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

SURREBUTTAL TESTIMONY OF ASA S. HOPKINS
ON BEHALF OF
SIERRA CLUB

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

A My name is Asa S. Hopkins. My business address is 485 Massachusetts Ave., Suite 3, Cambridge, MA 02139. I am a Vice President at Synapse Energy Economics.

Q Did you previously testify in this docket?

A Yes. I submitted testimony on behalf of the Sierra Club on June 1, 2021.

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

A I address various comments regarding my direct testimony that were made by Mr. Horrie, Mr. Lambert, Mr. Kuse, Ms. Mead, and Mr. Gerlikowski.

Q Please summarize your surrebuttal testimony.

A In this testimony I address the following:

- The conclusions and results regarding achievable energy efficiency potential in my direct testimony are correct even after accounting for concerns from Mr. Horrie and Mr. Lambert regarding net and gross energy savings.

- Addressing issues raised by Mr. Horrie and Mr. Gerlikowski, I calculate that peak-day percentage demand reductions from energy efficiency that targets space heating will be about 10 percent larger than the annual gas use reductions resulting from those same measures. This reinforces the conservatism of my assumptions regarding the potential for energy efficiency to avoid or defer the construction of the proposed new liquified natural gas ("LNG") facilities and associated natural gas pipelines near Ixonia and Bluff Creek, Wisconsin (the "Proposed Facilities").

- Addressing Mr. Horrie's concern that my analysis did not reflect the carbon value included in the modified total resource cost ("TRC") test, I show that additional energy efficiency targeting space heating to avoid expensive new capacity is cost-effective even without the carbon value.

- Counter to Mr. Lambert's testimony, Focus on Energy funding does not preclude the Commission from finding new capacity unnecessary or Wisconsin Electric Power Company ("WEGO") and Wisconsin Gas LLC (together "the Utilities") from implementing load-side programs to reduce peak day demand.

- Mr. Kuse's rebuttal testimony regarding the Utilities' load forecast methodology is inconsistent with his direct testimony and the supplied workpapers, and the Commission should give his rebuttal testimony on the load forecast no weight.

- Counter to Mr. Kuse's claim that the methods used here should be approved because they are consistent with methods used in the past, I conclude that the methods used for near-term gas supply planning are not suited for long-term

infrastructure decisions. The Utilities have also not justified key aspects of their load forecast methodology.

- Counter to Ms. Mead's claim that the temperature-based interruptible rates I proposed in my direct testimony shift focus away from reliability and introduce unfavorable cross-subsidies, the rates I proposed in my direct testimony focus on maintaining reliability and do not impose cross-subsidies on smaller customers. Instead, both large and small customers realize a lower capacity cost and share those savings compared to the Proposed Facilities.

- Ms. Mead and Mr. Gerlikowski misunderstand the New York gas utility rate examples in my direct testimony. They conflate established and demonstrated temperature-controlled rate programs with different programs offered by a different utility.

- Counter to Mr. Gerlikowski's claim that only infrastructure solutions are proven to meet capacity needs, I show that demand-side actions such as efficiency and interruptible rates are proven alternatives to infrastructure investments. Mr. Gerlikowski's rebuttal relies on the false premise that new [redacted] are the only alternative that maintains reliable service.

- The Utilities have not provided support for Mr. Gerlikowski's claim that the Proposed Facilities would provide net value even in the case in which natural gas use declines.

- A gas-industry report that Mr. Gerlikowski cites does not support the conclusions he draws from it.

- Heat pump technology has advanced in recent years and cold-climate performance is substantially better than that seen in an older study that Mr. Gerlikowski cites.

- Studies that I cited in my direct testimony are well suited for the purposes for which I used them.

- The Utilities' confidence that the Proposed Facilities will remain used and useful throughout their lives leads me to reiterate my recommendation that their shareholders, not ratepayers, should bear any stranded cost risk associated with these facilities.

Q Have any of your conclusions changed since your direct testimony in light of rebuttal testimony from Staff and the Utilities?

A No. The premise for the application is an ever-increasing use of natural gas, which is irreconcilable with the policy context of Governor Evers's and the Biden Administration's commitments to reducing emissions by 50–52 percent from 2005 levels by 2030. The proposed large and costly LNG storage facilities are not needed if gas use declines consistent with these policies, including the impact of electrification of space heating through new heat pump technology. In the more likely future, gas use will decline and strand the Proposed Facilities. The purported projected need is also inflated by double counting load growth by some customer classes and by including new load attributed to a large manufacturing facility in southeastern Wisconsin that appears unlikely to move forward as assumed. The claimed need for the facilities—meeting short-duration gas demand during infrequent cold weather events—can be met through demand-side approaches that are lower cost and that provide additional benefits.

Q How is your testimony organized?

A My testimony is organized by the witness to whom I am responding. I first address the testimony of Mr. Horrie, regarding energy efficiency, in Section I. I then address the testimony of Mr. Lambert, regarding energy efficiency, in Section II. In Section III, I address the testimony of Mr. Kuse, regarding load forecasting. In Section IV, I address the testimony of Ms. Mead, regarding interruptible rates and the cost of peak-day demand. In Section V, I address the

testimony of Mr. Gerlikowski, regarding peak gas demand, heat pump performance, and the suitability of several studies to support the Commission's decision-making in this proceeding.

Q Are you sponsoring any exhibits to your surrebuttal testimony?

A Yes. I am sponsoring eight exhibits:

- Ex.-SC-Hopkins-32 is a set of screenshots from the Focus on Energy evaluation dashboard, showing the components of the program's cost-effectiveness.

- Ex.-SC-Hopkins-33c is the first summary ("Graph") worksheet from each of a set of three Excel files provided by the Utilities in response to 2-Sierra Club-13.

- Ex.-SC-Hopkins-34c is an annotated screenshot of the Excel spreadsheet Response-Data Request-2-Sierra Club-13 2nd Models CONFIDENTIAL.

- Ex.-SC-Hopkins-35 is a packet of materials from Xcel Energy explaining its Interruptible Gas Rates Program.

- Ex.-SC-Hopkins-36 is the Utilities' response to 2-Sierra Club-17.

- Ex.-SC-Hopkins-37 contains specification sheets for two cold climate heat pump systems: a Trane system whose performance is cited by Mr. Gerlikowski, and a more recent Mitsubishi system.

- Ex.-SC-Hopkins-38 is a White House fact sheet about expansion and modernization of the electric grid.

- Ex.-SC-Hopkins-39c is an annotated version of the attachments to the Utilities' response to data request 5-Sierra Club-5.

I. ADDRESSING THE TESTIMONY OF MR. HORRIE

Q What aspects of Mr. Horrie's rebuttal testimony do you address?

A I address three aspects of Mr. Horrie's testimony. First, I address net versus gross energy savings and the relation to the *2016 Potential Study* (Ex.-SC-Hopkins-18). Next, I address two aspects regarding Wisconsin's cost-effectiveness test: the value of emission reductions and the value of gas peak capacity reductions. I also address Mr. Horrie's testimony regarding of the peak-day impacts of annual gas heating efficiency measures.

Net versus gross savings

Q What is the difference between *net* and *gross* energy efficiency savings?

A As defined by the American Council for an Energy-Efficient Economy, "[g]ross savings represent the changes in energy use and demand that result from program activities, regardless of what factors may have motivated the participant to take the energy efficiency actions….Net savings are determined by adjusting gross savings to account for what would have happened without the program (free riders) and for program-induced spillover and market effects."[1]

Q When comparing the efficiency achieved between different levels of program funding, does the net-to-gross ratio matter?

