BEFORE THE
MARYLAND PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF BALTIMORE GAS AND ELECTRIC COMPANY FOR AN ELECTRIC AND GAS MULTI-YEAR PLAN	* * *	CASE NO. 9692

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~~CONFIDENTIAL~~ DE-DESIGNATED SURREBUTTAL TESTIMONY

OF

Kenji Takahashi

ON BEHALF OF THE OFFICE OF PEOPLE'S COUNSEL

August 28, 2023

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SURREBUTTAL TESTIMONY OF
KENJI TAKAHASHI

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Kenji Takahashi. I am a Principal Associate at Synapse Energy Economics, Inc. (Synapse) located at 485 Massachusetts Avenue, Suite 3, Cambridge, MA 02139.

Q. Have you previously submitted testimony in this proceeding?

A. Yes. I submitted direct testimony in this proceeding on June 20, 2023, on behalf of the Office of People's Counsel.

Q. What is the purpose of this testimony?

A. The purpose of my surrebuttal testimony is to respond to the rebuttal testimony of Baltimore Gas and Electric Company's (BGE or the Company) witnesses McIntosh, Aas, and Case. Witness McIntosh is an employee of 1898 & Co., which conducted a study ("1898 & Co. study") on BGE's behalf concerning the implications of electrification for BGE's electricity distribution system. Witness Aas is an employee of E3, which conducted a decarbonization study ("E3 study") on BGE's behalf.

Q. How are the E3 study and the 1898 & Co. study relevant to this rate case?

BGE relied on the E3 and 1898 & Co. studies in two ways in developing the proposed programs and expenditures in this case. First, BGE designed its customer electrification plan to be "generally consistent with the pathways analysis" the E3 study,[1] which found that two scenarios (i.e., the Diverse scenario and the Hybrid scenario) that heavily rely on alternative fuels and electric heating with gas backup would "achieve Maryland's goals at a significantly lower cost and with less risk for customers and the State's economy" than the Limited Gas scenario that focuses on high electrification and a shift away from natural gas usage in buildings.[2] This is why BGE proposed to condition its heat pump rebates on customers' retaining their gas furnaces for back-up heat. Second—and more importantly given that the Commission has granted OPC's Motion to Strike the customer electrification plan—the E3 and 1898 & Co. studies are the analytical foundation of BGE's "future of gas" strategy and the gas system investments that BGE has proposed to further that strategy. On one hand, BGE witness Dickens argues that E3's study shows that using gas as a backup heating source is "the lowest cost and most practical/achievable approach for Maryland to realized its GHG reduction goals."[3] On the other, BGE witness Case argues that "[b]oth the E3 and the 1898 studies demonstrate the

[1] Direct Testimony of Mark D. Case, "List of Issues and Major Conclusions" (p. 2 of PDF).
[2] *Id.* at 47.
[3] Rebuttal Testimony of Derrick Dickens at 7-8.

significant increases in peak electric demand and the associated high costs and challenges of building out the generation, transmission, and distribution resources to accommodate a pathway that is predominately focused on electrification for all heating needs."[4]

Q. Do you address BGE's customer electrification plan in this testimony?

A. Because the Commission has granted OPC's Motion to Strike BGE's customer electrification plan from this case, I do not directly respond to the parts of BGE's rebuttal testimony, including the testimony of witness Case, that address my direct testimony concerning that plan. My silence on these points should not be interpreted as agreement, but only as recognition of the Commission's decision.

Q. How is this surrebuttal testimony organized?

A. My surrebuttal testimony begins with Section II where I summarize of my primary conclusions concerning witness McIntosh and Aas's rebuttal testimonies, followed by Section III where I address witness McIntosh's rebuttal testimony in more details and Section IV where I focus on witness Aas's rebuttal testimony. In these sections, I address key issues that I identified in each witness's rebuttal testimony, but do not address every

[4] Rebuttal Testimony of Mark D. Case at 18-19.

instance of my disagreement with that testimony. Thus, silence on any particular issue should not be interpreted as agreement.

Q. Was this testimony prepared by you or under your direction?

A. Yes. My testimony was prepared by me or under my direct supervision and control.

II. SUMMARY

Q. Please summarize your primary conclusions concerning Witness McIntosh.

A. My primary conclusions concerning Witness McIntosh's rebuttal testimony are as follows:

1. The 1898 & Co. study contains enough serious flaws that it cannot credibly be used as a basis for decision-making about decarbonization strategy and electric system planning; and

2. The 1898 & Co. study substantially overestimates peak load impacts on BGE's distribution grid, and thus does not provide any meaningful, "big picture" idea about how electrification is likely to impact BGE's grid.

Q. Please summarize your primary conclusions concerning Witness Aas's rebuttal testimony.

My primary conclusions concerning Witness Aas's rebuttal testimony are as follows:

1. Witness Aas has mischaracterized or failed to acknowledge one of the most consequential findings in my direct testimony concerning the E3 study; namely, that the study assumes little to no "net" reduction in the gas system in any scenario, including the Limited Gas scenario;

2. The E3 study's methodology, which assumes no meaningful net gas infrastructure retirements due to safety and reliability concerns, is flawed. Witness Aas and E3 failed to acknowledge and take into account the following important factors in the E3 study:

    a. Reductions in gas customer assets (e.g., service lines, meters, and, where in use, regulators)—amounting to nearly $1.3 billion (or 36 percent of BGE's distribution plant)—could be expected through electrification and retirement of these assets in the E3 study's "limited gas" pathway, but were not included in the E3 study. These gas reductions would have no system-level impact on safety or reliability because these components are relied upon only by individual customers and do not support the operation of the larger system.

b. The fact that certain customers may remain on the gas system has no impact on whether other customers' meters and services can be retired;

3. The Limited Gas scenario in the E3 study is highly likely to be substantially lower cost for Maryland than the Diverse and Hybrid scenarios that rely on gas heating backup if we correct the E3 study's key assumptions on (a) T&D avoided costs and (b) heat pump coefficienct of performance (COP) values. I estimate that the adjusted system cost of the Limited Gas scenario would be $3 billion, while the adjusted cost of the other two scenarios would be more than double, $7 to $8 billion. The Limited Gas scenario would be the least cost option even if we reduce the effects of T&D cost adjustment or COP adjustment by half. Further, these calculations do not include the potential capital cost reductions that we could expect from gas system retirements for the Limited Gas scenario. The two major errors are described as follows:

a. The E3 study's T&D cost estimate ($203 to $258/kW-year)—relying on an entirely new methodology and BGE's own projected distribution cost estimates that are not vetted and approved by stakeholders in the state—is extremely high compared to T&D cost estimates by many other utilities. It is also much higher than the T&D value used by BGE for its EV program ($25.1 to $34.09 per kW-year) that is estimated based on EmPower Maryland's methodology for T&D cost estimates.

b. The E3's assumption of a COP of 1.2 for the current cold climate heat pumps at the winter peak hours (at 1°F) and a COP of 1.8 by 2045 is overly conservative assumption given that today's heat pumps can already achieve a COP of 2 at 1°F without backup heating.

4. The E3 study incorrectly treated biomethane and other biofuels (e.g., renewable diesel) in the Diverse and Hybrid scenarios as net-zero emissions sources. On the contrary, many renewable natural gas (RNG) feedstocks have overall positive lifecycle GHG emissions, even if they have lower lifecycle emissions than fossil natural gas. Furthermore, Maryland's emissions inventory accounts for the CO_2 emissions from combusting landfill gas—a type of RNG that is the most widely used today among RNG stocks.

5. The E3 study wrongly assumes that biomethane and other biofuels use in buildings would be readily available to contribute to meeting

the state's net-zero target in 2045. Net-zero or negative emission feedstock resources (e.g., animal manure) will see demand from other sectors that have fewer options to electrify, and thus may be limited in their ability to contribute to emissions targets for the buildings sector.

Q. Do you have any recommendations concerning the errors in witness McIntosh's rebuttal testimony?

A. Yes. I strongly recommend that the Commission should not use the 1898 & Co. study as a basis for decision-making about decarbonization strategy and electric system planning because the study contains serious flaws and the study results concerning the cost of electrification are inflated.

Q. Do you have any recommendations concerning the errors in witness Aas's rebuttal testimony?

A. Yes. I have the following two recommendations:

- The economic analysis of decarbonization pathways is a high-stakes matter because such analysis will heavily influence the direction of building decarbonization policy in Maryland in the years and decades ahead. Thus, the quality of the analysis of the economics of decarbonization scenarios should be held to a very high standard and withstand high levels of scrutiny. As such, if BGE wishes to use the new T&D cost calculation methodology and value for program and planning purposes, I strongly recommend that such method and value should be transparent and vetted by stakeholders within EmPOWER Maryland program and approved by the Commission. Alternatively, it could be vetted as a part of a later phase of the Electrification Study Workgroup that the Commission convened[5] to examine the impact of electrification on grid investments in pursuant to the Climate Solutions Now Act's requirements.

- RNG stocks come with two inherent risks – (a) most of the RNG stocks are not net zero emissions and (b) net zero emissions sources such as animal manure will see competing demands from other sectors that are harder to electrify. E3 and BGE should acknowledge and take into account these risks for their evaluation of the merits of the Diverse and Hybrid scenarios against the Limited Gas scenario because clean RNG stocks are limited in their ability to contribute to emissions targets for the buildings sector.

III. RESPONSE TO WITNESS MCINTOSH'S REBUTTAL TESTIMONY

Q. What are the primary areas of your disagreement in witness McIntosh's rebuttal testimony?

[5] Maryland Public Service Commission. 2022. "Notice Establishing an Electrification Study Workgroup." July 19. *Available at*: https://www.psc.state.md.us/wp-content/uploads/Electrification-Study-Workgroup.pdf.

A. I disagree with witness McIntosh's characterization of my findings and critiques regarding the 1898 & Co study. In particular, I find that Mr. McIntosh does not understand the serious implications of numerous critical errors made in the 1898 & Co. study that I explained in my direct testimony.

Q. How does witness McIntosh characterize your discussion of the 1898 & Co. study?

A. Witness McIntosh provides the following statement about my findings of the study. "[Witness Takahashi] picks at various details with the study, but he does not acknowledge the larger picture, which is this: notwithstanding OPC Witness Takahashi's concerns, the study still does what it was intended to do; and it provides a big picture, reasonable, directional idea of how electrification may impact BGE's distribution grid at various levels of adoption."[6]

Q. Can a study with as many errors as the 1898 & Co. study provide an accurate "big picture" idea of how electrification may impact BGE's distribution grid??

