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EARTHJUSTICE

June 15, 2020

VIA ELECTRONIC FILING

Brinda Westbrook-Sedgwick
Commission Secretary
Public Service Commission
of the District of Columbia
1325 G Street, NW, Suite 800
Washington, DC 20005

Re: **Formal Case No. 1154,**
In the Matter of Washington Gas's Application for Approval of Project Pipes 2 Plan
[Sierra Club's Direct Testimony]

Dear Brinda Westbrook-Sedgwick:

Attached for filing please find the Sierra Club's Direct Testimony and accompanying exhibits of Sierra Club's witness Dr. Ezra D. Hausman.

Thank you for your attention to this matter. Should you have any questions, please contact me at smiller@earthjustice.org.

Sincerely,

Susan Stevens Miller

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BEFORE THE

PUBLIC SERVICE COMMISSION OF THE

DISTRICT OF COLUMBIA

IN THE MATTER OF	**)**	
	)	
WASHINGTON GAS LIGHT COMPANY'S	**)**	
APPLICATION FOR APPROVAL OF	**)**	**FORMAL CASE NO. 1154**
PROJECTPIPES 2 PLAN	**)**	
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SIERRA CLUB

DIRECT TESTIMONY OF EZRA D. HAUSMAN, PH.D.

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SIERRA CLUB

DIRECT TESTIMONY OF EZRA D. HAUSMAN, PH.D.

I. Professional Qualifications

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

A. My name is Ezra D. Hausman, Ph.D. I am an independent consultant doing business as Ezra Hausman Consulting, operating from offices at 77 Kaposia Street, Auburndale, Massachusetts 02466.

Q. What is your professional and educational background?

A. I have served as an independent consulting analyst and expert in energy and environmental issues since 2014. Before that, from 2005 until early 2014, I was employed at Synapse Energy Economics, Inc., a research and consulting company located in Cambridge, Massachusetts, where I served as Vice President, and Chief Operating Officer. At Synapse, and continuing as an independent consultant, I served as an analyst and expert in several areas, including: state and regional energy, capacity, and transmission planning, including both utility resource planning and long-term (multi-decadal) climate-constrained resource planning; regulatory and ratemaking proceedings; electricity and generating capacity market design and analysis; electric system dispatch modeling; economic analysis of environmental and other regulations, including greenhouse gas regulation, in energy markets; economic analysis, price forecasting, and asset valuation; quantification of the economic and environmental benefits of displaced emissions; energy efficiency and renewable energy programs and policies; and regulation and mitigation of greenhouse gas emissions.

I have provided testimony before public utility commissions or legislative committees in Arizona, Florida, Illinois, Indiana, Iowa, Kansas, Louisiana, Maryland, Massachusetts, Minnesota, Mississippi, Missouri, Nevada, New Hampshire, New Jersey, North Carolina, Oregon, South Carolina, South Dakota, Utah, Vermont, Virginia, and Washington State, as well as at the Federal level. I have provided expert representation for stakeholders at the PJM RTO, the California ISO, the Midcontinent ISO, and at the Federal Energy Regulatory Commission ("FERC"). While most of my testimony and analytical work has centered on issues in energy market economics, I have also brought my expertise as a scientist to bear on cases involving greenhouse gas regulation and mitigation in the United States.

Before joining Synapse, I was employed from 1998 through 2004 as a Senior Associate at Tabors Caramanis and Associates ("TCA") of Cambridge, Massachusetts. In 2004, TCA was acquired by Charles River Associates ("CRA"), where I remained until I joined Synapse in 2005. At TCA/CRA, I performed a wide range of electricity market and economic analyses and price forecast modeling studies. These included asset valuation studies, market transition cost/benefit studies, market power analyses, and litigation support. I have extensive experience with market simulation, production cost modeling, and resource planning methodologies and software.

I hold a BA in Psychology from Wesleyan University, an MS in Environmental Engineering from Tufts University, an SM in Applied Physics from Harvard University, and a PhD in Atmospheric Chemistry from Harvard University. I have provided a detailed resume as Exhibit SC/101.

Q. Have you ever testified before the Public Service Commission of the District of Columbia?

A. No.

II. Scope of Testimony and Recommendations to the Commission

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

A. In this proceeding, Washington Gas Light ("WGL") proposes to spend $277.1 million on continued upgrades to its distribution infrastructure, in addition to $28.2 million on DC's portion of transmission upgrades.[1] At the same time, WGL has made a commitment pursuant to its settlement agreement in Formal Case No. 1142[2] to "file with the Commission a long-term business plan on how it can evolve its business model to support and serve the District's 2050 climate goals (e.g., providing innovative and new services and products instead of relying only on selling natural gas)."[3] WGL filed its "Climate Business Plan" ("CBP") on March 13, 2020 and an extended comment period is still ongoing.

These two initiatives for WGL—its CBP and its distribution system replacement program—are fundamentally interdependent. I will show that the Company's proposal under Pipes 2 is incompatible with WGL's commitment to evolve its business model to be consistent with the District's climate commitments.

[1] Application at 5.
[2] *In the Matter of the Merger of AltaGas Ltd. And WGL Holdings, Inc.* The settlement agreement was approved in Order No. 19396.
[3] Formal Case No. 1142, ¶ 79 of settlement agreement.

Q. What are your recommendations for the Commission?

A. I make the following recommendations:

1. The Commission should defer action on WGL's proposed Pipes 2 program pending resolution of my following recommendations.

2. The Commission should open a new docket to gather stakeholder input and establish Commission-approved guidelines for WGL's infrastructure planning and investments that are consistent with the District's climate commitments, including carbon neutrality by 2050, to replace the Company's deficient CBP.[4] This docket should include a focus on non-pipeline alternatives to pipeline repair and initiate pilot non-pipeline alternative projects.

3. WGL should be directed to refile an infrastructure maintenance program, including a demonstration that its proposals are consistent with the District's climate commitment of carbon neutrality by 2050 and the Commission-approved guidelines established under recommendation #2. WGL should produce a plan to address the largest and most significant leaks and those presenting imminent risks to public health in order to reduce emissions and protect public safety first, but it should do so in a manner that is consistent with meeting the District's climate commitments.

4. Finally, the Commission should notify the Company that it will not allow recovery of or on depreciation expense for pipe distribution and transmission infrastructure beyond 2050, the time when the District is committed to being carbon neutral. Notably, a 30 year depreciation horizon proposed by WGL in this docket for the next 5 year phase of Project Pipes would already be in conflict with that deprecation timeline, highlighting the incompatibility between WGL's Pipes 2 plan and the District's established climate commitments.

[4] As detailed in my Technical Report on AltaGas Climate Business Plan and Renewable Natural Gas Study, attached as Exhibit EDH-2, the Climate Business Plan filed by AltaGas on March 16, 2020 is deficient and cannot serve as the basis for evaluating WGL's proposed infrastructure investments.

III. WGL's Proposal

Q. Please summarize WGL's proposal in this matter.

A. WGL requests a five-year extension of its Revised Accelerated Pipe Replacement Plan, originally approved by the Commission in Formal Case 1093, Order No. 17602, along with an extension of its previously approved PROJECT*pipes* surcharge mechanism.[5]

Q. Has WGL forecast how its proposal will affect natural gas sales in the District?

A. No. Sierra Club requested this information in Data Request 3. The Company objected to this request, stating that "Projected gas sales are not factored into the Company's assessment of pipe replacements."[6] The Company insists that its program is "not intended to increase revenues by directly connecting the infrastructure replacement to new customers."[7] However, the program includes increasing low-pressure systems to medium-pressure at least in part to expand the range of gas-fueled end uses it will support, including gas-fired back-up generators.[8] This modification seems likely to increase sales to customers.

Q. Over what time period does WGL propose to complete its pipeline replacement program?

A. WGL has proposed a 40-year replacement program, of which Pipes 2 is the second five-year phase.[9] On this schedule, the Company will have completed its replacements by 2055.

[5] Application at 1.
[6] WGL Response to Sierra Club Question 1-3.
[7] Jacas Direct at 23:6–8
[8] *Id.*, at 22:13–23:6.
[9] *Id.*, at 14:17–18.

Q. Over what time period does WGL propose to charge ratepayers for its pipeline replacement program?

A. It appears that WGL intends to depreciate each of its annual investments in Pipes 2 over a 30-year period.[10] Thus customers will not complete paying for WGL's replacement program until 30 years after replacements are complete, or 2085.

Q. How do these time periods correspond to the District's GHG mitigation commitments?

A. Under the leadership of Mayor Muriel Bowser, the District has committed to reducing GHG emissions by 50% relative to 2006 levels by 2032, and to reaching carbon neutrality by 2050. Thus WGL's plan would have the Company engage in an accelerated pipeline replacement program at the same time the District is committed to dramatically reducing emissions, and would complete its program five years *after* the District is supposed to have achieved carbon neutrality. The vast majority of deep decarbonization studies and numerous US states have concluded that the least cost path towards carbon neutrality likely involves complete or near-complete electrification of end uses that are currently served by gas.[11] Because widescale electrification is almost certainly the most viable path forward in DC as well, WGL's extensive pipeline infrastructure investments would no longer be used and useful, well before the end of their deprecation horizons. This would create a stranded asset problem and burden current and future WGL ratepayers. Under the Company's plan, customers who were born the year DC reaches

[10] Based on Exhibit WG(C)-1; dividing "Plant Additions" (Line 1) by Depreciation" (Line 4) yields 30.6 years.

[11] This is discussed in Exhibit EDH-2 at 14–16. Exceptions are AltaGas' CBP, and various studies funded by the American Gas Association. *See* Exhibit EDH-2 generally for a critique of AltaGas' approach and conclusions.

carbon neutrality would continue to pay for this infrastructure until their 35th birthdays. They may have to break out the history books to try to understand what they are paying for.

Q. Isn't the elimination of leaks from the District's gas pipeline system an important part of reducing GHG emissions?

A. Absolutely. However, this does not mean the Company should engage in a wholesale replacement program for its aging pipes. While WGL should identify, quantify, and address the most significant leaks quickly to minimize emissions of this powerful and hazardous greenhouse gas, the solution should involve striking a balance between upgrading the infrastructure and the need to avoid future stranded assets. One solution I would recommend is to pursue non-pipeline alternatives (NPA) such as weatherization and conversion of customers to non-gas solutions such as high-efficiency electric heat pumps. Such an approach can provide the same safety and environmental benefits while avoiding emissions of a potent greenhouse gas into the atmosphere and avoiding the risk of stranded assets. WGL should not be wasting ratepayer funds on investments that have no place in the District's carbon neutral future.

Q. Can you provide an example of non-pipeline alternative programs that has been successfully implemented elsewhere in the United States?

A. Yes. the Central Hudson Gas and Electric Corporation in New York created an NPA program pursuant to a settlement agreement in its 2017 rate case.[12] As described in the

[12] New York State Department of Public Service Matter No. 17-01632, Case 17-G-0460. The order accepting the settlement is provided as Exhibit EDH-3.

order accepting the settlement:

> The Company is being encouraged…to pursue non-pipes alternatives to meet demand for heating fuels. One way is through the incentives focused on geothermal heating and cooling…but the Company has also committed to pursue additional natural gas efficiency, demand response programs, and will issue an RFP focused on non-pipes alternatives that can displace traditional infrastructure projects. When combined with the reductions in methane leakage, the programs that seek to replace natural gas usage with other means of providing space heating or reducing fuel consumption will help ensure the transition to lower carbon energy markets in New York State.[13]

Q. Is the Central Hudson NPA cost effective?

A. Yes. According to the most recent (December 2019) Non-Pipeline Alternative Annual Report,[14] benefits of Central Hudson's NPA program outweigh costs by a ratio of 3.3 to 1 as measured by the Societal Cost Test (SCT).[15]

Q. Has WGL addressed the need to ultimately eliminate the sale of fossil fuels in the District in this or any other way in its current proposal?

A. No.

IV. WGL's Climate Business Plan

Q. You stated earlier that WGL filed its CBP on March 13, 2020. Please explain why this plan is or should be relevant to the current case.

A. Natural gas constitutes the third-largest source of greenhouse gas emissions for the District of Columbia constituting almost 18% of emissions in 2017, and possibly far

[13] *Id.* at 68–69.
[14] Exhibit EDH-4.
[15] *Id.* at 5.

more.[16] While it might be possible (though very difficult) to reach the District's 2032 climate commitment while still combusting natural gas at current levels, it is inconceivable to do so as the District approaches carbon neutrality per its 2050 commitment.

As a regulated utility in a sector that depends fundamentally on costly, long-lived infrastructure, WGL has an obligation to plan and invest for future customer needs. The question is, what future is the Company planning for? In the past it may have been reasonable to plan for a future predicated on continued and growing gas sales to customers, at least for as long as the lifetime of the Company's infrastructure investments, and to amortize these investments accordingly. Today, the District is committed to a different future: one in which our use of energy is redefined to be sustainable and protective of the climate. WGL must address its leaking pipes in the short term to help meet that goal, but its solutions, and its longer-term vision, must be constrained by the need to meet the Districts climate commitments. The Climate Business Plan is supposed to be the roadmap for how WGL can conform to this new reality. Without such a plan, it is virtually impossible for the Company to make prudent infrastructure investments on behalf of its customers.

[16] The 18% figure is based on the Washington DC Greenhouse Gas Inventory, available at https://doee.dc.gov/service/greenhouse-gas-inventories. However, recent research suggests fugitive emissions may be much larger than accounted for in the inventories. See Plant, G., Kort, E. A., Floerchinger, C., Gvakharia, A., Vimont, I., & Sweeney, C. (2019). Large fugitive methane emissions from urban centers along the U.S. East Coast. Geophysical Research Letters, 46, 8500– 8507. https://doi.org/10.1029/2019GL082635: "Our total CH_4 estimates are broadly consistent with previous studies of Boston and the Washington, DC, and Baltimore region in showing CH_4 emissions significantly larger than inventory estimates." (from Section 5, references removed.)

Q, Has WGL or its parent company, AltaGas, acknowledged the risks associated with climate change?

A. Yes. ¶76 of its settlement agreement in Formal Case 1142 states:

> AltaGas recognizes the scientific consensus that human activity – primarily GHG emissions and the conversion of land for agriculture and development – is contributing to changes in the global climate including changing weather patterns, rising sea levels and more extreme weather events. **AltaGas believes that actions must be taken now to stabilize and reduce emissions in line with the international goal of preventing temperatures from rising more than two degrees Celsius by the end of this century.** Climate change presents risks to AltaGas and its operations, but also provides it with an opportunity to be part of the solution. These factors underlie AltaGas's commitment to continued change and improvement in its operations, and provide an evolving portfolio of clean and renewable products and services to communities AltaGas serves. [emphasis added.]

Q. Has WGL's Climate Business Plan been filed with the Commission?

A. Yes. The Company filed its CBP on March 13, and the Commission set a 60-day comment period for the CBP, and a 60-day period for reply comments.[17] However, on May 11, the DC Government and the Office of People's Counsel (referred to as "Joint Movants" in Order No. 20346) requested an extension of the comment period, arguing that the Company's plan was deficient in "information regarding the assumptions, calculations, and methodologies included in the Climate Business Plan."[18] This second extension was granted, and the currently-extended comment period ends on June 26, 2020.

Q. Have you reviewed the Climate Business Plan filed by WGL?

A. Yes. At the request of the Sierra Club, I reviewed the CBP, an accompanying "Renewable

[17] Order No. 20346, ¶ 5.
[18] Formal Case 1142, Order No. 20346, ¶ 6.

Natural Gas" study,[19] and a supporting Technical Study that was posted by the company on its website approximately one month after it filed its CBP.[20] I also prepared a technical analysis of the Company's reports for Sierra Club to use in support of its comments on the CBP. I have provided this technical report as Exhibit EDH-2.

Q. Please summarize the conclusions of your technical report.

A. I found the Company's CBP to be deficient in numerous ways, and wholly inadequate as a guide to future infrastructure investments that would support and be consistent with the District's climate commitments.

As with the Joint Movants, I found that it was difficult to fully assess many of the claims in the Company's CBP and supporting materials because they lacked critical information regarding assumptions, sources, and methodologies. I also found them to be internally inconsistent in many instances, and in others crucial conclusions were presented as bold statements with no supporting information at all. As I stated in my report:[21]

> *The CBP relies on misleading nomenclature and false comparisons to support the continued use of gas in the District, and the claimed future cost savings relative to an electrification scenario are without foundation. In both [the CBP and the Renewable Natural Gas study], fundamental uncertainties are routinely brushed aside in favor of overly-optimistic projections that support AltaGas' preferred approach. Key assumptions on which the authors rely in both studies cannot be validated because they are described only vaguely and often inconsistently, without references, or sometimes referenced to unreliable and biased sources such as the "Playbook" of the American Gas Association, a gas*

[19] Appendix D to the CBP.

[20] ICF, Opportunities for Evolving the Natural Gas Distribution Business to Support the District of Columbia's Climate Goals, AltaGas (Apr. 2020), https://washingtongasdcclimatebusinessplan.com/wp-content/uploads/2020/04/Technical-Study-Report-Opportunities-for-Evolving-the-Natural-Gas-Distribution-Business-to-Support-DCs-Climate-Goals-April-2.pdf.

[21] *See* Exhibit EDH-2 at 28.

industry lobbying group. These shortcomings cast serious doubt on the validity of the reports' findings, at best making them impossible to credibly assess.

Q. Allowing for these shortcomings, does the CBP offer a roadmap for evolving WGL's business model consistent with the District's climate commitments, as required under the term 79 of the settlement in Formal Case 1142?

A. No. As I stated in my report, "Even taken at face value, the 'plan' would not eliminate gas-related emissions by 2050 as the company claims, because it would continue to rely on combustion of fossil gas for 42% of its fuel supply."[22] Thus the Company has simply not met its obligations under the merger settlement agreement, and has not produced a meaningful context for serving customers while evolving its business to be consistent with the District's climate commitments.

Q. How does WGL present the components of its Climate Business Plan?

A. Figure 1 is from the "Plan Overview" in the CBP, page 8. Focusing on the near-term (2032) commitment, we see three categories of emissions reductions, each with a reduction target relative to 2006 emissions: (a) end-use reductions (12% of 2006 emissions); leak detection and damage prevention, including but not limited to Pipes 2 (2%); and "sourcing and supply" (13%). The rest of the 2050 target is met by crediting the decrease in gas use in the District between 2006 and 2017, which is attributable to a 61% decrease in nonresidential gas use and a 29% reduction in distribution system losses. Residential use, by contrast, increased by almost 15% over this period.[23]

[22] *Id*.

[23] Based on 2006-2017 DC Greenhouse Gas Inventory, https://doee.dc.gov/service/greenhouse-gas-inventories (2017 is the last year for which data are available as of this writing).

Figure 1. Overview of WGL/AltaGas Climate Business Plan as presented therein. All percentages shown are relative to 2006 emissions baseline.

CLIMATE BUSINESS PLAN (2020-2050)		2032	2050
TOTAL End-Use REDUCTIONS	• Energy Efficiency (including Behavioral Programs and Gas Heat Pumps) • CHP and Distributed Energy Systems • Dual Fuel Systems (Hybrid Heating) • Emerging Technology and Offsets	12%	36%
TOTAL Distribution REDUCTIONS	• Second phase of PROJECT*pipes* • Advanced leak detection and response • Third-party damage prevention	2%	4%
TOTAL Sourcing and Supply REDUCTIONS	• Certified Gas Production (of geologic gas) and Transmission • Renewable Natural Gas (RNG) • Power-to-Gas and Hydrogen	13%	31%
	SUB-TOTAL of Climate Business Plan REDUCTIONS	27%	71%
	Net EMISSIONS REDUCTION from natural gas achieved between 2006 - 2017	27%	27%
	Net CHANGES in business as usual emissions after 2017	-3%	2%
TOTAL REDUCTION in GHG Emissions against Business as Usual		50%	100%

Note: numbers do not sum due to rounding

Q. Has WGL filed with the Commission for approval of end-use reduction programs that would reach the reduction levels shown in the first category of Figure 1?

A. No.

Q. Has WGL files with the Commission for approval of alternative sourcing and supply options such as those shown in the third category of Figure 1?

A. No.

Q. Has WGL taken into account either the usage reductions from the first category of Figure 1, or the alternate sources of supply shown in the third category of Figure 1, in devising its Pipes 2 proposal?

A. Not in any way that is reflected in the Company's filing in this matter.

Q. You describe the Company's CBP as "deficient" and "inadequate" to guide the Company's planning and investments. By what process should the Commission ensure that WGL complies with DC's climate commitment of carbon neutrality by 2050?

A. The Commission should institute a new proceeding commencing with Commission-directed stakeholder input on the kind of programs WGL can implement to continue providing safe and reliable heating services to homes consistent with the District's 2050 climate commitments. This would involve consideration of alternatives to gas such as electric heat pumps and electric water heaters as well as non-pipeline alternatives to address aging and leaking pipeline infrastructure. The Commission should use the input garnered during this process to direct the filing of both pilot programs and a longer-term plan to ensure WGL is transitioning its business consistent with the District's climate commitments. Review of any subsequent long-term plan must take place in the context of an evidentiary proceeding and require Commission approval of the final plan.

Q. Are you aware of other jurisdictions that have undertaken public processes to help gas utilities conform to the need to reduce carbon emissions?

A. Yes. The Massachusetts Attorney general requested that the state Department of Public Utilities "open an investigation…to examine the issues facing gas distribution companies as the Commonwealth rapidly moves to achieve its 2050 GHG emission reduction

mandate."[24] The Attorney general further requested that this investigation "provides the Department with the opportunity to solicit utility and stakeholder input and develop a nation-leading regulatory and policy roadmap to guide the evolution of the gas distribution industry companies, provide ratepayer protection, and allow the Commonwealth to move into its net-zero GHG emissions energy future.[25]

The Attorney General concluded:

> the Department should take proactive steps to investigate the future role of the [gas utilities] as the Commonwealth transitions to a clean, increasingly electrified, and decarbonized heating sector. An investigation will provide the platform for the Department to assess fully the prevailing concerns and relevant issues facing [gas utilities] and enable it to develop policies and a regulatory framework to ensure an orderly and fair transition to a clean energy heating sector, to ensure continued safe and reliable gas service even as demand declines, and to ensure that consumers do not pay unnecessary costs.[26]

V. Risks of WGL's Proposal

Q. What are the risks associated with the Company's proposal, in the context of the issues you raised above?

A. According to WGL witness Wayne A. Jacas,[27] WGL has already committed or spent approximately $110 million under its initial 5-year Pipes 1 plan. It proposes to spend an additional $305 million on the currently proposed plan, and billions more over the coming decades to continue to replace, upgrade, and modernize its distribution and transmission pipeline systems. The Company proposes to amortize these investments

[24] Exhibit EDH-4 at 18.
[25] *Id.* at 3.
[26] *Id.* at 17.
[27] Jacas Direct at 2:20–24.

over 30 years, earning a guaranteed rate of return from ratepayers through the year 2085, apparently through undiminished or even increased sales of natural gas.

Of course, this vision is a fantasy. Climate science tells conclusively us that we cannot continue to burn fossil fuels at current rates over the next several decades without catastrophic and irreparable harm to the climate of the planet.[28] If emissions are not curtailed, large areas of Washington, DC will be regularly inundated during storm surges, making currently valuable residential and business areas of the District inhospitable. This reality was identified as early as June 2013, when the Metropolitan Washington Council of Governments published the results of its 2010-2012 climate adaptation climate initiatives;[29] today, the projections are far more advanced and far more alarming.[30]

I am providing as Exhibit EDH-5 a Climate Central research report entitled "Washington, D.C. and the Surging Sea: A vulnerability assessment with projections for sea level rise and coastal flood risk." The report assessed a plausible climate change-induced scenario for the District as follows:

> As sea levels rise, they increase the chances of extreme floods by today's standards. We assessed when floods would exceed the highest-ever observed flood – 7.9 feet above the local high tide line – at the Washington,

[28] *See* Intergovernmental Panel on Climate Change Sixth Assessment Report, Working Group I, The Physical Science Basis (https://www.ipcc.ch/report/sixth-assessment-report-working-group-i/) and Working Group II, Impacts, Adaptation and Vulnerability (https://www.ipcc.ch/report/sixth-assessment-report-working-group-ii/). *See also* Exhibit EDH-5 for an analysis of specific possible impacts on the Washington DC area.

[29] Metropolitan Washington Council of Governments (Cog), Summary of Potential Climate Change Impacts, Vulnerabilities, and Adaptation Strategies in the Metropolitan Washington Region: A synopsis of lessons learned from the Metropolitan Washington Council of Governments' climate adaptation planning initiatives from 2010 – 2012, http://www.mwcog.org/uploads/pub-documents/pl5cXls20130701111432.pdf.

[30] For a recent global assessment of climate vulnerability, *see* Kulp, S.A., Strauss, B.H. New elevation data triple estimates of global vulnerability to sea-level rise and coastal flooding. Nat Commun 10, 4844 (2019). https://doi.org/10.1038/s41467-019-12808-z.

> D.C. water level station (see http://tidesandcurrents.noaa.gov/est/Top10_form_ft.pdf for historic flood listings), and found a one-in-two chance by 2040, based on [the US National Oceanic and Atmospheric Administration's] intermediate high scenario. Floods exceeding today's record become annual events by 2100 under the highest sea level rise scenario.[31]

The damage associated with this degree and frequency of flooding would be extreme:

> We find that in Washington D.C., some $4.6 billion in property value – half in the zip code of 20024 (a large portion of Southwest DC) – and more than 1,400 people in 400 homes sit on land less than 6 feet above the local high tide line. At 10 feet the totals increase to $9 billion and 4,833 people residing in 1,900 homes. Nonresidential buildings and infrastructure are widely at risk as well. All told, 21 miles of road lie on land below 6 feet in the District; 2 military facilities; 1 museum; and 12 EPA-listed sites, screened to include mostly hazardous waste sites, facilities with significant hazardous materials, and wastewater generators. At 10 feet, these numbers change to 46 miles of road, 4 military facilities, 3 museums, and 26 EPA-listed sites. 1 power plant sits on land below 10 feet [above today's high tide line.][32]

The message is clear: either the District and the nation take aggressive action to address global climate change, in which case WGL's investments will be stranded as gas consumption dwindles in the District, or uncontrolled climate change renders much of the District uninhabitable, destroying energy and other infrastructure, and similarly renders much of WGL's investment a waste of ratepayer funds. The District has chosen the former path through its greenhouse gas emissions reduction commitments; WGL should conform its infrastructure investment strategy to this reality.

VI. Recommendations and Conclusion

Q. What are your recommendations for the Commission?

A. I make the following recommendations:

[31] Exhibit EDH-5 at 12–13.
[32] *Id.* at 15.

1. The Commission should defer action on WGL's proposed Pipes 2 program pending resolution of my following recommendations.

2. The Commission should open a new docket to gather stakeholder input and establish Commission-approved guidelines for WGL's infrastructure planning and investments that are consistent with the District's climate commitments, including carbon neutrality by 2050, to replace the Company's deficient CBP.[33] This docket should include a focus on non-pipeline alternatives to pipeline repair and initiate pilot non-pipeline alternative projects.

3. WGL should be directed to refile an infrastructure maintenance program, including a demonstration that its proposals are consistent with the District's climate commitment of carbon neutrality by 2050 and the Commission-approved guidelines established under recommendation #2. WGL should produce a plan to address the largest and most significant leaks and those presenting imminent risks to public health in order to reduce emissions and protect public safety first, but it should do so in a manner that is consistent with meeting the District's climate commitments.

4. Finally, the Commission should notify the Company that it will not allow recovery of or on depreciation expense for pipe distribution and transmission infrastructure beyond 2050, the time when the District is committed to being carbon neutral. Notably, a 30 year depreciation horizon proposed by WGL in this docket for the next 5 year phase of Project Pipes would already be in conflict with that deprecation timeline, highlighting the incompatibility between WGL's Pipes 2 plan and the District's established climate commitments.

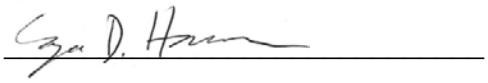
Q. Does this conclude your testimony?

A. Yes.

[33] As detailed in my Technical Report on AltaGas Climate Business Plan and Renewable Natural Gas Study, attached as Exhibit EDH-2, the Climate Business Plan filed by AltaGas on March 16, 2020 is deficient and cannot serve as the basis for evaluating WGL's proposed infrastructure investments.

ATTESTATION

I, Dr. Ezra D. Hausman, whose Testimony accompanies this Attestation, state that such testimony was prepared by me or under my supervision, that I am familiar with the contents thereof; that the facts set forth therein are true and correct to the best of my knowledge, information and belief; and that I adopt the same as true and correct.



DR. EZRA D. HAUSMAN

June 15, 2020

DATE

CERTIFICATE OF SERVICE

I hereby certify that on this 15th day of June 2020, a copy of the foregoing was served on the following parties by electronic mail:

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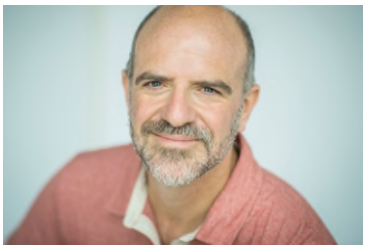
Exhibit EDH-1
Resume of Ezra D. Hausman, Ph.D.

EZRA HAUSMAN CONSULTING

Ezra D. Hausman, Ph.D.

Curriculum Vitae



I am an independent consultant in energy and environmental economics.

I have worked for over two decades as an energy market expert with a focus on market design and market restructuring, planning and ratemaking, energy efficiency programs, environmental regulation, and pricing of energy, capacity, transmission, losses and other electricity-related services. I have performed market analysis, provided expert testimony, led workshops and working groups, and provided other support in both regulated and restructured electricity markets for clients including federal and state agencies, offices of consumer advocate, legislative bodies, cities and towns, non-governmental organizations, foundations, industry associations, and resource developers.

I hold a Ph.D. in atmospheric science from Harvard University, an S.M. in applied physics from Harvard University, an M.S. in water resource engineering from Tufts University, and a B.A. in psychology from Wesleyan University.

PROFESSIONAL EXPERIENCE

Ezra Hausman Consulting, Newton, MA. President, March 2014 – Present.
I provide research, analysis, expert testimony, and policy support services in regulatory, litigation, and stakeholder processes covering a wide range of electric sector and electriciuty market issues. The focus of my consulting work includes:

- Ratemaking and regulatory proceedings
- Wholesale market design and analysis for electricity, generating capacity, and related services
- Demand-side management program design and cost/benefit analysis
- Interaction of air quality and environmental regulations with electricity markets
- Analysis and implementation of the Clean Power Plan and other greenhouse gas rules
- Clean Air Act enforcement support
- Long-term electric power system planning
- Energy efficiency and renewable energy programs and policies
- Consumer and environmental protection
- Market power and market concentration analysis in electricity markets.

Synapse Energy Economics Inc., Cambridge, MA.
Chief Operating Officer, March 2011 – February 2014;

Vice President, July 2009 – February 2014;
Senior Associate, 2005-2009.

- Conducted research, wrote reports, and presented expert testimony pertaining to consumer, environmental, and public policy implications of electricity industry regulation. Provided expert support and representation in planning, greenhouse gas mitigation, and other stakeholder processes.
- As Vice President and Chief Operating Officer, I was also responsible for day-to-day operations of the company, quality assurance, client service, and professional development of staff.

Charles River Associates (CRA), Cambridge, MA. Senior Associate, 2004-2005
CRA acquired Tabors Caramanis & Associates in October, 2004.

Tabors Caramanis & Associates, Cambridge, MA. Senior Associate, 1998-2004
As a member of the modeling group, developed and maintained dispatch modeling capability in support of electricity market consulting practice.

Performed modeling and analysis of electricity markets, generation and transmission systems. Projects included:

- Several market transition cost-benefit studies for development of Locational Marginal Price (LMP) based markets in US electricity markets
- Long-term market forecasting studies for valuation of generation and transmission assets,
- Valuation of financial instruments relating to transmission system congestion and losses
- Modeling and analysis of hydrologically and electrically interconnected hydropower system operations
- Natural gas market analysis and price forecasting studies
- Co-developed an innovative approach to hedging financial risk associated with transmission system losses of electricity
- Designed, developed and ran training seminars using a computer-based electricity market simulation game, to help familiarize market participants and students in the operation of LMP-based electricity markets.
- Developed and implemented analytical tools for assessment of market concentration in interconnected electricity markets, based on the “delivered price test” for assessing market accessibility in such a network
- Performed regional market power and market power mitigation studies
- Performed transmission feasibility studies for proposed new generation and transmission projects in various locations in the US
- Provided analytical support for expert testimony in a variety of regulatory and litigation proceedings, including breach of contract, bankruptcy, and antitrust cases, among others.

Global Risk Prediction Network, Inc., Greenland, NH. Vice President, 1997-1998
Developed private sector applications of climate forecast science in partnership with researchers at Columbia University. Specific projects included a statistical assessment of grain yield predictability in several crop regions around the world based on global climate indicators (Principal Investigator); a statistical assessment of road salt demand predictability in the United States based on global climate indicators (Principal Investigator); a preliminary design of a climate and climate forecast information website tailored to the interests of the business community; and the development of client base.

Hub Data, Inc., Cambridge, MA. Financial Software Consultant, 1986-1987, 1993-1997
Responsible for design, implementation and support of analytic and communications modules for bond portfolio management software; and developed software tools such as dynamic data compression technique to facilitate product delivery, Windows interface for securities data products.

Abt Associates, Inc., Cambridge, MA. Environmental Policy Analyst, 1990-1991
Quantitative risk analysis to support federal environmental policy-making. Specific areas of research included risk assessment for federal regulations concerning sewage sludge disposal and pesticide use; statistical alternatives to Most-Exposed-Individual risk assessment paradigm; and research on non-point sources of water pollution.

Massachusetts Water Resources Authority, Charlestown, MA. Analyst, 1988-1990
Applied and evaluated demand forecasting techniques for the Eastern Massachusetts service area. Assessed applicability of various techniques to the system and to regional planning needs; and assessed yield/reliability relationship for the eastern Massachusetts water supply system, based on Monte-Carlo analysis of historical hydrology.

Somerville High School, Somerville, MA. Math Teacher, 1986-1987
Courses included trigonometry, computer programming, and basic math.

EDUCATION

Ph.D., Earth and Planetary Sciences. Harvard University, Cambridge, MA, 1997

S.M., Applied Physics. Harvard University, Cambridge, MA, 1993

M.S., Civil Engineering. Tufts University, Medford, MA, 1990

B.A., Wesleyan University, Psychology. Middletown, CT, 1985

FELLOWSHIPS, AWARDS AND AFFILIATIONS

UCAR Visiting Scientist Postdoctoral Fellowship, 1997

Postdoctoral Research Fellowship, Harvard University, 1997

Certificate of Distinction in Teaching, Harvard University, 1997

Graduate Research Fellowship, Harvard University, 1991-1997

Invited Participant, UCAR Global Change Institute, 1993

House Tutor, Leverett House, Harvard University, 1991-1993

Graduate Research Fellowship, Massachusetts Water Resources Authority, 1989-1990

Teaching Fellowships:

Harvard University: *Principles of Measurement and Modeling in Atmospheric Chemistry; Hydrology; Introduction to Environmental Science and Public Policy; The Atmosphere*.

Wesleyan University: *Introduction to Computer Programming; Psychological Statistics; Playwriting and Production.*

Community Service

Vice President of Finance, Congregation Dorshei Tzedek, 2018 - Ongoing
Academic Mentor and Athletic Coach, SquashBusters Boston, 2014 - Ongoing
Judge, Cleantech Open innovation competitions, 2015-2016
President, Burr Elementary School Parent Teacher Organization, 2005-2007

EXPERT TESTIMONY AND SERVICES

Public Service Commission of the District of Columbia – 2020
Review and analysis of AltaGas d/b/a/ Washington Gas' "Climate Business Plan" and "Renewable Natural Gas" studies on behalf of Sierra Club.

New Jersey Division of Rate Counsel – 2016-Ongoing
General policy and stakeholder support on matters related to energy efficiency, renewable energy, and electrification of transportation in New Jersey.

New Jersey Board of Public Utilities – 2020-Ongoing
Expert participation is stakeholder process regarding conversion to high-efficiency street lights on behalf of Rate Counsel.

New Jersey Board of Public Utilities – 2019-Ongoing
Expert participation is stakeholder process regarding transportation electrification policies on behalf of Rate Counsel.

Washington Utilities and Transportation Commission – 2020-Ongoing
Expert witness on behalf of the Sierra Club regarding potential sale of ownership sale in Colstrip generating unit.

Utah Public Service Commission (Docket No. 18-035-36) – 2020-Ongoing
Expert witness on behalf of the Sierra Club in Rocky Mountain Power depreciation case.

PacifiCorp Multi-State Protocols Stakeholder Process – 2019-Ongoing
Participation on behalf of Sierra Club in stakeholder process to establish protocols for allocation of resource costs ad benefits among PacifiCorp states.

Advisory Consulting for Natural Resources Defense Council – 2019-2020
Provide advisory and technical support to analysis team.

Memphis Light, Gas and Water – Power Supply Alternatives Study (2019-Ongoing)
Expert support for Sierra Club participation in Power Supply Advisory Team.

Washington Utilities and Transportation Commission (Dockets UE-190334 and UG-190335) – 2019
Expert witness on behalf of the Sierra Club in Avista Energy rate case.

New Jersey Board of Public Utilities – 2014-Ongoing
Expert witness on behalf of the New Jersey Division of Rate Counsel, reviewing and providing testimony on cost effectiveness and program design of various New Jersey gas and electric utility energy efficiency programs.

Public Service Commission of South Carolina (Docket No. 2018-319-E) – 2019
Expert witness on behalf of the Sierra Club in Duke Energy Carolinas rate case.

Public Service Commission of South Carolina (Docket No. 2018-318-E) – 2019
Expert witness on behalf of the Sierra Club in Duke Energy Progress rate case.

Virginia State Corporation Commission (Case No. PUR-2018-00065) – 2018
Expert witness on behalf of the Sierra Club in Dominion Power IRP proceeding.

Missouri Public Service Commission (Case No. EO-2018-0038) – 2018
Expert services in support of Sierra Club's participation in integrated resource planning process.

