-year hedge by virtue of the Full Service Agreement with General Electric.

Long-term power market exposure arises when a supply portfolio relies too heavily on market purchase contracts rather than long-term assets, whether owned or contracted for. A portfolio is subjected to short-term power market exposure when its scheduled resources come up short of its load serving obligation. The variable nature of wind can expose a portfolio to short-term market volatility on both the buy and sell side, depending on how it has diverged from its schedule output. Environmental regulation includes GHG regulation as discussed previously, as well as SOx, NOx, and all other types of emitting regulations. Thermal plants are subject to volatility in the fuel markets such as coal and natural gas. Contract renewal risk is present when an existing contract expires and can include few or no counterparties to renew with, higher rates, or more stringent contract terms than the previous contract. Finally, operating risk concerns relate to all the costs associated with running and maintaining an owned asset. The addition of Spion Kop as an owned wind resource will provide a hedge from 1) long-term power market volatility through its 25-year fixed-pricing, 2) environmental regulations because of its clean fuel and REC value, 3) volatile fuel prices, 4) contract renewal risks because of the value of ownership, and 5) operating risk, because the General Electric Full Service Agreement mitigates much of the operating risk over the first 10 years of operation.

Consistency of the Spion Kop Acquisition with the 2007 and 2009 RPPs, and MCA

Q. Is the acquisition of Spion Kop Wind consistent with the overall approach toward wind generation contained in the 2007 and 2009 RPPs?

A. Yes. NorthWestern's 2007 and 2009 RPPs both included 150 MW of wind in their respective preferred portfolios. And, in the action items contained in each plan, NorthWestern stated its intention to conduct competitive resource solicitations with the objective of acquiring renewable resources in order to fulfill the portfolio need identified in the planning process. Following through on the stated action items in the 2007 RPP, NorthWestern initiated an RFI for renewable resources in the Fall of 2009.

The 2009 RFI was in progress during the development of the 2009 RPP, but the 2009 RPP action items were consistent with the intent of the RFI. In Chapter 9 of the 2009 RPP, NorthWestern concludes that wind resources present a number of operational and economic challenges; yet, recognizing the many benefits associated with wind, NorthWestern proposes a "cautious and incremental approach for new wind" and states that it will add approximately 50 to 75 MW of additional wind while it gains knowledge of how the additional wind will impact the supply portfolio. The acquisition of the 40 MW Spion Kop project is a strong step in fulfilling NorthWestern's intentions stated in Chapter 9.

Q. Is the acquisition of Spion Kop consistent with the three-year action plan in the 2009 RPP?

A. Yes. In the three-year action plan items contained in Chapter 10 of the 2009 RPP, NorthWestern states that, with regard to wind resources, it will: 1) look for opportunities to increase the geographic diversity of the wind portfolio (Action Item ("AI") 2.b.); 2) compare the value and costs of owned versus contracted wind resources when completing the 2009 RFI (AI 2.c.); 3) meet resource requirements through a combination of PPAs and equity acquisitions (AI 4.a.); 4) continue to meet RPS requirements by, among other methods, acquiring renewable projects through competitive solicitations (AI 5.b.); and 5) monitor carbon legislation and consider the risks associated with committing to resource acquisitions with and without carbon emissions (AI 9). The acquisition process of Spion Kop has been consistent with all of these action items.

Q. How does the addition of Spion Kop affect the GenTrader® modeling results and consequently the preferred portfolios selected in the 2009 RPP?

A. To assess the effect of Spion Kop on the 2009 RPP, stochastic modeling under 2009 RPP Base Case Scenario assumptions was conducted on the preferred portfolios with two cases added: 1) a no-wind case was added to examine the benefit achieved in a portfolio by adding wind (every portfolio except one, #54, in the 2009 RPP contained additional wind under the assumption that wind would be the primary renewable resource utilized to meet RPS requirements); and 2) a case in which the 40 MW Spion Kop project replaced 40 MW of the generic wind modeled in the 2009 RPP planning process. The addition of these two cases, along with the original base case stochastic modeling from the 2009 RPP, form a trio of cases by which the relative effects of adding generic wind to a no wind portfolio and then further replacing a portion of that generic wind with Spion Kop wind can be analyzed and evaluated.

Stochastic analysis was used rather than intrinsic analysis to determine the extent to which fixed price variable resources, such as wind, can add stability to a portfolio under volatile electric market conditions. The basic difference between stochastic and intrinsic modeling is that stochastic modeling incorporates volatility into model inputs, such as the electric price forecast and the fuel cost forecast. Because NorthWestern relies on the electric market to fulfill a significant portion of its load-serving obligation, the planning practice has been to add a volatility component to the electric market price forecast so that long-term portfolio risk can be evaluated along with long-term portfolio cost.

The following table reflects 20-year total costs for each of the three preferred portfolios under the three cases previously described using the 2009 RPP Base Case Scenario assumptions.

20-Year Total Porfolio Costs 2009 RPP Base Case Scenario			
Case	(A)	(B)	(C)
Preferred Portfolios	No Wind (does not meet RPS)	150MW Generic Wind (2009 RPP)	110MW Generic + 40MW Spion Kop
PF 21 300MW SCCT Frame	$11,580,060,000	$11,588,520,000	$11,539,330,000
PF 24 300MW SCCT Aero	$11,680,070,000	$11,688,570,000	$11,639,380,000
PF 27 200MW CCCT	$11,866,160,000	$11,874,630,000	$11,825,440,000
(D) Preferred Portfolio Avg	$11,708,763,333	$11,717,240,000	$11,668,050,000

Total Cost Differences between Preferred Portfolio Averages (D): Higher/(Lower)	
150 MW Hyp (2009 RPP) difference from No Wind: (B - A)	$8,476,667
Spion Kop difference from No Wind: (C- A)	($40,713,333)
Spion Kop difference from 150 MW Hyp (2009 RPP): (C - B)	($49,190,000)

The analysis shows that the average 150 MW Generic Wind case (2009 RPP) costs $8.5 million more than the average No Wind case over 20 years. The Spion Kop case costs $40.7 million less than the No Wind case and $49.2 million less than the 150 MW Generic Wind case. This result is due to

40 MW of higher-priced generic wind being replaced by 40 MW of lower-priced Spion Kop wind.

The next table shows the 20-year total upside portfolio cost risk under the same electric market volatility conditions used in the 2009 RPP. The table shows the increased cost above the 20-year total portfolio costs each of the three portfolios could reasonably expect to experience under volatile market conditions.

