STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

NORTHERN UTILITIES, INC.

Docket DG 09-141

Direct Testimony
Of
Stephen P. Frink
In Support of Revised Hedging Policy

February 23, 2010

Q. Please state your name and business addresses.

A. My name is Stephen P. Frink. I am employed by the New Hampshire Public Utilities Commission as Assistant Director of the Gas & Water Division. My business address is 21 S. Fruit Street, Suite 10, Concord, New Hampshire 03301.

Q. Please summarize your educational and professional experience.

A. ***See Attachment SPF-1.***

Q. What is the purpose of your testimony?

A. My testimony addresses the hedging objectives, the results of the current hedging policy, the risk of hedging cost shifting due to migration from firm sales to transportation service, and supports the Company's proposed revisions to its hedging policy.

Q. What are the objectives of the hedging policy?

A. The objective is to protect customers from unanticipated price spikes. Hedging is intended to reduce price volatility by serving as an "insurance policy" against sharp increases in natural gas rates. A natural gas hedging policy should be tailored to address the utility's average customers' aversion to risk and willingness to pay for reduced risk.

Q. How does a natural gas utility hedge against price spikes?

A. New Hampshire natural gas utilities utilize both physical and financial hedges. New Hampshire's two natural gas utilities have winter supply portfolios that include storage and pipeline supplies. Storage gas is purchased and placed into storage prior to the start of the winter period, therefore, the cost of those supplies is fixed prior to setting the winter cost of gas (COG) rate. That fixed cost serves as a hedge against fluctuations in natural gas commodity prices during the period. The price of pipeline supplies is typically tied to a market index and the cost is determined based upon when those supplies are utilized. Financial instruments can be used to essentially "lock in" a rate for pipeline supplies and serve as a financial hedge. The hedging policies approved by the Commission relate to financial hedges.

Q. What indications are there that New Hampshire's natural gas customers value hedging and are willing to pay a premium for reduced rate volatility?

A. Both EnergyNorth Natural Gas, Inc. (EnergyNorth) and New Hampshire Gas Company (NHGC) offer a winter "fixed price option" (FPO) and enrollment has been significant, fluctuating over the years in relation to customer expectations regarding where natural gas rates are likely to go. For example, EnergyNorth first offered a FPO on 20% of its supply in 1998. By 2000 demand for the FPO program exceeded supplies and the cap was raised. Since that time participation has varied from 15 to 30 percent as summarized in EnergyNorth's winter COG filing.[1] Similarly, the NHGC FPO was first offered in the winter of 2000 with availability limited to 20% of its winter gas supply. The initial offering was oversubscribed, and in 2001 availability was increased to 50%. Participation in the NHGC FPO program has ranged from 21 to 43 percent as summarized in NHGC's winter COG filing.[2] The EnergyNorth and NHGC FPO summaries can be found in ***Attachment SPF-2***.

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[1] Docket No. DG 09-162, Exhibit 1, Schedule 23.
[2] Docket No. DG 09-168, Exhibit 1, Supplemental Schedule E.

Northern offered a pilot winter fixed price program in 2001 but due to limited participation (9%), and the implementation of a hedging program designed to reduce rate volatility for all of Northern's customers, the FPO program was terminated.[3]

Q. Does the limited participation in Northern's pilot FPO indicate that Northern's customers have a high risk tolerance?

A. No, the likely explanation is found in the Commission analysis in its order approving Northern's termination of the fixed price option, which reads:

> "We do not believe the limited participation in the 2001/2002 Winter FPO program to be indicative of customers' sentiments regarding rate volatility, as identical programs offered by New Hampshire's two other gas utilities have grown in each of the years their FPO programs have been in existence. The lack of participation is more likely a reflection of publicity during the summer and fall of 2001 forecasting lower energy costs for the 2001/2002 winter period compared to the prior winter period and that the FPO program was a new offering. We believe that participation in the FPO program would increase if it were continued, as market conditions are likely to change and customers become more familiar with it. But given that the proposed hedging policy will lead to stable prices for all firm sales customers and save approximately $80,000 in annual administrative costs, we will approve termination of the FPO program."[4]

Q. Does a FPO eliminate the need for hedging?

A. No. The supplies available under a FPO need to be hedged prior to offering those supplies to customers in order to calculate the FPO rate. Furthermore, the fact that a customer does not enroll in the FPO program does not mean that customer's price risk tolerance is unlimited and hedging is desirable for all customers other than those with complete immunity to price volatility risks. While it is impossible to know the average risk tolerance of New Hampshire's natural gas customers, it

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[3] Order No. 24,037.
[4] *Id.* at 5-6.

is clear from participation in the FPO programs that there are a significant number of customers who desire reduced price volatility.

Q. Has Northern's hedging program reduced rate volatility?

A. Yes. Logically, the more gas supplies that have a fixed price prior to the time rates are set, the less volatility there will be in monthly rates, and the analysis bears that out. Monthly rates have been less volatile with hedging than without, more so in the summer than winter.

Q. Why does hedging have a greater impact on summer rate volatility?

A. Northern's total winter supply portfolio is composed of approximately 60% fixed price supplies (50% storage and 10% fixed price contracts) before any hedging is done. Approximately 40% of the remaining winter supply is subject to market prices. Of the 40% subject to market prices, Northern uses financial instruments to lock in between 40% and 70% of that amount, which represents 16% to 28% of total winter supplies. As a result, approximately 76% to 88% of Northern's projected winter supply is fixed prior to the start of the winter period and only 12% to 24% is subject to market prices.

Northern's summer supply portfolio contains no storage or fixed price supplies so 100% of its supply is subject to market prices. Northern uses financial instruments to lock in 28% of its summer supply leaving 72% subject to market fluctuations, thus the summer period hedging results in a greater impact on rate volatility.

Q. What analysis was performed to determine the impact of hedging on rate volatility?

A. Volatility is most often measured using standard deviation, *i.e.*, the more rates deviate from the standard, the greater the volatility. The analysis looks at Northern's actual monthly rates from November 1, 2003[5] through April 30, 2009, and calculates what rates would have been absent the financial hedges. The standard deviation was determined for the change in monthly rates over seven years for the winter and summer periods.

The analysis also measures volatility by finding the standard deviation of the returns and not of absolute prices. Returns are the log normal of the absolute price ratio from one period to the next, meaning the volatility is calculated as the standard deviation of the ratio (or percent change in the price from one period to the next) not the absolute price. The analysis measures the volatility between months within each COG period and excludes the rate change between the end and beginning period monthly rates, as the difference between the ending and beginning months encompasses seven months and would distort the month to month analysis.

Q. What were the results of the rate volatility analysis?

A. When simply looking at the rate change for each winter and summer month, including the beginning and ending rates, there is a 10.56% (hedging standard deviation 16.61% versus non-hedged standard deviation 18.36%) reduction in volatility for the winter period and a 28.75% (hedging standard deviation 15.85% versus non-hedged standard deviation 20.41%) reduction in volatility for the summer period.

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[5] Order No. 24,037 (August 16, 2002) approved Northern's current hedging policy whereby financial hedges are entered twelve months in advance. Therefore, winter 2003-2004, which commenced on November 1, 2003 represents the first fully hedged COG period under the current hedging policy.

