ALTERNATIVE REGULATION PLAN

This Alternative Regulation Plan (the "Plan") is established pursuant to 30 V.S.A. § 218d. The Plan establishes the method by which the Public Utility Commission ("PUC" or the "Commission") will regulate the rates charged for all jurisdictional products and services offered by Vermont Gas Systems, Inc. ("VGS" or the "Company"), during the term of the Plan.

1) Term of the Plan.

a) The Plan will commence on October 1, 2019, and have a term that will expire on September 30, 2020.

b) During the term of this Plan, nothing in this Plan shall prevent VGS or the Department from petitioning the Commission for a new alternative regulation plan for the Company.

2) Regulatory Framework.

a) Sections 218(a), 225, 226, 227 and 229 of Title 30 will continue to apply except as specified herein.

b) The objective of this Plan is to allow for VGS to update its gas costs on a quarterly basis as provided herein rather than through litigated, investigations.

3) Cost of Service.

a) The Company shall adjust the gas-charge provisions of its rates quarterly in accordance with the "Purchased Gas Adjustment" (the "PGA") established by Paragraph 4 of this Plan.

b) Rates may be modified to reflect the implementation of a natural gas energy efficiency charge pursuant to a Commission Order.

4) Quarterly PGA Adjustments.

a) Quarterly, no later than the third-to-last business day of November, February, May and August, VGS shall notify the PUC and the DPS of the PGA to be billed to firm customers commencing the first billing cycle beginning the third subsequent month (e.g. adjustment filed on November 25 is effective on bills rendered beginning in the first firm billing cycle in February).

b) The rate year reflected in the PGA shall be the twelve-month period beginning with the second subsequent month (e.g. adjustment filed on November 25 reflects January to December rate year.

c) VGS shall give individual notice to customers of each PGA of not less than 55 days before bills are rendered and not less than 25 days before service is rendered.

d) The PGA shall consist of an average cost per ccf based on forecasted costs and volumes for the rate year and to correct for any under- or over-collection of costs and weather normalization during the previous quarter, as follows:

   i) Costs to be recovered through the PGA are costs related to the purchasing, storing, production, and transporting of natural gas to serve sales customers. Renewable natural gas costs shall recoverable pursuant to the PGA pursuant to the method approved by the PUC in Docket No. 8667 or any subsequent proceeding. Costs to be recovered through the PGA include:

   (a) Firm commodity costs (including spot purchases);
   (b) Interruptible commodity costs (including spot purchases);
   (c) Storage withdrawals, including variable injection and withdrawal costs;
   (d) Peaking commodity costs;
   (e) Off-system commodity costs;
   (f) Propane air commodity (propane only) costs;
   (g) TCPL, Union or other pipeline tolls and charges;
   (h) Storage-related demand charges;
   (i) Peaking demand charges;
   (j) Hedging positions: natural gas, oil, and foreign exchange;
   (k) Hedging instrument premiums;
   (l) Canadian federal or provincial taxes imposed on gas purchases or pipeline tolls;
   (m) System losses; and
   (n) Other gas costs that may occur and are appropriately charged to FERC accounts 800 through 805

ii) The definition and determination of these components is shown in subparagraph f. In its quarterly supply filings pursuant to subparagraph 6b of this Plan, VGS will highlight any changes to its supply portfolio or to the definitions and determinations shown in subparagraph f.

iii) The PGA filing shall include:

(a) Forecasted Gas Costs for the 12 months beginning two months forward. Forecasted Gas Costs will be calculated based on then-current pipeline tolls, fixed-price contracts and market forecasts for unhedged indexed supplies, minus projected interruptible and off-system sales revenue;

(b) Forecasted Gas Sales Volumes for the 12 months beginning two months forward, based on projected numbers of customers and 10-year normal weather;

(c) Actual Gas Costs for the previous quarter, net of interruptible and off-system revenue;

(d) Actual Firm Gas Sales Volumes for the previous quarter;

(e) Actual Firm Gas Charge Revenues for the previous quarter;

(f) The proposed new Gas Charge, which will be calculated to recover on a 12-month basis Forecasted Gas Costs and to discharge any Adjustment required by over- or under- collection of Gas Costs from the previous quarters.

e) The PGA will be calculated using the following formula:

PGA = (12-MONTH COST FORECAST± GAS COST ADJUSTMENT +/- WEATHER VARIANCE)/12-MONTH VOLUME FORECAST

Where:

PGA	= Price per ccf for gas sold to firm customers.
12-Month Cost Forecast	= Forecast of Gas Costs identified above.
Gas Cost Adjustment	= The difference between previous quarters' Actual Gas Costs (net of interruptible and off-system revenue) and Actual Firm Gas Charge Revenues.
Weather Variance	= The difference between previous quarters actual firm distribution revenue and weather-normalized distribution revenue.
12-Month Volume Forecast	= Forecast of firm Gas Sales Volumes for the 12 months beginning 2 months forward, based on projected numbers of customers and 10-year normal weather.

f) The components of the 12-Month Cost Forecast consist of the following:

i) Firm commodity costs, including spot purchases, are non-storage, non-peaking supplies incurred for resale to the firm market and will be based on the contractual pricing and volumes associated with VGS's supply contracts in effect for the twelve month forecast period.

a) If VGS's supply contracts expire during the twelve-month forecast period and no replacement contracts have been executed, the remaining months of the forecast period will reflect the pricing of the existing contracts.

b) Spot gas that has not been pre-purchased will be priced at the then current NYMEX (Henry Hub) strip for the forecast period, adjusted for the then-current basis differential for the forecast period to the spot market purchase point.

c) NYMEX-based contracts will be priced at the then-current NYMEX (Henry Hub) strip for the forecast period.

d) AECO or Empress-based contracts will priced at the then-current NYMEX (Henry Hub) strip for the forecast period, adjusted for the then-current NYMEX (Henry Hub) to AECO or Empress basis differential for the forecast period.

e) The then-current NYMEX (Henry Hub) strip and basis differential will be based on the average of the last five trading days ending between two and five trading days before filing.

f) Contracts stated in Canadian dollars will be expressed in U.S. dollars based on the same five trading days as used for NYMEX and basis differential.

ii) Interruptible commodity costs (including spot purchases) will be determined as follows:

a) Interruptible commodity costs are all commodity costs incurred for resale to the interruptible market and will be based on the contractual pricing and volumes associated with VGS's supply contracts in effect for the twelve-month forecast period, including any pre-purchase of spot gas.

b) If VGS's supply contracts (excluding the pre-purchase of spot gas) expire during the twelve-month forecast period and no replacement contracts have been executed, the remaining months of the forecast period will reflect the pricing of the existing contracts.

c) Spot gas that has not been pre-purchased will be priced at the then current NYMEX (Henry Hub) strip for the forecast period, adjusted for the then-current basis differential for the forecast period to the spot market purchase point.

d) NYMEX-based contracts will be priced at the then-current NYMEX (Henry Hub) strip for the forecast period.

e) AECO or Empress-based contracts will priced at the then-current NYMEX (Henry Hub) strip for the forecast period, adjusted for the then-current basis differential for the forecast period.

f) The then-current NYMEX (Henry hub) strip and basis differential will be based on the average of the last five trading days ending between two and five trading days before filing.

g) Pre-purchased spot gas purchases will be reflected at the volumes and price agreed to in a confirmation transaction.

h) Contracts stated in Canadian dollars will be expressed in U.S. dollars based on the same five trading days as used for NYMEX and basis differential.

iii) Storage withdrawals, including variable injection and withdrawal costs, will be determined as follows:

i) Variable storage injection and withdrawal costs will be reflected at the rates in place at the time of the PGA filing.

j) Storage withdrawals are volumes of gas withdrawn from storage, including fuel, and will be priced using the projected storage weighted average cost of gas (“WACOG”). The projected WACOG will reflect projected injection and withdrawal volumes, current market prices for injected volumes, including the impact of any hedge positions in effect for storage injections, and then current TCPL fuel ratio for storage withdrawals.

iv) Peaking commodity costs will be determined as follows:

k) Peaking commodity costs will be based on the contractual pricing and volumes associated with VGS’s peaking supply contracts in effect for the twelve-month forecast period.

l) Market-based pricing such as an “Iroquois price” will be determined from then-current NYMEX (Henry Hub) strip for the forecast period plus a basis differential using the same 5 trading days previously described.

v) Off-system commodity costs will be priced at the point of sale and priced at the then-current NYMEX (Henry Hub) strip for the forecast period adjusted for the then-current basis differential.

vi) Propane commodity costs will be based on the then-current actual propane WACOG and will only include the cost of propane consumed, not any other costs of operating the propane air plant.

vii) TCPL and other pipeline tolls and charges will be established using the TCPL or other pipeline tolls to be in effect during the contract period applied to the contractual contract demand for the forecast period. Projected increases or decreases in such pipeline tolls will not be included until approved by the applicable regulatory agency, i.e., National Energy Board. Tolls stated in Canadian dollars will be expressed in U.S. dollars based on the then-current rate as defined above.

viii) Storage-related fixed charges will be based on the fixed charges pursuant to the pricing provisions contained in any storage contract in effect during the twelve-month forecast period.