20-Year Total Upside Porfolio Cost Risk 2009 RPP Base Case Scenario			
Case	(A)	(B)	(C)
Preferred Portfolios	No Wind (does not meet RPS)	150MW Generic Wind (2009 RPP)	110MW Generic + 40MW Spion Kop
PF 21 300MW SCCT Frame	$1,384,031,700	$1,184,812,900	$1,189,089,000
PF 24 300MW SCCT Aero	$1,252,658,700	$1,048,104,800	$1,052,488,800
PF 27 200MW CCCT	$1,182,302,200	$983,744,800	$987,915,600
(D) Preferred Portfolio Avg	**$1,272,997,533**	**$1,072,220,833**	**$1,076,497,800**
Total Upside Risk Differences between Preferred Portfolio Averages (D): Higher/(Lower)			
150 MW Hyp (2009 RPP) difference from No Wind: (B - A)			($200,776,700)
Spion Kop difference from No Wind: (C- A)			($196,499,733)
Spion Kop difference from 150 MW Hyp (2009 RPP): (C - B)			$4,276,967

Both the average 150 MW Generic Wind and Spion Kop cases reflect approximately $200 million in lower average upside portfolio cost risk than the No Wind case. The $4.3 million difference between the 150 MW Generic Wind case and the Spion Kop case is due to differences in the timing of the wind resources being placed into the portfolios. The conclusion that can be drawn is that, under the 2009 RPP Base Case Scenario modeling assumptions, adding moderate amounts of wind to a portfolio that doesn't contain wind reduces exposure to volatile electric markets and, therefore, reduces the risk of higher portfolio costs at little or no increase to the long-term cost of the portfolio.

These stochastic modeling results are further analyzed in comparative tables and displayed graphically in Exhibit_(TAG-03). Box 1 on page 1 shows how the preferred portfolios' 20-year levelized rates respond when the 150 MW of 2009 RPP generic wind was added to the No Wind case: the average 20-year levelized rate increased 0.3% but upside cost risk declined an average of 14.3%. Box 1 also shows that the No Wind case is subject to 10.1% upside cost risk while the 150 MW Generic Wind case is subject to 8.6% upside cost risk. By taking the percentage difference between the two upside cost risk values, the estimated decrease in upside cost risk by adding 150 MW of generic wind to a portfolio without wind is 14.3%.

Upside cost risk is measured as the difference between the 95% confidence level levelized rate, which represents the rate at which 95% of the modeled outcomes are either equal to or fall below, and the mean levelized rate (Upside Cost Risk = 95% Confidence Level – Mean Portfolio Cost). By using the 95% confidence level rate, extreme outliers are excluded from the analysis which reduces the likelihood of producing results that aren't meaningful. The upside cost risk is then taken as a percentage of the mean levelized rate to determine the relative relationship between the two so it can be compared with the other cases.

Box 2 on page 1 of Exhibit_(TAG-03) shows how the preferred portfolios' 20-year levelized rates respond when 40 MW of generic wind is replaced by 40 MW of Spion Kop wind – the average 20-year levelized rate actually declines 0.1% compared to the No Wind case, and the average upside cost risk is reduced by 13.6%.

The graph on page 2 of Exhibit_(TAG-03) reflects these results visually. The 2009 RPP preferred portfolios are represented by squares and define the efficiency frontier. Triangles represent the preferred portfolios in the No Wind case, demonstrating that when wind is taken out of the portfolio, a small decrease in cost is achieved at the expense of significantly higher upside cost risk. Circles represent the preferred portfolios in the Spion Kop case, reflecting a decrease in portfolio cost while maintaining the same level of upside cost risk as compared to the 2009 RPP preferred portfolios.

Q. Have you developed sensitivities on any 2009 RPP Base Case assumptions since the plan was submitted in June 2010?

A. Yes. A Sensitivity Market Scenario was developed subsequent to the filing *of the 2009 RPP that was based on November 2010 electric and natural gas* forward prices. The goal of this exercise was to determine the price and risk impact of lower market prices on the 2009 RPP preferred portfolios. The result was a significant decrease from the 2009 RPP Base Case electric price forecast and, consequently, a decrease in the total costs of the preferred portfolios.

Q. Does the Sensitivity Market Scenario have an impact on the price and risk associated with the preferred portfolios selected in the 2009 RPP, both with and without Spion Kop?

A. Yes. Stochastic models with the 2009 RPP Base Case Scenario market price forecast replaced by the Sensitivity Market Scenario market price forecast were run on the preferred portfolios under the three cases previously described, No Wind, 150 MW Generic Wind (2009 RPP), and 110 MW Generic Wind plus 40 MW Spion Kop Wind. The following table reflects 20-year total portfolio costs for each of the three preferred portfolios under these assumptions.

20-Year Total Porfolio Costs Sensitivity Market Scenario			
Case	(A)	(B)	(C)
Preferred Portfolios	No Wind (does not meet RPS)	150MW Generic Wind (2009 RPP)	110MW Generic + 40MW Spion Kop
PF 21 300MW SCCT Frame	$10,606,940,000	$10,751,030,000	$10,697,760,000
PF 24 300MW SCCT Aero	$10,750,050,000	$10,894,180,000	$10,840,900,000
PF 27 200MW CCCT	$10,964,460,000	$11,108,520,000	$11,055,300,000
(D) Preferred Portfolio Avg	**$10,773,816,667**	**$10,917,910,000**	**$10,864,653,333**
Total Cost Differences between Preferred Portfolio Averages (D): Higher/(Lower)			
150 MW Hyp (2009 RPP) difference from No Wind: (B - A)			$144,093,333
Spion Kop difference from No Wind: (C- A)			$90,836,667
Spion Kop difference from 150 MW Hyp (2009 RPP): (C - B)			($53,256,667)

Consistent with a lower market price forecast, total costs of each preferred portfolio decrease from the 2009 RPP Base Case Scenario costs by nearly $1 billion over 20 years. However, the 150 MW Generic Wind case cost difference from the No Wind case increases from $8.5 million to $144.1 million over 20 years, and the Spion Kop case's cost difference from the No Wind case goes from $40.7 million less costly to $90.8 million more costly over 20 years. The Spion Kop case is $53.3 million less costly than the 150 MW Generic Wind case.

The next table shows 20-year total upside portfolio cost risk under the Sensitivity Market Scenario.

20-Year Total Upside Porfolio Cost Risk Sensitivity Market Scenario			
Case	(A)	(B)	(C)
Preferred Portfolios	No Wind (does not meet RPS)	150MW Generic Wind (2009 RPP)	110MW Generic + 40MW Spion Kop
PF 21 300MW SCCT Frame	$1,034,210,700	$877,562,900	$881,530,800
PF 24 300MW SCCT Aero	$949,731,700	$792,086,600	$796,287,800
PF 27 200MW CCCT	$907,524,100	$754,279,000	$758,140,700
(D) Preferred Portfolio Avg	**$963,822,167**	**$807,976,167**	**$811,986,433**

Total Upside Risk Differences between Preferred Portfolio Averages (D): Higher/(Lower)	
150 MW Hyp (2009 RPP) difference from No Wind: (B - A)	($155,846,000)
Spion Kop difference from No Wind: (C- A)	($151,835,733)
Spion Kop difference from 150 MW Hyp (2009 RPP): (C - B)	$4,010,267

Both the 150 MW Generic Wind and Spion Kop cases reflect approximately $150 million in lower average upside portfolio cost risk than the No Wind case. The $4.0 million difference between the 150 MW Generic Wind case and the Spion Kop case is due to differences in the timing of the wind resources being placed into the portfolios. Comparing the two tables under the Sensitivity Market Scenario with the two tables under the 2009 RPP Base Case Scenario reveals that if electric market prices decline, the addition of fixed-priced wind increases the cost of a portfolio by a larger amount, and upside portfolio cost risk is mitigated by a smaller amount. However, both scenarios demonstrate that the addition of a moderate amount of fixed-priced wind benefits a portfolio in that there is a greater level of long-term price certainty, and that benefit is enhanced when the generic wind is replaced by Spion Kop wind.