A No, it does not. This is because the level of efficiency that would be achieved in the absence of any program is by definition not affected by program funding. Therefore, when calculating the difference between the efficiency achieved at one level of program funding and that achieved at a different funding level, the efficiency that would have occurred anyway cancels out. In my direct testimony, when I considered the increase in efficiency that would be possible with greater

[1] American Council for an Energy-Efficient Economy. "Evaluation, Measurement, and Verification." June 12, 2017. Accessed at https://www.aceee.org/toolkit/2017/06/evaluation-measurement-verification on July 5, 2021.

funding, compared with today's programs, I did not adjust for the difference between net and gross savings because, mathematically, no such adjustment is required.

Q Could you give a concrete example?

A In the *2016 Potential Study*, the gross savings in the "BAU Achievable" ("BAU") scenario are 270,506 therms between 2019 and 2030. The net savings from this scenario would be less because some actions that customers take would have happened anyway. Mr. Horrie identifies that for the 2015–2018 Focus on Energy programs, this ratio was 0.7, so the savings attributable to the program are approximately 0.7*270,506=189,354 therms. The savings that would have occurred absent the program, plus counteracting spillover, are 0.3*270,506=81,152. In the "high incentive" case that I used in my direct testimony, the gross achievable savings between 2019 and 2030 are 425,432 therms. The actions that would have happened absent any program, plus spillover, provide the same level of savings, 81,152 therms. This means that the net savings from the "high incentive" case are 425,432-81,152=344,280 therms. The relevant value for my analysis is the difference between the BAU and "high incentive" cases. Note that the difference in savings between the two gross cases (425,432-270,506=154,926 therms), is the same as the difference in savings between the two net cases (344,280-189,354=154,926 therms).

In my direct testimony, I utilized the difference between the BAU case and the "high incentive" case to calculate the amount of additional cost-effective savings that could be achieved as part of a targeted program to avoid or defer the Proposed Facilities. That difference is unaffected by my choice to use gross savings directly from the *2016 Potential Study*, rather than accounting for net savings. Therefore, while I appreciate Mr. Horrie pointing out the difference between gross and net, using gross or net produces the same results for purposes of my testimony.

Cost-effectiveness

Q Please summarize Mr. Horrie's concerns regarding the value of emission reductions in Wisconsin's cost-effectiveness screening framework.

A Mr. Horrie explains that Wisconsin's modified TRC cost-effectiveness test includes a value of avoided emissions—namely $15 per ton of avoided carbon dioxide emissions. This means that from a purely financial standpoint, the expanded programs that achieve the full "high incentive" potential will return slightly less to ratepayer pocketbooks, and more to society at large, than I had assumed.

Q Does accounting for this clarification change your results?

A No. I do not believe that the expanded portfolio of actions (resulting from additional actions to acquire peak savings by targeting additional energy efficiency at space heating measures) would have costs exceeding its benefits even if greenhouse gas emission value is excluded. The cost comparisons in my direct testimony took the extremely conservative position of assuming that the portfolio additions would have a benefit-cost ratio of 1.0. This is despite the fact that *each measure* making up the portfolio has a benefit-cost ratio of at least 1.0—and many measures have benefit-cost ratios above 1.0. Based on my review of the last three years of Focus on Energy programs at the Focus on Energy online evaluation dashboard, emission benefits account for about 16 percent of program benefits (see Ex.-SC-Hopkins-32). This means that, on average, *a portfolio* would need to maintain a benefit-cost ratio of about 1.2 in order to return positive financial returns to ratepayers.

While the *2016 Potential Study* does not provide separate benefit-cost ratios for each fuel (electricity and natural gas), it does show that the benefit-cost ratio using Wisconsin's modified TRC *increases* between the BAU case and the "high incentive" case (see Table D-29 in Ex.-SC-Hopkins-18). The fact that the benefit-cost ratio increases as the program becomes more ambitious means that the incremental programs must be more cost-effective, on average, than the BAU

programs. Based on the values presented in Ex.-SC-Hopkins-32, 2018 through 2020 Focus on Energy programs delivered a benefit-cost ratio (using the modified TRC) of 2.86, and a ratio of 2.4 if emissions benefits are not included.

What all of this means is that the expanded portfolio of actions identified in my direct testimony, as part of a demand-side alternative to the Proposed Facilities, very likely has a benefit-cost ratio well above 1.2. Thus, excluding the carbon value in the modified TRC from my calculations does not change the fundamental conclusion that expanded efficiency programs will be cost-effective from the perspective of total ratepayer costs, even before the avoided costs of the Proposed Facilities are included. And, of course, including the cost of the Proposed Facilities means the efficiency programs are even more cost-effective, while the carbon emission benefits from expanded efficiency would also be substantial and advance state policy.

Q Mr. Horrie also points out that the modified TRC used in the *2016 Potential Study* does not include the value of avoided gas capacity. What impact does this have on the cost-effective potential?

A Because Wisconsin's cost-effectiveness test does not include avoided gas capacity, it understates the benefits of efficiency measures that reduce winter peak demand.

This means that efficiency measures beyond those included in the cost-effective potential identified by the *2016 Potential Study* (and its successor study underway in 2021) are cost-effective when the cost of avoiding gas capacity, such as the proposed LNG facilities, is included. Thus, if a measure is cost-effective based on the potential study, it would be even more cost effective when new gas capacity costs are included. Additionally, measures that were not cost-effective in the potential study are cost-effective when costs of new gas capacity are included. This highlights that my analysis, which utilized the potential study results, is very conservative and energy efficiency alternatives are even more cost-effective compared to the proposed LNG facilities.

Q Mr. Horrie states that your direct testimony's assessment is more akin to a utility cost test, rather than a total resource cost test. Do you agree?

A No, I do not. My analysis used the same cost-effectiveness framework as was used in the *2016 Potential Study*, which uses Wisconsin's modified TRC, and therefore includes all participant costs. When I considered the costs to ratepayers in my direct testimony, I included all costs, including participant costs, and not only utility costs. Note that if I had used the utility cost test, participant costs would have been excluded, while retaining all of the utility system benefits in the analysis, which would make the efficiency measures *more* cost-effective compared to the Proposed Facilities.

Peak savings and annual savings

Q Mr. Horrie states that assessments based on annual savings (such as your direct testimony) may understate the impact of space heating efficiency on winter peaks. Do you agree?

A Yes, I agree. As I previously noted, my analysis is conservative. As Mr. Horrie points out, a disproportionate fraction of efficiency savings from heating efficiency and weatherization measures occurs on the coldest days because that is when heating systems are asked to perform the most and because space heating load makes up a larger fraction of the system load on the coldest winter days than it does on an annual average basis. In my direct testimony, I assumed (based on the *2016 Potential Study*) that about [redacted] percent per year of annual sales could be saved from cost-effective heating-focused efficiency measures. I conservatively carried that value of [redacted] percent over directly to peak demand reduction. However, as Mr. Horrie points out, I could have used a higher number. Doing so would have *increased* the cost-effectiveness of the efficiency approach compared to the proposed facilities and reduced the need to rely on demand response or other tools to bridge the gap between demand and the secured pipeline capacity.

Q How much higher would the annual peak savings number be, if the annual savings increase relative to the baseline is [redacted] percent?

A I can approximate the value, which will provide an indication of how conservative I was in my direct testimony. Based on the regression analyses that the Utilities use to estimate their peak loads (provided by the Utilities in response to request 2-Sierra Club-13, and reproduced as Ex.-SC-Hopkins-33), I calculated the fraction of annual firm sales that are heating-related. (This is the portion of sales that corresponds to the increase from the year-round baseline when the average daily temperature is below 65 degrees.) For both utilities, this ratio is 87.8 percent. This means that saving [redacted] percent of annual sales through heating efficiency corresponds to saving [redacted] percent of annual heating sales ([redacted]/87.8%=[redacted]). On the winter design day, heating is a larger fraction of firm sales. For both utilities, heating is 97 percent of firm sales on a design day. This means that efficiency which reduces heating demand by [redacted] percent per year will reduce the winter peak demand by [redacted] percent ([redacted]*97%=[redacted]).