Florida Public Service Commission (Docket No. 20170225-EI) – 2017-2018
Expert witness on behalf of the Sierra Club in FPL Determination of Need proceeding.

North Carolina Utilities Commission (Docket No. E-7, SUB 1146) – 2017-2018
Expert witness on behalf of the Sierra Club in Duke Energy Carolinas rate case.

North Carolina Utilities Commission (Docket No. E-2, SUB 1142) – 2017
Expert witness on behalf of the Sierra Club in Duke Energy Progress rate case.

Idaho Public Utilities Commission (Case No. AVU-E-17-01) – 2017
Expert witness on behalf of the Sierra Club in Avista Corporation rate case.

Iowa Utilities Board (Docket No. RPU-2017-0002) –- 2017
Expert witness on behalf of the Sierra Club for Interstate Power and Light petition for ratemaking principles for proposed 500 MW wind project.

Washington Utilities and Transportation Commission (Dockets UE-170033 and UG-170034) – 2017
Expert witness on behalf of the Sierra Club in Puget Sound Energy (PSE) rate case.

Clean Power Plan Modeling in PJM and MISO – 2016-2017
Participation on behalf of the Sustainable FERC Project in ISO initiative to model scenarios for state compliance with federal greenhouse gas mitigation rules.

California ISO/PacifiCorp Market Integration – 2015-2017
Technical support to Sierra Club in stakeholder review and participation in all relevant proceedings in California.

United States Department of Justice – US District Court Dallas, TX Division (U.S. vs. Luminant Generation Company, LLC, and Big Brown Power Company, LLC) – Ongoing
Expert witness on behalf of the United States Department of Justice on clean air act enforcement case.

United States Department of Justice – US District Court for the Eastern District of Missouri (Civil Action No. 4:11-CV-00077) – 2013-Ongoing
Expert witness on behalf of the United States Department of Justice on successful prosecution of clean air act case.

Missouri Public Service Commission (Case No. EO-2015-0084) – 2014-2015
Expert services in support of Sierra Club's participation in integrated resource planning process.

Missouri Public Service Commission (File No. ER-2014-0258) – 2014-2015
Expert witness on behalf of the Sierra Club in Ameren Missouri rate case.

Arizona Corporation Commission (Docket No. E-01345A-11-0224) – 2014
Expert witness on behalf of the Sierra Club regarding Arizona Public Service petition for rate treatment for acquisition of an additional ownership share of the Four Corners generating units.

Missouri Public Service Comission (Docket No. ET-2014-0085) – 2013
Testimony on behalf of the Missouri Solar Energy Industries Association regarding Union Electric (d/b/a Ameren Missouri) motion to suspend payment of solar rebates.

Missouri Public Service Comission (Docket No. ET-2014-0059 and ET-2014-0071) – 2013
Testimony on behalf of the Missouri Solar Energy Industries Association regarding Kansas City Power and Light Company's motions to suspend payment of solar rebates.

Eastern Interconnect Planning Collaborative (EIPC) – 2012-2013
Expert support on behalf of coalition of NGO stakeholders in transmission and resource planning process, including development and review of modeling assumptions and interim results, and development of comments.

Puget Sound Energy (PSE) – 2012-2013
Expert participant in PSE's 2013 IRP stakeholder process on behalf of the Sierra Club.

Washington Utilities and Transportation Commission (Docket Nos. UE-111048 and UG-111049) – 2011
Testimony on behalf of the Sierra Club regarding the cost of operating the Colstrip power plant and other power procurement issues.

Kansas Corporation Commission (Docket No. 11-KCPE-581-PRE) - 2011
Presented written and live testimony on behalf of the Sierra Club regarding Kansas City Power and Light request for predetermination of ratemaking principles.

Vermont Department of Public Service - 2011
Provided scenario analysis of the costs and benefits of various electric energy resource scenarios in support of the state Comprehensive Energy Plan.

Massachusetts Department of Energy Resources – 2009-2011
Served as expert analyst and modeling coordinator for analysis related to implementation of the Massachusetts Global Warming Solutions Act.

Iowa Office of Consumer Advocate – 2010-2011
Assisted Consumer Advocate in evaluating a proposed power purchase agreement for the output of the Duane Arnold nuclear power station.

Missouri Public Service Commission (Docket No. EW-2010-0187) – 2010
Expert participant on behalf of the Sierra Club in stakeholder process to develop a "demand side investment mechanism" in Missouri.

Louisiana Public Service Commission (Docket No. R-28271 Subdocket B) – 2009-2010
Expert participant on behalf of the Sierra Club in Renewable Portfolio Standard Task Force considering RPS for Louisiana.

Joint Fiscal Committee of the Vermont Legislature – 2008-2010
Serving as lead expert advising the Legislature on economic issues related to the possible recertification of the Vermont Yankee nuclear power plant.

Town of Littleton, NH – 2006-2010
Serving as expert witness on the value of the Moore hydroelectric facility.

Nevada Public Service Commission (Docket No. 08-05014) – August 2008
Presented prefiled and live testimony on behalf of Nevadans for Clean Affordable Reliable Energy regarding the proposed Ely Energy Center and resource planning practices in Nevada.

Mississippi Public Service Commission (Docket No. 2008-AD-158) – July 2008
Presented written and live testimony on behalf of the Sierra Club regarding the resource plans filed by Entergy Mississippi and Mississippi Power Company.

Kansas House of Representatives - Committee on Energy and Utilities – February 2008
Presented testimony on behalf of the Climate and Energy Project of the Land Institute of Kansas on a proposed bill regarding permitting of power plants. Focus was on the risks and costs associated with new coal plants and on their contribute to global climate change.

Vermont Public Service Board (Docket No. 7250) – 2006-2008
Prepared report and testimony in support of the application of Deerfield Wind, LLC. For a Certificate of Public Good for a proposed wind power facility.

Iowa Utilities Board (Docket No. GCU-07-1) – October, 2007 – January 2008

Presented wrtten and live testimony on behalf of the Iowa Office of Consumer Advocate regarding the science of global climate change and the contribution of new coal plants to atmospheric CO_2.

Nevada Public Service Commission (Docket No. 07-06049) – October 2007
Presented prefiled direct testimony on behalf of Nevadans for Clean Affordable Reliable Energy regarding treatment of carbon emissions costs and coal plant capital costs in utility resource planning.

Massachusetts General Court, Joint Committee on Economic Development and Emerging Technologies – July 2007
Presented written and live testimony on climate change science and the potential benefits of a revenue-neutral carbon tax in Massachusetts.

Town of Rockingham, VT – 2006-2007
Served as expert witness on the value of the Bellows Falls hydroelectric facility.

South Dakota Public Utilities Commission (Case No EL05-22) – June 2006
Minnesota Public Utilities Commission (Docket TR-05-1275) – December 2006
Submitted prefiled and live testimony on the contribution of the proposed Big Stone II coal-fired generator to atmospheric CO_2, global climate change and the environment of South Dakota and Minnesota, respectively.

Arkansas Public Service Commission (Docket No. 06-070-U) – October 2006
Submitted prefiled direct testimony on inclusion of new wind and gas-fired generation resources in utility rate base.

Federal Energy Regulatory Commission (Docket Nos. ER055-1410-000 and EL05-148-000) – May-Sept 2006

- Participant in settlement hearings on proposed capacity market structure (the Reliability Pricing Model, or RPM) on behalf of State Consumer Advocates in Pennsylvania, Ohio and the District of Columbia
- Invited participant on technical conference panel on PJM's proposed Variable Resource Requirement (VRR) curve
- Filed Pre- and post-conference comments and affidavits with FERC
- Participated in numerous training and design conferences at PJM on RPM implementation.

Illinois Pollution Control Board (Docket No. R2006-025) – June-Aug 2006
Prefile and live testimony presented on behalf of the Illinois EPA regarding the costs and benefits of proposed mercury emissions rule for Illinois power plants.

Long Island Sound LNG Task Force – January 2006
Presentation of study on the need for and alternatives to the proposed Broadwater LNG storage and regasification facility in Long Island Sound.

Iowa Utilities Board (Docket No. SPU-05-15) – November 2005

Presented written and live testimony on whether Interstate Power and Light's should be permitted to sell the Duane Arnold Energy Center nuclear facility to FPLE Duane Arnold, Inc., a subsidiary of Florida Power and Light.

PUBLICATIONS AND REPORTS

Hausman, E., The Worst of Both Worlds: Why the Ohio Legislature's OVEC Bailout Bill would Harm Consumers, Impede Competition, Increase Pollution, and Impair the Health and Welfare of Ohioans for Decades. White paper produced on behalf of The Sierra Club, June 2017.

Hausman, E., Risks and Opportunities for PacifiCorp - State Level Findings: Utah, Produced on behalf of the Sierra Club, October 2014.

Hausman, E., Risks and Opportunities for PacifiCorp - State Level Findings: Oregon, Produced on behalf of the Sierra Club, October 2014.

Hausman, E., Risks and Opportunities for PacifiCorp in a Carbon Constrained Economy, Produced on behalf of the Sierra Club, October 2014.

Luckow, P., E. Stanton, B. Biewald, J. Fisher, F. Ackerman, E. Hausman, 2013 Carbon Dioxide Price Forecast, Synapse Energy Economics, November 2013.

Stanton, E., T. Comings, K. Takahashi, P. Knight, T. Vitolo, E. Hausman, Economic Impacts of the NRDC Carbon Standard: Background Report prepared for the Natural Resources Defense Council, Synapse Energy Economics for NRDC, June 2013

Comings T., P. Knight, E. Hausman, Midwest Generation's Illinois Coal Plants: Too Expensive to Compete? (Report Update) Synapse Energy Economics for Sierra Club, April 2013

Stanton E., F. Ackerman, T. Comings, P. Knight, T. Vitolo, E. Hausman, Will LNG Exports Benefit the United States Economy? Synapse Energy Economics for Sierra Club, January 2013

Chang M., D. White, E. Hausman, Risks to Ratepayers: An Examination of the Proposed William States Lee III Nuclear Generation Station, and the Implications of "Early Cost Recovery" Legislation, Synapse Energy Economics for Consumers Against Rate Hikes, December 2012

Wilson R., P. Luckow, B. Biewald, F. Ackerman, and E.D. Hausman, 2012 Carbon Dioxide Price Forecast, Synapse Energy Economics, October 2012.

Fagan B., M. Chang, P. Knight, M. Schultz, T. Comings, E.D. Hausman, and R. Wilson, The Potential Rate Effects of Wind Energy and Transmission in the Midwest ISO Region. Synapse Energy Economics for Energy Future Coalition, May 2012.

Hausman, E.D., T. Comings, "Midwest Generation's Illinois Coal Plants: Too Expensive to Compete? Synapse Energy Economics for Sierra Club, April 2012.

Hausman, E.D., T. Comings, and G. Keith, Maximizing Benefits: Recommendations for Meeting Long-Term Demand for Standard Offer Service in Maryland. Synapse Energy Economics for Sierra Club, January 2012.

Keith G., B. Biewald, E.D. Hausman, K. Takahashi, T. Vitolo, T. Comings, and P. Knight, Toward a Sustainable Future for the U.S. Power Sector: Beyond Business as Usual 2011 Synpase Energy Economics for Civil Society Institute, November 2011.

Chang M., D. White, E.D. Hausman, N. Hughes, and B. Biewald, Big Risks, Better Alternatives: An Examination of Two Nuclear Energy Projects in the U.S. Synpase Energy Economics for Union of Concerned Scientists, October 2011.

Hausman E.D., T. Comings, K. Takahashi, R. Wilson, and W. Steinhurst, Electricity Scenario Analysis for the Vermont Comprehensive Energy Plan 2011. Synapse Energy Economics for Vermont Department of Public Service, September 2011.

Wittenstein M., E.D. Hausman, Incenting the Old, Preventing the New: Flaws in Capacity Market Design, and Recommendations for Improvement. Synapse Energy Economics for American Public Power Association, June 2011.

Johnston L., E.D. Hausman, B. Biewald, R. Wilson, and D. White. 2011 Carbon Dioxide Price Forecast. Synapse Energy Economics White Paper, February 2011.

Hausman E.D., V. Sabodash, N. Hughes, and J. I. Fisher, Economic Impact Analysis of New Mexico's Greenhouse Gas Emissions Rule. Synapse Energy Economics for New Energy Economy, February 2011.

Hausman E.D., J. Fisher, L. Mancinelli, and B. Biewald. Productive and Unproductive Costs of CO2 Cap-and-Trade: Impacts on Electricity Consumers and Producers. Synapse Energy Economics for National Association of Regulatory Utility Commissioners, National Association of State Utility Consumer Advocates, National Rural Electric Cooperative Association, and American Public Power Association, July 2009.

Peterson P., E. Hausman, R. Fagan, and V. Sabodash, Report to the Ohio Office of Consumer Counsel, on the value of continued participation in RTOs. Filed under Ohio PUC Case No. 09-90-EL-COI, May 2009.

Schlissel D., L. Johnston, B. Biewald, D. White, E. Hausman, C. James, and J. Fisher, Synapse 2008 CO2 Price Forecasts. July 2008.

Hausman E.D., J. Fisher and B. Biewald, Analysis of Indirect Emissions Benefits of Wind, Landfill Gas, and Municipal Solid Waste Generation. Synapse Energy Economics Report to the Air Pollution Prevention and Control Division, National Risk Management Research Laboratory, U.S. Environmental Protection Agency, July 2008.

Hausman E.D. and C. James, Cap and Trade CO2 Regulation: Efficient Mitigation or a Give-away? Synapse Enegy Ecomics presentation to the ELCON Spring Workshop, June 2008.

Hausman E.D., R. Hornby and A. Smith, Bilateral Contracting in Deregulated Electricity Markets. Synapse Energy Economics for the American Public Power Association, April 2008.

Hausman E.D., R. Fagan, D. White, K. Takahashi and A. Napoleon, LMP Electricity Markets: Market Operations, Market Power and Value for Consumers. Synapse Energy Economics for the American Public Power Association's Electricity Market Reform Initiative (EMRI) symposium, "Assessing Restructured Electricity Markets" in Washington, DC, February 2007.

Hausman E.D. and K. Takahashi, The Proposed Broadwater LNG Import Terminal Response to Draft Environmental Impact Statement and Update of Synapse Analysis. Synapse Energy Economics for the Connecticut Fund for the Environment and Save The Sound, January 2007.

Hausman E.D., K. Takahashi, D. Schlissel and B. Biewald, The Proposed Broadwater LNG Import Terminal: An Analysis and Assessment of Alternatives. Synapse Energy Economics for the Connecticut Fund for the Environment and Save The Sound, March 2006.

Hausman E.D., P. Peterson, D. White and B. Biewald, RPM 2006: Windfall Profits for Existing Base Load Units in PJM: An Update of Two Case Studies. Synapse Energy Economics for the Pennsylvania Office of Consumer Advocate and the Illinois Citizens Utility Board, February 2006.

Hausman E.D., K. Takahashi, and B. Biewald, The Glebe Mountain Wind Energy Project: Assessment of Project Benefits for Vermont and the New England Region. Synapse Energy Economics for Glebe Mountain Wind Energy, LLC., February 2006.

Hausman E.D., K. Takahashi, and B. Biewald, The Deerfield Wind Project: Assessment of the Need for Power and the Economic and Environmental Attributes of the Project. Synapse Energy Economics for Deerfield Wind, LLC., January 2006.

Hausman E.D., P. Peterson, D. White and B. Biewald, An RPM Case Study: Higher Costs for Consumers, Windfall Profits for Exelon. Synapse Energy Economics for the Illinois Citizens Utility Board, October 2005.

Hausman E.D. and G. Keith, Calculating Displaced Emissions from Energy Efficiency and Renewable Energy Initiatives. Synapse Energy Economics for EPA website 2005

Rudkevich A., E.D. Hausman, R.D. Tabors, J. Bagnal and C Kopel, Loss Hedging Rights: A Final Piece in the LMP Puzzle. Hawaii International Conference on System Sciences, Hawaii, January, 2005 (accepted).

Hausman E.D. and R.D. Tabors, The Role of Demand Underscheduling in the California Energy Crisis. Hawaii International Conference on System Sciences, Hawaii, January 2004.

Hausman E.D. and M.B. McElroy, The reorganization of the global carbon cycle at the last glacial termination. Global Biogeochemical Cycles, 13(2), 371-381, 1999.

Norton F.L., E.D. Hausman and M.B. McElroy, Hydrospheric transports, the oxygen isotope record, and tropical sea surface temperatures during the last glacial maximum. Paleoceanography, 12, 15-22, 1997.

Hausman E.D. and M.B. McElroy, Variations in the oceanic carbon cycle over glacial transitions: a time-dependent box model simulation. Presented at the spring meeting of the American Geophysical Union, San Francisco, 1996.

PRESENTATIONS AND WORKSHOPS

American Public Power Association: Invited expert participant in APPA's roundtable discussion of the current state of the RTO-operated electricity markets. October 2013.

California Long-Term Resource Adequacy Summit (Sponsored by the California ISO and the California Public Utility Commission): Panelist on "Applying Alternative Models to the California Market Construct." February 26, 2013.

ELCON 2011 Fall Workshop: "Do RTOs Need a Capacity Market?" October 2011.

Harvard Electricity Policy Group: Presentation on state action to ensure reliability in the face of capacity market failure. February 2011.

NASUCA 2010 Annual Conference: "Addressing Climate Change while Protecting Consumers." November 2010.

NASUCA Consumer Protection Committee: Briefing on the Synapse report entitled, "Productive and Unproductive Costs of CO_2 Cap-and-Trade." September 2009.

NARUC 2009 Summer Meeting: Invited speaker on topic: "Productive and Unproductive Costs of CO2 Cap-and-Trade." July, 2009.

NASUCA 2008 Mid-Year Meeting**:** Invited speaker on the topic, "Protecting Consumers in a Warming World, Part II: Deregulated Markets." June 2008.

Center for Climate Strategies: Facilitator and expert analyst on state-level policy options for mitigating greenhouse gas emissions. Serve as facilitator/expert for the Electricity Supply (ES) and Residential, Commercial and Industrial (RCI) Policy Working Groups in the states of Colorado and South Carolina. 2007-2008.

NASUCA 2007 Mid-Year Meeting**:** Invited speaker on the topic, "Protecting Consumers in a Warming World" June 2007.

ASHRAE Workshop on estimating greenhouse gas emissions from buildings in the design phase: Participant expert on estimating displaced emissions associated with energy efficiency in building design. Also hired by ASHRAE to document and produce a report on the workshop. April, 2007.

Assessing Restructured Electricity Markets An American Public Power Association Symposium: Invited speaker on the history and effectiveness of Locational Marginal Pricing (LMP) in northeastern United States electricity markets, February, 2007.

ASPO-USA 2006 National Conference: Invited speaker and panelist on the future role of LNG in the U.S. natural gas market, October, 2006.

Market Design Working Group: Participant in FERC-sponsored settlement process for designing capacity market structure for PJM on behalf of coalition of state utility consumer advocates, July-August 2006.

***NASUCA 2006 Mid-Year Meeting*:** Invited speaker on the topic, "How Can Consumer Advocates Deal with Soaring Energy Prices?" June 2006.

Soundwaters Forum, Stamford, CT: Participated in a debate on the need for proposed Broadwater LNG terminal in Long Island Sound, June 2006.

Energy Modeling Forum: Participant in coordinated academic exercise focused on modeling US and world natural gas markets, December 2004.

Massachusetts Institute of Technology (MIT): Guest lecturer in Technology and Policy Program on electricity market structure, the LMP pricing system and risk hedging with FTRs. 2002-2005.

LMP: The Ultimate Hands-On Seminar. Two-day seminar held at various sites to explore concepts of LMP pricing and congestion risk hedging, including lecture and market simulation exercises. Custom seminars held for FERC staff, ERCOT staff, and various industry groups. 2003-2004.

Learning to Live with Locational Marginal Pricing: Fundamentals and Hands-On Simulation. Day-long seminar including on-line mock electricity market and congestion rights auction, December 2002.

LMP in California. Led a series of seminars on the introduction of LMP in the California electricity market, including on-line market simulation exercise. 2002.

Resume updated May 2020

Exhibit EDH-2
Technical Report on AltaGas Climate Business Plan and Renewable Natural Gas Study.

EARTHJUSTICE

VIA ELECTRONIC FILING **June 15, 2020**

Brinda Westbrook-Sedgwick
Commission Secretary
Public Service Commission
of the District of Columbia
1325 G Street, NW, Suite 800
Washington, DC 20005

Re: **Formal Case No. 1142,**
In the Matter of the Merger Application of AltaGas Ltd. and WGL Holdings, Inc.

Dear Brinda Westbrook-Sedgwick:

Attached please find the **Comments and Request to Institute An Evidentiary Proceeding of Sierra Club** for filing in the above-captioned proceeding.

Thank you for your attention to this matter. Should you have any questions, please contact me at smiller@earthjustice.org.

Sincerely,

Susan Stevens Miller

Susan Stevens Miller, DC Bar No. 1026066
Earthjustice
(202) 667-4500
smiller@earthjustice.org

Counsel for Sierra Club

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

IN THE MATTER OF THE MERGER OF ALTAGAS LTD. AND WGL HOLDINGS, INC.	)))	**Formal Case No. 1142**

COMMENTS AND REQUEST TO INSTITUTE AN EVIDENTIARY PROCEEDING OF SIERRA CLUB

Sierra Club, pursuant to the District of Columbia Public Service Commission's ("Commission") Order No. 20310 issued in the above-captioned proceeding, hereby files these initial comments on the AltaGas Climate Business Plan and Renewable Gas Study. Included with these comments is a technical review performed by Dr. Ezra D. Hausman.[1] As summarized below and set forth in detail in Dr. Hausman's review, the Commission should find that: 1) AltaGas has failed to comply with either Merger Commitments No. 79 or Merger Commitment No. 6; 2) the Climate Business Plan fails on its face to achieve carbon neutrality in 2050, continuing to rely on climate-damaging fossil gas for nearly half of Washington Gas's 2050 sales; 3) both the Climate Business Plan and the Renewable Gas Study are rife with unsupported claims and assertions and, where assumptions are revealed, plagued with unrealistic and overly-optimistic projections; and 4) the dearth of meaningful information and credible analysis undermines the validity of the Climate Business Plan and the Renewable Gas Study and impairs stakeholders' and the Commission's review of the documents. The Commission should institute an evidentiary proceeding and instruct parties to develop a plan to transition WGL to a business model consistent with DC's climate commitment of carbon neutrality.

[1] Ezra D. Hausman, Ph.D., Review of AltaGas' Climate Business Plan and Renewable Gas Study prepared on Behalf of the Sierra Club, (May 14, 2020) ("Hausman Report" or "Exhibit A").

I. BACKGROUND

In 2013, DC issued *Sustainable DC*, the District's sustainability plan, which included the commitment to reduce greenhouse gas (GHG) emissions by 50% from 2006 levels by 2032, and 80% below 2006 levels by 2050. In December 2017, recognizing the pressing need to keep global average temperature rise below 1.5°C, Mayor Muriel Bowser announced an even stronger commitment – reaching "carbon neutrality" in the District by 2050.[2]

On June 29, 2018, the Commission approved the Unanimous Agreement of Stipulation and Full Settlement on the merger of AltaGas Ltd. and WGL Holdings, Inc. in the above-captioned proceeding.[3] The Settlement Agreement set forth a number of merger commitments, including Merger Commitment No. 79, which provides:

> By January 1, 2020, AltaGas will file with the Commission a long-term business plan on how it can evolve its business model to support and serve the District's 2050 climate goals (e.g., providing innovative and new services and projects instead of relying only on selling natural gas) ("Climate Business Plan"). After the business plan is filed, AltaGas will hold bi-annual public meetings to report on and discuss its progress on the business plan.[4]

Under another merger commitment, Merger Commitment No. 6, AltaGas agreed to fund a study to evaluate renewable gas facilities in the District of Columbia.[5]

In August 2018, the DC government released *Clean Energy DC: the District of Columbia Climate and Energy Action Plan*,[6] described as "the District's proposal to reduce

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[2] Press Release, Office of the Mayor, *Mayor Bowser Commits to Make Washington, DC Carbon-Neutral and Climate Resilient by 2050* (Dec. 4, 2017), https://mayor.dc.gov/release/mayor-bowser-commits-make-washington-dc-carbon-neutral-and-climate-resilient-2050.
[3] Formal Case No. 1142, Order No. 19396, App. A (June 29, 2018) ("Settlement Agreement").
[4] *Id.* ¶ 79.
[5] *Id.* ¶ 6.
[6] Clean Energy DC, *The District of Columbia Climate and Energy Action Plan*, Department of Energy & Environment (Aug. 27, 2018) ("Clean Energy DC") https://doee.dc.gov/sites/default/files/dc/sites/ddoe/page_content/attachments/Clean%20Energy%20DC%20-%20Full%20Report_0.pdf.

greenhouse gas (GHG) emissions at least 50% below 2006 levels by 2032 while increasing renewable energy and reducing energy consumption, as directed by the landmark Sustainable DC plan; and to put us on a path to achieve carbon neutrality by 2050."[7] Within this document, there is a recognition that reaching DC's climate commitments requires, among other things, and "a shift away from fossil fuels, including natural gas" so that the district can ultimately "eliminate fossil fuel use."[8]

Subsequent to the approval of the Settlement Agreement, the District of Columbia Council passed and Mayor Bowser signed the CleanEnergy DC Omnibus Amendment Act of 2018 ("Clean Energy Act"). The Clean Energy Act mandates that the Commission consider "the preservation of environmental quality, including effects on global climate change and the District's public climate commitments."[9] DC's climate commitments include a 50 percent reduction of greenhouse emissions by 2032 and carbon neutrality by 2050, as well as ensuring that new buildings operate at net zero carbon by 2030 and all buildings are net zero carbon by 2050.[10] Thus, the Commission must now consider the AltaGas Climate Business Plan within the context of the Plan's effects on the District's public climate commitments.

On December 6, 2019, AltaGas filed a motion for extension of time, requesting that the filing of the Climate Business Plan be delayed until March 16, 2020.[11] In this motion, AltaGas also stated that "renewable" natural gas ("RNG") is expected to be a component of A1taGas's

[7] *Id.* at v.
[8] *Id*. at 156.
[9] D.C. Code § 34-808.02 (2018).
[10] Sustainable DC 2.0 Plan, District of Columbia, at 43, (Apr. 23, 2019) http://www.sustainabledc.org/wp-content/uploads/2019/04/sdc-2.0-Edits-V5_web.pdf; Clean Energy DC, at v; *Net Zero Carbon Buildings Declaration*, C40 Cities (Aug. 23, 2018), https://www.c40.org/other/net-zero-carbon-buildings-declaration.
[11] Formal Case No. 1142, AltaGas Ltd.'s Motion for Extension of Time, ¶ 3 (Dec. 6, 2019).

Climate Business Plan.[12] The Commission granted the AltaGas motion for an extension of time, permitting AltaGas to delay filing of the Climate Business Plan until March 16, 2020.[13]

On March 16, 2020, AltaGas submitted a Climate Business Plan in an attempt to comply with Merger Commitment No. 79. This filing also included the AltaGas Renewable Natural Gas Study Summary purporting to comply with Merger Commitment No. 6 of the Settlement Agreement. In addition, the plan filed in March included a "Technical Study Summary Report" providing an overview of ICF's approach. Approximately one month later, ICF published the full Technical Report on its website. To date, AltaGas has not filed the full report in this proceeding.[14]

On March 18, 2020, the Commission issued Order No. 20310. In this Order, the Commission granted the Joint Motion of the Office of the People's Counsel for the District of Columbia ("OPC") and District of Columbia Government ("DCG") for Enlargement of Time to File Comments to AltaGas Ltd.'s ("AltaGas") Merger Commitment Nos. 6 and 79 Filings ("Joint Motion").[15] The Commission directed that comments on the Climate Business Plan would be due within 60 days of the Climate Business Plan filing, and reply comments would be due within 60 days of the filing of comments.[16]

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[12] *Id.* ¶ 4.
[13] *See* Formal Case No. 1142, Order No. 20276 (Dec. 19, 2019).
[14] ICF, *Opportunities for Evolving the Natural Gas Distribution Business to Support the District of Columbia's Climate Goals*, AltaGas (Apr. 2020) https://washingtongasdcclimatebusinessplan.com/wp-content/uploads/2020/04/Technical-Study-Report-Opportunities-for-Evolving-the-Natural-Gas-Distribution-Business-to-Support-DCs-Climate-Goals-April-2.pdf .
[15] Formal Case No. 1142, Order No. 20310, ¶ 10 (Mar. 18, 2020).
[16] Sierra Club notes that on May 11, 2020, the DC Government and the Office of People's Counsel filed a Joint Motion for Second Enlargement of Time to Provide Comments to AltaGas Ltd.'s Merger Commitments No. 6 and 79 Filings ("Second Joint Motion"). The basis of this request is AltaGas's failure to respond to discovery requests from the parties. On May 14, 2020, the Commission granted the extension request. Comments are now due June 26, 2020 and reply

II. COMMENTS

This Commission is at a crossroads. Decisions made now will determine the path forward for DC's gas utility, and whether DC will be able to meet its climate commitments of a 50% GHG emissions reduction by 2032 and carbon neutrality by 2050. AltaGas was given the opportunity to shape this discussion through its Climate Business Plan, but failed to provide the Commission with a starting point for a path forward. The AltaGas Climate Business Plan does not represent even a useful first step in the Commission's determination process.

1. The AltaGas/WGL Climate Business Plan Does Not Comply with Merger Commitment No. 79.

A. The Climate Business Plan Continues WGL's Reliance on Fossil Gas for Nearly 50 Percent of WGL's Gas Supply in 2050 and Does Not Achieve the Required Carbon Neutrality

The Commission should find that the AltaGas Climate Business Plan does not comply with Merger Commitment No. 79. The settlement agreement approved by the Commission stated that the combined company would "evolve its business model to support and serve the District's 2050 climate goals (e.g., providing innovative and new services and products *instead of relying only on selling natural gas*)".[17] The District's 2050 climate commitment is carbon neutrality. However, the Climate Business Plan anticipates that 42% of gas delivered by Washington Gas in 2050 would be neither RNG nor low-carbon gas[18] Since the Climate Business Plan does not purport to identify carbon-negative activities to offset the continued burning of climate-intensive fossil gas for nearly half its fuel, the Plan fails on its face to meet DC's climate commitment for 2050.[19] Sierra Club submitted a data request to AltaGas asking how a plan which relies on fossil

comments are due August 25, 2020.
[17] Settlement Agreement ¶ 79 (emphasis added).
[18] Climate Business Plan at 18.
[19] Hausman Report at 24, 27 ("Even taken at face value, the "plan" would not eliminate gas-

gas for 42% of the gas delivered is consistent with carbon neutrality. However, AltaGas objected to the discovery questions and the Commission ruled that AltaGas did not have to respond to the questions.[20]

B. The Climate Business Plan Fails to Evolve WGL's Business Model Away From Selling Gas.

Moreover, the Climate Business Plan calls for using what AltaGas refers to as "renewable gas," also called "biomethane," which does not constitute a non-gas innovative service. Similarly, the Climate Business Plan also recommends use of combined heat and power and gas heatpump and hybrid heating/heat pumps.[21] The Climate Business Plan relies on these gas and hybrid heat pumps for 19% of the assumed emissions reductions.

Thus, contrary to the requirements of the Settlement Agreement, AltaGas did not submit a Climate Business Plan that relies on innovative and new services and products. The Company's Plan to an overwhelming extent largely rests on WGL continuing to provide gas services. The Commission should find that the AltaGas Climate Business Plan does not comply with Merger Commitment No. 79.

2. The AltaGas Renewable Gas Study Does Not Comply with Merger Commitment No. 6

Similarly, the AltaGas Renewable Gas Study does not comply with Merger Commitment No. 6. That Commitment required that the study assess "the potential

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related emissions by 2050 as the company claims, because it would continue to rely on combustion of fossil gas for 42% of its fuel supply.")

[20] Order No. 20342 at 5.

[21] AltaGas relies on "hybrid heating" for achieving 19% of its emissions reductions by 2050, which appears to include both gas-fired heat pumps and electric heat pumps with gas backup. The summary chart on page 10 of the CBP includes only "hybrid heating", but the text discussion on pages 13 and 14 describes these technologies separately.

environmental benefits of repurposing *locally sourced waste streams* into pipeline quality renewable gas, compressed natural gas and/or liquefied natural gas that can be used for carbon neutral vehicle fueling and onsite energy production.[22] The AltaGas Study presents opaque assumptions regarding the availability of locally sourced waste streams. In the absence of discovery, the Commission cannot analyze WGLs generalized estimate of biogas availability. Moreover, these overly generalized estimates do not comply with Commitment No. 6's very specific directive requiring AltaGas to access local waste streams. As a result, the Commission should also find that AltaGas failed to comply with Merger Commitment No. 6.

3. As Dr.Hausman Details in His Analysis, the Climate Business Plan Relies on Unrealistic and Unsupported Assumptions

In his technical review, Dr. Hausman sets out in detail the myriad flaws contained in both the Climate Business Plan and the Renewable Gas Study, including unsupported assumptions, unaddressed uncertainties and contradictory statements. Some of these flaws include:

- assuming that AltaGas would have priority access to the lowest-cost renewable natural gas resource when basic principles of economics belie this assumption;
- failure to provide the actual cost assumptions underlying the analyses, including the assumptions for the actual sources of RNG used in developing the Climate Business Plan;
- failing to identify the sources of the costs projections in either the RNG report or the Climate Business Plan, or provide crucial details such as whether the costs include transportation or other processing costs;
- claimed future cost savings which are predicated on one (unrealistic) alternative rather

[22] Settlement Agreement ¶ 6 (emphasis added).

than a realistic range of potential alternatives;

- offering no support for the claim that its preferred approach would cost the District $2.7 billion less (through 2050) than the electrification alternative it evaluated, when other credible sources have found that electrification is both a lower cost and lower risk alternative to continued reliance on the existing gas distribution model;[23]
- reliance on biased industry sources for vital data assumptions instead of using readily available information from credible technical sources;
- the failure to disclose the actual composition or cost of its assumed RNG contribution;
- the claim, without attribution or evidence, that "RNG is carbon neutral"; and
- reliance on the currently non-existent certified natural gas.

These flaws severely undermine the credibility of the analysis and the conclusions that AltaGas attempts to draw from it.

4. The Flaws in the Climate Business Plan Analysis Identified Dr. Hausman Are Reinforced by Other Analyses, Which Have Also Reached Conclusions Contrary to the Climate Business Plan Regarding the Relative Costs of the Electrification Alternative

The Commission should be aware that there are several (more credible) analyses that reach diametrically opposed conclusions regarding the relative cost of electrification. For

[23] Hausman Report at 14 (discussing a recent study by Energy + Environmental Economics, Inc ("E3 Study"). Dr. Hausman's report also highlights the asymmetric risks involved. AltaGas faces no risk under its preferred approach—it would be guaranteed recovery of all associated costs from its ratepayers. Hausman Report at 25–26. However, there is enormous risk to Washington Gas's customers, including risks that non-fossil gas alternatives fail to materialize or are significantly more expensive than AltaGas claims. Hausman Report at 14–15 (discussing the E3 Study). A belated recognition of the need to shift to electrification risks creating massive stranded assets in the form of ongoing upgrades to the gas distribution system. *Id.*

example, in April 2020, Energy + Environmental Economics ("E3") prepared an extensive modeling study on behalf of the California Energy Commission examining several options to achieve California's decarbonization goals. The E3 study evaluated scenarios that achieve an 80 percent reduction in California's GHG emissions by 2050 from 1990 levels.[24]

The E3 study concluded that in all the long-term GHG reduction scenarios it evaluated, electrification of buildings, and particularly the use of electric heat pumps for space and water heating, leads to lower energy bills for customers in the long run. Similarly, building electrification was found to lower the total societal cost of meeting California's long term climate goals.[25] Finally, the E3 study recommends avoiding gas system expansion. Gas system investments come with long lifetimes. Making such investments in the context of declining throughput—an outcome that occurs in all of E3's mitigation scenarios—will increase the average cost of gas service.[26]

In addition to the report from Energy and Environmental Economics, Inc., the Rocky Mountain Institute (RMI) has recently demonstrated the positive economics of home electrification.[27] The RMI report determined that air source heat pumps are better options economically and for the climate in multiple regions in the country. The closest geographic area to the District analyzed in the RMI Report was Providence, Rhode Island. In Providence it is already less expensive to build new homes with air source heat pumps rather than build with gas, oil, or propane heating systems. Home heat pump retrofits are also already lower cost

[24] Dan Aas et al., *The Challenge of Retail Gas in California's Low Carbon Future*, E3, (Apr. 2020) https://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/CEC-500-2019-055-F.pdf
[25] *Id.* at 4.
[26] *Id* at 58.
[27] Sherri Billimoria et al., *The Economics of Electrifying Buildings*, RMI, (2018) https://rmi.org/insight/the-economics-of-electrifying-buildings/ ("RMI Report").

investments than oil or propane system retrofits.[28]

The unsubstantiated claim that electrification is more expensive than the elusive strategy outlined in the Climate Business Plan is also inconsistent with the findings of the Integrated Energy Plan of New Jersey. Their IEP shows that least cost attainment of their climate goal of an 80 percent reduction in greenhouse gases by 2050 involves aggressive electrification of buildings. Demand for pipeline gas falls significantly as 90% of buildings are transitioned from gas appliances to electric by 2050 under the least cost option.[29] The IEP studied a variant of the plan where gas use was retained in buildings and found that variation to be a poor foundation for further reductions beyond 80 percent. It also determined that retaining gas in buildings would require further biofuel use, and potentially synthetic fuels production which it found to be more expensive than electrification alternatives.[30] The IEP concluded that retaining gas use in buildings would increase costs sharply.

