Prefiled Testimony of James D. Simpson

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
SUMMER PERIOD 2010
COST OF GAS ADJUSTMENT FILING
PREFILED TESTIMONY OF
JAMES D. SIMPSON

I. INTRODUCTION

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

A. My name is James D. Simpson. I am a Vice President with Concentric Energy Advisors, 293 Boston Post Road West, Marlborough, Massachusetts 01752

Q. Please describe your relevant work experience.

A. I have over 30 years experience in the energy industry in a variety of roles and responsibilities with an overall focus on economics, pricing, forecasting and regulatory matters. I was employed by Bay State Gas Company ("Bay State") from 1982 until 2000; for much of my time at Bay State, I was responsible for rates and regulatory affairs for Bay State and Northern Utilities, Inc. ("Northern" or "Northern Utilities"). I have been with Concentric Energy Advisors ("Concentric") since 2005. My professional qualifications and experience are provided in Attachment-1 of this testimony.

Q. Have you previously testified before the New Hampshire Public Utilities Commission ("Commission")?

A. Yes, I testified on behalf of Northern Utilities in the 2009 / 2010 Winter Cost of Gas ("COG") proceeding, Docket No. DG 09-167 and the 2009 Summer Cost of Gas proceeding, Docket No. DG 09-052. In addition, while I was employed by Bay State, I testified before the Commission on behalf of Northern Utilities in many proceedings on a variety of issues related to rates, growth-related projects and other economic and regulatory matters.

Q. Please explain the purpose of your prefiled direct testimony in this proceeding.

A. Francis X. Wells, Senior Energy Trader for Unitil, Todd Bohan, Senior Regulatory Analyst for Unitil and I are sharing the responsibility in this proceeding for describing and explaining the proposed 2010 Summer New Hampshire Division COG rate adjustments that the Company is proposing to make effective May 1, 2010. Mr. Wells will describe and explain the forecast of gas demand and the resulting forecasted gas sendout and gas costs that he developed for the New Hampshire and Maine divisions. Mr. Wells will also describe the impact of the Company's Hedging Program for the 2010 Summer period. Mr. Bohan will discuss the New Hampshire 2009 Summer Cost-of-Gas Reconciliation Filing and analyses of the proposed Summer COG rates on typical bills.

I will describe and explain the calculation of the COG that Northern Utilities proposes to bill from May 1, 2010 to October 31, 2010.

Q. Have you prepared any schedules in support of the Summer COG rate calculations?

A. Yes. The schedules that I prepared in support of the Summer COG rate calculations are listed below.

Attachment-1	James D. Simpson Professional Qualifications
Summary Schedule	Supporting Detail to the Tariff Sheets Bad Debt, Working Capital
Schedule 1A	Allocation of New Hampshire Fixed Capacity Costs To Months and Seasons
Schedule 1B	New Hampshire Division Commodity Cost Analysis
Schedule 3	New Hampshire Division (Over) / Undercollection Balances and Interest Calculations
Schedule 9	Variance Analysis / Comparison to 2009 Off-Peak
Schedule 10A	Allocation of New Hampshire Demand Costs To New Hampshire Firm Sales Rate Classes
Schedule 10B	Division Sales and Sendout Forecast
Schedule 10C	Allocation of New Hampshire Variable Gas Costs To New Hampshire Firm Sales Rate Classes
Schedule 14	Northern Utilities Inventory Activity
Schedule 21	Allocation of Northern Fixed Capacity Costs To New Hampshire and Maine Divisions
Schedule 22	Allocation of Northern Commodity Costs To New Hampshire and Maine Divisions
Schedule 23	Supporting Detail to Proposed Tariff Sheets

II. COST OF GAS FACTOR

A. COG Calculation Methodology and Filing Format

Q. In testimony that you submitted in Northern's two most recent COG proceedings, Docket Nos. DG 09-167 and DG 09-052, you described several modifications that Concentric made to Northern's COG calculation process. Do you have any further modifications to describe at this time?