A. No. As my testimony demonstrated, the 1898 & Co. study contains enough serious flaws that it cannot credibly be used as a basis for decision-making about decarbonization strategy and electric system planning. For example, I found that 1898 & Co.'s EV load forecast is likely to be overstated by a factor of 3.75. As shown in McIntosh rebuttal testimony, the 1898 & Co

[6] McIntosh Rebuttal Testimony at 3:10-13.

study estimates nearly 9,000 MW load increase in 2045 due to EV, which is close to the entire peak load of 10,178 MW in 2022 for BGE. If reasonable assumptions are used for the EV analysis, I expect that the EV load increase would be just about 2,400 MW in 2045.[7] The 1898 & Co. also employed overly conservative assumptions on energy efficiency improvements, such as no improvements to building codes in the future, as I discussed in my direct testimony. The study also unreasonably assumes that all BGE's residential customers with air-source heat pumps (ASHPs) would use electric resistance backup heating during polar vortex conditions and does not assume any cold climate heat pumps in the analysis. Due to these and other errors, I conclude that the 1898 & Co. study substantially overestimates peak load impacts. Consequently, it does not provide any meaningful, "big picture" idea about how electrification is likely to impact BGE's distribution grid. I therefore recommend that the 1898 & Co. study not be relied upon for the conclusions that Witness McIntosh and Case draw from it.

Q. Do you have any other disagreements with witness McIntosh's rebuttal testimony concerning the 1898 & Co. study?

A. Yes. Witness McIntosh incorrectly characterizes load forecasts by the New York Independent System Operator (NYISO). McIntosh contrasts the results

[7] 9,000 MW divided by a factor of 3.75 equals 2,400 MW.

from the 1898 & Co. study with NYISO's load forecast as follows: "This range of estimated potential impacts from electrification are [sic] in line with estimates from other studies, including the recent study published by New York Independent System Operator (NYISO) in 2024 that was referred to by OPC Witness Takahashi as a more accurate assessment." (5:10-11) In fact, the study results are not in line with estimates from NYISO's study. 1898 & Co.'s peak load estimates (250% relative to today's load) are substantially higher NYISO's mid-case forecast (185% relative to today's load) and even higher than NYISO's high-end estimates (230% relative to today's load). Moreover, it is important to note that the 1898 & Co. study and the NYISO study use different methodologies. If 1898 & Co. had used NYISO's methodology, we should instead expect lower peak loads in BGE territory than NYISO, both in relative and absolute terms, because heating loads in Maryland are much lower than in New York.

IV. RESPONSE TO WITNESS AAS'S REBUTTAL TESTIMONY

Q. What are the primary issues you found in witness Aas's rebuttal testimony?

A. I found serious issues in the following five areas in witness Aas's rebuttal testimony with regard to E3's BGE Integrated Decarbonization Strategy report ("E3 study"):

- Gas system retirements and capital cost reductions

- Feasibility of gas system retirements
- Transmission and distribution costs
- Heat pump coefficient of performance (COP)
- Emissions from biomethane

Q. Please explain the key issues regarding gas system retirements and capital cost reductions in witness Aas's rebuttal testimony.

A. Witness Aas made the following statement in his rebuttal testimony:

> "Contrary to the assertions of OPC Witness Hopkins and OPC Witness Takahashi, E3 assumed cost reductions associated with retirement of mains and services, as well as reductions in O&M expense. Those reductions include:
>
> - Avoidance of 30% of STRIDE and 15% of other capex beyond 2030 in all decarbonization scenarios, relative to business-as-usual.
> - Reductions in O&M costs as a function of customer departures."

In this statement, witness Aas has mischaracterized or failed to acknowledge my finding concerning the E3 study's treatment of gas system retirement and capital cost reductions. First, contrary to witness Aas's statement, I did mention that ~~****BEGIN CONFDENTIAL****~~ "the E3 study allows for some decreases in O&M costs under the Limited Gas pathway" ~~****END**~~

~~CONFIDENTIAL~~** on page 48 in my direct testimony.[8] Second, while the E3 study may have assumed some reduction in main and service plant through a slower pace of replacement, these reductions are "relative to business-as-usual," as Mr. Aas pointed out, and do not necessarily reflect a smaller gas system. E3's analysis is more reflective of a slower pace of asset replacement than of a shrinking system. That is, I find that the E3 study assumes no or little "net" reduction in the gas system in any scenario, including the Limited Gas pathway, as reflected in the total amount of plant in service being almost unchanged among the scenarios, as I pointed out on page 48 of my direct testimony.[9]

Q. Are there any other problems with witness Aas's statement about gas capital retirements?

A. Yes, the E3 study also fails to explain why STRIDE and other gas capital expenditures beyond 2030 would be reduced by the same amount in all of the study's decarbonization cases, given that one of those cases is the Limited Gas case while the other two cases contemplate extensive use of gas. Two examples make clear why this assumption is problematic: First, in the Limited Gas pathway the gas utility has substantially fewer customers than in the other cases. The net plant associated with the meters and services

[8] Takahashi Direct Testimony at 48:7-8.
[9] Takahashi Direct Testimony at 48: 8-11.

that are no longer used and useful should be removed from rate base, yet E3's modeling does not capture this at all. Second, witness White insists that leak-prone pipe replacement must occur at the planned pace and cost in order to maintain safety and reliability.[10] Witness White's insistence on continued replacement in futures that continue to require the full gas system is not consistent with witness Aas's position that all of the pathways assume decreases in gas system investments. E3's assumed capital cost reductions in the Diverse scenario and the Hybrid scenarios thus are not supported by BGE witness White.

Q. Please explain the key issues regarding the feasibility of gas system retirements.

A. Witness Aas defends the E3 study's methodology that does not assume any meaningful net gas infrastructure retirements as follows:

> "E3 notes that any gas capital reductions have not yet been demonstrated in practice and achieving such reductions hinges on several uncertain factors. Key uncertainties include the extent to which gas capex can be avoided while maintaining safety and reliability, the timing over which targeted electrification programs can achieve scale, implications for customer

[10] *See*, e.g., White Rebuttal Testimony, i:25-33, 77:3-5, and 83:17-19

> choice if there are hold-outs on a gas segment who would prefer not to electrify, and the cost-effectiveness of these projects."[11]

E3 disregards the contributions of the assets that serve individual customers (service lines, meters, and, where in use, regulators) to gas plant. Customer meters and services constitute a significant fraction of gas plant. According to BGE's FERC Form 1 annual report for 2021, about 36 percent of BGE's distribution plant, amounting to nearly $1.3 billion, is meters, services, meter installations, and house regulators.[12] Reductions in these components of gas capital plant (e.g., through electrification and retirement of these assets that we could expect in the E3 study's "limited gas" pathway) would have no system-level impact on safety or reliability because these components are at the edges of the gas network. They are relied upon only by individual customers and do not support the operation of the larger system. The fact that certain customers may remain on the gas system also has no impact on whether other customers' meters and services can be retired. Finally, in the "limited gas" case in the E3 study, at least some service-related leak-prone pipe replacement costs would be avoided

[11] Aas Rebuttal Testimony at 8:14-19.
[12] *See* BGE 2021 Annual Report to Commission (May 24, 2022), *available at* https://www.psc.state.md.us/annual-utility-reports/

(because there are fewer customers) and it would be reasonable to assume that some main retirements would be possible.

Q. Are you aware of any examples where a gas utility modeled gas system retirement and estimated gas capital cost reductions?

A. Yes. Gas distribution utilities in Colorado are now required to file clean heat plans (CHPs) that need to include plans to meet certain GHG emission reduction targets for 2025 and 2030. I explained this policy in detail in my direct testimony.[13] Xcel Energy recently filed its first CHP on August 1, 2023.[14] For this plan, Xcel Energy hired E3 to develop multiple building decarbonization scenarios, including an all-electric scenario.[15] This analysis was in fact led by witness Aas of E3. Xcel Energy then took the results of E3's analysis and estimated avoided gas infrastructure costs due to electrification. Xcel estimated that the all-electric scenario could avoid approximately $9.4 billion in gas capital costs due to electrification.[16]

Q. Please explain the key issues regarding transmission and distribution cost estimates

[13] Takahashi Direct Testimony at 22 – 24.
[14] Direct Testimony of Jack W. Ihle. Proceeding No. 23A-0392EG, before the Public Utilities Commission of the State of Colorado, available at: https://www.xcelenergy.com/company/rates_and_regulations/filings/clean_heat_plan.
[15] Direct Testimony of Jack W. Ihle. Proceeding No. 23A-0392EG, at 158.
[16] Direct Testimony of Jack W. Ihle. Proceeding No. 23A-0392EG at 161.

A. I found three key issues in witness Aas's rebuttal testimony regarding electric transmission and distribution (T&D) cost estimates as follows:

- The methodology to estimate T&D costs used by the E3 study and witness Aas deviates substantially from the current methodology used by EmPOWER Maryland.
- Witness Aas does not provide sufficient justification for the new T&D cost estimates that are based on projected, rather than historical, costs to assess the cost impact of electrification.
- Witness Aas's rebuttal testimony revealed that the E3's T&D costs are very high compared to the T&D costs used by BGE's peer utilities.

Q. How does the methodology used by the E3 study deviate from the current methodology used by EmPOWER Maryland?

A. As BGE explained in its response to OPCDR22-14 and witness Case explained in his rebuttal testimony, BGE's other consultant Brattle evaluated the economics of its proposed EV fleet program using a methodology that "is consistent with the historical methodology used to estimate the avoided costs of T&D for EmPOWER programs." [17] This methodology relies on historical T&D investments to estimate T&D costs. Based on this approach,

[17] Case Rebuttal Testimony at 41-42.

Brattle estimated the avoided T&D cost estimates ranging from $25.1 to $34.09 per kW-year. On the other hand, E3 employed a totally new approach that relies on projected T&D costs by BGE and estimated substantially higher T&D costs of $203/kW-year to $258/kW-year.

Q. Please explain why witness Aas's arguments fail to support E3's use of T&D costs projected by BGE, rather than the T&D costs based on EmPOWER Maryland's methodology, which uses historical costs.

A. When discussing the use of historical costs versus projected costs for estimating marginal costs of T&D systems, Witness Aas is incorrect about the definition of marginal costs for T&D systems, when he states as follows:

> "Marginal cost values are imperfect because they are generally developed based on historical relationships between changes in peak demand and cost."[18]

In fact, estimating the cost of increasing (or decreasing) loads necessarily means estimating the marginal costs of system investments, because we are seeking to identify the costs associated with incremental changes in system loads.

Notwithstanding Mr. Aas's conflation of historical costs and marginal costs, marginal costs can be estimated based on either historical costs or

[18] Aas Rebuttal Testimony at 13.

projected costs, or a combination of the two types of costs. Projected costs are more suitable when evaluating impacts of load changes in specific locations. For generic estimates, projected or historical costs are both useful. One caveat or pitfall of using projected costs for evaluating benefits on a system wide level is that the underlying data used to estimate projected costs should represent average or typical investments and should not be unique projects. The benefit of the use of historical costs is that it is easy and straightforward to develop marginal costs that represent the full range of typical investments based on historical costs, because historical investment data are readily available.

Mr. Aas defends E3's use of T&D costs projected by BGE, rather than historical costs, as follows:

> "One key aspect in which the E3 study adds to the existing literature of decarbonization in Maryland is that it leverages BGE's expertise on the costs of operating and expanding its electric system. Upon reviewing the magnitude of demand growth observed in all scenarios, BGE's experts concluded that higher levels of investment would be needed to accommodate those demands"[19]

[19] Aas Rebuttal Testimony at 13.

