SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

CASE NO. EL05-022

IN THE MATTER OF THE APPLICATION BY OTTER TAIL POWER COMPANY ON BEHALF OF THE BIG STONE II CO-OWNERS FOR AN ENERGY CONVERSION FACILITY SITING PERMIT FOR THE CONSTRUCTION OF THE BIG STONE II PROJECT

PREFILED REBUTTAL TESTIMONY

OF

GERALD A. TIELKE

OPERATIONS MANAGER

MISSOURI RIVER ENERGY SERVICES

JUNE 16, 2006

**** PUBLIC, VERSION****

PREFILED REBUTTAL TESTIMONY OF GERALD A. TIELKE

TABLE OF CONTENTS

BEFORE THE SOUTH DAKOTAPUBLIC UTILITIES COMMISSION

PREFILED REBUTTAL TESTIMONY OF

GERALD A. TIELKE

I. INTRODUCTION

Q: Please state you name and business address.

A: Gerald A. Tielke, Missouri River Energy Services, 3724 West Avera Drive, Sioux Falls, South Dakota.

Q: Did you previously submit testimony in this proceeding?

A: Yes. I submitted direct testimony, Applicants' Exhibit 14.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q: What is the purpose of your testimony?

A: The purpose of my rebuttal testimony is to present the results of the recent capacity expansion modeling that Missouri River Energy Services (MRES) completed in May 2006. This modeling effort also included an analysis of Hutchinson Utility Commission's (HUC) future needs. Another purpose of my testimony is to respond to some of the statements made by MCEA witnesses Schlissel and Sommer in their May 26 direct testimony regarding MRES' resource planning efforts.

Q: Please summarize your testimony.

A: The capacity expansion modeling that MRES recently completed confirms that a coal plant like Big Stone Unit II is the least cost option to MRES for meeting a projected need for 110 MW of additional generating capacity. The modeling also shows that Big Stone Unit II is the least cost option for addressing a need by HUC for 40 MW of baseload capacity. MRES took into account the possibility of lowering demand by expanding its DSM and conservation efforts in these modeling efforts. Witnesses Schlissel and Sommer have made a number of incorrect assumptions about MRES's resource planning modeling and other efforts.

III. NEED FOR AND TIMING OF BASELOAD CAPACITY

Q: At pages 3 to 4 of their May 26 testimony, MCEA witnesses Schlissel and Sommer state that the Applicants do not need additional baseload capacity in 2011. Do you agree?

A: No. MRES prepares a resource plan on a periodic basis. The most recent resource plan was filed with the Minnesota Public Utilities Commission (MPUC) in July 2005, and was the source for the information used in developing the Application in this matter. On May 9, 2006 MRES filed a Supplement to its Integrated Resource Plan that built upon the resource planning data and assumptions used in the Application and provided, among other things, additional information regarding our capacity expansion modeling. A copy of the Supplement was provided to MCEA, et al. at that time. I describe this supplemental data in more detail later in my testimony.

The results of the Supplement analysis confirm the conclusion that MRES needs baseload capacity and that its proposed 110 MW of the Big Stone Unit II project is least cost. This is in addition to obtaining 40 MW of Big Stone Unit II to satisfy the Hutchinson Power Sale Agreement, under which MRES has an obligation to sell, and HUC to purchase, 40 MW of capacity and related energy from the proposed Big Stone Unit II. MRES conducted a separate resource plan analysis for HUC, and submitted it as part of the Supplement.

Q: How does MRES know it needs baseload capacity, rather than other sources?

A: MRES has performed a detailed power supply capacity expansion study to examine its future energy resource needs to test the results against our already extensive modeling exercises which formed the basis for our participation in the project. This study confirms the need for Big Stone Unit II's baseload capacity starting in 2011, along with other resources including demand-side management (DSM) and renewables.

The MRES capacity expansion study is based on an updated load forecast, and on estimates of current and feasible DSM activities. Through substantial analysis, a Preferred Alternative was identified. This Preferred Alternative confirms that baseload power, specifically 110 MW of Big Stone Unit II, is needed to meet growing member demand and is least cost.

IV. FORECASTING

Q: What are the future capacity and energy requirements for MRES according to its forecasts?