These stochastic modeling results are further analyzed in comparative tables and displayed graphically in Exhibit_(TAG-04). Boxes 1 and 2 on page 1 show that the comparative results are very similar to the results in Exhibit_(TAG-03) discussed earlier, except that the portfolio cost and upside risk levels are lower.

The graph on page 2 of Exhibit_(TAG-04) reflects these results visually. Compared to the graph in Exhibit_(TAG-03), this graph is much more condensed and closer to the origin, indicating lower cost and lower risk portfolios. However, it can still be construed that by taking wind out of the 2009 RPP Sensitivity Market Scenario preferred portfolios, represented by boxes, a decrease in cost is achieved at the expense of higher upside cost risk, as represented by the No Wind case triangles. Furthermore, by replacing 40 MW of generic wind with 40 MW Spion Kop wind, represented by circles, cost decreases with little or no difference in upside cost risk.

Q. Are there any provisions of ARM 38.5.8228 that require explanation with regard to NorthWestern meeting minimum filing requirements for approval of electricity supply resources?

A. Yes. ARM 38.5.8228(2)(a) requires "a complete and thorough explanation and justification of all changes to the utility's most recent long-term resource plan and three year action plan, including how the utility has responded to all Commission written comments". To date, NorthWestern has not received written comments on the 2009 RPP from the Commission which was filed in June 2010.

Since the filing of the 2009 Plan, NorthWestern recognized, and has communicated to both the Commission and the ETAC a major change to the natural gas market that has had an immediate impact on the price of natural gas. This fundamental downward shift in North American natural gas prices is significant for resource planning purposes because it impacts both the electric market in the northwest and gas-fired resource costs. The change in the natural gas market is driven by fracking technology, horizontal drilling techniques, and the development of non-traditional shale resources.

The preferred resources identified in the 2009 Plan continue to provide the best balance of cost and risk when considered in the portfolio context of the 2009 Plan. The Sensitivity Market Scenario developed in November 2010 does not change NorthWestern's conclusions about the addition of renewable wind resources to the portfolio or the value of Spion Kop.

Q. Is NorthWestern Energy's resource planning process consistent with the requirements of § 69-8-419, MCA?

A. Yes. NorthWestern plans for future electricity supply resource needs consistent with § 69-8-419, MCA, managing a portfolio of resources to serve our customers' electricity needs and procuring new electricity supply resources as needed. NorthWestern's RPP process meets the five objectives contained in § 69-8-419 (2), MCA. NorthWestern evaluates a wide range of resources and evaluates those resources not only in terms of price, but also on the basis of non-price factors like resource diversity, environmental attributes, and ability to mitigate market and fuel price risks. Preferred resource portfolios in both the 2007 RPP and 2009 RPP provide resource diversity while mitigating the potential impacts of environmental, fuel, and market price risk at lowest long-term total cost to ratepayers. As previously discussed, the acquisition of Spion Kop is consistent with the 2009 RPP which identified wind as a priority resource.

Q. Is the acquisition of Spion Kop consistent with the requirements of ARM 38.5.8212 2(a)?

A. Yes. In fulfilling the requirements of § 69-8-419, MCA, NorthWestern clearly defined its resource need in the 2007 RPP, AI #1. In AI #3 in the 2007 RPP, NorthWestern discussed issuing an RFP for renewable resources in 2008, which it did with insufficient results. This led to the design of the RFI that NorthWestern issued in August of 2009, resulting in the acquisition of Spion Kop. That RFI process is discussed in detail in the Prefiled Direct Testimony of Steve Lewis.

Conclusion

Q. Please summarize your conclusions.

A. There are many requirements, risks, and costs that must be considered when adding a resource to the energy supply portfolio, and there is not a "one-size-fits-all" type of energy resource that can accommodate every concern. That is why it is important to not only consider the potential resource by itself but also in the context of the total supply portfolio. Spion Kop provides 25-year fixed-cost energy, RECs that will help achieve RPS requirements, shelter from potential GHG regulations, protection from volatile fuel markets, and ownership value beyond the initial 25-year period, all at a levelized cost that is lower than the current long-term QF-1 Option 3, Wind Only rate of $69.21/MWh. Although there are economic and operational challenges associated with wind resources, when combined with all the other NWE energy supply resources, owning this project will enhance NorthWestern's entire energy supply portfolio.

Q. Does this conclude your testimony?

A. Yes, it does.

NorthWestern En
Spion Kop Project urbines: 82.5 Meter Rotor Diameter
Revenue Requirement

		1 2013	2 2014	3 2015	4 2016	5 2017	6 2018	7 2019	8 2020	9 2021	10 2022	11 2023	12 2024
Rate Base:		$ 86,115,035	$ 86,115,035	$ 86,115,035	$ 86,115,035	$ 86,115,035	$ 86,303,509	$ 86,406,695	$ 86,604,711	$ 86,857,677	$ 87,105,717	$ 87,532,200	$ 87,969,345
Adjustments													
Accumulated Depreciation (Book Life)		3,406,715	6,813,429	10,220,144	13,626,858	17,033,573	20,447,609	23,869,151	27,298,308	30,735,506	34,180,708	37,642,479	41,121,232
Accumulated Deferred Income Tax Asset - NOL		(19,543,120)	(23,166,765)	(24,720,623)	-	-	-	-	-	-	-	-	-
Accumulated Deferred Income Taxes - Accelerated Tax Depr.		18,631,346	20,385,785	22,050,670	22,580,942	23,108,730	22,705,401	21,650,024	20,515,040	19,385,937	18,262,768	17,153,517	16,063,504
Total Year End Rate Base		$ 85,420,095	$ 82,102,566	$ 78,564,836	$ 49,507,235	$ 45,972,732	$ 43,060,469	$ 40,977,520	$ 38,881,285	$ 36,776,234	$ 34,662,241	$ 32,736,205	$ 30,784,608
Average Annual Rate Base		$ 85,767,565	$ 83,761,342	$ 80,333,713	$ 64,236,037	$ 47,939,984	$ 44,516,616	$ 42,019,010	$ 39,920,403	$ 37,826,760	$ 35,719,238	$ 33,693,223	$ 31,760,406
Return (Avg. Rate Base*Cost of Capital)	7.52%	$ 6,449,721	$ 6,298,855	$ 6,041,085	$ 4,830,550	$ 3,605,087	$ 3,347,649	$ 3,159,830	$ 3,002,091	$ 2,644,723	$ 2,686,087	$ 2,534,182	$ 2,388,383
Turbine and BOP O&M	2.60%	$ 1,742,500	1,786,063	1,830,714	1,676,462	1,923,394	1,783,005	1,827,580	1,873,269	1,920,101	1,968,103	1,804,065	1,849,166
Compass' Site Landowner Maintenance - BOP O&M	FLAT	$12,000	$12,000	$12,000	$12,000	$12,000	$12,000	$12,000	$12,000	$12,000	$12,000	$12,000	$12,000
Total Annual On-Going Landowner Costs and ROW Costs	2.50%	$12,280	$12,586	$12,901	$13,224	$13,554	$13,893	$14,240	$14,596	$14,961	$15,335	$15,719	$16,112
MT Electrical Energy Producers Tax ($0.20 per MWH)	$0.20	27,600	27,600	27,600	27,600	27,600	27,600	27,600	27,600	27,600	27,600	27,600	27,600
Landowner Royalty Fees	3% Yrs 1-15 & 4% Yrs 16-25	209,119	284,495	276,754	223,480	165,400	149,880	142,969	131,861	120,599	120,000	300,810	295,959
NWE Property Insurance		$125,000	$128,125	$131,328	$134,611	$137,977	$141,426	$144,962	$148,586	$152,300	$156,108	$160,011	$164,011
Wind Generation Facility Impact Fee		$161,466	$161,466	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Wildlife Study & Management Costs		$112,000	$114,800	$117,670	$12,923	$13,246	$13,577	$13,916	$14,264	$14,621	$14,986	$15,361	$15,745
Property Taxes		423,076	416,498	409,326	401,535	393,099	385,038	376,313	366,896	356,756	345,863	335,525	324,416
MCC/MPSC Taxes	0.55%	36,944	50,261	48,893	30,481	29,221	26,479	25,258	23,205	21,306	19,342	53,143	52,286
Depreciation		3,406,715	3,406,715	3,406,715	3,406,715	3,406,715	3,414,037	3,421,542	3,429,235	3,437,120	3,445,202	3,461,771	3,478,754
Deferred Income Taxes		16,831,346	3,554,437	1,664,893	530,288	527,788	(313,329)	(1,145,377)	(1,134,084)	(1,129,103)	(1,123,169)	(1,109,252)	(1,090,012)
Income Taxes		(22,579,120)	(6,770,728)	(4,754,751)	(4,059,545)	(4,741,762)	(4,005,262)	(3,255,184)	(3,513,959)	(3,773,026)	(4,037,984)	2,416,075	2,330,870
Total Revenue Requirement		$ 6,970,646	$ 9,463,173	$ 9,225,139	$ 7,449,322	$ 5,513,318	$ 4,905,992	$ 4,765,650	$ 4,305,350	$ 4,019,959	$ 3,649,475	$ 10,027,009	$ 9,865,288