The unsubstantiated assumptions and lack of analysis detailed in Dr. Hausman's report

[28] *Id.* at 34. While gas to heat pump retrofits were shown to be marginally more expensive in Providence, this has little bearing on whether they would be a cost-effective long term solution in the District. First, the Providence data overstates the cost of electric heat pump retrofits, as Rhode Island has the second highest electric utility rates in the country, whereas the District ranks 19th. Indeed, the electric utility costs in Rhode Island are nearly double than the District's. Further, the RMI Report acknowledges the cold-weather climate in Providence impacts the efficiency of some heat pumps. The high electricity costs and cold weather climate are major factors in the retrofit economics for Providence. The lower electric utility costs and the warmer weather climate in the District likely result in a much greater cost-effective scenario for District homes switching from gas heating systems to heat pumps. Second, the Providence analysis understates the cost of the continued use of gas for home heating, since it assumes the continued use of fracked gas, which is incompatible with the District's climate commitments. In order to achieve the District's climate goals, any gas burned in the future will need to be carbon neutral. Even if truly carbon-neutral gas exists, which is a highly questionable assumption, this form of gas would be far more expensive than the fossil gas used in the Providence comparison.
[29] Evolved Energy Research, *Technical Appendix to New Jersey's 2019 IEP*, at 12 (Nov. 29, 2019) https://nj.gov/emp/pdf/New_Jersey_2019_IEP_Technical_Appendix.pdf.
[30] *Id.* at 18.

are compounded by AltaGas's refusal to participate in any discovery process. As noted previously, AltaGas is refusing to respond to data requests propounded by parties to the merger proceeding.

The myriad flaws, unsupported assumptions and missing analysis in both the Climate Business Plan and the Renewable Gas Study renders both these filings useless for Commission purposes.

III. REQUEST TO INSTITUTE AN EVIDENTIARY PROCEEDING

Clearly, formal evidentiary hearings are necessary regardless of whether or not the Commission finds that the Climate Business Plan and the Renewable Gas Study comply with the Settlement Agreement. The only information before the Commission is AltaGas's untested assertions and flawed analysis which, on its face, fails to actually achieve the District's climate commitments. Moreover, AltaGas has refused to answer any discovery requests and the Commission has found that AltaGas has no obligation to respond to these requests. Without the scrutiny of an evidentiary proceeding, it will be impossible for the Commission to fulfill its policy and legal mandates to ensure the achievement of DC's climate commitments in a manner that safeguards the public interest.

Moreover, as illustrated by the Second Joint Motion, AltaGas has refused to be open and transparent about the assumptions, calculations and methodologies underlying certain statements and numbers contained within the Climate Business Plan.[31] AltaGas is refusing to respond to data requests propounded by parties to the merger proceeding, only agreeing to an informal process which prevents any party or stakeholder other than the District Government

[31] Second Joint Motion at 2.

from seeing the AltaGas responses.[32] Discovery is an essential tool for the Commission, the parties, and the impacted public to analyze the AltaGas data and test the efficacy of its assumptions. The intransigence of AltaGas in refusing to allow any meaningful analysis of either the Climate Business Plan or the Renewable Gas Study renders those filings useless. Neither filing can be relied upon by the Commission to determine the steps necessary to achieve DC's climate commitments.

The AltaGas response to Merger Commitment Nos. 79 and 6 is fatally deficient. However, the Commission must move forward and determine the manner in which the gas utility shall operate in the future. Accordingly, Sierra Club requests that the Commission reject the AltaGas filings and establish a formal evidentiary proceeding where the stakeholders can present and analyze proposals to evolve WGL's business model to achieve carbon neutrality by 2050 instead of relying on selling gas, and to ensure that by 2050 no greenhouse gases are emitted by the gas utility.

For example, WGL is fundamentally a company that enables households to heat their homes and heat their water. WGL can continue to serve this fundamental purpose without selling gas and contributing to the climate crisis.

To achieve this gas-free commitment, WGL could deploy two proven zero-carbon technologies for heating services:

1. Air- or ground-source heat pumps that heat and cool homes.

[32] *Id.* at 2-3.

2. Where cost-effective, clean energy micro-district heating systems that require a network of pipes in the ground that carry hot water in the winter and cold water in the summer from central units which generate the hot or cold water through geothermal energy, industrial-scale heat pumps, and sewage waste heat extraction.

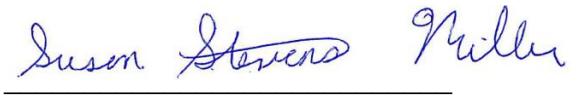
These are just two examples of the issues stakeholders would explore in an evidentiary proceeding. This proceeding is necessary to ensure that the Commission fulfills its mandate to consider "the preservation of environmental quality, including effects on global climate change and the District's public climate commitments." DC's climate commitments require that the District move away from the burning of fossil fuels, including gas. The Commission should institute an evidentiary proceedings to resolve the issues necessary to achieve this transition in a timely manner.

IV. CONCLUSION

It is impossible to reconcile the AltaGas Climate Business Plan with DC's climate commitments to reduce greenhouse gas (GHG) emissions at least 50% below 2006 levels by 2032 and achieve carbon neutrality by 2050. The continued use of gas to supply energy to District residents is contrary to these public climate commitments and also is contrary to the District's clear intention that D.C. transition away from fossil fuels, including gas.

The Commission should reject both the Climate Business Plan and the Renewable Gas Study. The Commission also should institute an evidentiary proceeding to explore methods of evolving WGL's business plan to complete the transition of the District's energy system toward clean energy and to ensure that DC meets its climate commitment of carbon neutrality by 2050.

Respectfully submitted,



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CERTIFICATE OF SERVICE

I hereby certify that on this 15th day of June 2020, a copy of the foregoing was served on the following parties by electronically mail:

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EXHIBIT A

Review of AltaGas' Climate Business Plan and Renewable Natural Gas Study

Prepared by

Ezra D. Hausman, Ph.D.

On Behalf of

The Sierra Club

May 14, 2020

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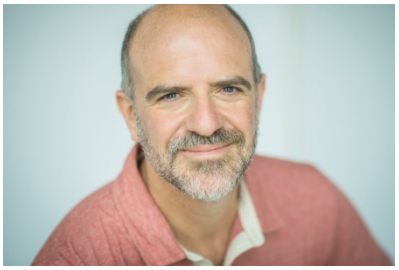

Ezra D. Hausman, Ph.D. is an independent consultant in energy and environmental economics.

Ezra has worked for over two decades as an energy market expert with a focus on market design and market restructuring, environmental regulation in electricity markets, and pricing of energy, capacity, transmission, losses and other electricity-related services. Ezra has performed market analyses, provided expert testimony, led workshops and working groups, and provided other support in both regulated and restructured electricity markets for clients including federal and state agencies, consumer advocates, legislative bodies, cities and towns, non-governmental organizations, foundations, industry associations, and resource developers.

Ezra holds a Ph.D. in atmospheric science from Harvard University, an S.M. in applied physics from Harvard University, an M.S. in water resource engineering from Tufts University, and a B.A. in psychology from Wesleyan University.

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I. Executive Summary

On March 16, 2020, AltaGas Ltd. filed a Climate Business Plan (CBP) for Washington, DC along with a Renewable Gas Study (RGS), both in response to terms of AltaGas' settlement agreement for its merger with WGL Holdings, d/b/a Washington Gas. The CBP represents the company's "long-term business plan on how it can evolve its business model to support and serve the District's 2050 climate goals (e.g. providing innovative and new services and products instead of relying only on selling natural gas)."[1] In the CBP, the Company proposes to reduce its greenhouse gas (GHG) footprint and contribute to meeting DC's climate commitments through a combination of strategies, including end-use efficiencies, loss prevention, and relying on non-fossil sources of gas. AltaGas claims that its "Fuel Neutral Decarbonization" approach is $2.7 billion less expensive than the alternative it evaluated, which it calls "Policy-Driven Electrification," when evaluated over the next 30 years.

The plan filed in March included an "ICF Technical Study Summary" as Appendix E. Approximately one month later, Washington Gas published the full, 140-page Technical Report prepared by ICF on its website.[2]

Sierra Club commissioned the current study as an independent technical review of AltaGas' filings and Technical Report, including a review of the methodologies, assumptions, and projections upon which its conclusions are based. This review also evaluates the extent to which AltaGas' filings meet the requirements of the settlement agreement and comport with the District's climate commitments.

The validity of any study is dependent on the validity and credibility of its input data, assumptions, and the methods underlying its results. The AltaGas studies encompass a wide range of assumptions about future resource cost and availability that are fundamental to their findings; the conclusions are also predicated on the specific alternatives considered. With respect to AltaGas' filings, I find that to the limited extent that the CBP and the RGS reveal their assumptions at all, they are plagued with unrealistic projections of both resource availability and cost. Both studies routinely brush aside uncertainties in key assumptions of a magnitude that, if reasonably considered, would likely overwhelm the studies' findings. The CBP report relies upon misleading nomenclature, along with false comparison to a poorly

[1] DC Public Service Commission Order No. 19396, Appendix A, ¶79.
[2] https://washingtongasdcclimatebusinessplan.com/wp-content/uploads/2020/04/Technical-Study-Report-Opportunities-for-Evolving-the-Natural-Gas-Distribution-Business-to-Support-DCs-Climate-Goals-April-2.pdf.

defined alternative to support its conclusions. Even taken at face value, it does not appear that AltaGas' plan meets the District's climate commitment because it continues to partly rely on fossil gas. Finally, many key assumptions on which the authors rely in both studies are either unreferenced, or are referenced to unreliable and biased sources such as the American Gas Association, a gas industry lobbying group. Often, the reports rely heavily on assertions that are not supported by any reference at all. All of these shortcomings cast serious doubt on the validity of the reports' findings, at best making them impossible for the reader (or the Commission) to credibly assess.

One particularly unrealistic set of assumptions permeating the reports concerns the world outside of the Washington Gas system. The authors assume that while Washington customers are paying billions of dollars over the study period to decarbonize their economy, *no other region is taking any action at all* beyond current renewable portfolio standard (RPS) rules.[3] AltaGas also ignores other, likely more economically plausible uses for the resources the company claims it will exploit as part of its future supply – including extremely high-value uses such as supporting electric system reliability and low-carbon aviation fuel. Consultant ICF finds, paradoxically, that there is almost no impact on the regional electricity market, even if Washington customers implement a complete transition to electrification, because no other state in the region is taking any action at all. In fact, there is no recognition of the impact that a nationwide switch to low- or zero- GHG sources of energy would have on crucial assumptions in the study, including availability of fuels such as "renewable" natural gas (RNG) and hydrogen fuels, or on the operation of the electric grid.

Of course, it is difficult to model unknown future policy initiatives, especially when greenhouse gas policy has largely devolved to the individual states due to a lack of action on the federal level. There are various solutions to this challenge that have been applied in numerous studies.[4] What is not reasonable is to select and model a single, vaguely-defined scenario that fails to comport with economic or policy reality, as AltaGas and its consultant have done. In so doing, the company has denied the Commission and other stakeholders a meaningful assessment of low-GHG energy options under likely and realistic future conditions.

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[3] Page TS-2: "ICF has assumed that other states in the region meet current RPS and other policy requirements, but do not implement more aggressive RPS, climate change or electrification policies." This ignores, for example, the recent Virginia Clean Economy Act mandating that Virginia reach 100% clean energy resources by 2045. See https://www.washingtonpost.com/local/virginia-politics/virginia-dominion-energy-bill/2020/03/06/4524cd20-5fc1-11ea-b29b-9db42f7803a7_story.html.

[4] For a recent (November 2019) example, see "Getting to Zero: A US Climate Agenda" by the Center for Climate and Energy Solutions, available at https://www.c2es.org/content/getting-to-zero-a-u-s-climate-agenda/.

I find that AltaGas' cost assessments for its policy options cannot be taken at face value, because they are based on wild and largely unsupported guesses about future resource availability and costs with no attempt to analyze the impact of uncertainty. Despite the fact that AltaGas' consultant ICF has provided both a 150-page RNG study and a 140-page "Technical Report," nowhere has it provided the actual cost assumptions underlying its analyses, including specification of the nature and sources of RNG assumed in developing and analyzing the Climate Business Plan. In the not unlikely event that the speculative resources envisioned by AltaGas turn out to be significantly more expensive than assumed in the CBP, the company's preferred scenario could turn out to be much more costly than a focus on electrification.

The CBP is most specific on the policy changes AltaGas would require before it would pursue GHG mitigation strategies. These policy changes generally entail transferring the risk of the speculative and costly resources outlined in AltaGas' plan away from the company, ensuring that Washington ratepayers would cover all costs, while compensating AltaGas for any lost sales and rewarding the company with an elevated return on equity (ROE) for meeting its obligations. This approach places an unfair burden on the District's ratepayers, and especially on its lower-income ratepayers, while ensuring that its stockholders will earn a generous return whether the company's analyses and forecasts were right or wrong, and however imprudent its actions.

Overall, I conclude that AltaGas has failed in its commitment to credibly "file with the Commission a long-term business plan on how it can evolve its business model to support and serve the District of Columbia's 2050 climate goals."[5]

[5] Order No. 19396, Appendix A, ¶79.

II. Background

Washington DC Climate Commitments

In 2013 the District of Columbia created *Sustainable DC*,[6] the District's sustainability plan, including the goal of reducing greenhouse gas (GHG) emissions by 50% from 2006 levels by 2032. In December 2017, in recognition of the pressing need to keep global average temperature rise below 1.5°C, Mayor Muriel Bowser announced an even stronger commitment: reaching "carbon neutrality" for the District by 2050.[7]

In August 2018 the District released *Clean Energy DC: the District of Columbia Climate and Energy Action Plan*,[8] described as "the District's proposal to reduce greenhouse gas (GHG) emissions at least 50% below 2006 levels by 2032 while increasing renewable energy and reducing energy consumption, as directed by the landmark *Sustainable DC* plan; and to put us on a path to achieve carbon neutrality by 2050."[9] Within this document, there is a recognition that reaching DC's climate commitments requires addressing all of the energy-using sectors of the DC economy, including transportation, electricity, and energy use in buildings. For the building sector, decarbonizing means aggressively pursuing energy efficiency, implementing strict energy building codes including adoption of "net-zero" energy building codes,[10] and "a shift away from fossil fuels, including natural gas" so that the district can ultimately "eliminate fossil fuel use."[11] As one possible action, *Clean Energy DC* proposes to "explore how biologically derived fuels such as methane captured from agricultural processes, wastewater treatment, or landfills can service" residual needs after aggressive energy efficiency and electrification.[12]

[6] https://www.sustainabledc.org/
[7] https://mayor.dc.gov/release/mayor-bowser-commits-make-washington-dc-carbon-neutral-and-climate-resilient-2050
[8] Available at https://doee.dc.gov/cleanenergydc.
[9] *Clean Energy DC*, page v.
[10] "Net-zero" buildings achieve energy-neutrality through very high levels of efficiency and on-site renewable generation, so that they produce as much energy as they consume over the course of a year.
[11] *Clean Energy DC*, page 156.
[12] *Ibid*., page 157.

Natural Gas and the AltaGas/WGL Settlement

Combustion of natural gas contributed 22.8% of GHG emissions associated with building energy use in DC in 2017, and 17.7% of DC's greenhouse gas emissions overall,[13] making it the third-largest source of emissions after electricity and transportation. Because GHG emissions in the District have already dropped by 30% from 2006 levels, meeting the District's 2032 climate commitment will require reducing today's emissions by 28%.[14] Thus, while it is conceivable to meet the District's near-term climate commitment while continuing to emit some GHGs from the combustion of natural gas, this will be far more difficult, if not impossible, as the District strives to meet its 2050 commitment of carbon neutrality. It is in this context that AltaGas agreed, as part of its commitment under the settlement agreement for its merger with WGL Holdings (d/b/a Washington Gas), to create a business plan for how it could "evolve its business model to support and serve the District of Columbia's 2050 climate goals."[15]

Further, perhaps because the settling parties anticipated that AltaGas' Climate Business Plan might rely on replacement of fossil natural gas with one or more gas resources with a lower GHG impact, the company agreed to commission a study of the availability and cost of such resources to serve the DC market:

> *AltaGas will provide $450,000 to fund a study to assess the development of renewable (bio) gas facilities in the Greater Washington, D.C. metropolitan area. The study will assess the potential environmental benefits of repurposing locally sourced waste streams into pipeline quality renewable gas, compressed natural gas and/or liquefied natural gas that can be used for carbon neutral vehicle fueling and onsite energy production. The study will evaluate the economic viability, identify operating challenges and solutions, and offer recommendations relating to regulatory and market approaches that can facilitate the utilization of renewable sources to support the achievement of local, state, and regional climate and energy plans.* (Settlement agreement, ¶6.)

To address this requirement, AltaGas' commissioned a "Renewable Natural Gas" study from the consulting firm ICF that was released as an appendix to the company's Climate Business Plan.

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[13] Based on 2006-2017 DC Greenhouse Gas Inventory, available at https://doee.dc.gov/service/greenhouse-gas-inventories. 2017 is the last year for which data are available as of this writing.
[14] Ibid. Citywide GHG emissions calculated for DC dropped from 10,496,684 $MTCO_2e$ in 2006 to 7,328,971 $MTCO_2e$ in 2017. To reach the 2032 commitment of a 50% reduction from 2006 levels requires a reduction to 5,243,342 $MTCO_2e$, or a reduction of 28% from 2017 levels.
[15] Settlement, ¶79.

III. Summary of AltaGas Studies

On March 16, 2020, AltaGas Ltd. filed its Climate Business Plan for Washington, DC along with its Renewable Gas Study, in compliance with the terms of its settlement agreement for its merger with WGL. The CBP claims that AltaGas could reduce its GHG footprint and contribute to meeting DC's climate commitments through a combination of strategies, including end-use efficiencies, loss prevention, and use of renewable sources of gas. AltaGas also claims that its "Fuel Neutral Decarbonization" approach would cost the district $2.7 billion less than the alternative approach it evaluated, which it calls "Policy-Driven Electrification," when evaluated over the next 30 years. The company offers no analytical support for this cost-savings claim, at least in its publicly-available reports.

AltaGas' nomenclature in the report – calling its preferred scenario "fuel neutral" and the electrification scenario "policy-driven" – is misleading, and will not be adopted here.[16] Both approaches to decarbonization considered by the company's consultant, ICF, would be fundamentally driven by policy choices, and the company's preferred approach is in no meaningful sense fuel-neutral. In fact, *any* strategy to reduce greenhouse gases below the Business-as-Usual (BAU) baseline is policy-driven by definition, because in the absence of policy the costs of GHG emissions are socialized and external to the economic calculus of the user. In the CBP, even the BAU scenario is policy-driven, in part, because it includes compliance with the District's 100% Renewable Portfolio Standard (RPS).

Nor is it feasible to design an optimal "fuel-neutral" approach to reaching the District's long-term GHG emissions commitments. As acknowledged in the CBP and the Technical Report, we simply cannot know today what the least-cost approach will be to achieving high levels of emissions reductions. Policymakers and experts have to make educated guesses regarding the costs and capabilities of future technology solutions, along with the availability and cost of renewable biofuels, carbon capture and sequestration, biological offsets, and other unknown approaches. There is a fundamental interdependence between policy, technology development and deployment, and cost. For these

[16] The term "policy-driven electrification" appears to have originated with the pro-gas lobbying group the American Gas Association. For example. A July 2018 gas association study, also prepared by consultant ICF, is entitled "Implications of Policy-Driven Residential Electrification" (https://www.aga.org/research/reports/implications-of-policy-driven-residential-electrification/.) As noted in the text, this term is misleading because *any* strategy to internalize the costs of GHG emissions and address climate change will be driven by policy. A critique of the AGA approach to electrification by the environmental policy group NRDC may be found at https://www.nrdc.org/experts/amanda-levin/why-agas-report-gets-electrification-wrong.

reasons, AltaGas's pretense of comparing a "policy-driven" scenario with a "fuel-neutral" scenario should be disregarded.

ICF asserts that its analysis for AltaGas identifies and evaluates an approach to meeting the District's energy needs that comports with the District's climate commitments while still relying on gaseous fuels delivered through Washington Gas' existing distribution infrastructure.[17] In its report, AltaGas puts forth such a plan for consideration,[18] and purports to compare it to its alternative, more conventional plan for achieving the District's commitments that involves extensive electrification of end-uses such as residential heating, hot water, and cooking, so that such energy demands could be served with renewable energy.[19] ICF also considers two approaches that do not meet the District's commitments: Business-as-Usual (as noted, including the 100% RPS) and "Partial Decarbonization." All cost results are reported relative to the cost to the BAU scenario but, as noted above, are not supported by any analytical details or calculations; nor has AltaGas provided any uncertainty or sensitivity analysis, despite the inevitable reliance on future unknowns.

AltaGas' Preferred Approach

AltaGas' proposed GHG mitigation pathway is summarized in Figure 1 and Figure 2, below. In Table 2, the plan components from Figure 1 are re-cast to show AltaGas' projected contribution of each to achieving the GHG reductions called for by the District's 2032 and 2050 climate commitments.

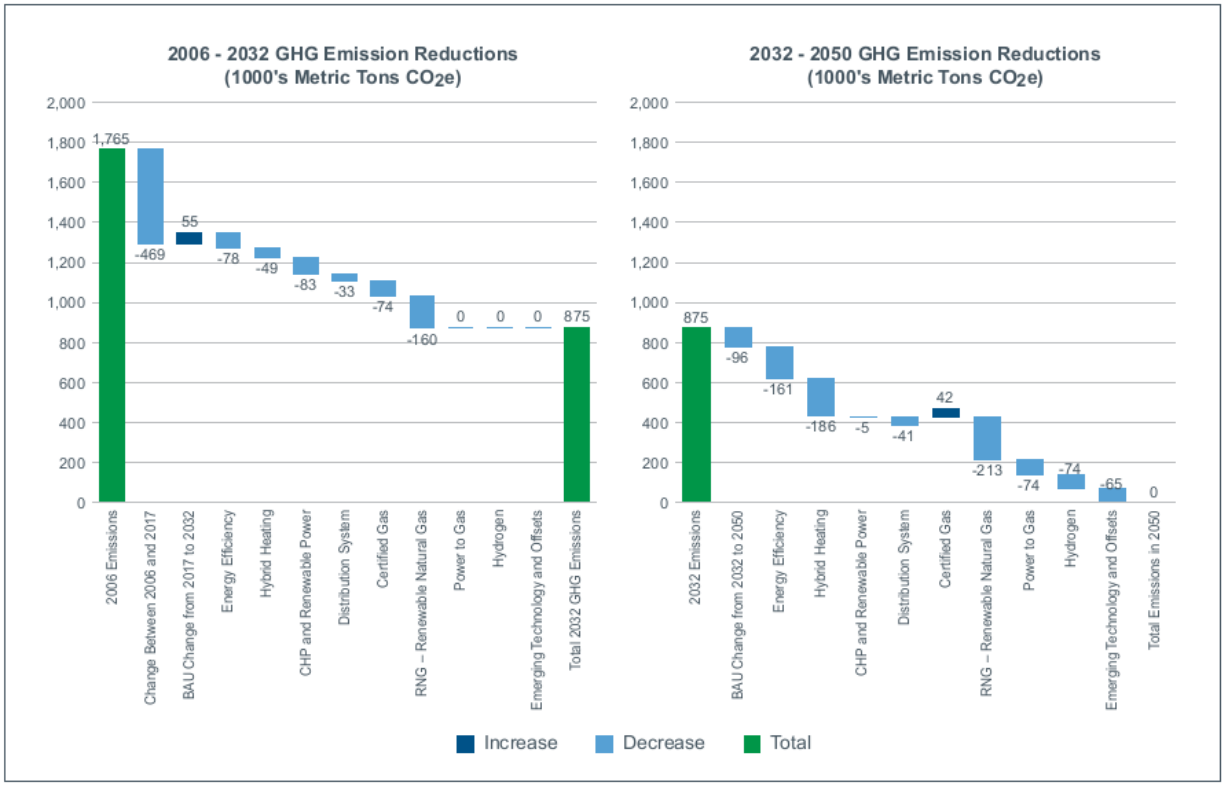
Most of the strategies relied upon by AltaGas in its preferred plan are untested and speculative, as will be discussed in detail below. As a result, neither the availability nor the cost of these strategies can be projected with any reasonable degree of confidence. Under these circumstances, the appropriate response would be for researchers to estimate, and explain, the range of possible costs, and to explore the implications of that range of inherent uncertainty on the robustness of the report's conclusions. AltaGas does not provide such an analysis.

It also does not appear that even AltaGas believes its strategies will meet its GHG reduction targets. The company projects that 58% of the gas it sells in the District will come from low-carbon sources by

[17] CBP, pages 2-3. It should be noted that even taken at face value, AltaGas' plan does not actually meet the District's 2050 commitments, and ultimately relies on "emerging technology and offsets" to close the gap.
[18] As discussed below, AltaGas' plan does not appear to actually meet the District's climate commitment because it continues to rely in part on fossil gas.
[19] The alternative plan, involving extensive electrification of end-uses, could be broadly consistent with the *Clean Energy DC* Plan.

2050,[20] meaning that 42% will still come from fossil sources. The report is silent on the apparent contradiction between continuing to deliver fossil gas and the claim of eliminating 100% of GHG emissions. Inconsistencies aside, AltaGas' preferred approach is as shown in the figures and table below.

Figure 1. GHG mitigation plan as presented on page 10 of the AltaGas Climate Business Plan.



[20] CBP, page 18.

Figure 2. Relative contribution of each component to DC 2032 and 2050 climate commitments, per AltaGas' Climate Business Plan.

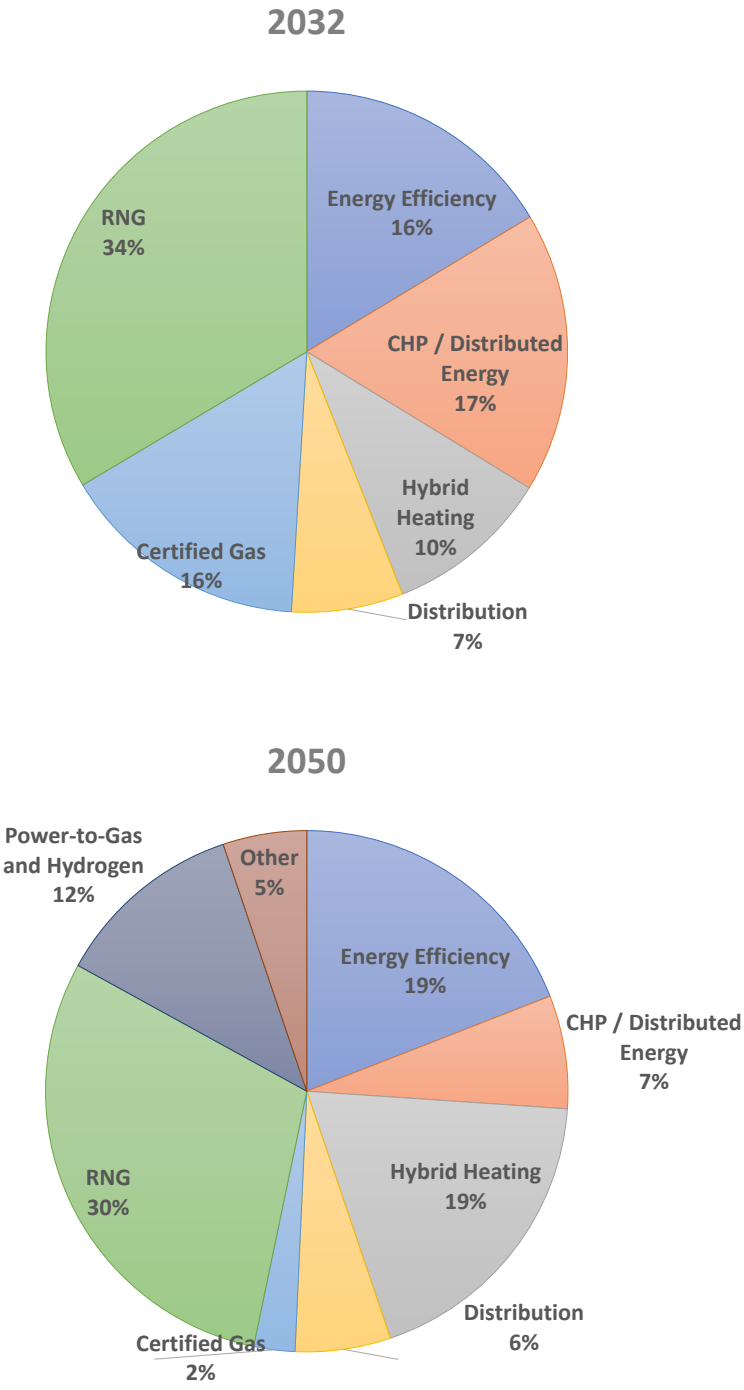


Table 1. Projected GHG Emissions reductions from AltaqGas' Climate Business Plan, and proposed emissions reductions relative to 2017 levels as reported in the DC GHG inventory.

		2032			2050		
		$MTCO_2e$ (000)	% of Target Change	% of 2017 Emissions	$MTCO_2e$ (000)	% of Target Change	% of 2017 Emissions
	2017 Emissions [1]	1,296			1,296		
	BAU Change from 2017 [2]	55			(41)		
	BAU Emissions [3]	1,351			1,255		
	Emissions Goal [4]	883			-		
	Total target change	***(469)***			***(1,255)***		
Plan Components	**Energy Efficiency**						
	EE	-78	16.6%	6.0%	-239	19.0%	18.4%
	Hybrid Heating	-49	10.5%	3.8%	-235	18.7%	18.1%
	CHP and Renewable Power	-83	17.7%	6.4%	-88	7.0%	6.8%
	EE Total	**-210**	**44.8%**	**16.2%**	**-562**	**44.8%**	**43.4%**
	Distribution System	**-33**	**7.0%**	**2.5%**	**-74**	**5.9%**	**5.7%**
	Gas Alternatives						
	Certified gas	-74	15.8%	5.7%	-32	2.5%	2.5%
	RNG	-160	34.2%	12.3%	-373	29.7%	28.8%
	Power to Gas	0	0.0%	0.0%	-74	5.9%	5.7%
	Hydrogen	0	0.0%	0.0%	-74	5.9%	5.7%
	Gas Alternatives Total	**-234**	**49.9%**	**18.1%**	**-553**	**44.1%**	**42.7%**
	Emerging and Offsets	**0**	**0.0%**	**0.0%**	**-65**	**5.2%**	**5.0%**
	Projected Emissions Reduction	***(477)***	***101.8%***	***36.8%***	***(1,254)***	***99.9%***	***96.8%***
	Projected Target Year Emissions	***874***			***1***		

Notes:

[1] From DC GHG emissions inventory

[2] "BAU change" projected in Climate Business Plan through 2032 and 2050, relative to 2017

[3] 2017 emissions + BAU Change

[4] for 2032, 50% of 2006 emissions; for 2050 net zero emissions.

Electrification Alternative

AltaGas claims to have compared the costs of its preferred approach to the alternative of widespread electrification of end uses, which, given the DC 100% renewable portfolio standard, would allow building energy demand to be served without reliance on fossil fuels. While providing no details on how its costs

were derived, AltaGas claims that this approach would cost $2.7 billion more over 30 years than its preferred, gas-oriented approach to eliminating GHG emissions.[21]

This result is contrary to the wide range of independent, credible studies of deep decarbonization scenarios have found that electrification of end-uses is essential to meeting ambitious emissions reduction goals. For example, a recent study by Energy and Environmental Economics, Inc. (E3) on behalf of the California Energy Commission evaluated numerous scenarios to achieve an 80% reduction in California's GHG emissions by 2050. According to the E3 study:

> *These scenarios suggest that building electrification is likely to be a lower-cost, lower-risk long-term strategy compared to renewable natural gas (RNG, defined as biomethane, hydrogen and synthetic natural gas [SNG], methane produced by combining hydrogen and carbon). Furthermore, electrification across all sectors, including in buildings, leads to significant improvements in outdoor air quality and public health.*[22]

The study also finds excessive cost associated with any plan that relies on RNG:

> *Another key finding of this study is that relatively inexpensive RNG (for example, biomethane from landfills and wastes) is limited and cannot alone reduce the GHG intensity of pipeline gas enough to achieve 80 percent reduction. Once the biomethane portion of the RNG supply curve is exhausted, then the state must turn to more expensive hydrogen and yet more expensive SNG. The result is that by 2050, the commodity cost of blended pipeline gas is more than four to seven times that of natural gas today.*[23]

The AltaGas study does not address this issue. Instead it offers only statements about the comparative cost of residential gas versus electric use for heating, cooking and clothes drying *today*[24] – while the more applicable comparison would be a comparison to the much higher, and much less certain, cost of the speculative gas resources relied upon in AltaGas' plan.

One further significant advantage to an electrification strategy over relying on unknown future RNG resources is the asymmetry of risk. As described in the E3 study:

> *The main barriers to building electrification are upfront capital cost and consumer acceptance. However, once these costs are paid and consumers gain familiarity with electric appliances, even if inexpensive sources of RNG become available later, the*

[21] CBP, page 2. Also section 4.3 of the Technical Report.
[22] Aas, D. *et al*., *The Challenge of Retail Gas in California's Low-Carbon Future: Technology Options, Customer Costs and Public Health Benefits of Reducing Natural Gas Use.* California Energy Commission. Publication Number: CEC-500-2019-055-F, page iii. Available at: https://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/index.html.
[23] *Ibid*, page 69.
[24] For example, on page 4 of the CBP, citing the "Playbook" of the American Gas Association.

> *state's climate goals will still be met, and residents will be able to heat their homes relatively affordably. In contrast, should building electrification be delayed in the hope that RNG technology will progress more rapidly than considered in the optimistic P2G [power-to-gas] cost scenario here, and these RNG cost reductions do not materialize, then it will be difficult to recover from delays in building electrification and it may prove difficult to reduce emissions at reasonable cost. Further, customers who do not electrify face the risks associated with high cost of gas, while customers who electrify, do not face the same level of rate impact risk.*[25]

Once again, the risks associated with these plausible scenarios are not addressed in the CBP or its supporting Technical Report, leaving the reader with an incomplete and misleading picture of the costs and risks associated with AltaGas' plan. If the company is asking the Commission to endorse a plan so thoroughly at odds with the body of scholarship and technical studies in this area, it bears a high burden of proof that its projections are realistic and that it has fully explored the risks. That burden has not been met.

IV. Components of AltaGas' Climate Business Plan

AltaGas claims that it has developed a plan to meet the District's climate commitments at an incremental cost of $3.8 billion between 2020 and 2050, in 2018 dollars.[26] But what, exactly, is the plan, and how are these costs derived? Despite providing a 236-page report, including appendices, followed by posting a 140 page "Technical Report" on its website, the details are scarce. AltaGas provides the general breakdown of components shown in Table 1, but many of these components are described only in general terms. AltaGas' consultant appears to have taken into account neither the great uncertainty in resource availability and cost, nor the competition for these resources from other uses. In fact, most viable bioenergy sources are already being used in a manner that is far more economic than the uses AltaGas envisions; other solutions, such as "green hydrogen," would have far more valuable applications in a low-carbon economy than displacing fossil methane in the gas distribution system. This is why the vast majority of deep-decarbonization studies, including the E3 study discussed above and the *Clean Energy DC* report,[27] conclude that electrification of end uses is the least-cost and most feasible approach to deep decarbonization.

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[25] E3 Study, page 70.
[26] Appendix E, ICF Technical Study Summary, page 18. AltaGas claims that its Case 2, the "Partial Decarbonization" case, would cost $0.6 billion over BAU, and that its preferred Case 4 would cost $3.2 billion more than Case 2.
[27] https://doee.dc.gov/cleanenergydc.

AltaGas' alternative approach, which it claims is less costly, includes the components was shown in Figure 1 and Table 2. A narrative description of the components is provided on pages 11 through 20 of the CBP.[28] These components are each explored and evaluated below.

a. Change since 2006

GHG emissions in DC from transportation and use of natural gas have decreased by approximately 469,000 $MTCO_2e$ between 2006 and 2017, according to the DC GHG inventory,[29] consistent with the claim in the CBP. The GHG inventory shows that the overwhelming sources of this decrease are a 60% decrease in nonresidential gas use in the District, along with a 30% decrease in fugitive emissions from the distribution system.[30]

b. Reduced Gas Use through Energy Efficiency

AltaGas includes three strategies under the rubric of "energy efficiency" in its plan: (1) Equipment and building upgrades ("Energy Efficiency" in Figure 2); (2) combined heat and power ("CHP and Renewable Power" in Figure 2); and (3) "Hybrid Heating', which appears to include gas heat pumps. AltaGas relies on these three strategies for almost 45% of its 2032 and 2050 emissions reductions (see Table 2.)

- ***Energy Efficiency.*** Today, energy efficiency, including equipment and building upgrades, is the lowest-cost way to reduce both energy bills and emissions, but most current gas efficiency goals are much less ambitious than the levels projected in the CBP. For example, New Jersey has recently enacted one of the most aggressive statewide energy efficiency programs in the country, which calls for reaching an annual reduction in sales of gas of 0.75% over the next five years. AltaGas' projection equates to approximately a 6% reduction in energy use by 2032 and 18% by 2050. I am unaware of any state that has long-term gas efficiency goals that approach this level of savings, and doing so would almost certainly require electrification of many end-uses. This is in part because most of today's modern gas appliances are already extremely

[28] The narrative description on pages 11 through 20 include large-font "enables us to achieve" percentages claimed for each category of strategies, with ambiguous and apparently erroneous labeling (i.e., the reference to a "2050 50% GHG reduction target.") Based on my analysis, I conclude that these numbers are intended to refer to what percent of 2006 emissions AltaGas projects could be avoided by applying each category of strategies by 2032 and 2050. The claimed emissions benefit for energy efficiency savings in 2050 includes 4% savings for "emerging and technology and offsets" which are left undefined.

[29] https://doee.dc.gov/service/greenhouse-gas-inventories.

[30] Fugitive methane emissions have historically been difficult to measure, and some research suggests that they are consistently underreported. See Alvarez, R. *et al.,* "Assessment of methane emissions form the US oil and gas supply chain." Science, Vol. 361, Issue 6398, pp. 186-188, July 13, 2018.

efficient, meaning that significant further reductions in gas use from increased appliance efficiency cannot be attained.

In ICF's Technical Report, the authors claim that "building shell improvements" will "reduce energy consumption by 2% per building," [31] and the authors predict an aggressive penetration rate of 71% of building meters by 2050. ICF also cites "behavioral programs" that can reduce residential energy use by 0.85% for each participant, although such measures cannot continue to produce incremental savings every year for the same customers, and their impact may in fact deteriorate over time.[32] AltaGas and ICF provide no further information on how these very high levels of gas savings would be achieved, nor any specific estimate of their cost.