A: The 2006 summer peak demand for the MRES member cities is forecasted at 818 MW, of which MRES will be responsible for 418 MW plus 15% planning reserves, or 480 MW. The MRES forecasts estimate that member total demand will grow annually by an average of 1.8% between 2006 and 2010, and by an average of 1.5% between 2010 and 2020. By 2011, MRES will have an expected shortfall of 8 MW of generation capacity, increasing to 230 MW by 2020.

The MRES portion of the total energy demand is forecasted to grow at an average annual growth rate of 3.6% over the period 2006-2015.

MRES also created short-term and long-term load forecasts for HUC. However, MRES and Western Area Power Administration (WAPA) do not serve any portion of HUC, so only the total load of HUC was forecasted. The HUC load forecast uses the same sources as MRES uses for its Minnesota member load forecasts. The HUC load is reported separately, and is not included in any of the total MRES load values reported.

Q: Why is the MRES annual energy growth rate so high, when the growth rates for your members are only about half that rate?

A: MRES provides only "supplemental" power and energy service to its members; not their entire load. This is service over and above what the members take from other suppliers, primarily the Western Area Power Administration (WAPA). Member contracts with WAPA are for a fixed amount, and do not provide any additional power, but instead decease slightly over time. As a result, because loads continue to grow, MRES was created to serve this "supplemental" need. MRES currently serves about half of the member needs, on average. As a result, the MRES annual energy growth rate, calculated on an MRES base energy amount that is about half that of the members' total energy use, yields an MRES annual growth rate (in %) of about twice that of the members. It is the same annual growth in MWH as the members, but calculated on a smaller, MRES base energy.

V. DEMAND-SIDE MANAGEMENT (DSM)

Q: MCEA witnesses Schlissel and Sommer advocate the use of demand-side management (DSM) in conducting resource planning. Does MRES consider DSM in its resource plans?

A: Yes. The members of MRES have enacted significant DSM measures. Equally important, the MRES resource plan includes the accomplishment of a significant amount of new DSM in future years, in addition to Big Stone Unit II.

Q: What has MRES accomplished in DSM to-date?

A: Our best estimate is that DSM and conservation efforts among MRES members have reduced generation capacity requirements by approximately 57 MW as of 2005.

Q: Please explain the ongoing DSM planning efforts of MRES.

A: MRES has modeled potential DSM additions to allow the capacity expansion software to analyze the direct impact of various levels of additional DSM on supply-side choices, in order to allow DSM to compete directly against supply-side (including renewables) resources in developing the optimal resource mix. The results of this capacity expansion modeling were filed as part of a recent Supplemental filing with the Minnesota PUC on May 8, 2006.

To prepare the DSM models, MRES estimated the current amount of DSM, and evaluated the potential for new DSM by its long-term power-supply members. (A separate analysis was performed for HUC.) MRES staff surveyed members, reviewed their most current energy efficiency and conservation reports, and conducted telephone interviews to assess current DSM activities within the membership. Based on this information, the current DSM activities total an estimated 57 MW of demand reduction, and 22,408 MWH per year of energy impact.

MRES also retained a consulting firm, Summit Blue, to review the information MRES collected concerning existing DSM activities of MRES members. Based on this information and on benchmark data from Minnesota investor-owned utilities, Summit Blue estimated the current saturation amounts for 27 commercial/industrial and 13 residential DSM technologies (programs) likely to be feasible. Summit Blue also estimated the technical potential theoretically possible, and the achievable potential most likely to be reached under each program by 2020, if they were implemented.

According to the results of the final Summit Blue study, the potential DSM programs had an estimated total achievable potential of up to 85 MW and 233,250 MWh per year by 2020, at a total cost of almost $25 million in 2006 dollars. These are potential load reduction impacts in addition to current DSM activities already assumed in the historic and forecasted loads. However, not all of the 40 potential DSM programs were found to be cost-effective when compared against future supply-side options.

MRES used the results of the Summit Blue analysis to group the 40 potential DSM programs into ten DSM Portfolios, each representing between two and seven individual DSM programs. The ten DSM portfolios, and the DSM programs making up those portfolios, were defined as shown in the table below. Also shown are the amounts of additional load reduction expected from each DSM portfolio and the Net Present Value (NPV) in millions of 2006 dollars of the cost of each DSM portfolio.