COST OF SERVICE RATE CALCULATION.												
$ per kW Cost of Service Rate:	$0.051	$0.069	$0.067	$0.054	$0.040	$0.036	$0.035	$0.032	$0.029	$0.026	$0.073	$0.071
$ per MWH Cost of Service Rate:	$50.51	$68.72	$66.85	$53.98	$39.95	$36.20	$34.53	$31.85	$29.13	$26.45	$72.66	$71.49
Annual Production (MWH):	138,000	138,000	138,000	138,000	138,000	138,000	138,000	138,000	138,000	138,000	138,000	138,000

Full Levelizing Calculations:

	Years:	
Total Revenue Requirement	Yrs 1 - 25	$ 192,755,630
Total NPV Revenue Requirement		$ 82,577,309
Levelized Revenue Requirement (PMT)	25	$ 7,421,067
	25 LEV $ per kWH	*$0.054*
	25 LEV $ per MWH	$53.78

Income Taxes:		1	2	3	4	5	6	7	8	9	10	11	12
Tax Calculation Revenues		$ 6,970,646	$ 9,485,173	$ 9,225,139	$ 7,449,322	$ 5,513,318	$ 4,905,992	$ 4,765,650	$ 4,395,350	$ 4,019,959	$ 3,649,475	$ 10,027,009	$ 9,865,288
Turbine and BOP O&M		1,742,500	1,786,063	1,830,714	1,676,462	1,923,394	1,783,005	1,827,580	1,873,269	1,920,101	1,968,103	1,804,065	1,849,166
Compass' Site Landowner Maintenance - BOP O&M		12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000
Total Annual On-Going Landowner Costs and ROW Costs		12,280	12,586	12,901	13,224	13,554	13,893	14,240	14,596	14,961	15,335	15,719	16,112
MT Electrical Energy Producers Tax ($0.20 per MWH)		27,600	27,600	27,600	27,600	27,600	27,600	27,600	27,600	27,600	27,600	27,600	27,600
Landowner Royalty Fees		209,119	284,495	276,754	223,480	165,400	149,880	142,969	131,861	120,599	120,000	300,810	295,959
NWE Property Insurance		125,000	128,125	131,328	134,611	137,977	141,426	144,962	148,586	152,300	156,108	160,011	164,011
Wind Generation Facility Impact Fee		161,466	161,466	-	-	-	-	-	-	-	-	-	-
Wildlife Study & Management Costs		112,000	114,800	117,670	12,923	13,246	13,577	13,916	14,264	14,621	14,986	15,361	15,745
Property Taxes		423,076	416,498	409,326	401,535	393,099	385,038	376,313	366,896	356,756	345,863	335,525	324,416
MCC/MPSC Taxes		36,944	50,261	48,893	30,481	29,221	26,479	25,258	23,205	21,306	19,342	53,143	52,286
Tax Depreciation (MACRS)		51,496,274	13,562,249	8,163,553	4,921,760	4,514,681	2,518,810	140,056	186,423	211,113	236,148	202,481	364,432
Montana Corporate Income Tax		(3,349,186)	(624,427)	(262,664)	(127,164)	(227,022)	(83,237)	63,401	37,692	12,491	(13,143)	414,053	399,451
Interest Expense	2.60%	2,229,957	2,177,795	2,088,677	1,670,137	1,246,440	1,157,432	1,092,494	1,038,164	983,546	928,700	876,100	825,771
Federal Taxable Income		$ (46,268,383)	$ (8,626,337)	$ (3,631,413)	$ (1,756,748)	$ (3,136,270)	$ (1,149,910)	$ 875,879	$ 520,703	$ 172,563	$ (181,569)	$ 5,720,062	$ 5,518,340
Federal Income Tax	35.00%	$ (19,229,934)	$ (6,146,296)	$ (4,491,887)	$ (3,932,381)	$ (4,514,739)	$ (3,522,024)	$ (3,318,565)	$ (3,551,651)	$ (3,785,517)	$ (4,024,841)	$ 2,002,022	$ 1,931,419
Federal Taxable Income		$ (46,268,383)	$ (8,626,337)	$ (3,631,413)	$ (1,756,748)	$ (3,136,270)	$ (1,149,910)	$ 875,879	$ 520,703	$ 172,563	$ (181,569)	$ 5,720,062	$ 5,518,340
Montana Corporate Income Tax		(3,349,186)	(624,427)	(262,664)	(127,164)	(227,022)	(83,237)	63,401	37,692	12,491	(13,143)	414,053	399,451
Montana Corporate Taxable		$ (49,617,569)	$ (9,250,764)	$ (3,894,277)	$ (1,883,912)	$ (3,363,292)	$ (1,233,147)	$ 939,281	$ 558,395	$ 185,054	$ (194,712)	$ 6,134,115	$ 5,917,791
MT Corporate Income Tax	6.75%	$ (3,349,186)	$ (624,427)	$ (262,664)	$ (127,164)	$ (227,022)	$ (83,237)	$ 63,401	$ 37,692	$ 12,491	$ (13,143)	$ 414,053	$ 399,451
Production Tax Credits - PTC ($22 per MW, if utilized)	$22.00	$3,036,000	$3,127,080	$3,220,892	$3,317,519	$3,417,045	$3,519,556	$3,625,143	$3,733,897	$3,845,914	$3,961,291	$0	$0
PTC Escalation Rate	3%	1	2	3	4	5	6	7	8	9	10	11	12