For the winter periods the average standard deviation of the log normal was 1.58% for the hedged rates and would have been 1.66% absent hedging, a difference of 0.08% or a 4.58% reduction in monthly rate volatility.

For the summer periods the average standard deviation of the log normal was 0.01% for the hedged rates and would have been 0.89% absent hedging, a difference of 0.88% or an 98% reduction in monthly rate volatility. ***See Attachment SPF-3 (DR 3-1 & 3-2)***.

Q. How would you characterize the impact of hedging on rate volatility?

A. Limited. Northern's current hedging policy has had a limited impact on rate volatility.

Q. What are the costs associated with hedging?

A. Hedging costs can be broken into three categories: internal, external and opportunity costs. Internal costs include the utility's personnel costs for tracking and managing the hedging program and borrowing costs related to maintaining a margin account for trading. External costs are the transaction fees charged by Northern's broker. Opportunity costs are losses that occur when natural gas prices fall below the contract price, which are offset by gains when market prices exceed contract prices.

Q. What are Northern's internal hedging costs?

A. Northern staff performs the following activities in support of the hedging program: preparing and reviewing the hedging plan for inclusion in the COG filing; issuing instructions to the broker for plan implementation; calculating and reporting margin requirements each day; monitoring margin requirements each day and funding as needed; preparing, approving and filing the monthly hedging report; updating accounting reports each month; and general oversight. The estimated personnel costs, including overhead, associated with the hedging program is $21,700 annually. Northern recovers its costs associated with salaries and wages in base rates. ***See Attachment SPF-4 (DR 2-6)***.

Another internal cost is the interest expense associated with the short-term borrowing needed to fund margin requirements, which varies depending on the current value of the contracts. The financing costs are funded by short-term debt borrowed from the Unitil money pool. Under the current hedging program Northern estimates the margin costs for the 2009-2010 winter period to be $64,449, and under the proposed hedging policy Northern estimates that the costs would be $40,311. There is no specific mechanism under which Northern recovers the interest expense associated with funding the margin account. ***See Attachment SPF-5 (DR 2-8 & 2-9)***

Q. What are Northern's external costs?

A. External costs are the transaction fees charged by Unitil's broker. The broker executes the contract purchases as instructed by Northern and sends written confirmation verifying that the transactions were completed in accordance with the approved hedging plan. Under the current hedging program, Northern estimates the broker fees for the 2009-2010 winter period to be $4,182, and under the proposed hedging policy Northern estimates that the costs would be $4,182. There is no specific mechanism under which Northern recovers the interest expense associated with funding the margin account. The broker charge is included in the COG.

Q. What is the opportunity cost?

A. When a contract is closed out there is a gain or loss depending on the price of natural gas at the time the contract is closed. If the market price is higher than the contract price, a profit is realized and credited to the COG. If the market price is lower than the contract price, there is a loss which is charged to the COG. Northern has experienced gains and losses during the seven and a half years the current hedging program has been in effect, resulting in a net loss of approximately $3,000,000. ***See Attachment SPF-6 (DR 2-10)***.

Q. It is appropriate to include the opportunity cost when considering the cost of hedging?

A. No, based upon the expectation that gains and losses will balance out over time. Although there was a precipitous drop in natural gas prices recently due to a confluence of events that are unlikely repeat themselves any time soon – the financial crisis, new LNG liquefaction plants coming on-line, discovery of new gas fields that have substantially increased domestic gas reserves - natural gas prices now reflect these developments.

Q. What are Northern's hedging costs as a percentage of its gas costs?

A. As Unitil only recently began managing the Northern gas portfolio and hedging program, a review of the current winter period provides the most relevant information regarding hedging and gas costs to expect going forward. Excluding the opportunity cost, Northern's total internal and external hedging costs allocated to New Hampshire under the current hedging policy are estimated to be $42,841 on total gas costs of $24,239,380, or 0.3% of total gas costs. Under the proposed hedging policy total hedging costs are estimated to be $29,815 or 0.2% of total gas costs.

Q. Why are hedging costs under the proposed policy expected to be lower?

A. There will be fewer financial hedges. Under the current policy, 84% of the 2009-2010 gas supplies were hedged and under the proposed policy only 70% would be hedged, with physical and fixed-price contract gas supplies remaining unchanged, the reduction will come from a decrease in the financial hedges.

Q. Do the cost estimates under the proposed program reflect the cost of the revised proposed hedging policy?

A. No, the amount of financial hedging under the revised proposed hedging policy will be about one third less than under the original proposed hedging policy. While that should have little impact on the internal labor costs, the margin financing costs should see a corresponding drop of approximately one third.

Q. Should there be a corresponding decrease in the hedging impact on rate volatility?

A. No, there should be very little change in the rate volatility impact due to the revised hedging proposal. The original hedging proposal called for eliminating summer hedging but would have hedged storage gas in advance of placing those supplies in storage. The cost of the storage gas is fixed prior to setting winter rates, regardless of whether those supplies were hedged prior to being stored.

Therefore, eliminating those financial hedges will have no impact on the volatility of a customer's monthly COG rates.

Q. Please compare the cost of hedging to the reduction in rate volatility.

A. Ignoring opportunity costs, the current hedging program increased COG rates by 0.3% and reduced rate volatility by 5%. The total gas bill for a typical residential heating customer for the 2009-2010 winter period was estimated to be $1,414,[6] of which $4.24 can be attributed to hedging. That cost would drop to $2.83 under the proposed hedging program.

Q. Does Staff support continued hedging given the limited impact on rate volatility?

A. Yes, although at a reduced level. While it is true that hedging has had a limited impact on rates, it is also safe to say the cost to hedge is minimal, ignoring gains and losses.

Q. Is locking in 70% of winter supply costs reasonable?

A. As discussed earlier in my testimony, many customers see value in reduced rate volatility and Staff therefore believes it is in the public interest to perform some level of hedging. Locking in 70% is reasonable when compared to the amount of hedging done by other natural gas utilities, and is in line with the 65% of fixed cost supply in EnergyNorth's winter supply portfolio. A study performed by Northern's broker, Risk Management Inc. (RMI), in which 31 of its utility clients participated, found that the average amount of maximum forecasted load that is hedged prior to a given month or season was 69%. ***See Attachment SPF-7 (DR 3-5).*** The American Gas Association (AGA) conducted a 2007-2008 hedging

[6] Docket No. DG 09-167, Exhibit 1, Attachment NUI-JDS-13 p. 1 of 2.

survey of its members and the results were consistent with that found in the RMI study. Although the AGA survey information is proprietary, EnergyNorth is a member and summarized the finding in a hedging presentation to the Commission and during one of the technical sessions in this proceeding.

Q. Are there any other reasons why Northern should reduce its hedging program?

A. Yes, it would reduce the risk that commercial and industrial (C&I) customers might switch between firm sales and transportation in order to avoid hedging losses or partake in hedging gains. Although internal hedging costs are not included in the COG rates and broker fees are minimal, large hedging gains or losses could influence whether some C&I customers would take firm sales service or transportation service.

Q. If C&I customers switch between firm sales service and transportation service as a result of hedging gains or losses, how does that impact firm sales rates?