Therefore, accounting for the effect correctly pointed out by Mr. Horrie means that the cost-effective level of efficiency associated with the "high incentive" case from the *2016 Potential Study* is 10 percent higher ([redacted]=110%) than I conservatively estimated in my direct testimony. Making Mr. Horrie's change strengthens my point that demand-side options are able to meet customers' need for reliable service at lower cost than the Proposed Facilities, while being consistent with both Governor Evers's climate change mitigation commitments and with federal policy.

II. ADDRESSING THE TESTIMONY OF MR. LAMBERT

Q What aspects of Mr. Lambert's testimony are you addressing?

A I address two arguments from Mr. Lambert. First, I address his argument that I failed to account for the difference between net and gross savings from energy efficiency. Second, I address his argument that the Utilities are supporting

efficiency to the extent they are required to by law and it is therefore unrealistic to consider a future with substantially increased energy efficiency support for the Utilities' gas customers.

Net and gross savings

Q Mr. Lambert states that you misused the utility-specific efficiency information provided in Exhibit Ex.-WEGO WG-Lambert-6c because that exhibit contains gross savings, while only net savings result in changes in load, and that your savings estimates are therefore off by as much as 31 percent. Is Mr. Lambert correct?

A No, he is incorrect regarding how I used the data presented in Exhibit Ex.-WEGO WG-Lambert-6c. I used these data to estimate how much efficiency is already built into the baseline load forecast presented by Mr. Kuse, because it is reflected in current efficiency programs. I concluded that the gross savings included in the forecast amount is about [redacted] percent per year from space heating measures. I then compared this to the 0.98 percent per year gross savings achievable in space heating measures using the "high incentive" case. I then approximated the difference in gross savings between current and "high incentives" cases as [redacted] percent. As I discussed above, responding to Mr. Horrie's testimony, this math is unaffected by the use of gross versus net savings. Therefore, Mr. Lambert is incorrect that my results likely overstate energy efficiency potential by "as much as 31%." (Rebuttal-WEGO WG-Lambert-8)

Additional efficiency program funding

Q Does Wisconsin law prevent the Utilities from identifying the need for additional cost-effective energy efficiency to reduce ratepayer costs or prevent the Utilities from supporting programs to achieve that savings?

A No. Mr. Lambert asserts that because the applicants met their funding requirements they "have fully met their state law obligations for energy efficiency and contribution." (Rebuttal-WEGO WG-Lambert-4:21-22.) That's not quite accurate, depending on what he means by "state law obligations." It is my

understanding that state law imposes a number of obligations that relate to energy efficiency. Levels of funding and Commission-ordered programs are one obligation, but not the only one.

In fact, as Mr. Lambert states (Rebuttal-WEGO WG-Lambert-9:10), the Utilities are allowed to, and do, offer voluntary programs that are coordinated with Focus on Energy but funded separately. Wis. Stat. § 196.374(2)(b)2 states that "An energy utility may, with commission approval, administer or fund an energy efficiency or renewable resource program that is in addition to the programs required under par. (a) [Focus on Energy] or authorized under subd. 1 [large commercial, industrial, and agricultural programs]. The commission may not order an energy utility to administer or fund a program under this subdivision."

Additionally, the certificate of authority statute and Energy Priorities Law require the Commission to deny authorization for new utility capacity where cost-effective and technically feasible energy efficiency can displace the projected need. Those are not obligations of the utility, but they are obligations of the Commission and, indirectly, affect whether utilities can undertake projects. Where cost-effective energy efficiency is available and sufficient to displace (or delay) a proposed project, the Commission can deny the project on that basis. That does not constitute ordering the utility to fund a program. If a capacity deficiency still exists after such denial, it is up to the utility to propose an alternative solution or manage load. I am not a lawyer, but my lay person understanding of Wis. Stat. § 196.374(2)(a)3 is that it does not prevent the utility from pursuing demand-side options to avoid capacity shortfalls. Doing so does not require a change to state law as Mr. Lambert states. (Rebuttal-WEGO WG-Lambert-6:8)

III. ADDRESSING THE TESTIMONY OF MR. KUSE

Q What aspects of Mr. Kuse's rebuttal testimony do you address?

A I address two arguments from Mr. Kuse's rebuttal testimony. First, I address Mr. Kuse's claim that the Utilities' long-term forecasts correctly accounted for commercial and industrial loads. Second, I address Mr. Kuse's claim that because the Commission has not objected to methods for short-term supply plans, the Utilities' long-term infrastructure load projections are necessarily correct.

Overstated load growth

Q Do you agree with Mr. Kuse that load forecasts can be decomposed into contributions from various components?

A Yes, I agree with Mr. Kuse that, conceptually, it is useful to develop load forecasts by accounting for various drivers of change in load, and that modeling each of those changes separately can be an effective way to develop a forecast. I also agree with Mr. Kuse that a useful decomposition for the purposes of gas peak planning is (1) changes in load from existing customers (either increases or decreases, including the loss of existing customers), (2) changes due to customers switching off and onto firm gas service; (3) growth from the addition of new customers. However, I would further decompose the third category into two subcategories. I separate (3A) growth from the addition of customers which are not individually accounted for (e.g., new residential customers due to population growth), from (3B) growth from the addition of large, identified customers who have specific needs and timelines.

Q Does this decomposition line up with the forecast as presented by Mr. Kuse?

A Only partly. Mr. Kuse's direct and rebuttal testimony are contradictory so it is impossible to make this categorization line up with all of his testimony.

In his direct testimony, Mr. Kuse presents forecasts composed of three parts. See Ex.-WEGO-Kuse-1c and Ex.-WG-Kuse-2c. The first part, labeled "Consensus Forecast," starts at a level that is developed from a weather-load regression model, and then increases as a function of a simple customer growth rate through 2022/2023.[2] Nothing in the workpapers or testimony presented by Mr. Kuse or other witnesses explains the origin of the [redacted] percent per year growth rate used in the years after 2022/2023. I return to this gap later in my testimony.

The second part, labeled "Adjustments for Customer Changes," reflects component 2 (changes due to customers switching off and onto firm gas service), while the third part, labeled "Adjustments for Other Growth," reflects component 3B (growth from the addition of large, identified customers who have specific needs and timelines). The fact that Mr. Kuse's projections specifically identify the load for components 2 and 3B implies that his "Consensus Forecast" component is only the sum of component 1 (changes in load from existing customers) and component 3A (growth from the addition of customers which are not individually accounted for). However, as my direct testimony points out, Mr. Kuse's approach makes no distinction between the average growth from the addition of large customers (including those with individually-accounted-for loads) and the average growth from the addition of any other customers. Instead, it includes the growth attributable to new customer loads (component 3B) in trends used to calculate the "Consensus Forecast" despite separately adding them as component 3B. In other words, the growth from new large customer loads is included in both the "Consensus Forecast" and added as "Adjustments for Other Growth" as part of component 3B. Therefore, Mr. Kuse's method double counts the 3B load. I presented a method for correcting this double-counting in my direct testimony.

[2] While the Utilities' Gas Supply Plans and Mr. Kuse's testimony refer to a second regression model, the workpapers presented in Ex.-SC-Hopkins-34 (from Response-Data Request-2-Sierra Club-13 2nd Models CONFIDENTIAL) show that the forecasts used in this proceeding use a growth rate that is simply half of the growth rate in the number of customers.