NorthWestern Energy
Spion Kop Project - GE Turbines: 82.5 Meter Rotor Diameter
Revenue Requirement

		13 2025	14 2026	15 2027	16 2028	17 2029	18 2030	19 2031	20 2032	21 2033	22 2034	23 2035	24 2036	25 2037
Rate Base:		$ 88,417,418	$ 88,876,693	$ 89,347,450	$ 90,071,239	$ 90,813,122	$ 91,573,553	$ 92,352,984	$ 93,151,921	$ 94,243,789	$ 95,362,953	$ 96,510,096	$ 97,685,918	$ 98,891,135
Adjustments:														
Accumulated Depreciation (Book Life)		44,617,363	48,131,397	51,663,689	55,224,100	58,813,333	62,432,108	66,081,165	69,761,259	73,463,771	77,249,763	81,060,321	84,916,558	88,819,618
Accumulated Deferred Income Tax Asset - NOL		-	-	-	-	-	-	-	-	-	-	-	-	-
Accumulated Deferred Income Taxes - Accelerated Tax Depr.		14,984,239	13,910,490	12,842,426	11,779,423	10,727,579	9,686,677	8,650,842	7,620,163	6,604,601	5,610,872	4,627,951	3,649,152	2,674,536
Total Year End Rate Base		$ 28,815,786	$ 26,834,806	$ 24,841,334	$ 23,067,715	$ 21,272,210	$ 19,454,767	$ 17,620,987	$ 15,770,409	$ 14,155,416	$ 12,502,318	$ 10,821,824	$ 9,120,207	$ 7,396,981
Average Annual Rate Base		$ 29,800,197	$ 27,825,296	$ 25,838,070	$ 23,954,525	$ 22,169,962	$ 20,363,488	$ 18,537,877	$ 16,695,743	$ 14,962,958	$ 13,328,867	$ 11,662,071	$ 9,971,016	$ 8,258,594
Return (Avg. Rate Base*Cost of Capital)	7.52%	$ 2,240,975	$ 2,092,462	$ 1,943,023	$ 1,801,380	$ 1,667,181	$ 1,531,334	$ 1,394,048	$ 1,255,620	$ 1,125,214	$ 1,002,331	$ 876,988	$ 749,820	$ 621,046
Turbine and BOP O&M	2.50%	1,895,396	1,942,780	1,991,350	1,799,871	1,844,868	1,890,989	1,938,264	1,986,721	1,763,422	1,807,507	1,852,695	1,899,012	1,946,488
Compass' Site Landowner Maintenance - BOP O&M	FLAT	$12,000	$12,000	$12,000	$12,000	$12,000	$12,000	$12,000	$12,000	$12,000	$12,000	$12,000	$12,000	$12,000
Total Annual On-Going Landowner Costs and ROW Costs	2.50%	$16,515	$16,927	$17,351	$17,784	$18,229	$18,685	$19,152	$19,631	$20,121	$20,624	$21,140	$21,669	$22,210
MT Electrical Energy Producers Tax ($0.20 per MWH)	$0.20	27,600	27,600	27,600	27,600	27,600	27,600	27,600	27,600	27,600	27,600	27,600	27,600	27,600
Landowner Royalty Fees 3% Yrs 1-15 & 4% Yrs 16-25		291,117	286,288	281,443	363,526	358,160	352,742	347,333	341,894	326,003	321,708	317,414	313,122	308,787
NWE Property Insurance		$168,111	$172,314	$176,622	$181,037	$185,563	$190,202	$194,957	$199,831	$204,827	$209,948	$215,196	$220,576	$226,091
Wind Generation Facility Impact Fee		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Wildlife Study & Management Costs		$16,139	$16,542	$16,956	$17,380	$17,814	$18,259	$18,716	$19,184	$19,663	$20,155	$20,659	$21,175	$21,705
Property Taxes		312,502	299,747	286,115	273,284	259,560	244,902	229,268	212,615	197,094	180,539	162,903	144,134	124,180
MCC/MPSC Taxes	0.53%	51,431	50,578	49,722	48,167	47,456	46,738	46,022	45,301	43,195	42,626	42,057	41,489	40,914
Depreciation		3,496,161	3,514,004	3,532,292	3,560,411	3,589,233	3,618,775	3,649,056	3,680,094	3,722,513	3,765,092	3,810,558	3,856,238	3,903,060
Deferred Income Taxes		(1,079,265)	(1,073,749)	(1,068,064)	(1,063,003)	(1,051,841)	(1,040,902)	(1,035,835)	(1,030,679)	(1,015,562)	(993,730)	(982,921)	(978,799)	(974,617)
Income Taxes		2,255,229	2,185,432	2,115,030	2,048,709	1,978,188	1,907,227	1,842,745	1,777,027	1,703,984	1,625,392	1,559,058	1,500,018	1,440,223
Total Revenue Requirement		$ 9,703,909	$ 9,542,925	$ 9,381,446	$ 9,088,147	$ 8,954,008	$ 8,818,553	$ 8,683,326	$ 8,547,338	$ 8,150,075	$ 8,042,693	$ 7,935,347	$ 7,828,055	$ 7,719,687
COST OF SERVICE RATE CALCULATION														
$ per kW Cost of Service Rate:		$0.070	$0.069	$0.068	$0.066	$0.065	$0.064	$0.063	$0.062	$0.059	$0.058	$0.058	$0.057	$0.056
$ per MWH Cost of Service Rate:		$70.32	$69.15	$67.98	$65.86	$64.88	$63.90	$62.92	$61.94	$59.06	$58.28	$57.50	$56.73	$55.94
Annual Production (MWH):		138,000	138,000	138,000	138,000	138,000	138,000	138,000	138,000	138,000	138,000	138,000	138,000	138,000

Full Levelizing Calculations:

	Years: Yrs 1 - 25
Total Revenue Requirement	
Total NPV Revenue Requirement	
Levelized Revenue Requirement (PMT)	25
	25 LEV $ per kWH
	25 LEV $ per MWH