A. There is very little impact. Grandfathered transportation customers, Northern's largest customers, are exempt from capacity assignment costs and would lose that exemption if they were to switch to firm sales service. The financial benefit realized from being grandfathered far exceeds any one-time benefit that might be realized from participating in hedging savings, therefore the transportation customers with the greatest usage would not do so. Also, customers switching from firm sales to transportation service must remain on transportation service for a minimum of twelve months, thereby limiting the ability of C&I customers to jump between firm sales and transportation service in order to take advantage of hedging gains or losses.

Q. What has been the impact on the firm sales rate as a result of stranded hedging gains or losses due to migration to transportation service?

A. There has been a slow but constant migration from firm sales to transportation service since hedging was incorporated, regardless of hedging gains or losses. During the year in which the hedging losses were the greatest, November 1, 2008 through October 30, 2009, the cost shift only amounted to $149,491 compared to overall gas cost of $46,546,058 during that period. Under the current hedging program, since 2003 the net impact of C&I customers migrating to transportation service has resulted in firm sales customers absorbing $167,566 of hedging losses that they would not have otherwise incurred, compared to gas costs of $306,296,178 over that period. ***See Attachment SPF-8 (DR 2-12 & 2-13).***

Q. Should changes be made to the COG mechanism or the hedging policy to protect against cost shifting due to migration to transportation service?

A. No, there is very little shifting of hedging costs due to C&I migration to transportation service.

Q. How will selling contracts that appreciate 40% affect rate volatility?

A. It could go either way, depending on where natural gas prices are when the contract would otherwise have been sold. If gas prices are higher, then selling the contract earlier will result in lower savings with which to offset the increase in non-hedged supplies and higher COG rates. On the other hand, if prices drop the additional savings realized from having taken the 40% profit will serve to offset the increase in non-hedged supplies and should result in more stable rates.

Q. Does Staff support the proposal to sell contracts that appreciate 40%?

A. Yes. It has been said no one has ever lost money taking a profit, and realizing a 40% gain would be extremely beneficial to customers, even if prices were to continue to rise.

Q. How will suspending hedging based on a price ceiling impact rate volatility?

A. That will most likely result in greater rate volatility but protects against locking in high prices. Locking in high prices will reduce rate volatility, at least month to month within a period, as a higher percentage of the period supplies will be fixed prior to setting the COG rate.

Q. Does Staff support setting a price cap on hedging?

A. Yes. The objective of hedging is to protect against sharp rate increases, not decreases. Locking in high rates may reduce rate volatility but will limit the Company's ability to take advantage of potential rate decreases, which are a greater possibility when prices are extremely high and a market correction can be expected. To a certain extent, natural gas producers have the ability to adjust production in relation to prices and high prices are likely to increase supply. Also to a certain extent, customers have the ability to adjust usage in relation to prices and high prices are likely to decrease demand. If natural gas prices reach the proposed ceiling at which hedging is suspended, there is a good possibility that 18 months later natural gas prices may be lower due to market forces. Furthermore, such increases in natural gas costs are likely to entail greater scrutiny regarding what is happening, both in the natural gas market and the Company's hedging policy, and adjustments could be made to the hedging policy at that time if necessary.

Q. Do you have any other observations to make regarding Northern's proposed hedging program or natural gas hedging in general?

A. Yes. First, I want to thank all who participated in this proceeding, particularly Northern. Northern presented a well reasoned proposal and its look back at the costs and results of the existing hedging program were critical in formulating a program designed to better serve customers.

Over the seven years Northern's hedging policy has been in effect natural gas prices have ranged from a high of $14 per MMBtu to a low of just over $2.00 per MMBtu. With gas price currently in the $5 to $6 range, the upside risk (price increase) would seem to exceed the down side risk (price decrease). So while the goal of hedging is to limit price spikes, locking in rates at this time under the proposed program is more likely to produce substantial savings than substantial costs.

While reducing rate volatility is in the public interest, the proposed hedging program provides for very limited financial hedging and is expected to have only a minor impact on rate volatility. However, the cost of the program is minimal, and the financial hedging may need to be increased after next winter to ensure that 70% of winter supplies are at a fixed price when setting rates, since the fixed price contract representing 10% of Northern's winter supply is set to expire.

Northern has also proposed enhanced reporting which will assist the Commission in monitoring the results of the program. The enhanced reporting should enable the Company and Commission to determine if the program is providing the intended benefits and, if not, whether the program should be discontinued or modified.

Q. Does this conclude your testimony?

A. Yes.

Stephen P. Frink

Educational & Professional Experience

Mr. Frink graduated from the University of New Hampshire with a Bachelor of Arts degree in Sociology in 1977 and a Masters in Business Administration in 1980. He attended and completed Depreciation Programs sponsored by Depreciation Programs, Inc. at Grand Rapids, Michigan in 1992, 1993, 1994 and is a member in good standing of the Society of Depreciation Professionals since 1994.

In 1981, Mr. Frink worked as a High School Math Teacher in Manchester, New Hampshire.

In 1982, Mr. Frink relocated to Texas and worked as an Auditor for Dallas County. He audited various county departments and performed monthly reconciliations of various fund accounts.

In 1985, Mr. Frink went to work for Schenley Industries, Inc., a wholesale liquor distributor located in Dallas, Texas, where he audited national and international manufacturing plants.

In 1986, Mr. Frink left Schenley to work for the City of Dallas as a Budget/Financial Analyst, where he prepared and monitored budgets, prepared pro forma statements, amortization schedules and performed cash flow analysis. He was promoted to Senior Analyst in 1987.

In 1988, Mr. Frink left the City of Dallas to work for the City of Austin as a Financial Analyst. There he prepared budgets and fiscal impact statements, developed a capital projects tracking and monitoring system, and provided training and technical assistance in the implementation of a new accounting system.

In 1990, Mr. Frink joined the Finance staff of the New Hampshire Public Utilities Commission. Working as a member of the PUC Audit Team, he conducted or participated in audits of the books and records of public utilities. He performed desk audits and determined rates of returns. He prepared schedules and exhibits supporting testimony in dockets involving rate increases and participated in settlement conferences. In 1995, Mr. Frink became a full time Analyst for the Finance Department and in 1996 was promoted to a Senior Analyst position, primarily responsible for analyzing and advising the Commission on issues of depreciation, cost of gas adjustment filings, special contracts, and finance and rate increase petitions. In 1998, Mr. Frink was promoted to Assistant Finance Director. As Assistant Finance Director, he assisted in the direction of all aspects of a department responsible for the audit, analysis and review of public utility financial operations, including financing, rate cases and various utility studies filings related to public utility regulation. In 2001, New Hampshire Public Utilities Commission operations were restructured and Mr. Frink became Assistant Director of the Gas & Water Division and now administers all aspects of regulation of gas utilities.