MRES DSM Portfolios				
DSM Portfolios	Class	MW by 2020	GWh by 2020	15-Year NPV
		[TRADE SECRET DATA BEGINS		
Cooling – Low Cost	**R/C/I**			
Cooling – High Cost	**R/C/I**			
Custom Comm. – Low Cost	**C/I**			
Custom Comm. – High Cost	**C/I**			
Water Heating – Low Cost	**R**			
Water Heating – High Cost	**R**			
Lighting Measures	**R/C/I**			
Refrigeration	**C/I**			
Building Envelope	**C/I**			
Direct Load Control	**R/C/I**			
		TRADE SECRET DATA ENDS]		
Grand Totals:		85.2 MW	233.2 GWh	$24.9 M

We used our Strategist planning model to calculate the least-cost combination of supply-side and DSM resources in each scenario. DSM portfolios were included in the Strategist model as optional resources, freely available for selection by the model as economics dictated. For the Preferred Case scenario results, nine of the ten DSM portfolios were found to be optimal for MRES. By 2020 the resource need is reduced by 82 MW due to the added new DSM. In order to grow to 82 MW of new DSM by 2020, MRES has assumed a constant increase of 6.8 MW per year in DSM programs starting in 2009.

Because energy efficiency programs are usually implemented at the retail level, DSM has traditionally been the responsibility of each individual member. Internally, MRES staff has traditionally focused on existing, but loosely-coordinated efforts such as digital infrared thermography, compressed air leak detection and similar, large customer energy efficiency programs.

In an effort to bridge the traditional DSM gap between MRES as a wholesale supplier and members as retail DSM providers, the MRES Board of Directors and staff have begun taking additional steps to expand the extent of MRES' involvement with its members in influencing the amounts of DSM. To this end, the MRES Board of Directors created the DSM Task Force, the purpose of which is to evaluate conservation and demand strategies that will allow MRES to achieve the DSM goals identified in the MRES IRP Supplement, and to make recommendations to the Board of Directors regarding implementation of those strategies.

Q: What effects do new DSM programs have on the MRES capacity requirements?

A: The new DSM programs were chosen by Strategist when calculating the optimum combination of resources, including Big Stone Unit II, renewables, and other options. The effects of the new DSM programs were to reduce the amount of new capacity additions required starting in 2011.

Q: At page 6 of their May 26 testimony, MCEA witnesses Schlissel and Sommer state that MRES projects an 11 MW capacity surplus, including new DSM, in the peak summer hours in 2011 without Big Stone Unit II. Do you agree?

A: Their math is correct. The important fact, however, is that MRES is deficit of capacity by 8 MW in 2011 without adding new DSM programs. As described above, the new DSM programs were cost-effective only in the context of a combination of resources including Big Stone Unit II, so the statement by Schlissel and Sommer uses the new DSM amount in the wrong context.

Q: Please explain how MRES included potential DSM programs in the HUC capacity expansion modeling.

A: A separate DSM study was not performed for HUC. Rather, it was assumed that HUC would have similar DSM characteristics and opportunities as the existing MRES membership. Because the HUC total load is approximately 15% in size relative to the total load of the MRES membership excluding HUC, we assumed that the amount of potential DSM effect for HUC would be equal to 15% of the total DSM potential for MRES members. The same ten DSM portfolios were used, but sized at 15% of the membership amounts, as shown in the following table:

HUC DSM Portfolios				
DSM Portfolios	Class	MW by 2020	GWh by 2020	15-Year NPV
		[TRADE SECRET DATA BEGINS		
Cooling – Low Cost	**R/C/I**			
Cooling – High Cost	**R/C/I**			
Custom Comm. – Low Cost	**C/I**			
Custom Comm. – High Cost	**C/I**			
Water Heating – Low Cost	**R**			
Water Heating – High Cost	**R**			
Lighting Measures	**R/C/I**			
Refrigeration	**C/I**			
Building Envelope	**C/I**			
Direct Load Control	**R/C/I**			
				TRADE SECRET DATA ENDS]
Grand Totals:		12.8 MW	35.0 GWh	$3.74 M

We used the Strategist planning model to calculate the least-cost combination of supply-side and DSM resources in each scenario for HUC. The HUC model was based on the HUC load characteristics and forecasts, as well as the resources owned by HUC, rather than on MRES loads and resources. For the Base Case scenario results, only eight of the ten DSM Portfolios were optimal; High-cost Cooling and Direct Load Control were not optimal. Results were calculated for HUC under other scenarios as well. The same eight DSM portfolios were also found to be optimal in most of the other scenarios considered for HUC.