Income Taxes:		13	14	15	16	17	18	19	20	21	22	23	24	25
Tax Calculation Revenues		$ 9,703,909	$ 9,542,925	$ 9,381,446	$ 9,088,147	$ 8,954,008	$ 8,818,553	$ 8,683,326	$ 8,547,338	$ 8,150,075	$ 8,042,693	$ 7,935,347	$ 7,828,055	$ 7,710,687
Turbine and BOP O&M		1,895,396	1,942,780	1,991,350	1,799,871	1,844,868	1,890,989	1,938,264	1,986,721	1,763,422	1,807,507	1,852,695	1,899,012	1,946,488
Compass' Site Landowner Maintenance - BOP O&M		12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000
Total Annual On-Going Landowner Costs and ROW Costs		16,515	16,927	17,351	17,784	18,229	18,685	19,152	19,631	20,121	20,624	21,140	21,669	22,210
MT Electrical Energy Producers Tax ($0.20 per MWH)		27,600	27,600	27,600	27,600	27,600	27,600	27,600	27,600	27,600	27,600	27,600	27,600	27,600
Landowner Royalty Fees		291,117	286,288	281,443	363,526	358,160	352,742	347,333	341,894	326,003	321,708	317,414	313,122	308,787
NWE Property Insurance		168,111	172,314	176,622	181,037	185,563	190,202	194,957	199,831	204,827	209,948	215,196	220,576	226,091
Wind Generation Facility Impact Fee		-	-	-	-	-	-	-	-	-	-	-	-	-
Wildlife Study & Management Costs		16,139	16,542	16,956	17,380	17,814	18,259	18,716	19,184	19,663	20,155	20,659	21,175	21,705
Property Taxes		312,502	299,747	286,115	273,284	259,560	244,902	229,268	212,615	197,094	180,539	162,903	144,134	124,180
MCC/MPSC Taxes		51,431	50,578	49,722	48,167	47,456	46,738	46,022	45,301	43,195	42,626	42,057	41,489	40,914
Tax Depreciation (MACRS)		412,546	446,149	480,682	523,260	583,864	644,770	689,528	735,296	820,908	926,764	1,002,213	1,059,670	1,118,441
Montana Corporate Income Tax		386,488	374,527	362,463	351,096	339,010	326,849	315,799	304,639	292,019	278,550	267,182	257,064	246,817
Interest Expense	2.60%	774,805	723,498	671,790	622,818	576,419	529,451	481,985	434,089	389,037	346,551	303,214	259,246	214,723
Federal Taxable Income		$ 5,339,261	$ 5,174,015	$ 5,007,354	$ 4,850,324	$ 4,683,365	$ 4,515,365	$ 4,362,703	$ 4,208,537	$ 4,034,186	$ 3,848,120	$ 3,691,074	$ 3,551,297	$ 3,409,731
Federal Income Tax	35.00%	$ 1,868,741	$ 1,810,905	$ 1,752,574	$ 1,697,614	$ 1,639,178	$ 1,580,378	$ 1,526,946	$ 1,472,988	$ 1,411,965	$ 1,346,842	$ 1,291,876	$ 1,242,954	$ 1,193,406
Federal Taxable Income		$ 5,339,261	$ 5,174,015	$ 5,007,354	$ 4,850,324	$ 4,683,365	$ 4,515,365	$ 4,362,703	$ 4,208,537	$ 4,034,186	$ 3,848,120	$ 3,691,074	$ 3,551,297	$ 3,409,731
Montana Corporate Income Tax		386,488	374,527	362,463	351,096	339,010	326,849	315,799	304,639	292,019	278,550	267,182	257,064	246,817
Montana Corporate Taxable		*$ 5,725,749*	*$ 5,548,542*	*$ 5,369,817*	*$ 5,201,420*	*$ 5,022,375*	*$ 4,842,214*	*$ 4,678,502*	*$ 4,513,177*	*$ 4,326,205*	*$ 4,126,671*	*$ 3,958,256*	*$ 3,808,361*	*$ 3,656,548*
MT Corporate Income Tax	6.75%	$ 386,488	$ 374,527	$ 362,463	$ 351,096	$ 339,010	$ 326,849	$ 315,799	$ 304,639	$ 292,019	$ 278,550	$ 267,182	$ 257,064	$ 246,817
Production Tax Credits - PTC ($22 per MW, if utilized)	$22.00	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PTC Escalation Rate:	3%	13	14	15	16	17	18	19	20	21	22	23	24	25

NorthWestern Energy
RPS Compliance Forecast Comparison
With and Without Spion Kop

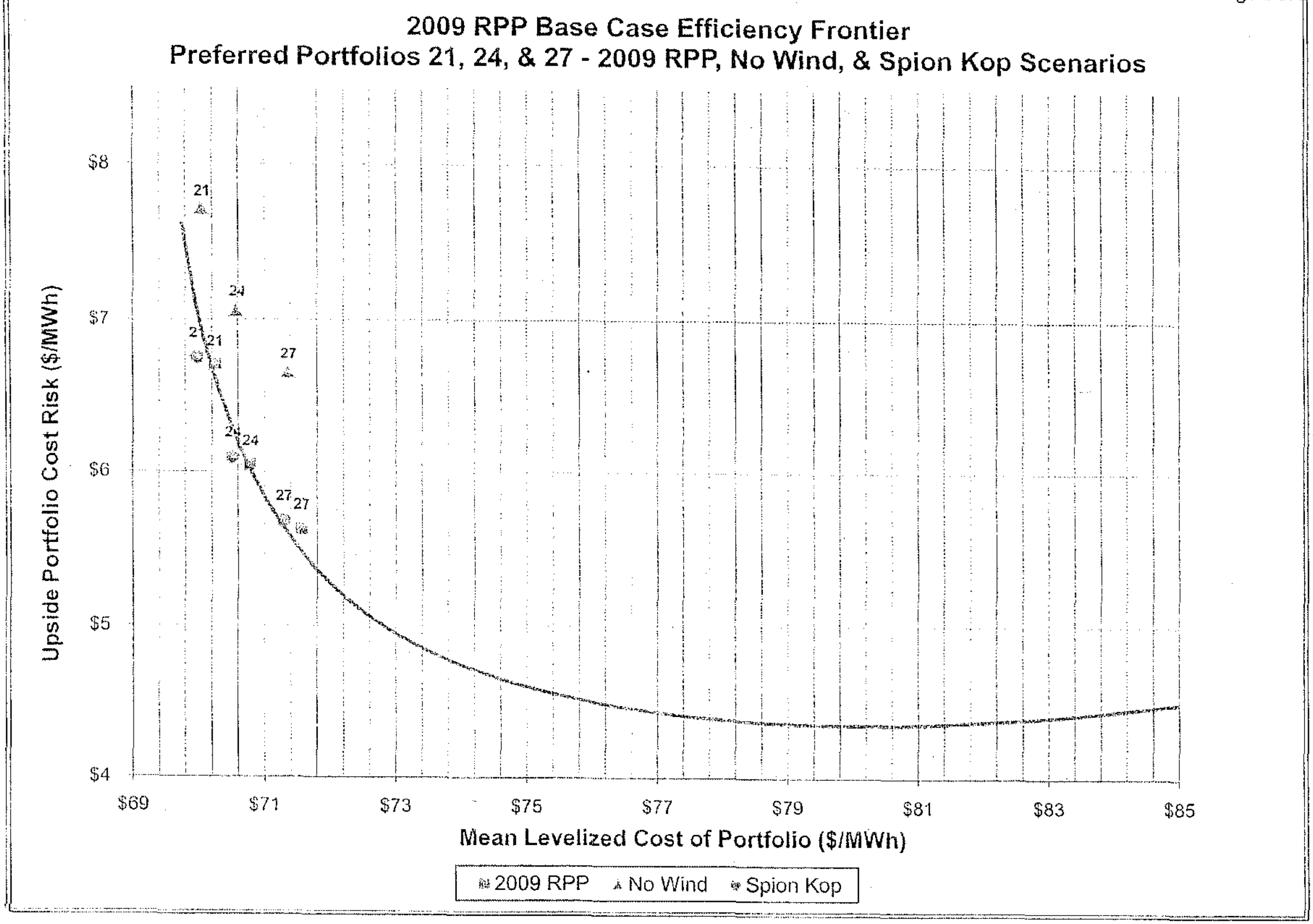
With Spion Kop	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Annual RPS Requirement Calculation														
Supply Load (2011 20-year forecast)	5,863,559	5,958,482	5,807,973	5,751,240	5,956,919	6,024,562	6,097,846	6,174,666	6,253,776	6,334,403	6,416,151	6,498,765	6,582,096	6,666,023
RPS (%)		5%	5%	10%	10%	10%	10%	10%	15%	15%	15%	15%	15%	15%
RPS MWH based on prior yr load		293,178	297,924	580,797	575,124	595,692	602,456	609,785	926,200	938,066	950,160	962,423	974,815	987,314
Renewable Resources' REC Generation														
Judith Gap MWH (2011-2020 based on 2006-2010 avg)		500,828	455,985	414,004	459,498	459,498	459,498	459,498	459,498	459,498	459,498	459,498	459,498	459,498
Turnbull Hydro					25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000
Spion Kop 40MW (39.5% NCF)						23,000	138,000	138,000	138,000	138,000	138,000	138,000	138,000	138,000
Gordon Butte 9.6MW (39.92% NCF)					5,595	33,571	33,571	33,571	33,571	33,571	33,571	33,571	33,571	33,571
Mussleshell One 9.2MW (32.66% NCF)						4,387	26,321	26,321	26,321	26,321	26,321	26,321	26,321	26,321
Mussleshell Two 9.2MW (32.01% NCF)						4,300	25,797	25,797	25,797	25,797	25,797	25,797	25,797	25,797
Total RECs Generated		500,828	455,985	414,004	490,093	549,755	708,188	708,188	708,188	708,188	708,188	708,188	708,188	708,188
Annual RPS Compliance Determination														
Current Yr REC			455,985	414,004	490,093	549,755	708,188	708,188	708,188	708,188	708,188	708,188	708,188	708,188
Prior Yr Carry-Over REC			207,650	365,711	198,918	113,886	67,950	173,681	272,084	54,072	0	0	0	0
Total Available REC		500,828	663,635	779,715	689,010	663,642	776,137	881,869	980,272	762,259	708,188	708,188	708,188	708,188
RPS		293,178	297,924	580,797	575,124	595,692	602,456	609,785	926,200	938,066	950,160	962,423	974,815	987,314
REC Balance / RPS Compliance Determination		207,650	365,711	198,918	113,886	67,950	173,681	272,084	54,072	-175,807	-241,973	-254,235	-266,627	-279,127

