STATE OF VERMONT
PUBLIC UTILITY COMMISSION

Case No. ________

Petition of Vermont Gas Systems, Inc. for a change in rates and for use of the System Expansion and Reliability Fund in connection therewith	

DIRECT TESTIMONY OF
JOHN ST. HILAIRE
ON BEHALF OF VERMONT GAS SYSTEMS, INC.

February 15, 2022

SUMMARY OF TESTIMONY

Mr. St. Hilaire describes the Company's operating expenses in the Rate Year, particularly in the area of transmission and distribution integrity management. Additionally, Mr. St. Hilaire sponsors exhibits that detail VGS's capital investments and additions in the Rate Year and discusses some of the more notable capital investments. Finally, Mr. St. Hilaire provides the forecast of capital expenditures as required by Commission Rule 2.402.

EXHIBITS

Exhibit VGS-JSH-1	FY2022 Plant Addition Index
Exhibit VGS-JSH-2	FY2023 Plant Addition Index
Exhibit VGS- JSH-3.1 to 3.12	Specification sheets for plant additions
Exhibit VGS-JSH-4	Forecast of Capital Expenditures
Exhibit VGS-JSH-5	Historical Comparison of Transmission Maintenance Budget to Actual Spend

**DIRECT TESTIMONY OF
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ON BEHALF OF VERMONT GAS SYSTEMS, INC.**

Q1. Please state your name, occupation, and business affiliation.

A1. My name is John St. Hilaire. I am the Vice President of Operations and Infrastructure at Vermont Gas Systems, Inc. ("VGS" or the "Company").

Q2. Please describe your educational background and pertinent professional experience.

A2. I have an Associate in Science Degree in Mechanical Engineering Technology from Vermont Technical College (1989), a B.S. in Business Management from Champlain College (1999), an M.S. in Administration from St. Michaels College (2005), and a B.S. in Accounting from Champlain College (2010). I have been at VGS since 1990 in positions of increasing responsibility. In April 2013, I was promoted to Director, Operations Services, Gas Supply and Gas Control, and in September 2015, I was promoted to Vice President of Operations. In my current position, I have overall responsibility for the design, installation, and ongoing safe operation of the Company's pipeline system. Finally, I am currently serving as the Executive Sponsor of the Company's Customer Information System ("CIS") upgrade project.

Q3. Have you previously provided testimony before the Vermont Public Utility Commission (the "Commission")?

A3. Yes. I have testified in Docket No. 8472 relating to the Phase VII looping project; Docket No. 7970 concerning natural gas supply and other matters relating to the Addison Natural Gas Project ("ANGP" or "Project"); and Docket No. 8710 regarding the ANGP budget, schedule, and costs. I have also provided testimony in several other cases involving the ANGP, and testified in Case Nos. 17-1238-INV, 18-0409-TF, 19-0513-TF, 20-0431-TF, and 21-0898-TF relating to plant additions and other issues pertaining to VGS's recent rate cases.

Q4. Please provide a summary of the topics you cover in your testimony.

A4. As head of the VGS Operations team, my testimony addresses those aspects of the COS that are driven by our operational priorities. At VGS, our central operational priority remains unchanged: safe and reliable operation of our system. We continue to build on this core mission by implementing leading safety, inspection, and integrity management programs. Our operations team also has an integral role to play in implementing our Climate Action Plan to further reduce Greenhouse Gas emissions on behalf of customers. In my testimony, I describe investments and strategies that minimize system risk and strengthen best practices.

My testimony addresses two broad categories of the COS, (1) operating expenses, and (2) capital investments. First, I explain some of the key transmission and distribution integrity management initiatives that we are undertaking in the Rate Year. This testimony provides additional background and information in support of the operating expenses discussed in Mr. Mitchell's testimony. Second, I discuss some of the capital investments that are included in this COS. These include capital investments that are planned to go into service after the end of the Test Year (calendar year ending December 31, 2021) as well as capital investments we are making in the Rate Year.

Operating Expenses

Q5. Please describe how the Company's operating expenses for the Rate Year promote system safety, reliability, and integrity.

A5. As we have described in prior proceedings, VGS has a variety of programs that support our strong safety record. These include ongoing transmission and distribution integrity management programs, our cross-bore program, ongoing leak surveys, mainline replacement work, first-responder training, and pipeline safety management system development, among others. This rate filing reflects continued investment in these key safety programs. I describe some of these initiatives in more detail below, including (1) specific investments we are making as part of our transmission integrity management program, (2) targeted investments in distribution integrity during the Rate Year, and (3) continuation of our cross-bore program.