In sum, there has been simply no evidence presented to the public to support AltaGas' aggressive gas savings projections based on the building and equipment upgrades and behavioral programs described in the Technical Report, and I conclude that they are unfounded.

- ***Combined Heat and Power.*** The CBP assumes that "penetration of CHP units in the District could grow to 12 units per year by 2026 and remain stable through 2034" before the rate of new installations begins a "gradual decline."[33] This scenario, undergirding AltaGas' projection of a 6.4% reduction in today's emissions through CHP by 2032, is extremely optimistic. Largescale adoption of CHP has generally been found to be difficult because of the necessity of having a large thermal or steam load, and because of complex market and regulatory barriers such as interconnection rules, net metering, standby rates, and other issues.[34] Further, the thermal load must be present 24 hours per day for CHP systems to achieve high efficiency.[35] According to the U.S. Department of Energy (DOE) CHP database,[36] there has been approximately one CHP installation per year in the District over the last five years, including very small (130 kW) installations at multifamily buildings. ICF's Technical Report assumes DC can achieve 5% of the "technical potential" for CHP systems of under 1 MW and 15% for CHP systems of over 1 MW

[31] The report does not specify if these savings reflect gas or electricity usage, or both.
[32] See Allcott, H. and T. Rogers, "The Short-Run and Long-Run Effects of Behavioral Interventions: Experimental Evidence from Energy Conservation," NBER Working Paper No. 18492, Revised January 2014. Available at https://www.nber.org/papers/w18492.
[33] Climate Business Plan, page 13.
[34] *See,* https://www.aceee.org/toolkit/2020/02/deploying-combined-heat-and-power-chp-projects.
[35] Oak Ridge National Laboratory, "Combined Heat and Power: Effective Energy Solutions for a Sustainable Future," December, 2008. Available at https://info.ornl.gov/sites/publications/files/Pub13655.pdf.
[36] https://doe.icfwebservices.com/chpdb/state/DC

by 2050.[37] Based on the DOE technical potential study used by ICF,[38] this would be approximately 11 new sites over 1 MW and 34 new sites under 1 MW by 2050[39] – a level that is quite aggressive, but still far *below* the "12 units per year" projected in the CBP. No explanation is provided for this apparent contradiction.

Beyond its optimistic assumption about penetration rates, AltaGas' assumption about emissions benefits from CHP appears to be overstated and unfounded.[40] AltaGas' consultant appears to be assuming that the energy used for the heat load would be unchanged, while electricity generation in the PJM region would be avoided based on the size rating of the CHP system. This is simply not the case – under favorable conditions CHP systems are more efficient than separate thermal and electric systems, but there is still a significant fuel cost for simultaneously serving both electric and steam loads. Thus both AltaGas' scenario for penetration rate of new CHP systems and its projection of emissions benefit from each system appear to be exaggerated and unrealistic.

- ***Hybrid Heating / Heat Pumps.*** AltaGas relies on "hybrid heating" for achieving 10.5% and almost 19% of its emissions reductions by 2032 and 2050, respectively. This strategy appears to include both gas-fired heat pumps and electric heat pumps with gas backup.[41] There is no indication in the CBP or the Technical Report of what mix of electric heat pumps versus hybrid heating systems is assumed in the company's analysis, what they would cost, or exactly how the emissions benefit was calculated. However, the Technical Report projects that gas heat pumps will become "readily available" between 2026 and 2039 and that they are expected to have a coefficient of performance (COP) of 1.4.[42] On the other hand, according to a 2016 review, "COP

[37] Technical report, page 22.
[38] https://www.energy.gov/sites/prod/files/2016/04/f30/CHP%20Technical%20Potential%20Study%203-31-2016%20Final.pdf
[39] The DOE report finds a "technical potential" of 681 sites under 1 MW and 75 sites with capacity of 1 MW or greater in Washington, DC. Although the DOE study uses four size categories, no information is given in the CBP or the Technical Report on what size installations were assumed beyond the greater or less than 1 MW categories.
[40] As with many elements of its analysis, the details provided are insufficient to fully explain AltaGas' and its consultant's assumptions and approach. The actual MW, cost, and emissions benefit calculation for CHP have not been provided and can only be deduced based on the scant clues provided.
[41] The summary chart on page 10 of the CBP includes only "hybrid heating," but the text discussion on pages 13 and 14 describes these technologies separately.
[42] Technical report, page 8. The US Department of Energy reports that gas-fired "absorption" heat pumps are "mainly used in industrial and commercial settings" and are "only appropriate for homes on the scale of 4,000 square feet or more." See https://www.energy.gov/energysaver/heat-pump-systems/absorption-heat-pumps.

values for market available [electric] heat pump units lie in the range of 3.2 to 4.5 for air source heat pumps (ASHP) and between 4.2 and 5.2 for ground source heat pumps (GSHP)."[43] The only argument provided for using a far less-efficient gas heat pump is that for periods that are below the efficient temperature range for heat pumps, it is less costly to use gas than electric resistance heating, assuming today's natural gas prices. However, today's heat pump technology now allows them to operate efficiently even in colder climates.[44] Further, were AltaGas to rely on more expensive sources of "renewable" gas such as proposed in the CBP, any current cost advantage over electric resistance for backup heating would likely be reversed.

I conclude that gas heat pumps are not an appropriate technology for most DC residents, and that they fall far short of the efficiency of electric heat pumps for most applications.

c. Distribution System

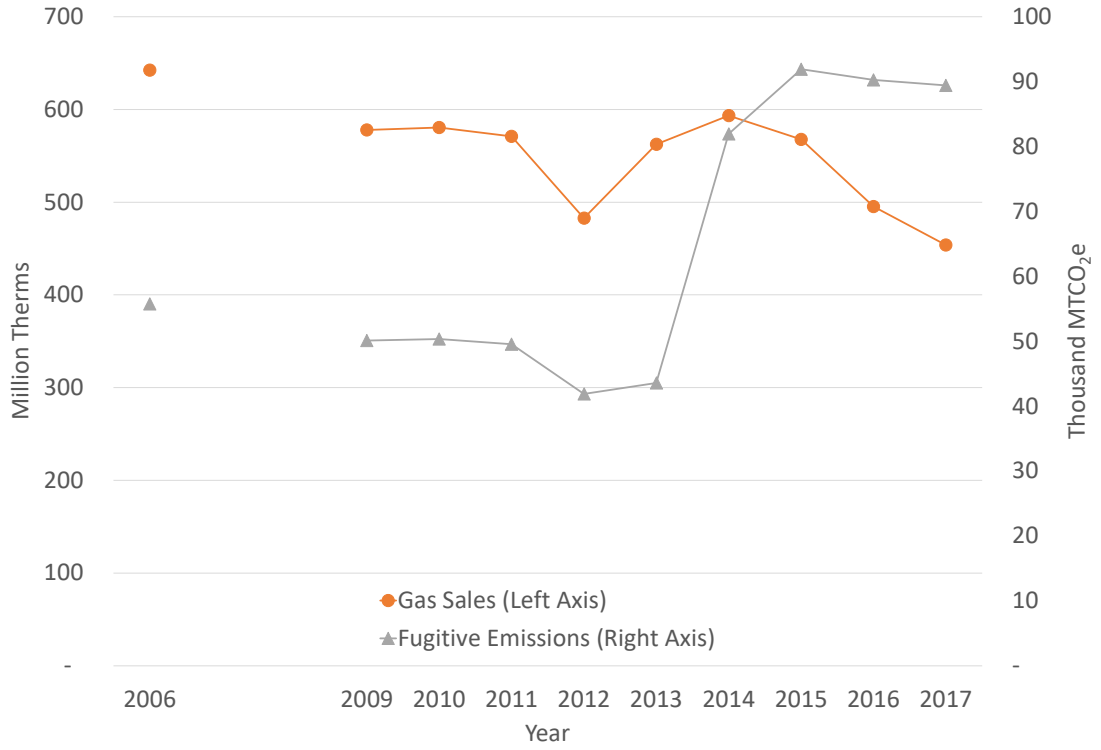
It is certainly the case that addressing leaks in the natural gas distribution system is an important, and often cost-effective, way to both conserve gas and reduce GHG emissions, especially considering the greenhouse potential of methane, which is 84-86 times more powerful a greenhouse gas as CO_2 over a 20-year timeframe.[45] Further, fugitive emissions may have increased substantially since 2006, even as gas sales in the district have fallen (see Figure 3.)[46] Washington Gas should be encouraged or even required to address these wasteful and dangerous emissions. AltaGas asserts that it could eliminate 2.5% and 5.7% of GHG emissions associated with natural gas by 2032 and 2050, respectively, and proposes to "reduce methane emissions associated with the WGL distribution system by 80% per unit of throughput by 2050."[47] This is a worthy goal and may be attainable.

However, whether the company should be permitted to engage in a full overhaul of its gas distribution system at ratepayer expense should be weighed against the need to dramatically reduce gas sales in keeping with the District's climate commitments. AltaGas notes that there is a risk of imposing large

[43] Fischer, David, & Madani, Hatef. (2017). On heat pumps in smart grids: A review. http://doi.org/10.1016/j.rser.2016.11.182.
[44] See https://www.energy.gov/energysaver/heat-and-cool/heat-pump-systems.
[45] Intergovernmental Panel on Climate Change (IPCC) Working Group 1 Fifth Assessment Report, Chapter 8, "Anthropogenic and Natural Radiative Forcing," Table 8.7. Available at https://www.ipcc.ch/site/assets/uploads/2018/02/WG1AR5_Chapter08_FINAL.pdf.
[46] Based on Washington DC Greenhouse Gas Inventory. However, I consider these fugitive emissions data suspect, given the apparent step-function increase between 2013 and 2014. It may be that a change in measurement or definition is responsible for this change, or it may be that it reflects a real change in operational practices.
[47] Technical report, page 10.

costs on remaining customers if gas sales decrease substantially.[48] The best way to avoid this outcome is to reduce investment in the gas distribution system as quickly as possible, focusing investment on the very few gas leaks that are generally responsible for most fugitive emissions.[49] The goal would be to ensure that the distribution system is largely depreciated by the time it is retired. It is also worth noting that the Commission will not be required to allow full recovery of undepreciated assets if it finds that the company's investments were not used and useful, or if the company spent imprudently in the face of the need to dramatically reduce gas use.

Figure 3. Total gas deliveries vs. fugitive emissions from distribution system as reported in the DC Greenhouse Gas Inventory. These data suggest that fugitive emissions may have increased substantially over the last decade, even as gas sales in the district have fallen. Data from 2007 and 2008 were not available.



d. Gas Alternatives

Reliance on "gas alternatives" is a fundamental part of AltaGas' Climate Business Plan, comprising 50% of its 2032 emissions reduction strategy and almost 44% of its strategy for 2050. The primary

[48] See, for example, page 61 of the Technical Report.
[49] Von Fisher, J., *et al.*, "Rapid, vehicle-based identification of location and magnitude of urban natural gas pipeline leaks." *Environ. Sci. Technol.* 2017, 51, 7, 4091-4099. https://pubs.acs.org/doi/full/10.1021/acs.est.6b06095.

component of this strategy is so-called "renewable natural gas," or RNG. AltaGas also includes "certified natural gas," "power-to-gas," and hydrogen. Each of these will be discussed below.

- ***RNG.*** Following the gas industry lobbying group, the American Gas Association, AltaGas states that "Renewable natural gas (RNG) is derived from biomass or other renewable resources and is a pipeline-quality gas that is fully interchangeable with conventional natural gas."[50] The CBP goes on to claim, without attribution or evidence, that "RNG is carbon neutral."[51] AltaGas relies on RNG for approximately 34% and 30% of its 2032 and 2050 reduction strategies, respectively.

  Even its own RNG study does not make the extraordinary claim of carbon neutrality, instead using a more credible definition from the National Association of Regulatory Utility Commissioners (NARUC) that RNG is "Pipeline-compatible gaseous fuel derived from biogenic or other renewable sources that **has lower lifecycle carbon dioxide equivalent (CO_2e) emissions than geological natural gas**."[52] This distinction notwithstanding, the RNG report later describes RNG as "a valuable renewable resource with carbon-neutral, and in some cases carbon-negative, characteristics"[53] and later states that "RNG has a carbon intensity of zero."[54]

  AltaGas and its consultant ICF do not reveal the actual composition or cost of its assumed RNG utilization, making its claim of carbon neutrality particularly difficult to assess. Nor do the authors acknowledge the high level of uncertainty in the cost of developing this resource and delivering it to the gas pipeline system, or the fact that to the extent that it is a viable resource, there is likely to be significant competition for other applications that may be more economically viable. For example, many landfills today collect and combust landfill methane on-site either to power on-site operations or to generate power for the grid. In fact, as stated in the RNG report (page 27, emphasis added):

  > *EPA's [Landfill Methane Outreach Program] database shows that there are about 620 operational [landfill gas (LFG)] to energy projects nationwide; however,* ***only 60 (10%)***

[50] CBP, page 18. AltaGas does not provide a specific citation for this quote, but it is similar to one found on the American Gas Association website at https://www.aga.org/natural-gas/renewable/.
[51] *Ibid*.
[52] RNG Report, page 12, citing GA, 2019. RNG: Opportunity for Innovation at Natural Gas Utilities, https://pubs.naruc.org/pub/73453B6B-A25A-6AC4-BDFC-C709B202C819. Emphasis added.
[53] *Ibid*, page 5.
[54] *Ibid*, page 84.

> ***of them produce RNG, and only 52 of those actually inject RNG into the pipeline****. Most of the projects capture LFG and combust it in reciprocating engines to make electricity (72%) or have a direct use (18%) for the energy (e.g., thermal use on-site).*

It is illogical for AltaGas to assume that it would be more economical to collect, dry and condition the gas and invest in the infrastructure to deliver it into the municipal gas distribution system when on-site combustion is cost-effective today; nor could this possibly provide an emissions benefit relative to using the resource on-site, both because of the cost and energy requirement for transportation, and because some degree of leakage from the pipeline system is inevitable.

The RNG report is silent on these practical considerations. Instead, the authors present a "combined RNG supply-cost curve"[55] and assume that AltaGas would have access to the lowest-cost resource at their cost of production. In addition to ignoring uncertainty, this approach violates basic economic principles of how markets work and disregards the likely competition for these resources from other regions or other applications. In reality, a single consumer (i.e., Washington Gas) would not get to claim all the lowest-cost resource in a market before anyone else, nor can it force each producer to sell at the cost of production when the market clearing price is higher. Indeed, the RNG Report acknowledges that: "In principle, the RNG price should reflect the marginal cost of RNG production on the system."[56] However, AltaGas' consultant then goes on to "posit" that AltaGas would essentially be able to cherry-pick the lowest-cost resources on the supply curve at their production cost,[57] in clear violation of these basic market principles.

- ***Certified Natural Gas.*** In theory, certified gas would be gas that has achieved a "best-in-class" certification from some certifying authority for reducing environmental impacts, similar to LEED certification for sustainable building practices.[58] However, it is entirely unclear what specific environmental qualities AltaGas is referring to, or how it could have calculated emissions

[55] RNG Report, page 79. ICF does not identify what the quantities and costs of each resource underlying the "supply curve are or how they were established, despite the significant uncertainty in both parameters.
[56] *Ibid*.
[57] This is my interpretation of the vague and ambiguous language used to describe ICF's pricing assumptions on page 79 of the RNG Report. As noted throughout this report, ICF and AltaGas never actually reveal the cost or quantity assumptions for this or any other resource used in its plan, so it is impossible to be certain.
[58] https://www.usgbc.org/leed.

reductions or costs for this purported resource. According to the CBP, "Washington Gas is currently in talks to collaborate with the Rocky Mountain Institute and others to more clearly quantify GHG emissions reductions from gas supply produced by best practice companies. With the necessary government policy and regulatory support, certified natural gas can be blended into existing gas supply **and is expected to result in a 1 – 2 percent GHG emissions reduction.**"[59]

The Technical Report, on the other hand, states that "ICF has assumed that most of the natural gas consumed in the District of Columbia in the future will be sourced from certified natural gas, and that the certification process will lead to **a reduction in methane emissions associated with the production and processing of natural gas of 0.2% of natural gas throughput**."[60] This Technical Report description paints a far less rosy picture for the emissions impact of certified gas than seen in the CBP; it would affect only a very small portion of the gas, and would only reduce emissions associated with the production and processing of that gas, but not with combustion. Once again there is no explanation for the very different assertions in the CBP and the supporting Technical Report. Even with the higher 1-2% reduction in emissions, it is hard to square AltaGas' projection for emissions benefits with this resource, which comprises almost 16% of its strategy for meeting the District's 2032 climate commitment. Without further explanation for these inconsistencies and enigmas, AltaGas' claimed emissions benefit associated with certified natural gas should be disregarded.

- ***Power-to-Gas and Hydrogen.*** It is possible to use renewable energy to separate water into hydrogen and oxygen, and the hydrogen would constitute an energy-dense fuel with numerous possible applications. It is certainly also possible to chemically convert this hydrogen into methane. As with landfill gas, however, it is extremely unlikely that the economics would support use of this fuel to displace fossil gas in municipal distribution systems. As the United States moves toward a very low-carbon economy, the likely most economic uses of this resource will be (1) high-density energy storage to accommodate very high penetration of variable-output renewable generation, and (2) transportation fuel, and in particular aviation fuel. The first application will be crucial to maintaining electric reliability, and it has the substantial benefit that the combustion of the fuel would take place at the same location as its production, eliminating transportation losses and costs. The second application reflects the fact that there is

[59] CBP, page 20, emphasis added.
[60] Technical Report, page 10, emphasis added.

essentially no other known non-fossil source of aviation fuel, making this an extremely high-value application. AltaGas' assumption that it could achieve almost 12% of its 2050 emissions reductions from such resources is inconsistent with these economic and technical realities.

AltaGas' projections for each gas alternative in its plan is vague to silent on specific resource mix, market conditions including competing uses, and cost. In this author's opinion, the only way any of these resources would play a significant role in DC's energy future would be through extreme market-distorting policies and subsidies, diverting them away from uses that would be more efficient and have more significant environmental benefits.

The cost and availability of low-carbon fuel feedstocks are crucial considerations in evaluating AltaGas' plan. In its RNG report, AltaGas' consultant ICF presents a range of costs for each of the RNG feedstock types considered, concluding that "RNG will be available from various feedstocks in the range of $7/MMBtu to $44/MMBtu."[61] Further, ICF estimated that RNG can provide "GHG emission reductions at a cost of $55 to $295 per ton of carbon dioxide equivalent (tCO_2e)." [62] These reported ranges should not be mistaken as an acknowledgement or analysis of uncertainty. To the contrary, ICF used these ranges to produce a "combined RNG supply-cost curve"[63] and assumed that AltaGas would have access to the lowest-cost resource at their cost of production. In addition to ignoring uncertainty, this approach violates basic economic principles of how markets work, and ignores any possible competition for these resources from other regions or other applications. Nor does AltaGas or ICF identify the sources of the cost projections in either the RNG report or the CBP, or provide crucial details such as whether the costs include transportation or other processing costs. Any of these omissions would seriously compromise the credibility of AltaGas' cost analysis. Together, they render such projections essentially meaningless.

Finally, it should be noted that AltaGas' plan does not actually call for the elimination of fossil gas from its system. The table on page 18 of the CBP shows that by 2050, the company proposes to use "low-carbon gas" of the kinds described above to replace 58% of its gaseous fuel, with the remainder presumably being fossil gas. The report is silent on the clear contradiction between continuing to rely on fossil gas, while claiming to eliminate 100% of GHG emissions from gas.

[61] RNG Study, page 67.
[62] *Ibid*, Table 3, page 69.
[63] *Ibid*, page 79.

V. Equity and Ratepayer Considerations

The *Clean Energy DC* Climate and Energy Action Plan includes an entire chapter on "An Equitable Transformation," recognizing that climate change is likely to affect certain groups more than others, and that these groups are often vulnerable populations that "are more exposed to climate hazards, have less capacity to adapt to climate hazards, and have increased sensitivity to those hazards."[64] Given this, it is crucial that climate and energy planning in the District retain a focus on consumer protection, job creation, and environmental justice concerns.

AltaGas' Climate Business Plan fails this test. While the plan is vague on the details and cost of every resource AltaGas proposes to pursue in reducing its carbon footprint, it is specific in one area: ratepayers, including the District's low income population, would bear all of the cost and risk of the company's speculative and expensive strategy. AltaGas states that: "The significant reductions in GHG emissions available through the utilization of low carbon fuel supply are predicated upon the timely approval of supportive policy."[65] Translating the regulatory jargon, "supportive policy" means (1) legislation or rulemakings insulating the company from all risks that its investments are unwise or more costly than anticipated;[66] (2) "decoupled" ratemaking meaning that if load decreases *for any* reason, including an economic downturn, the company will be made whole for any revenue losses;[67] and (3) a *bonus* ROE for doing what it is required to do anyway to serve customers in a low-carbon future.[68]

In warning against an approach that would wean DC customers off the gas distribution system, the Technical Report further states that "the…Electrification Case is likely to lead to the shut-down and decommissioning of the natural gas distribution system, leading to significant stranded assets and unrecovered ratebase for the gas distribution system that would need to be recovered."[69] Although

[64] *Clean Energy DC*, page 42.
[65] CBP page 29.
[66] For example, page 28 and 29: "Developing a cost recovery mechanism that would socialize the costs and benefits of gas use to all energy users." Also, "Ensuring cost recovery and enabling utilities to earn a return on investment (ROI) for investments in next-generation end-use technology" and "Allocate incremental cost of low carbon gas supply to all customers in the District."
[67] *Ibid*.: "Decoupling rates from volumetric throughput. This will enable Washington Gas to support energy efficiency while recovering operating costs to preserve safety and reliability."
[68] *Ibid*.: "Utilizing accelerated recovery mechanisms to support infrastructure investment in service areas of high CHP/demand potential" and "Applying tiered performance incentives (e.g. ROI adders) to support the implementation of behavioral energy efficiency programs" and "Built-in incentives for performance that reward timely deployment and results."
[69] Technical Report, page 61.

AltaGas does not include the cost of these "stranded assets" in its analysis, it appears to be claiming that it would continue to invest in upgrading its distribution system even in the face of a switch to end-use electrification, and would then expect the Commission to allow it to continue recovering those costs (presumably at its full ROE) from DC ratepayers long after the assets were used and useful. Thus in either case, the company's proposal is to impose all costs and risks on its ratepayers while rewarding its shareholders with a generous return on equity.

There are other approaches that better serve DC customers and the DC economy. Investments in energy efficiency and electrification are particularly effective in supporting local employment, in contrast to fossil or other imported resources for whom the primary benefit is reaped by outside investors. Energy efficiency saves ratepayers money immediately – switching to electric heat pumps, for example, can reduce heating costs by a factor of three or four,[70] far more than the Company's proposal of gas heat pumps. Electric heat pumps are also a well-established and commercially available technology, while gas heat pumps are available only for limited applications and offer only a comparatively small reduction in energy use. Renewable energy involves significant up-front capital costs but the energy itself is free – again contrasting with the company's proposed resources, which involve high capital costs and ongoing likely very high energy costs for resources like RNG.

Any approach to meeting DC's climate commitments will require investments in new infrastructure and energy resources. Companies like Washington Gas have an obligation to serve customers for a guaranteed, generous return on investment.[71] AltaGas' presumption that it should earn at this level *or higher* while shifting significant additional costs and current and future risks to ratepayers is inconsistent with its obligation to serve at just and reasonable rates. For all of these reasons, the "Climate Business Plan" may be an attractive blueprint for investors, but it represents unnecessary risk and cost for ratepayers in the District.

VI. Conclusion

Because of the ambiguity, inconsistencies, and numerous unsupported and unrealistic assumptions underlying AltaGas' Climate Business Plan and its Renewable Gas Study, I find that the company has not

[70] See footnote 43.
[71] According to Washington Gas' 2019 form 10-K, page 189, its 2018 ROE was 9.53%, which was 7 basis points *higher* than its allowed ROE. Available at https://www.washingtongas.com/-/media/465cda57d589485a9f635d3465e40b74.pdf.

met its obligation under ¶79 of its settlement agreement in any meaningful sense. The CBP relies on misleading nomenclature and false comparisons to support the continued use of gas in the District, and the claimed future cost savings relative to an electrification scenario are without foundation. In both reports, fundamental uncertainties are routinely brushed aside in favor of overly-optimistic projections that support AltaGas' preferred approach. Key assumptions on which the authors rely in both studies cannot be validated because they are described only vaguely and often inconsistently, without references, or sometimes referenced to unreliable and biased sources such as the "Playbook" of the American Gas Association,[72] a gas industry lobbying group. These shortcomings cast serious doubt on the validity of the reports' findings, at best making them impossible to credibly assess. Even taken at face value, the "plan" would not eliminate gas-related emissions by 2050 as the company claims, because it would continue to rely on combustion of fossil gas for 42% of its fuel supply.

The authors appear to assume that Washington Gas would have unfettered access to low-carbon gas alternatives at essentially the cost of production, ignoring likely competition from other states or utilities, along with likely more economically justified uses for these resources such as supporting electric system resiliency and low-carbon aviation fuel. AltaGas further assumes that no other states or utilities would take any actions during the study period to address GHG emissions beyond current RPS rules, ignoring for example the recent Virginia Clean Economy Act mandating that Virginia reach 100% clean energy resources by 2045.[73] There is no recognition at all of the impact that a nationwide switch to low- or zero- GHG sources of energy would have on the availability of fuels such as "renewable" natural gas (RNG) and hydrogen fuels, or on the operation of the electric grid.

AltaGas' wholly unsupported cost assessment for its policy options cannot be taken at face value. To the extent that any assumptions are shared with the reader, they are wild and largely unsupported guesses about future resource availability and cost with no attempt to analyze the impact of uncertainty. Nowhere in ICF's 150-page RNG study or its 140-page "technical report" has it provided the cost assumptions underlying its analyses, including specification of the actual sources of RNG used in developing and analyzing the Climate Business Plan. In the not unlikely event that the speculative

[72] https://www.aga.org/news/aga-playbook/ The term "Policy-Driven Electrification", which appears frequently in AltaGas' reports, also appears to derive from AGA publications.
[73] https://www.washingtonpost.com/local/virginia-politics/virginia-dominion-energy-bill/2020/03/06/4524cd20-5fc1-11ea-b29b-9db42f7803a7_story.html.

resources envisioned by AltaGas turn out to be significantly more expensive than assumed in the CBP, its preferred scenario could turn out to be far more costly than a focus on electrification.

Through its policy proposals, AltaGas shows that it is unwilling to assume any of the risk associated with the speculative and costly strategies outlined in its plan, and instead recommends that Washington DC ratepayers cover all costs and risks while compensating AltaGas for any lost sales and rewarding the company with a generous bonus ROE for meeting its climate commitments. This places an unfair burden on the District's ratepayers, and especially on its lower-income ratepayers, while ensuring that its stockholders will continue to be rewarded no matter how wrong its analyses or how imprudent its actions.

Overall, I conclude that AltaGas has failed in its commitment under its settlement agreement to credibly "file with the Commission a long-term business plan on how it can evolve its business model to support and serve the District of Columbia's 2050 climate goals."

Exhibit EDH-3
New York State Department of Public Service Matter No. 17-01632, Case 17-G-0460, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan. Issued June 14, 2018.

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 17-E-0459 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service.

CASE 17-G-0460 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service.

ORDER ADOPTING TERMS OF JOINT PROPOSAL AND ESTABLISHING ELECTRIC AND GAS RATE PLAN

Issued and Effective: June 14, 2018

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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on June 14, 2018

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James S. Alesi

CASE 17-E-0459 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service.

CASE 17-G-0460 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service.

ORDER ADOPTING TERMS OF JOINT PROPOSAL AND ESTABLISHING ELECTRIC AND GAS RATE PLAN

(Issued and Effective June 14, 2018)

BY THE COMMISSION:

INTRODUCTION

This order establishes a three-year rate plan for electric and gas service provided by Central Hudson Gas & Electric Corporation (Central Hudson or Company), for the period July 1, 2018, through June 30, 2021. The order adopts terms of a Joint Proposal (JP) executed by the Company; the New York State Department of Public Service trial staff (Staff); Multiple Intervenors (MI); Pace Energy and Climate Center (Pace); New York Geothermal Energy Organization (NY-GEO); the Utility Intervention Unit of the Department of State, Division of

Consumer Protection (UIU); Dutchess County; Acadia Center; the Public Utility Law Project of New York, Inc. (PULP); the Natural Resources Defense Council (NRDC) (partial); Bob Wyman; and the U.S. Army Legal Services Agency, representing the U.S. Department of Defense and all other Federal Executive Agencies (Army Legal Services).

BACKGROUND OF THE PROCEEDING

Central Hudson distributes electricity to approximately 300,000 customers and natural gas to about 80,000 customers in the Mid-Hudson River Valley region of New York.[1] The Company's most recent electric and gas rate plan was adopted in a rate order issued in June 2015.[2] In that order, the Commission approved the implementation of a three-year electric and gas rate plan for Central Hudson.

On July 28, 2017, Central Hudson filed tariff leaves and testimony seeking to increase its electric and gas delivery revenues based on a rate year starting July 1, 2018, and ending June 30, 2019 (Rate Year). Central Hudson also included select financial information for two additional rate years. Central Hudson's proposed delivery rates were designed to produce an electric delivery revenue increase of approximately $63.4 million and a gas delivery revenue increase of approximately $22.2 million, resulting in delivery revenue increases of 21.2% and 24.3%, respectively, or total system-wide revenue increases

[1] Hearing Exhibit 1, Pre-filed direct testimony of Company Witness Buckley, p. 31.

[2] Cases 14-E-0318 and 14-G-0319, Central Hudson Gas & Electric Corporation – Rates, Order Approving Rate Plan (issued June 17, 2015) (2015 Rate Order).

of 12% and 18%, respectively.[3] Central Hudson requested a 9.5% overall return on equity and an equity ratio of 50%.[4]

The presiding administrative law judges (ALJs) held a procedural conference and a technical conference on September 7, 2017. By ruling issued September 19, 2017, they established a case schedule requiring the filing of Staff and intervenor testimony on November 21, rebuttal testimony on December 15, and the commencement of an evidentiary hearing on January 9, 2018. By ruling issued September 29, 2017, the ALJs granted a request for reconsideration of a portion of that schedule and established a revised rebuttal filing due date of December 18, 2017.

The Company filed supplemental testimony and exhibits on October 19, 2017. Staff, UIU, MI, NRDC, PULP, Pace, Dutchess County, Bard College, Bob Wyman, and Citizens for Local Power (CLP) filed direct testimony. In its testimony, Staff noted that the Company's proposed electric revenue increase had been revised to $66.2 million (a 22.1% delivery revenue increase). Among other things, Staff recommended an electric revenue increase of $27.8 million, a gas revenue increase of $7.6 million,[5] an overall return on equity of 8.3%, and an equity ratio of 48%.[6] Staff's recommended revenue increases included the impact of collecting energy efficiency related costs through base rates, as opposed to through a surcharge. This proposal

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[3] Hearing Exhibit 22, Joint Proposal, p. 2.

[4] Hearing Exhibit 1, Pre-filed direct testimony of Company Witness Buckley, p. 5.

[5] Hearing Exhibit 16, Pre-filed direct testimony of Staff Accounting Policy and Revenue Requirements Panel, pp. 10-11.

[6] Hearing Exhibit 16, Pre-filed direct testimony of Staff Finance Panel, pp. 9-10.

would result in a base rate increase of $8.5 million for electric and $0.8 million for gas, but no net bill impact.

By letter dated December 8, 2017, Central Hudson filed a notice of impending settlement negotiations, advising that the first negotiation session would be held on December 21, 2017, in Albany. In accordance with the Commission's rules, the required review of the notice was completed and reported, also on December 8.

Rebuttal testimony and exhibits were filed by the Company, UIU, Pace, MI, and CLP. On December 21, 2017, Central Hudson requested the postponement of the evidentiary hearing that was scheduled to commence on January 9, 2018, to facilitate the settlement discussions and allow additional time to negotiate and finalize a joint proposal. Thereafter, several additional postponements were requested and granted.

The settlement negotiations ultimately proved successful, resulting in the filing of the April 18, 2018, JP between the Company, Staff, MI, Pace, NY-GEO, UIU, Dutchess County, Acadia Center, PULP, NRDC, Bob Wyman, and Army Legal Services (collectively, the Signatory Parties). The Signatory Parties assert that the JP, together with its accompanying appendices, contain a comprehensive set of terms and conditions for a three-year rate plan for Central Hudson’s electric and gas service. They recommend that the rates and surcharges of Central Hudson be determined in accordance with the understandings, principles, qualifications, terms, and conditions set forth therein. The filing of the JP was accompanied by a summary of the JP, bill impact tables, and a

scheduling proposal.[7] Statements in support of the JP were filed by the Company, MI, Pace, Acadia Center, PULP, NY-GEO, Bob Wyman, and Staff.[8] CLP filed a statement on the JP. No party filed a statement opposing the JP. On May 9, the Company filed a letter in lieu of reply statement in support of the JP. An evidentiary hearing was held on May 21, 2018.[9]

PUBLIC COMMENTS AND NOTICE OF PROPOSED RULEMAKING

Pursuant to the State Administrative Procedure Act (SAPA) §202(1), Notices of Proposed Rulemaking were published in the State Register on October 11, 2017 (SAPA No. 17-E-0459P1 and SAPA No. 17-G-0460P1).

On September 11, 2017, a notice was issued describing the Company's rate filing and announcing the dates, times, and locations of six public statement hearings and public information sessions. The notice further stated that comments also could be made by internet, mail, or the Commission's toll-free Opinion Line. Consistent with the notice, afternoon and evening public information sessions and public statement hearings were held in Poughkeepsie, Kingston, and Newburgh, on October 3, 10, and 16, 2017, respectively.[10] Between two to 20 people spoke at each public statement hearing and five to 45 people attended each hearing.

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[7] On April 19, 2018, a Ruling on Schedule was issued establishing the due dates for filing initial and reply statement on the JP and the start date of the evidentiary hearing.

[8] On May 8, 2018, Staff filed a letter clarifying and correcting portions of its statement in support.

[9] See Notice of Evidentiary Hearing (issued May 2, 2018).

[10] Commissioner Sayre presided at the Poughkeepsie public statement hearings and Commissioner Burman presided at the public statement hearings in Newburgh.

After the Joint Proposal was filed, an April 20, 2018, Notice was issued establishing a further period for public comments on the JP.

Public Statement Hearing Comments

Comments were made by 15 people at the Poughkeepsie hearings, 33 people at the Kingston hearings, and 17 people at the Newburgh hearings. Most individuals spoke on their own behalf, while others commented on behalf of various educational institutions, environmental groups, and other nonprofit organizations. Frank Skartados and Kevin Cahill of the New York State Assembly, as well as other local elected officials, also spoke at the hearings.

Most commenters opposed the Company's requested rate increases in their entirety. Comments generally focused on the issues of affordability, even at the existing rates, especially with respect to residential customers living on fixed or limited incomes who also are facing rising costs for necessities such as groceries, prescription medications and health insurance. Various commenters stated that Central Hudson's delivery rates already were too costly, especially for the large population of low income customers in the Company's service territory, and that the requested increases were too much and simply would ensure more profits for the Company. Similarly, commenters noted that there were already too many utility shut-offs of the Company's customers. Commenters also complained about Central Hudson's high fixed customer charge.

Some commenters said that the Company should expand its energy efficiency and conservation programs, focus on increasing the use of renewable resources, use rate structures such as time-of-use options to promote conservation, and use its profits to pay for needed infrastructure upgrades. Other commenters questioned Central Hudson's intended use of the rate

increases, noting that the Company had relied on several of the same categories of increased costs to raise rates previously, without any corresponding increase in service quality or reliability.

A few commenters mentioned the high costs of vegetation management and the Company's claimed need to address trees affected by the Emerald Ash Borer Beetle, expressing that the costs appeared to be inflated for the tree and vegetation clearing program. Others expressed concern with the Company's proposed training facility, opining that adequate training facilities already existed in the local communities. Several individuals also expressed concern with the Commission's prior approval of the Fortis Inc. acquisition of Central Hudson.[11] One commenter expressed concerns with the potential impact of the rate increase on the small-business community, while other individuals stated that the proposed rate increases would have a disproportionate impact on residential customers.

Written Comments and Opinion Line Comments

In addition to the public statement hearing comments, almost 800 comments were received either through the Commission's opinion line or filed with the Commission's Secretary. Virtually all the written and opinion line comments received were from individual customers expressing opposition to the proposed rate increases. There were, however, a few comments received after the Joint Proposal was filed that expressed support for the reductions from the Company's initial filing that are reflected in that proposal.

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[11] See Case 12-M-0192, Joint Petition of Fortis Inc. et al. and CH Energy Group, Inc. et al. for Approval of the Acquisition of CH Energy Group, Inc. by Fortis Inc. and Related Transactions.

Citing low or nonexistent cost-of-living adjustments and rising costs for necessities like housing, food, prescriptions and health insurance, many commenters stated that the proposed rate increases were too high, especially for people on low or fixed incomes, and that the Company should reduce executive compensation or other Company profits to fund any cost and expense increases. Some commenters stated that the Company should not receive any increases given the Company's current level of profits.

Numerous commenters, including various Town, City and County officials, stated that fixed customer charges are too high and need to be reduced. They said that high fixed charges not only minimize incentives to conserve energy and to invest in renewable energy systems, but also undermine Reforming the Energy Vision (REV) policy initiatives seeking to give consumers more control over energy use and costs, and have a disproportionate impact on moderate and low income customers who purportedly use less energy than average. Finally, several commenters stated that the Company already shuts off service for too many customers for nonpayment and that an increase in rates will only exacerbate the problem.

SUMMARY OF JOINT PROPOSAL[12]

Term[13]

The JP proposes a three-year rate plan for Central Hudson's electric and gas businesses that would begin on July 1, 2018, and continue until June 30, 2021. Rate Year 1 consists of

[12] In the following discussion, some terms of the JP, along with any issues related thereto, are generally summarized and discussed. The summary is provided for the reader's convenience.

