BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Electric Power Company and Wisconsin Gas LLC for a Certificate of Authority under Wis. Stat. § 196.49 and Wis. Admin. Code § PSC 133.03 to Construct a System of New Liquified Natural Gas Facilities and Associated Natural Gas Pipelines near Ixonia and Bluff Creek, Wisconsin	)	Docket No. 5-CG-106

DIRECT TESTIMONY OF BRANDON GERLIKOWSKI
ON BEHALF OF
WISCONSIN ELECTRIC POWER COMPANY AND WISCONSIN GAS, LLC

I. INTRODUCTION

Q. Please state your name, business address, and position.

A. My name is Brandon Gerlikowski. My business address is 700 North Adams Street, Green Bay, Wisconsin 54037. I am employed by WEC Business Services, LLC, a wholly owned subsidiary of WEC Energy Group, Inc. ("WEC"), as a Manager – Fuel Cost Planning.

Q. Please describe your education and professional background.

A. I graduated from the University of Wisconsin Green Bay in 2003 with a Bachelor of Science in Accounting and Finance. I joined Wisconsin Public Service Corporation ("WPS"), now a wholly owned subsidiary of WEC, in December 2003 as a Planning Analyst. I have been with the company for almost 17 years. I became a Senior Energy Resource Planning Financial Analyst in 2009 and in that position I performed energy resource planning for WPS's electric utility. In that role, I developed various energy resource planning tools and conducted long-range economic evaluations on strategic energy related projects. Prior to my current position, my title was Principal Business Specialist, and in that role I provided strategic and financial support related to natural gas supply projects for all of WEC's subsidiaries, including Wisconsin Electric Power Company ("WEPCO") and Wisconsin Gas LLC ("WG"), (together, "Applicants"). I was promoted to Manager – Fuel Cost Planning in June, 2020, and my responsibilities include identification of: areas of service benefits and risks; the potential for synergies across WEC's subsidiaries; and economic (cost/benefit) analyses associated with operational and strategic solutions.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my testimony is two-fold. First, my testimony provides the Commission with information about the need for additional firm deliverability and supply for Joint Applicants, in particular during periods of peak demand, in order to serve their natural gas customers in Southeast Wisconsin. Second, my testimony explains the economic and operational reasons Joint Applicants selected the proposed Liquefied Natural Gas ("LNG") facilities near Ixonia and Bluff Creek, Wisconsin (the "LNG Project") to meet their needs for additional firm deliverability and supply.

Q. Please summarize your conclusions.

A. The LNG Project is a cost-effective solution to address Joint Applicants' needs for additional deliverability and supply, and to meet their customers' peak demand during Wisconsin's cold winters. Wisconsin is a very challenging environment for firm natural gas capacity and supply, because there is no underground storage and interstate pipeline capacity is fully-subscribed. Similar to other gas utilities around the country with constrained storage and transport capacity, Applicants have sought ways to get lower-cost, firm gas deliverability into Wisconsin while improving system reliability, resilience, and providing a new source of capacity and supply that best fits their demand profile. To meet demand, Joint Applicants will need incremental firm deliverability, and the LNG Project provides a superior, long-term solution when compared to available alternatives—[redacted]

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. I am sponsoring the following exhibit:

Ex.-WEGO WG-Gerlikowski-1c is a map showing the Joint Applicants' service areas that will be directly served by the LNG Project.

II. JOINT APPLICANTS NEED ADDITIONAL DELIVERABILTY AND SUPPLY

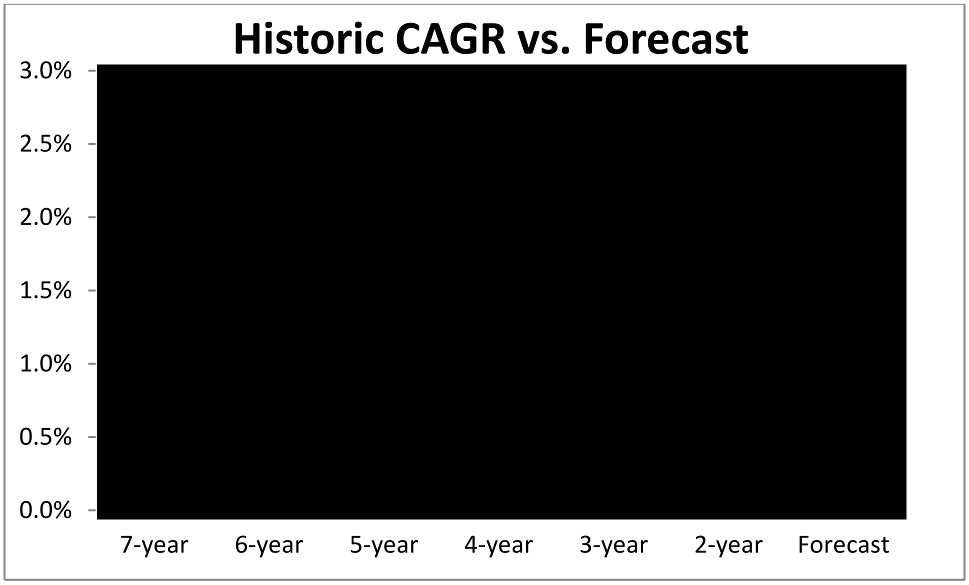
Q. Please summarize Joint Applicants' need for additional natural gas deliverability and supply resources.