ENERGY NORTH NATURAL GAS, INC.
d/b/a National Grid NH
Peak 2009 - 2010 Winter Cost of Gas Filing
Fixed Price Option

		Participation	Premium	FPO Volumes	Premium Revenue	FPO Rate	Residential Average COG Rate	Residential Total Bill FPO Rate	Residential Total Bill COG Rate	Difference	% Difference	FPO Rate	C&I Average COG Rate	C&I Total Bill FPO Rate	C&I Total Bill COG Rate	Difference	% Difference
1	Nov 98 - Mar 99	6%				$0.3927	$0.3722	$ 943.37	$ 926.93	$ 16.44	1.77%	$0.3927	$0.3736	$ 1,570.86	$ 1,546.08	$ 24.79	1.60%
2	Nov 99 - Mar 00	9%				$0.4724	$0.4628	$ 679.85	$ 672.22	$ 7.63	1.13%	$0.4724	$0.4636	$ 1,161.81	$ 1,149.15	$ 12.67	1.10%
3	Nov 00 - Mar 01	20%				$0.6408	$0.7656	$ 816.25	$ 916.09	$ (99.84)	-10.90%	$0.6408	$0.7189	$ 1,376.64	$ 1,533.43	$ (156.79)	-10.22%
4	Nov 01 - Apr 02	24%				$0.5141	$0.4818	$ 790.65	$ 760.55	$ 30.10	3.96%	$0.5238	$0.4928	$ 1,301.07	$ 1,256.88	$ 44.19	3.52%
5	Nov 02 - Apr 03	24%	$0.0051	25,107,016	$ 128,046	$0.5553	$0.5758	$ 821.32	$ 840.44	$ (19.11)	-2.27%	$0.5658	$0.5860	$ 1,344.02	$ 1,372.86	$ (28.84)	-2.10%
6	Nov 03 - Apr 04	23%	$0.0219	25,220,575	$ 552,331	$0.8597	$0.8220	$ 1,115.55	$ 1,080.46	$ 35.09	3.25%	$0.8759	$0.8352	$ 1,798.38	$ 1,740.30	$ 58.08	3.34%
7	Nov 04 - Apr 05	30%	$0.0100	27,378,128	$ 273,781	$0.8925	$0.9425	$ 1,142.96	$ 1,189.55	$ (46.60)	-3.92%	$0.9092	$0.9562	$ 1,844.75	$ 1,911.86	$ (67.10)	-3.51%
8	Nov 05 - Apr 06	30%	$0.0200	25,944,091	$ 518,882	$1.2951	$1.1342	$ 1,526.01	$ 1,376.01	$ 150.00	10.90%	$1.3192	$1.1686	$ 2,450.66	$ 2,235.77	$ 214.89	9.61%
9	Nov 06 - Apr 07	15%	$0.0200	13,135,684	$ 262,714	$1.2664	$1.1656	$ 1,509.79	$ 1,415.80	$ 93.99	6.64%	$1.2666	$1.1647	$ 2,321.15	$ 2,175.70	$ 145.45	6.68%
10	Nov 07 - Apr 08	16%	$0.0200	14,078,553	$ 281,571	$1.2043	$1.1746	$ 1,433.09	$ 1,405.40	$ 27.69	1.97%	$1.2044	$1.1725	$ 2,232.39	$2,186.92	$ 45.47	2.08%
11	Nov 08 - Apr 09	15%	$0.0200	13,041,335	$ 260,827	$1.2835	$1.0888	$1,555.31	$1,373.85	$ 181.46	13.21%	$1.2836	$1.0958	$2,467.49	$2,199.54	$ 267.95	12.18%
12	Nov 09 - Apr 10 1/					$0.9863	$0.9663	$1,250.80	$1,232.16	$ 18.64	1.51%	$0.9864	$0.9665	$1,984.14	$1,955.74	$ 28.40	1.45%
13																	
14	Total									$ 395.48						$ 589.15	

1/ The total bill calculation reflects the increase in base distribution rates as approved in Order 24,888 in DG 08-009 (Temporary Rates)

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Supplemental Schedule E

New Hampshire Gas Corporation
COG FPO vs Non-FPO Price Comparison

Winter Period	FPO Rate	Amount of Premium	Percent Participation (therms)	Actual FPO Volumes	Premium Revenue	Typical Residential FPO bill	Average Non-FPO Rate	Typical Residential non-FPO bill	Cost/(Savings) to FPO Customers
2008-2009	$2.2408	$0.02	21.08%	205,970	$4,119	$2,974	$1.7347	$2,492	$482
2007-2008	$1.5212	$0.02	28.01%	266,419	$5,328	$2,288	$1.7646	$2,520	($232)
2006-2007	$1.4741	$0.02	21.86%	206,686	$4,134	$2,250	$1.5397	$2,313	($63)
2005-2006	$1.5260	$0.02	42.91%	348,849	$6,977	$2,248	$1.3742	$2,103	$145
2004-2005	$1.2323	n/a	39.44%	340,315	n/a	$1,946	$1.2647	$1,976	($30)
2003-2004	$0.8877	n/a	38.78%	316,300	n/a	$1,580	$1.0325	$1,718	($138)
Total						$13,286		$13,121	$164

NORTHERN UTILITIES, INC.
DG 09-141
STAFF 3rd SET DATA REQUESTS - FINANCIAL HEDGING PROGRAM

Date Request Received: 01/15/2010 **Date of Response: 01/29/2010**

Request No. Staff 3-1 **Witness: Robert S. Furino**

Request:

Please provide a schedule with the following information:

Monthly winter COG rates for the period November, 2003 through April, 2009
Monthly winter COG rates without hedging for the same period
Standard deviation of changes in rates for both hedged and non-hedged rates
Log normal of the absolute price ratio within each winter period
Standard deviation of the log normal for each winter period
Comparison of the standard deviation of the log normal for each period and in total

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Response:

Please refer to the following key for the data requested, which is provided in Attachment 3-1:

Key	Data Item
a	Monthly winter COG rates for the period November, 2003 through April
d	Monthly winter COG rates without hedging for the same period
h, i	Standard deviation of changes in rates for both hedged and non-hedged rates
b, e	Log normal of the absolute price ratio within each winter period
c, f	Standard deviation of the log normal for each winter period
g	Comparison of the standard deviation of the log normal for each period and in total

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Northern Utilities, Inc
Monthly Average Cost of Gas Rate Volatility