[13] Hearing Exhibit 22, Joint Proposal, §III.

the 12-month period beginning on July 1, 2018, and ending June 30, 2019. Rate Years 2 and 3 consist of the next two successive 12-month periods ending June 30, 2020, and June 30, 2021, respectively. Unless specifically noted otherwise, the provisions of Rate Year 3 would remain in effect until superseding rates or terms become effective.

Revenue Requirements[14]

The JP would increase electric and gas base delivery revenues in each of the three rate years. The JP recommends electric delivery revenue increases of $19.725 million in Rate Year 1, $18.581 million in Rate Year 2, and $25.083 million in Rate Year 3, and gas delivery revenue increases of $6.654 million in Rate Year 1, $6.702 million in Rate Year 2, and $8.183 million in Rate Year 3. To mitigate the customer bill impacts that would be associated with these increases, the proposed increases have been moderated by using available regulatory liabilities and applying them as credits. After applying credits totaling $6 million in Rate Year 1, $9 million in Rate Year 2, and $11 million in Rate Year 3, the net electric delivery revenue increase will be $13.725 million in Rate Year 1, $15.581 million in Rate Year 2, and $23.083 million in Rate Year 3. After applying credits totaling $3.5 million in Rate Year 1, $4.0 million in Rate Year 2, and $4.0 million in Rate Year 3, the net gas delivery revenue increases will be $3.154 million in Rate Year 1, $6.202 million in Rate Year 2, and $8.183 million in Rate Year 3. These amounts include the impact of Staff's proposal to collect energy efficiency-related costs through base rates, as opposed to through a surcharge. This change resulted in a base rate increase of $8.5 million for electric and $0.8 million for gas, but no net bill impact.

[14] Id., §IV.

The Rate Year 1 delivery revenue increases include the impact of Staff's proposal to collect energy efficiency-related costs through base rates, as opposed to through a surcharge. Because the Company will no longer collect these costs through a surcharge, the Rate Year 1 electric delivery revenue increase experienced by customers is offset by an $8.479 million surcharge reduction and the Rate Year 1 gas delivery revenue increase experienced by customers is offset by a $0.837 million surcharge reduction. This results in a Rate Year 1 net increase experienced by customers for electric service of $5.246 million, or approximately 1% of their total bill and a net increase experienced by customers for gas service of $2.317 million, or approximately 1.5% of their total bill. [15]

The net increases experienced by electric customers for Rate Year 2 of $15.581 million, or about 2.8%, and for Rate Year 3 of $23.083 million, or approximately 4%, are not impacted by the shifting of energy efficiency-related costs from a surcharge to base rates. The same is true for the net increases experienced by gas customers for Rate Year 2 of $6.202 million, or 3.6%, and for Rate Year 3 of $8.183 million, or 4.4%.

Equity Ratios, Return on Equity, and Earnings Sharing Mechanism[16]

The revenue requirements for all three years of the proposed rate plan are based on a capital structure with a common equity ratio of 48% in Rate Year 1, 49% in Rate Year 2, and 50% in Rate Year 3, and an allowed return on common equity (ROE) of 8.8%. The JP includes an earning sharing mechanism (ESM) that is triggered if Central Hudson's actual ROE in any year, after certain adjustments, exceeds 9.3%. Earnings above

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[15] The estimated percentage increases experienced by customers is calculated assuming the Company's delivery revenues represents 60% of the customers' total bills.

[16] Id., §VI.A.

9.3% and up to 9.8% would be shared equally between the Company and ratepayers; ratepayers would receive 80% of any earnings over 9.8% up to 10.3%; and ratepayers would receive 90% of any earnings over 10.3%.

Electric and Gas Revenue Allocation and Rate Design[17]

JP Appendix L sets forth the signatories' agreed-to electric and gas revenue allocation. JP Appendix M sets forth the signatories' agreed-to electric and gas rate design.

The electric bill credits will be allocated to each service class in proportion to class responsibility for the overall delivery rate increase and will be refunded to customers on kilowatt-hour (kWh) or kilowatt (kW) basis through the existing Electric Bill Credit Mechanism. The gas bill credits will be allocated to each service class in proportion to class responsibility for the overall delivery rate increase and will be refunded to customers on a hundred cubic feet (Ccf) basis through the existing Gas Bill Credit Mechanism which is applicable to firm Service Classifications (SCs) 1, 2, 6, 11 (Distribution Large Mains (DLM), Distribution (D) and Transmission (T)), 12, and 13. For billing purposes, any applicable credit up to $1 million resulting from Service Classification (SC) 11 gas delivery service to the Danskammer Generating Station (see JP Section IX.A) will be included in and combined with the Gas Bill Credit, thus appearing as one line item on customer bills.

The JP provides that the current customer charge for certain electric customers (i.e., SC 1 residential, SC 2 non-demand, and SC 6 residential time-of-use) and the minimum charge for SC 1 residential gas customers will be reduced by $3.00 in

[17] Id., §X.

Rate Year 1, $1.00 in Rate Year 2, and $0.50 in Rate Year 3.[18] As a result, the SC 1 residential electric customer charge will be $21.00 in Rate Year 1, $20.00 in Rate Year 2, and $19.50 in Rate Year 3. The SC 1 gas residential minimum charge will decrease by $1.00, $0.50, and $0.25 in Rate Year 1, Rate Year 2, and Rate Year 3, resulting in a minimum charge of $25.00 in Rate Year 1, $24.50 in Rate Year 2, and $24.25 in Rate Year 3. The JP notes that future changes to these charges may be decided in other related proceedings, including, but not limited to, the Value of Distributed Energy Resources (VDER) proceeding.[19]

The JP calls for the establishment of a three-part rate for the gas service provided pursuant to the SC 11 tariff (the Firm Transportation Rate) that would consist of (1) a monthly minimum charge; (2) a volumetric charge applicable to a customer's monthly consumption exceeding 1,000 Ccf per month; and (3) a demand charge applicable to a customer's Maximum Daily

[18] The current electric customer charges are $24.00 for SC 1 (residential), $35.00 for SC 2 (general service, non-demand), and $27.00 for SC 6 (residential time-of-use). The current minimum charge for SC 1 residential gas service is $26.00. See Hearing Exhibit 1, Pre-filed direct testimony of Central Hudson's Forecasting and Rates Panel, pp. 54, 58.

[19] Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources.

Quantity (MDQ).[20] In addition, the three SC 11 transmission rates from the 2015 Rate Plan[21] will be combined into one transmission rate called SC 11 Transmission and the two SC 11 distribution rates from the 2015 Rate Plan[22] will be combined into one distribution rate called SC 11 Distribution, while SC 11 DLM rate will be maintained.[23] The volumetric rate will be set to recover approximately 15% of delivery revenue allocated to SC 11 with the remaining estimated revenue less the minimum charge being recovered through the MDQ charge.

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[20] The existing SC 11 tariff entitled "Firm Transportation Rate – Core" is applicable to use of service for transportation of customer-owned gas to those customers that have the capability of transporting and receiving at one service point 75,000 thousand cubic feet (Mcf) or greater per year where: 1) the customer's premises are (a) located adjacent to the Company's existing gas mains having adequate capacity to supply customer's prospective requirements in addition to the simultaneous requirements of present or prospective customers taking firm or interruptible service from such mains; or (b) at other points under arrangements made in accordance with General Information, Section 25; and 2) service is to be provided under an agreement as included in General Information, Section 40.

[21] i.e., Transmission Annual x<300,000 Mcf, Transmission Annual 300,000<x<800,000 Mcf and Transmission Annual x>800,000 Mcf.

[22] i.e., Distribution Annual x<100,000 Mcf and Distribution Annual x>=100,000 Mcf.

[23] JP Appendix M indicates that SC 11 subclass, Electric Generation (SC 11 EG), also will be maintained. This subclass, established July 1, 2015, applies to electric generation facilities with a minimum generation capacity of 50 megawatts taking firm natural gas transportation service from Central Hudson facilities at transmission pressures. See 2015 Rate Order, p. 35.

Net Plant Targets and Reconciliations[24]

Electric and Gas Net Plant Targets[25]

JP Appendix C sets forth the depreciation expense targets and the net plant targets upon which the electric and gas revenue requirements are based. These targets are applicable only to the time periods specified in the JP. Actual average electric and gas net plant balances and depreciation expense at the end of each Rate Year will be calculated using the calculation methods described in JP Appendix D.

Net Plant Target Reconciliations[26]

The JP provides that actual electric and gas net plant balances and depreciation expense will be reconciled to the combined electric and gas net plant targets and depreciation expense targets for Rate Year 1, Rate Year 2, and Rate Year 3 on an annual Rate Year basis. The revenue requirement impact (i.e., return and depreciation as described in Appendix D) resulting from the total difference (whether positive or negative) between actual average net plant balances and depreciation expense and the combined target levels will carry forward for each of the Rate Years and will be summed algebraically at the end of Rate Year 3.

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[24] Hearing Exhibit 22, Joint Proposal, §V.A.2.

[25] Actual Net Plant and the Net Plant Targets have the following components: 1) the Average Electric or Gas Net Plant; 2) the Average Electric or Gas Non-Interest Bearing Construction Work in Progress (NIBCWIP); 3) the Average Common Net Plant allocated to Electric or to Gas; and 4) the Average Common NIBCWIP allocated to Electric or to Gas. Hearing Exhibit 22, Joint Proposal, §V.A.

[26] Hearing Exhibit 22, Joint Proposal, §V.A.3.

Deferral for the Benefit of Ratepayers[27]

If, at the end of Rate Year 3, the cumulative incremental revenue requirement impact from net plant balances and depreciation expense differences is negative, the Company will defer the revenue requirement impact for the benefit of customers; if it is positive at the end of Rate Year 3, no deferral will be made. Carrying charges at the pre-tax rate of return will be applied by the Company to the amount deferred from the end of Rate Year 3 until the date that the Company's next rate order takes effect.

Existing Reporting[28]

The Company will continue to provide Staff with yearly reports, due by March 1 of each year, on its capital expenditures during the prior calendar year. The Company also will continue to annually file its five-year capital investment plan with the Secretary to the Commission; this report will be filed by July 1 and will include an explanation of any cost variance between the approved budget and an actual expenditure greater than 10% for any single project identified in the Company's Major Capital Project Report shown in JP Appendix E, Sheet 1. The proposed three-year capital investment plan is set forth in JP Appendix Y.

New Reporting[29]

The Company will be subject to two new reporting requirements, 1) a quarterly capital variance report and 2) a detailed annual report that identifies planned information technology (IT) projects. The IT report will include: (1) the final variance summary of all on-going and active capital

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[27] Id., §V.A.4.

[28] Id., §V.A.5.

[29] Id., §V.A.6.

projects and programs; (2) an explanation of any cost or timeline exceeding 10% of forecast; (3) a narrative on changes to any IT project design, contracts, or software; (4) a description of benefits of any new IT projects or programs; and (5) any quantitative benefit/cost analysis to date and/or forecast, including the methodology used. Starting with the quarter ending March 31, 2019, the Company will file with the Secretary the first of its quarterly reports that will include: (1) any changes to the IT project prioritization with an explanation; (2) the expense variance by project; and (3) an explanation for any cost variance exceeding 10% of the project's approved budget.[30]

Deferral Accounting[31]

The JP provides for the continuation, without modification, of numerous accounting deferrals for revenues, expenses, and costs, including but not limited to, Environmental Site Investigation and Remediation (SIR) Costs, Pension Expense and Post-Employment Benefits Other than Pensions (OPEBs), Property Taxes, and REV Demonstration Projects. The JP specifies the modification of several other 2015 Rate Plan accounting deferrals including, for example, the ESM, Economic Development, the Low Income Program, the Electric Revenue Decoupling Mechanism (RDM), Right-of-Way Tree Trimming Costs, and Gas Leak Prone Pipe (LPP). The JP lists the accounting deferrals from the 2015 Rate Plan that will expire. Finally, it lists the new accounting deferrals that will be added. A summary listing of accounting deferrals and applicable examples is set forth in JP Appendix F, together with the specific deferral method and associated carrying charge for each. The

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30 See id., Appendix P.

31 Id., §V.B.

accounting deferrals that are authorized by the terms of this JP will not terminate at the end of Rate Year 3, but instead are intended to continue until they are superseded or expressly revoked.

Impact of Federal Tax Changes

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (Tax Act) was signed into law. The Tax Act significantly lowered the Company's federal income tax expense, starting in 2018. The JP reflects the Signatory Parties' best estimate of the impact the Tax Act will have on expenses for the three years of the rate plan. Staff states that Rate Year 1 revenue requirements were lowered by approximately $13.2 million for electric and $4.8 million for gas due to the decrease, from 35% to 21%, in the federal income tax rate applicable to the Company.[32] The revenue requirement impact that the Tax Act has on the January 1, 2018, to June 30, 2018, time period, the six months when the Tax Act is in effect but before the rate plan in the JP begins, will be deferred for future customer benefit and we will address such balances at a future time.

Low Income Customer Provisions[33]

The JP notes that low income discounts will be provided to Home Energy Assistance Program (HEAP) recipients, consistent with the requirements set forth in the orders issued

[32] Staff Statement in Support of Joint Proposal (Staff Statement), p. 31.

[33] Id., §XI.

by the Commission in the generic proceeding.[34] The annual funding for these credits total $8.612 million in Rate Year 1, $11.015 million in Rate Year 2, and $12.018 million in Rate Year 3. The specific bill discount credits, set forth in the electric and gas tariffs, may change based on the annual Low Income Plan the Company is required to file with its analysis of customer bills. However, as proposed in the JP, eligible low income customers will receive monthly low income discounts ranging from $19.00 to $72.00.[35]

The level of funding for the bill discount credits is subject to symmetrical deferral.[36] Any accumulated balances of program under-spending will be deferred for future use in the Low Income Program and carrying charges will be applied at the pre-tax rate of return. If higher than forecasted participation renders the rate allowance specified for the discounts inadequate to provide them to all qualifying customers, the Company is authorized to defer the difference between the rate allowance and the actual discounts.

The Low Income Order authorized the continuation of an Arrears Forgiveness Program that will be phased out during Rate Year 2. The JP therefore provides for total allowances for this

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[34] Case 14-M-0565, Proceeding on Motion of the Commission to Examine Programs to Address Energy Affordability for Low Income Utility Customers, Order Adopting Low Income Program Modifications and Directing Utility Filings (issued May 20, 2016)(Low Income Order), and Order Granting in Part and Denying in Part Requests for Reconsideration and Petitions for Rehearing (issued February 17, 2017)(Low Income Rehearing Order).

[35] This range assumes that the customer receives a heating discount for one fuel type. Eligible non-heating low income customers will receive discounts ranging from $3.00 to $56.00.

[36] See Hearing Exhibit 22, Joint Proposal, §V.B.2.e.

program of $142,000 in Rate Year 1 and $6,000 in Rate Year 2. These allowances also are subject to symmetrical deferral.

The Low Income Order also authorized the continuation of the waiver of Reconnection Fees. The JP notes that an allowance of $51,000 for each Rate Year (split 80/20 between electric and gas), also subject to symmetrical deferral, has been established.

Tariff Related Matters[37]

Existing tariff provisions and related rate making will generally be continued, but with some exceptions and modifications, such as including storage batteries in the definition of "designated technologies" under section 14.5 of the standby service tariff; combined Nitrous Oxides emissions for designated technologies exempt from standby rates under section 14.5 will be reduced under 4.4 lbs/megawatt hour (MWh) to 1.6 lbs/megawatt (MW) under the standby service tariff for customers that complete a Coordinated Electric System Interconnection Review (CESIRs) on or after July 1, 2018 (CESIRs completed before July 1, 2018, will be grandfathered under the 4.4 lbs/MWh standard); graduated increases in reconnection charges applicable to service restoration to the same customer at the same meter location within 12 months after discontinuance of service; and expanding the electric RDM to additional customer classifications, and implementing a new Gas Miscellaneous Charge mechanism and bill line item to address the recovery and refund of new initiatives.

Energy Efficiency[38]

The JP provides that, beginning in Rate Year 1, Central Hudson's electric and gas Energy Efficiency Transition

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[37] Id., §XII.

[38] Id., §XIII.

Implementation Plan (ETIP) costs will be recovered in base rates instead of the Energy Efficiency Tracker Surcharge portion of the System Benefit Charge (SBC).[39] The annual electric and gas ETIP costs included in base delivery rates are $9.8 million and $1.2 million, respectively.[40]

Training Center[41]

In its initial testimony, the Company proposed to construct an integrated and modern facility dedicated to providing hands-on and scenario-based learning and indoor/outdoor electric and gas training (the Training Center). The Company also proposed to construct an integrated transmission and distribution system operations center (the Primary Control Center).[42] The centers were proposed to be co-located, with the Training Center estimated to cost

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[39] The Company will apply an appropriate credit to those customers that currently have exemptions from the Energy Efficiency Tracker Surcharge portion of the SBC, such that the credit will preserve the economic value of the exemptions that otherwise would be lost by shifting the recovery of electric and gas ETIP costs from the SBC to base rates. To the extent a service class is not included in the RDM and the actual value of such exemptions provided differs by $10,000 or more from the value imputed in base rates (see Hearing Exhibit 22, Joint Proposal, Appendix M, Sheets 5 through 7), the entire difference will be deferred for future disposition subject to Commission approval.

[40] Central Hudson's Energy Efficiency Program costs and targets are subject to change pursuant to Commission action in Case 18-M-0084, In the Matter of a Comprehensive Energy Efficiency Initiative. If the Commission does not provide specific cost recovery directives for any modifications to such budgets, the JP would authorize the Company to defer and recover any such changes approved by the Commission.

[41] Hearing Exhibit 22, Joint Proposal, §XV.

[42] See Hearing Exhibit 1, Pre-filed testimony of Central Hudson's Training and Development Panel, and of Witness Anthony S. Campagiorni (Policy and Overview).

approximately $32.5 million while the Primary Control Center spending would be $2.2 million in 2018 and $1.7 million in 2019.[43]

The JP states, in relevant part, that within 30 days of the Commission's issuance of a final order in these proceedings, the Company will file an initial report with the Secretary containing the proposed Training Center and the scope of the Primary Control Center Projects (Projects) and a timeline of major performance milestones, including deadlines for functional capability and operation/integration of the Projects and the Company's expected incremental capital expenditures and operating expenses that would be incurred if the Projects are not pursued. Within 60 days after this filing, the JP states that Staff and the Company will meet to discuss the major performance milestones timeline and, if they do not reach agreement regarding said milestones, either the Company or Staff may seek a ruling from the Commission regarding appropriate milestones. Thereafter, the Company would file with the Secretary a major milestone performance report within 30 business days of a milestone completion date (Milestone Report) that describes, *inter alia*, the Projects' compliance with the applicable milestone(s); identifies the Company's view of the Projects' direct customer benefit(s); describes the electric and gas business impacts; and, if necessary, also indicates potential and appropriate remedial action for a specific Project that has not fully met a milestone. Finally, Staff will present its review of the Milestone Report(s) to the Director of the Office of Electric, Gas and Water for approval and the Director's approval of the continuation of the Projects shall be

[43] See Hearing Exhibit 1, Pre-filed Exhibits of Central Hudson's Training and Development Panel, TDP-3.

documented in a letter from the Director to the Company with a copy filed with the Secretary.

Electric Reliability[44]

We are mindful of the severity of recent storms and the impact to customers that prolonged outages bring. As the Department conducts its comprehensive statewide investigation into the utility companies' preparation and response to those events, which may lead to a variety of recommendations for different companies, the Commission encourages the Company to continue to consider its approaches to reduce the likelihood of storm damage and enhance its storm response activities.

The JP recommends continuation of the electric service annual metrics for System Average Interruption Frequency Index (SAIFI) and Customer Average Interruption Duration Index (CAIDI).[45] SAIFI, which is currently set at or below 1.30 will be set at the following targets: (1) 2018 - 1.38; (2) 2019 - 1.34; and (3) 2020 - 1.30. The slightly increased 2018 and 2019 SAIFI targets reflect our acknowledgment that the Emerald Ash Borer is causing unprecedented danger tree-related risks. Adopting the SAIFI targets set forth in the JP will provide the Company with the ability to implement the Emerald Ash Borer Danger Tree Program while still requiring the Company to maintain and improve reasonable reliability performance levels. The target for CAIDI will continue to be set at or below 2.50.

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[44] Id., §XVI.

[45] Electric reliability performance is primarily measured by the Commission utilizing the SAIFI and CAIDI indices. SAIFI is the average number of times that a customer is interrupted for five minutes or more during a year, while CAIDI is the average interruption duration time in hours for those customers that experience an interruption during the year. See, e.g., New York State Department of Public Service, 2016 Electric Reliability Performance Report, filed session of June 15, 2017.

Potential negative revenue adjustments for SAIFI and CAIDI can be incurred up to 30 basis points each, or up to about $4.1 million total, if the Company fails to achieve these targets.

Gas Safety[46]

The JP continues and further enhances existing gas safety performance metrics and safety programs. Specifically, the JP provides that the Company will continue to replace LPP at a rate of 15 miles per year and increases the Company's negative revenue adjustment from eight basis points to 12 basis points for failing to achieve this target.[47] The JP recommends cumulative potential negative revenue adjustments for the Company's gas operations of up to 150 basis points and recommends up to 43 basis points of positive revenue adjustments for surpassing various gas safety metrics, including LPP replacement, Type 3 leak reduction, emergency response, and damage prevention.[48]

The JP recommends the creation of new gas safety programs, including residential methane detection and first responder training. Within 60 days, the Company will file an implementation plan for its Residential Methane Detection Program. Within 120 days, the Company will file an implementation plan for its First Responder Training Program. Both programs will be funded with code rule violation negative revenue adjustments that the Company may incur as part of its safety performance metrics. Any costs in excess of the available amounts may be deferred.

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46 Id., §XVII.

47 The 2019 pre-tax dollar value of 12 basis points equals $309,000.

48 For 2019, the pre-tax dollar value of 150 basis points would be $3.9 million. The 2019 pre-tax dollar value of 43 basis points is $1.1 million.

The JP requires the Company to submit an implementation plan for each identified non-pipe alternative and provides an incentive to the Company to seek out these alternatives to traditional gas infrastructure investments. It is envisioned that the identified non-pipe alternatives would include projects that will reduce peak day demand, as well as provide for transportation mode alternatives. The Company will also be required to issue a request for proposals to solicit technology and fuel neutral market responses to a defined level of peak reduction and then determine the value of various levels of peak reduction provided by a Demand Response program.

Customer Service[49]

The JP introduces new Customer Service initiatives, including the elimination of fees associated with payments made by credit/debit card or at walk-in locations and the Company's agreement to study the feasibility of implementing an electronic Deferred Payment Agreement (DPA) program. The JP establishes more stringent targets for existing Customer Service Quality Performance Mechanisms, including the Customer Satisfaction Index and the Public Service Commission (PSC) Complaint Rate. In addition, the JP provides for the implementation of a new Call Answer Rate metric and a new mechanism designed to encourage the Company to reduce both residential service terminations and residential uncollectibles. The JP also provides funding for additional customer service employees over the term of the Rate Plan.

The JP provides for a maximum total of $3.0 million or about 32 basis points of negative revenue adjustments across both electric and gas operations if the Service Quality metrics are not met. In addition, a positive revenue adjustment of

[49] Id., §XVIII.

$925,000 or about 10 basis points is provided for exceeding goals relating to residential terminations and uncollectibles. As noted above, Central Hudson's residential termination practices were identified as one of the areas where the Company's practices should be improved; establishing this positive revenue adjustment should encourage the Company to reduce the number of residential terminations.

Earnings Adjustment Mechanisms[50]

The JP recommends adoption of various Earnings Adjustment Mechanisms (EAMs). The proposed electric EAMs are intended to provide the Company with incentives to: 1) increase electric system efficiency through peak reduction and distributed energy resource utilization; 2) increase achieved electric and gas energy efficiency; 3) reduce residential and commercial customers' electric energy intensity (total usage on a per customer basis); 4) increase residential customer participation in voluntary Time of Use rates; and 5) reduce carbon emissions through increased penetration of emissions-reducing technologies. The JP also recommends allowing the Company to petition for approval of Interconnection EAM targets. The Gas Energy Efficiency EAM is intended to incentivize the Company to achieve energy efficiency savings that are significantly above 37,296 dekatherms (Dth).[51]

Central Hudson has the potential to earn a maximum earnings adjustment of $2.0 million in 2018, $4.3 million in calendar year 2019, $4.7 million in calendar year 2020, and $4.9 million in calendar year 2021 for its electric business. With

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[50] Id., §XXI.

[51] 37,296 dekatherms (Dth) is the current net savings target for the gas ETIP.

respect to the gas business, Central Hudson has the potential to earn a maximum earnings adjustment of $0.18 million in 2018, $0.39 million in calendar year 2019, $0.44 million in calendar year 2020, and $0.47 million in calendar year 2021.[52] The financial consequences of EAMs will be excluded from the computations of actual regulatory earnings.[53]

Geothermal Rate Impact Credit[54]

The JP establishes a geothermal rebate or "rate impact credit" to facilitate installations of this emerging technology.[55] The credit will be funded by incremental heating usage that would be monetized and provided to non-participants through the RDM. To qualify for the annual $264 rate impact credit, a customer must have equipment that meets the requirements of the New York State Energy Research and Development Authority (NYSERDA) Geothermal Rebate Program, and the customer must enroll in Central Hudson's Insights+ offering.[56]

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[52] Hearing Exhibit 22, Joint Proposal, Appendix W lists all EAM targets and incentives.

[53] See Hearing Exhibit 22, Joint Proposal, p. 34.

[54] Id., §XXII.

[55] Following the development of a technology agnostic DER or mass market default rate or a rate that is specifically intended to mitigate the rate impact of geothermal heat pump systems, no further rate impact credit will be paid out. Such a rate is expected to be developed in Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources.

[56] Insights+ is an offering provided on the CenHub Platform that allows customers the ability to enroll in a voluntary, subscription-based service that introduces enhancements to the current Insights experience. The program includes replacement of the customer's existing house meter with an Insights+ meter, enabling the customer to view hourly usage data.

Platform Service Revenues and Demonstration Projects[57]

Central Hudson's online self-service platform, CenHub, was developed by the Company as a REV demonstration project. On April 3, 2016, the CenHub Platform was made available to Central Hudson's customers and, as of December 31, 2017, 42% of Central Hudson's customers have engaged with the CenHub Platform. Upon issuance of this order, CenHub will no longer be considered a demonstration project, but rather will be funded through base rates, with the Platform Service Revenues (PSRs) it generates shared 80/20 between customers and the Company.[58]

Insights+ is an offering provided on the CenHub Platform. It has not been available to customers long enough to assess the value that it can provide to customers. As a result, it will continue as a demonstration project.

Miscellaneous Provisions

Among other provisions of the JP are the following:

1) Acknowledgement that JP terms may be subject to update arising out of generic Commission proceedings, including but not limited to (i) the REV Proceeding; (ii) Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources; (iii) Case 18-M-0084, In the Matter of a Comprehensive Energy Efficiency Initiative; and (iv) Case 17-M-0815, Proceeding on Motion of the Commission on Changes in Law that May Affect Rates;[59] and

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[57] Hearing Exhibit 22, Joint Proposal, §XXIV.

[58] This PSR will be excluded from the calculation of the Company's regulatory earnings.

[59] Hearing Exhibit 22, Joint Proposal, §XXV.A.

2) A proposed process for how disputes regarding the interpretation of the JP or implementation of any of the provisions of the JP should be resolved.[60]

DISCUSSION

Based on our review of the JP and the evidence and arguments supplied by its proponents, we conclude that the JP meets the criteria set forth in the Commission's Settlement Guidelines,[61] such that its terms should be adopted and incorporated into a rate plan for Central Hudson for the next three years. We find that all procedural protections were afforded to all participants in the case, such that the parties had full notice and opportunity to make their views known in both the litigated and settlement tracks of the proceeding. The JP that has resulted from the settlement negotiations reflects compromises made by diverse and ordinarily adversarial parties with strong incentives to craft resolutions that addressed their various interests. It is a proposal that could reasonably be expected to result from litigation. However, as a rate plan developed by so many parties with specialized knowledge, we conclude that it is likely superior to the probable outcome of adversarial litigation. We find that the proposed rate plan reflects an appropriate balancing of ratepayer and shareholder interests, such that the rate increases are close to the minimum necessary to provide the Company with a fair return on its investment while enabling it to provide safe and adequate service and advance important State policy objectives. As such,

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[60] Id., §XXV.F.

[61] Cases 90-M-0255, et al., Procedures for Settlements and Stipulation Agreements, Opinion 92-2 (issued March 24, 1992) (Settlement Guidelines).

the resulting rates are just and reasonable, and in the public interest.

We find much in the JP that is laudable, and we highlight some of its more salient provisions below.

Revenue Increases/Term

We find that the three-year term of the rate plan is in the public interest because it provides customers and the Company with long-term delivery rate certainty and greater stability and ability to plan than would be possible in a one-year litigated case. The three-year term is described by MI as "a sweet spot" that provides the utility with increased revenue certainty and the ability to focus on operating as efficiently as possible without repeated forays into the rate-setting process, provides customers increased rate certainty, and allows utilities, customers, and regulators with the opportunity to avoid annual rate case litigation. Instead, it affords parties the ability to resolve certain issues creatively, in ways not often possible through litigation, including moderating near-term rate impacts over a longer period.[62] The three-year term agreed to in this JP indeed provides the benefits highlighted by MI. In addition, we note that an added benefit of three years is that it is long enough to justify the extensive commitment of time and resources that is required to craft such a comprehensive proposal but still short enough to likely avoid the greater risks of inaccuracy that would accompany the forecasts and projections that would have to be used in a longer-term plan.

The recommended $19.725 million electric delivery revenue increase for Rate Year 1 is substantially lower than the

[62] Statement of Multiple Intervenors in Support of JP (MI Statement), pp. 4-5.

Company's corrected and updated requested Rate Year 1 increase of $66.2 million. The electric revenue increases are driven mainly by increased capital investments and depreciation expense, the change from collecting $8.5 million of energy efficiency costs through base rates instead of via a surcharge, right-of-way maintenance (transmission and distribution), and information technology.

The recommended $6.7 million gas delivery revenue increase for Rate Year 1 is much lower than the Company's requested Rate Year 1 increase of $22.2 million. The gas delivery revenue increases are driven mainly by increased capital investments and depreciation expense, and increases in operational and maintenance expenses related to funding low income programs, the change from collecting $0.8 million of energy efficiency costs through base rates instead of via a surcharge, information technology, and site investigation and remediation costs.

The proposed electric and gas increases reflect adjustments to and compromises from the parties' litigation positions, including compromises between Staff and the Company on items such as the overall electric revenue and gas revenue levels, use of regulatory liabilities as moderators, and the recommended ROE and common equity ratios. MI views the electric and gas revenue requirements, the reflection of anticipated federal tax savings in those revenue requirements, the use of rate moderators and energy efficiency program cost recovery, among others, as some of the most important issues resolved by

this JP.[63] UIU likewise highlights the beneficial impact that concessions by the Company on its requested ROE and equity ratio had on the revenue requirement levels. CLP notes that it argued against a rate increase and the JP proposes more modest increases.[64]

Staff states that the rate increases provided for under the JP are necessary to allow the Company to continue to provide safe, reliable, and affordable service and are driven, on the electric side, by increased capital spending and related depreciation expense and the transfer of energy efficiency expenses currently collected through a surcharge into base rates. Staff adds that while these drivers are not unique to Central Hudson, they are subject to inevitable increase and are difficult to control. We agree with Staff that the revenue levels agreed to in this JP are necessary to ensure that the Company has sufficient funding to provide safe and adequate service at just and reasonable rates. We find the revenue levels to be reasonable, especially in light of the Company's acknowledgement that the JP's lowered revenue requirements results in a rate plan that ensures it has adequate resources to fulfill its statutory obligation to provide safe, adequate, and reliable service, including providing the funding to increase

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[63] MI Statement, pp. 2, 4. MI notes that the electric service classes most relevant to it are (1) SC 3 (Large Power Primary Service) and (2) SC 13 (Large Power Substation and Transmission Service), while the gas service classes most relevant to its interests are (1) SC 9 (Interruptible Transportation Rate) and (2) SC 11 (Firm Transportation Rate – Core, subclasses (a) Transmission and (b) Distribution). The other issues that MI views as among the most important resolved by the JP signatories include the electric and gas revenue allocations and the electric and gas rate designs applicable to large nonresidential customers. Id., p. 2.

[64] Citizens for Local Power Statement on the Joint Proposal (CLP Statement), p. 3.

employee numbers to better serve its customers and handle increasing business complexities, modernize the electric and gas infrastructure, and enhance the Company's IT systems.[65]

We note that the proposed rate increases have been significantly mitigated because of lower federal income tax expense resulting from the recently enacted Tax Act, lower employee pension and OPEB costs because of pension fund gains and a change in accounting, and a decreased overall rate of return and other changes to rate base and have been moderated by the application of credits. Indeed, in support of the revenue requirements that are advocated in the JP, MI credits the "fortuitous timing of a substantial federal income tax reduction and the availability of tens of millions of dollars in regulatory liabilities (*i.e.*, deferred customer credits) for use as rate moderators" for helping to get the increases to a level that it could support, rather than oppose.[66] The Company, Staff, and MI acknowledge that the revenue requirement amounts set forth in the JP reflect material estimated federal income tax

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[65] Statement of Central Hudson Gas & Electric Corporation in Support of Joint Proposal (Company Statement), pp. 8-9, 11.

[66] MI Statement, p. 7. While MI supports the JP revenues requirements, it urges the Commission to reevaluate some of its policies and priorities and thereby help to "stem the tide of significant utility delivery rate increases that are threatening the ability of businesses and industries to remain competitive in New York State." MI Statement, pp. 5-6; see also MI Statement, p. 8.

reductions,[67] which they and others agreed to allocate 100% to customers, as fair, equitable, and in the public interest. MI adds that the capture of 100% of the estimated Tax Act savings for the benefit of customers in the form of lower delivery rates starting in Rate Year 1 was very important and indeed contributed to its decision to execute and support the JP.[68]

With respect to the proposed use of credits, we note that, by adopting Staff's recommendation to spread the regulatory credits over a three-year period instead of the Company's litigation recommendation to use all the credits to offset Rate Year 1 increases, the JP will provide rate mitigation both during and after the term of the rate plan.[69] The agreement regarding the use of credits garnered widespread support among the Signatory Parties. MI says that it strongly supported the negotiated return of $34.5 million of regulatory

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[67] The JP proposes that the Company be "held harmless for any changes it is required to make due to the [Tax Act] and/or any state or local action resulting from the [Tax Act] and is authorized to defer the revenue requirement of any changes it is required to make due to the [Tax Act]." JP, p. 26. At the hearing, the Company explained that, due to time constraints, the parties had been able only to estimate the financial effects the Tax Act would have on the Company and the associated amounts to be allocated to the ratepayers. As such, the Company explained, the term "held harmless" was included in the JP to clarify that the Company would be able to defer the revenue requirement impacts not directly related to the Tax Act or other impacts that were unknown at the time the JP was executed. Evidentiary Hearing Transcript (Tr.), pp. 17-28.

[68] MI Statement, pp. 9-12.

[69] Staff acknowledges that the use of a bill credit to moderate electric rates in Rate Year 3 will force a small rate increase at the end of the Rate Plan's three-year term, but says that the impact is minimal and the rate moderators proposed under the JP do not use all projected available net regulatory liabilities, thus leaving a portion available for future offset use. Staff Statement, pp. 21-23.

liabilities to electric and gas customers, adding that the amounts settled upon provide substantial moderation of what otherwise would be considerably higher delivery rate impacts.[70] UIU similarly touts the proposed use of credits when it observes that the JP further cushions customer impacts by (1) spreading the revenue recovery over a three-year period and (2) allocating electric and gas bill credits to each service class as rate moderators, both of which help soften customer rate shock. Moreover, UIU adds that it supports the Company's passing back customer credits in a timely manner while reserving some customer credits to help mitigate future rate increase.[71] The JP's approach to the use of bill credits is another one of several of its recommendations that are evidence of a result that falls within a range of reasonable litigated outcomes and is supported by record evidence.

Almost all the public comments received in these proceedings voiced opposition to any rate increases. However, we find that the increases recommended in the JP are necessary as they provide sufficient revenues to allow Central Hudson to maintain and improve the provision of safe and reliable electric and gas service, at just and reasonable rates. Among other things, increases are needed to allow the Company to maintain and upgrade its electric and gas infrastructure and information systems, fund additional energy efficiency expenses, and significantly expand its low income customer discount programs. The use of customer credits to offset the increases will moderate the delivery rate impacts, providing some measure of rate relief for all customers. With such offsets, the total monthly bill for a typical residential customer will increase,

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[70] MI Statement, pp. 12-13.

[71] Utility Intervention Unit Statement in Support of the Joint Proposal (UIU Statement), pp. 3-4.

on average, by $1.46 (or 1.3%) for electric service and $2.54 (or 2.1%) for gas heating service in Rate Year 1. In addition, the numerous reconciliation provisions, along with the earnings sharing mechanism, will protect ratepayers to the extent there are variances between the estimated costs that comprise the revenue requirement and the Company's actual expenditures.

Staff was the only party to present a case in support of alternative overall revenue requirements. Ultimately the parties that engaged in the extensive negotiations that led to this JP agreed to the amount of the proposed increases that we are now approving. We find that the results of those negotiations are in the public interest and fall within the reasonable range of outcomes likely to result from litigation.

Cost of Capital

For Rate Year 1, the JP establishes rates based on a return on equity of 8.8% and a 48% common equity ratio for both Central Hudson's electric and gas businesses. The common equity ratio increases to 49% in Rate Year 2 and 50% in Rate Year 3. The foregoing provides the Company with an overall after-tax cost of capital of 6.44% in Rate Year 1, 6.49% in Rate Year 2, and 6.54% in Rate Year 3.

In its litigated case, Central Hudson initially sought a 9.5% ROE, which its ROE witness described as the low end of a 9.48% to 10.15% range of reasonableness.[72] The Company's witness derived her range of results by employing combinations of her low, mean and high Discount Cash Flow (DCF) analyses with her Capital Asset Pricing Model (CAPM) analyses and either weighting the two methodologies equally or two-thirds DCF to one-third

[72] Hearing Exhibit 1, Pre-filed direct testimony of Company Witness Buckley, p. 5.