A. Joint Applicants' firm demand forecasts conservatively estimate a need for new capacity and deliverability in their service territories within the next 10 years. The base forecast starts with Joint Applicants' respective three-year gas supply plans and conservatively assumes demand growth of [redacted] percent annually. Joint Applicants also modeled low and high demand scenarios. All three scenarios show Joint Applicants have a significant need for capacity to serve their customers in the near term, ranging from a shortfall of approximately [redacted] in the winter of 2023-24 up to approximately [redacted] in the winter of 2028-29 under the base growth scenario. Using the low and high growth scenario the need for capacity ranges from [redacted] in the winter of 2023-24 to as much as [redacted] in the winter of 2028-29.

Based on conservative assumptions about increasing firm demand for natural gas in their service territories and the lack of available pipeline capacity to meet that demand, Joint Applicants need new infrastructure that will provide incremental firm deliverability, capacity, and supply in the near future.

Q. Would you explain why Joint Applicants' growth assumptions as conservative?

A. Joint Applicants' assumptions are conservative, because they are lower than the historic growth of their customers' demand. In the base case, Joint Applicants assumed firm demand would grow at a rate of only [redacted] per year, with a low and high range between [redacted] and [redacted]. But the compound average growth rate ("CAGR") of Joint Applicants' firm demand over the last seven years has been higher than [redacted] as illustrated by this chart[1]:



Joint Applicants' growth assumptions are conservative, because historically Joint Applicants' firm demand has grown at a higher rate and there are not any structural changes that would warrant a meaningful reduction in future forecasts versus the historical growth trends.

Q. How is the need for incremental deliverability ("capacity") determined?

A. The need for capacity is determined based on the level of existing capacity[2] Joint Applicants have compared to their projected demand. Moreover, Joint Applicants must plan to serve their forecasted customer demand plus a 5.0% reserve margin securing

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1 For reference, the 7-year CAGR is calculated from 2013 to 2020, whereas the 3-year CAGR is calculated from 2016 to 2020.

2 Existing capacity is in the form of either firm interstate pipeline capacity or peaking capacity embedded on Applicants' distribution system.

additional firm capacity to address the risk of potential disruptions on third-party pipelines (e.g., force majeure, incremental non-captured load additions, and forecasting error). A reserve margin less than 5.0% suggests there is a need for new capacity (aka deliverability), while a reserve margin less than 0.0% indicates the utility does not have enough capacity to meet the peak firm demand.

Q. Is there a demonstrable need for incremental deliverability for Joint Applicants?

A. Yes. As Mr. Kuse states in his testimony, Joint Applicants forecast a continued increase in demand for their firm natural gas supply and distribution services in the near term (2023-2029). The growth in demand for natural gas is comprised of continued systemic growth in firm system sales as well as large incremental demand additions, such as commercial and industrial operations that have been expanding or establishing in Southeast Wisconsin.

Under the base demand growth scenario Wisconsin Gas's firm demand is expected to grow approximately [redacted] in its Southeast, Central and Fox Valley service areas by the winter of 2028-2029 with a potential range in growth between [redacted] using the growth rates in the low and high scenarios, respectively.[3] Of the total expected growth in demand in these service areas, approximately [redacted] of the growth is attributable just to the Wisconsin Gas's Southeast service area, which will be directly satisfied by the proposed Ixonia LNG facility.

[3] The demand growth figures are the forecasted growth in demand without a 5% reserve margin included. For peak day gas supply planning the 5% reserve margin is added to these figures.

Wisconsin Electric – Gas Operations' firm demand is expected to grow approximately [redacted] in its Lakeshore/Western, Southern, Fox Valley, Sharon and Lima service areas by the winter of 2028-2029 with a potential range in growth between [redacted] using the growth rates in the low and high scenarios, respectively. Of the total expected growth in demand in these service areas, approximately [redacted] of the growth is attributable to Wisconsin Electric's Lakeshore/Western and Southern service areas, which will be directly served by the proposed Bluff Creek LNG facility.

The specific areas the LNG facilities will serve for each utility are shown in Ex.-WEGO WG-Gerlikowski-1c.

Q. Is the forecasted increase in demand the only factor driving Joint Applicants' need for incremental deliverability?

A. No. The challenge today, as mentioned in Ex.-WEGO WG-Application, Section 2.2.1, is that the capacity of the [redacted] for the foreseeable future, meaning there is [redacted] for incremental demand. Therefore, any forecasted increase in demand will require [redacted] on either the interstate pipeline or Applicants' distribution system in order to increase deliverability.