This argument does not justify the use of projected costs rather than historical costs. T&D costs often differ by the type of investment (e.g., underground area network system vs. radial system), but I do not expect that "[h]igher levels of investment" in the future would significantly change the type of distribution systems and therefore unit costs of investments (dollars per kW).

It is possible that unit costs could be lower if the scale of investments are greater due to the economies of scale. Furthermore, the incremental T&D costs associated with additional load due to electrification could be particularly low in areas where BGE is already planning to expand the capacity of existing T&D facilities or replace existing assets at end of life. In such cases, the incremental cost of electrification represents only any increase in capacity of the facilities that are already being planned.

Witness Aas has failed to demonstrate that the projected costs used by BGE are more suitable or accurate than the T&D cost estimate based on the current EmPOWER methodology, and therefore has failed to show that E3's use of those projections was reasonable.

Q. Please explain how E3's assumed T&D costs compare with the T&D costs of other utilities.

A. Witness Aas presents a survey of avoided T&D costs used by peer utilities conducted by the Mendota Group in 2014 and notes in his rebuttal testimony that "the costs provided by BGE are higher than industry averages but are not out of step with values observed from peer utilities (Table 2) as summarized by the Mendota Group in 2014.[20] However, the BGE's assumed T&D cost ($233 per kW-year with a range from $203 to $258/kW-year) is substantially higher than the median T&D value ($144 per kW-year) based on the survey by the Mendota Group and very close to the high end value ($268) from the survey. Further, as I explained in my direct testimony, the avoided T&D costs BGE is using to evaluate its EV program ($25.1 to $34.09 per kW-year, using the EmPOWER methodology) are substantially lower. BGE's T&D cost estimate is extremely high compared to T&D cost estimates by many other utilities and also much higher than the T&D value used by BGE for its EV program.

Q. Do you have any recommendation on what T&D costs should be used for assessing the impacts of electrification?

A. As I discussed above, the BGE/E3's proposed methodology, as well as the resulting T&D cost estimate, present a significant departure from the current method and avoided T&D values. That significant departure is critical, because the economic analysis of various decarbonization pathways is likely

[20] Aas Rebuttal Testimony at 14.

to have a major influence the direction of building decarbonization in Maryland in the years ahead. The impact of T&D system costs is potentially a large part of the economic analysis. This analysis is also much more important than estimating the economics of the proposed EV fleet program. Thus, the quality of the analysis of the economics of decarbonization scenarios should be held to the highest standard and withstand high levels of scrutiny. Consequently, if BGE wishes to use the new T&D cost calculation methodology and value for program and planning purposes, I strongly recommend that such method and value should be transparent and vetted by stakeholders within EmPOWER Maryland program and approved by the Commission. Alternatively, it could be vetted as a part of a later phase of the Electrification Study Workgroup that the Commission convened to examine the impact of electrification on grid investments pursuant to the Climate Solutions Now Act's requirements. For the evaluation of the proposed EV fleet program, I suggest BGE maintain the current methodology employed by Brattle Group.

Q. Please explain the key issues regarding heat pump coefficient of performance (COP) assumed by the E3 study.

A. E3 employed overly conservative estimates for the performance of heat pumps in terms of COP. Witness Aas's rebuttal testimony also acknowledged that E3 made an error reporting COP values in winter peak hours. Correcting that error, witness Aas mentioned that "the COP in the near-term would be 1.2 [instead of 1.4], and over time the average COP of heat pumps rises to 1.8 [instead of 2]" in winter peak hours.[21] According to E3, these COP values represent the performance of cold climate heat pumps that are supported by backup/supplemental electric resistance heaters at 1°F.[22] More specifically, the E3 study assumes that heat pumps use supplemental electric resistance heating below 20F. I believe that these are overly conservative assumptions. As I demonstrated in my direct testimony, cold climate heat pumps currently available in the market can already achieve a COP of 2 at 1°F and do not require backup heating if sized properly to meet the full heating load.[23] Furthermore, I noted in my direct testimony that both New York and Massachusetts—regions that are much colder than Maryland—have been operating building electrification programs that strongly promote the installation of whole-home heat pumps and the removal of existing fossil-fuel-based heating systems.[24]

Q. What would be the potential impact of assuming the use of cold climate heat pumps at 1°F without backup supplemental heating?

Witness Aas noted in his rebuttal testimony that E3 conducted a sensitivity analysis using higher levels of COP given the uncertainty of "the realized

[21] Aas Rebuttal Testimony at 10-11.
[22] BGE Response to OPCDR14-02.
[23] Takahashi Direct Testimony at 36-40
[24] Takahashi Direct Testimony at 42-44.

performance of cold-climate heat pumps both today and in the long-run."[25] In this analysis, E3 assumes that the performance of cold climate heat pumps is improved by an additional 50 percent such that "they achieve a COP of 2.4 at 1°F, and a share of electric resistance boilers are replaced by heat pump technologies."[26] E3 estimates that in this case the electric system costs in the Limited Gas scenario are reduced by $11.4 billion, while the Hybrid and Diverse scenarios see lowered electric system costs by about $5 to 6 billion. This narrows the gap between the Limited Gas scenario and the other two scenarios by about $5 to 6 billion.

While this analysis assumes an impact of a higher performance of cold climate heat pump technologies, we can also view this as a potential impact of relying on properly sized cold climate heat pumps without backup electric resistance heating at 1°F, because as I mentioned above, cold climate heat pumps that are already available in the market can achieve a COP of 2 at 1°F. This means that cold climate heat pumps should be able to produce a substantial amount of electric system benefits even without assuming the 50 percent performance improvement that was assumed in E3's sensitivity analysis.

[25] Aas Rebuttal Testimony at 11: 6-7.
[26] Aas Rebuttal Testimony at 11: 10-11.

Q. Can you combine the corrections for T&D costs and heat pump performance to reassess which of E3's scenarios are lowest cost?

A. Yes. The most important implication of this potential change in COP assumptions is that the Limited Gas scenario with properly sized cold climate heat pumps (that do not need to rely on backup electric resistance heating) would be the lowest cost scenario among all if we also correct for the potential overestimation of T&D system cost by E3 (about $25 billion) that I discussed on page 49 to 50 of my direct testimony. Table 1 below shows the original net incremental costs by scenario, from Figure 17 of the E3 study, and my recalculations of net incremental costs, accounting for the potential cost adjustments for T&D costs (assuming Brattle's T&D cost estimates) and COP for cold climate heat pumps. As shown in this table, I found that the Limited Gas scenario would be substantially lower cost than the other two scenarios. This result would be still true even if we reduce the effects of T&D cost adjustment or COP adjustment by half. Furthermore, it is important to note that these calculations do not even include the potential cost reductions that we could expect from gas system retirements for the Limited Gas scenario.

Table 1. 2045 Incremental costs by scenario relative to Reference Scenario in the E3 study for BGE ($Billion)

	Limited gas	Hybrid	Diverse
Original net cost	52	38	40
- T&D cost adjustment	-25	-12	-9
- Cold Climate Heat Pump COP adjustment	-11.4	-4.8	-6.3
Adjusted net cost	15	21	25

Q. E3 recalculated the cost of the scenarios reflecting the impact of the Inflation Reduction Act (IRA) in witness Aas's surrebuttal testimony. Would your conclusion that the Limited Gas scenario is the lowest cost scenario still be the same using the updated scenario cost results?

A. Yes. I recalculated the impacts of both reduced T&D costs and adjusted COP values using E3's revised scenario cost estimates in Table 2 below. The revised net incremental costs are based on the data presented in Figure 12 of the revised E3 study on page 16.[27] I also revised T&D system cost reduction estimates using the new total T&D cost estimates shown in Figure 12 of the revised E3 study and the same T&D cost adjustment factors that are discussed on page 49 to 50 of my direct testimony.[28] As shown in the table below, I still find that the Limited Gas scenario is the least cost scenario for Maryland. This result holds even if we reduce the effects of T&D cost adjustment or COP adjustment by half. And again, these

[27] Exhibit DRA-2, Addendum: BGE Integrated Decarbonization Strategy – Inflation Reduction Act Update, Table 12, page 16.
[28] This essentially assumes the Brattle Group's T&D cost estimate.

calculations do not even include the potential cost reductions that we could expect from gas system retirements for the Limited Gas scenario.

Table 2. Incremental costs by scenario relative to Reference Scenario in the E3 study for BGE, ($Billion)

	Limited gas	Hybrid	Diverse
Revised net cost	36	21	22
- Revised T&D cost adjustment	-22	-10	-8
- COP adjustment	-11.4	-4.8	-6.3
Adjusted net cost	3	7	8

Q. E3 assumed biomethane and other biofuels are net-zero. Please explain your concerns with this assumption

A. Witness Aas provides the following statement about biomethane:

> "E3 assumed that biomethane and other biofuels (e.g., renewable diesel) would not contribute towards Maryland's gross emissions target (60% below 2006 levels by 2031) but would contribute towards the net-zero emissions target (net-zero by 2045).[29]

There are two issues with Aas's statement: First, the assumption that biomethane and other biofuels would contribute to meeting the state's net-zero emissions targets and second, the assumption that biomethane and other biofuels are net-zero.

[29] Aas Rebuttal Testimony at 12.

Taking the second issue first, the last sentence, as written, implies that E3 treated biomethane and other biofuels (e.g., renewable diesel) as net-zero. E3's assumption is incorrect. The emissions reduction potential of biomethane greatly depends on the feedstock from which it is produced. California's CA-GREET life cycle model was developed for the California Air Resources Board (CARB) to calculate GHG emissions under the state's Low Carbon Fuel Standard. Using this model, CARB generated lifecycle carbon intensities of biofuels from various feedstocks.[30] Animal manure is one of the only RNG feedstocks for which CARB calculates a negative carbon intensity.[31] Many RNG feedstocks have overall positive lifecycle GHG emissions, even if they have lower lifecycle emissions than fossil natural gas.

Assuming net zero emissions from use of biomethane can be a risky approach to meeting the state's targets because these gases may not, in the end, prove to provide the expected reductions.

[30] California Air Resources Board. *LCFS Life Cycle Analysis Models and Documentation.* Available at: https://ww2.arb.ca.gov/resources/documents/lcfs-life-cycle-analysis-models-and-documentation

[31] California Air Resources Board. "Temporary Pathways Table (Table 8)." *LCFS Life Cycle Analysis Models and Documentation.* Available at: https://ww2.arb.ca.gov/resources/documents/lcfs-life-cycle-analysis-models-and-documentation

Table 3. Lifecycle emissions from biomethane feedstocks based on LCFS estimates

	Feedstock	Emissions (gCO_2e/MJ)
Anaerobic Digestion	Landfill Gas	55.7
	Animal Manure	-164.2
	Water Resource Recovery Facilities	55.8
	Food Waste	30.8
Thermal Gasification	Agricultural Residues	30.8
	Forestry and Forest Residues	30.8
	Energy Crops	30.8
	Municipal Solid Waste	30.8

Source: Emissions based on LCFS lifecycle carbon intensities, adjusted for pipeline compression: California Air Resources Board. "Temporary Pathways Table (Table 8)." LCFS Life Cycle Analysis Models and Documentation. Available at: https://ww2.arb.ca.gov/resources/documents/lcfs-life-cycle-analysis-models-and-documentation

Furthermore, in assuming that biomethane and other biofuels would contribute to meeting net-zero targets, E3 should have considered price and supply risk. These net-zero or negative emission feedstock resources will see demand from other sectors that have fewer options to electrify, and thus may be limited in their ability to contribute to emissions targets for the buildings sector.