CAPM.[73] The Company also requested a 50% common equity ratio.[74] In contrast, Staff's litigated position supported an 8.3% ROE.[75] Staff's position was rooted in the Commission's traditional weighting of two-thirds DCF to one-third CAPM results recently reaffirmed in our 2018 rate order for Niagara Mohawk Power Corporation.[76] Staff recommended a 48% common equity ratio.[77]

Central Hudson, MI, UIU, and Staff note that the proposed ROE and common equity ratios reflect a balancing of the concessions made by the Signatory Parties in the context of the financial and economic circumstances anticipated for Central Hudson during the JP's term.[78] UIU, for example, notes that the reduction in ROE from 9% to 8.8% reduces the electric and gas revenue requirements each of the three rate years, thus benefitting customers. In its support of the proposed 8.8% ROE and the increasing common equity ratios, Staff notes that these

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[73] Id., pp. 3-5.

[74] Id., p. 90.

[75] Hearing Exhibit 16, Pre-filed direct testimony of Staff Finance Panel, pp. 9-10.

[76] See Case 17-E-0238 and 17-G-0239, Niagara Mohawk Power Corporation – Rates, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans (issued March 15, 2018), p. 37 (2018 Niagara Mohawk Rate Order).

[77] Hearing Exhibit 16, Pre-filed direct testimony of Staff Finance Panel, pp. 9-10.

[78] See, e.g., Company Statement, pp. 21-22; MI Statement, pp. 7-8; Staff Statement, p. 42; and UIU Statement, pp. 3-4. Central Hudson and UIU, for example, note that the Company's concessions regarding the reductions in its requested ROE (moving from 9.5% to 8.8%) and equity ratio (50% to 48% in Rate Year 1 and 49% in Rate Year 2) helped to reduce the electric and gas revenue requirements, while MI notes that its compromise on equity ratio should not be read as an intent to modify, or signal any movement away from, the Commission's longstanding practice of capping a utility's equity ratio for ratemaking purposes at 48% absent extenuating circumstances.

terms adequately recognize the increased financial risk and business risk that are inherent when setting rates over a multi-year period and the higher interest rate environment since its 8.3% recommended ROE determination.[79] These terms also recognize the pressure on the Company's financial metrics attributable to the Tax Act.

Regarding the 50 basis point difference between its 8.3% ROE recommendation and the JP's 8.8% ROE, Staff explained that, "as opposed to a single-year rate decision, the extended term of the JP inherently carries more financial risk as investors are subject to additional risk economic conditions will change and the actual cost of capital will increase during the three-year interim."[80] Staff adds that "because the JP also locks in forecasted amounts for numerous elements of expense for the three-year term of the JP, Central Hudson's business risk is also impacted by the potential that actual operating costs turn out to be greater than those forecasted."[81]

Staff also represents that current economic conditions indicate that the Commission's preferred ROE methodology would produce a higher ROE than the 8.3% ROE it recommended using data through September 2017. It notes that in September 2017, the yield requirements on 10-year and 30-year U.S. treasuries were 2.31% and 2.87%, respectively. When the JP was signed on April 18, 2018, those same yields had increased to 2.87% and 3.06%.[82]

In the most recent National Fuel Gas Distribution Company (NFG) rate order, the Commission reaffirmed the

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79 Staff Statement, p. 40.

80 Id., p. 41.

81 Id., pp. 41-42.

82 Id., p. 40.

principles underlying our long-standing methodology for calculating a reasonable return on equity for a rate plan, regardless of whether it is ordered on a settlement or litigated track.[83] Those elements consist of the application of DCF and CAPM analyses to a representative proxy group of utility companies; the use of a two-stage DCF computation with inputs derived from Value Line; the basing of CAPM results on an average of the outcome from standard and zero-beta models with a risk-free rate based on Treasury bonds, market risk premium provided by Merrill Lynch's Quantitative Profiles, and betas taken from Value Line; and the use of a 2/3 – 1/3 weighting of the DCF and CAPM results, respectively.[84]

We agree with Staff that that a return on equity that is higher than the one produced by our preferred methodology is reasonable in this case considering the added financial and business risk accepted by Central Hudson. Specifically, we find the JP's 8.8% ROE is reasonable as it is based on the application of our cost of equity methodology plus a rational premium to compensate investors for the additional risk that economic conditions could increase the cost of capital during the three-year rate plan as well as for the possibility that actual operating costs turn out to be greater than those forecasted by the JP. With respect to increases in the cost of capital, we note that an update of our preferred methodology is now 8.6%. This is evidence of the very real financial risk being borne by the Company as the soonest its rates may be adjusted to reflect increases in the cost of capital is July 1, 2021.

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[83] Case 16-G-0257, National Fuel Gas Distribution Corporation – Rates, Order Establishing Rates for Gas Service (issued April 20, 2017), pp. 53, 57 (2017 NFG Rate Order).

[84] Id., pp. 52-53.

We also find the ESM included in the JP to be reasonable. As we have previously stated, such mechanisms give the utility an incentive to cut costs during the rate plan. If the savings achieved are significant enough, customers will benefit during the rate plan. The higher sharing percentages as the ROE increases provide an important protection for customers against forecasted cost errors, especially in the later years of the rate plan. When rates are reset, customers will capture the full benefit of the cost-cutting going forward.

Turning to the 49% Rate Year 2 and 50% Rate Year 3 common equity ratios, Central Hudson and Staff state that the specific intent is to provide the Company with a reasonable opportunity to maintain its credit ratings within the "A" categories of the major credit ratings agencies.[85] In testimony, Central Hudson argued that a 50% common equity ratio was needed for it to be upgraded to an "A" rating from Standard & Poor's while Staff argued that increasing the Company's authorized common equity ratio from 48% to 50% was neither necessary or cost-effective. Subsequently, on December 22, 2017, the Tax Act was signed into law. For utilities, the cash flow ramifications that result from the Tax Act's provisions are largely viewed negatively by the major credit ratings agencies and according to the JP, the compromise common equity ratios contained in the JP acknowledge the change in Central Hudson's creditworthiness associated with the Tax Act.

According to Staff, the JP's use of a greater equity cushion over the next several years is warranted because the modest cost incurred to strengthen Central Hudson's balance sheet, and thereby materially enhance the Company's critical cash flow metrics, is a reasonable tradeoff considering the

[85] Company Statement, pp. 21-22; Staff Statement, pp. 40-41.

potential costs to ratepayers should the Company's credit ratings fall out of the "A" ratings categories.[86] Central Hudson opines that the proposed equity ratios reflect a reasonable compromise between the litigated positions of it and Staff.[87]

Given the degree of uncertainty regarding the ultimate impact of the Tax Act on the Company's creditworthiness, we find the JP's use of higher common equity ratios in Rate Year 2 and Rate Year 3 to be a responsible and reasonable measure to forestall, or at least diminish, the prospect of higher future borrowing costs attributable to a diminution in Central Hudson's creditworthiness over the next several years. As Staff points out, the Company could face higher borrowing costs of approximately $5 to $10 million on a net present value basis with a one-notch downgrade, while the added cost of the thicker common equity layer, in terms of revenue requirement, is about $1 million in Rate Year 1 and $2 million in Rate Year 2.[88] In sum, while each utility will have different circumstances, the parties to this JP have adequately demonstrated the reasonableness of bolstering Central Hudson's ratemaking common equity ratio in the short run during the rate plan to counter the near-term negative impacts of the Tax Act.

IT Upgrades

The JP includes enhancements to the Company's IT that will allow it to modernize its systems and meet increasing customer, regulatory, and business demands. One such project is the planned modernization of the Company's Customer Information System (CIS), which is more than 35 years old. The pursuit of this project is consistent with the high priority placed on IT

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86 Staff Statement, p. 41.

87 Company Statement, pp. 21-22.

88 Staff Statement, p. 41.

modernization by the Commission in the most recent management audit of Central Hudson.[89]

The JP's new reporting requirements related to IT projects, set forth in JP Appendix P and summarized earlier in this order, will help to ensure accountability and transparency. We find that the provision of funding that will permit the Company to prioritize IT capital projects, especially when coupled with these new reporting requirements, is in the public interest and should be approved.

Training Center and Primary Control Center Projects

In its initial testimony, Central Hudson proposed to construct a Training Center that would allow it to educate its changing workforce in a safe and controlled environment that simulates real-life field conditions. The Company asserted that the Training Center would benefit customers by allowing Central Hudson to conduct drills with first responders; provide training on pipeline operation and maintenance in response to changes in gas safety regulations; and conduct electric progression training under simulated conditions, thereby no longer requiring the Company to take equipment out of service to conduct such training. Central Hudson contended that the Training Center's goal was to ensure that Central Hudson continues to provide safe and reliable service. The Training Center was proposed to be a multi-year, dual-phase project, estimated to cost about $32.5 million dollars, with an in-service date of January 2021.[90]

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[89] Case 16-M-0001, In the Matter of a Comprehensive Management and Operations Audit of Central Hudson Gas & Electric Corporation, Order Releasing Audit Report (issued October 24, 2017).

[90] See Hearing Exhibit 1, Pre-filed testimony of Central Hudson's Training and Development Panel (TDP) and Exhibit, TDP-3.

Central Hudson also proposed to construct a new, more modern Transmission and Distribution Primary Control Center, co-located with the Training Center. The Company stated that the current control center is too small and lacks the technology needed to support the Distribution Management System, a system that will allow remote control monitoring of the electric distribution system.[91] The Company proposed to spend about $2.2 million in 2018 and $1.7 in 2019 on the Primary Control Center.[92]

In its pre-filed testimony, Staff agreed that the centers were needed, stating, among other things, that a centralized training center with classrooms equipped with computers, IT support, Internet, site security protocols, and hands-on equipment, would provide more efficient and effective training programs for Company employees and contractor personnel, including training capable of keeping pace with the increased training requirements for pipeline operation and maintenance. Staff stated that, since the proposed Training Center would provide value to ratepayers, the provision of training at the proposed facility to both Company personnel and non-Company personnel (e.g., qualified contractors performing work for the utility and first responders) is appropriately ratepayer funded.

Staff asserted that the need for additional training could reasonably be expected as requirements pertaining to work performed on electric and gas facilities are expected to be expanded in the near term. However, given its concerns that the Company had not yet purchased land or finalized the permitting process, Staff stated that the Company's proposed timeline was

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[91] See Hearing Exhibit 1, Pre-filed Testimony of Central Hudson's Distributed System Platform Panel.

[92] See Hearing Exhibit 1, Pre-filed Exhibits of Central Hudson's Training and Development Panel, TDP-3.

too aggressive and the scope and final cost of the Training Center might be excessive. With respect to the proposed Primary Control Center, Staff noted that under the Company's proposed timeline, it would not be in service until 2021. As a result, Staff recommended that the Company meet with Staff quarterly regarding both Projects; file annual progress reports on both Projects with the Commission; and not be given full symmetrical deferral of all Primary Control Center expense items. Staff also recommended the disallowance of proposed 2018 and 2019 capital budget amounts associated with the Primary Control Center.[93]

As noted in the summary of the JP, *supra*, the Joint Proposal outlines a process that requires the Company to provide information about the scope of and timeline for the Projects, and then provide periodic major milestone reports thereafter. Under the JP, the Company would be allowed to develop the Projects, subject to approval, delay, or cancellation of such deployment and implementation by either the Director of the Office of Electric, Gas, and Water or by the Commission.

The Company and Staff have persuasively demonstrated, due to emerging technologies and changing safety standards and workforce, that the Company needs a centralized approach to training that offers hands-on and scenario-based training opportunities for Central Hudson employees, outside contractors (such as tree trimming contractors and LPP contractors), municipal agencies (e.g., Department of Public Works, first responders, etc.) and mutual aid crews, to ensure that the Company continues to provide customers with safe and reliable service. They also have convincingly established that the

[93] Hearing Exhibit 16, Pre-filed Testimony of Staff Training Panel, pp. 13-15.

Primary Control Center will ensure that Central Hudson retains the ability to monitor and control its distribution system.

We find that the process outlined in the JP, with one additional requirement, will facilitate the development of the proposed Training Center and Primary Control Center and a utility workforce with necessary skills to consistently, efficiently, and effectively construct and maintain the safety, adequacy, and reliability of the electric and gas facilities and systems used to provide electric and gas service to Central Hudson customers. While the JP requires Staff and the Company to meet and discuss the major performance milestones timeline within 60 days of the filing of the Initial Report and provides for a Commission ruling if mutual agreement cannot be reached, the Company is hereby not authorized to make any capital expenditures on the Training Center and Primary Control Center prior to receiving approval of the Initial Report and major performance milestones timeline from the Director of the Office of Electric, Gas, and Water, upon consultation with the Commissioners at the direction of the Chair. We also caution that the Training Center should be dedicated to the betterment of the workforce and be designed for the necessary functions the workforce performs and not for unnecessary or duplicative objectives that could be reasonably performed elsewhere. In addition, we note that one near-term focus should be on improving and meeting operator qualifications and meeting gas safety requirements. By defining the scope, major performance milestones, and associated checkpoints; allowing for the establishment of a specific time for meeting clear, readily measured indicators that show functional capabilities as well as operational integration; and defining a method to implement and document the Projects' checkpoint compliance, review, and approval process, the process supports careful and considered

planning by the Company and ensures periodic review by the Staff. By expressly making the continuation of the Projects' development and implementation subject to potential alteration or cancellation by the Director of the Office of Electric, Gas, and Water, in consultation with the Commissioners at the direction of the Chair, or by the Commission itself, the process we are approving should help ensure that the concerns about the cost and scope of the centers are appropriately balanced against need for training and for a qualified and capable utility workforce.[94] Moreover, by this Order, we are limiting the amount of plant in service for the Projects to the proposed $5 million. Any additional amounts will be authorized only by future Commission approval. With these additional requirements, the gradual and considered development of these Projects as outlined in the JP reflects a reasonable compromise and is in the public interest.

Low Income Programs

Changes to the Company's current Low Income Program, called the Enhanced Powerful Opportunity Program (EPOP), are required to satisfy program modifications established in the Commission's generic low income proceeding.[95] The Low Income Order established a policy to limit energy costs for low income households to no more than six percent of household income and adopted a default methodology for setting tiered discount levels

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[94] It is our understanding that the Rate Year 2 and Rate Year 3 revenue requirements include a total of $5 million in funding for the development of the proposed centers. The Company and Staff testified that this amount reflects the levels of plant in service assumed in the Rate Year 2 and Rate Year 3 revenue requirements, adding that this amount is intended to fund the acquisition of land and the construction of the proposed gas village. Tr. 38-39.

[95] Case 14-M-0565, supra, Low Income Order and Low Income Rehearing Order.

that vary based on the level of need. The Low Income Order also established a funding limit such that the utility's total budget may not exceed two percent of total electric or gas revenues for sales to end-use customers. Pursuant to the Low Income Order, on September 16, 2016, Central Hudson filed a Low Income Program Implementation Plan with the Commission, which approved the plan with modifications on February 17, 2017.[96]

The Company's current EPOP has three components: a bill discount, arrears forgiveness, and a reconnection fee waiver. The Company's initial testimony indicated that it stopped accepting enrollments into EPOP on April 15, 2017, and, beginning on or about November 15, 2017, EPOP would be replaced with its new Low Income Bill Discount Program in accordance with the Implementation Plan, as modified by the Implementation Order. Low income customers are eligible for the Low Income Bill Discount Program if they receive HEAP benefits for their electric, gas, or other fuel services. The new Low Income Bill Discount Program will have the following components: monthly low income bill discounts; automatic enrollment in Budget Billing, with an opt-out option; and reconnection fee waivers.

The JP proposes significant incremental funding for the new Low Income Bill Discount Program: $8.612 million in Rate Year 1 ($5.727 million for electric and $2.885 million for gas); $11.015 million in Rate Year 2 ($7.325 million for electric and $3.690 million for gas); and $12.018 million in Rate Year 3 ($7.992 million for electric and $4.026 million for gas). These funding levels will result in bill discounts for electric heating and non-heat customers of between $19 and $39 per month, gas heating customers of between $30 and $50 per

[96] Case 14-M-0565, supra, Order Approving Implementation Plans with Modifications (issued February 17, 2017) (Implementation Order).

month, and gas non-heating customers of $3 per month.[97] These discounts are much greater than the current monthly discounts of $5.50 for non-heating gas and non-heating electric customers, $17.50 for electric heating customers, $5.50 for gas heating customers, $23 for heating customers utilizing both electric and gas, and $11 for non-heating customers utilizing both electric and gas.[98]

The Company will phase out the arrears forgiveness aspect of EPOP during Rate Year 2. However, Central Hudson will maintain the arrears forgiveness component of the EPOP program for customers who were EPOP participants for so long as they continue to qualify for the program and/or until they have completed the arrears forgiveness component. Given that the arrears forgiveness program under EPOP provided a benefit for 36 months, the last EPOP customer is expected to exit the program in or about March 2020. The total costs associated with the arrears forgiveness component of EPOP are forecasted to be $142,000 in Rate Year 1 and $6,000 in Rate Year 2. These amounts fall well under the amount approved in the Implementation Order, which was $260,482 per year.

The Low Income Order provides utilities with the option to charge or waive reconnection fees for low income customers. The JP proposes continuing Central Hudson's Reconnection Fee Waiver Program, with an increased allowance of

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[97] Hearing Exhibit 1, Pre-filed direct testimony of Central Hudson's Low Income Panel, p. 7, Table 1. The discounts will be calculated according to the eligibility criteria described in the Low Income Order. Hearing Exhibit 16, Pre-filed direct testimony of Staff's Consumer Policy Panel, p. 16.

[98] Hearing Exhibit 16, Pre-filed direct testimony of Staff's Consumer Policy Panel, p. 9.

$51,000 for each Rate Year.[99] This funding level is within the permissible budget total established in the Low Income Order, and will permit the Company to offer eligible low income customers a one-time waiver of the reconnection fee.[100]

The JP proposes that the Company will defer Low Income Bill Discount program costs in excess of the proposed amounts for future recovery from ratepayers, as authorized by the Low Income Order, and it will defer under-expenditures for future use to support low income programs. Symmetrical deferred accounting is proposed for costs associated with the arrears forgiveness phase-out and the Reconnection Fee Waiver Program. In addition, the Low Income Bill Discount Program will undergo annual adjustments to account for changes in enrollment projections, average bill amounts, and State Median Income levels that underlie HEAP income eligibility limits.

Finally, the JP requires the Company to update and improve its customer service Integrated Voice Response (IVR) messaging system to include information about the new Low Income Program, including the availability of and requirements for eligibility for the program.[101]

The Company states that the proposed Low Income Program is consistent with the Low Income Order and will serve nearly 25,000 customers by the end of Rate Year 3. It states that the provision for the automatic enrollment of eligible customers in the Budget Billing Program serves the public interest by offering those customers levelized bills. The

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[99] Current allowance for this program is $35,000 annually. Id., p. 22.

[100] The Company's reconnection fees currently range from $20 to $100. Hearing Exhibit 1, Pre-filed direct testimony of Central Hudson's Low Income Panel, p. 12.

[101] Hearing Exhibit 22, Joint Proposal, p. 59.

Company believes that the levelized bills will protect those customers from the rate shock associated with price spikes resulting from periods of high energy consumption. In addition, the Company believes that the proposed enhancements to its IVR system will provide customers with greater transparency regarding payment options, which will reduce the number of service terminations for customers in arrears. The Company adds that the planned phase-out of the arrears forgiveness program is reasonable given the overall increase in funding and customer outreach associated with the new Low Income program.

Staff comments that the funding levels for the new Low Income Program will provide eligible low income customers with reductions in their monthly bills of between 17% and 65%.[102] Staff reports that the Signatory Parties all agreed that the Company should replace its existing low income customer program with the proposed new program. According to Staff, the new Low Income Program complies with the Implementation Order, and the annual rate allowances comply with Commission directives to cap the budget for the program at 2% of sales revenue.

PULP adds that it supports this new Low Income Program given that the program will serve more customers and receive greater funding than the previous program and, thus, better serve the public interest.[103]

We agree that the JP's proposal to implement the new Low Income Discount Program as approved by the Implementation Order is reasonable. It is estimated that Central Hudson's new Low Income Program ultimately will serve nearly 25,000 customers, which is approximately three times the number of customers currently being served under the EPOP. We previously

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[102] Staff Statement, p. 9.

[103] PULP Statement in Support of JP, pp. 6-7.

have recognized there is a significant energy "affordability gap,"[104] and the proposed program considers the projected increased customer participation and discount levels sufficient for participating customers to keep their energy burden at or below 6% of the household income. Central Hudson's new Low Income Program follows the structure for low income programs established in the Low Income Order and Rehearing Order, which resulted from an extensive process designed to carefully balance the interests of low income customers, other customers, and the utilities.

Vegetation Management

Generally, the purpose of funding for Central Hudson's vegetation management programs is to minimize customer outages caused by trees and tree limbs coming into contact with overhead power lines. The Company's transmission right-of-way (ROW) vegetation management program consists of routine ROW maintenance, including vegetation trimming, danger tree removal, and ROW edge reclamation. The Company's main distribution ROW maintenance activity is scheduled on- and off-road line clearance, which work is performed on a four-year cycle. The JP proposes funding levels for Central Hudson's ROW maintenance programs for both transmission and distribution lines that are increased above those levels established in the prior rate order.

In its initial filing, the Company proposed a distribution ROW vegetation management program budget of $25.57 million for Rate Year 1, which included $11.50 million in incremental funding for its line clearance cycle, reinstatement of the Enhanced Line Clearance Program, and a new activity to mitigate the impacts of the Emerald Ash Borer. Staff agreed

[104] Low Income Order, supra, pp. 4, 8.

with the Company that the Emerald Ash Borer was causing unprecedented tree-related risks. Staff nevertheless recommended downward adjustments to aspects of the Company's proposed distribution ROW vegetation management program, resulting in a recommended rate allowance of $19.59 million in Rate Year 1. Staff specifically recommended that the Enhanced Line Clearance Program not be allocated any funds since, if the work proposed under the other aspects of the Company's ROW maintenance programs were completed, reliability performance gains comparable to those proposed in the Enhanced Line Clearance Program would be achieved.[105]

The JP follows Staff's recommendations for funding the Company's distribution line ROW clearance program at $19.59 million in Rate Year 1, $20.00 million in Rate Year 2, and $20.419 million in Rate Year 3, for a total of $60.01 million.[106] The variance between the figures proposed in the JP and the Company's initial request is due to the elimination of the proposed incremental line clearance miles associated with the Company's on- and off-road line clearance and the re-funding of the Enhanced Line Clearance Program.

As for its transmission ROW vegetation management program, the Company initially proposed a budget of $2.45 million for Rate Year 1. The Company later filed supplemental testimony proposing to increase the Rate Year request to $4.77

[105] Hearing Exhibit 16, Pre-filed direct testimony of Staff's Vegetation Management Panel, pp. 25-27.

[106] Hearing Exhibit 22, Joint Proposal, Appendix A, Schedule 1.

million, an increase of approximately $2.3 million.[107] Central Hudson claimed that the increased request related to its need to perform work that was not completed within the 2015 Rate Plan budget. Staff recommended downward adjustments to Central Hudson's transmission ROW maintenance budget to $2.25 million.[108] In rebuttal, the Company proposed $3.5 million to address time-sensitive backlog work.

The JP proposes to accept the Company's figure offered in rebuttal for Rate Year 1, and proposes $2.9 million in Rate Year 2 and $2.61 million in Rate Year 3.

Finally, the JP proposes that the allowances now will be subject to an annual reconciliation, which will permit the Company to have more flexibility by allowing specified dollar amounts to be used as necessary in different Rate Years.[109] Specifically, the JP proposes that the Company may defer funds from under-spending on vegetation management in Rate Year 1 for use in Rate Year 2 and from under-spending in Rate Year 2 for use in Rate Year 3. For distribution ROW vegetation management,

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[107] See Case 17-E-0250, Petition of Central Hudson, Order Denying, in Part, Deferral Accounting and Recovery of Additional Distribution and Transmission Vegetation Management Funds and Relief from the 2016 Frequency Performance Metric (issued September 18, 2017). Central Hudson had petitioned the Commission for additional funding to implement a targeted distribution danger tree program, as well as additional funding for transmission ROW maintenance. The Commission denied the Company's request for an additional $1.9 million in incremental funding for transmission ROW maintenance, finding that, unlike with distribution ROW maintenance, which had been affected by the rapid migration of the Emerald Ash Borer, there were no unforeseen circumstances that affected the Company's transmission ROW maintenance.

[108] Hearing Exhibit 16, Pre-filed direct testimony of Staff's Vegetation Management Panel, pp. 8-14.

[109] Hearing Exhibit 22, Joint Proposal, p. 18.

the amount that can be deferred is capped at $1 million, and for distribution ROW maintenance the amount is capped at $500,000. In Rate Year 3, if the Company underspends the Rate Year 3 allowance and any other previously deferred funds, all the underspent funds will be deferred for ratepayer benefit.

Similarly, the Company may defer overspending from one rate year to the next, thereby reducing the next rate year allowance. The same deferral caps are applicable. If Central Hudson overspends in Rate Year 3, all overspending will be absorbed by the Company, with no deferral.

The Company says that the reconciliation method proposed in the JP will provide it with flexibility between Rate Years, but also provides ratepayers with protection by proposing a downward-only deferral mechanism at the end of Rate Year 3. The Company explains that this asymmetrical deferral will benefit customers by safeguarding them from any overspending by the Company and prevent the Company from benefitting if it underspends.

Staff says that the vegetation management funding levels proposed in the JP will allow Central Hudson to improve reliability by reducing tree-related outages on distribution and transmission lines. Staff agrees with the Company that the Emerald Ash Borer is causing significant tree-related risks and that the Company must proactively address the threat.

An aggressive vegetation management program designed to decrease tree-related outages and thereby improve reliability is of critical importance. The funding levels proposed in the JP strike a fair compromise between the respective budgets initially proposed by the Company and Staff. The Commission recognizes the effect the Emerald Ash Borer and other invasive species have on trees within Central Hudson's territory and believes that the level of funding provided for in the JP, as

well as the new policy permitting annual reconciliation, will provide the Company with the necessary funds and flexibility to effectively implement its vegetation management programs, thereby preserving electric system reliability for customers.

Geothermal Rate Impact Credit

The JP proposes that, within its Carbon Reduction Program (CRP), Central Hudson will develop a Geothermal Rate Impact Credit program in collaboration with NYSERDA. The rate impact credit, which is proposed to be $264, would be paid to participating residential customers annually, by June 30 of each year. The credit was calculated by comparing the additional delivery revenue that the Company would receive from the incremental energy use during the heating season of the geothermal heat pump under the current rate design, to what those revenues would be under a more cost reflective rate design. This difference, for an averaged size geothermal system in the Company's territory results in $264. In order to qualify for the credit, customers must install equipment that meets the requirements of NYSERDA's Geothermal Rebate Program. In addition, the JP proposes that the participating customer be required to enroll in Central Hudson's Insights+ program.[110]

The JP proposes funding the Geothermal Rate Impact Credit through an expense component of the electric RDM. Specifically, Geothermal Rate Impact Credits paid to customers

[110] Insights+ is a subscription-based, demonstration project that Central Hudson began offering on its CenHub Platform in June 2017. Central Hudson currently offers the subscription at a subsidized cost of $4.00/month. The subsidization will end once Insights+ no longer qualifies as a demonstration project. However, since Insights+ has not been available for a sufficient period-of-time to evaluate its value to customers, the program will remain a demonstration project following the issuance of this Order. Hearing Exhibit 22, Joint Proposal, pp. 73, 75.

taking service under SCs 1 and 6 will be subtracted from Actual Delivery revenue in the month that they are incurred prior to the monthly comparison of Actual Delivery Revenue to the Delivery Revenue Target.[111] The JP further proposes that, while the rate impact credit will not be included in the CRP funding cap, any necessary customer outreach, education, or implementation funding will be included.

The Company states that this proposal is in the public interest as it promotes geothermal systems, which are both environmentally and customer-friendly in that they are emissions-free and energy-efficient systems.

NY-GEO, CLP, and Bob Wyman also all generally support the Geothermal Rate Impact Credit and consider it a step forward in helping ratepayers adopt more energy-efficient alternatives to fossil fuels, thereby reducing carbon and other greenhouse gas emissions in the State.

The reduction of carbon emissions is a primary goal of New York State's Energy Policy. The Geothermal Rate Impact Credit will assist in reducing the upfront cost of investment in this energy-efficient alternative to the carbon-intensive heating and cooling methods currently utilized by many of Central Hudson's customers. In addition, by pairing the credit with NYSERDA's Geothermal Rebate Program, Central Hudson's program will assist customers in choosing and identifying quality equipment and contractors. Furthermore, funding of the credit is provided by the increased delivery revenue associated with the incremental electric usage during the heating season that the geothermal system customer will provide. This rebate recognizes the benefits that additional off-peak energy usage can provide to the system at the same time as not increasing the

[111] Hearing Exhibit 22, Joint Proposal, p. 42.

system peak and therefore costs. This program will provide encouragement to customers to adopt this emerging, environmentally beneficial technology, which, in turn, will help the customers reduce their total energy bill and, at the same time, help the State meet its ambitious energy efficiency and carbon reduction goals.

CenHub

CenHub is the Company's website and portal where customers can engage by learning about their energy consumption to help them make decisions about their usage. Beginning as a REV demonstration project, over 40% of the Company's residential customers are now enrolled in the platform and the Joint Proposal includes provisions to fund the platform through base rates. This platform will allow for the seamless provision of information, decision making and access to incentives and rebates for a host of energy efficient products and services. Overall, this platform will increase the Company's effectiveness in delivering energy efficiency programs and have a positive impact on reducing customer bills.

Energy Efficiency

Central Hudson originally proposed an ETIP annual budget, including evaluation, measurement, and verification (EM&V) and administrative costs, of approximately $8,479,345 for electric and $837,356 for gas. Staff recommended that the Company increase its annual ETIP funding for electric to $9,772,740 and for gas to $1,182,179.[112] Staff also recommended in its testimony a downward-only reconciliation of the Company's actual expenditures, to be conducted cumulatively every three years, as well as recovery of the electricity energy efficiency

[112] Hearing Exhibit 16, Pre-filed direct testimony of Staff Markets & Innovation and Energy Efficiency Panel, p. 12.

program costs between individual service classifications on an energy basis to ensure revenue-neutral cost allocation.[113]

The JP adopts Staff's proposed funding levels for each rate year, resulting in totals for the yearly energy efficiency budgets that are approximately 15 percent larger for electric and 40 percent larger for gas. As of July 1, 2018, these amounts will be collected in each rate year through base rates, as Staff had proposed in its testimony, rather than through the energy efficiency tracker surcharge portion of the SBC. This shift is consistent with Commission policy because it promotes a more comprehensive approach to energy efficiency, which can be combined with peak-reduction and system-efficiency activities, as cohesive components of the Company's core business.

The electric ETIP cost allocation will be based on 87.3% Energy and 12.7% Coincident Peak Demand. The gas allocation will reflect the residential (SCs 1 and 12) and non-residential (SCs 2, 6, 11 and 13) cost recovery responsibility split of 86.7% and 13.3%, respectively, currently applied to the ETIP amounts authorized for recovery in Case 15-M-0252 (Matter of Utility Energy Efficiency Programs). These costs will be carefully allocated in accordance with the JP provisions, so that some customers will remain exempt from responsibility for these costs in the same way that they enjoyed exemption from costs under the Energy Efficiency Tracker (EE Tracker).

In addition, the JP proposes that the Company be allowed to defer any over- or underspending for the period July 1, 2018, through June 30, 2021. At December 31, 2021, any net cumulative under expenditures will be deferred by the Company for funding future energy efficiency programs, but any over-spending will be absorbed by the Company. During the

[113] Id., pp. 14-15.

period of the rate plan, the Company still will be required to file ETIPs, however, which eventually will become a more comprehensive System Energy Efficiency Plan.

Along with the increased budgets, the JP proposes a 40% increase of the Company's current ETIP targets for energy efficiency programs, with corresponding EAM incentives for achieving or exceeding those targets, all of which will result in significant electric and gas savings. As proposed in the JP, the Company must achieve electric energy efficiency net savings of 47,936 MWh per year in the calendar years 2018 through 2021, and gas energy efficiency savings of 52,214 Dth per year in the same period.[114] The Energy Efficiency EAM targets for electric and gas should be converted to gross MWh and gross MMBtu targets, respectively, for electric and gas to be consistent with the Order issued on March 15, 2018 in Case 15-M-0252.[115] Therefore, the minimum gross MWh target for electric energy efficiency savings is 53,262 MWh and the minimum gross MMBtu target for gas is 58,016 MMBtu. The revised 2018 through 2021 minimum, midpoint, and maximum energy efficiency EAM targets for both electric and gas are reflected in the Appendix W Revised Sheets 9 and 10 of 13 which are appended to this order as Attachment 3.

In addition, under the JP, Central Hudson will implement a moderate income electric efficiency offering in Rate Year 2. The JP requires the Company to collaborate with NYSERDA and convene a stakeholder meeting by December 31, 2018, to receive input on this program.

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[114] Hearing Exhibit 22, Joint Proposal, Appendix W, Sheets 9 and 10 of 13.

[115] Case 15-M-0252, In the Matter of Utility Energy Efficiency Programs, Order Authorizing Utility-Administered Energy Efficiency Portfolio Budgets and Targets for 2019-2020 (issued March 15, 2018).

In support of the JP, Staff notes that the Company originally had been opposed to the change in its recovery of energy efficiency program costs through base rates, but that the Company ultimately agreed to Staff's proposal. According to Staff, this change in recovery method will not affect customers' overall energy bills because no matter how the costs are recovered, the Company is not authorized to exceed the energy efficiency portfolio budgets set by the Commission. Staff also highlights the provision of the JP that provides for a downward-only reconciliation of ETIP costs over the term of the rate plan.

CLP says the JP represents important progress toward strengthening Central Hudson's energy efficiency savings targets. CLP notes that the savings targets for 2018 initially proposed by the Company were nearly 25% lower than the value established in its ETIP, and only half of the level of reduction the Company achieved in 2016.[116] CLP opines that increasing energy efficiency is a cost-effective way to reduce carbon emissions and ultimately will result in savings for ratepayers.

For its part, Pace states that it supports the targets, because the targets initially proposed by Central Hudson were not sufficiently ambitious. According to Pace, because the targets in the JP are more aggressive than those initially proposed in the Company's ETIP, they do more to promote REV goals.[117] Pace also supports the moderate income energy efficiency offering, stating that such program will extend energy efficiency benefits to a broader range of

[116] CLP Statement, p. 5.

[117] Statement of Pace Energy and Climate Center in Support of JP (Pace Statement), pp. 11-13.

customers, and the stakeholder process will allow Pace and other parties to actively participate in developing the program.[118]

We agree that the JP recommends a reasonable program of energy efficiency budgets and targets. They greatly improve upon the targets initially contemplated by Central Hudson, thereby providing strong incentives to achieve more aggressive energy savings. In that respect alone, they comport with our stated policies specifically and the public interest generally. Importantly, the significant increases in the historic levels of the Company's electric and gas energy efficiency targets are coupled with only a modest increase in the budgets. These modest budget increases can be accommodated reasonably within an overall rate plan that balances the need for energy efficiency against affordability concerns.

While we find that the budgets and targets are reasonable based on current information and policies, we do note that this issue could be re-examined and reopened as it relates to the joint Department of Public Service-NYSERDA comprehensive energy efficiency White Paper, New Efficiency: New York, that was filed in April, 2018 in response to the Governor's State of the State Address.[119] The JP specifically contemplates the reopening of the rate plan we establish here to accommodate the outcome of generic proceedings such as that considering issues related to energy efficiency targets and policy.

Earnings Adjustment Mechanisms

As noted above, EAMs are proposed in the JP as a tool to incentivize actions by the Company and its customers to

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[118] Id., pp. 13-14.

[119] On February 8, 2018, a new case (Case 18-M-0084, In the Matter of a Comprehensive Energy Efficiency Initiative) was started to consider the issues related to energy efficiency targets and policy.

improve the efficiency of the electric and gas systems and of customers' electric and gas usage, to promote development of the market for distributed energy resources, and to shift usage to cleaner technologies.[120] All these actions advance State policies to reduce emissions of greenhouse gases and other pollutants while improving the reliability and resiliency of our energy infrastructure.

Under the JP, the Company would adopt EAMs for its electric and gas businesses starting January 1, 2018, with the EAMs to be measured on a calendar year basis. The JP proposes five electric EAMs, comprised of a total of seven metrics, and one gas EAM, comprised of one metric. Each metric would contain targets set at minimum, midpoint, and maximum performance levels that generally would become more stringent each calendar year. The Company will earn a pre-tax earnings adjustment on a prorated basis for performance between the minimum and midpoint performance levels, and between the midpoint and maximum performance levels. Central Hudson has the potential to earn a maximum earnings adjustment of $2.0 million in 2018, $4.3 million in calendar year 2019, $4.7 million in calendar year 2020, and $4.9 million in calendar year 2021 for its electric business. For its gas business, Central Hudson has the potential to earn a maximum earnings adjustment of $0.18 million in 2018, $0.39 million in calendar year 2019, $0.44 million in calendar year 2020, and $0.47 million in calendar year 2021. All EAM targets and incentives are set forth in JP Appendix W.

The five proposed electric EAMs are System Efficiency, Electric Energy Efficiency, Customer Engagement, Environmentally

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[120] EAMs were proposed as a ratemaking tool in Case 14-M-0101, Reforming the Energy Vision, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (issued May 19, 2016) (REV Track Two Order).

Beneficial Electrification, and Interconnection. The System Efficiency EAM is composed of two metrics – Peak Reduction and DER Utilization. The Peak Reduction metric would incentivize Central Hudson to reduce its New York State Independent System Operator (NYISO) Zone G-J Locality peak. The DER Utilization EAM metric incentivizes Central Hudson to work with third parties to expand the use of DER resources including large solar, combined heat and power, standalone or behind the meter electric energy storage resources, and fuel cells in Central Hudson's service territory.