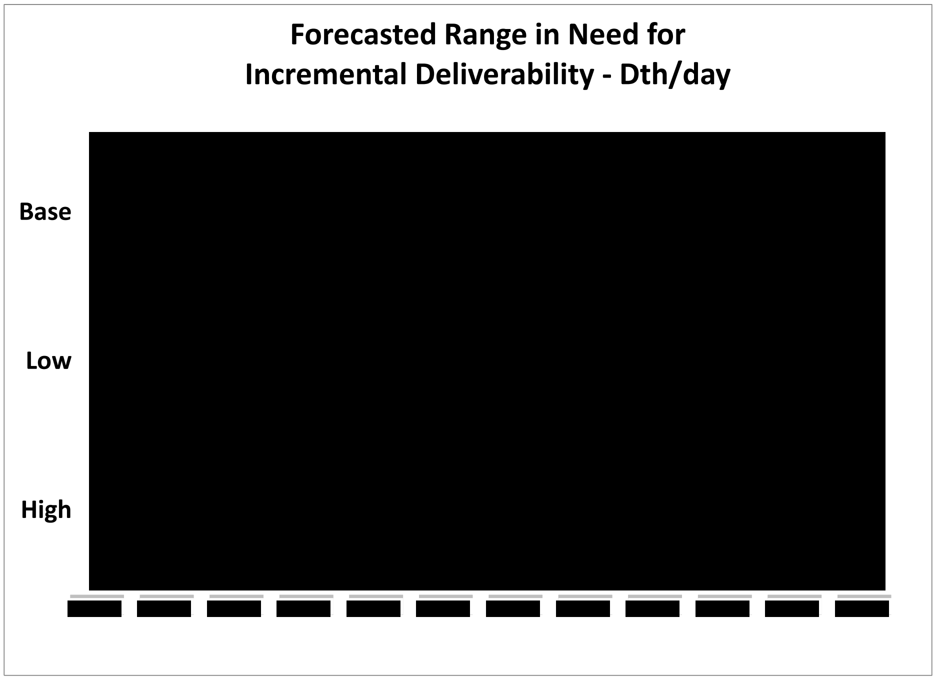
Exacerbating the challenge with interstate pipeline capacity is the significant increase in demand for interstate pipeline capacity in Wisconsin from shippers other than Joint Applicants. This has caused a significant increase in third-party shipper contracts with Guardian compared to historical levels. Supporting the increase in third-party shipper contracts was the fact that not all of the capacity Joint Applicants held included right of first refusal ("ROFR") on their contractual step-downs in capacity established when Guardian was first placed in-service. Whereas capacity held that includes ROFR can be retained indefinitely as long as the holder agrees to pay the prevailing market price and for the market prevailing term, contracted capacity *without* ROFR is not guaranteed to be available to the existing holder upon expiration. With interstate systems at capacity, pipelines are incentivized to offer non-ROFR capacity to the market as opposed to seeking term extensions with existing contract holders as expiration approaches.

Regardless of the circumstance, because of other shippers securing Joint Applicants' non-ROFR capacity as existing contracts step-down, Joint Applicants *were not* able to secure the same level of capacity upon expiration. This serves to put Joint Applicants at risk of being short of their required firm deliverability sooner than expected and further contributes to the need for incremental deliverability. In response to this development, Joint Applicants have sought and were successful in securing the remaining non-ROFR capacity that was available to extend. As part of the negotiations with Guardian those contract extensions now include ROFR and are reflected in the forecasted capacity in the Ex.-WEGO WG-Application, Volume I, Appendix F, Attachment 1.

Q. How do Joint Applicants' demand and capacity forecasts affect their reserve margins over the next few years?

A. To show the level of incremental deliverability needed, Joint Applicants developed 10-year demand (load) and capacity tables by using the base, low and high demand forecasts. Joint Applicants' demand forecasts in support of the LNG Project incorporate their gas supply plans for 2020-2023, and then increase at a modest rate through the winter of 2028-2029. The demand and capacity tables include the forecasted demand, the projected capacity resources over the next 10 years, and the net firm capacity to firm demand position (*i.e.*, shortfall or surplus). Even without this modest projected growth, Joint Applicants anticipate a significant need for additional capacity and deliverability in 2023 to meet a 5.0% reserve margin necessary to protect customers against disruptions on third-party pipelines (*e.g.*, force majeure, incremental non-captured load additions, and forecasting error). Without the proposed LNG Project both Joint Applicants are forecasted to have negative reserve margins starting in winter of 2023-24 under all three load growth scenarios, as shown in Ex.-WEGO WG-Application, Volume I, Appendix F, Attachment 1.

Combining the effect of increasing demand and the lack of [redacted], the table below shows Joint Applicants' forecasted range in capacity shortfall between the winter of 2023-24 and 2028-29 for each of the load growth scenarios evaluated. The overall forecasted annual capacity shortfall through the winter of 2028-29 is provided in Table 2-1 of Ex.-WEGO WG-Application-c.



In the base case forecast, the combined capacity shortfall ranges from approximately [redacted] in the winter of 2023-24 to [redacted] in the winter of 2028-29. As a result, Joint Applicants have determined the appropriate incremental deliverability needed to meet the capacity shortfall over this timeframe is approximately [redacted] for WEPCO and approximately [redacted] for WG, or [redacted] in total, to protect customers from supply disruptions.

Q. Will the LNG Project meet Joint Applicants' needs for additional deliverability and supply?

A. Yes. The LNG Project will not only meet the need for additional deliverability and supply but it provides a superior solution—both economically and operationally—to the available alternatives.