Q6. Please describe transmission integrity management expenses in this case and explain why that work is an important part of VGS's system safety and reliability.

A6. Our transmission integrity work is an investment in the continued safety and integrity of VGS's transmission system. Our annual transmission integrity budget in this case is $1,040,997. This includes required tests and inspections under federal code 49 CFR Part 192, Subpart O and other state regulatory obligations; clearing of transmission right of ways; monitoring of the 12" corridor for invasive vegetation; plowing of access roads and gate stations; and other miscellaneous transmission corridor maintenance and repair.

This COS includes expenses we will incur in the Rate Year for transmission integrity work on the 12" transmission line commissioned in 2017, including, (1) an In-Line Inspection

("ILI")[1] and (2) a Close Interval Survey. We last performed an ILI on our 12" transmission pipeline, which runs approximately 41 miles from Colchester, Vermont, to Middlebury, Vermont, in 2018. Accordingly, we are confident this work will be able to be completed, and our COS reflects the costs we expect to incur performing that work. The performance of this ILI in the Rate Year is consistent with VGS's commitment in the Stipulated Remedial Action Compliance Plan from Case No. 18-0395-PET in which the Department and VGS agreed that VGS would perform ILIs on the 12" pipeline on a 5-year interval.[2]

The close interval survey is also known as a pipe-to-soil survey. Consistent with our agreement with the Department noted above, we will conduct this survey on the 12" transmission pipeline in conjunction with the ILI discussed above, which will provide an assessment of the effectiveness of the cathodic protection systems on that transmission line. We also perform annual surveys separately that take pipe-to-soil readings approximately every mile (as required by federal code), but a close interval survey takes readings at a much smaller interval of under one meter. Appropriate adjustments to the Test Year for transmission integrity work are discussed in Mr. Mitchell's testimony.

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[1] As we have previously explained, ILIs are a best practice and the preferred assessment method due to the amount and quality of data that can be collected. An ILI involves passing a series of ILI tools through a pipeline, with the final tool having various sensors to gather data on the integrity of the pipeline.

[2] The Case No. 18-0395-PET Stipulated Remedial Action Plan is pending Commission approval in that case.

Q7. Has VGS performed a comparison of budgeted transmission integrity management expense to costs actually incurred as required by the Commission's October 15, 2021 order in last year's rate case?

A7. Yes, as we prepared this case, we reviewed our transmission integrity program over the last five years and compared our annual spend to what we have included in prior rate cases. This was responsive to the Commission's October 15, 2021 Order in our last rate case, which called for VGS to "compare actual spending on non-labor transmission integrity management activities with the amounts included in the cost of service and present a budgeted-to-actuals comparison in its next rate proceeding." Please see **Exhibit VGS-JSH-5**.

Q8. What does VGS's budgeted-to-actuals comparison demonstrate about planned transmission integrity management expenses?

A8. In general, our budgeted transmission integrity work varies from year to year. As in this case, we have included costs in prior rate cases for work that is planned during the upcoming rate year. This budget changes from year to year based on the type of integrity test that is planned (e.g., ILI, Direct Assessment, pressure test) as well as the age, construction, configuration, and location of the transmission facilities for which we are planning integrity work. Some planned work may vary from the budgeted costs based on differing field conditions experienced, weather, contractor availability, tool availability, and time of year. The extent to which budgeted amounts are subject to change also varies depending on the type of work that is planned. For example, each type of integrity test incurs costs differently throughout the testing timeline. The cost of a direct assessment is primarily incurred in mobilization and demobilization of contractors and less in actual days worked, while ILI costs are primarily incurred when each tool is run and if additional days or tool runs are needed.

Over the last 5 years we reviewed, actual costs incurred for transmission integrity work have varied from the amounts included in our COS filings. We incurred substantially higher costs than we budgeted in one year, and lower costs in others. In last year's rate case, we discussed the primary driver of the largest variances—those relate to ILI costs on our 10" transmission pipeline in FY2020 and FY2021. As detailed in prior filings, we budgeted for ILIs to be performed on this part of our system, which was installed in the 1960s. We successfully ran portions of the inspection, but also identified upgrades that would be needed to complete the ILIs.

Q9. Do budgeted-to-actuals for transmission integrity management activities over the last five years show any trends or reveal any current or future safety concerns?