Without Spion Kop	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Annual RPS Requirement Calculation														
Supply Load (2011 20-year forecast)	5,863,559	5,958,482	5,807,973	5,751,240	5,956,919	6,024,562	6,097,846	6,174,666	6,253,776	6,334,403	6,416,151	6,498,765	6,582,096	6,666,023
RPS (%)		5%	5%	10%	10%	10%	10%	10%	15%	15%	15%	15%	15%	15%
RPS MWH based on prior yr load		293,178	297,924	580,797	575,124	595,692	602,456	609,785	926,200	938,066	950,160	962,423	974,815	987,314
Renewable Resources' REC Generation														
Judith Gap MWH (2011-2020 based on 2006-2010 avg)		500,828	455,985	414,004	459,498	459,498	459,498	459,498	459,498	459,498	459,498	459,498	459,498	459,498
Turnbull Hydro					25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000
Spion Kop 40MW (39.5% NCF)						0	0	0	0	0	0	0	0	0
Gordon Butte 9.6MW (39.92% NCF)					5,595	33,571	33,571	33,571	33,571	33,571	33,571	33,571	33,571	33,571
Mussleshell One 9.2MW (32.66% NCF)						4,387	26,321	26,321	26,321	26,321	26,321	26,321	26,321	26,321
Mussleshell Two 9.2MW (32.01% NCF)						4,300	25,797	25,797	25,797	25,797	25,797	25,797	25,797	25,797
Total RECs Generated		500,828	455,985	414,004	490,093	526,755	570,188	570,188	570,188	570,188	570,188	570,188	570,188	570,188
Annual RPS Compliance Determination														
Current Yr REC			455,985	414,004	490,093	526,755	570,188	570,188	570,188	570,188	570,188	570,188	570,188	570,188
Prior Yr Carry-Over REC			207,650	365,711	198,918	113,886	44,950	12,681	0	0	0	0	0	0
Total Available REC		500,828	663,635	779,715	689,010	640,642	615,137	582,869	570,188	570,188	570,188	570,188	570,188	570,188
RPS		293,178	297,924	580,797	575,124	595,692	602,456	609,785	926,200	938,066	950,160	962,423	974,815	987,314
REC Balance / RPS Compliance Determination		207,650	365,711	198,918	113,886	44,950	12,681	-26,916	-356,012	-367,879	-379,973	-392,235	-404,627	-417,127

2009 RPP Stochastic Modeling Comparisons
Base Case Assumptions
Replace 40MW Generic Wind with 40MW Spion Kop Wind
(the No Wind and Spion Kop stochastic scenarios were not included in the 2009 RPP)

BOX 1	No Wind (does not meet RPS)			150MW Generic Wind (2009 RPP)			Price	Upside Risk
	A Mean 20-Year Levelized Rate	B 95% Confidence Level - Mean	B/A Upside Risk / Mean Rate	C Mean 20-Year Levelized Rate	D 95% Confidence Level - Mean	D/C Upside Risk / Mean Rate	C/A-1 Increase with Addition of Wind	D/B-1 Reduction with Addition of Wind
Preferred Portfolios	($/MWh)	(Upside Risk)	(%)	($/MWh)	(Upside Risk)	(%)	(%)	(%)
PF 21 300MW SCCT Frame	$70.04	$7.72	11.0%	$70.25	$6.70	9.5%	0.3%	-13.2%
PF 24 300MW SCCT Aero	$70.58	$7.07	10.0%	$70.79	$6.05	8.5%	0.3%	-14.4%
PF 27 200MW CCCT	$71.35	$6.66	9.3%	$71.56	$5.64	7.9%	0.3%	-15.3%
Preferred Portfolio Avg	$70.66	$7.15	10.1%	$70.87	$6.13	8.6%	0.3%	-14.3%

BOX 2	No Wind (does not meet RPS)			110MW Generic Wind + 40MW Spion Kop Wind			Price	Upside Risk
	A Mean 20-Year Levelized Rate	B 95% Confidence Level - Mean	B/A Upside Risk / Mean Rate	C Mean 20-Year Levelized Rate	D 95% Confidence Level - Mean	D/C Upside Risk / Mean Rate	C/A-1 Increase with Addition of Wind	D/B-1 Reduction with Addition of Wind
Preferred Portfolios	($/MWh)	(Upside Risk)	(%)	($/MWh)	(Upside Risk)	(%)	(%)	(%)
PF 21 300MW SCCT Frame	$70.04	$7.72	11.0%	$69.99	$6.75	9.6%	-0.1%	-12.6%
PF 24 300MW SCCT Aero	$70.58	$7.07	10.0%	$70.52	$6.10	8.6%	-0.1%	-13.7%
PF 27 200MW CCCT	$71.35	$6.66	9.3%	$71.30	$5.68	8.0%	-0.1%	-14.6%
Preferred Portfolio Avg	$70.66	$7.15	10.1%	$70.60	$6.18	8.7%	-0.1%	-13.6%