Q How is Mr. Kuse's testimony internally contradictory?

Mr. Kuse's rebuttal testimony makes a different claim regarding the composition of the forecast than he presented in his direct testimony. In rebuttal, Mr. Kuse defines the values in the "Consensus Forecast" as "natural growth of existing customer demand." (Rebuttal-WEGO WG-Kuse-3c:7-8) (The values cited on line 8 are those labeled as Consensus Forecast in Ex.-WEGO-Kuse-1c.) In other words, Mr. Kuse claims that the Consensus Forecast reflects *only* component 1. He then states that the "Adjustments for Other Growth" reflects all new customer growth (that is, both component 3A and component 3B). (Rebuttal-WEGO WG-Kuse-3c:11-12) However, Mr. Kuse's direct testimony and his workpapers include components 1, 3A, and 3B *as part of* the "Consensus Forecast," and then add 3B. That is, contrary to what he claims in rebuttal, his direct testimony and workpapers include new customer loads in the "Consensus Forecast" rather than limiting the "Consensus Forecast" to only natural growth of existing customers. This table illustrates the conflicting testimony:

Component	Kuse Direct Testimony	Kuse Rebuttal Testimony
1) Existing customer changes	Consensus Forecast	Consensus Forecast
2) Moving on and off firm gas service	Adjustments for Customer Changes	Adjustments for Customer Changes
3A) Growth form customers other than specific large C&I	Consensus Forecast	Adjustments for Other Growth (*no values provided*)
3B) Specific new large C&I customers	Consensus Forecast **and** Adjustments for Other Growth (*counted twice*)	Adjustments for Other Growth

Q Given these contradictory explanations from Mr. Kuse, what should the Commission do?

A Of these two contradictory explanations for the forecast, it is only the approach described in Mr. Kuse's direct testimony that is consistent with the workpapers provided. The data used to derive his "Consensus Forecast" contain all growth due to new customers, including the long-term trend of the growth that he also includes in "Adjustments for Other Growth."

The contradictory rebuttal testimony appears to be post hoc and false rationalization that is unsupported by the underlying data. That raises doubts about not only the double counting of new customer additions but the credibility of all of the Utilities' underlying load forecasts. As I stated in my direct testimony, there are numerous other errors with the Utilities' forecasts that lead to an overstating of load.

Q Mr. Kuse says the large C&I customer in WEGO territory and its associated ancillary load "is not a meaningful driver of the need for the LNG Project to meet peak-day demand." (Rebuttal-WEGO WG-Kuse-4p:16–17) Do you agree?

A No, I do not. Tellingly, Mr. Kuse compares that large C&I customer (and associated growth) to the company's *total* capacity requirement, not to the projected capacity deficit used to justify the LNG facilities. While the customer may represent "merely approximately 2% of WEGO's capacity requirement" (Rebuttal-WEGO WG-Kuse-4p:16), it is 29 percent of WEGO's claimed capacity gap in 2023–24 (including the 5 percent margin). Contrary to Mr. Kuse's assertion, that reflects a "meaningful driver" of WEGO's projected need for the project. Making this obvious correction to the Utilities' peak demand forecast, as well as other smaller corrections for the double-counted C&I load, significantly reduces the projected capacity deficiency. Enhanced energy efficiency and other load-side solutions can meet the reduced capacity need, and thus avoid the need for the WEGO facility.

Planning methods

Q Mr. Kuse states that the forecasts used in this proceeding have been prepared in "exactly the same way as gas supply plans, which have been approved by the Commission." (Rebuttal-WEGO WG-Kuse-4p:19-20) Should the Commission expect the same load forecasting methodology to apply in long-term infrastructure planning as is used in three-year gas supply plans?

No. There is no *a priori* reason to expect that methods which apparently went unchallenged in plans looking ahead three years are the best, or even appropriate,

methods for long-term forecasts. First, the Commission should consider the purpose for which a forecast is prepared. In the case of a gas supply plan forecast, the purpose is to ensure that the gas utilities have procured sufficient supply to provide reliable service for the next three years. If a forecast is slightly too high, it simply adds to the conservativism of the forecast (which already reflects weather that is unlikely to occur in any given year). If the utility has secured supply to meet an erroneously inflated forecast, then actual load is necessarily met. Because of the relatively short horizon, the degree of overestimation is also necessarily limited. However, when considering a long-term infrastructure investment with a life of 30 to 40 years, errors that produce relatively small overestimations in the short term compound and result in a vastly different assessment of the need to be met. This raises the stakes for the forecast, and greater scrutiny is warranted.

Second, changes in policy and economic trends typically do not significantly alter the short-run projections but dramatically change forecasts in the medium to longer term. This means that ignoring policy context is unlikely to result in large magnitude errors in a near-term forecast like the forecast for gas supply planning. However, as I showed in my direct testimony, the failure to consider the Biden and Evers administrations' climate change goals and actions produces a substantial difference between the Utilities' forecasts and the level of need that is consistent with the Biden and Evers policy prescriptions.

Lastly, it appears from the dockets that Mr. Kuse references that very little process occurred before the short-term plans were approved. No hearings were held, and the Commission did not even consider the plans. Instead, the plans were apparently approved by staff through a delegation.

Q Did the Utilities actually use the Gas Supply Plan methodology to extend the forecast beyond the period covered by the three-year supply plans?

A No. In particular, the Utilities assigned a [redacted] percent per year growth factor to the "Consensus Forecast" portion of the load that extends beyond the period covered by the Gas Supply Plans. Contrary to Mr. Kuse's claim that the

companies used the same methodology as the Gas Supply Plans, there is no connection between those plans and their methodology and the [redacted] percent annual growth factor the Utilities used. No witness has provided any quantitative analysis in this proceeding to show how the value of [redacted] percent per year was derived, or why it is the same for each utility. Similarly, the Utilities have provided no analytical support for the use of [redacted] percent per year or [redacted] percent per year for low- or high-growth cases. The Commission should not put ratepayers on the hook for $460 million (present value) in ratepayer money based on a forecast with such lack of support, especially one which is built on the flawed foundation of the methods described by Mr. Kuse.

IV. ADDRESSING THE TESTIMONY OF MS. MEAD

Q What aspects of Ms. Mead's testimony are you addressing?

A In her rebuttal testimony, Ms. Mead makes three arguments which I address. The first area I address is whether the "focus" of the interruptible rate proposal I made in my direct testimony is *economic* or *reliability* concerns. Second, I address the practicality of implementing temperature-controlled or other interruptible rates beyond those offered by the Utilities today. I also address Ms. Mead's and Mr. Gerlikowski's apparent misunderstanding of the New York interruptible rate offerings I described in my direct testimony.

Focus for interruptible rates

Q Ms. Mead states that you proposed "a fundamental change of focus from safety and reliability to instead interrupting service to avoid future costs." (Rebuttal-WEGO WG-Mead-4:12–14) Do you agree with that characterization?

A No, I do not. Nothing in my illustrative demand-side proposal in intended to, or would have the effect of, reducing safety or reliability. I simply set out to illustrate that the Proposed Facilities are not the only option available to achieve

safety and reliability as the companies would like the Commission to believe. Instead, other options are not only available but lower cost. When implemented in concert with energy efficiency and electrification, the rate approach that I describe maintains peak demand below the amount of capacity that the Utilities have already secured, thus meeting the same reliability premise the Utilities use to justify the Proposed Facilities. I also made clear that supplemental low-commitment supply-side options, such as temporary trucking of compressed or liquified natural gas, may also play a role in a lower-cost solution.