A9. No. As noted above, the most meaningful variances we identified were related to the 2020 and 2021 ILIs on our 10" inch transmission line. This was a unique situation because we were attempting to complete a new kind of inspection on that pipeline. The vast majority of our other transmission integrity management expenses are more predictable, though they are also subject to modest and normal variances from budget. In my view, the budget-to-actuals look-back really highlights how much of a cost impact the ILIs had in 2020 and 2021.

Those variances, however, do not indicate current or future safety concerns. Our actual costs on transmission integrity management fully address our obligations under federal code and ensure that we are performing adequate inspections on our transmission line. For example, we performed alternative inspections to the ILIs that we did not complete in 2020 and 2021, and we undertook additional integrity work such as casing removals. We also decided to perform an ILI on the 16" transmission line in FY2021 ahead of our normal schedule. Although these endeavors did not cost as much as the budgeted ILIs, they helped balance out our integrity work in the coming years.

Q10. Given variances in the transmission integrity management costs in prior years, do you expect there will be variances in the budgeted-to-actual amount spent in the Rate Year?

A10. Some variance is normal and to be expected, but I do not believe the significant variances I discussed above from 2020 and 2021 will be repeated in the Rate Year. Although our overall transmission budget in this case is over $1 million, the inspections on our 12" pipeline discussed above account for the majority of that expense. Unlike the ILIs attempted on our 10" pipeline, we have performed ILIs on our 12" line before and therefore we are confident that we will be able to complete those inspections as planned.

Q11. Please discuss VGS's distribution integrity management program and any notable costs for distribution maintenance in the Rate Year.

A11. VGS also invests each year in the ongoing maintenance and operation of its distribution network. This rate case continues this work with investments in our capital replacement project; legacy cross-bore program; erosion repair on one of our large distribution laterals; and costs for general repair and maintenance such as Dig Safe expenses, traffic control, site restoration, permits, and various materials. In the Rate Year, we are undertaking several distribution integrity initiatives that I discuss in more detail below.

First, we continue to support our proactive legacy cross-bore[3] program and have included related costs in this case. As discussed in Mr. Mitchell's testimony, cross-bore costs reflect an adjustment to the Test Year, but that adjustment is driven by the timing of the work performed, not a change in the annual cost of our cross-bore work. The last rate case, Case 21-0898-TF, included approximately $393,000 for our legacy cross-bore program. In the Rate Year, the program will be maintained at the same level with only a $7,870 increase to account for forecasted inflation.[4] As explained in prior cases, our cross-bore program is part of our Distribution Integrity Management Program ("DIMP") required by federal code. VGS is in a favorable position because it has already replaced old bare steel pipe, which is what the DIMP for most distribution utilities is focused on. Accordingly, we can focus on building more resilience in other areas, which includes prioritizing cross-bore inspection.[5]

Second, during our 2021 erosion patrol inspections, we identified an ongoing erosion issue over one of our largest distribution laterals that feeds the South Burlington and southern sections of the distribution network. We have engaged an engineering firm to scope out and design the appropriate remediation and we plan to complete the work during Fiscal Year 2023.

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[3] A "cross-bore" occurs when a natural gas line traverses through or "bores" a sewer line during the installation of the natural gas line. This is a risk that has emerged more widely in the natural gas industry as "trenchless" installation technology has become more prevalent. Gas companies across the nation are now focused more closely on this risk. In trenchless technology, a natural gas line may be installed without opening a trench and visually identifying the presence of a sewer line. Because most municipal waste-water companies are not required to be members of one-call systems (in Vermont that is Dig Safe), the locations of sewer lines are not always identified prior to construction.

[4] See Schedule 4 to Exhibit VGS-MM-1. For a more detailed description of the Rate Year to Test Year adjustment for this expense, please see the Direct Testimony of Matthew Mitchell at 9.

[5] We have also implemented systems to prevent cross-bores during installation of gas lines, including identifying customer cleanouts and locating sewer laterals and mains.

The erosion repair is expected to cost $202,000 based on a similar erosion control project we performed in 2016. We expect that construction costs have increased since 2016 and we therefore included an increase from the 2016 costs based on inflation.

Capital Investments

Q12. Please describe the capital investments that are included in the COS for the Rate Year.