III. THE LNG PROJECT IS AN ECONOMICAL AND EFFICENT PROJECT

Q. Why did Joint Applicants select the LNG Project to meet the needs of their customers?

A. The LNG Project is a strong strategic and economic fit for Joint Applicants and their customers. First, LNG peaking facilities provide an additional source of supply for customers and an alternative to building [redacted] Second, the LNG Project provides additional operational benefits, including increased reliability and resiliency, over other alternatives. Third, the LNG Project will have a reduced impact on the environment as compared to [redacted].

Although the LNG Project is substantial, and will be critical for reliability during peak periods when Wisconsin customers rely on natural gas for heat, it ultimately constitutes only [redacted] of Joint Applicants' overall capacity. Based on current demand forecasts, the LNG Project will avoid the costs of [redacted] Wisconsin, or at a minimum delay [redacted] some years into the future.

The primary alternative—[redacted]—is not a solution that is readily scalable and it would be very costly to customers to request [redacted] to meet demand growth. Under this alternative, Joint Applicants would therefore essentially have "one shot" at predicting the [redacted]. Joint Applicants base case includes lower demand growth than they have actually experienced in the last six years—[redacted]. However, because demand could continue to increase at the same rate as it has in the past, Joint Applicants would likely need to request a [redacted] now, and would likely request an increase in capacity of [redacted]. Joint Applicants would need to request an overbuilt alternative to ensure sufficient supply.

In contrast, the LNG Project provides a "right fit" for Joint Applicants' capacity needs, allowing them to react to and manage both lower and higher demand. If demand exceeds projections, Joint Applicants could [redacted], or add additional vaporization, *i.e.* deliverability, at each site [redacted] On the other hand, if demand is lower than currently anticipated Joint Applicants could [redacted] and avoid some of the increased costs of [redacted]. The LNG Project will help Joint Applicants meet their customers' demand for natural gas whether it increases or declines.

1. The LNG Project will save money compared to the alternatives.

Q. Please describe the alternatives that were evaluated in the economic analysis.

A. Joint Applicants currently meet the majority of their firm peak obligations by taking supply deliveries [redacted]. Incremental long-term firm capacity [redacted] where demand continues to increase [redacted] An alternative of "Doing Nothing" is not prudent nor is it feasible because it would result in Joint Applicants not meeting their obligation to serve customers. Therefore, the only alternative is to [redacted]

To evaluate the economic impact of the proposed LNG Project to customers of Joint Applicants, the net present value ("NPV") life-cycle cost of the LNG Project was compared to life-cycle costs of the alternative deliverability solutions. The alternatives Joint Applicants evaluated in the economic analysis address the need for increased deliverability (capacity *and* supply) to meet the growth requirements in southeastern Wisconsin, increased reliability, and to provide similar daily load balancing attributes.

The alternatives evaluated in the life cycle economic analysis included the following attributes:

Capacity – Given the constrained nature of [redacted], each alternative includes the cost [redacted] system, [redacted], in order to increase deliverability between [redacted] depending on the demand forecast growth rate scenario. [redacted] were considered in the evaluation because both pipelines serve the same service areas the LNG facilities will serve for both Joint Applicants.

Supply – The LNG facilities provide a firm [redacted] of LNG that can be vaporized and delivered to the distribution system when needed. An alternative to the firm supply the LNG facilities provide is a term swing supply for the same quantity of deliverable natural gas. Third party swing supply contracts are very common sources of supply Joint Applicants' use in their annual Gas Supply Plans. As a result, each alternative includes a comparable swing supply contract that provides the same firm supply that each LNG facility provides. Therefore, each utility would need to secure a [redacted] term swing contract for [redacted] in order to firm up the supply of natural gas each winter in the study period.

Reliability – The reliability and resiliency benefits of the proposed LNG facilities are difficult to monetize. However, Joint Applicants performed a high-level assessment of the potential risk of disruption for a given pipeline(s) based on factors such as design, volumetric exposure, and historical experience. For example, since 2013 [redacted] notified shippers on three separate occasions of force majeure, compressor-related, firm flow reductions of varying degrees. In order to model comparable improvements to reliability, Joint Applicants imputed a comparable pipeline cost [redacted] that would address the risk of interruptions. In this way, the reliability and resiliency value LNG provides is reflected as an additional cost [redacted] in the economic analysis for the alternatives.

Load Balancing – LNG facilities enable Joint Applicants to avoid future purchases of incremental load balancing pipeline products, such as [redacted], and the costs to have those products as firm sales demand. In the absence of the LNG facilities, Joint Applicants would need to increase their level of load balancing products to mitigate the impact of unanticipated, real-time changes in customer end-use patterns and market-area temperature variations from that forecast. As a result, the economic analysis includes additional levels of [redacted] for the forecasted increase in demand.