2009 RPP Base Case Efficiency Frontier
Preferred Portfolios 21, 24, & 27 - 2009 RPP, No Wind, & Spion Kop Scenarios
Upside Portfolio Cost Risk ($/MWh)
$8
$7
$6
$5
$4
21
24
27
21
24
27
$69
$71
$73
$75
$77
$79
$81
$83
$85
Mean Levelized Cost of Portfolio ($/MWh)
2009 RPP
No Wind
Spion Kop

2009 RPP Stochastic Modeling Comparisons

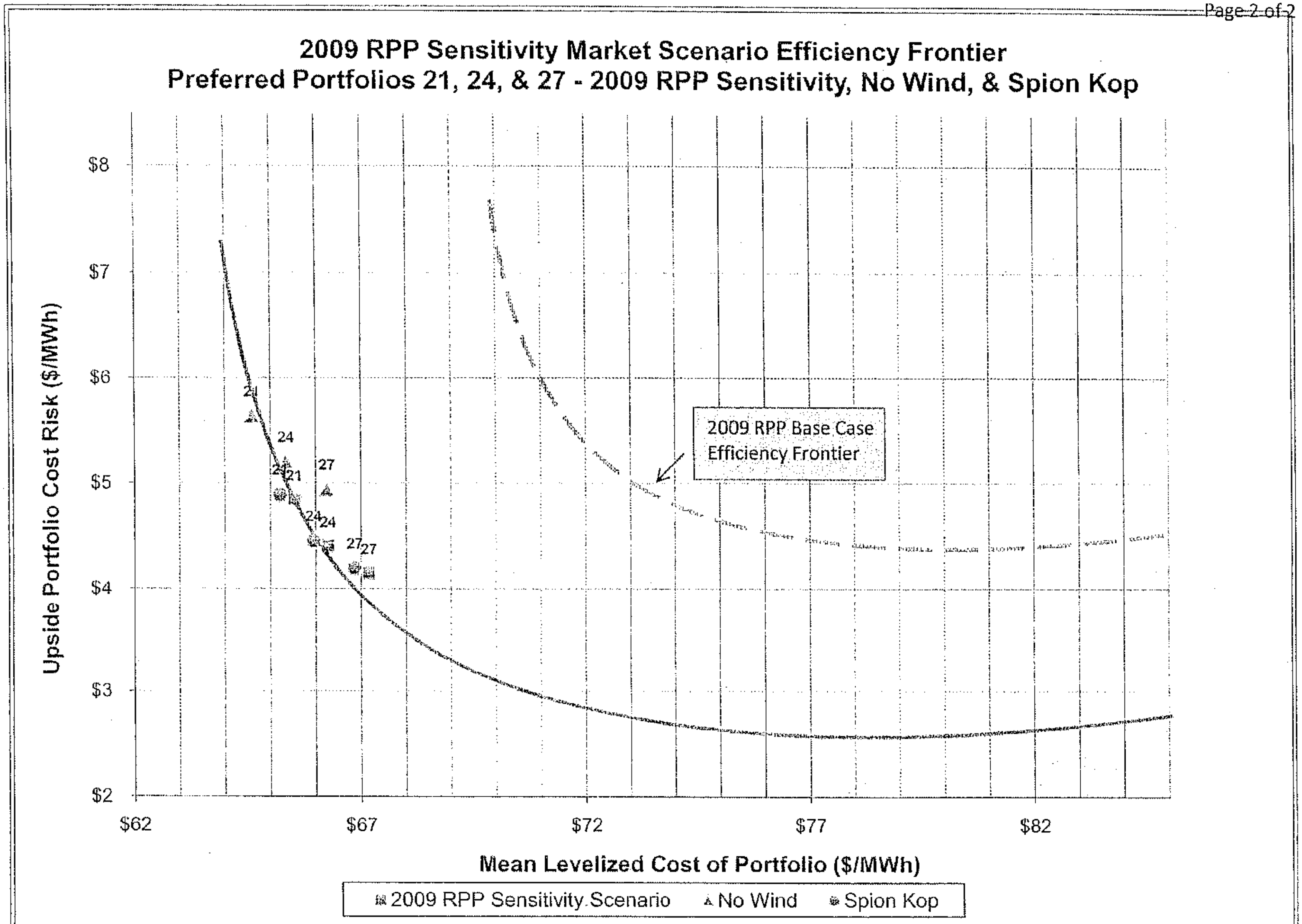
Sensitivity Market Scenario (Nov 2010)

Replace 40MW Generic Wind with 40MW Spion Kop Wind

(the No Wind and Spion Kop stochastic scenarios were not included in the 2009 RPP)

BOX 1	No Wind (does not meet RPS)			150MW Generic Wind (2009 RPP)			Price	Upside Risk
	A Mean 20-Year Levelized Rate	B 95% Confidence Level - Mean	B/A Upside Risk / Mean Rate	C Mean 20-Year Levelized Rate	D 95% Confidence Level - Mean	D/C Upside Risk / Mean Rate	C/A-1 Increase with Addition of Wind	D/B-1 Reduction with Addition of Wind
Preferred Portfolios	($/MWh)	(Upside Risk)	(%)	($/MWh)	(Upside Risk)	(%)	(%)	(%)
PF 21 300MW SCCT Frame	$64.60	$5.64	8.7%	$65.53	$4.85	7.4%	1.4%	-14.0%
PF 24 300MW SCCT Aero	$65.34	$5.21	8.0%	$66.27	$4.41	6.7%	1.4%	-15.2%
PF 27 200MW CCCT	$66.25	$4.94	7.5%	$67.17	$4.16	6.2%	1.4%	-15.9%
Preferred Portfolio Avg	$65.40	$5.26	8.0%	$66.32	$4.47	6.7%	1.4%	-15.0%

BOX 2	No Wind (does not meet RPS)			110MW Generic Wind + 40MW Spion Kop Wind			Price	Upside Risk
	A Mean 20-Year Levelized Rate	B 95% Confidence Level - Mean	B/A Upside Risk / Mean Rate	C Mean 20-Year Levelized Rate	D 95% Confidence Level - Mean	D/C Upside Risk / Mean Rate	C/A-1 Increase with Addition of Wind	D/B-1 Reduction with Addition of Wind
Preferred Portfolios	($/MWh)	(Upside Risk)	(%)	($/MWh)	(Upside Risk)	(%)	(%)	(%)
PF 21 300MW SCCT Frame	$64.60	$5.64	8.7%	$65.21	$4.90	7.5%	0.9%	-13.2%
PF 24 300MW SCCT Aero	$65.34	$5.21	8.0%	$65.95	$4.46	6.8%	0.9%	-14.3%
PF 27 200MW CCCT	$66.25	$4.94	7.5%	$66.86	$4.20	6.3%	0.9%	-15.0%
Preferred Portfolio Avg	$65.40	$5.26	8.0%	$66.01	$4.52	6.8%	0.9%	-14.1%


2009 RPP Sensitivity Market Scenario Efficiency Frontier
Preferred Portfolios 21, 24, & 27 - 2009 RPP Sensitivity, No Wind, & Spion Kop
Upside Portfolio Cost Risk ($/MWh)
$8
$7
$6
$5
$4
$3
$2
$62
$67
$72
$77
$82
Mean Levelized Cost of Portfolio ($/MWh)
2009 RPP Base Case Efficiency Frontier
21
24
27
2009 RPP Sensitivity Scenario
No Wind
Spion Kop