A. No. I did not make any further modifications to the manner in which the COG rates are calculated. Prior to the 2009 Summer COG and the 2009 / 2010 COG filings, Concentric made a number of modifications to spreadsheet organization, formatting, and formulas. As I explained in testimony that I provided in those proceedings, the revisions that I made (a) allowed for easier review and validation of the COG calculations and (b) improved the accuracy of the calculations. I have not identified any further revisions that should be made to Northern's COG calculation process at this time. These prior modifications have been incorporated in the present filing.

Although I have not made any changes to the way the COG rates are calculated in this 2010 Summer COG filing, Northern Utilities has modified the way that supporting detail to the COG calculations has been labeled and organized. These changes are the outcome of a collaborative effort with PUC Staff to assist the Staff in reviewing this filing

B. Cost of Gas Factor

Q. Please explain the calculation of the proposed New Hampshire Division Cost of Gas factors for the 2010 Summer period.

A. The Summary Schedule, which is a copy of COG tariff pages 38 and 39, has been prepared to explain the calculation of the proposed 2010 Summer COG factors. The text descriptions in the added column: (1) explain the calculations on this tariff page; and (2) provide references to other schedules for the sources of the data that appear on COG tariff Pages 38 and 39. This Summary Schedule shows the calculation of the 2010 Summer period COGs for each of Northern's three COG Rate Groups (1) Residential classes R-1 and R-2, (2) C&I Low Winter period use classes G-50, G-51 and G-52; and (3) C&I High Winter period use classes G-40, G-41 and G-42.

As shown on Summary Schedule for the 2010 Summer period, the projected Average Cost of Gas is $0.6981 per therm (Line 77), which is the sum of the Average Direct Cost of Gas, $0.7571 per therm (Line 70), and the Average Indirect Cost of Gas, $(0.0590) per therm (Line 74).

Q. What are the major components of the 2010 Summer Anticipated Direct Cost of Gas?

A. The table below identifies the major components of Anticipated Direct Gas Costs, as shown in the Summary Schedule.

			Summary Schedule, Line:
1	Purchased Gas Demand Costs	$470,438	3
2	Purchased Gas Supply Costs	$5,269,861	4
3	Storage and Peaking Capacity Costs	$576,398	7
4	Storage and Peaking Commodity Costs	$26,395	8
5	Hedging (Gain) / Loss	$(6,982)	10
6	Interruptible Costs	$0	12
7	Capacity Release	$0	14
8	Total Anticipated Direct Cost of gas	$6,336,110	16

Q. What are the major components of the 2010 Summer Anticipated Indirect Cost of Gas?

A. The table below identifies the major components of Anticipated Indirect Gas Costs, as shown in the Summary Schedule.

			Summary Schedule, Line:
1	Prior Period (Over) / Undercollection	$(544,057)	20
2	Interest	$(5,817)	21
3	Refunds	$0	22
4	Capacity Reserve Charge Revenue	$0	23
5	Interruptible Margins	$0	34
6	Working Capital Allowance	$3,596	34
7	Bad Debt Allowance	$21,272	48
8	Local Production and Storage	$0	50
9	Miscellaneous Overhead	$31,261	52
10	Total Anticipated Indirect Cost of Gas	$(493,745)	54

Q. Please explain the calculation of the Working Capital allowance.

The total Working Capital allowance, $3,596 shown on Line 34 of the Summary Schedule is the sum of the current period working capital allowance, $12,039 (Line 30) plus interest, $(143), (Line 32) plus the prior period Working Capital reconciliation balance, $(8,299) (Line 31).

Q. Please explain the calculation of the Bad Debt factor.

A. The Bad Debt allowance of $21,272 (Line 48) is the sum of the current period bad debt allowance, $26,054 (Line 45) plus interest, $106, (Line 46) plus the prior period Working Capital reconciliation balance, $(4,888) (Line 47).