A12. VGS is committed to investing capital to promote safety and reliability, while also advancing our decarbonization goals. This rate case includes VGS's investment of approximately $23 million, largely focused on maintaining infrastructure necessary to ensure safe and reliable service for our customers as well as standard investment in mains and services. As in prior cases, we present these capital investments in two buckets. First, capital investments that went, or will go, into service after the Test Year and before the Rate Year are detailed on **Exhibit VGS-JSH-1 – FY22 Plant Additions.** Investment during the Rate Year (Fiscal Year 2023) are detailed on **Exhibit VGS-JSH-2 – FY23 Plant Additions**.

Consistent with the Department's recommendations and VGS's prior rate case practice, (1) Exhibit VGS-JSH-1 identifies any differences in costs or timing for FY2022 net plant additions from the cost and timing for those investments in our prior rate case filing in Case No. 21-0898-TF, and (2) **Exhibits VGS-JSH-3.1** to **JSH-3.12** provide known and measurable support for any expenditure that exceeds $100,000 (Exhibits VGS-JSH-3.1 to JSH-3.12). I provide a brief narrative summary of some key investments below.

Q13. Please discuss some of the FY2022 capital investments listed on Exhibit VGS-JSH-1 (FY2022 Plant Additions) in more detail.

A13. Highlights of the FY2022 investments include the replacement of the Lake Street Main Line Valve ("MLV"), which will be replaced to allow future ILI operations on this section of the 10" transmission line. We will also replace the Mallets Bay MLV that was also installed in the early 1970s when the original 8" transmission line was installed. Also included in the 2022 plant additions are distribution mains, services, and meters to support customer growth within our current footprint along with costs associated with the Milton reinforcement project that was partially postponed in 2021 due to continued Covid-19-related quarantine delays and limitations with contractors.[6] The Milton replacement project is a multi-year distribution project to connect five individual distribution networks supplied by their own transmission gate stations in the Milton area into one connected system fed by multiple transmission gate stations. The multiple feeds provide redundancy in the case of a station outage, while also eliminating the need and cost to rebuild the Murray Avenue and Quail Hollow gate stations, which are in need of replacement. These two stations will be decommissioned once the interconnections are completed. The large Milton gate station will be the oldest remaining station and is scheduled for replacement within the next five years.

All January-September 2022 plant additions are indexed on Exhibit VGS-JSH-1, and the investments are included in rate base consistent with the timing of the investments as detailed on Schedule 12c to Exhibit VGS-MM-1. All 2022 plant additions are expected to be completed and placed into service as of October 1, 2022, coinciding with the start of the Rate Year.

[6] These investments are shown on Exhibit VGS-JSH-1 under Mains.

Q14. Looking ahead to the Rate Year (FY2023), please provide a brief description of some of the key plant investments listed on Exhibit VGS-JSH-2 (FY2023 Plant Additions).

A14. All of the capital investments discussed below are planned to be in-service during the Rate Year and represent investments necessary to operate and maintain a safe and reliable natural gas transmission and distribution network as well as meet the expectations of our customers. As noted above, for all capital projects in excess of $100,000, a detailed Specification Sheet has been provided. (See Exhibits VGS-JSH-3.1 to 3.12) The corresponding Specification Sheet is noted on Exhibit VGS-JSH-2. Highlights of the 2023 capital plan are described below.

Mains and Services Replacement: This COS reflects a continuation of VGS's proactive main and service replacement program based on a risk assessment identifying areas to be replaced. (Spec Sheet provided as Exhibit VGS-JSH-3.3.)

Municipal Replacement: This COS separately identifies mains and services that will be replaced in connection with municipal infrastructure projects, such as road widening. VGS has historically managed this work within the main and service replacement budget. However, due to an increase in municipal project replacements, we now track this work as a standalone program to ensure we continue to address targeted risks on the distribution system as described above. (Spec Sheet provided as Exhibit VGS-JSH-3.5.)

In-Footprint Mains and Services: These represent investments in distribution mains and services (including services associated with previously installed Addison County distribution networks) in response to demand for natural gas service from new customers. The methodology for determining the costs of these investments is essentially unchanged from prior proceedings. Please note that the COS does not include any investment for expansion into any new communities and as such reflects an overall slowing of customer growth. (Spec Sheet provided as Exhibit VGS-JSH-3.4.)

Meters and Meter Installation: The COS includes investments in new meters and meter installation (the capitalized labor associated with meter installation) associated with both serving new customers and the Company's Commission-approved meter testing and replacement initiatives (Spec Sheets provided as Exhibits VGS-JSH-3.7 and JSH-3.8). It is worth noting that we continue our proactive program to move remaining indoor regulators and meters outside when it is feasible to do so.