These supply and emission risks do not exist for electrification. Thus, E3 and BGE should acknowledge and take into account such risks for their evaluation of the merits of the Diverse and Hybrid scenarios against the Limited Gas scenario.

Q. Do you have any other concerns about Witness Aas's assumption that E3's GHG accounting method is consistent with Maryland's emissions accounting?

A. Yes. Although the E3 study assumes net zero emissions for RNG, Maryland's emissions inventory accounts for the CO_2 emissions from combusting landfill gas to generate electricity.[32] If landfill gas, which is a type of RNG, were assumed not to count toward the state's gross emissions, the inventory's CO_2 emissions from this combustion would be zero. Instead, the state's inventory treats CO_2 from this combustion as equivalent to CO_2 resulting from combustion of fossil gas. Therefore, the E3 study's assumptions regarding emissions from RNG are not consistent with Maryland's emissions accounting.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

[32] Maryland Department of the Environment. 2024. "MD_2020_GHG_Inventory_2022-09-24.xlsx." Available at: https://mde.maryland.gov/programs/air/climatechange/pages/greenhousegasinventory.aspx.

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Item No.: OPCDR14-01

Building electrification proposal

Refer to the following statement on pages 52 – 53 of Mark D. Case, Direct Testimony, "today's ASHP technology is limited in home heating effectiveness below certain temperatures… in our region ASHPs typically require a backup heat source to ensure customers' winter safety and comfort."

A. Below what temperature does BGE expect that ASHPs need to rely on a backup heat source?
B. What type of ASHPs does BGE assume for this assumption? Does the assumption include cold climate heat pumps?
C. Please provide all the data sources and/or BGE's analysis to support its expectation about the temperature level below which ASHPs need a backup heating source.

RESPONSE:

A. There is not a standard temperature across ASHP makes and models. The E3 Pathways study for BGE assumes that in the early modeling years, air source heat pumps (ASHPs) are sized to cover all heating demands at temperatures greater than approximately 20° F and continue to cover a share of heating load below that point. Below this temperature, electric resistance provides supplemental heating alongside the heat pump. E3 assumes that the cold-weather performance of heat pumps increases over time. In actual practice, BGE expects for many heat pumps that supplemental heating begins at temperatures well above 20 degrees.

B. The E3 Pathways study for BGE assumes that all heat pumps meet the Northeast Energy Efficiency Partnerships (NEEP) Cold Climate ASHP Product Specification. In early model years, heat pumps are assumed to meet the minimum requirements of that specification. E3 assumes that the cold-weather performance of heat pumps increases over time.

C. BGE has not conducted any independent analyses on this topic.

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Item No.: OPCDR14-02

Building electrification proposal

Refer to pages 52 – 53 of Mark D. Case, Direct Testimony. What is BGE's understanding regarding the efficiencies of regular heat pumps and cold climate air-source heat pumps in terms of coefficient of performance (COP) at design day temperatures in Maryland cities? Please provide the COP data for these heat pumps along with data sources. If BGE does not have this data, please explain the basis for BGE's claim that "in our region ASHPs typically require a backup heat source."

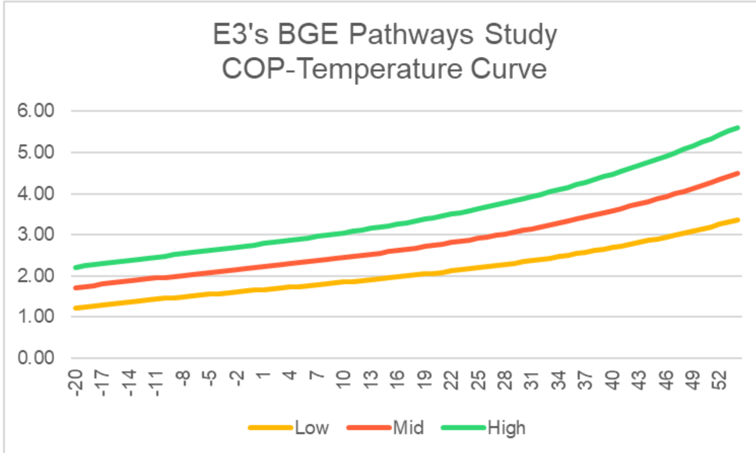
RESPONSE:

E3's technical appendix discusses assumptions and modeling methodology utilized for heat pump modeling. See the paragraphs copied from pages 70-71 of the published study[1]:

> In the early years, the heat pumps modeled by E3 reflect commonly installed technologies and current installation practices. However, E3 assumes that over time all of the heat pumps deployed in the economy meet the Northeast Energy Efficiency Partnerships Cold Climate Air Source Heat Pump Product Specification Version 2.0. As a result, the installed performance of heat pumps increase due to the effects of technology improvements and changes to installation practices that reduce reliance on resistance supplemental heat.
>
> In 2022, the first modeled year, ASHPs were sized to cover all heating demands at temperatures greater than approximately 20° F, below which electric resistance provides supplemental heating alongside the heat pump. Under those assumptions, ASHPs achieve a COP of 1.4 during the coldest hour of a 1-in-10 year cold-snap, when the minimum temperature falls to 1° F. Over time, the heat pump performance increases. The cold-snap COP increases to over 2 as heat pump performance improves and as the heat pump is increasingly sized to cover a higher proportion of load without resistance supplement.

The graph below was used by E3 to model projected heat pump performance in 2045 as the technology continues to advance.

[1] https://www.ethree.com/wp-content/uploads/2022/10/BGE-Integrated-Decarbonization-White-Paper_2022-11-04.pdf


E3's BGE Pathways Study
COP-Temperature Curve
6.00
5.00
4.00
3.00
2.00
1.00
0.00
-20
-17
-14
-11
-8
-5
-2
1
4
7
10
13
16
19
22
25
28
31
34
37
40
43
46
49
52
Low
Mid
High

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Item No.: OPCDR14-03

Building electrification proposal

Refer to the following statement on page 56 of Mark D. Case, Direct Testimony, "BGE sought to target C&I electrification opportunities based on proven cost-effectiveness, strong market traction in other nationally benchmarked programs, and conduciveness to BGE's specific C&I customer segments."

A. Please provide all data and analyses that Mr. Case or BGE is aware of and that support the "proven cost-effectiveness" of C&I electrification.
B. Please provide all data that Mr. Case or BGE have that support C&I electrification's "strong market traction in other nationally benchmarked programs."

RESPONSE:

A. There is a lack of public evaluation studies from similar benchmarked utility programs, but the referenced testimony and the NEPE model found in StaffDR69-26 CONFIDENTIAL Attachment 1 includes the BCA calculations showing high cost effectiveness results.

B. Similar programs are seen at utilities across the country, including programs that ICF has successfully launched such as the JEA Electrification Rebate Program[2], the Salt River Project Electrification Rebate Program[3], and the Entergy eTech Program[4].

2 JEA Electrification Rebate Program. https://www.jea.com/Business_Resources/Rebates_for_Businesses/Electrification/.
3 SRP Electrification Rebate Program. https://www.srpnet.com/energy-savings-rebates/business/rebates/electrification.
4 Entergy eTech Program. https://entergyetech.com/.

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Item No.: OPCDR14-04

Building electrification proposal

Refer to the following statement on page 8 of Exhibit MDC-5 to the Direct Testimony of Mark D. Case, “The C&I Non-Road Electrification Program was informed by two key processes: a Market Assessment and a Benefit Cost Analysis.” Please provide all the analyses BGE and ICF conducted in association with this Market Assessment, in MS Excel files with all the formulas intact.

RESPONSE:

Please refer to StaffDR69-26 CONFIDENTIAL Attachment 1 which was built by ICF Resources LLC to support the benefit cost analysis of the Non-Road Electrification Program within the Customer Electrification Plan. The “high scenario” case is the chosen program design. Other scenarios available in the model may not hold the latest information and should not be used for comparative analysis.

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Item No.: OPCDR14-05

Building electrification proposal

Refer to the "Measure Types" table on pages 10 to 11 of Exhibit MDC-5, regarding incentive levels for non-road electrification measures.

A. Please provide ICF and/or BGE's estimates for the number of measures that would be installed over the five-year implementation time frame for each measure type.
B. Please provide the average incentive level that ICF and BGE assume for each measure under BGE's MRP.
C. If BGE takes into account any state or federal incentives for any of the measures, please provide the assumed state or federal incentives for each measure.
D. Please provide ICF and/or BGE's estimates for the average total measure cost assumed for each measure.
E. Please provide ICF and/or BGE's estimates for the level of incentives as a percentage of the total measure cost for each measure.
F. Please provide ICF and/or BGE's estimates for the average total measure cost for the baseline fossil fuel technology applicable to each electrification measure (i.e., the measure that the customer would have to purchase if the electrification measures were not available),

RESPONSE:

A. Please refer to the "C2.2 Measure Results" tab in StaffDR69-26 CONFIDENTIAL Attachment 1 for the number of measures and average installation details.

B.

Measure Type	**Measure Name**	**Incentives**
Airport GSE	Belt Loaders	3520
Airport GSE	Container Loaders	13200
Airport GSE	Ground Power Units (GPUs)	24080
Airport GSE	Pre-Conditioned Air Units (PCAs)	76520
Airport GSE	Pushbacks	6600
Airport GSE	Tug/Tow Tractors	4400
Material Handling Equipment	Electric Standby Truck Refrigeration Units - Box	900

Material Handling Equipment	Electric Standby Truck Refrigeration Units - Trailer	2000
Material Handling Equipment	Forklifts - Conventional Charge	3000
Material Handling Equipment	Forklifts - Rapid Charge	3000
Material Handling Equipment	Golf Carts	200

C. The model does not assume any state or federal incentives for the Non-Roads program.

D. Please refer to the "C4. Market Adoption" tab in StaffDR69-26 CONFIDENTIAL Attachment 1 under the column "Incremental Capital Costs".

E.

Measure Type	Measure Name	Incentives % Capital Cost
Airport GSE	Belt Loaders	68%
Airport GSE	Container Loaders	35%
Airport GSE	Ground Power Units (GPUs)	37%
Airport GSE	Pre-Conditioned Air Units (PCAs)	33%
Airport GSE	Pushbacks	44%
Airport GSE	Tug/Tow Tractors	56%
Material Handling Equipment	Electric Standby Truck Refrigeration Units - Box	49%
Material Handling Equipment	Electric Standby Truck Refrigeration Units - Trailer	44%
Material Handling Equipment	Forklifts - Conventional Charge	19%
Material Handling Equipment	Forklifts - Rapid Charge	18%
Material Handling Equipment	Golf Carts	20%

F. Please refer to the "A1. Technology Assumptions" tab in StaffDR69-26 CONFIDENTIAL Attachment 1 for the baseline cost assumptions.