Furthermore, weatherization would increase customer safety in the event of power outage by increasing the ability of homes and other buildings to retain heat until power can be restored. (Neither gas nor electric heating options work without electricity.) The smarter systems the Utilities might deploy in order to implement more advanced interruptible rates might also allow greater flexibility in system operation than do today's manual approaches.

Q Ms. Mead states that the Utilities offer interruptible rates to small customers to address distribution constraints, under tariff schedule X-140. What lessons can this offering provide for the current proceeding?

A Under schedule X-140, as Ms. Mead describes, "[i]f distribution capacity in the area is constrained, Joint Applicants' engineers will place a customer on this service, crediting them a portion of their distribution margin rate in exchange for the system reliability afforded by their willingness to be interrupted. An alternative to this option in this type of area would be to build a more robust or expanded distribution system, which can be quite expensive." (Rebuttal-WEGO WG-Mead-5:23–6:4) That is the analogous situation to the premise for this proceeding, but at the distribution rather than transmission level. Ms. Mead's logic for providing this tariff offer to small customers is identical to the logic for utilizing interruptible rates for all customers, and more generally for pursuing demand-side solutions to winter peak capacity needs, as I have argued throughout my testimony.

In this proceeding, the Utilities face a situation in which the transmission capacity is constrained and expanding interruptible rate offerings to customers—including making them more economically advantageous for participants—makes sense "in exchange for the system reliability afforded by their willingness to be interrupted." The alternative to this option would be to build the Proposed Facilities, which are "quite expensive" at $460 million.

Implementing interruptible rates

Q Ms. Mead describes the process the Utilities currently use to effectuate interruptible rates, which includes a manual telephone call to the customer, monitoring the load after an interruption call is placed, and, if necessary, dispatching a truck to shut off service. Is this the only way an interruptible or temperature-controlled rate could be implemented?

A No. While Ms. Mead states that the Utilities "are not able to call an interruption remotely or automatically, much less to a large number of customers," (Rebuttal-WEGO WG-Mead-9:20–21) what she describes is the Utilities' current practices rather than identifying an immutable limitation. There is no reason the companies can't make changes to adopt standard tools that other utilities currently use. First, automatic dialers are well established technology and manual customer-by-customer calls are not required. Xcel Energy uses automated systems in Wisconsin, as well as neighboring states, to inform customers about interruptions and receive their confirmation (see Ex.-SC-Hopkins-35, page 6). Second, customer-by-customer manual monitoring is not required if customers have time-resolved meters capable of measuring whether the customer used gas during the interruption event. Smart gas meters are commercially available and in use by other utilities, such as Baltimore Gas and Electric. While the Utilities would require a procurement process of some sort to develop a quote for such technology, it can be obtained for participating customers for a small expenditure when compared with the cost of the Proposed Facilities.

It is also unnecessary that broadly applicable interruption calls of the sort I proposed be accompanied by a physical shutoff. A sufficient penalty, such as Xcel

Energy's $2 per therm for typical interruption, and $10 per therm when it is a "Critical Day" (see Ex.-SC-Hopkins-35, page 10) should achieve high levels of compliance. It is not necessary to roll a truck to each customer to implement an interruptible tariff.

The interruptible rate structure for capacity during extreme winter weather is also not exclusive. The Utilities can run additional interruption programs as necessary for safety purposes, such as the third-party damage situation Ms. Mead describes on lines 1-3 of Rebuttal-WEGO WG-Mead-5. The Utilities could maintain their existing abilities to physically shut off customers in the event of such a safety incident without any impact on the interruptible program I suggest.

Q How do the general principles of rate design inform your approach to the rates you described in your direct testimony?

A. Under principles of economic efficiency, which underlie most modern concepts of just and reasonable rate designs, customers can (in fact, should) be offered rates which reflect the marginal costs caused by their actions (to the extent possible, while collecting the allowed revenue requirement) and also compensate them for a variety of services they provide to the gas system.

Not every therm of gas imposes the same cost on the utility. Providing a therm during the critical peak hours costs significantly more than during other times. Customers should see pricing that gives them the choice to use, or not use, gas and which reflects the marginal cost to provide it. Providing customers a marginal rate during peak hours commensurate with a substantial capacity cost (here, the $460 million, present value, cost of peak capacity) reflects the actual cost of service.

For example, the Bluff Creek facility covers a remaining design day gap (after energy efficiency is accounted for) of [redacted] Dth/day in 2024–25. The design day average temperature for WEGO is minus 20°F in the Lakeshore-Western area where more than 85 percent of the existing and projected peak demand served by

the proposed facility would be found, but days with temperature at or below minus [redacted] would also exceed the capacity of WEGO's secured supply. In a typical winter, there are no days in Milwaukee in which the average temperature falls below minus [redacted]. However, in each year on average over the last 50 years there have been 0.02 days of minus [redacted], 0.02 days of minus [redacted], 0.02 days of minus [redacted], and 0.02 days of minus [redacted]. Averaged across many years, the proposed WEGO facility would be required to gasify [redacted] Dth of gas per year during very cold days, to meet these needs. With an annual cost of [redacted] million (averaged over 2024 to 2028), the resulting per-therm cost associated with this capacity is about [redacted] per therm. That reflects the avoidable marginal cost of winter peak capacity for WEGO. Many customers would opt for alternative fuel or conservation at that price. Building the facility despite these economics would represent a failure of regulation to reflect economic efficiency.

The example is less extreme for Wisconsin Gas. Here, the capacity gap is larger so the facility would be needed at slightly higher temperatures. Specifically, in the year with the largest remaining gap, 2023–24, the demand (including the 5 percent margin) would exceed Wisconsin Gas's secured capacity when temperatures are at or below minus [redacted] in the Southeast area. In an average year, based on the last 50 years, the proposed WEGO facility would be required to gasify [redacted] Dth of gas during days with average temperature at or below minus [redacted]. With an annual cost of [redacted] million, the resulting per-therm avoidable marginal cost associated with this capacity is about [redacted] per therm. While this cost is much lower than for WEGO, many customers are still likely to opt for conservation or alternative fuels rather than incur that marginal price.

In my direct testimony, I proposed buying down capacity needs from customers willing to be interrupted by using a rate credit throughout the year, rather than imposing a marginal cost price on use during the coldest days. This is the rate structure that the Utilities' customers are familiar with for interruptible rates. It better reflects the marginal cost of capacity during peak days than does the default flat rate pricing. The total value of the participants' curtailment can be estimated,

and then spread over the annual consumption as a credit. The bill credit for curtailment is relatively large because the savings are large.

Q Ms. Mead claims that your approach would result in a cross-subsidy between customers, with smaller customers subsidizing large customers. Would your approach lead to such a subsidy?

A No. There is no basis for that claim. A cross-subsidy only occurs where a class pays less than its marginal cost of service, or a lower percentage of its marginal cost of service, than other classes. An interruptible rate set at less than the avoidable (marginal) cost of new LNG capacity does not subsidize the participating customer. In fact, as calculated in my illustrative rate proposal, if anything large customers would subsidize small customers by accepting compensation that is less than the full value of the service they provide. This is how the demand-side approach results in net savings compared to the Proposed Facilities.

At 25 cents per therm and sufficient participation to avoid the need for the Proposed Facilities ([redacted] percent of customers who use more than 4,000 therms per year, or [redacted] percent of overall sales), I estimated that the Wisconsin Gas ratepayers, of all classes, would pay [redacted] million to those customers who provide the curtailment service. The value of that service averages [redacted] million per year from 2024 to 2028 (the avoided annual cost of the Ixonia Facility), so all customers are paying less than they would if the Proposed Facility were built. The equivalent calculation for WEGO is more extreme, showing a program cost of [redacted] million, versus [redacted] million of value provided. Because they are being paid less than the avoidable cost, the customers who participate in the interruptible rate program are being compensated at a rate lower than the marginal cost for their service, and thereby effectively subsidizing all other customers.