The Energy Efficiency EAM is composed of three metrics: (1) Electric Energy Efficiency; (2) Residential Electric Energy Intensity; and (3) Commercial Electric Energy Intensity.[121] The Electric Energy Efficiency EAM incentivizes the Company to achieve energy efficiency savings in calendar years 2018 through 2021 that are significantly above its annual savings target of 34,240 MWh. It will be measured as the sum of MWh savings from all of Central Hudson's administered electric ETIP Energy Efficiency Programs, including behavioral programs, which may be utilized to achieve MWh targets. As a precondition to earning the incentive associated with this metric, the Estimated Useful Life (EUL) of the Company's ETIP portfolio must be at least 90% of the current weighted average EUL for New York State utilities, and earnings related to this metric will be prorated between this level and the Company's historic EUL. The Electric Energy Efficiency EAM is subject to change pursuant to

[121] An Outreach and Education budget for the Electric Energy Intensity Metric is included in rates as indicated in JP Appendix A.

a Commission determination in the Energy Efficiency Proceeding.[122]

The Residential Electric Energy Intensity EAM and the Commercial Electric Energy Intensity EAM will incentivize Central Hudson to reduce residential (SCs 1 and 6) and commercial (SC 2 non-demand) customers' total usage on a per customer basis. The Customer Engagement EAM incentivizes the Company to increase residential customer participation in Voluntary Time of Use (VTOU) rates.

The Environmentally Beneficial Electrification EAM incentivizes the Company to reduce carbon emissions by facilitating greater penetration of technologies that utilize electricity and reduce carbon emissions relative to traditional technologies that rely on more carbon intensive fuel sources. Examples of these technologies include geothermal heating and cooling, air source heat pumps for heating and cooling, and electric vehicles. It will be measured as the lifetime short tons of avoided carbon dioxide from environmentally beneficial electrification technologies as identified in the Company's Carbon Reduction Implementation Plan, which will be filed within 30 days of the issuance of this order.

Finally, the Company may petition the Commission for approval of metrics and targets consistent with a future Commission order regarding the Interconnection EAM Metric in Case 16-M-0429.[123] The Company will reserve 1 basis point minimum, 2.5 basis points midpoint, and 5 basis points at maximum for interconnection-related EAMs.

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[122] Hearing Exhibit 22, Joint Proposal, p. 68; see also Appendix W, Sheets 3-4.

[123] Case 16-M-0429, In the Matter of Earnings Adjustment Mechanism and Scorecard Reforms Supporting the Commission's Reforming the Energy Vision.

The Gas Energy Efficiency EAM will incentivize the Company to achieve energy efficiency savings that are significantly above 37,296 dekatherms (Dth).[124] It will be measured as the sum of Dth savings from all Central Hudson's administered gas ETIP Energy Efficiency Programs. As a precondition to earning the incentive associated with this metric, the EUL of the Company's ETIP portfolio must be at least 90% of its historic EUL for Central Hudson's Gas ETIP portfolio, and earnings related to this metric will be prorated between this level and the Company's historic EUL. Like its electric counterpart, the Gas Energy Efficiency EAM is subject to change pursuant to a Commission determination in the Energy Efficiency Proceeding.

The JP provides that the incentives associated with Electric EAMs will be recovered through the Miscellaneous Charges EAM Factor, which will be a component of the Company's Energy Cost Adjustment Mechanism. Recovery will be over a 12-month period commencing with the first billing batch in July following the EAM measurement period. Recovery will be on a kWh basis for non-demand customers and on a kW basis for demand customers, with rates determined for each service classification or sub-classification based on the aggregate results of the following allocation methodologies: (1) Peak Reduction EAM, allocated using the transmission demand allocator; (2) Energy Efficiency, Energy Intensity and Environmentally Beneficial Electrification EAMs, allocated using the energy allocator; and (3) DER Utilization EAM, allocated using three allocators which will be equally weighted (coincident peak, non-coincident peak, and energy allocator). These rates will be applied to the energy (kWh) or demand (kW) deliveries, as applicable, on the

[124] 37,296 dekatherms (Dth) is the current net savings target for the gas ETIP.

bills of all customers served under SCs 1, 2, 3, 5, 6, 8, 9, 13, and 14. Customers taking service under SC 14 will be billed the rate applicable to their parent service classification, which is the service classification that the customer would otherwise qualify for based on the customer's usage characteristics.

Recoveries (11 months actual, one month forecasted) will be reconciled to allocable costs for each 12-month recovery period ending June 30, with any over or under recoveries included in the development of succeeding Miscellaneous Charges EAM Factors. Reconciliation amounts related to the one-month forecast will be included in the next subsequent rates determination.

For billing purposes, recovery for non-demand customers will be included in Miscellaneous Charges, with the combined amount shown as one line item on customer bills. Cost recovery for demand customers will be through Miscellaneous Charges II, a separate line item on customer bills.

Incentives associated with Gas EAM will be recovered through the new Gas Miscellaneous Charge mechanism. Recovery will be over a 12-month period commencing in July, and will be on a Ccf basis with a uniform factor developed, based on forecast Ccf over the respective recovery period, and applied to all deliveries on the bills of all customers served under SCs 1, 2, 6, 11, 12, 13, 15 and 16. Recoveries (11 months actual, one month forecast) will be reconciled to allocable costs for each 12-month recovery period ending June 30, with any over or under recoveries included in the development of succeeding Miscellaneous Charges EAM Factors. Reconciliation amounts related to the forecast versus actuals for the final month of the rate plan will be included in the next rate determination.[125]

[125] Hearing Exhibit 22, Joint Proposal Appendix W, Sheets 12 and 13.

MI notes that Central Hudson will have an opportunity to earn EAMs, funded by customer surcharges, that could cost electric and gas customers almost $17.4 million over the three-and-one-half year period they are proposed to be in effect, if Central Hudson achieves the prescribed maximum performance levels. While MI states its disagreement with the concept of positive-only EAMs for utility shareholders and expresses skepticism that their implementation will provide customers with net benefits that could not have been achieved at a substantially lower potential cost or no cost, it states that, given the Commission's current policies requiring the funding of EAMs, the specific EAMs set forth in the JP are acceptable to it.[126]

Pace submits that the JP's proposed EAMs adequately reflect REV principles and other State policies aimed at reducing energy usage and integrating DERs into the grid and are highly beneficial to customers and the environment.[127] Pace states that the EAM targets for electric and gas energy efficiency energy are greater than historical levels and may be increased when the Commission acts on Staff's Earth Day Energy Efficiency Proposal.

Noting its opposition to funding the expansion of the natural gas system, Pace contends that the JP proposal concerning the Environmentally Beneficial Electrification EAM is superior to the Company's original proposal because it no longer includes gas conversions as a metric.[128] Pace supports the System Efficiency EAM targets, stating that reducing system peaks is very important because peak demand drives many capital

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[126] MI Statement, pp. 21-22.

[127] Pace Statement, pp. 11-16.

[128] CLP also supports the elimination of gas expansion proposals. CLP Statement, p. 4.

improvements, transmission and distribution investments, and system costs, and that generation used only during peak periods is associated with higher rates of marginal pollutant emissions. Finally, Pace notes that the DER utilization metric provides incentives for increased DER penetration, which will be highly beneficial to customers and the environment.

Among other things, NY-GEO and Bob Wyman express support for the reduction of gas expansion that is reflected in the JP and for the funding that is being made available for both electrical energy efficiency and beneficial electrification.[129]

The Company states that the agreed-to EAMs reasonably balance the competing interests of shareholders and customers, as well as environmental concerns, to establish new incentives that will increase the Company's existing efforts to promote energy efficiency and the integration of new clean energy technologies. It notes that System Efficiency EAM reflects various compromise positions between the Company, Staff, and the parties, while the Customer Engagement EAM reflects compromises between the litigating positions of it and Staff. It contends that the EAMs should be adopted without modification.[130]

Staff asserts that the JP's EAM provisions balance shareholder, customer, environmental, and public interests to establish new incentive mechanisms that will align the Company's business activities with New York State energy and climate policy goals. Staff adds that the EAMs will support energy efficiency programs that will integrate new clean energy technologies from emerging markets. Staff also adds that the proposed EAMs are within the range of outcomes advocated in the parties' initial and rebuttal testimony. Staff concludes that

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[129] NY-GEO (letter of) support for the Joint Proposal; Statement in Support of Joint Settlement Proposal, pp. 4-5.

[130] Company Statement, pp. 46-52.

the EAM proposals are reasonable, in the public interest, and should be adopted.[131]

We find that the proposed incentives are appropriately set at amounts that will encourage the Company to satisfy EAM target levels. We acknowledge the important balance struck by the JP signatories between the objective to incentivize Company behavior using ratepayer funds and the need to minimize increases in rates, and we recognize that this is the first time that Central Hudson will be operating under EAMs. Based on the experience gained during this rate plan, the Commission can review the appropriateness of the incentive amounts in the Company's next rate case. However, for now, we agree with the JP signatories that the EAM targets and mechanisms established in these proceedings will advance important State policy objectives and goals and are in the public interest, and therefore should be adopted as proposed in the JP.

Natural Gas Safety and Reliability

The JP advances natural gas safety and reliability and reduces its environmental impact in several important ways. First, it continues the replacement of leak prone infrastructure and accelerates the repair of non-hazardous leaks. One way this is accomplished is through a new positive revenue adjustment related to leak repair. When added to the program focused on increased adoption by residential customers of methane detection technology, natural gas leaks and the resulting greenhouse gas emissions will be significantly reduced.

The Company is being encouraged through this JP to pursue non-pipes alternatives to meet demand for heating fuels. One way is through the incentives focused on geothermal heating and cooling, mentioned above, but the Company has also committed

[131] Staff Statement, pp. 84-91.

to pursue additional natural gas efficiency, demand response programs, and will issue an RFP focused on non-pipes alternatives that can displace traditional infrastructure projects. When combined with the reductions in methane leakage, the programs that seek to replace natural gas usage with other means of providing space heating or reducing fuel consumption will help ensure the transition to lower carbon energy markets in New York State.

Customer and Minimum Charges

In its litigated case, the Company recommended increasing the electric customer charge and the gas minimum charge so they would be closer to the embedded costs of service.[132] Staff acknowledged that the Company's proposed changes to the residential electric customer charges were cost-based. Staff recommended keeping the electric customer charges and gas residential minimum charge at current levels, pending a determination in the VDER proceeding as to how they should be changed to better achieve New York's energy policy goals.[133] UIU, PULP, CLP, Bard College, and Pace recommended reducing such charges.[134] Pace also recommended that the Company be directed

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[132] Hearing Exhibit 1, Pre-filed direct testimony of the Central Hudson's Forecasting and Rates Panel, pp. 54, 58. See also Company Statement, pp. 25-27.

[133] Hearing Exhibit 16, Pre-filed direct testimony of Staff Electric Rates Panel, p. 23, and Pre-filed direct testimony of the Staff Gas Rates Panel, pp. 44-45.

[134] Hearing Exhibit 14, Pre-filed direct testimony of UIU Rate Panel, pp. 20-21; Hearing Exhibit 10, Pre-filed direct testimony of PULP Witness Yates, p. 8; Hearing Exhibit 18, Pre-filed direct testimony of CLP Witness Metzger, p. 21; and Hearing Exhibit 21, Pre-filed direct testimony of Bard College Reliability, Affordability and Sustainability Panel, p. 21.

to prepare a new model for classifying customer costs and calculating customer and minimum charges.[135]

The proposed residential customer and minimum charge amounts, which are a reduction from the current amounts, are the product of compromise between the litigation positions of the Company, Staff, Pace, Acadia Center,[136] UIU, PULP, and CLP. They are recommended as a means of garnering support from some Signatory Parties and some non-signatory parties. We approve them but note that such proposals will not take precedence over any subsequent Commission order that is applicable to Central Hudson and to the design of its rates.[137]

Management and Operations Audit Compliance

Upon the application of a gas or electric corporation for a major change in rates, Public Service Law (PSL) §66(19)(c) requires that the Commission review the corporation's compliance with the directions and recommendations made previously by the Commission as a result of the most recently completed management and operations audit. Staff addressed the

[135] Hearing Exhibit 7, Pre-filed direct testimony of Pace Witness Rábago, pp. 10-11. See also Pace Statement, pp. 3-5.

[136] Acadia Center supports the JP because it reduces the residential electric customer charges. Statement in Support of Joint Proposal by Acadia Center, pp. 3-8.

[137] The JP expressly notes that these reductions are not intended to set statewide policy or take precedence over any subsequent Commission order applicable to Central Hudson regarding rate design. See Hearing Exhibit 22, Joint Proposal, p. 37.

most recently completed management and operations audits of Central Hudson in its testimony in this case.[138]

In 2009, the Commission instituted a comprehensive management and operations review of Central Hudson's gas and electric businesses, with a specific focus on the Company's construction program planning processes and operational efficiency.[139] On February 11, 2010, the Commission approved the selection of NorthStar Consulting Group (NorthStar) to perform the audit. On May 20, 2011, the Commission issued its "Order Directing the Submission of an Audit Implementation Plan" to address the recommendations for improvement that were provided in NorthStar's final audit report, publicly published the same day. The Company filed its audit implementation plan on July 1, 2011. In an audit closeout letter, dated February 24, 2016, Staff stated that all the recommendations from the audit had been satisfactorily implemented.

Because audits must be performed every five years, in 2016, the Commission instituted a comprehensive management and operations review of Central Hudson's gas and electric businesses that, like the 2009 audit, also focused on the

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[138] See Hearing Exhibit 23, Lavery Affidavit and Pre-filed direct testimony of Staff Witness Lavery. Witness Lavery also provided testimony concerning the status of the audits in Case 13-M-0314, Review of Reliability and Customer Service Systems of NYS Gas and Electric Utilities (instituted July 16, 2013) (Data Audit) and Case 13-M-0449, Operations Audit of Major Utility Internal Staffing Levels and Use of Contractors for Selected Core Functions (Staffing Audit). We approved the implementation plans for the Data Audit on March 10, 2017, and the Staffing Audit on December 15, 2017. The Company currently is in the implementation stage with respect to the recommendations from those audits.

[139] Case 09-M-0764, Comprehensive Management and Operations Audit of Central Hudson Gas and Electric Corporation's Electric and Gas Businesses, Letter to Carl Meyer (dated November 12, 2009).

Company's construction program planning processes and operational efficiency.[140] On July 14, 2016, the Commission approved the selection of Overland Consulting Inc. (Overland) to perform the audit. Overland's final audit report was issued by the Commission on October 24, 2017. Initial and updated implementation plans were filed by the Company on November 17 and December 14, 2017. We note that the Company has begun implementing some of the Overland audit recommendations.

Pursuant to PSL § 66(19), we find that Central Hudson is currently in compliance with the directions and recommendations made in the most recently completed management and operations audits.

Other Miscellaneous Provisions

There are several other areas agreed to by the Signatory Parties, including, but not limited to, the continuation of existing electric and gas economic development fund programs; elimination of per-transaction fees associated with payment centers and payment of utility bills by credit/debit card; training for Company customer service representatives; and the implementation of electronic deferred payment agreements. These provisions demonstrate the comprehensive nature of the JP as the parties have resolved numerous complex rate and policy issues, while providing the Company's customers with some measure of rate predictability for at least three years.

Section XXV, subsections B, C, D, E, H, I, and J, of the JP do not require our adoption. There are no disputes about any of these terms but this rate plan need not and should not

[140] Case 16-M-0001, In the Matter of a Comprehensive Management and Operations Audit of Central Hudson Gas & Electric Corporation, Letter to James P. Laurito (dated March 17, 2016).

include terms that govern the relationship among the parties. Our decision not to adopt such provisions does not indicate or imply that such terms are not important, it merely reflects that they are unnecessary for this rate plan.

Future REV-Based Initiatives

The Commission notes that the JP was filed while several REV-related proceedings continue to make progress. The Company may and is encouraged to petition the Commission for approval of REV-based initiatives that advance goals established in this rate case at improved economics, and especially so if the Company has identified opportunities for shared savings. Under REV, New York seeks to lower the costs and speed of the achievement of the State's policy goals through accelerating the deployment at scale of solutions that create the most economic value for both consumers and the State's energy system, drawing on innovation and investment from all sectors.

The Company has untapped potential to work with innovative third parties to develop alternative solutions to achieve the results committed to by the Company in this proceeding at lower ratepayer expense, at a faster rate, or both. These solutions can take the form of technology or deployment alternatives that are more optimal for specific locations or other utility needs, or business model alternatives that yield additional savings or produce additional revenues, in both cases yielding economics which can be shared among customers, the innovative provider, and the Company.

Mechanisms for such shared savings/benefits can take the form of the EAMs identified in this JP for specified outcomes, a non-wires alternative sharing mechanism, sharing of platform service revenues, or future shared savings/benefits constructs designed for specific opportunities and approved by the Commission. The Commission requires the Company to actively

continue and expand its work with third parties to identify opportunities for such solutions, to develop them as warranted, and to bring them forward to the Department and/or the Commission as needed. Such third parties are likely to be customers, providing payment to the Company for valuable services rendered by the Company, as well as providers who receive payment from the Company for valuable services rendered to the Company. The Commission recognizes that achieving such benefits from third parties may require the Company to enter into long-term contracts. As these contracts would represent long-term financial liabilities, the Commission will require the Company to demonstrate long-term net savings or benefit structures that would support entering into the contract. The Commission specifically encourages the Company to bring forward shared savings/benefits approaches to compensation as an alternative or complement to traditional cost recovery or rate-based approaches.

Given the State's policy objectives, especially promising opportunities for such solutions include (but are not limited to):

- AMI, which offers the potential for alternative business models that can generate revenues to the Company;
- Data provision, including system and usage data (subject to necessary protections), to enable third parties to develop novel and economic solutions to Company needs;
- Energy efficiency, which offers the potential for market-based solutions to reduce the cost of achieving energy savings or to offset those costs by revenues or savings elsewhere in the energy system;
- Low and moderate income focused initiatives, which can provide benefits to the energy system through strategic

deployment of distributed resources or energy efficiency in locations or against time-windows where the energy system faces constraints;

- Non-wire alternatives and non-pipe alternatives, explored as a universal practice as an alternative to traditional investments that meet the Company's predefined NWA suitability criteria;
- Grid modernization, including the use of technology to deliver reliability and system functionality at the best economics for ratepayers;
- Supply cost reduction, where novel approaches deliver savings in commodity and capacity payments; and
- Operating cost reduction, where novel approaches deliver savings in asset utilization, in operations expenditures, or in administrative/central expenditures.

Across all of these opportunities, the Company is encouraged to develop processes that invite and consider proposals that address proposer-identified opportunities (consistent with stated system needs) and whose solution would provide economic value as described above.

CONCLUSION

We conclude from our review of the record that the JP terms that we are adopting appropriately and reasonably balance the interests of ratepayers and the Company. The JP provides sufficient funding, via modest rate increases, that will allow Central Hudson to maintain safe and reliable service and attract the capital needed to ensure the Company's long-term viability, while mitigating the ratepayer impact by using credits and by taking other steps that moderate bill impacts. The execution of the JP by several parties with diverse and often adverse

interests demonstrates the parties' diligent efforts to address and resolve the outstanding issues in a comprehensive and practical fashion. Finally, the terms of the JP evidence its consistency with our environmental, social and economic policies and those of the State. In consideration of the foregoing, we find that the terms of the JP are in the public interest, and we adopt the majority of them as a rate plan for Central Hudson.

The Commission orders:

1. The rates, terms, conditions, and provisions of the Joint Proposal dated and filed April 18, 2018, in these proceedings and attached hereto as Attachment 1, except for Section IV, subsection F; and Section XXV, subsections B, C, D, E, H, I, and J; are adopted and incorporated herein.

2. Central Hudson Gas & Electric Corporation is directed to file cancellation supplements, effective on not less than one day's notice, on or before June 21, 2018, cancelling the tariff amendments and supplements listed in Attachment 2.

3. Central Hudson Gas & Electric Corporation is authorized to file, on not less than one day's notice, to take effect on July 1, 2018, on a temporary basis, such tariff changes as are necessary to effectuate the terms of this Order for the rates in the rate year beginning July 1, 2018, including tariff changes necessary to effectuate removal of the EE Tracker surcharge component of the System Benefit Charge, and to incorporate any tariff amendments that were previously approved by the Commission since the tariff amendments listed on Attachment 2 were filed.

4. Central Hudson Gas & Electric Corporation shall serve copies of its filings on all active parties to these proceedings. Any party wishing to comment on the tariff amendments may do so by filing its comments with the Secretary

to the Commission and serving its comments upon all active parties within ten days of service of the tariff amendments. The amendments specified in the compliance filings shall not become effective on a permanent basis until approved by the Commission and will be subject to refund if any showing is made that the revisions are not in compliance with this Order.

5. On December 21, 2017, Central Hudson Gas & Electric Corporation consented to extend the suspension period through and including July 24, 2018. On January 24, 2018, Central Hudson Gas & Electric Corporation consented to an extension of the suspension period through and including August 23, 2018. On February 20, 2018, and March 23, 2018, Central Hudson Gas & Electric Corporation consented to an extension of the suspension period through and including September 22, 2018 and October 22, 2018, respectively. Because this order is made within the suspension period to and including June 24, 2018, the request for a make-whole (set forth in JP Section IV, subsection F) is dismissed as moot.

6. Central Hudson Gas & Electric Corporation is directed to file tariff changes in 2019 and 2020 to effectuate the rates for Rate Year 2 and for Rate Year 3. The Rate Year 2 changes shall be filed on not less than 30 days' notice to be effective on a temporary basis on July 1, 2019. The Rate Year 3 changes shall be filed on not less than 30 days' notice to be effective on a temporary basis on July 1, 2020.

7. The requirement of the Public Service Law §66(12)(b) and 16 NYCRR 720-8.1 that newspaper publication be completed prior to the effective date of the amendments for Rate Year 1 are waived and Central Hudson Gas & Electric Corporation is directed to file with the Secretary to the Commission, no later than six weeks following the effective date of the amendments, proof that a notice to the public of the changes set

forth in the amendments and their effective date had been published once a week for four consecutive weeks in one or more newspapers having general circulation in the service territory. The requirements of Public Service Law §66(12)(b) and 16 NYCRR 720-8.1 are not waived with respect to Rate Year 2 and Rate Year 3.

8. In the Secretary's sole discretion, the deadlines set forth in this order may be extended. Any request for an extension must be in writing, must include a justification for the extension, and must be filed at least one day prior to the affected deadline.

9. The proceedings in Cases 17-E-0459 and 17-G-0460 are continued.

By the Commission,

(SIGNED) KATHLEEN H. BURGESS
Secretary

Exhibit EDH-4
Central Hudson Gas & Electric Corporation's Non-Pipeline Alternatives Annual Report (filed pursuant to New York Public Service Commission Case 17-G-0460).

Paul A. Colbert
Associate General Counsel
Regulatory Affairs

December 2, 2019

Hon. Michelle L. Phillips
Acting Secretary
New York State Public Service Commission
Agency Building 3
Albany, NY 12223-1350

Re: Case 17-G-0460 - *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service*; Non-Pipeline Alternatives Compliance Filing

Dear Secretary Phillips:

In compliance with the Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan issued on June 14, 2018 in the above-referenced case, Central Hudson Gas & Electric Corporation hereby submits its Non-Pipeline Alternatives Annual Report.

Questions regarding this filing may be directed to Mark Sclafani at (845)486-5979 or msclafani@cenhud.com.

Respectfully submitted,

/s/*Paul A. Colbert*

Paul A. Colbert
Associate General Counsel
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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service	**Case 17-G-0460**

Central Hudson Gas & Electric Corporation's Non-Pipeline Alternatives Annual Report

December 2, 2019

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
284 South Avenue
Poughkeepsie, N.Y. 12601

Central Hudson Gas & Electric Corporation
Case 17-G-0460
Non-Pipeline Alternatives – Annual Report

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Background

Non-Pipeline Alternatives ("NPAs") are projects designed to displace the need for traditional gas infrastructure investment. Central Hudson Gas & Electric Corporation ("Central Hudson" or "the Company") proposed to incorporate NPA projects into its system planning process within its 2017 Rate Case. [1] On June 14th, 2018 the Commission issued an Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan ("Order"). The order adopted proposed NPA strategies and required the Company to submit an implementation plan and subsequent annual report for each identified NPA project.

Central Hudson provides the following annual report on the progress of each of our NPA projects.

Non-Pipeline Alternative Projects

The Company is pursuing two categories of NPA projects, both of which employ non-traditional solutions to avoid traditional infrastructure construction. The two categories are as follows:

1) *Load Growth-Based Projects*

These types of projects would be designed to manage locational constraints that are associated with peak demand.

2) *Transportation Mode Alternatives*

Central Hudson's transportation mode alternatives projects are designed for strategic abandonment of leak prone pipe through electrification where it is more cost effective than replacement and system reliability is not negatively impacted.

Load Growth-Based Projects

Overview

In an effort to understand location-specific gas distribution costs, Central Hudson employed a consultant, Demand Side Analytics, to perform a system-wide gas distribution avoided costs study. The

[1] Case 17-G-0460 *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service.*

study includes the analysis of approximately 40 localized gas systems throughout Central Hudson's gas service territory. Probabilistic forecasting methods, including simulations of nonlinear growth trajectories, have been used to identify areas of demand growth. This study follows a similar strategy employed for the electric system ("Location Specific T&D Avoided Cost Study Report"[2]), the results of which were included within the Company's DSIP[3]. These results have been combined with an analysis of distribution capacity to identify predicted constraints. Once the study results are finalized, any constrained areas will be evaluated as potential candidates for a load growth-based NPA solution or incorporated into the development of a system-wide value.

Current Status

Central Hudson is currently finalizing the results of the system-wide gas distribution avoided costs study and expects to confirm suitable areas for NPA solutions. Once identified, a technology agnostic market solicitation will occur, following the procedure put in place for Non-Wires Alternatives. Following the solicitation, the Company will file an Implementation Plan in accordance with the Order.

Transportation Mode Alternatives

Overview

Central Hudson's current Transportation Mode Alternatives ("TMA") are designed to facilitate strategic abandonment of leak-prone pipe ("LPP"). LPP is considered to be any natural gas distribution piping that is not made of either plastic or "protected"[4] steel pipe. Common leak-prone materials are wrought iron, cast iron, and unprotected steel. In order to improve safety and reduce ongoing maintenance costs, LPP that cannot be protected or abandoned must be replaced with new plastic pipe. LPP replacement is costly; the Company estimates that it will cost approximately $1.9 million per mile on average in 2019.[5] For a TMA initiative to be successful, each customer's natural gas service would need to be retired.

[2] *Case 15-E-0751 – in the Matter of the Value of Distributed Energy Resources, Central Hudson Gas & Electric Corporation's Avoided T&D Cost Study. July 31, 2018*
[3] *Central Hudson Distribution System Implementation Plan. Revised July 31, 2018*
[4] Pipelines are protected either physically with coatings or with cathodes and sacrificial anodes to prevent corrosion.
[5] Joint Proposal "Case 17-G-0460 *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service." Section XVII.E*

Approach

To date, the Company has identified three separate project locations throughout the service territory where it is likely feasible and cost-effective to permanently retire sections of LPP. These three areas, referred to as "cases", were identified in the Company's Implementation Plan & Compliance Filing for Non-Pipe Alternatives ("Implementation Plan").[6] The three locations in Newburgh and Saugerties contain approximately 20 residential customers in total.

The Company is utilizing ICF along with its existing HVAC Trade Ally network to deliver these NPA project solutions. Due to the small number of customers and the need for 100% participation within each area, the Company is utilizing a direct-install approach. Central Hudson is utilizing high efficiency cold climate air-source heat pumps and electric heat pump water heaters to replace the primary natural gas end uses.[7] Other natural gas appliances such as cooking ranges and clothes dryers will be replaced with electric units where applicable. The standard conversion package will be offered at no cost to the customer.[8]

Current Status

The Company initiated its first TMA shortly after filing its Implementation Plan. The case is meeting the expectations of the Company's initial timeline milestones. The initiative utilized a highly targeted marketing approach, followed by customer education and enrollment. The Company has completed its first customer conversion which included converting use of natural gas equipment to efficient electric heating and hot water end uses. Recruitment for the remaining two cases will begin early next year, targeting case completions by the end of 2020.

Benefit Cost Analysis

Central Hudson primarily evaluated the economics of its three ongoing TMA cases based on the Societal Cost Test prescribed within the Company's BCA Handbook.[9] Where applicable, the valuation methodologies from the BCA Handbook, which is primarily intended for electric projects, have been

[6] Case 17-G-0460 - Central Hudson Gas & Electric Corporation's Non-Tariff Implementation Plan & Compliance Filing for Non-Pipe Alternatives: Three Transportation Mode Alternatives, Filed June 21st 2019
[7] Customers will be educated and have the option to install a geothermal system by covering the incremental cost above the incentive provided for air-source heat pumps
[8] There may be cases where customers desire an "upgraded" appliance, the incremental cost of which would be borne by the customer.
[9] Central Hudson Gas & Electric Benefit-Cost Analysis (BCA) Handbook, Version 2.0, Revised July 31st, 2018.

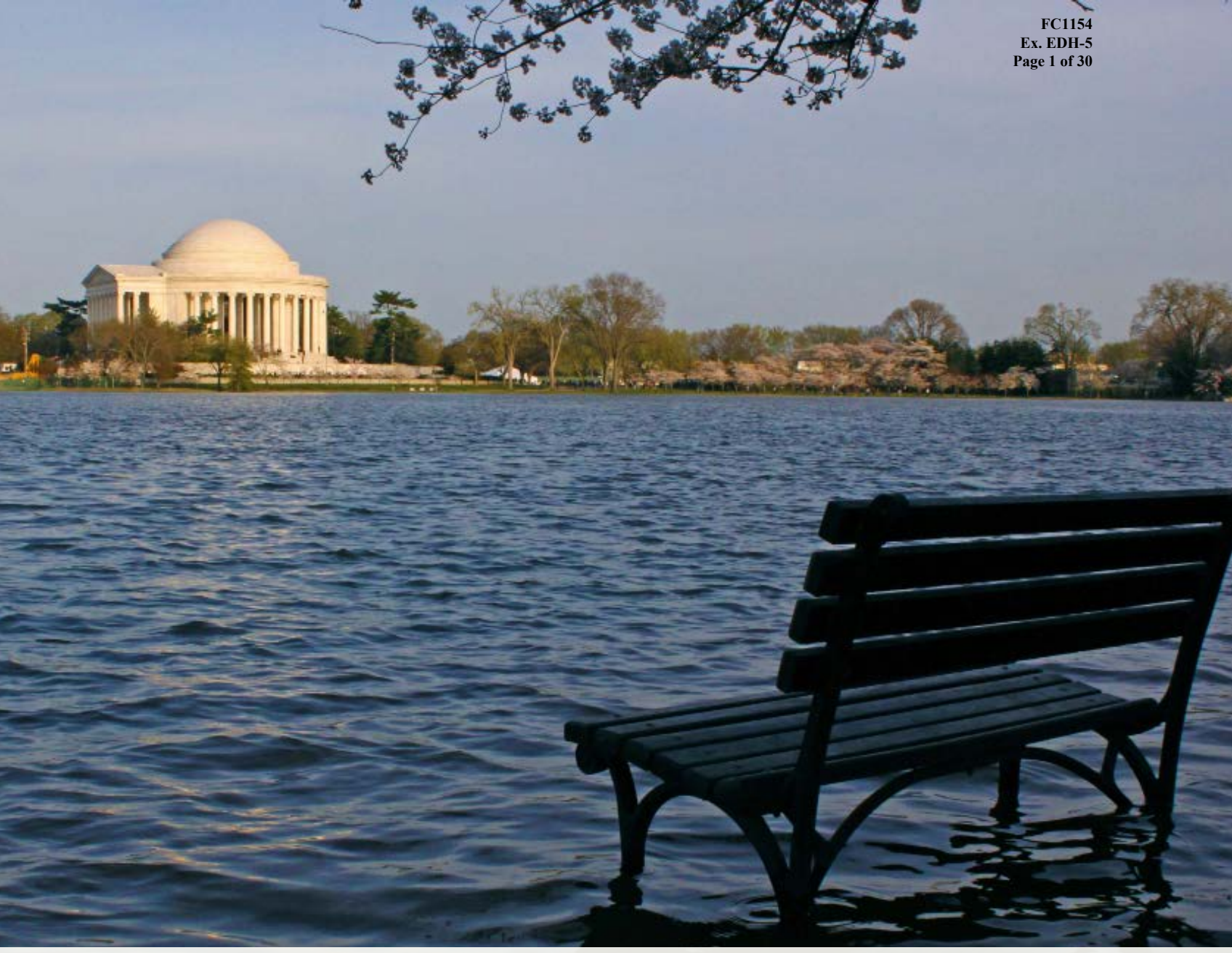
used. Some natural gas specific benefits and costs have been included in a way that is similar to those within the BCA Handbook. Relevant benefits and costs have been included in a detailed BCA analysis, developed with support of third party consultants.

The Company estimates these NPA cases to have a Benefit Cost Ratios (BCR)[10] greater than 1.0 based on the three tests included in the BCA Handbook, as reported in more detail within the Implementation Plan. The BCA results within the table below have been revised based on the most current assumptions. Although most BCA results have changed only slightly, the UCT result for Case 3 has changed moderately due to a correction that does not fundamentally affect the viability of the project.

Transportation Mode Alternative – Benefit Cost Ratio by Location			
Case	SCT	UCT	RIM
1	1.41	1.07	2.74
2	6.99	2.14	2.53
3	3.18	1.60	2.28
Weighted Average	3.34	1.64	2.21

[10] Benefit cost ratio, primarily determined by the societal cost test.

Exhibit EDH-5
Strauss, B., C. Tebaldi, S. Kulp, S. Cutter, C. Emrich, D. Rizza, and D. Yawitz (2016). Washington, D.C. and the Surging Sea: A vulnerability assessment with projections for sea level rise and coastal flood risk. Climate Central Research Report.



CLIMATE CENTRAL

WASHINGTON, D.C. AND THE SURGING SEA

A vulnerability assessment with projections for sea level rise and coastal flood risk

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CLIMATE CENTRAL

WASHINGTON, D.C. AND THE SURGING SEA

A VULNERABILITY ASSESSMENT WITH PROJECTIONS FOR SEA LEVEL RISE AND COASTAL FLOOD RISK

ABOUT CLIMATE CENTRAL

Climate Central surveys and conducts scientific research on climate change and informs the public of key findings. Our scientists publish and our journalists report on climate science, energy, sea level rise, wildfires, drought, and related topics. Climate Central is not an advocacy organization. We do not lobby, and we do not support any specific legislation, policy or bill. Climate Central is a qualified 501(c)3 tax-exempt organization.

Climate Central scientists publish peer-reviewed research on climate science; energy; impacts such as sea level rise; climate attribution and more. Our work is not confined to scientific journals. We investigate and synthesize weather and climate data and science to equip local communities and media with the tools they need.

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Vice President for Climate Impacts and Director of the Program on Sea Level Rise, Climate Central

Dr. Strauss directs Climate Central's Program on Sea Level Rise. He has published multiple scientific papers on sea level rise, testified before the U.S. Senate, and led development of the SurgingSeas.org coastal flood risk tool, leading to front-page coverage in the New York Times and Washington Post, appearances on NBC, ABC, CBS, PBS and NPR national programming. He holds a Ph.D. in Ecology and Evolutionary Biology from Princeton University, an M.S. in Zoology from the University of Washington, and a B.A. in Biology from Yale University.

CLAUDIA TEBALDI, PhD

Project Scientist, National Center for Atmospheric Research and Science Fellow, Climate Central

Dr. Tebaldi is a climate statistician at the National Center for Atmospheric Research and collaborates with the Climate Science and Impacts groups at Climate Central. Her research interests include the analysis of observations and climate model output in order to characterize observed and projected climatic changes and their uncertainties. She has published papers on detection and attribution of these changes, on extreme value analysis, future projections at regional levels, and impacts of climate change on agriculture and human health and she is currently a lead author for the IPCC Assessment Report, within Working Group 1. She has a Ph.D. in statistics from Duke University.

SCOTT KULP

Senior Developer and Research Associate, Climate Central

Scott Kulp serves as Senior Developer and Research Associate for Climate Central's Program on Sea Level Rise. Most recently he has worked on the development of Climate Central's Surging Seas 2.0 Analysis System and Risk Finder web toolkit. Previously, at Rutgers, he published several papers on the topic of 3D blood flow simulations as well as worked for the U.S. Department of Defense on several research projects. Scott holds an M.S. and is finishing a Ph.D. in Computer Science at Rutgers University, and holds a B.S. in Computer Science from Ursinus College.

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ACKNOWLEDGEMENTS

To NOAA's Coastal Services Center, which has provided high-accuracy coastal elevation data, consistent courtesy, and leadership with its Sea Level Rise Viewer, an enterprise this research strives to extend.

To officials at the Environmental Protection Agency (EPA), the Federal Communications Commission (FCC), and other agencies, who provided special guidance regarding their extensive public geospatial datasets.

To Climate Central's financial supporters for this project: The Kresge Foundation, The Rockefeller Foundation, The Schmidt Family Foundation, and Island Foundation.

And finally to all of our present and past colleagues at Climate Central not listed as authors or contributors, but who have provided support on this project in small ways and large, with particular thanks to Remik Ziemlinski, and also Paul Ferlita, Lindsay Harmon, and Alyson Kenward.

SUGGESTED CITATION

Strauss, B., C. Tebaldi, S. Kulp, S. Cutter, C. Emrich, D. Rizza, and D. Yawitz (2014). Washington, D.C. and the Surging Sea: A vulnerability assessment with projections for sea level rise and coastal flood risk. Climate Central Research Report. pp 1-28.

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EXECUTIVE SUMMARY

Washington, D.C. is likely to see record flooding by 2040 under a mid-range sea level rise scenario. A low-range scenario leads to a better-than-even chance by 2030 of flooding more than 6 feet above the local high tide line – a level topped just once in the last 70 years. And under high-range projections, there is a near certain chance of flooding above 10 feet by end of century – the highest level incorporated into our analysis.

1,350 acres of land lie less than 6 feet above the high tide line in Washington D.C. Some $4.6 billion in property value, and 1,400 people in 400 homes, sit on this area. These figures jump to $9 billion and 4,833 people residing in 1,900 homes on 2,500 acres of land under 10 feet.