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Item No.: OPCDR14-06

Building electrification proposal

Refer to Figure 2 on page 9 of Exhibit MDC-5 and the “Measure Types” table on pages 10 to 11 of Exhibit MDC-5.

A. Please provide ICF and/or BGE’s estimates for the current annual sales share of the electrification technology and the equivalent fossil fuel-based technology for each measure as presented on the “Measure Types” table. When answering this question, please state which geographic area is applicable to the annual sales share and provide data sources.

RESPONSE:

This analysis has not been performed by ICF or BGE.

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Item No.: OPCDR14-07

Building electrification proposal
Refer to Table 1 on page 11 of Exhibit MDC-5, regarding non-road electrification 3-year cycle summary.

A. Please provide a detailed description of each program cost type (e.g., Total Utility Incentives, Implementation Costs, Utility administrative costs), including a description of the specific costs that are included in each cost category.
B. Please explain why the implementation costs are higher than the incentive costs in 2024.
C. Please explain how ICF developed BGE's budget for the implementation costs, utility administrative costs, and EM&V costs. Please provide any supporting documents and/or analyses that ICF used to develop BGE's budget.
D. Please explain how ICF estimated avoided GHG reductions. Provide all supporting analyses used to estimate the avoided GHG reductions in MS Excel files with the original formulas intact.

RESPONSE:

A. The cost categories listed in the referenced table are meant to align with cost categories used in EmPOWER Maryland programs and are described as follows:

- Utility Incentives: Equipment rebates from the Company budget (excludes potential federal rebate programs)
- Outside Services: Represents the core implementation budget for an implementation contractor to manage the Building Electrification Program including a range of implementation activities such as program management, incentive processing, data collection, trade ally management.
- Marketing and Media Buys: This budget includes all marketing related activities such as, but not limited to, development of collateral, ad campaigns (digital, print, social media, search, etc.), public relations, trade ally webinars, case studies, and other customer awareness and engagement tactics.
- Utility Admin: The Company's internal costs in managing the program which may touch all aspects of the program including activities such as marketing and implementation oversight, IT management, data collection and reporting.
- EM&V: Costs for EM&V contractor to perform EM&V activities discussed on pages 61 and 62 of the referenced testimony.

B. This is a result of the program startup and initial market engagement costs being higher in the first program year which will induce program ramp up in following years due to longer sales cycles of technologies in this program.

C. Implementation and Marketing costs were developed by ICF based on similar programs run by ICF and BGE's EmPOWER program benchmarks, summarized below. Implementation and Marketing budgets are comparable to EmPOWER programs in scale to total budget.

Utility Admin and EM&V budgets are initially assumed to be 3%-6% of total program costs based on BGE's experience in EmPOWER programming. Adjustments are made from there based on size of the program, complexity of measures, and other variables. The Utility Admin and EM&V budgets in scale to total program budgets are comparable to corresponding budgets found in EmPOWER programs.[5]

Year 1	
Marketing	$80,485
Non-Cash Incentive	$292,379
Program Delivery	$682,219
Total	$1,055,083
Year 2	
Marketing	$60,197
Non-Cash Incentive	$215,697
Program Delivery	$503,294
Y2 Total	$779,188
Year 3	
Marketing	$53,276
Non-Cash Incentive	$200,452
Program Delivery	$467,721
Y3 Total	$721,449

D. The detailed analysis and model are available in the "B3. Emissions" tab of StaffDR69-26 CONFIDENTIAL Attachment 1.

The calculation is as follows:

1. **<u>Net GHG Emission Reductions</u>** = Site Reductions – Source Increases

    1. Source Increases = Program Cumulative Annual (kwh) * Emission factor <u>(MT CO2/kwh) {GGRA Plan Annual Emission Rates}</u>
    2. Site Reductions = Program Cumulative Annual Load (kwh) * Fuel Emission assumptions * Energy Economy Ratio

2. **<u>Lifetime</u>** = Net GHG Emission Reductions * Estimated Useful Life (EUL)

[5] BGE 2022 Year-End EmPOWER Maryland Report. Maillog # 301355

Definitions:

- Site Reductions: Captures the displaced emissions on premise, quantifying the total emissions that would have been generated by a gas, diesel, or propane unit.
- Source Increases: Capture emissions from electricity production. We currently use GGRA Plan Emission Rates, which captures upstream and downstream emissions. This GGRA source was agreed upon to calculate EmPOWER Maryland GHG impacts and was used to align with EmPOWER methodologies which may be further clarified through the EmPOWER evaluation process in the future.

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Item No.: OPCDR14-08

Building electrification proposal

Refer to Figure 3 “Building Electrification Program Design Process” on page 13 of Exhibit MDC-5. Please provide ICF’s analysis that covers the program design process and that produced the program forecasts as illustrated in Figure 3. Please provide this analysis in an MS Excel file with all the formulas intact.

RESPONSE:

Please refer to OPCDR14-08-CONFIDENTIAL *Attachment 1*. This was built by ICF Resources LLC to support the Buildings Electrification Program within the Customer Electrification Plan.

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Item No.: OPCDR14-09

Building electrification proposal

Refer to the "Measure Types" table on page 18 to 19 of Exhibit MDC-5, regarding incentive levels for building electrification measures.

A. Please provide ICF and/or BGE's estimates for the average total measure cost assumed for each measure.
B. Please provide ICF and/or BGE's estimates for the level of incentives as a percentage of the total measure cost for each measure.
C. Please provide ICF and/or BGE's estimates for the average total measure cost for the baseline fossil fuel technology applicable to each electrification measure (i.e., the measure that the customer would have to purchase if the electrification measures were not available).

RESPONSE:

A. Please refer to OPC14-08-CONFIDENTIAL Attachment 1 which includes the total measure cost in the "Model Inputs (w federal caps)" tab in column K.

Measure	Total Measure Cost
GSHP	$26,732
ASHP	$11,542
HPWH	$3,268
Electric Fireplace	$425
Electric Range	$873
Induction Cooktop	$3,763
Electric Clothes Dryer	$1,085
Make Ready Incentive	$4,500

B. The cost and incentive details are available in OPC14-08 CONFIDENTIAL Attachment 1 in the "Model Inputs (w federal caps)" tab. Total Cost can be found in Column K and Utility Incentive per unit can be found in Columns BZ-CB. Federal funding assumptions were capped based on DOE allocations[6], so the variance in IRA HEERA funding based on participation leads to changes in forecasted average BGE incentive per year. As final HEERA program guidance has not been released, the Company has forecasted IRA funding based on current understanding but is subject to change.

Measure	Incentive % of Measure Cost
GSHP	28%
ASHP	59%
HPWH	61%
Electric Fireplace	21%
Electric Range	34%
Induction Cooktop	21%
Electric Clothes Dryer	38%
Make Ready Incentive	57%

C. This analysis has not been performed.

[6] *Biden-Harris Administration Announces State and Tribe Allocations for Home Energy Rebate Program*. US Department of Energy. November 2, 2022. https://www.energy.gov/articles/biden-harris-administration-announces-state-and-tribe-allocations-home-energy-rebate

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Item No.: OPCDR14-10

Building electrification proposal

Refer to the "Measure Types" table on page 18 to 19 of Exhibit MDC-5 and the following statement on page 19 of the same exhibit: "the Inflation Reduction Act of 2022 will include significant rebates for low- and moderate-income (LMI) customers which BGE may supplement but avoid over-incentivizing during implementation." The Inflation Reduction Act (IRA) provides different levels of incentives for the low-income customer (with less than 80 percent of the area median income) and (b) the moderate-income customer segment (with 80 to 150 percent of the area median income).

A. Please provide ICF and/or BGE's estimates of the number of measures over the three-year implementation time frame for each measure by three customer segments, using the IRA's definitions for income: (a) the low-income customer; (b) the moderate-income customer segment; and (c) the remaining residential customers.
B. If BGE takes into account any state or federal incentives for any of the measures, please provide the assumed state or federal incentives for each measure. If BGE incorporates incentives available from the IRA, please provide the total IRA incentive available for each measure for the low-income customer segment and for the moderate-income customer segment, separately, as defined by the IRA. If IRA incentives are not reflected in the level of incentives proposed by BGE, please explain why not.

RESPONSE:

A. The participation details are available in OPCDR14-08 CONFIDENTIAL Attachment 1 in the "Model Inputs (w federal caps)" tab. With some unknowns on the implementation of IRA during the MYP period, the assumed split of participation for residential measures is 30% for low-income customers (<80% AMI), 40% for moderate income customers (80%-150% of AMI) and 30% for non-LMI customers (>150% AMI).

B. The incentive table below provides the LMI estimated incentives from the IRA HEERA Program. These estimates are not included in BGE budgets and offset BGE incentives.

	IRA HEERA Incentives		
Measure	**<80% AMI**	**80%-150% AMI**	**>150% AMI**
GSHP	$0	$0	$0
ASHP	$8,000	$5,771	$0
HPWH	$1,750	$1,634	$0
Electric Fireplace	$0	$0	$0
Electric Range	$840	$437	$0
Induction Cooktop	$840	$840	$0
Electric Clothes Dryer	$820	$542	$0
Make Ready Incentive	$4,500	$2,250	$0

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Item No.: OPCDR14-11

Building electrification proposal

Refer to Figure 3 on page 13 of Exhibit MDC-5 and the "Measure Types" table on page 18 to 19 of Exhibit MDC-5.

A. Please provide ICF and/or BGE's estimates for the current annual sales share of the electrification technology and the fossil fuel-based technology for each measure. When answering this question, please state which geographic area is applicable to the annual sales share and provide data sources.

RESPONSE:

This analysis has not been performed.

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Item No.: OPCDR14-12

Building electrification proposal

Refer to the table titled "Program Costs and Impacts" on pages 19-20 of Exhibit MDC-5, regarding building electrification programs.

A. Please explain how ICF developed BGE's budget for the outside services costs, marketing and media buys costs, utility admin costs, and EM&V costs. Please provide any supporting documents and/or analyses that ICF used to develop BGE's budget.
B. Please provide a detailed description of each program cost type (e.g., Total Utility Incentives, outside services costs, utility admin costs), including the specific costs that are included in each cost category.
C. Please explain how ICF estimated avoided GHG reductions. Provide all supporting analyses used to estimate the avoided GHG reductions in MS Excel files with the original formulas intact.

RESPONSE:

A. Implementation and Marketing costs were developed by ICF based on similar programs run by ICF and BGE's EmPOWER program benchmarks, summarized below. Implementation and Marketing budgets are comparable in scale to EmPOWER budgets based on the expected program efforts and participation, but the incentive budget makes up a larger percentage of the overall budget.