Ms. Mead is correct that "[f]irm customers rates would go up to pay for this expansion of interruptible service." (Rebuttal-WEGO WG-Mead-11:16-17) But that's compared to doing nothing. Firm customers' rates will go up to pay for the

LNG facilities as well. The relevant point is that firm customers' rates will go up less under an interruptible service approach than they would under the Utilities' proposed plan to build the LNG facilities.

Q Ms. Mead states that the "actual peak-day demand costs" are 7 cents per therm for WEGO and 9 cents per therm for Wisconsin Gas. (Rebuttal-WEGO WG-Mead-12) How do you reconcile that with the 25 cents per therm rate discount you proposed?

A Ms. Mead is not accounting for the actual marginal cost of winter peak capacity in her calculation, because she is not including the cost of the Proposed Facilities. The existing rates, which Ms. Mead claims reflect the "actual peak-day demand costs" reflect peak-day backup costs. These rates do not reflect the marginal cost of peak firm capacity, which is reflected by the cost of the proposed LNG facilities at issue in this case.

Q Ms. Mead expresses concerns that the Utilities would be unable to implement a temperature-controlled rate because of temperature variation across their service territories. Is this a solvable problem?

A Yes. First, the Utilities already divide their service territories into a number of sub-areas for the purposes of planning. Evaluating the climate for each area to set an appropriate curtailment temperature in the tariff would be a simple matter of evaluating weather and consumption data, which is available to the Utilities with fine temporal and spatial resolution. Similarly, location-specific weather forecasts are widely available on the internet, including from official government sources. I agree that evaluating the forecast for the coming day to see whether the aggregate forecasted load across each Utility's service areas exceeds the secured supply might require additional effort beyond that which is conducted today. But building and operating LNG storage facilities requires additional effort as well. Ultimately, the comparison is not whether more must be done compared to what the Utilities' currently do, but whether it is possible and, more importantly, whether it is more cost-effective than building a $460 million (present value) facility instead. Any additional effort in forecasting is small when compared to

the value to ratepayers from deferring or avoiding the cost of the Proposed Facilities.

Q Does your weather and demand analysis provide an indication of the temperatures at which the temperature-controlled rates would need to be implemented, and the frequency of such calls?

A Yes. In my direct testimony, I suggested that the temperature-controlled rates might be triggered at a temperature as high as zero degrees, with multiple interruptions per winter. In fact, the 50-year weather calculations I performed in response to the Utilities' rebuttal indicates that the relevant temperature would be minus [redacted] for WEGO in the year with the largest need, and minus [redacted] for Wisconsin Gas. There have only been [redacted] days in the last 50 years in which the WEGO interruption would be called (for an average of less than once per decade). There have been [redacted] days in the last 50 years in which the temperature would warrant the Wisconsin Gas interruption (for an average just once every four years, approximately).

New York gas rates

Q Ms. Mead and Mr. Gerlikowski discuss a supposed temperature-controlled rate pilot by Con Edison in New York. Are you familiar with that rate pilot?

A No, I am not. Ms. Mead and Mr. Gerlikowski seem to be confusing two different rate and demand response approaches that I discussed in my direct testimony. The New York utility that has implemented the temperature-controlled rate I discussed in my testimony was National Grid. Con Edison is a different utility. Con Edison has a number of pilots, which Mr. Gerlikowski criticizes as limited. (Rebuttal-WEGO WG-Gerlikowski-19) But Mr. Gerlikowski fails to recognize, or fails to acknowledge, that those have nothing to do with the National Grid's temperature-controlled rate, which is a better model for the rate option I discussed in my testimony. National Grid offered about a 20 percent rate discount for participation in its temperature-controlled rate program, and about 10 percent of its annual sales were to customers enrolled in this program. This resulted in a substantial

reduction in its winter peak demand, which is proof that such programs are effective. National Grid's was not a small pilot program, but a core rate offering with participation at a scale comparable to that which would avoid or defer the Proposed Facilities.

V. ADDRESSING THE TESTIMONY OF MR. GERLIKOWSKI

Q What aspects of Mr. Gerlikowski's testimony are you addressing?

A I begin by addressing the consistency of peak capacity options with climate change policy and Mr. Gerlikowski's claimed use case for the Proposed Facilities in the event of declining load. I address the cause of the capacity shortfall in 2023 and the role of utility profit incentives. I then discuss two reports which Mr. Gerlikowski cites, and I contest the applicability of their results to this proceeding. I then address Mr. Gerlikowski's concerns regarding two studies of deep decarbonization pathways that I cited in my direct testimony. I particularly address his concerns regarding the relationship between annual average and peak-day gas use reductions. I conclude by addressing Mr. Gerlikowski's confidence that the Proposed Facilities will not become stranded assets.

Consistency with climate change policy

Q Do you agree with Mr. Gerlikowski that the Proposed Facilities are "more consistent with state and federal climate change policies than the practical alternatives" (Rebuttal-WEGO WG-Gerlikowski-2:4-5)?

A No, I do not. I disagree with the premise of this statement in two respects. First, I disagree that the only "practical alternatives" to the Proposed Facilities are [redacted] alternatives. Second, it is not logical to compare two options that are both fundamentally inconsistent with state and federal climate policy and judge one of them to be "more consistent."

Q Do you agree with Mr. Gerlikowski that the [redacted] alternatives examined by the Utilities are the "only proven alternative" (Rebuttal-WEGO WG-Gerlikowski-3:19) to the Utilities' LNG approach?

A No. Conservation, efficiency, and load management are proven alternatives to infrastructure investments. As Ms. Mead testifies (Rebuttal-WEGO WG-Mead-5:16-6:4), the Utilities themselves use interruptible rates as an alternative to distribution investments. My proposal is simply to do the same as an alternative to capacity investments.

Moreover, energy efficiency has already proven to avoid infrastructure for the Utilities over many decades. Over the 30 years from 1989 to 2019, annual residential and commercial natural gas consumption in Wisconsin grew by 28 percent, while the number of customers grew by 64 percent. That is, the average use per customer fell by 22 percent. While these data are for annual consumption, I showed earlier that peak-day changes are greater than average annual changes for heating-dominated sectors such as firm supply to residential and commercial buildings. If use per customer had stayed constant, instead of falling because of efficiency and conservation, the Utilities' peak-day demand would be at least 22 percent higher, and substantially more infrastructure would have been built to serve this need.

Use case for the Proposed Facilities

Q Mr. Gerlikowski claims that in the event that natural gas use declines, "there is a high likelihood the value of the LNG Project would *increase*" (Rebuttal-WEGO WG-Gerlikowski-22:8-9) due in large part to the value of reduced third-party transportation costs from releasing existing interstate pipeline capacity (Rebuttal-WEGO WG-Gerlikowski-3:14-18). Have the Utilities provided any evidence of the value of released capacity or compared that value with the cost of the Proposed Facilities?

No, they have not. The Utilities' Application was based solely on scenarios of ever-increasing peak-day demand for natural gas from firm customers. The Utilities did not analyze a case with falling peak-day gas demand and release of additional pipeline capacity. They have not presented any evidence modeling how

the Proposed Facilities would be utilized in such a case, nor have they compared the value of the services the facilities would provide in that case to their cost.