The District has 21 miles of road below 6 feet, plus 2 military facilities; 1 museum; and 12 EPA-listed sites such as hazardous waste dumps and sewage plants. At 10 feet, these numbers grow to 46 miles of road, 4 military facilities, 3 museums, and 26 EPA-listed sites.

Sea levels are rising at an accelerating rate, and the scientific community is confident that global warming is the most important cause. Higher sea levels translate to more and higher coastal floods. To forecast future risk, this analysis integrates historic local sea level trends and flood statistics with global sea level rise scenarios, developed by a multi-agency federal task force led by NOAA in support of the recent U.S. National Climate Assessment.

This report is being released as a high-level summary of findings and methods, coincident with the online launch of a Surging Seas Risk Finder tool for the District, providing much more detailed and localized findings, and accessible via http://sealevel.climatecentral.org/ssrf/dc

The tool includes:

- Interactive local projections of sea level rise and increasing coastal flood risk from 1-10 feet by decade;
- A zooming, zip-searchable map of low-lying areas threatened, plus layers showing social vulnerability, population density and property value;
- Detailed assessments of populations, property, infrastructure and contamination sources exposed, for each implicated county, city, town, zip code, planning district, legislative district and more;
- State- and county-wide heat maps facilitating high-level vulnerability comparisons; and
- Brief customized "fast look" reports that integrate key findings from across all analyses for each locality, and provide interpretation and context.

Detailed knowledge of vulnerability is a critical tool for communities seeking to build resiliency to the climate challenges of today and the future.

01. INTRODUCTION

IN BRIEF

In March 2012, Climate Central released its first analysis of sea level rise and coastal flood threats in the United States. We published two scientific papers in a peer-reviewed journal; a national report; fact sheets for each coastal state; and an interactive online map called *Surging Seas*. About 800 stories in local to national media covered our findings, and a U.S. Senate committee invited Climate Central to testify about the research in April 2012 – six months before Hurricane Sandy.

This report represents a major extension to our analysis for Washington, D.C., using the same essential methods as our original work, but incorporating greatly improved and expanded data. The report summarizes major themes and findings taken from a much larger body of results accessible via a new interactive online tool, the Surging Seas Risk Finder, available for a growing set of coastal states throughout the U.S.

RESEARCH IMPROVEMENTS

Our 2012 analysis used the best available national coverage elevation dataset at the time. This analysis uses far more accurate laser-based (lidar) elevation data. Our 2012 research assessed land, population and housing vulnerable to sea level rise and coastal flooding. This research assesses over 100 additional variables, including socially vulnerable populations, populations by racial and ethnic group, property value, roads, rail, airports, power plants, sewage plants, hazardous waste sites, schools and churches. Our 2012 analysis tabulated exposure at state, county, and city levels. This analysis adds zip codes, congressional districts, planning districts, state and local legislative districts, and more.

For sea level rise projections, this report relies primarily upon scenarios produced by a multiagency task force for the U.S. National Climate Assessment (Parris et al 2012), locally adapted to Washington, D.C.. However, the full analysis and Risk Finder also include many other global sea level rise models and projections -- also locally adapted – not included in our 2012 analysis. We localize by factoring in local effects, such as sinking land, employing the same methods as in our original peer-reviewed research.

We also carry forward the same methods we previously used to characterize storm surge risk, and integrate it with projected sea levels, to develop projections of overall local flood risk by decade. However, we have updated analysis inputs to include the full available record of hourly water levels at each water level station through the end of 2012. This means decades more data for most stations than the standard 30-year period used in the original analysis, increasing the robustness of our findings.

01. INTRODUCTION

SURGING SEAS RISK FINDER: A NEW ONLINE TOOL

The Surging Seas Risk Finder is searchable by geography, and offers easy navigation and visualization of analysis results from hundreds of thousands of combinations of location, water level, and risk element. The Risk Finder is divided into five components:

- **Map:** Interactive zooming map of sea level and flood risk zones
- **Forecast:** Projections of sea level rise and flood risk
- **Analysis:** Detailed analysis of exposed population, assets and infrastructure by individual location, from zip to state level
- **Comparison:** Comparisons of exposure across the whole state or selected county
- **Fast Look:** Brief customized reports that integrate key findings from across all analyses for each locality, and provide interpretation and context

02. A TIMELINE OF GROWING RISKS

Long before sea level rise permanently submerges new land, it will make its presence felt through higher and more frequent coastal floods, because higher seas raise the launch pad for storm surge.

In fact, every coastal flood today is already wider, deeper and more damaging because of the roughly 8 inches (IPCC 2013) of warming-driven global sea level rise that has taken place since 1900. This analysis finds that an intermediate high sea level rise scenario leads to a one-in-two chance of a record-breaking D.C.-area flood by 2040.

This section explores projected sea level rise and how it aggravates coastal flooding.

SEA LEVEL RISE PROJECTIONS

Using scenarios from a NOAA-led technical report to the National Climate Assessment (Parris et al 2012), this analysis makes mid-range or "intermediate high" local sea level rise projections for Washington, D.C. of roughly 1.2 feet by mid-century, and 4.0 feet by 2100. These figures all use sea level in 2012 as the baseline.

Global Sea Level Rise Projections

The Earth's average temperature has warmed by more than one degree Fahrenheit over the last century, and scientists overwhelmingly agree that most or all of this warming comes from human influence (IPCC 2013). This influence comes mainly through the burning of fossil fuels and resulting accumulation of carbon dioxide in the atmosphere.

Global sea level rise is one of the scientifically best-established consequences of this warming. Warming shrinks glaciers and ice sheets, adding water to the ocean; and also heats up the ocean, expanding it. Over the past two decades, global sea level has risen roughly twice as fast as it did during the 20th century.

Projecting future sea level is a difficult scientific challenge, not least because it will depend upon how much more carbon humans put into the atmosphere. For global sea level rise projections, this analysis relies on scenarios developed by the National Oceanic and Atmospheric Administration (NOAA) and collaborating agencies for the U.S. National Climate Assessment (Parris et al 2012). We focus on the intermediate low, intermediate high, and highest sea level rise scenarios, which point to 1.6 ft, 3.9 ft, or 6.6 ft of sea level rise globally by 2100, from a 1992 starting point. For simplicity, we call these scenarios "slow", "medium" and "fast."

We omit the NOAA lowest scenario in this report. This scenario projects this century's average rate of sea level rise as the same as last century's, lower than the average rate from the last two decades. Such an outcome seems very unlikely given projections for warming this century, and the strong observed relationship between global temperature and sea level change over the last century (Vermeer and Rahmstorf 2009).

02. A TIMELINE OF GROWING RISKS

The Intergovernmental Panel on Climate Change recently released its Fifth Assessment Report on climate science (IPCC 2013). IPCC's sea level projections range from 0.9-3.2 feet by 2100, but explicitly do not include a potential rapid ice sheet breakdown scenario. NOAA's highest projection is intended to capture such a possibility, and thus the highest plausible sea level rise for the century, as an indicator of maximum risk for planning purposes.

Research published since these projections were made indicates that the West Antarctic Ice Sheet has begun an unstoppable collapse that will likely lead to 10-plus feet of rise over centuries (Joughin et al 2014, Rignot et al 2014). Further research indicates that Antarctic ice loss rate has recently doubled, albeit over a short measurement period (McMillan et al 2014), and that Antarctica contributed more than 6 feet of sea level rise per century during a geologically recent warming episode (Weber et al 2014).

Surging Seas Risk Finder, the interactive web tool accompanying this report, includes projections based on scenarios developed by NOAA for the National Climate Assessment; IPCC projections; U.S. Army Corps of Engineers guidelines, semi-empirical projections developed by Vermeer and Rahmstorf (2009); and a no-global-warming scenario for comparison. We will add additional global sea level rise projections over time.

Local Sea Level Rise Projections

Local sea level rise can differ from global sea level rise for many reasons. The ocean is not flat, and shifting currents and sea surface temperatures can alter local sea level trends over years or decades. In addition, the land itself is slowly sinking or (more rarely) rising in many coastal areas, augmenting or diminishing local sea level rise. Later in the century, gravity effects will also play a role: as ice sheets diminish, so will the gravitational force they exert on the oceans, and ocean surface water will make subtle adjustments accordingly.

For its main projections, this analysis uses locally adapted scenarios from NOAA's report to the National Climate Assessment (Parris et al 2012). For estimates based on global projections from other studies, this analysis employs the same method as Tebaldi et al (2012) to develop projections for each location studied. In essence, we compare global sea level rise to local sea level rise measured at a water level station over a 50-year period. We use the difference to define a local component of sea level rise, and assume that the local component rate will continue unchanged into the future. This is a reasonable assumption at least for the effects of sinking or rising land, effects important enough to account for most or all of the long-term local component in most places (Tebaldi et al 2012). (See Appendix A or Tebaldi et al (2012) for more detail.)

For this report and as presented by the Surging Seas Risk Finder, we developed projections at the long-term NOAA water level station at Washington, D.C. The full range of projections, slow to fast, was 0.6-1.8 ft by midcentury, and 1.9-6.4 ft. by the end of the century.

The projections given in this analysis should be taken as indicative of long-term trends, and not as precise projections for specific years. Global and local sea level experience natural ups and downs over years and decades that may temporarily obscure the underlying trend, but which will balance out over time.

02. A TIMELINE OF GROWING RISKS

COASTAL FLOODING: HISTORY AND PROJECTIONS

Rising seas raise the launch pad for storm surge, driving coastal floods higher. This study projects future flood risk by superimposing sea level rise projections onto historical patterns of flooding. In other words, we assume that coastal storm statistics remain constant – the same frequency and intensity of coastal storms – while sea levels rise. If storms instead worsen, then this analysis would underestimate flood risk.

Historical Analysis to Define Extreme Floods

The first step in this approach is to characterize historical coastal flood risk at each study site – in this case, at the water level station assessed in Washington D.C.. We apply standard methods to estimate the precise relationship between a flood's height and its annual likelihood (the higher the rarer), based on a long historical record of hourly water levels. For example, based on sea level in 2012, we estimate that a flood with a 1% annual chance – what we call an "extreme" flood in this study, and commonly referred to as a "100-year" flood – reaches 11 feet above the high tide line at Washington. The all-time observed high (in 1942) was recorded at 7.9 feet above the local high tide line, driven by torrential rains flooding the Potomac basin. Three other floods exceeded or were close to 7 feet above the local high tide line: 7.4 feet in 1936 (driven by river runoff from successive rainstorms), 7.1 feet in 2003 (from Hurricane Isabel and its coastal storm surge), and 6.9 feet in 1933 (the Potomac-Chesapeake Hurricane and its surge). All other flood heights at this station since the start of records in 1931 were less than 6 feet above the local high tide line.

We apply the same methods as Tebaldi et al (2012) for this analysis (see Appendix A for a briefer summary). However, we update our previous findings by now including water level records through the end of 2012, and back to the earliest year with reliable records at each water level station. This allows us to project future risks of "unprecedented" floods as well as statistically "extreme" ones.

In this report, we give all flood heights and water levels in elevations relative to Mean Higher High Water (MHHW), or what we more simply call today's "high tide line," defined based on tide levels during NOAA's standard 1983-2001 tidal "epoch." Our purpose is to give a good sense of how high floods might reach above normal local high water lines. Note that different sources use different reference frames; tidesandcurrents.noaa.gov (more specifically here) provides data for inter-conversions at most stations, for example to and from Mean Lower Low Water (MLLW) and standard modern map elevation (North American Vertical Datum 1988, or NAVD88).

Coastal Flood Projections

As sea levels rise, they increase the chances of extreme floods by today's standards. We assessed when floods would exceed the highest-ever observed flood – 7.9 feet above the local high tide

02. A TIMELINE OF GROWING RISKS

line – at the Washington, D.C. water level station (see http://tidesandcurrents.noaa.gov/est/Top10_form_ft.pdf for historic flood listings), and found a one-in-two chance by 2040, based on NOAA's intermediate high scenario ("medium" rise, here). Floods exceeding today's record become annual events by 2100 under the highest sea level rise scenario.

We conducted similar analyses for standard water levels from 1-10 ft above the high tide line, computing probabilities for each level by decade, for all of the stations analyzed.

For example, at 6 feet MHHW – a level exceeded just once in the last 70 years – there is a better-than-even chance of flooding at the Washington station by 2030 under NOAA's intermediate low ("slow") sea level rise scenario. Under NOAA's highest ("fast") scenario, such floods would be annual events by 2080.

Under the same fast scenario, at least one flood reaching above 10 feet would be close to certain this century.

Therefore, 6-to-10 feet can be viewed as a reasonable range where historically high floods are *likely* this century along the whole Washington D.C. coast, depending upon sea level rise scenario. Much higher floods are also possible but with lower probability.

The Surging Seas Risk Finder presents complete results for all levels and locations.

It is important to note that while sea level rise projections are fairly similar for most neighboring water level stations, local flood risk profiles tend to vary more substantially (as illustrated here by the differences in projected flood risks according to location). In general, flood risk by elevation can vary significantly across short distances, depending upon local geography. Thus the escalating flood risks computed for each station may be taken as *indicative* of increasing risk in its wider area, but should not be interpreted as providing *predictions* for nearby areas.

Global warming multiplies extreme flood risk

Since sea level rise multiplies extreme coastal flood risk, and global warming contributes to sea level rise, global warming multiplies flood risk. This effect is independent of any potential warming influence on storm frequency or intensity. We assessed the sea level driven global warming multiplier by comparing flood probabilities with and without the global component of sea level rise (leaving out local components that might come from sinking or rising land).

Multipliers for cumulative flood probabilities behave more complexly, because the cumulative risk for an extreme flood becomes substantial when accumulated across many decades, even in the absence of global sea level rise. This puts a cap on multiplier values: for example, a background 50% cumulative risk cannot have a multiplier any greater than 2X.

03. PEOPLE, PROPERTY AND INFRASTRUCTURE IN HARM'S WAY

1,350 acres of land lie less than 6 feet above the high tide line in Washington D.C. Some $4.6 billion in property value, and 1,400 people in 400 homes, sit on this area. These figures jump to $9 billion and 4,833 people residing in 1,900 homes on 2,500 acres of land under 10 feet.

The District has 21 miles of road below 6 feet, plus 2 military facilities; 1 museum; 0 power plants; and 12 EPA-listed sites such as hazardous waste dumps and sewage plants. At 10 feet, these numbers grow to 46 miles of road, 4 military facilities, 3 museums, and 26 EPA-listed sites. One power plant sits on land below 10 feet MHHW.

LAND

Washington D.C. has 1,350 acres of land at less than 6 feet MHHW, increasing to more than 2,500 acres less than 10 ft above the tide line. Three zip codes make up about half of the 6-foot exposure: 20024 (Southwest), 20019 (Greenway, NE) and 20372 (Foggy Bottom).

These values are based on analysis of high-resolution land and tidal elevation data from NOAA, after screening out areas classified as saltwater wetlands by the U.S. Fish and Wildlife Service (see Appendix A for more detailed methodology).

We further analyzed how much low-lying land might be protected by levees or other flood control structures (as represented in FEMA's Midterm Levee Inventory), or natural features such as ridges (as represented in the elevation data): 2% of the total area below 6 feet, and 9% below 10 feet. We take potential protection or isolation into account when providing exposure estimates here.

Our approach does not take into account, and also avoids complications from, future erosion or the migration of marshes as sea levels rise. It also does not address the uneven surfaces of floodwaters driven by individual storms, and influenced by details of local geography.

Overall, the maps and analyses here should not be taken as precise predictions or flood emergency guides. Rather, we present them as risk indicators in a world of rising sea levels and increasing floods.

03. PEOPLE, PROPERTY AND INFRASTRUCTURE IN HARM'S WAY

PEOPLE, PROPERTY AND INFRASTRUCTURE

Once maps of vulnerable land are established, it is relatively straightforward to account for the populations, property and infrastructure exposed within these zones. The Surging Seas Risk Finder presents hundreds of thousands of combinations of analysis results by geography, water level, and variable. Here we present some of the major categories and highlights, with a focus on exposure below 6 and 10 feet.

We find that in Washington D.C., some $4.6 billion in property value – half in the zip code of 20024 (a large portion of Southwest DC) – and more than 1,400 people in 400 homes sit on land less than 6 feet above the local high tide line. At 10 feet the totals increase to $9 billion and 4,833 people residing in 1,900 homes.

Nonresidential buildings and infrastructure are widely at risk as well. All told, 21 miles of road lie on land below 6 feet in the District; 2 military facilities; 1 museum; and 12 EPA-listed sites, screened to include mostly hazardous waste sites, facilities with significant hazardous materials, and wastewater generators. At 10 feet, these numbers change to 46 miles of road, 4 military facilities, 3 museums, and 26 EPA-listed sites. 1 power plant sits on land below 10 feet MHHW.

This analysis simplifies most facilities as points with a single latitude and longitude. It also evaluates exposure by evaluating the height of the land that structures sit upon. It takes into account neither the full footprint of a facility; nor the potential elevation of structures or equipment above ground; nor the possibility of unsealed basement areas. We regard such analysis as useful for assessing the general exposure of different facility types across different geographies, and as useful for screening the possible exposure of individual facilities. However, authoritative assessments for individual facilities are best served by on-the-ground measurement.

THE MOST VULNERABLE

Social vulnerability is a broad term that describes the sensitivity of populations to the impacts of environmental risks and hazards, including coastal flooding. Social vulnerability helps explain why some places can experience hazards differently even without differences in exposure. The Social Vulnerability Index is a tool that synthesizes socioeconomic characteristics of populations – characteristics known to influence a community's ability to prepare for, respond to, and recover from hazard events like floods (see e.g. Emrich and Cutter 2011; Finch et al 2010; Cutter et al. 2013).

Accounting for potential protections, our analysis found 20 people in the high Social Vulnerability Index class below 6 feet across Washington D.C.. The total grows to 43 below 10 feet.

The Social Vulnerability Index compares places based on their relative levels of social vulnerability. For this analysis, vulnerability was assessed at the Census tract level, using 27 variables from the 2010 Census and the 2006-10 American Community Surveys (see Appendix A for further

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methodological details). The online Submergence Risk Map that accompanies this report includes a feature visualizing social vulnerability levels in areas that are physically vulnerable to coastal flooding and sea level rise.

The Social Vulnerability Index shows where there is uneven capacity for preparedness and response and where pre and post-event resources might be most effectively used to reduce pre-existing vulnerability and increase resilience post-disaster. The index is also a useful indicator in understanding spatial differences in disaster recovery. It has been used in combination with other disaster data to provide emergency responders with a much clearer understanding of disaster impacts, thus providing decision makers with an objective comparison of damages sustained across the full spectrum of affected communities (see http://webra.cas.sc.edu/hvri/products/SoVIapplications.aspx).

04. CONCLUSION

Long before rising seas redraw local maps, they will result in more coastal floods reaching higher. They are already having this effect.

The research in this report underscores the high concentration and wide range of populations, property, infrastructure, buildings, and potential contamination sources in low-lying coastal areas. In the densest areas, the most socially vulnerable populations are exposed the most. Patterns vary from place to place.

It will not require major storms to cause extensive economic damage and suffering in the future. Knowledge of vulnerabilities can lead to better preparation for the next inevitable flood, and the ones after. Higher floods in the future are certain, but how much damage they inflict is not – and will depend on the measures coastal communities take.

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APPENDIX A: METHODS

PROJECTING LOCAL SEA LEVEL RISE

To localize the various global sea level rise projections used, including the scenarios prepared for the National Climate Assessment (Parris et al 2012), we followed the same essential methods as Tebaldi et al (2012). In that study, we added "semi-empirical" projections of global sea level rise to separate local sea level change components developed for 55 water level stations around the contiguous U.S. Here we use the example of projections built on top of a semi-empirical model, as in Tebaldi et al., to explain the methodology.

For the global component in our semi-empirical approach, we used projections from Vermeer and Rahmstorf (2009). Their approach, based on the recent historic relationship between global sea level and global average temperature, has successfully hind-casted sea level rise over the last century and millennium with great fidelity. The relation estimated over the past observed records of sea level rise and global warming can be applied to projections of future temperature change produced by climate models. By this approach, therefore, future global sea level rise is not directly derived from the output of climate models, but is projected on the basis of the future temperature projections of these models. As projections based on historical observed relationships generally do, this approach assumes that the dynamics captured by the past relation will remain the same for the projected future period. If the ongoing increase in global temperatures leads ice sheets to unravel in ways not experienced during the model's twentieth century calibration period, then this approach may understate the problem.

Use of Vermeer and Rahmstorf's approach allowed this analysis to take into account a wide range of possible futures, from ones where humanity continues to send great amounts of heat-trapping gasses into the atmosphere, to ones where we sharply reduce these emissions. Through Vermeer and Rahmstorf's method we were also able to incorporate a range of possible relationships between emissions and global temperature increases (by using a range of climate model parameters and thus exploring the dimension of model uncertainty), and a range of possible relationships between temperature and sea level (by considering the uncertainty in the parameters of the empirical model). Our analysis rolled all of these factors together to produce one set of best estimates, and a range of potential outcomes around them.

For the current Surging Seas Risk Finder, we updated our semi-empirical projections to employ the most recent carbon emissions scenarios ("Representative Concentration Pathways") and warming models being used by the global scientific community (Moss et al 2010).

In addition to future SLR estimates based on the empirical relation fitted between global temperature projections and SLR, we used global SLR models and scenarios that NOAA prepared for the National Climate Assessment (Parris 2012), and from the IPCC (2013) and from the U.S. Army Corps of Engineers (2011).

Changes in local sea level come not only from changes in global sea level, but also from local effects such as the slow rising or sinking of coastal land, driven largely by the ancient retreat of massive

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ice sheets across North America. To determine local effects, we removed global rise from the total observed local sea level increase over a 50-year period (1959-2008) at each of the 55 nationwide stations we analyzed in our original study. The difference between the total observed local component and global rise during the same period (both of them expressed as linear trends of sea level change per year) is what we call the local component, and, in our projections, we assumed that each local component will continue as a constant rate into the future that offsets or adds on to the global component as an additive term. A detailed analysis using multiyear data from high-precision continuous GPS stations showed that vertical land motion can explain most or all of these local components. The forces behind such motion generally stay constant for thousands of years.

Our projections should not be interpreted as precise predictions for specific years, but rather best estimates that indicate overall trends, because of all of the factors that could lead to a range of outcomes (for example, different emissions futures) and because of natural year-to-year and decade-to-decade variability. For this reason, we present projections at the decade scale only.

PROJECTING COASTAL FLOOD RISK

In Tebaldi et al (2012) and here, to project the probabilities of reaching different high water levels in the future, through combinations of storms, tides and sea level rise, we developed statistics based on patterns of historical extreme water levels, and then superimposed projected sea level rise onto these. For this report, we used local statistics and local sea level projections for the Potomac River water level station in Washington, D.C.

We used statistical methods specialized for handling extreme values to analyze records of hourly data. We expanded our analysis from the fixed standard 30-year period (1979-2008) used in Tebaldi et al, to use the maximum available high quality data for each water level station through the end of 2012 – starting in 1931 for Washington, D.C.

We estimate the parameters of a Generalized Pareto Distribution at each station, characterizing the probability density of extreme water levels at that location, and on the basis of those parameters we derive what is called a "return level curve" for each water level station. Our return level curves relate water heights (in MHHW) to their annual probability (given sea level in 2012): for example, heights with a 1% chance of being reached in any given year ("100-year" or "century" or "extreme" floods) are higher than heights with a 10% chance ("decade floods"), and so forth. We filtered out the effects of ongoing historic sea level rise at each station by estimating a linear trend over the length of the record and subtracting it out, in order to calculate baseline return level curves influenced only by tides, storms, and seasonal shifts in water level.

Once we establish a curve for the baseline period (that we can think of as today in most cases), it is easy to modify it for a given time in the future, on the basis of the effects of sea level rise alone. For example, if at that future time sea level has risen by one foot, an event reaching 5 feet of elevation will have at that future time the same probability of occurring as a minor event reaching 4 feet has today. Thus, sea level rise will make rare high water events of today more likely in the future.

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These considerations allow us to compute the chance that a particular height H will be reached in some future year (say, for example the chance that an event reaching 5 feet will happen in 2030). All that is needed is the amount of sea level rise, say L, between today (the baseline) and that target year, and the return level curve for the baseline: we then take H, subtract L and find, on the curve, the probability associated to the event of size H-L.

Slightly more complex is the computation of the cumulative risk of at least one such event by some future year, i.e., the estimate of the chance that a particular height H will be reached or exceeded by some future year. The way to think of this is as the complement of (i.e., one minus) the probability that such event will never be reached by that year. As an example, let's say the event H is currently a "100-year" event. That means that this year it has 0.01 chances of occurring, and therefore 0.99 chances of not occurring. Next year, if nothing changed, the chance of it not occurring would be the same, therefore the probability of H not occurring this year or next year would be 0.99*0.99=0.98; its complement, that is the chance of H occurring by next year, would be 1-0.98=0.02.

The same calculation applies for any number of years until the target year. We simply multiply the chances of the event H not occurring every year for the entire period, and then take its complement.

Critically, however, sea level rise makes the chance of any event higher –at least on average decade after decade. Therefore we compute changing probabilities over the years, taking into account the effect of sea level rise. To do so, we incorporate local projections of sea level rise decade by decade, not just the total rise projected by the target year.

More specifically, we used the return level curve for each decadal year, e.g. 2040, incorporating sea level rise projected through that year, and applied the same curve for the five preceding and four succeeding years as well. We then used the probability of exceeding H each year between 2011 and the target year to compute the overall odds of exceeding H at least once during the period.

To continue with the example of H as the 100-year event of today one can imagine that for a target year far enough in the future the multiplication will involve values sooner or later (depending on the pace of sea level rise at this station and on the shape of its return level curve) significantly smaller than 0.99, therefore producing a significantly larger value of the complement, by the target year, compared to that computed under the assumption of no sea level rise.

As with our projections of sea level rise, and for similar reasons, we limit our presentation to odds of reaching different flood levels at decade resolution. Any given year, even within a steady long-term trend of sea level rise, may see dips and jumps in the actual value of sea level rise at a given location. Our estimates of sea level rise are appropriate only as long-term average trends, decade after decade.

Note that the same type of calculation performed for a detailed range of values and years in the future allow us to answer a question mirroring the one above. We can search among our results for which size event will become, say, at least Q% likely by the next 20 years, rather than starting with a given size event and ask what its likelihood of occurring at least once in the next 20 year will be. Similarly we can ask questions about waiting times, looking for the number of years it will take for a given size event to occur with at least an Q% chance.

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Our calculations all concern flood levels reaching elevations relative to a stable baseline, the average high tide level during a fixed historic reference period at each station, the so called tidal datum epoch (the current standard epoch is 1983-2001). This way of measuring flood levels is different than pure storm surge, which is calculated as the extra water height above the predicted tidal water level for the very same moment in time. Our focus was not storm surge, but rather how high water actually gets, due to storm surge, plus tide, plus sea level rise.

This analysis assumed that historic storm patterns will not change; in other words, it did not address the possibility that storms might become more or less frequent or severe due to climate change.

This analysis was based on data taken at water level stations. Tides, storm surge, and the resulting statistics vary from place to place, sometimes over short distances, due to factors including land and ocean geometry and storm directions. On the other hand, in our national analysis (Tebaldi et al 2012), results for distantly spaced water level stations within the same region were often similar. Therefore, results from stations may be taken as rough indicators but not precise estimates for their neighborhoods and regions, and the quality and coverage of indication will vary.

ESTIMATING GLOBAL WARMING FLOOD RISK MULTIPLIERS

To estimate how global warming is shifting the odds of high storm surges, through sea level rise, we calculated the odds of extreme events in a hypothetical world with no past or future global sea level rise due to warming, to compare against our original calculations, which included warming. We did this comparison at each water level station in the study. The approach basically translated to subtracting out the roughly 8 inches of historical global sea level rise measured from 1880-2009, and then also assuming no future global sea level rise, for the no-warming scenario at each station (a scenario viewable in the Surging Seas Risk Finder). The no-warming scenarios still included local sea level rise from factors other than warming, such as sinking or lifting land — the full local component of sea level rise.

We made one further adjustment, which was to add back 10% of the historic global sea level rise (10% of 8 inches), in the event that some of the observed historic rise has come from factors other than warming. Research on the sea level budget assigns the great majority of the 8 inches to warming-caused effects: expansion of the ocean as it has warmed, and the melting and calving of glaciers and ice sheets. Small fractions of global sea rise unaccounted for are widely viewed to come at least in part from additional ice loss. We assume 90% of the 8 inches are due to global warming, and thus deduct this amount for our comparison.

For comparison of odds with and without warming, we used standard "100-year" or "century" floods as our reference, meaning water station water levels high enough that they have just a 1% chance of occurring in any given year. We calculated the elevations 100-year floods reach when starting on top of baseline 2012 sea level at each station, using the same data and methods as for our overall water level probability projections. Elevations were relative to average local high tide (MHHW) during a fixed past reference period (the 1983-2001 tidal epoch), as with all elevations in related studies.

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In comparing the probabilities of flood levels with and without global warming, we cut ratios off at ten, because higher ratios start to lose a sense of meaning. We also do not compute ratios at all when the chance of flooding is very close to zero without global warming. These situations create very large ratios whose exact values are meaningless: tiny changes in near-zero odds (odds without global warming) would lead to enormous changes in the ratio value.

This analysis did not address the possibility that storms might become more or less frequent or severe due to climate change. We also limited ourselves to looking at the total effects of global warming, and did not aim to separate fractions caused by humans versus natural variations. The strong scientific consensus points to people as causing most, if not all, of the average warming observed over the last century, and to being the dominant cause of future warming.

MAPPING LOW COASTAL AREAS

To develop our maps of at-risk areas, we used high-resolution, high-accuracy laser-based (lidar) elevation data provided by NOAA. These data have a roughly 5 m (16.5 ft) horizontal resolution. In any small fraction of low-lying areas not covered, we used the highest resolution data available from the National Elevation Dataset (NED), a product of the U.S. Geological Survey.

For general discussion of the accuracy of elevation data and what it means for our maps and statistics, see Strauss et al (2012), which used 1/3 arc-second NED data exclusively, as lidar data were not sufficiently available. This discussion concluded that NED quality data are sufficient for the types of analysis conducted here. Nonetheless, the reported vertical accuracy (root mean square error) of lidar data, as used in this analysis, is roughly ten times more accurate than NED.

We began our process by classifying all cells as ocean (ocean, bay, estuary or saltwater wetland) or land (land or freshwater wetland), because ocean or saltwater marsh misclassified as land would lead to overestimates of susceptible total land area. We admitted cells as land according to a conservative consensus of three independent data sets. First, the cells had to be designated as land within the elevation data itself. Second, we included only cells with centers landward of NOAA's Medium Resolution Digital Vector Shoreline. Finally, we eliminated cells with centers inside areas classified in the National Wetlands Inventory (NWI) as estuarine or marine wetland or deepwater. In computing total land area susceptible, we included NWI freshwater wetlands.

Next, we adjusted the elevation of each cell to be in reference to the nearest average high tide line, instead of a standard zero. For example, if a cell's elevation were five feet, but the local high tide reached three feet, then we would compute an elevation of two feet relative to the tide line. Clearly, sea level rise or a storm surge would need to reach only two feet above high tide to threaten this cell with inundation. Sea level and tidal amplitude vary sometimes widely from place to place, and therefore also the average height of high tide. For local high tide elevations, we used values of Mean Higher High Water from VDatum, a NOAA data product and tidal model.

Based on these elevations adjusted relative to MHHW, we identified the set of cells beneath each water level threshold from one to ten feet above local high tide, and drew maps of each area.

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Finally, we distinguished areas connected to ocean at a given water level, versus isolated areas, to use in different exposure analyses, and for differential display in our online mapping application. We included levees from the Midterm Levee Inventory in this analysis of connectivity, assuming each levee to be of sufficient height and condition to offer protection at every water level. Additional discussion can be found in the main body of this report (see "Land" in Table of Contents).

ASSESSING SOCIAL VULNERABILITY

The Social Vulnerability Index for 2006-10 marks a change in the formulation of the SoVI® metric from earlier versions (see e.g. Emrich and Cutter 2011). New directions in the theory and practice of vulnerability science emphasize the constraints of family structure, language barriers, vehicle availability, medical disabilities, and healthcare access in the preparation for and response to disasters, thus necessitating the inclusion of such factors in SoVI®. Extensive testing of earlier conceptualizations of SoVI®, in addition to the introduction of the U.S. Census Bureau's five-year American Community Survey (ACS) estimates, warrants changes to the SoVI® recipe, resulting in a more robust metric. These changes, pioneered with the ACS-based SoVI® 2005-09, carry over to SoVI® 2006-10, which combines the best data available from both the 2010 U.S. Decennial Census and five-year estimates from the 2006-2010 ACS.

The table below gives a complete list of the 27 variables used in SOVI® 2006-10 for Census tract level analysis.

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Table A1. Variables Used in Social Vulnerability Analysis

VARIABLE	DESCRIPTION
QASIAN	Percent Asian
QBLACK	Percent Black
QHISP	Percent Hispanic
QNATAM	Percent Native American
QAGEDEP†	Percent of Population Under 5 Years or 65 and Over
QFAM†	Percent of Children Living in Married Couple Families
MEDAGE	Median Age
QSSBEN	Percent of Households Receiving Social Security
QPOVTY	Percent Poverty
QRICH200K	Percent of Households Earning Greater Than $200,000 Annually
PERCAP	Per Capita Income
QESL†	Percent Speaking English as a Second Language with Limited English Proficiency
QFEMALE	Percent Female
QFHH	Percent Female Headed Households
QNRRES	Percent of Population Living in Nursing and Skilled-Nursing Facilities
QED12LES	Percent with Less Than 12th Grade Education
QCVLUN	Percent Civilian Unemployment
PPUNIT	People Per Unit
QRENTER	Percent Renters
MDHSEVAL†	Median House Value
MDGRENT†	Median Gross Rent
QMOHO	Percent Mobile Homes
QEXTRCT	Percent Employment in Extractive Industries
QSERV	Percent Employment in Service Industry
QFEMLBR	Percent Female Participation in Labor Force
QNOAUTO†	Percent of Housing Units with No Car
QUNOCCHU	Percent Unoccupied Housing Units

For this analysis, we assessed Social Vulnerability Index scores by Census tract across the entire state. We then assigned tracts high, medium, or low social vulnerability scores, based on whether they fell within the top 20%, middle 60%, or bottom 20%, respectively, of vulnerability for the whole set within each state.

More information on the Social Vulnerability Index is available at http://webra.cas.sc.edu/hvri/products/sovi.aspx

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ESTIMATING EXPOSURE OF PEOPLE, PROPERTY, AND INFRASTRUCTURE

To calculate potential risks at each water level within areas such as zip codes, cities or counties, we used boundaries provided by the 2010 U.S. Census to overlay against our maps of land beneath different water level thresholds. We then computed the amount of land below each threshold in each place. For denominators in percentage calculations, we used our own computations of land area for each place, because our definitions of coastline differed slightly in places from that of the Census.

To tabulate population and housing potentially affected, we used block-level data from the 2010 U.S. Census, and assumed development on dry land only (neither freshwater nor saltwater wetland). For each Census block, we divided the population and number of housing units by the number of dry land cells with centers inside the block. We assigned the resulting per-cell density values back to each cell, creating new datasets for population and housing unit density. To estimate the population or housing at risk for a particular water level, we simply added up population and housing densities of land cells affected under the specification. Our analysis considered the elevation of land upon which housing stands, and made no special provision for elevated or multi-story buildings.

We followed the same approach for property value, computing value density based on Census block group resolution data from Neumann et al (2010). The property value is derived almost exclusively from individual parcel assessed just values, evaluated in 2008, which we adjusted using the Consumer Price Index to 2012 dollars. The data include residential, commercial, industrial, institutional and government property, both taxable and tax-exempt.

For analysis of linear features such as roads and rail, we computed the length of each feature on land below the water level in question, and made totals by feature type (e.g. total roads, federally-owned roads, or mainline rail).

For airports, we used linear runway data, and determined the percentage of runway length on land below each water level. We counted an airport as vulnerable at a given level when this percentage exceeded a threshold of 25%.

For point features, we simply use latitude/longitude coordinates overlaid onto our MHHW elevation map to evaluate whether a building, site or facility falls below a given water level. This approach does not take into account the actual footprint of a structure, nor the possibility that critical features may be elevated above the ground (or stored in an unsealed basement).

The first step in each analysis is to properly filter and de-duplicate records for the feature class or subclass of interest from a source dataset – for example, state-owned roads, commuter rail stations, nuclear power plants, or major hazardous waste sites. We primarily used federal datasets. References for each are accessible via the Surging Seas Risk Finder (within the "Analysis" section, click on a tile to see a details panel with sources listed, linked, and described (via tool tips on a mouse hover)).

APPENDIX B: GLOSSARY AND ABBREVIATIONS

EPA – U.S. Environmental Protection Agency

Extreme flood – As used in this report, a coastal flood height with a 1% or lower annual chance, assuming the sea level for 2012.

High tide line – see MHHW

IPCC – Intergovernmental Panel on Climate Change

Lidar – Light detection and ranging technology. A method of measuring distance that relies on firing laser beams and analyzing their returned, reflected light.

MHHW – Mean Higher High Water: a local frame of reference for elevation based on the elevation of the higher of the two high tides each day averaged across a reference period. The reference period used is the current tidal epoch, 1983-2001. This report uses "high tide line" as the equivalent of the height of MHHW.

MLLW – Mean Lower Low Water. See MHHW; MLLW is instead a frame of reference based on the elevation of the lower of the two low tides each day.

NCA – National Climate Assessment

NOAA – National Oceanic and Atmospheric Administration

NRC – National Research Council

Sea level rise, slow – In this report, the NRC lower-range sea level rise projection

Sea level rise, medium – In this report, the NRC main sea level rise projection

Sea level rise, fast – In this report, the NRC upper-range sea level rise projection

SLR – Sea level rise

Social vulnerability - A broad term that describes the sensitivity of populations to the impacts of environmental risks and hazards, including coastal flooding; related to a community's ability to prepare for, respond to, and recover from hazard events.

Storm tide – The height of tidal stage plus storm surge

Tidal epoch – Period over which tidal levels are defined. See definition for MHHW.

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