VI. RENEWABLES

Q: Describe the status of MRES' efforts in adding renewables to its system.

A: MRES has existing renewable energy resources, and is planning significant renewable resource additions as part of its good faith effort to meet Minnesota's Renewable Energy Obligation (REO) (which effectively requires that MRES meet 10% of our Minnesota load requirements through qualifying renewable technologies). MRES is currently supplied with the wind energy output of four wind turbines at its Worthington, Minnesota, Wind Project. These four turbines have a total nameplate capacity of 3.7 MW.

Q: Is MRES in compliance with its REO?

A: In 2005, MRES' renewable energy resources were sufficient to satisfy the requirement that 1% of total sales to Minnesota members be generated by eligible energy technologies under the REO. MRES expects to achieve the goal of 10% renewables by 2015.

VII. RESOURCE PLANNING

Q: Please summarize the results of your Resource Plan and Supplement, including the capacity expansion modeling.

A: The Supplement was based on data and assumptions from the Resource Plan filing, with updated load forecasts and improvements in DSM and renewable modeling. In essence, our capacity expansion analysis using Strategist modeling software has replaced our previous production cost analysis. MRES allowed all resource options to be evaluated in all scenarios, including DSM, wind, coal, combustion turbine, and integrated-gasification combined-cycle units. Consistent with the Resource Plan, the Supplement covered the period 2006-2020 for all MRES load, not just the Minnesota members. Emission costs were included in the analysis, at the environmental cost prices established by the Minnesota PUC. The HUC requirements for Big Stone Unit II were analyzed separately – i.e., not included in the MRES scenario analysis.

Because MRES has committed to a 110 MW share of Big Stone Unit II, several scenarios limited the amount of Big Stone Unit II capacity to 110 MW. Due to the change in modeling software, the commitment to a 110 MW share of Big Stone Unit II, the addition of DSM to the analysis, and the updated load forecast data, the Scenario Analysis results have changed from those in the original Resource Plan.

The resulting least-cost, Base Case scenario has a present value cost over 15 years of $559.8 million in 2005 dollars, and shows that the least-cost amount of Big Stone Unit II for MRES is 155 MW, along with 85 MW of DSM by 2020. Surplus sales revenues were not considered in determining the optional resource mix, so that the resource decision focused on member power supply rather than on potential energy surplus energy sales. The results, shown on the following table do include surplus sales revenues, reflecting the actual expected cost effects once the resource mix was established for each scenario. Several additional scenarios, also summarized in the following table, determine the effects of various changes in assumptions in comparison to the Base Case.

MRES Scenario Results Compared to the Base Case							
Scenario Name	**BSP II MW**	**RC MW**	**CT MW**	**Wind MW (Accredited)**	**IGCC MW**	**DSM MW**	**Cost vs Base Case**
Base Case (least-cost):	**155**	**0**	**0**	**0**	**0**	**85**	**---**
Base Case against which other scenarios were compared.							
Wind: 10% of MN Load (REO)	135	0	15	40 (6)	0	85	+1.1%
40 MW Wind added in 2011, accredited at 6 MW.							
Wind: 10% of S-1 Load:	130	0	15	80 (12)	0	82	+1.6%
40 MW Wind (accredited at 6 MW) added in 2011 and 40 MW in 2014.							
50% Renewable Energy	105	0	15	280(42)	0	85	+4.6%
75% Renewable Energy	60	0	0	760 (114)	0	85	+22.9%
110 MW BSP II, 10% REO for MN (Preferred Alternative):	**110**	**0**	**45**	**40 (6)**	**0**	**82**	**+1.9%**
Limited BSP II to contractual 110 MW and sufficient resources to meet MN REO.							
110 MW BSP II, 10% REO for all S-1 members:	110	0	45	80 (12)	0	82	+2.4
Considered the application of MN REO of 10% to all S-1 members.							

The revised Preferred Alternative, chosen upon review of the above scenarios, is the least-cost scenario that meets the Minnesota REO, given that MRES has a maximum share of 110 MW of Big Stone Unit II. It is important to point out that the Revised Preferred Alternative also includes 45 MW of future natural gas combustion turbine units, 40 MW of wind, and 82 MW of DSM by 2020.