A simple calculation indicates the financial challenge the utilities would face if they did try to demonstrate that the proposed LNG facilities are more cost effective than retaining pipeline capacity in a future where gas use declines. In winter 2021-22, WEGO will pay [redacted] million for pipeline reservations to secure about [redacted] Dth/day of capacity, reflecting a cost of approximately [redacted] per Dth/day. (See Ex.-SC-Hopkins-39c.) At an annual cost of about [redacted] million, the WEGO LNG facility would add 100,000 Dth/day to this portfolio, reflecting a cost of approximately [redacted] per Dth/day. Not only is the cost of the LNG facility significantly higher than the cost of pipeline capacity, but to offset the increase in annual costs of the LNG facility, WEGO would have to release [redacted] of its capacity (about [redacted]0 Dth/day) to offset the cost (at current reservation costs) of the LNG facility to the point where ratepayers save money. The equivalent calculation for Wisconsin Gas indicates the breakeven at [redacted] of Wisconsin Gas's capacity (about [redacted] Dth/day). In other words, capacity on existing pipelines costs less than the LNG facility so to save ratepayers money by adding the LNG Facilities if gas use declines, the Utilities would have to release significantly more pipeline capacity than they are adding with LNG capacity. At the costs presented in this docket, the math would never work out that the Utilities would meet reliability requirements at a lower cost by adding the LNG Facilities and releasing existing pipeline capacity. I understand that both pipeline contracts and the Proposed Facilities have other costs and benefits beyond this simple capacity-cost perspective. However, because the Utilities did not present any case on their new theory of utilizing the LNG facility capacity to release pipeline capacity, those potential costs and benefits are not in the record. The higher cost of the LNG Facility compared to existing pipeline capacity means that it would be difficult to justify the Proposed Facilities on the basis of releasing pipeline reservations.

Q Mr. Gerlikowski expresses concern that the Utilities face a deliverability need in the winter of 2023–2024, which is less than three years from now. Did the Utilities create the short timeframe to meet this need and do they stand to benefit from it?

A Yes, they created the short timeframe and need and yes, they stand to benefit from it. The Utilities are allowed a profit based on infrastructure investment in ratebase, whereas they are not allowed profit on demand-side solutions. The utilities knew well before their application in this case when their existing pipeline capacity expired and about their limited rights of first refusal. By waiting until just before the claimed need for replacement capacity and now claiming that the short time before that need precludes demand-side solutions, the Utilities created (or seek to create) a self-fulfilling prophesy of an infrastructure investment as the only option, which then serves to increase their profits.

The utilities appear to have prejudiced the potential supply side alternatives as well. It appears that the Utilities only pursued potential short-term capacity contracts on existing pipelines as alternatives to the LNG Facilities, which led to them not being able to secure capacity, in turn setting up the purported near-term need for the Proposed Facilities. The Utilities claim that [redacted] The only example of this behavior provided in the Application is that [redacted] (Ex.-WEGO WG-Application: Volume I, Appendix F, Attachment 1:3). In other words, the Utilities apparently did not obtain pipeline capacity because they declined to offer terms of longer than [redacted] years, despite their claims in this case that they expect an ever-increasing peak day demand. Compared with the capacity cost (roughly [redacted] per Dth/day) and duration (30 to 40 years) of the Proposed Facilities, even pipeline contract bids that offered [redacted] times the average reservation fee of the Utilities' existing pipeline capacity portfolio and lasted for [redacted] or more would have been better for ratepayers than the Proposed Facilities. The purported need for the LNG facility and timing of capacity deficiency was self-created by the timing of the application in this case and the limited bidding terms the Utilities

offered. The Utilities are now seeking to capitalize on that self-serving strategy to justify a large ratebase increase as the only available option.

Policy-driven electrification report

Q Mr. Gerlikowski cites several conclusions from the study "Implications of Policy-Driven Residential Electrification." Are you familiar with this study?

A Yes. Mr. Gerlikowski describes the study as an "ICF report" (Rebuttal-WEGO WG-Gerlikowski-4:15), which elides the fact that it is actually an American Gas Association (AGA) study conducted with ICF based on AGA's prescribed inputs. The report was published in 2018. As the report states, "This is an American Gas Association (AGA) Study. The analysis was prepared for AGA by ICF. AGA defined the cases to be evaluated, and vetted the overall methodology and major assumptions." Mr. Gerlkowski linked to the study on an independent energy policy information website, rather than on its official home page, which is on the AGA website (https://www.aga.org/research/reports/implications-of-policy-driven-residential-electrification/).

Q Does the AGA/ICF report, or anything else, support Mr. Gerlikowski's assumption that customers who electrify their home heating will "shift to using natural gas for backup heating" and "will not reduce overall peak natural gas demand"?

A No. There is no basis for those claims. In fact, the AGA/ICF report that Mr. Gerlikowski purports to rely on assumes the opposite: that customers who electrify will rely on electric resistance heating for backup. Mr. Gerlikowski's entire premise that a future where more heating loads shift to electricity will not reduce peak gas demand appear to be his own unsupported and baseless assumption that "it is reasonable to assume most customers in the Joint Applicants' service territories required to reply upon heat pumps as a primary heating source would need to maintain natural gas fired furnaces as a back-up heat source as temperatures fall below 5 F." (Rebuttal-WEGO WG-Gerlikowski-

5:4-8) He does not cite anything for that assumption, which conflicts with the assumptions made in the AGA/ICF report he relies on.

Q Does the AGA/ICF report state that "policies that advance electrification will lead to more peak demand for natural gas from local distribution companies" as Mr. Gerlikowski claims on page 4, lines 10−11?

A No, it does not. The report does not claim that electrification will increase "local distribution company" demand at all. What it does claim is that demand for natural gas for *all purposes*, including electric generation, would go up during winter peaks based on AGA/ICF's assumptions that: (1) buildings using heat pumps are using electric resistance backup heat during the peak; (2) there will be no change in efficiency and effectiveness of heat pump technology; and (3) all the electricity used to meet increased electric demand comes from natural gas generation. There are a number of problems with Mr. Gerlikowski's use of the AGA/ICF study.

First, increases to total gas use due to electric generation will not impact demand on the local gas distribution utility that the LNG project in this case is premised on. Second, heat pump technology has already advanced beyond what the AGA/ICF report assumed. I address the increasing performance of heat pumps during cold weather below. Third, AGA/ICF's pro-gas assumption that all new electric generating capacity will be gas-fired is not realistic and not what the electric utility industry in Wisconsin is projecting. As Mr. Gerlikowski testifies, the Utilities' parent company, WEC, is targeting 2050 carbon emissions that are consistent with Governor Evers's Executive Order #38 goal of 100 percent carbon-free electricity. (Rebuttal-WEGO WG-Gerlikowski-10:18-19, and Ex.-SC-Hopkins-3) Meanwhile, the Biden administration is pursuing a nationwide target of zero carbon electricity by 2035 (see Ex.-SC-Hopkins-6, page 5). That is inconsistent with the AGA/ICF study's assumption of meeting capacity with gas. If Wisconsin's future electricity is carbon-free, then the electricity demanded on winter peak will not be generated by natural gas and any increased demand for gas will not occur.

Minnesota heat pump study

Q Mr. Gerlikowski also cites a 2017 study from Minnesota on the performance of air source heat pumps at cold temperatures. Are you familiar with this study?

A Yes, I am.

Q Is the 2017 Minnesota report a good resource to understand the performance of currently available cold climate air source heat pumps?

A No. The Minnesota study is dated. There have been substantial improvements in cold climate air source heat pump performance in the last few years. The products that were studied in that 2017 report were installed in 2015, so products available today have the advantage of six years of additional technology development.

Q Do the Utilities track the state of the heating market in their service territories to understand the market share or efficiency of heating systems available to, and being installed by, their customers?