C. Summary Analyses

Q. How does the proposed 2010 Summer period COG rate compare with the 2009 Summer period COG rate?

A. I have prepared Schedule 9 to compare the proposed 2010 Summer COG with the 2009 Summer COG. Schedule 9, Page 3 of 3 indicates that the proposed 2010 Summer period COG rates are slightly lower than the 2009 Summer period COG rates. The overall change in the proposed 2010 Summer rate compared to the 2009 Summer period is primarily due to changes in (1) gas costs; (2) forecasted sales and sendout volumes, and (3) prior period over / undercollection balances. As shown in Schedule 9 Line 120, Total 2010 Summer gas costs are lower than 2009 Summer gas costs by approximately $950,000, which is mostly attributable to a change in indirect gas costs of almost $1.1 million[1].

D. Allocation of Demand-Related Costs to New Hampshire and Maine Divisions

Q. Please explain how the projected fixed capacity-related costs, i.e. (a) pipeline reservation and gas supply demand charges, (b) underground storage capacity costs and (c) peaking resource capacity costs are allocated between Northern's New Hampshire and Maine divisions.

A. Total Northern capacity-related costs are allocated between the New Hampshire and Maine divisions by application of the Modified Proportional Responsibility ("MPR") methodology. The MPR methodology allocates fixed capacity-related gas costs to the New Hampshire and Maine divisions in a two-step process: (1) total Northern capacity-related costs, by resource type[2], are allocated to months by application of MPR allocation factors, and (2) the capacity-related costs allocated to each month are allocated to the New Hampshire and Maine

1 The change in indirect gas costs of almost $1.1 million is the difference between: (a) the 2010 Summer total anticipated indirect gas cost credit of $(493,745) that is primarily due to the prior period (Summer 2009) overcollection balance of $(544,057) (See Summary Schedule, Line 20); and (b) the 2009 Summer total anticipated indirect gas cost charge of $604,516 that is primarily due to the prior period (Summer 2008) undercollection balance of $502,551. (See Attachment NUI-JDS-9, Line 32; Updated 2009 Summer Period Proposed Cost of Gas Adjustment, filed April 13, 2009.)

2 These Resources are: pipeline, storage, and peaking.

divisions based on the relative shares of Design Year demand[3] in that month. This MPR methodology was orally approved by the Commission on December 30, 2005 to be effective January 1, 2006. Subsequently, on June 1, 2006, the Commission issued Order No. 24, 627 in docket DG 05-080 granting written approval of the MPR methodology.

Q. Please provide a summary of the process that you followed to allocate total Northern demand costs for the period November 2009 through October 2010 to the New Hampshire and Maine divisions.

A. The allocation of total Northern capacity-related costs between the New Hampshire and Maine divisions is determined in each Winter period filing, according to the MPR methodology. Schedule 21 demonstrates how I calculated the MPR factors and then how I used these factors to allocate total Northern annual demand costs for the period November 2009 through October 2010 ("2009 / 2010 COG Period") to the New Hampshire and Maine divisions. Schedule 21 is identical to Attachment NUI-JDS-2 that was filed by letter dated October 15, 2009 in the Company's 2009 / 2010 Winter COG proceeding, Docket No. DG 09-167.

Schedule 21 is arranged in three major sections: In Section (1), total fixed capacity costs, by type of resource (pipeline, storage, and peaking) are summarized in Lines 1 through 10. In Section (2), these fixed capacity costs for each resource type are allocated to each month in the 2009 / 2010 COG Period according to MPR allocators that were developed specifically

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3 For the MPR allocation process, Design Year demand is calculated as the actual demand to New Hampshire and Maine firm sales and assigned capacity/non-grandfathered transportation customers for the period May, 2008 through April 2009, adjusted to reflect design year conditions.

for each resource type as shown on Lines 13 through 56 (shown on pages 1 and 3); the MPR allocators are based on design year sendout volumes for each resource type. In Section (3), the fixed capacity costs that are allocated to each month in Step 2 are then allocated to the New Hampshire and Maine divisions according to design year total firm sendout as shown in Lines 58 through 90. As shown in Schedule 21 page 3, line 81, the allocation of Northern's capacity-related costs to New Hampshire for the twelve months beginning November 2009 is 52.54%.