The MRES capacity expansion modeling shows that MRES should obtain ownership in at least 110 MW of the Big Stone Unit II project. This is in addition to obtaining 40 MW of Big Stone Unit II to satisfy the Hutchinson Power Sale Agreement. MRES should also continue to expand its renewable resources to meet the 10% Minnesota REO goal by 2015, by constructing and/or purchasing energy generated by wind, biomass and/or other eligible technologies. Finally, MRES should also implement additional DSM research and development.

Q: Please summarize the results of your Resource Plan for HUC, including the capacity expansion modeling.

A: While HUC is exempt from the Minnesota resource planning requirements, MRES felt that presenting a separate capacity expansion analysis for HUC's need would be useful. Currently, HUC owns no baseload resources, and is entirely dependent on natural gas, fuel oil, and short-term energy purchases for its supply. The MRES analysis showed that obtaining Big Stone Unit II capacity, along with implementing additional DSM, would meet the goals of HUC of obtaining adequate and reliable generation that also reduces HUC's power supply risks related to natural gas supply and market purchases.

Q: Why are these capacity-planning results showing a benefit for adding Big Stone Unit for HRC?

A: As I mentioned earlier, HUC currently has no baseload resources. Their existing capacity is fueled by oil and natural gas, and a power supply contract that is due to expire. In a world where natural gas prices are high, and both natural gas and purchased energy prices are potentially very volatile, baseload energy is a preferable offset to energy that would otherwise be purchased or produced by its gas-fired units. So, this is an energy cost situation for HUC, rather than a question of having enough capacity. Simply, they have enough capacity, but the production (energy) costs of that existing capacity are too high.

The analysis considered wind in all scenarios as well, but wind was unable to successfully compete with other alternatives in the HUC scenarios.

Q: Could MRES and HUC use more baseload capacity than their proposed share of Big Stone II?

A: We find that our proposed shares are a good fit for both MRES and HUC. As I noted earlier, our Supplement modeling shows a 155 MW share of Big Stone Unit II would be optimum for MRES, in addition to the amount required for HUC. This is larger than our proposed 110 MW share of the unit. If anything, our modeling shows that we could increase our proposed share. Similarly, our modeling for HUC shows that a 45 MW share of Big Stone Unit II would be optimum for them. This also is larger than their proposed 40 MW share.

Q: What do you conclude from the capacity expansion modeling for MRES and HUC?

A: We conclude that the best, most cost-efficient plan includes a diverse and balanced mix of optimum levels of conservation, renewables, and baseload resources.

Q: At footnote 6 to page 6 of their May 26 testimony, MCEA witnesses Schlissel and Sommer state that the assumption of extreme weather biases MRES' demand forecast to the high side by a significant amount. Do you agree?

A: No. Their suggested alternative, of building capacity only to meet the needs of load conditions under normal weather conditions, would cause capacity shortages whenever a heat wave which exceeds normal conditions came through the system. Basing the capacity expansion plan on normal weather would mean that there would be a 50% chance that MRES would be deficient in capacity during peak periods.

The MRES demand forecast corrects for this with the goal of having a demand forecast high enough to predict loads under 90% of historical weather conditions. It should be noted that the energy forecast is still based only on an average weather year. This methodology has been the standard practice of MRES and has been accepted in all past resource plans filed with the Minnesota PUC.

Q: At page 11 of their May 26 testimony, MCEA witnesses Schlissel and Sommer state that none of the Applicants' economic studies reflected any dispatching of the proposed Big Stone II facility, in response to changes in demand or any other factors. Do you agree?

A: No. Each of the scenarios considered and submitted by MRES was calculated using a capacity-expansion planning model which used a load duration curve analysis to estimate the amounts of energy production from each resource in detail. Many variables were modeled in calculating the amount of energy production from Big Stone Unit II in the model, including the relative fuel costs of the units, their other operating costs, MRES loads inside and outside of the Midwest Independent System Operator footprint, system losses, and how those values changed over the time period of the model. MCEA has had our new information since on or about May 9, 2006, when it was filed with the Minnesota PUC.