A No. As the Utilities stated in response to 2-Sierra Club-17 (Ex.-SC-Hopkins-36), "The Joint Applicants do not have information from the HVAC market to evaluate the number and efficiency of gas or electric fuels space heating systems when developing load forecast. [sic] Furthermore the Joint Applicants do not have HVAC market data outside of what is available in Focus on Energy evaluation reports, potential studies, and similar documentation, publicly available on the Focus on Energy web site."

Q How does the actual performance and efficiency of today's heat pump products compare to those evaluated in the 2017 Minnesota study?

A Products available today are substantially more efficient, and maintain their capacity to a lower temperature, than the products evaluated in the 2017 Minnesota study. For example, compare the Trane system whose performance is illustrated in the figure at the top of page Rebuttal-WEGO WG-Gerlikowski-6 with a recent comparable 3-ton ducted system from Mitsubishi:

	Trane	Mitsubishi
Heating seasonal performance factor (HSPF)	10	11.4
Maximum capacity at 5°F as % of maximum capacity at 47°F	62%	95%
Coefficient of performance (COP) at max output at 5°F	1.88	2

Mitsubishi makes additional performance information available that shows this system significantly outperforms the system assumed by AGA/ICF in its report, and by Mr. Gerlikowski. For example, the Mitsubishi system maintains a COP of 1.5 down to minus 13°F (17 degrees colder than the AGA/ICF assumption of the temperature at which COP=1). At minus 13°F, the system still supplies more than three-quarters of its maximum heating capacity. In addition, the Mitsubishi system will run down to minus 22°F, which is colder than the design temperature for the relevant portion of the Utilities' service territories. See Ex.-SC-Hopkins-37 for the specifications for both Trane and Mitsubishi systems.

The Mitsubishi system is a centrally ducted system that can be installed in existing ductwork; mini-split systems can achieve even greater efficiency and performance. This high-performance Mitsubishi system integrates with electric resistance backup to provide supplemental heat on the coldest days, but it is not designed to operate with a gas furnace sharing the same ductwork. The dual fuel hybrid configuration envisioned by Mr. Gerlikowski (Rebuttal-WEGO WG-Gerlikowski-5:4-8) is not feasible with these modern systems.

Princeton and Maryland studies

Q Mr. Gerlikowski expresses concern that the Princeton study that you cited in your direct testimony (Ex.-SC-Hopkins-9) is a theoretical study, and not a practical roadmap to inform infrastructure investment decisions. How should the Commission consider the insights provided by these studies?

A As Mr. Gerlikowski quotes from an article about the Princeton study, one purpose of that study is to help guide investment priorities. The Commission is being asked to weigh investment priorities, in light of the need for reliable service while maintaining just and reasonable rates. The premise for the application is an ever-

increasing use of natural gas, which is irreconcilable with the policy context of Governor Evers's and the Biden Administration's commitments to reducing emissions by 50–52 percent from 2005 levels by 2030. The Princeton study serves to illuminate what that level of reduction means for natural gas usage. The question for the Commission is whether gas use consistent with the Evers and Biden policies, as reflected in the Princeton study, or the applicants' assumption of ever-increasing use is more likely and which produces more ratepayer risk.

Q Mr. Gerlikowski discusses the extent of the transmission buildout in the Princeton study as evidence that the study does not reflect the reality of executing a plan. How relevant are electric transmission buildout plans to the decision facing the Commission in this proceeding?

A They are not relevant. The illustrative set of demand-side alternatives that I showed could avoid or defer the need for the Proposed Facilities do not depend on electric transmission. The rate of energy efficiency and electrification adoption that I used in developing that alternative approach is grounded in Wisconsin-specific potential studies and reflects the time necessary to transform the Utilities' customers' homes, buildings, and heating equipment using known programmatic approaches.

Ironically, the transmission buildout scenarios analyzed in the Princeton study and criticized by Mr. Gerlikowski are relevant to We Energies' plans to meet its electric sector carbon emission reduction commitments. The company has not retracted its planned electric generation based on any concern about feasibility of transmission buildout. Moreover, the Biden administration has identified transmission buildout as a key priority and is taking actions to address the kinds of delays that Mr. Gerlikowski discusses. See Ex.-SC-Hopkins-38.

Q Mr. Gerlikowski states that the 17 percent reduction in gas use identified in the Maryland study (Ex.-SC-Hopkins-8) is not Wisconsin-specific and does not reflect peak gas demand. Do you share these concerns with the Maryland study?

A No, I do not. First, the Princeton study's Wisconsin-specific analysis shows a 17 percent reduction in gas use in buildings between 2020 and 2030, which indicates that using the national Maryland study number is reasonable as a guide for what Wisconsin's share of the overall reductions would be. Second, as Mr. Horrie testifies (Rebuttal-PSC-Horrie-4:1-5:4), and as I further explained earlier in my testimony, energy efficiency targeting heating systems and building shells (as I proposed in my direct testimony) is likely to result in peak gas demand reductions that are *greater* than the annual average reduction, rather than *less*. Mr. Horrie presented analysis to support this contention, and I have further quantified this effect, whereas Mr. Gerlikowski and the Utilities have not. The record in this case confirms that, if anything, my estimates of the impact of energy efficiency on peak-day demand reductions were conservative.

Q Mr. Gerlikowski states that "the relationship between annual reductions and peak-day reductions is hard to predict" but that most reductions in natural gas use would occur during off-peak hours with little to no impact on peak use. (Rebuttal-WEGO WG-Gerlikowski-9:19-20) Is that accurate?

No. Mr. Gerlikowski ignores or fails to comprehend several facts. First, the 17 percent reduction that Mr. Gerlikowski challenges is the reduction that should be expected specifically from the buildings sector. That means that industrial and power customers, who use less gas for heating and therefore have a less predictable relationship between annual and peak gas consumption, are not part of this discussion at all. There is a very high level of alignment between residential and commercial buildings and firm gas customers. And there is a strong correlation between residential and commercial building gas use and heating-driven peak-day use. I concluded that about 88 percent of firm gas use is heating-related, and that peak-day reductions from heating-related efficiency measures are about 10 percent higher, on average, than the percent reduction of annual sales from those measures. Thus, a 17 percent reduction in annual gas use among firm

customers (the building sector), driven by climate change policies, would reduce firm winter peaks by 18.7 percent. A less-ambitious climate policy that achieved only a 15.5 percent reduction in annual gas sales in buildings would still reduce winter peaks by 17 percent. In contrast, Mr. Gerlikowski's contrary claim that the gas use reduction from efficiency would be greater in off-peak periods has no basis and is counterintuitive.

Stranded cost risk

Q Do the Utilities express confidence that the Proposed Facilities will be used and useful throughout their life, even in the face of potentially changing policies and usage patterns?

A Yes. Mr. Gerlikowski asserts confidence that the LNG project "will not become a stranded asset during its lifetime." (Rebuttal-WEGO WG-Gerlikowski-20:23)

Q How should the Commission manage ratepayer stranded cost risk for the Proposed Facilities, if it chooses to approve them?

A If it chooses to approve the construction of these facilities despite the lack of evidence to support such a decision in this docket, the Commission should make explicitly clear that the Utilities' shareholders, not ratepayers, will bear any and all stranded cost risk for these facilities. Specifically, in the event that prudent, reliable, and low-cost management of the Utilities' gas systems no longer requires the use of these facilities, ratepayers should not pay any further return *of* or *on* the undepreciated plant balance for these assets (whether through rates or any kind of securitization or other support package). If the Utilities are as confident of the usefulness of these assets as Mr. Gerlikowski says, they should have no reasonable objection to imposing that risk on themselves and their shareholders, rather than on ratepayers.

Q Does this conclude your surrebuttal testimony?

A Yes, it does.