Q. Please describe how the alternative [redacted] were developed.

A. Joint Applicants used the expertise of [redacted] to [redacted] the system delivery capabilities for [redacted] confirmed [redacted] For that reason an evaluation was performed to determine what [redacted] to provide similar incremental deliveries to the same service areas the LNG Project will serve. [redacted] to determine the incremental pipeline facilities required to deliver the following incremental pipeline capacity to Southeast Wisconsin:

1. [redacted] – low load growth scenario
2. [redacted] – base load growth scenario
3. [redacted] – high load growth scenario

Q. What additional facilities will [redacted] to southeast Wisconsin?

A. Based on [redacted], both [redacted] will need significant additional facilities in order to increase deliverability to southeast Wisconsin. The new facilities required [redacted] include a combination of [redacted]

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[4] GSC provides WEC and its other clients the development of hydraulic flow models of interstate pipeline systems to assess capabilities and potential expansion opportunities and development of high-level cost estimates of potential pipeline expansion facilities.

[redacted] The table below summarizes the additional compression, expressed in total horsepower ("HP") required, and pipeline facilities needed for each expansion scenario identified. In addition, all expansion scenarios would require a new meter station.

[redacted]

In the base scenario [redacted] would require [redacted] would require [redacted] Even the low scenario [redacted] requires significant additional facilities for [redacted]

Q. What is the estimated cost for each of the alternatives?

A. The capital costs for the [redacted] required in each scenario were based upon costs incurred or estimated [redacted] for recent projects on its system. Because [redacted] has not made any significant expansions to its system recently, the same representative costs were used for the specific [redacted] required for [redacted] system as were used [redacted]. The estimated costs of the alternatives conservatively include only costs incurred by [redacted] and do not include any costs Joint Applicants might need to incur to upgrade their distribution systems in order to receive incremental pipeline capacity. The estimated capital cost for each alternative is summarized in the table below.

[redacted]

The cost of [redacted] is typically recovered from the shipper through a levelized annual reservation rate ($/Dth/day), typically over 15-20 years, that includes a surcharge [redacted], including ongoing maintenance expenses and the current reservation rate posted in their tariff.

This table includes the estimated surcharge for each of the alternatives:

Table 2-2: [redacted]

[redacted]

The [redacted] do not include [redacted] associated with [redacted]. In addition to the recovery of their investment to expand their pipeline system, a [redacted]

[redacted] Therefore, [redacted] to calculate the total cost for [redacted]. After the recovery period, in this case [redacted], the pipeline expansion investment has been fully recovered and surcharge is eliminated. The only costs going forward are the forecasted recourse tariff rate for the annual reservation of the firm transportation capacity.

Q. How did the economic analysis evaluate these alternatives against the LNG Project?

A. We conducted three interrelated analyses to evaluate the overall economic benefit (or detriment) of the studied alternatives against the LNG Project:

1. Scenario Analysis – A scenario analysis is a method of analyzing the expected value by considering alternative planning assumptions, sometimes called alternative planning futures. The scenario analysis considers alternative planning assumptions under different load growth scenarios, including low, base, and high growth rates.
2. Sensitivity Analysis – The sensitivity analysis determined how different values of an independent variable (*i.e.*, planning assumptions) affect the economic value the proposed project provides.
3. Risk Analysis – The risk analysis is an extension of the sensitivity analysis but incorporates a complete enumeration of all the changes in the independent variables whereas the sensitivity analysis studies the impact of changing only one variable at a time.

The overall economic analysis compares the quantitative attributes of the LNG Project to the alternatives, and demonstrates that the LNG Project will provide significant NPV savings for customers if it is approved.

Q. How much does the economic analysis show customers will save by constructing the LNG Project instead of pursuing the alternatives?

A. In the base case, building the LNG Project results in a $224 million NPV savings over Alternative 1 (expansion of [redacted]), and a combined $267 million NPV savings compared to Alternative 2 (expansion of [redacted]). This table summarizes the Scenario Analysis and the savings expected by constructing the LNG Project in each scenario:

Table 2-3: NPV Results of Scenario Analysis ($MM)

	Comparison to Alternative 1			Comparison to Alternative 2		
	Base Scenario	Low Scenario	High Scenario	Base Scenario	Low Scenario	High Scenario
Alternative	$685	$658	$818	$727	$716	$940
Proposal	$460	$469	$497	$460	$469	$541
Savings	**$224**	**$189**	**$322**	**$267**	**$247**	**$399**
% Savings	**33%**	**29%**	**39%**	**37%**	**34%**	**42%**

The complete economic analysis was included in the Application. *See* Ex.-WEGO WG-Application-Vol. 1: Appendix F, Attachment 3.

Q. Did Joint Applicants consider increased conservation as an alternative?

A. Yes. First, the methodology and development of the demand forecasts include the effects of energy efficiency on decreasing overall demand, so each of the scenarios includes energy conservation. As discussed above, even the base case reflects a significantly lower rate of demand growth than Joint Applicants have experienced in the past six years. But, second, the low scenario includes a low demand forecast that reflects significantly increased energy efficiency and conservation. However, even this scenario still requires some construction—either the LNG Project or one of the alternatives—and the LNG Project would save customers at least approximately $190 million in NPV over the alternatives even in a low demand growth environment resulting from increased energy conservation. Given the magnitude of the need for additional capacity and supply, increased energy efficiency, even if it cost nothing to achieve, could not nearly meet Applicants' projected need for capacity and deliverability.