		With Hedging			Without Hedging			Difference
		a	b	c	d	e	f	g f-c
	Month	Res. Heat COG Rate	Log Normal of Absolute Price	Standard Deviation of Log Normal	Res. Heat COG Rate	Log Normal of Absolute Price	Standard Deviation of Log Normal	Difference of Std Dev
	Nov-03	$0.9030		4.87%	$0.9141		5.63%	0.76%
	Dec-03	$0.9030	0.00		$0.9080	-0.01		
	Jan-04	$0.9030	0.00		$0.8927	-0.02		
	Feb-04	$1.0068	0.11		$0.9991	0.11		
	Mar-04	$1.0068	0.00		$1.0042	0.01		
	Apr-04	$1.0068	0.00		$0.9798	-0.02		
	Nov-04	$0.9798		4.12%	$0.9484		2.22%	-1.90%
	Dec-04	$0.9798	0.00		$0.9545	0.01		
	Jan-05	$0.9798	0.00		$0.9787	0.02		
	Feb-05	$1.0063	0.03		$1.0050	0.03		
	Mar-05	$1.0688	0.06		$1.0646	0.06		
	Apr-05	$1.1758	0.10		$1.0656	0.00		
	Nov-05	$1.2831		11.49%	$1.1773		9.64%	-1.85%
	Dec-05	$1.2831	0.00		$1.2398	0.05		
	Jan-06	$1.2831	0.00		$1.2422	0.00		
	Feb-06	$1.0907	-0.16		$1.0869	-0.13		
	Mar-06	$1.0907	0.00		$1.1013	0.01		
	Apr-06	$1.2831	0.16		$1.2563	0.13		
	Nov-06	$1.2984		12.04%	$1.3458		10.27%	-1.77%
	Dec-06	$1.3259	0.02		$1.3747	0.02		
	Jan-07	$1.1629	-0.13		$1.2408	-0.10		
	Feb-07	$1.2859	0.10		$1.3291	0.07		
	Mar-07	$1.5581	0.19		$1.5952	0.18		
	Apr-07	$1.5581	0.00		$1.6249	0.02		
	Nov-07	$1.0610		8.15%	$1.0765		3.77%	-4.38%
	Dec-07	$1.0610	0.00		$1.0887	0.01		
	Jan-08	$1.0610	0.00		$1.0951	0.01		
	Feb-08	$1.0610	0.00		$1.0781	-0.02		
	Mar-08	$1.0610	0.00		$1.0609	-0.02		
	Apr-08	$1.2732	0.18		$1.1446	0.08		
	Nov-08	$1.2636		8.11%	$1.3311		10.97%	2.86%
	Dec-08	$1.2636	0.00		$1.3376	0.00		
	Jan-09	$1.2636	0.00		$1.3172	-0.02		
	Feb-09	$1.2636	0.00		$1.3618	0.03		
	Mar-09	$1.0540	-0.18		$1.1543	-0.17		
	Apr-09	$1.0540	0.00		$1.3267	0.14		
	Total Winter		1.58%			1.66%		0.08%
h	STDEV	16.61%			18.36%			
i	STDEVPA	16.37%			18.10%			

STDEVPA standard deviation of entire population
STDEV assumes sample of population

NORTHERN UTILITIES, INC.
DG 09-141
STAFF 3rd SET DATA REQUESTS - FINANCIAL HEDGING PROGRAM

Date Request Received: 01/15/2010 **Date of Response: 01/29/2010**

Request No. Staff 3-2 **Witness: Robert S. Furino**

Request:

Please provide a schedule with the following information:

Monthly summer COG rates for the period May, 2004 through October, 2009
Monthly summer COG rates without hedging for the same period
Standard deviation of changes in rates for hedged and non-hedged rates
Log normal of the absolute price ratio within each summer period
Standard deviation of the log normal for each summer period
Comparison of the standard deviation of the log normal for each period and in total

Response:

Please refer to the following key for the data requested, which is provided in Attachment 3-2:

Key	Data Item
a	Monthly summer COG rates for the period May, 2004 through October, 2009
d	Monthly summer COG rates without hedging for the same period
h, i	Standard deviation of changes in rates for both hedged and non-hedged rates
b, e	Log normal of the absolute price ratio within each summer period
c, f	Standard deviation of the log normal for each summer period
g	Comparison of the standard deviation of the log normal for each period and in total

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Northern Utilities, Inc
Monthly Average Cost of Gas Rate Volatility

Attachment 3-2

		With Hedging			Without Hedging			Difference
		a	b	c	d	e	f	g f-c
	Month	Res. Heat COG Rate	Log Normal of Absolute Price	Standard Deviation of Log Normal	Res. Heat COG Rate	Log Normal of Absolute Price	Standard Deviation of Log Normal	Difference of Std Dev
	May-04	$0.8192		3.35%	$0.7547		6.03%	2.68%
	Jun-04	$0.8192	0.00		$0.8192	0.08		
	Jul-04	$0.8192	0.00		$0.8192	0.00		
	Aug-04	$0.8830	0.07		$0.8830	0.07		
	Sep-04	$0.8830	0.00		$0.8830	0.00		
	Oct-04	$0.8830	0.00		$0.8290	-0.06		
	May-05	$0.9577		11.55%	$0.9315		27.75%	16.20%
	Jun-05	$0.8330	-0.14		$0.8330	-0.11		
	Jul-05	$0.8330	0.00		$0.8330	0.00		
	Aug-05	$0.9160	0.09		$0.9160	0.09		
	Sep-05	$1.0828	0.17		$1.0828	0.17		
	Oct-05	$1.1493	0.06		$0.6329	-0.54		
	May-06	$1.0104		7.82%	$1.0833		15.98%	8.16%
	Jun-06	$0.8809	-0.14		$0.8809	-0.21		
	Jul-06	$0.8809	0.00		$0.8809	0.00		
	Aug-06	$0.8809	0.00		$0.8809	0.00		
	Sep-06	$0.9538	0.08		$0.9538	0.08		
	Oct-06	$0.9538	0.00		$1.2068	0.24		
	May-07	$0.9040		6.82%	$0.9185		14.71%	7.89%
	Jun-07	$0.9040	0.00		$0.9040	-0.02		
	Jul-07	$0.8440	-0.07		$0.8440	-0.07		
	Aug-07	$0.7232	-0.15		$0.7232	-0.15		
	Sep-07	$0.7232	0.00		$0.7232	0.00		
	Oct-07	$0.7232	0.00		$0.9195	0.24		
	May-08	$1.1315		15.20%	$0.9033		23.59%	8.39%
	Jun-08	$1.3231	0.16		$1.3231	0.38		
	Jul-08	$1.3231	0.00		$1.3231	0.00		
	Aug-08	$1.2050	-0.09		$1.2050	-0.09		
	Sep-08	$0.9305	-0.26		$0.9305	-0.26		
	Oct-08	$0.9305	0.00		$0.9806	0.05		
	May-09	$0.7385		9.98%	$1.1238		43.90%	33.92%
	Jun-09	$0.7385	0.00		$0.7385	-0.42		
	Jul-09	$0.7385	0.00		$0.7385	0.00		
	Aug-09	$0.7385	0.00		$0.7385	0.00		
	Sep-09	$0.7385	0.00		$0.7385	0.00		
	Oct-09	$0.9231	0.22		$1.6249	0.79		
	Total Summer		0.01%			0.89%		0.88%
h	STDEV	15.85%			20.41%			
i	STDEVPA	15.63%			20.12%			

STDEVPA standard deviation of entire population
STDEV assumes sample of population

Date Request Received: 11/30/09 **Date of Response: 12/18/2009**

Request No. Staff 2-6 **Witness: Robert S. Furino**

Request:

Ref. DR 1-9 response: please describe the internal hedging cost components and the amount of each component for the summer and winter periods (personnel costs including overhead).

Response:

Northern does not separately track staff time associated with activities required to support the hedging program. These activities include the following: preparing and reviewing the hedging plan for inclusion in the cost of gas filing, issuing instructions to RMI for plan implementation, calculating and reporting margin requirements each day, monitoring margin requirements each day and funding as needed, preparing, approving and filing the monthly hedging report, updating accounting reports each month and general oversight.