   Utility Admin and EM&V budgets are initially assumed to be 3%-6% of total program costs based on BGE's experience in EmPOWER programming. Adjustments made from there based on size of the program, complexity of measures, and other variables. The Utility Admin and EM&V budgets in scale to total program budgets are comparable to corresponding budgets found in EmPOWER programs.[7]

B. The cost categories listed in the referenced table are meant to align with cost categories used in EmPOWER Maryland programs and are described as follows:

   - Utility Incentives: Equipment rebates from the Company budget (excludes potential federal rebate programs)

7 BGE 2022 Year-End EmPOWER Maryland Report. Maillog # 301355.

- Outside Services: Represents the core implementation budget for an implementation contractor to manage the Building Electrification Program including a range of implementation activities such as program management, incentive processing, data collection, trade ally management.
- Marketing and Media Buys: This budget includes all marketing related activities such as, but not limited to, development of collateral, ad campaigns (digital, print, social media, search, etc.), public relations, trade ally webinars, case studies, and other customer awareness and engagement tactics.
- Utility Admin: The Company's internal costs in managing the program which may touch all aspects of the program including activities such as marketing and implementation oversight, IT management, data collection and reporting.
- EM&V: Costs for EM&V contractor to perform EM&V activities discussed on pages 61 and 62 of the referenced testimony.

C. The detailed emission calculations are available in the "Delta GHG Emissions" tab of StaffDR69-14 CONFIDENTIAL Attachment 1. The avoided GHG reductions were estimated in two parts:

Changes in Emissions = Part 1 (Decrease, Other Fuels from Electricity) – Part 2 (Increase, Emissions from electricity)

Part 1:

- Reductions in Annual Emissions = Baseline Reductions (MMBTU) * Emissions Factor for fuel type (lbs/MMBTU)
- Total Emissions = Reductions in Annual Emissions*Estimated Useful Lifetime

Part 2:

- Increase in Annual Emissions = Increased usage (kWh) * GGRA Plan Emission Factor (lbs./kWh)
- Total Emissions = Increase in Annual Emissions * Estimated Useful Life

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Item No.: OPCDR14-13

Benefit Cost Analysis

Refer to the following statement on page 54 of Mark D. Case, Direct Testimony, "Importantly, a BCA will not capture the policy benefits accrued to the State for incentivizing these essential measures…" Please elaborate on this statement and explain what is meant by "the policy benefits."

RESPONSE:

In his Direct Testimony at page 54, Company Witness Case explains, "Importantly, a BCA will not capture the policy benefits accrued to the State for incentivizing these essential measures *to help significantly advance progress towards meeting the State's established CSNA decarbonization goals*." (*emphasis added*). The first part of Mr. Case's statement identified in this above question which mentions "policy benefits" specifically is referring to these proposed measures' impact in helping the State to meet its policy goals in CSNA – namely, decarbonization goals for 2031 and 2045.

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Response to OPC Data Request 14
Request Received: April 21, 2023
Response Date: May 05, 2023
Sponsor(s): Mark D. Case

Item No.: OPCDR14-14

Benefit Cost Analysis

Refer to APPENDIX B "Building Electrification Program Cost-Effectiveness Details" to Exhibit MDC-5, which provided costs and benefits of the building electrification program using different benefit cost tests.

A. Please provide the analysis workbook used to produce Appendix B, in an MS Excel file with all the formulas intact.
B. Did ICF conduct this benefit cost analysis on its own? If not, please explain which entity conducted this analysis or supported this analysis.
C. Are the underlying values used in this study consistent with the values used in Brattle's benefit cost analysis provided in Exhibit MDC-1? If not, please explain what part of the analysis is not consistent with the analysis in Exhibit MDC-1.

RESPONSE:

A. Please refer to StaffDR69-14-CONFIDENTIAL Attachment 1 which was built by ICF Resources LLC to support the benefit cost analysis of the Buildings Electrification Program within the Customer Electrification Plan.

B. Yes, ICF conducted this analysis independently.

C. A full comparison of inputs has not been performed. Based on informal discussion, the inputs are generally aligned, though may vary based on evolving EmPOWER reference guidance during the development of these programs.

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Item No.: OPCDR14-15

Benefit Cost Analysis

Refer to APPENDIX A "Customer Electrification Plan Cost-Effectiveness Details" to Exhibit MDC-5.

A. For each value stream listed in the "Value Streams included in CE Testing" table, please provide the values and/or datasets ICF used for its benefit cost analysis of BGE's electrification programs.
B. Please provide all the underlying analyses that ICF conducted or relied on to produce the value streams for its benefit cost analysis of BGE's electrification programs. Please provide these analyses in MS Excel files with original formulas intact as well as any written documents associated with the analyses, if any.

RESPONSE:

Please refer to StaffDR69-14-CONFIDENTIAL Attachment 1.

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Item No.: OPCDR14-16

Workforce development

Refer to the workforce development related activities described on page 21 of Exhibit MDC-5. Please provide the following analyses:

- A formal workforce development review
- A Training Provider Asset Map
- An occupational gap analysis

RESPONSE:

These documents may be found in the "ICF Workpapers – PUBLIC" subfolder under "Case Direct Testimony Workpapers – PUBLIC" on the Exelon SharePoint site BGE has set up for this matter and are accessible to Staff, OPC and other parties through the link provided below.

Home - BGE Rate Case (sharepoint.com)

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Item No.: OPCDR14-17

Workforce development

Refer to the following statement on page 22 of Exhibit MDC-5, "past similar workforce development efforts have shown that expenditures range from roughly $7,500 to $15,000 per training participant." Please provide examples of past similar workforce development efforts that indicate training expenditures within this cost range.

RESPONSE:

Please see OPCDR14-17-*Attachment 1*. This provides actual data from past or current workforce development initiatives.

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Item No.: OPCDR22-01

Refer to the following statement on page 47 of Mark D. Case, Direct Testimony: "The Limited Gas pathway, meanwhile, would result in a significantly higher cost, more economic and energy system disruption, and a less diverse/resilient system compared to IES scenarios."

A. What is meant by "more" economic disruption? Please characterize, and provide any analysis that supports this statement.
B. What is meant by "energy system disruption"? Please characterize, and provide any analysis that supports this statement.
C. Please explain what is meant by "less diverse/resilient system." Please provide any analysis that supports this statement.

RESPONSE:

The Hybrid and Diverse scenarios of the 2022 E3 Pathways Study use multiple energy delivery systems and therefore provide a degree of back up and reinforcement that a single primary energy delivery system, such as the approach in the Limited Gas scenario, cannot provide. This results in a less diverse/resilient system in the Limited Gas scenario. Retaining a degree of energy infrastructure diversity through, for example, a secondary energy system may be particularly valuable as the majority of the economy-wide energy usage shifts to the electric system. Absent this diversity and redundancy, outages or disruptions in the electric systems would have a more disruptive impact on Maryland's energy use and delivery, individual residential and business customers' finances and the economy and society more broadly due to reliance on a single system for the majority of energy needs.[1] In addition, with respect to economic disruption, it is important to note that the Limited Gas scenario is estimated to require the highest costs across sectors in BGE's service territory to achieve net zero GHG emissions by 2045.[2]

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[1] *See* page 41 of BGE Integrated Decarbonization Strategy (ethree.com) ("2022 E3 Pathways Study")
[2] *See* page 30 of the 2022 E3 Pathways Study

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Item No.: OPCDR22-02

Please refer to the following statement on page 47 of Mark D. Case, Direct Testimony: "However, the most important finding by E3 is that the Hybrid and Diverse pathways, which leverage the combined capabilities of electric and gas delivery systems, achieve Maryland's goals at a significantly lower cost and with less risk for customers and the State's economy. These IES pathways also deliver greater resiliency, fuel diversity, more realistic constructability, and less disruption to customers and the State's economy."

A. Please explain what is meant by "realistic constructability." Please identify the specific portion of the E3 analysis that supports this statement.
B. Please explain what is meant by "less disruption to customers." Please identify the specific portion of the E3 analysis that supports this statement.

RESPONSE:

A. Constructability is defined in Figure 15 of the 2022 E3 Pathways Study as the "pace and scale of electric and gas sector infrastructure additions". Realistic constructability as used in the Direct Testimony of Company Witness Case assumes the pace and scale could practically be executed. See pages 36-37 of the 2022 E3 Pathways Study for more information on constructability. Challenges to supply chain, available land and rights of way, and workforce are only some examples of variables that can affect realistic constructability.

B. See page 39 of the 2022 E3 Pathways Study. Adoption of electrification measures means that customers may need to retrofit their homes. The extensiveness, costs, and resulting disruptions of customer retrofits may vary. Note that the quoted sentence from the Direct Testimony of Company Witness Case points out that the Limited Gas scenario would require more extensive retrofitting projects when compared to the Hybrid and Diverse scenarios, as noted on page 39 of the 2022 E3 Pathways Study.

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Item No.: OPCDR22-03

Refer to Figure 13 on page 27 and Figure 14 on page 28 of the E3 study referenced in Mark D. Case's direct testimony.

A. Please provide the full underlying data in Figure 13, showing annual electricity sales by sector (i.e., "Heating," "Transportation," and "All Other Uses") for each scenario, in the form of an MS Excel file.
B. Please provide E3's estimates of annual revenues from electricity sales for each scenario by sector in the form of an MS Excel file.
C. Please provide the breakdown of the electric peak demand estimates, as shown in Figure 14, separately by sector for each scenario in the form of an MS Excel file.
D. Please provide the breakdown of the electric peak demand estimates, as shown in Figure 14, separately by sector for the Reference Scenario (which is mentioned on page 30 of the E3 study).

RESPONSE:

A. See OPCDR22-03-*Attachment 1*.

B. See the tab titled "Electric Revenue" in OPCDR22-04-CONFIDENTIAL-Attachment 1.

C. See OPCDR22-03-*Attachment 2*. The three scenarios switch from summer peaking to winter peaking over the time horizon. The reference scenario remains summer peaking throughout the time horizon.

D. See the response to subpart (C), above.

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Item No.: OPCDR22-04

Refer to Figure 16 on page 31 of the E3 study regarding the total incremental energy system costs by scenario and Figure 17 on page 33 of the study regarding 2045 incremental costs by component relative to Reference Scenario.

A. Please provide a forecast of the total cost for each cost component (following the category of the cost component presented in Figure 17) from 2020 through 2045 for all the scenarios including the Reference Scenario.
B. Please provide the workbooks used to produce Figures 16 and 17 with all supporting calculations and underlying assumptions.

RESPONSE:

See OPCDR22-04-CONFIDENTIAL *Attachment 1*. Please refer to the tab titled “Summary” for a summary of the requested components. The calculations used to generate those values are included in the workbook. Note that this workbook calculates costs for one scenario at a time. Users should change the scenario on the tab titled “Toggles” in cell E5 and cell F7 on the tab titled “Summary”. In the process of responding to this request, E3 identified an error in its economy-wide cost calculation. That error has been corrected in OPCDR22-04-CONFIDENTIAL Attachment 1. Each scenario is approximately $2 billion more expensive relative to the originally published values in the 2022 E3 Pathways Study.

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Item No.: OPCDR22-05

Refer to Figure 16 on page 31 of the E3 study as well as the following statement on page 32 of the E3 study: "The Limited Gas scenario sees decreasing gas system utilization, raising the possibility of decommissioning some gas infrastructure to reduce total energy system costs. However, the scale of those potential savings from decommissioning is small relative to incremental expenditures in other sectors of the economy for several reasons."