Q. In the last response you stated that Schedule 21 is identical to the version of Attachment NUI-JDS-2 that was filed by letter dated October 15, 2009 in the Company's 2009 / 2010 Winter COG proceeding, Docket No. DG 09-167. Please explain this.

A. As noted earlier, total Northern capacity-related costs are allocated between the New Hampshire and Maine divisions by application of the Modified Proportional Responsibility ("MPR") methodology. According to the MPR methodology, capacity-related allocators are determined every Winter period filing based on actual demand for gas, adjusted to design year effective degree days for the most recent twelve months ended April. Thus, the allocation of Northern capacity-related costs to New Hampshire and Maine divisions in each Summer filing will be identical to the allocators that were determined in the prior Winter COG filing.

E. Allocation of New Hampshire Demand-Related Costs to Seasons

Q. Please explain how the capacity-related costs to be recovered in the 2010 Summer period are determined.

A. Schedule 1A provides detailed support for the allocation of New Hampshire Sales Customer demand costs to the Summer period. Schedule 1A is also identical to the version of Attachment NUI-JDS-3 that was filed by letter dated October 15, 2009 in the Company's 2009 / 2010 Winter COG proceeding, Docket No. DG 09-167.

Lines 2 through 4 of Schedule 1A summarize (1) Pipeline and (2) Storage and Peaking demand costs that are allocated to the New Hampshire Division, as determined in Schedule 21. Lines 13 through 23 of Schedule 1A show the calculation of Net Demand Costs for firm sales customers, which is Total Demand Costs allocated to New Hampshire less the capacity assignment revenues from New Hampshire transportation customers. For the 2009 / 2010 Winter period filing, Mr. Wells calculated the capacity assignment revenue credit. Mr. Wells' calculations were provided in the 2009 / 2010 Winter period filing dated October 13, 2009, in Attachment NUI-FXW-4, Page 7 of 10. As shown on Line 76 of Schedule 1A, the Summer period gas costs do not include capacity assignment revenues; all capacity assignment revenues are credited to the Winter Cost of Gas.

The Summer rates that will be charged to New Hampshire firm sales customers from May through October 2010 will recover the portion of the following demand-related costs that are allocated to the 2010 Summer period: (1) the Net Pipeline Demand costs shown on Line 20 and (2) the Net Storage and Peaking demand costs shown on Line 21 and 22 of Schedule 1A. Lines 27 through 41 of Schedule 1A show the calculation of Pipeline demand costs for sales customers, separated into (1) Base Use demand costs and (2) Remaining Use demand costs.[4] The Base Use that is shown on Line 32 of Schedule 1A is the average projected daily use in July and August 2010[5], for all firm sales classes; the Base Pipeline Demand cost that is shown on Line 39 of Schedule 1A is calculated by multiplying Base Use times the weighted average annual cost of pipeline capacity, as shown on Line 36 of Schedule 1A. Line 41 shows the Remaining Net Pipeline Demand costs for sales customers, which is the difference between total net pipeline demand costs and base use pipeline demand costs.

Lines 45 through 50 show the calculation of the PR factor that is used to allocate (a) Remaining Net Pipeline Demand costs, (b) Storage and Peaking costs, and (c) Other A&G expense related to Firm Sales customers to the twelve months, November 2009 through October 2010. Lines 52 through 57 show the calculation of the PR factor that is used to allocate (d) Capacity Release and Asset Management revenues, (e) Interruptible margins and Delivery-to-Sales revenues and (f) Local Production and Storage costs to the six Winter months, November 2009 through April 2010. These PR factors are summarized by type of capacity cost in lines 61 through 65. Line 69 of Schedule 1A shows that one twelfth of the Net annual base use pipeline demand costs are allocated to each month and Lines 70 through 85 show the detailed allocation to months of all components that are included in the Total Net Demand Costs, based on the "All Months" and "Peaking Months Only" allocation factors.