Q. Please describe the sensitivity analysis Joint Applicants conducted as part of their economic analysis.

A. The sensitivity analysis was designed to provide a robust evaluation of the LNG Project compared to the alternatives. Joint Applicants analyzed a total of seventeen sensitivities for each of the alternatives. Key parameters varied from the base assumptions included:

1. Project Capital Costs – Joint Applicants analyzed the effect on NPV savings if the capital costs for the LNG Project were 15% lower or higher than projected.
2. Alternative Capital Costs – Joint Applicants analyzed the effect on NPV savings if the capital costs for each of the alternatives were 15% lower or higher than projected.
3. Operating Costs – Joint Applicants analyzed the effect on NPV savings if the operating costs of the LNG Project were 15% lower or higher than projected.
4. Escalation Rates – Joint Applicants analyzed the effect on NPV savings of significant changes in the escalation rate of projected costs.
5. [redacted] – Joint Applicants analyzed low and high [redacted] as well as a [redacted]

discount in the [redacted], to analyze the effect of a very unlikely, but substantial discount.

6. Study Period – Rather than a lifecycle analysis, the Utilities analyzed the NPV savings if the study period was limited to 30 years.

7. Discount Rate – Joint Applicants analyzed the effect on NPV savings of low and high discount rates.

Q. What were the results of the sensitivity analysis?

A. The sensitivity analysis confirms that the LNG Project is cost-effective compared to the alternatives. In the scenarios Joint Applicants consider plausible, the NPV savings for the LNG Project range from a low of $170 million compared to Alternative 1 to a high of $336 million compared to Alternative 2. Even in the unlikely event of a [redacted] the LNG Project would save $149 million in NPV compared to Alternative 1, and $209 million in NPV compared to Alternative 2.

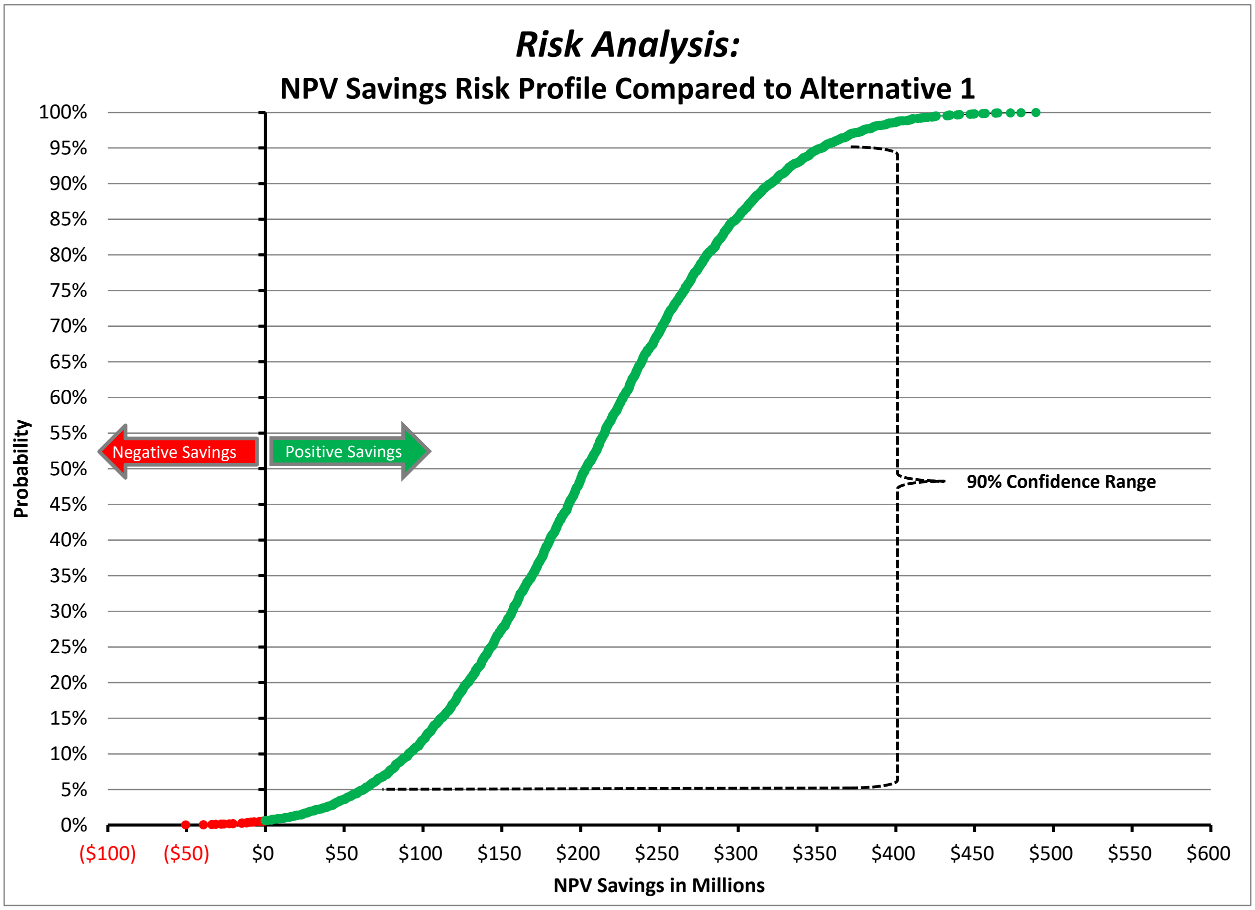
Q. Please describe the risk analysis Joint Applicants included in the economic analysis.