A. Provide all analyses, workpapers, and documents used to quantify "the scale of those potential savings from decommissioning" as described in the above quotation.
B. For each of the three scenarios as presented in Figure 16 and for the Reference Scenario, please provide, for each year that it is available between 2020 through 2045:
   i. The modeled, estimated, or assumed additions to gas plant
   ii. The modeled, estimated, or assumed additions to gas plant associated with leak-prone pipe replacement activities (e.g., STRIDE and its successor(s))
   iii. The modeled, estimated, or assumed retirements of gas plant
   iv. The modeled, estimated, or assumed retirements of gas plant associated with leak-prone pipe replacement activities (e.g., STRIDE and its successor(s))
   v. The modeled, estimated, or assumed gas system O&M costs (with and without the cost of gas)
C. Please provide the total gas throughput estimated or assumed for BGE for each of the three scenarios as presented in Figure 16 from 2020 through 2045, and for the Reference Scenario.
D. Please provide the workpapers, spreadsheets, and other documents used to develop the answers to this request, with all formulas and links intact.

RESPONSE:

A. See the response to subpart (B) below for data and analysis that adds additional context to the referenced quotation.

B. See OPCDR22-05-CONFIDENTIAL *Attachment 1*. Please note the following:
   - Additions and subtractions of gas plant are shown in the tab titled "CAPEX_all_mitigation_scenarios".
   - O&M costs are shown in the tabs titled "O&M_Limited_Gas", "O&M_Diverse", "O&M_Hybrid" and "O&M_Reference".

C. See the tab titled "Gas Sales" in OPCDR22-05 CONFIDENTIAL-Attachment 1.

D. See OPCDR22-05-CONFIDENTIAL Attachment 1.

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Item No.: OPCDR22-06

Refer to Table 26 and the following statement on page 79 of the E3 study: "Generation capacity marginal costs were derived from E3's 2020 PJM studyI, while transmission and distribution capacity costs were provided by BGE as an overnight cost and levelized by E3 using expected asset lifetimes and BGE's weighted average cost of capital."

A. Please provide the overnight cost of transmission and distribution capacity costs that BGE provided to E3.
B. Please explain how BGE developed the overnight cost of transmission and distribution capacity costs.
C. Please provide the estimates of asset lifetimes E3 used to estimate the marginal costs of transmission and distribution capacity.
D. Please provide the weighted average cost of capital E3 used to estimate the marginal costs of transmission and distribution capacity.

RESPONSE:

A. The overnight cost of a transmission and distribution investment is assumed to be $1,880,000 - $2,390,000 per MW.

B. E3 worked with BGE to understand the types of costs included under generation, transmission, and distribution in an effort to capture costs that reflect the magnitude of load growth reflected in the 2022 E3 Pathways Study due to economy-wide electrification and avoid double counting across segments. The transmission costs included capacity expansion for peak load growth and costs due to increased imports/exports if needed. Transmission costs did not include costs due to new installed generation if required, as these are already captured in the E3 RESOLVE modeling from PJM EPSA study as part of the generation capacity expansion costs. The distribution costs were a blend reflective of substation, sub-transmission and distribution feeder installation costs downstream of the transmission system. The costs used were based on high-level estimates as of 2022 and do not include inflation or potential changes in system design that may be adopted in future years. While efforts have been made to reflect "typical" expected project costs, they are not intended to replace a detailed engineering study and individual executed project costs could vary substantially.

C. E3 assumed an average asset lifetime of 40 years.

D. The after-tax weighted average cost of capital E3 used is 6.75%.

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Item No.: OPCDR22-07

Refer to page 28 and 68 of the 2022 E3 Pathways Study ("E3 study") referenced in Mark D. Case direct testimony, regarding peak load impacts by scenario. Further refer to Figure 29 on page 70 and the following statement on page 71 of the E3 study:

"In 2022, the first modeled year, ASHPs were sized to cover all heating demands at temperatures greater than approximately 20° F, below which electric resistance provides supplemental heating alongside the heat pump. Under those assumptions, ASHPs achieve a COP of 1.4 during the coldest hour of a 1-in-10 year cold-snap, when the minimum temperature falls to 1° F. Over time, the heat pump performance increases. The cold-snap COP increases to over 2 as heat pump performance improves and as the heat pump is increasingly sized to cover a higher proportion of load without resistance supplement."

A. What are the assumptions associated with the 1-in-10 winter peak condition used to estimate winter electric peak loads?
B. What ambient temperature did the E3 study assume for the 1-in-10 peak conditions?
C. How did the E3 study project weather data through 2045?
D. Please provide a COP curve for non-cold climate heat pumps analyzed in the E3 study.
E. What is the rationale of using 20° F as the switchover point between HPs and electric resistance? Please provide all analyses E3 conducted and any other studies E3 relied on to determine this temperature threshold.
F. Please provide the share of and the total number of cold climate heat pumps and regular heat pumps assumed in the E3 study for each scenario from 2020 through 2045.

RESPONSE:

A. The temperature condition is described in the text quoted by OPC. E3 used 1-degree Fahrenheit (1F) as the temperature for a 1-in-10-year peak condition in a winter-peaking BGE system. The 1-in-10-year condition was determined by assessing the 2045 coincident peak demand of the BGE system across all the simulated weather years noted in the response to subpart (C) below.

B. See the response to subpart (A) above.

C. E3 used historical weather data between 1979-2018 (inclusive) from the North American

Regional Reanalysis, produced by NOAA[1] for the purposes of developing hourly loads. Overall annual heating and cooling demand were adjusted based on changes in heating and cooling degree days for the Mid-Atlantic in the 2021 Annual Energy Outlook.

D. No such system was explicitly modeled. The heat pump performance curve modeled and shown in Figure 29 on page 70 of the 2022 E3 Pathways Study was derived using manufacturer reported data from the Northeast Energy Efficiency Partnerships Cold Climate Air Source Heat Pump Product Specification Version 2.0.[2] As noted in the response to subpart (E) below, E3 sized the heat pump based on current practices, which leads to the COP of 1.4 at the peak condition of 1F noted in the study. Over time, the performance of heat pumps is assumed to improve such that the peak COP at 1F increases to 2.

E. E3 reviewed literature on heat pump performance in the field as the basis for this assumption. For example, a study of heat pump performance by RDH Consultants in British Columbia found that electric resistance supplemental heat is typically engaged between -5-degrees Celsius (-5C) and 5C; -5C is approximately 23F. [3] A study from the Center for Energy and Environment in Minnesota shows that supplemental heating systems for homes there were engaged between approximately 10F and 30F.[4] Based on these studies and E3's professional judgement, E3 selected 20F as the temperature point where heat pumps require supplemental resistance heating today.

F. See the tab titled "Device Sales" in OPC22-04-CONFIDENTIAL Attachment 1. Please note E3 only modeled a single representative air-source heat pump technology, which is assumed to have a performance curve consistent with a cold-climate heat pump and improve over time per the discussion above in subpart D. The sizing and operations of these systems were calibrated based on empirical studies, such as those described above in subpart E.

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[1] North American Regional Reanalysis | National Centers for Environmental Information (NCEI) (noaa.gov)
[2] https://neep.org/sites/default/files/ColdClimateAirSourceHeatPumpSpecification-Version3.0FINALMEMO.pdf
[3] FortisBC Energy Inc. (rdh.com)
[4] CARD_Final_Report_ASHP v2 to DER (mncee.org)

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Item No.: OPCDR22-08

Refer to the following statement on page 71 of the E3 study: "Hybrid HPs were sized to cover all heating demands at temperatures greater than approximately 30° F, below which a backup gas furnace is used to meet heating demand."

A. What is the rationale of this assumption to use 30° F as the switchover point between HPs and gas furnaces? Please provide all analyses E3 conducted and any other studies E3 relied on to determine this temperature threshold.

RESPONSE:

E3 based that temperature threshold on its industry knowledge, including its review of literature discussed in the response to OPCDR22-07, subpart E. In practice, the operation of a fuel-backup system could be determined by a number of factors, including a customer operating the system in response to differentials operating costs, [1] in response to utility costs via a demand-response program, or using a temperature-based threshold like that applied in this study.

[1] See, for example: Heat-Pump-Switchover-Temperature-Optimization-Study-Memo_2Sept2022_Final.pdf (ma-eeac.org)

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Item No.: OPCDR22-09

Refer to the following statement on pages 46-47 of Mark D. Case, Direct Testimony: "Finally, the Diverse scenario also "[e]mphasizes high levels of electrification but incorporates a mixture of strategies to decarbonize the building heating sector, including both all-electric buildings and hybrid electrification, as well as emerging strategies like gas powered heat pumps and networked geothermal systems." Please answer the following questions:

A. The E3 study assumes the COPs for gas heat pumps are 1.4 and 1.3 for residential and commercial systems, respectively, as shown in footnote 46 on page 72 of the study. Please provide the data source for this assumption.
B. The E3 study assumes that the total installed costs of a gas heat pump are $8,500 per unit for a single-family building and $7,500 per unit for a multi-family building. Please also explain how E3 estimated these costs and provide the data sources.
C. In what year are gas heat pumps expected to begin to be installed in residential buildings? Please provide all data sources or studies used to support this assumption.

RESPONSE:

A. E3 has based its assumptions on the performance of gas heat pumps on work done by the Northwest Energy Efficiency Alliance.[1]

B. These data appear to be incorrectly reported in Table 30 on page 83 of the 2022 E3 Pathways Study. The cost of a gas heat pump in E3's calculations is correctly captured in the tab titled "Capex Prices" in OPCDR22-04-CONFIDENTIAL Attachment 1. The capital cost of a gas heat pump is assumed to be $13,725 for a single-family home in BGE's service territory. The total costs of water heating and HVAC for such a system in an average single-family residential home are assumed to be the following:

Technology Category	Building Type	Technology	Capital Cost
Water Heating	Residential	Gas Heat Pump Storage	$1,950
Space Heating	Residential	Gas Heat Pump	$13,725
Central Air Conditioning	Residential	Air Conditioning	$6,580
Total			**$22,255**

[1] See, for example, Future of Gas Presentations - 10-26-2021 (thefutureofgas.com)

Note that E3 assumes electric air conditioning in a home with a gas heat pump and provides that value for comparison to a heat pump system which provides both heating and cooling.

C. These data are provided in the tab titled “Device Sales” in OPC22-04-CONFIDENTIAL Attachment 1. E3 assumes a small number of gas heat pump installations in early model years, but the market for these technologies only begins to achieve meaningful scale in the late 2020s.

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Item No.: OPCDR22-10

The E3 study that Mr. Case references in his testimony provides customer costs of building and transportation electrification measures on Table 24 on page 75 of the study. The E3 study references E3's own report titled "2021 Maryland Building Decarbonization Study" for the costs of air source heat pump, hybrid air source heat pump, gas furnace + central air, and efficient gas furnace + central air. However, the 2021 Maryland Building Decarbonization Study does not provide data sources for these customer costs.