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4 This separation is necessary because the SMBA allocation methodology assigns base use demand costs and remaining demand costs to seasons using different allocators.

5 Average Projected Daily demand by class in July and August is shown in Schedule 10B, Line 89.

The total anticipated direct demand costs to be recovered in the 2010 Summer COG rates, $1,046,835, is shown on Line 80 of Schedule 1A. Each Summer month, May through October 2010, one-sixth of that total, $174,473, will be recorded as Summer capacity-related costs.[6]

F. Allocation of New Hampshire Summer Period Demand Costs to Customer Classes

Q. Please explain how the New Hampshire Division sales service demand-related costs that were allocated to the Summer period are then allocated to each sales rate class.

A. The New Hampshire Division sales service base demand-related costs for each month are allocated to each sales service rate class based on that class's pro rata share of total forecasted firm sendout to sales customer under normal weather conditions in that month. The remaining demand-related costs for a month are allocated to each sales service rate class based on that class's pro rata share of total forecasted firm sales design day temperature sensitive demand.

Schedule 10B shows the calculation of the factors that are used to allocate New Hampshire Division sales service Summer period base demand-related costs for each month to each sales service rate class. The firm sales forecast, shown on Lines 1 to 16, and the firm sendout forecast by class, shown on Lines 18 to 33, are used to determine (a) daily base use, shown on Lines 35 to 48; (b) base sendout, shown on Lines 49 to 64; and (c) remaining sendout, shown on Lines 66 to 80. These base and remaining sendout values for each class

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6 Each Summer month, the difference between total invoiced capacity-related costs and the Summer portion of $174,473 will be recorded as Winter period capacity-related costs.

are used to allocate the Summer period demand costs to New Hampshire Division firm sales classes.

Schedule 10A shows the allocation of Summer period New Hampshire Net Demand costs to each firm sales rate class, based on (a) the New Hampshire Net Demand costs that are allocated to each Summer period month as shown in Schedule 1A, Lines 67 through 85 and (b) the Rate Class allocators as shown Schedule 10B, Lines 49 to 80. The Base Sendout allocators, which are used to allocate base demand costs to firm sales rate classes, are shown on Lines 3 through 22 of Schedule 10A and the Remaining Design Day allocators, which are used to allocate all other demand-related costs and credits to firm sales rate classes, are shown on Lines 39 through 48.

The following table shows the location in Schedule 10A of the Net Demand-related costs and credits by component allocated to each firm sales rate class:

Demand Cost Component	Schedule 10A
Base Demand	Lines 24 through 37
Remaining Pipeline Demand	Lines 50 through 66
Peaking and Storage Demand	Lines 68 through 84
Capacity Release and Asset Management	Lines 86 through 102
Interruptible Margins	Lines 104 through 120
Remaining Re-entry Fee Credit	Lines 122 through 138
Total Non-Base Capacity Costs	Lines 140 through 154
Total Capacity Costs	Lines 156 through 170

The Summer total capacity-related costs shown on Line 166, $1,046,835[7], is the same as the Summer period capacity-related costs to be recovered during the Summer period, as determined in the 2009 / 2010 Winter COG Filing, Schedule 1A, line 80.

G. Allocation of Variable Costs

Q. Please provide a description of variable costs, and explain how variable costs are allocated to Northern's New Hampshire and Maine divisions.

A. Variable costs include commodity costs and variable pipeline and storage costs[8] for firm sales. Mr. Wells prepared a forecast of Northern variable gas costs by month, which is provided in Schedule 6A. These variable gas costs have been allocated between the New Hampshire and Maine divisions based on each division's percentage of monthly firm normal sendout. Schedule 22 shows the allocation of the 2010 Summer period variable gas costs between New Hampshire and Maine.