Q: At pages 23 and 31 of their May 26 testimony, MCEA witnesses Schlissel and Sommer state that all but two of the MRES scenarios assumed some participation in Big Stone II. Do you agree?

A: No. In fact, in each of the first seven scenarios presented and summarized in Table A-2 of the MRES Supplement, the amount of Big Stone Unit II would have been allowed to vary to as low as zero MW depending on the capacity expansion software model results. In each of those scenarios a non-zero amount of Big Stone II was selected by the model. In the remaining scenarios, after the first seven, the amount of Big Stone Unit II was pre-selected at 110 MW by design to study other factors such as low or high load growth. In this way the effects of those other factors could be seen given the decision to participate in Big Stone Unit II at the level of 110 MW.

Q: At pages 23 and 31 of their May 26 testimony, MCEA witnesses Schlissel and Sommer state that MRES did not include any non-coal or natural gas alternatives in their evaluation. Do you agree?

A: No. Unless explicitly excluded in a given scenario, natural gas-fired combustion turbines, integrated-gasification combined-cycle units, wind units, and DSM were included for evaluation in each scenarios.

Q: In Table 2 of their May 26 testimony, MCEA witnesses Schlissel and Sommer show a cost comparison of coal versus combinations of wind and gas units. Did you examine similar combinations?

A: Yes. The IRP process followed by MRES examined combinations of gas and wind, along with combinations of other resource alternatives, in each scenario. This is part of the basic design of the Strategist capacity expansion software. In no scenario was such a combination found to be less expensive than the results presented in the Supplement.

In addition, MRES ran some specific cases to mimic the combinations described in Table 2 of the Schlissel and Sommer testimony. While Table 2 was based on up to 1200 MW of wind and up to a 480 MW of combined-cycle gas turbine (CCGT), the MRES cases were based on a pro-rata share of those amounts. The pro-rata share was based on the 110 MW MRES share of the proposed Big Stone Unit II out of the total 600 MW planned rating.

For this table, MRES assumed that the production tax credit (PTC) will be a levelized \$12 per MWh for ten years, and that all new capacity would require transmission at a cost of \$129 per kW in 2005 dollars. The Minnesota PUC published CO2 externalities for a unit outside of the state was assumed, namely zero dollars per ton. For some of these cases MRES assigned wind a 25% capacity credit only to mimic the results of the Schlissel and Sommer table; other than in these calculations, MRES applies a maximum of 15% capacity credit to wind. Based on MAPP accreditation history, the assumed maximum accreditation credit for wind should not exceed 15%.

Q: What were the results of your comparison?

A: The results shown in the table below compare the wind and CCGT to the MRES Preferred Alternative scenario results.

Cost Comparison: Wind/CCNG vs. MRES Preferred Alternative

Wind MW	Wind Accreditation %	Combined Cycle Natural Gas	Production Tax Credit?	% Increased Cost vs. Preferred Alternative	Increased Cost vs. Preferred Alternative
800	15%	480	No PTC	+19.2%	$110M
1200	15%	420	No PTC	+21.3%	$122M
800	25%	400	No PTC	+17.6%	$100M
1200	25%	300	No PTC	+18.2%	$104M
800	15%	480	With PTC	+7.9%	$45M
1200	15%	420	With PTC	+4.7%	$27M
800	25%	400	With PTC	+6.3%	$36M
1200	25%	300	With PTC	+1.6%	$9M

Q: Please explain the results.

A: These results show that in all cases the wind and combined-cycle combinations are more expensive than the Preferred Alternative results. This analysis used the Strategist load-duration curve calculation which modeled each month over many years, rather than the much less detailed levelized-cost spreadsheet relied upon by the Schlissel and Sommer testimony. In addition, as

Mr. Koegel and Mr. Morlock discuss in their related testimonies, the cases which rely on 25% capacity accreditation for wind over the summer peak are not realistic for utilities in MAPP. Finally, it should be realized that there is a great deal of uncertainty in the pricing of natural gas and in the availability of the PTC, not to mention the hourly production pattern of wind. So, those alternatives have additional risks beyond the penalties shown on the table.

Q: What do the cost penalties on your Cost Comparison table represent?

A: These are direct cost penalties our customers would pay on their electric bills if the Commission would choose a wind/gas combination to replace Big Stone Unit II.

Q: Does this conclude your prepared testimony?

A: Yes.