A. Please provide the original data sources that E3 used to develop the costs of air source heat pumps and gas furnace + central air systems in the 2021 Maryland Building Decarbonization Study as well as in E3's BGE Integrated Decarbonization Strategy study.

RESPONSE:

E3 derived its cost estimates for electric heat pumps and furnace + central air systems from several sources, not all of which are available in the public domain. Examples of public data sources referenced include both empirical real-world estimates and those developed by professional cost estimators:

- Empirical Data Sources
  - Massachusetts Clean Energy Center, *Air-Source Heat Pump Residential Projects Database*[1]
  - Massachusetts Clean Energy Center, *Whole Home Pilot (ASHP) Projects Database*[2]
- Cost Estimator Data Sources
  - Cadmus Group, *Buildings Sector Report*[3]
  - E3 (developed with AECOM), *Residential Building Electrification in California*.[4]
  - Lotus Engineering and Sustainability (developed with E3 and AECOM), *The Energy Denver Renewable Heating and Cooling Plan*.[5]

In both the 2021 MD Building Decarbonization Study and the 2022 E3 Pathways Study, E3 used its professional judgement to derive final cost assumptions. Note that many of these assumptions were generated prior to a period of substantial inflation, so prices seen by consumers today may be higher.

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[1] https://files-cdn.masscec.com/uploads/Residential%20ASHP%20Data_For%20Website%20%282%29.xlsx
[2] https://files-cdn.masscec.com/uploads/WholeHomePilotProjectDatabase_08.11.2021%20%283%29.xlsx
[3] download (mass.gov)
[4] E3_Residential_Building_Electrification_in_California_April_2019.pdf (ethree.com)
[5] denver-renewable-heating-and-cooling-plan_june-2021.pdf (denvergov.org)

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Item No.: OPCDR22-11

Refer to the following statement on page 75-76 of the E3 study:
"E3 then developed a BGE specific assessment of those costs based on an evaluation of the building stock in BGE's service territory. E3 assumed that all-electric conversions of buildings built prior to World War 2, or approximately 38% of the current BGE building stock, incur an upgrade cost of $3,400 per home that is meant to reflect costs of panel upgrades, wiring or ductwork. Those costs are not assumed for hybrid conversions. Conversely, E3 assumed that all-electric new construction includes a cost savings of approximately $5,000 associated with the avoided gas infrastructure within a customer premise."

A. Please provide all the data sources and studies the E3 study used to develop the upgrade cost of $3,400 for panel upgrades, wiring or ductwork.
B. Please provide all the data sources and studies the E3 study used to develop the avoided gas infrastructure cost of $5,000.

RESPONSE:

A. E3 estimated the costs of panel upgrades, wiring, and ductwork by consulting data sources such as:

- The Palo Alto Electrification study, which assumed a panel upgrade cost of $3,100 in 2016.[1]
- The Massachusetts Clean Energy Center, which estimates a range of between $2,500 to $4,500 for electric panel upgrades.[2]

Note that those costs are for panel upgrades alone, so E3's value of $3,400 to capture panel upgrades, wiring and ductwork may be an underestimate.

B. E3's sentence quoted by OPC from the 2022 E3 Pathways Study incorrectly attributes the $5,000 entirely to the reduced cost of gas infrastructure within a customer premise. In fact, that value is meant to reflect the total upfront costs savings for an all-electric building as compared to a mixed-fuel building. E3 reviewed several studies to develop these costs such as:

- E3 (developed with AECOM), *Residential Building Electrification in California*[3]

[1] Palo Alto Electrification Study (cityofpaloalto.org)
[2] Electrical Service Upgrade - Massachusetts Clean Energy Center (masscec.com)
[3] E3_Residential_Building_Electrification_in_California_April_2019.pdf (ethree.com)

- Cadmus Group, *Buildings Sector Report*[4]
- E3 (developed with AECOM), *Residential Building Electrification in California*[5]
- Rocky Mountain Institute, *The Economics of Electrifying Buildings: Residential New Construction*[6]

[4] download (mass.gov)
[5] E3_Residential_Building_Electrification_in_California_April_2019.pdf (ethree.com)
[6] The Economics of Electrifying Buildings: Residential New Construction - RMI

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Item No.: OPCDR22-12

Refer to the following statement on page 46 of Mark D. Case, Direct Testimony: "The Hybrid scenario "[e]mphasizes electrification, including high levels of electrification in the buildings sector," but with a vast majority of existing gas customers adopting a "hybrid approach to electrification," with the industrial sector relying on a "combination of electrification and renewable fuels," and with buildings relying on "air-source heat pumps" backed by "the gas system and renewable gases" during colder conditions." Also refer to Figure 11 on page 26 of the 2022 E3 Pathways Study referenced by Mark D. Case in his testimony.

A. The E3 study assumes that synthetic natural gas (SNG) is expected to be available in the market around 2030 as shown in Figure 11 of the study. Please provide all data sources or studies that support this assumption.
B. The E3 study assumes that transportation hydrogen and pipeline hydrogen are expected to be available in the market around 2030 as shown in Figure 11 of the study. Please provide all data sources or studies that support this assumption.
C. What are the types and feedstocks of renewable fuels assumed in the E3 study?
D. What are the costs and availability of renewable fuels assumed in the E3 study?
E. What amount or share of BGE's allotted share of renewable fuels is used in the building sector versus other sectors in each scenario? Please provide all data sources used to back up this assumption.
F. The E3 study mentions on page 65 that "all advanced biofuels would have net zero CO2 emissions based on the negative carbon sink of the biomass feedstock." Please provide all studies and analyses that support this assumption. If the E3 study assumes different emission rates by feedstock type, please provide the emissions rates by feedstock type.
G. Does the E3 study make assumptions regarding the geographic provenance of advanced biofuels? If so, please detail the geographic assumptions. That is, where is the "negative carbon sink of the biomass feedstock" located?

RESPONSE:

A. The International Energy Agency rates methanation of hydrogen, also called SNG, as a 7 on its Technology Readiness Level (TRL) scale.[1] A rating of 7 means that the technology has been implemented as a pre-commercial demonstration. Given the higher reliance on this technology in the Diverse scenario, E3 rates that scenario has having the highest "Level of challenge" in terms of technology readiness in Figure 15 on page 30 of the 2022 E3 Pathways Study. See Figures 20 and 21 for a more detailed Technology Readiness Scale and application in E3 scenarios.

[1] ETP Clean Energy Technology Guide – Data Tools - IEA

B. The International Energy Agency rates hydrogen production, delivery and use with TRLs between 9 and 11. For example, alkaline electrolyzers have a TRL of 9, which means the technology has reached commercial operation and hydrogen pipelines have a TRL of 10 which means the technology has been deployed at scale. [2] Hydrogen trucks have a TRL of between 7 and 8, while hydrogen light commercial vehicles have a TRL of 9.[3]

E3 assessed that the Limited Gas scenario has the lowest "level of challenge" in terms of technology readiness, in part because it leverages less hydrogen and no SNG.

C. E3's Renewable Fuels module includes renewable diesel, renewable jet kerosene, renewable gasoline and renewable natural gas as final fuels. As noted on page 65 of the 2022 E3 Pathways Study, E3 assumed feedstocks including municipal solid waste, landfill gas, manure, agricultural residues, and forest residues. E3 excluded purpose-grown energy crops.

D. The costs of renewable fuels are provided in the tab titled "Fuel Prices" in OPCDR22-04-CONFIDENTIAL Attachment 1.

E. E3 models biofuels using an optimization tool that allocates the biomass feedstocks described in the response to OPCDR22-12 subpart (C) above, to the final fuels described in the same response. The fuels produced via the tool are then assumed to be blended with their equivalent fossil fuels. As a result, the allocation of biomethane to different sectors of the economy is determined by the remaining natural gas usage in each sector. This results in the following percentages of biomethane as a share of total biofuels used in BGE's service territory in each scenario:

- Diverse Energy Solutions: 33%
- Hybrid: 31%
- Limited Gas: 62%

Note that the Limited Gas scenario has a higher share of biomethane due to lower overall requirements for renewable diesel. That result follows from the design of the scenarios and the resulting set of measures required to meet net-zero emissions by 2045.

F. E3 followed current EPA and IPCC guidance on GHG accounting of biofuels. These frameworks assume that biofuels carry a zero net CO_2 emission factor.[4]

G. As described on page 65 of the 2022 E3 Pathways Study, E3 assumed that the state of Maryland would have access to its population weighted share of the waste biomass resources, noted in the response to subpart (C) above, that are east of the Mississippi. The amount of biomass available to BGE's service territory was then scaled based on that region's population compared to the state. Beyond those parameters, E3 does not make any specific assumptions about the geographic provenance of biofuels feedstocks.

[2] *Id.*
[3] *Id.*
[4] https://www.epa.gov/system/files/documents/2022-04/us-ghg-inventory-2022-main-text.pdf (p.250)

Case No. 9692
Baltimore Gas and Electric Co.
Response to OPC Data Request 22
Request Received: May 05, 2023
Response Date: May 19, 2023
Sponsor(s): Laura Wright

Item No.: OPCDR22-13

Refer to an Excel file titled "OPCDR01-18-Attachment3" that BGE provided in response to OPCDR01-18.

A. Please provide hourly electric loads from 2015 to present for each substation operated by BGE.
B. For which distribution feeders does BGE have a record of hourly electric loads?
C. Does BGE have hourly actual or estimated electric loads for any customer classes or sectors? If so, please provide the data from 2015 to present.

RESPONSE:

A. Please see OPCDR22-13-*CONFIDENTIAL CEII Attachments 1 through 8* for requested data by years 2015-2022. Note, due to the volume of data, multiple attachments were required. The number of data elements exceeds the available rows in the Excel application and these files will need to be opened in notepad or a database program. In addition, BGE maintains load data at the substation transformer level, not the substation level.

B. BGE has hourly electric loads for all distribution feeders except for the distribution feeders at the following 4kV substations: Calverton Road, Govans, Forest Park, Clifton Park and Monument Street.

C. Please see OPCDR22-13-*Attachment 9* and OPCDR22-13-*CONFIDENTIAL Attachment 10*.

Case No. 9692
Baltimore Gas and Electric Co.
Response to OPC Data Request 22
Request Received: May 05, 2023
Response Date: May 19, 2023
Sponsor(s): Mark D. Case

Item No.: OPCDR22-14

Refer to an Excel file titled "Fleet Electrification BCA_Final" filed as part of Mr. Case's Direct Testimony.

A. The "Dist Price" worksheet of this workbook provided distribution costs in $/kW-year, which ranges from $25.1 to $34.09 per kW-year. Please explain how BGE estimated these costs and provide all analyses used to estimate this assumption in a MS Excel format with all formulas and data sources intact.

RESPONSE:

Please see the tab titled "Avoided Dist Price" in the Excel file titled "Fleet Electrification BCA_Final" that was included in the supporting workpapers for the Direct Testimony of Company Witness Case in the Brattle Workpapers subfolder. BGE's estimation of avoided distribution costs is consistent with the methodology used for the EmPOWER MD plan.