Q. Please explain Schedule 22 in more detail.

A. Lines 1 through 9 of Schedule 22 show the projected sendout volumes, by month and by resource type, which Mr. Wells provided to me. Mr. Wells also provided the projected variable costs by month and by type of gas supply resource that are shown on Lines 11, and 18 through 20 of Schedule 22. The pipeline commodity costs shown on lines 11 and 18 are based on projected NYMEX prices as of January 25, 2010. Lines 23 through 29 show the estimated gains and losses based on the Company's hedging program then in effect, and the

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7 Total anticipated Summer period Direct Demand Costs are also shown on Schedule 1A, Line 80.

8 Specifically, variable costs include Pipeline usage / commodity charges, Pipeline fuel retention, Storage commodity injection and withdrawal charges, and Storage Fuel retention.

projected NYMEX prices. As Mr. Wells has explained, the Company hedging program applies to the Summer months of May and October only[9]. The variable gas costs and hedging gains and losses for firm sales service that are summarized on Lines 40 and 41 are allocated to New Hampshire and Maine based on projected monthly firm sales sendout in each division; the allocators are shown on Lines 46, 47, 51 and 52. Schedule 22 also shows the allocation of (a) Commodity costs (Maine: Lines 57, 59, and 60; New Hampshire: Lines 66, 68, and 69); and (b) hedging gains and losses (Lines 58 and 67) to New Hampshire and Maine. Finally, Schedule 22 shows the inventory finance costs for underground storage and LNG resources (Lines 90 to 93); the allocation of these costs to New Hampshire and Maine (Lines 95 to 98) and the allocation of New Hampshire's allocated share of annual inventory finance costs to the Winter period, using the firm sales remaining sendout allocators (Lines 102 to 104).

Schedule 1B summarizes the New Hampshire Division variable gas costs that were determined in Schedule 22; this attachment also shows the calculation of base and remaining commodity costs.

Q. Please explain how the New Hampshire Division variable gas costs for sales customers are allocated to each firm sales class.

A. Schedule 10C shows the allocation of New Hampshire Division variable gas costs to each firm sales class. Lines 1 to 21 show the calculation of the Base Sendout allocators, by rate class. Lines 22 to 49 show the allocation of the monthly New Hampshire Division Base

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9 In addition, the Company's hedging program applies to all six Winter period months, November through April.

Commodity and Base Hedging costs[10] to each rate class. Lines 51 to 70 show the calculation of the Remaining Sendout allocators, by rate class. Lines 71 to 98 show the allocation of the monthly New Hampshire Division Remaining Commodity and Remaining Hedging costs[11] to each rate class. A summary of all commodity costs allocated to New Hampshire firm sales classes is shown on Lines 99 to 140.

H. (Over) / Undercollection Balances

Q. Have you prepared a schedule to show (Over) / Undercollection balances throughout the period October 2009 through October 2010?

A. Yes, I have prepared Schedule 3 to show monthly (Over) / Undercollection balances and associated interest calculations for Direct Gas costs, Working Capital allowance and Bad Debt allowance.

I. Refunds

Q. Are there any refunds included in this filing?

A. No, there are no refunds included in this filing.

J. Miscellaneous Charges and Credits

Q. Are you projecting that Northern will receive any Re-Entry Fee Credits from transportation customers returning to sales service during the 2010 Summer period?

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10 New Hampshire Division Winter Period base commodity costs and hedging costs by month are shown in Attachment NUI-JDS-7 Lines 37 and 38.

11 New Hampshire Division Winter Period remaining commodity costs and hedging costs by month are shown in Attachment NUI-JDS-7 Lines 39 and 40.