The costs to operate the program are similar for the winter and summer periods. Northern estimates that approximately 186 hours of staff time are associated with hedging program operations in support of the winter seasons and that approximately 162 hours of staff time are associated with hedging program operations in support of the summer seasons. The estimated personnel costs, including overhead, are $11,600 for the winter seasons and $10,100 for the summer seasons, respectively or approximately $21,700 annually.

Date Request Received: 11/30/09 **Date of Response: 12/18/2009**

Request No. Staff 2-8 **Witness: Robert S. Furino**

Request:

Please provide a spread sheet for the 2009-2010 winter period based on actual and projected costs under the current hedging policy with the following information: internal hedging costs, margin costs, broker costs, total internal and external hedging costs, direct and indirect gas costs, total gas costs, hedging costs as a percentage of total gas costs, total winter revenue (delivery, commodity and LDAC) and hedging costs as a percentage of winter revenue.

Response:

Attachment 2-8 provides the actual and projected internal hedging costs, margin costs, broker costs, total internal and external hedging costs, direct and indirect gas costs, total gas costs, hedging costs as a percentage of total gas costs, total winter revenue (delivery, commodity and LDAC) and hedging costs as a percentage of winter revenue. The internal hedging costs reported are based on the activities reported in Staff 2-6. Since there is no way to predict the future price movement of the NYMEX futures contracts in the portfolio, and hence no way to predict margin requirements, Northern assumed a consistent level of borrowing need and used a 2.5% monthly borrowing interest rate to calculate the margin costs. The actual account balance as of November 30, 2009 was used as the basis for the margin cost calculation. The bulk of the broker fees listed reflect the cost of implementing the HH Swaps; however, as described in Staff 2-5, Northern typically earns a small margin on the swaps that more than offsets the transaction fees. As shown in the attachment, projected hedging program costs under the current program for the current peak season are approximately 0.3% of total revenue. During a program year when margin requirements are lower, program costs would be much lower.

Attachment 2-8

Northern Utilities, Inc.
Projected NH Division Winter Season Hedging Costs, Current Program

Month	Margin Costs	Broker Fees	Internal Staff Cost Estimate	Total Program Internal and External Costs	NH Allocator	NH Hedging Costs	Direct Gas Costs	Indirect Gas Cost	Total Gas Costs	Hedging Costs / Total Gas Costs	Delivery Revenue	Commodity Revenue	LDAC Revenue	Total Winter Revenue	Hedging Costs / Total Revenue
Nov-09	$ 10,742	$ 557	$ 1,930	$ 13,229	53.98%	$ 7,141	$ 2,890,768	$ 163,382	$ 3,054,150	0.4%	$ 1,622,039	$ 2,968,184	$ 85,821	$ 4,676,044	0.3%
Dec-09	$ 10,742	$ 678	$ 1,930	$ 13,350	52.62%	$ 7,025	$ 3,997,843	$ 167,007	$ 4,164,850	0.3%	$ 2,751,585	$ 5,116,563	$ 139,908	$ 8,008,056	0.2%
Jan-10	$ 10,742	$ 674	$ 1,930	$ 13,345	51.84%	$ 6,918	$ 4,560,395	$ 167,478	$ 4,727,873	0.2%	$ 2,977,435	$ 6,763,289	$ 183,075	$ 9,923,799	0.1%
Feb-10	$ 10,742	$ 645	$ 1,930	$ 13,317	54.08%	$ 7,202	$ 4,855,982	$ 164,765	$ 5,020,747	0.2%	$ 2,409,210	$ 7,078,444	$ 180,543	$ 9,668,197	0.1%
Mar-10	$ 10,742	$ 786	$ 1,930	$ 13,457	52.85%	$ 7,112	$ 4,208,211	$ 155,440	$ 4,363,651	0.2%	$ 2,413,918	$ 5,528,860	$ 154,785	$ 8,097,563	0.1%
Apr-10	$ 10,742	$ 842	$ 1,930	$ 13,513	53.67%	$ 7,253	$ 2,762,994	$ 145,115	$ 2,908,109	0.4%	$ 1,592,561	$ 3,810,133	$ 116,465	$ 5,519,159	0.2%
Total	$ 64,449	$ 4,182	$ 11,580	$ 80,212	53.41%	$ 42,841	$ 23,276,193	$ 963,187	$ 24,239,380	0.3%	$ 13,766,747	$ 31,265,473	$ 860,598	$ 45,892,817	0.2%

Date Request Received: 11/30/09 **Date of Response: 12/18/09**

Request No. Staff 2-9 **Witness: Robert S. Furino**

Request:

Please provide a spread sheet for the 2009-2010 winter period based on actual and projected costs under the proposed hedging policy with the following information: internal hedging costs, margin costs, broker costs, total internal and external hedging costs, direct and indirect gas costs, total gas costs, hedging costs as a percentage of total gas costs, total winter revenue (delivery, commodity and LDAC) and hedging costs as a percentage of winter revenue.

Response:

Attachment 2-9 provides the projected costs internal hedging costs, margin costs, broker costs, total internal and external hedging costs, direct and indirect gas costs, total gas costs, hedging costs as a percentage of total gas costs, total winter revenue (delivery, commodity and LDAC) and hedging costs as a percentage of the proposed program. For purposes of this presentation, Northern has used modeling results associated with the 4-year price ceiling calculation method, as discussed described to Staff at the technical conference on December 7, 2009. To calculate anticipated margin costs under this program, Northern assumed a consistent level of borrowing need and used a 2.5% monthly borrowing interest rate to calculate the margin costs using the calculated margin requirement of $3,224,851 as of October 30, 2009. Under the proposed program hedging margin requirements are anticipated to be lower than under the current program, which would reduce total hedging costs, otherwise program costs would remain the same as under the current program. As shown in the attachment, projected hedging program costs under the proposed program for the current peak season would be approximately 0.2% of total revenue. Again, during a program year when margin requirements were projected to be lower, program costs would be lower as well.

Northern Utilities, Inc.
Projected NH Division Winter Season Hedging Costs, Proposed Program

Month	Margin Costs	Broker Fees	Internal Staff Cost Estimate	Total Program Internal and External Costs	NH Allocator	NH Hedging Costs	Direct Gas Costs	Indirect Gas Cost	Total Gas Costs	Hedging Costs / Total Gas Costs	Delivery Revenue	Commodity Revenue	LDAC Revenue	Total Winter Revenue	Hedging Costs / Total Revenue
Nov-09	$ 6,718	$ 557	$ 1,930	$ 9,206	53.98%	$ 4,969	$ 2,890,768	$ 163,382	$ 3,054,150	0.3%	$ 1,622,039	$ 2,968,184	$ 85,821	$ 4,676,044	0.2%
Dec-09	$ 6,718	$ 678	$ 1,930	$ 9,327	52.62%	$ 4,908	$ 3,997,843	$ 167,007	$ 4,164,850	0.2%	$ 2,751,585	$ 5,116,563	$139,908	$ 8,008,056	0.1%
Jan-10	$ 6,718	$ 674	$ 1,930	$ 9,322	51.84%	$ 4,833	$ 4,560,395	$ 167,478	$ 4,727,873	0.2%	$ 2,977,435	$ 6,763,289	$183,075	$ 9,923,799	0.1%
Feb-10	$ 6,718	$ 645	$ 1,930	$ 9,294	54.08%	$ 5,026	$ 4,855,982	$ 164,765	$ 5,020,747	0.2%	$ 2,409,210	$ 7,078,444	$180,543	$ 9,668,197	0.1%
Mar-10	$ 6,718	$ 786	$ 1,930	$ 9,434	52.85%	$ 4,986	$ 4,208,211	$ 155,440	$ 4,363,651	0.2%	$ 2,413,918	$ 5,528,860	$154,785	$ 8,097,563	0.1%
Apr-10	$ 6,718	$ 842	$ 1,930	$ 9,490	53.67%	$ 5,093	$ 2,762,994	$ 145,115	$ 2,908,109	0.3%	$ 1,592,561	$ 3,810,133	$116,465	$ 5,519,159	0.2%
Total	$ 40,311	$ 4,182	$ 11,580	$ 56,073	53.41%	$ 29,815	$ 23,276,193	$ 963,187	$ 24,239,380	0.2%	$ 13,766,747	$ 31,265,473	$860,598	$ 45,892,817	0.1%