A. The risk analysis is an extension of the sensitivity analysis and quantifies the potential cost to customers across almost 4,000 different unique scenarios (comprised of all the combinations of the sensitivities) for both alternatives. Similar to a Monte Carlo analysis, the parameters for each of the scenarios included in the risk analysis vary simultaneously and the analysis attempts to capture the full range of potential outcomes.

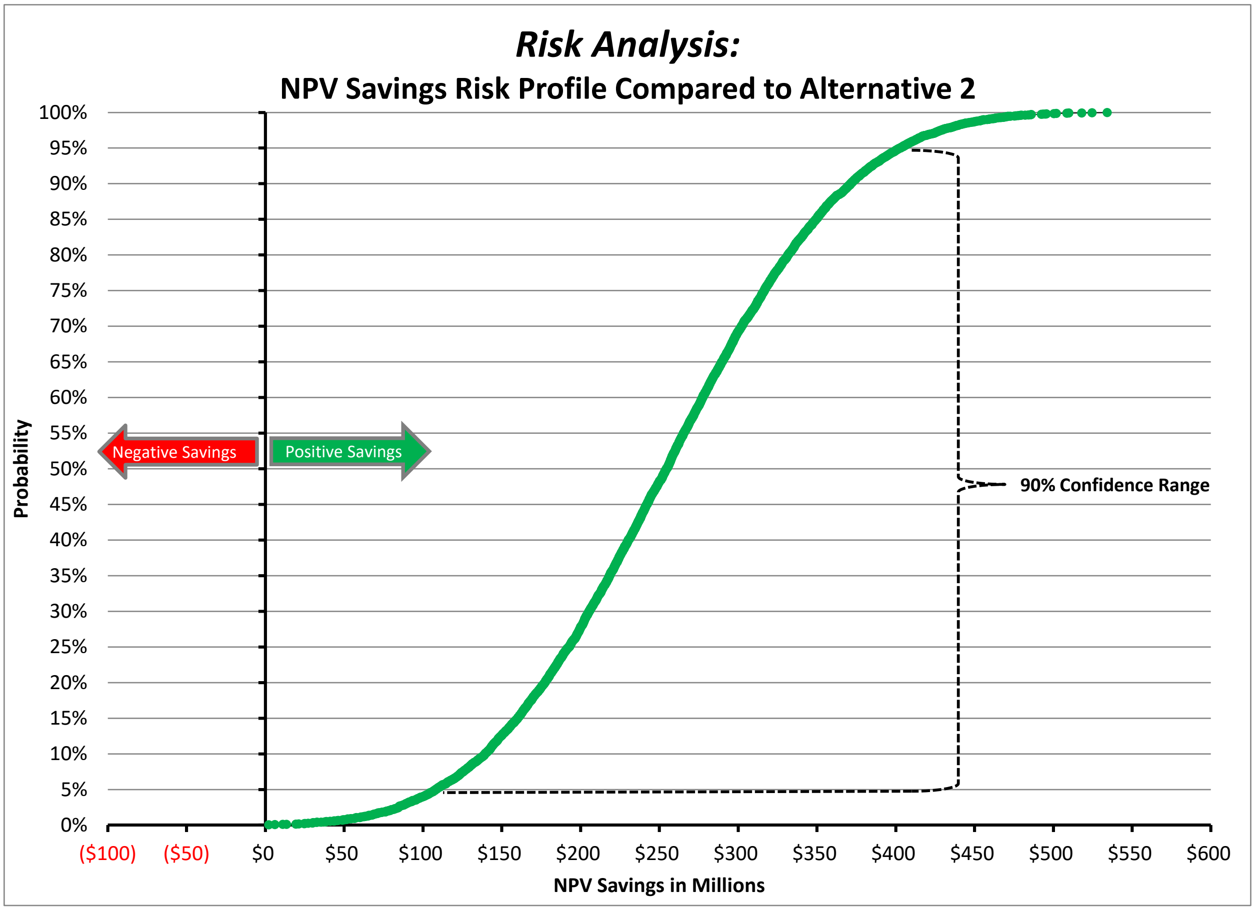
Q. Please describe the results of the risk analysis.

A. The risk analysis also confirms the LNG Project is cost-effective compared to the alternatives. In 95% of cases, the LNG Project saves customers between $62 million and $489 million in NPV as compared to Alternative 1, and between $108 million and $534 million in NPV compared to Alternative 2. In fact, out of nearly 8,000 total scenarios, only 23 (0.3%) scenarios result in a NPV cost to customers compared to the alternatives, and the LNG Project results in a NPV savings compared to Alternative 2 in every scenario. All 23 scenarios that result in a NPV cost to customers include [redacted]—a very unlikely possibility.

This chart plots the NPV savings of the scenarios compared to Alternative 1:



This chart plots the NPV savings of the scenarios compared to Alternative 2:



Joint Applicants' risk analysis shows it is extremely unlikely the LNG Project will cost customers more than the alternatives.