ix) Peaking demand charges will be set based on the contractual demand charges, if any, established in the peaking supply contracts in effect for the twelve-month forecast period.

x) Hedging positions for natural gas, oil, and foreign exchange will reflect all hedges executed at the time of the PGA filing and in effect during the twelve¬month forecast period, whether for firm or interruptible customers.

xi) Hedging instrument premiums will reflect any premiums actually incurred by VGS for the twelve month forecast period.

xii) System losses will be based on VGS's historical actual system losses, including company use, for the most recent 12-month period.

xiii) Other gas costs include costs that may occur and are appropriately charged to FERC accounts 800 through 805, for example, the purchase of LNG or bio-methane. To the extent VGS includes any other gas costs in its quarterly PGA filing, such costs will be identified in the supporting information and will be described in the quarterly reports described in subparagraph 6b of the Successor Alternative Regulation Plan.

xiv) For purpose of determining weather-normalized variance, the use per degree day, per customer, by firm rate class in the rate filing from Docket No. 8710 will be applied to the difference between actual degree days and degree days in the rate filing in Docket No. 8710 times the actual number of customers. The resulting Mcf adjustment, by rate class, will be multiplied by the distribution charge, by rate, class to determine the weather adjustment. The calculation, by firm rate class, by month will be as follows:

WV = (Customers * UDD * (DDa – DDn)) *DR

Where:

WV = Weather Variance

Customers = Actual number of customers

UDD = Use per degree day from Annual Rate filing

DDa = Actual Degree Days

DDn = Degree Days per Annual Rate Filing

DR = Distribution Rate

The resulting WV will be returned to or collected from customers in the subsequent PGA filing.

g) Nothing in this Plan will be interpreted as preventing the DPS from asking the PUC to investigate or the PUC from investigating the prudence of the gas costs charged to VGS customers under the PGA.

5. Service Quality and Reliability Plan.

a) VGS shall continue to comply with its existing Service Quality and Reliability Plan (the "SQRP").

6. Management of Gas Supply.

b) Annually, no later than July 1 during the term of this Plan, the Company shall file with the DPS and t h e PUC its gas-supply plan for the gas year commencing on November 1 of that year (the "Gas-Supply Plan"), which Gas Supply Plan shall also provide an overview of the Company's strategy for procuring, storing and selling in wholesale markets natural gas required to serve its customers over a three-year period.

c) No later than the 15th day of each of February, May, August and November during the term of this Plan, VGS shall provide notice to the DPS and the PUC of changes to any contracts for the supply, storage, transmission or hedging of its gas supply or exchange rates, including changes to any such contracts and the rates paid or positions taken thereunder.

7. System Expansion.

d) Annually, no later than March 15 during the term of this Plan, VGS will meet with the DPS to discuss the investments made by the Company during the previous calendar year, including the cost, location and customer base therefor, to expand its system as well as the Company's preliminary plans for such investment in the current calendar year, including the cost, location and customer base therefor, and to discuss VGS's long-range plans for expansion of its system in Vermont.

e) Annually, no later than August 15 of any Plan year, VGS shall update estimates of actual customer additions for the current fiscal year and notify the DPS of any changes in its capital plans that would impact forecasts of customer additions.

f) Annually, no later than November 1 of any Plan year, VGS shall report to the PUC and the DPS on changes in energy markets or customer demand that present an opportunity for VGS to offer new services.

8. Dispute Resolution.

g) VGS and the DPS will resolve any disputes about regulation of VGS under this Plan in accordance with the provisions of this paragraph.

h) VGS or the DPS, as the case may be, will provide notice in writing of any such dispute.

i) For the DPS, notice shall be provided to the DPS Commissioner.

ii) For VGS, notice shall be provided to its Chief Executive Officer ("CEO").

i) Within 30 days of such notice, representatives of VGS and the DPS will meet to attempt to resolve the dispute.

j) If the representatives of VGS and the DPS are unable to resolve the dispute within 60 days of such notice, the dispute will be referred to the DPS's Commissioner and VGS's CEO, who will meet at least once to attempt to resolve the dispute.

k) If the dispute is not resolved within 90 days of such notice, either VGS or the DPS may petition the PUC to resolve the dispute, which, if appropriate, may be treated by the PUC as a petition to amend the Plan under Paragraph 9 of this Plan.

9. Amendment of Plan.

l) Subject to the requirements of 30 V.S.A. § 218d, VGS or the DPS, jointly or separately, may request that this Plan be amended to modify its existing provisions or to add provisions.

m) If the request to amend is not made jointly by the parties, then the procedures of Paragraph 8 will apply to any request to amend the Plan.