A. No. Northern is not projecting any Re-Entry Fee Credits in this period.

III. FINAL MATTERS

Q. Will the Company propose to revise the COG if it receives any new or updated information on supplier or transportation rates?

A. Yes. The Company plans to file a revised calculation of its 2010 Summer Period COG to reflect updated gas cost projections and/or other information a few weeks prior to the effective date of May 1, 2010.

Q. Does this conclude your testimony?

A. Yes it does.

Attachment-1

James D. Simpson Professional Qualifications

James D. Simpson
Vice President

Mr. Simpson is a senior executive with more than 30 years of experience in the energy industry. He has held positions at a natural gas utility; an entrepreneurial company providing a proprietary service to generating companies; and state regulatory agencies. His responsibilities have included pricing strategy, regulatory affairs, analysis and planning and business development.

REPRESENTATIVE PROJECT EXPERIENCE

Regulatory Affairs

Representative engagements and responsibilities include:

- Designed decoupling mechanism and prepared supporting testimony for several New England utilities.
- Prepared testimony in support of Concentric sales forecast for two New England utilities.
- Designed rates, provided supporting testimony for a New England utility
- Prepared strategic assessment of PBR options for South Central utility
- Prepared validation of sales forecast and analysis of declining use per customer for Northeast utility
- Prepared rate design for Mid Atlantic utility for rate increase filing
- Prepared marginal cost study and testimony for Northeast utility
- Prepared Marginal Cost Study and rate design for Northeast utility
- Preparing an assessment of forecast methodology and forecast accuracy for Northeast utility
- Served as primary rate design witness for Bay State Gas Company, Northern Utilities (Maine and New Hampshire) and Granite State Gas Transmission on issues including rate reclassification, restructuring, market competitiveness, and earnings stability

Business Strategy and Operations

Representative engagements and responsibilities include:

- Held position of Chief Operating Officer for a major New England gas company, responsible for all regulated business activities including Gas Supply, Operations, Engineering, Marketing and Sales, and Planning
- Developed marketing plan and developed and implemented sales strategies
- Developed brand awareness strategy; created coordinated electronic and physical marketing materials; created and implemented a trade publication strategy. Simplified and shortened sales process; focused on prospective client decision making and understanding of company value proposition
- Implemented new Optimal Growth strategy to identify opportunities and track investments
- Led team that created plan to align company structure and culture with new competition-based growth and customer-focus strategy. Led organization during implementation of new strategy, structure, and culture

Contract Negotiations

Representative engagements and responsibilities include:

- Successfully negotiated contract for first new North America operations site in four years

- Persuaded state regulators to reverse established regulatory policies in conflict with company strategy
- Successfully negotiated unique contract with largest customer on company's system, reversing ten years of unproductive discussions
- Directed negotiation of groundbreaking labor contract that allowed company to use outside contractors and to reduce the union work force by 10%
- Negotiated agreement with pipeline for short term incremental capacity at significant savings
- Negotiated company's commitment to conduct residential customer choice pilot program that provided stakeholders with residential unbundling experience
- Successfully argued for changes to regulators' rate design policies, to improve growth opportunities and customer understanding of pricing. Changes resulted in improved growth rate and customer satisfaction

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PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2005 – Present)
Vice President
Assistant Vice President
Executive Advisor

Separation Technologies, Inc. (2001 – 2004)
Vice President, Business Development

Bay State Gas Company (1982 – 2000)
Senior Vice President, Large Customer Sales and Regulatory Affairs (1999 – 2000)
Senior Vice President/COO of Regulated Utility Business (1996 – 1999)
Vice President, Market Analysis and Pricing (1993 – 1996)
Director/Manager of Rates (1982 – 1993)

Massachusetts Department of Public Utilities (1978 – 1982)
Director
Senior Analyst

Wisconsin Public Service Commission (1977 – 1978)
Senior Analyst

EDUCATION

M.S., Economics, University of Wisconsin
B.A., Economics, University of Minnesota, magna cum laude