Nason Street Gate Station Heater Replacement: As previously mentioned in my testimony, the heaters at the Nason Street gate station are approximately 22 years old and nearing the end of their operational capacity. The heaters are used to heat the gas prior to the pressure reduction stage to ensure the gas does not drop below freezing. Adequate heating is necessary to ensure that gate station components are not damaged and regulator operations are maintained. The Nason Street gate is in continuous operation and 100% of the volumes that flow south of St. Albans pass through the Nason Street gate station. Gas entering the station ranges from approximately 400 psi to about 800 psi and has a temperature around 40^0F. The station regulates gas at the higher transmission pressure down to lower transmission and distribution pressures, which could mean a more than 300 psi drop in pressure. Per the Joule-Thomson Effect, for every 100 psi reduction in pressure, the temperature of the gas is reduced by 7^0F.

Over the last 22 years the demand in Chittenden and Addison counties has increased and thus increased the demand on the heaters. The heaters were originally installed at the former Beebe Road gate station and were repurposed when the Nason Street station was built. The current heaters are gas-fired water bath heaters and they will be replaced with more efficient gas-fired hydronic heaters. The use of multiple efficient heaters will reduce the heaters' energy consumption while also providing added redundancy and greater heating capacity. We have already obtained a Phase I design proposal from our engineers, will be ordering materials this summer, and plan to perform the installation in the summer of 2023. (Spec Sheet provided as Exhibit VGS-JSH-3.1)

Winooski Gate Station Heater Replacement: As previously mentioned in my testimony, the heaters at the Winooski gate station are nearing the end of their useful lives. The Winooski gate operates 24/7/365 and is one of our large regulating stations feeding the greater Burlington distribution network. Similar to the Nason Street gate station described above, the gas must be heated prior to reducing the pressure to ensure temperatures stay above freezing to reduce the risk of damage to components or impeding regulator operation. (Spec Sheet provided as Exhibit VGS-JSH-3.2)

Distribution Reinforcement: The COS incudes distribution reinforcement extensions to connect smaller distribution networks fed by a single small gate station to larger distribution systems with multiple gate station feeds. These extensions will provide additional redundancy, reliability, and flexibility for system operations. (Spec Sheet provided as Exhibit VGS-JSH-3.6.)

IT Hardware and Software: VGS must continually upgrade its various computer systems, both hardware and software. The COS reflects approximately $109,000 associated with replacing tablets and laptop computers to ensure our teams have the tools to perform their jobs efficiently in a hybrid work environment. (Spec Sheet provided as Exhibit VGS-JSH-3.10.) Also included is $181,000 associated with a server storage refresh (Spec Sheet provided as Exhibit VGS-JSH-3.11.)

I note that Commission Rule 2.402 requires that rate filings be accompanied by a forecast of projected construction expenditures by category for each of the following two years. **Exhibit VGS-JSH-4** satisfies this requirement.

Q15. Notably, the COS in this case does not include VGS's investment in a Customer Information System. Please provide an update on that project and describe VGS's request regarding rate treatment for the CIS in this case.

A15. As we explained in the previous COS, our current customer information system was implemented over 20 years ago. This outdated system presents us with a variety of challenges including lack of system support and incompatibility with mobile and online functionality that customers now expect. To address these substantial obstacles, the Company undertook the most significant IT investment in years: a complete replacement of the CIS.

This effort has involved some disappointing delays, including our vendor's challenges with a ransomware cyberattack and their loss of some key CIS contractor employees. The project has also experienced serious headwinds from the Covid-19 pandemic and related coordination, in addition to some of the standard challenges that are typical of large IT projects of this kind. We have included the CIS investment in prior cases and are disappointed that we have not been able to go live as planned. Current project spend is hovering around our original budgeted level of $4.8M due to savings in the early stages of the project and holding the CIS vendor to their fixed price contract.

At this time, we are working with our CIS vendor to establish a new go-live date and are working in earnest to get to go-live, but we are uncertain of when exactly that go-live will occur. Accordingly, instead of including the CIS in the COS, we are requesting approval to set aside the CIS investment as regulatory asset, which we would then amortize and include in rates once we have a system that is in service. Ms. McNeil explains our request with respect to CIS treatment in more detail in her testimony.

Q16. Does this conclude your testimony?

A16. Yes.