Date Request Received: 11/30/09 **Date of Response: 12/23/2009**

Request No. Staff 2-10 **Witness: Robert S. Furino**

Request: Hedging Gains and Losses

For each summer and winter period the current hedging program has been in place, please provide the hedging gain or loss, total cost of gas (direct and indirect), the gain or loss as a percentage of total gas costs, total revenue (delivery, commodity and LDAC) and gain or loss as a percentage of revenue.

Response:

Attachment 2-10 provides the gains or losses under the hedging program for each season the program has been in place. The gains or losses for the combined program were adjusted by the variable allocator in order to determine the gains or losses attributable to the New Hampshire (NH) division. Total gas costs and cost of gas revenue for the NH division are shown along with gains or losses as a percentage of each. As shown, hedging losses have averaged one percent (1%) of gas costs over the period of the program. Historical delivery and LDAC revenue were not available; however the typical residential bill impact analysis shown in response to Staff 2-11 on Attachment 2-11(b) indicates that during the historical period, gas supply costs were 77 percent of the total bill during the winter period and 49 percent of the total bill during the summer period.

Northern Utilities, Inc.
Hedging Gains and Losses

Attachment 2-10

Season	(a) Hedging Results Gain/(Loss)	(b) NH Allocator	(c)=(a)*(b) NH Hedging Results Gain/(Loss)	(d) NH Total Gas Costs	(e)=(c)/(d) Gain/(Loss) PCT of Gas Costs	(f) NH Cost of Gas Revenue	(g)=(c)/(f) NH Gain/(Loss) PCT of Gas Revenue
Winter 02/03	$ 1,453,400	51.4%	$ 747,213	$ 28,537,170	2.6%	$ 28,340,116	2.6%
Summer 2003	$ 106,900	50.9%	$ 54,455	$ 7,041,264	0.8%	$ 6,898,513	0.8%
Winter 03/04	$ 328,000	56.8%	$ 186,423	$ 33,445,052	0.6%	$ 35,304,857	0.5%
Summer 2004	$ 450,240	57.0%	$ 256,739	$ 7,469,427	3.4%	$ 7,730,991	3.3%
Winter 04/05	$ 1,275,350	55.8%	$ 711,504	$ 37,012,824	1.9%	$ 42,181,040	1.7%
Summer 2005	$ 2,278,010	54.9%	$ 1,250,387	$ 9,002,615	13.9%	$ 9,391,894	13.3%
Winter 05/06	$ 1,954,830	56.6%	$ 1,106,890	$ 39,435,957	2.8%	$ 38,074,820	2.9%
Summer 2006	$ (1,343,260)	53.0%	$ (712,200)	$ 8,829,867	-8.1%	$ 9,022,429	-7.9%
Winter 06/07	$ (3,217,450)	52.7%	$ (1,694,155)	$ 37,124,007	-4.6%	$ 42,200,486	-4.0%
Summer 2007	$ (643,600)	51.5%	$ (331,527)	$ 6,933,539	-4.8%	$ 6,382,735	-5.2%
Winter 07/08	$ (385,890)	49.1%	$ (189,643)	$ 35,461,640	-0.5%	$ 33,548,997	-0.6%
Summer 2008	$ 484,140	73.3%	$ 354,800	$ 9,456,758	3.8%	$ 8,890,099	4.0%
Winter 08/09	$ (5,240,770)	54.9%	$ (2,875,319)	$ 40,546,058	-7.1%	$ 37,063,505	-7.8%
Summer 2009*	$ (3,257,060)	57.1%	$ (1,861,155)	*$ 6,000,000*	-31.0%	*$ 6,000,000*	-31.0%
PERIOD	$ (5,757,160)	52.0%	$ (2,995,588)	$ 306,296,178	-1.0%	$ 311,030,482	-1.0%
Winter AVG	$ (547,504)	53.9%	$ (286,727)	$ 35,937,530	-0.8%	$ 36,673,403	-0.8%
Summer AVG	$ (274,947)	56.8%	$ (141,214)	$ 7,819,067	-1.8%	$ 7,759,523	-1.8%

* Gas cost and revenue for Summer 2009 not yet available, values shown are estimates.

NORTHERN UTILITIES, INC.
DG 09-141
STAFF 3rd SET DATA REQUESTS - FINANCIAL HEDGING PROGRAM

Date Request Received: 01/15/2010 **Date of Response: 01/29/2010**

Request No. Staff 3-5 **Witness: Robert S. Furino**

Request:

What is normal industry practice regarding Local Distribution Companies hedging, nationally and regionally? Please summarize and/or provide any supporting studies, surveys or other information.

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Response:

RMI conducted a survey of its utility clients (including Northern) in March of 2009. 31 utilities nationwide responded, which included investor owned, municipals and cooperatives. Below are the highlights of the resulting RMI Utility Hedging Survey:

- The most common length of time that the surveyed companies begin to hedge natural gas prior to a season or month was 18 months
- The average percentage of maximum forecasted load that is hedged prior to a given month or season was 69%
- The average percentage of minimum forecasted load that is hedged prior to a given month or season was 42%
- 81% of the LDCs hedge summer and winter volumes
- Futures contracts and physical supplies were among the top tools used for hedging

The RMI Utility Hedging Survey is provided as Attachment 3-5.