2. The LNG Project will provide significant qualitative benefits to customers.

Q. Will the LNG Project provide other benefits to customers?

A. Yes, the LNG Project will provide several additional benefits to customers, including (1) increased reliability and resiliency; (2) direct control over natural gas supplies during the winter months; (3) a physical hedge against higher gas prices; and (4) the ability to manage and control additional expansion. The alternatives do not provide any of these benefits to customers.

Q. How would the LNG Project provide increased reliability and resiliency?

A. From a capacity perspective, the LNG Project is designed to cover increased demand on essentially [redacted] highest days of firm demand. But, on other days the LNG Project is able to provide a firm, short-term supply alternative to real-time upstream pipeline flow disruptions on interstate pipelines serving Joint Applicants' distribution system. This benefit is enhanced for Joint Applicants' customers, because [redacted]. The LNG Project is also designed to feed an integrated downstream distribution system that receives gas from more than one pipeline, and would therefore be able to mitigate disruption across those pipelines. Flow disruption can occur on any pipeline and repairs can take several days. The LNG Project will be able to provide additional short-term supply to serve customers if disruptions occur.

Joint Applicants performed a high-level assessment of the potential risk of disruption, based on the LNG Project's design, volumetric exposure, and their historical experience. For example, since 2013 [redacted] three separate occasions of force majeure, compressor-related, firm flow reductions of varying degrees. The economic analysis conservatively includes the cost of [redacted] to provide a simple model of the reliability benefits of the LNG Project.

Q. Please describe the benefit of having direct control over a local source of firm deliverability.

A. Currently, Joint Applicants and their customers are almost entirely dependent on interstate pipelines for natural gas during the winter months. The LNG Project will lessen the Joint Applicants' dependency on interstate pipelines, and provide Joint Applicants with direct control over a localized source of firm deliverability and stored supply embedded in their distribution systems.

Unlike [redacted], the Commission will have jurisdiction over the project's scope and cost from start to finish. With [redacted], the final cost is not fully known until after a shipper is in binding contracts for the final cost and capacity off-take, which creates significant uncertainty in pricing for the expansion.

Finally, the LNG Project's location on the distribution system provides load-balancing necessary to mitigate unanticipated, real-time changes in customer use and market-area temperature. By providing local load balancing, the LNG Project could allow Joint Applicants to avoid purchasing other load balancing products and services.

Q. Please describe how the LNG Project would act as a physical gas price hedge.

A. The LNG Project will provide enough storage [redacted] of service, and will have the ability to refill relatively quickly. These attributes allow the LNG Project to act as a physical supply hedge against transitory changes in gas prices, and allow for arbitrage opportunities for the benefit of customers. Joint Applicants will be able to execute on these opportunities more frequently than if they had a smaller amount of storage.

Q. Would the LNG Project have delivered customer savings if it were in-service during the recent natural gas price spike experienced during the Presidents' Day weekend?

A. Yes. Joint Applicants' customers would have had the potential to save up to approximately $100 million in avoided spot-priced natural gas during that [redacted]-day period of significantly-elevated natural gas prices.

Q. Could you explain how that estimate of customer savings was developed?

A. Certainly. This past winter from February 13th through the 16th the spot natural gas prices in Chicago were $129.84/Dth or approximately 4,230% higher than normal. Calculating the estimate for customer savings is simply the incremental cost of natural gas that would have been avoided for the daily volumes of natural gas that each LNG Facility will be able to vaporize each day over the course of the four-day period. Using $3.00/Dth as a proxy for the normal average cost of natural gas and the daily spot price of $129.84/Dth yields an incremental cost of $126.84/Dth, which in this case would be the avoided cost of natural gas the LNG facilities would have been able to provide all of its customers. Applying that to the daily [redacted] withdrawal capacity for each facility for the four-day period results in approximately $100 million in customer savings.

3. The LNG Project will have less impact on the environment than the alternatives.

Q. How does the environmental impact of the LNG Project compare to the alternatives?

A. [redacted] requires either increased [redacted], or both. The LNG Project will be strategically placed on existing distribution systems, and will have significantly lower environmental impacts than a [redacted] It will simply disturb and disrupt less ground than the alternatives.

Furthermore, the LNG Project is designed to provide natural gas for the highest peak portion of Joint Applicants' load duration curve. [redacted] designed to meet the same forecasted growth in peak demand will allow natural gas to flow the entire year, whether it is being transported for Joint Applicants and their customers or other off-takers. By avoiding [redacted], the LNG Project avoids additional natural gas flowing and being burned by others, on a subsidized basis, the remaining [redacted] of the year. Compared to [redacted] the LNG Project will therefore reduce the carbon impact of the addition of new deliverability resources to Joint Applicants' systems.

IV. CONCLUSION

Q. What do you conclude from your analysis?

A. The LNG Project is clearly Joint Applicants' most prudent, cost-effective option to manage their near term growth in demand, and will provide Joint Applicants and their customers with significant strategic benefits. It is an economical and efficient solution that will provide substantial net benefits to all customers.

Q. Does this conclude your direct testimony?

A. Yes.