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RMI Utility Hedging Survey

RMI 2009 UTILITY HEDGING SURVEY

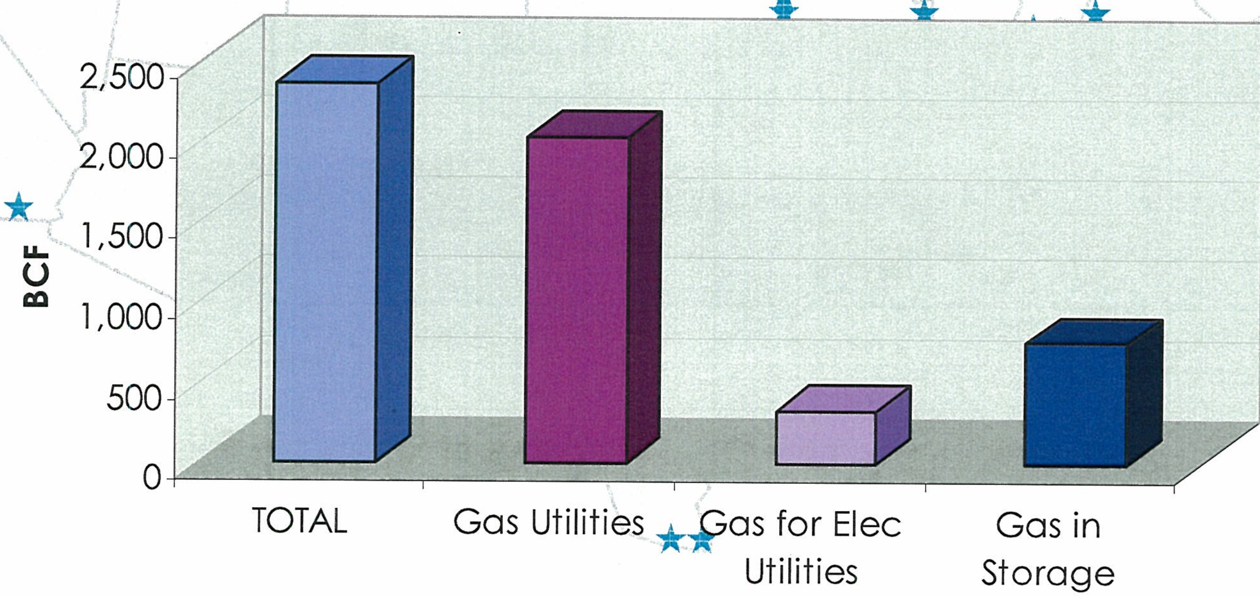
SURVEY CONDUCTED MARCH 2009

NUMBER OF RESPONDENTS: 31 Utilities Nationwide

Investor-Owned, Municipals, and Cooperatives
Gas Distribution and/or Gas Consumption for Electric Generation

TOTAL ANNUAL BCF CONSUMPTION: 2.4 TCF

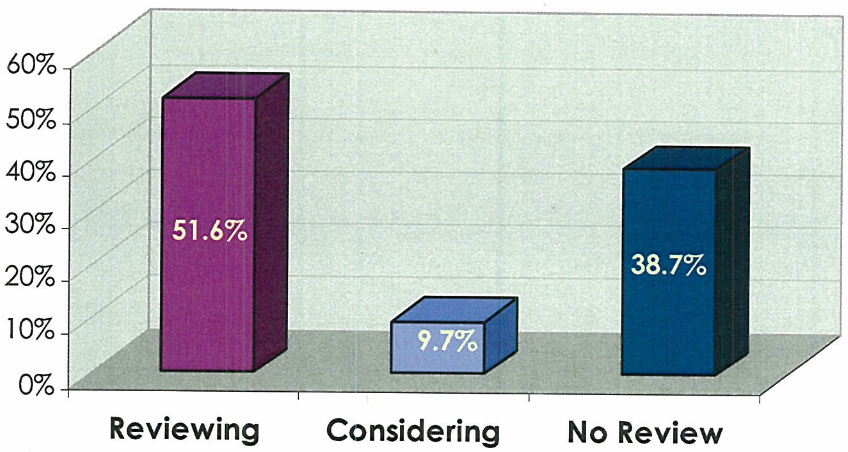
10% of Overall 23.4 TCF Consumed in the U.S. Annually
30% of the 8 TCF of U.S. Residential & Commercial Demand Annually



CURRENT OR POTENTIAL HEDGE PLAN REVIEW

CURRENT HEDGE PLAN REVIEW?

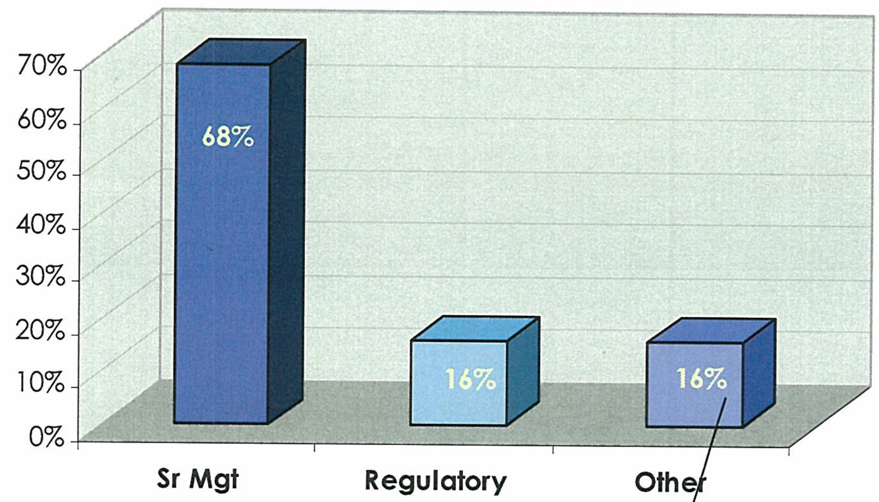
% Respondents with Current or Potential Plan Review



Over 60% of respondents currently reviewing or considering the review of hedge plan or practices in light of the economic crisis.

WHO REQUESTED REVIEW?

Review Request Source



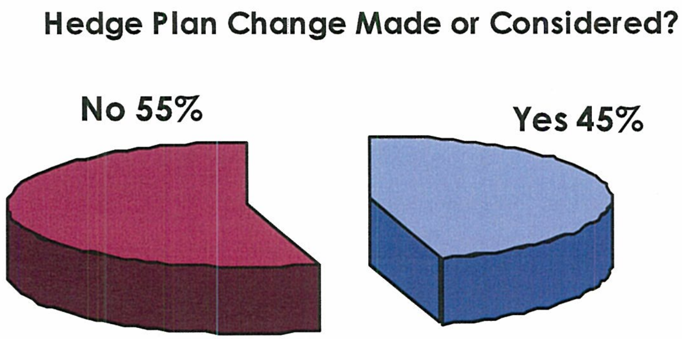
"Other" category responses included:

- ✓ The Risk Oversight Committee
- ✓ Gas Supply Department
- ✓ Hedging Staff
- ✓ Board of Trustee Committee
- ✓ Self

SPF-7

HEDGE PHILOSOPHY/PROGRAM CHANGES

HEDGE PLAN CHANGES OR CHANGES CONSIDERED IN LAST 6 MONTHS IN RESPONSE TO ECONOMIC CRISIS?



If yes, what changes have been made or considered?

- **Lengthening the Time Horizon of Hedge Program**
- **Horizon/Volume Reduction/Shortening**
- **Price Trigger Change to Longer-Term Matrix**
- **Managing Corporate Credit Exposure**
- **Diversifying Pricing Tools**
- **Outsourcing Hedge Strategy Development**

Excerpt from RMI Special Report September 08

This Winter, RMI released Special Reports to address the impact of the financial crisis on energy markets. Given the unprecedented environment, RMI proposed the following potential action items to keep hedge plans current with the new challenges surfacing:

1. Introduction of the 8-Year Matrix

Especially for hedge needs further into the future

2. Review Hedging Tools and Consider a Greater Use of Options

Options strategies to either initiate a purchase or protect purchases already made

3. Consider a Review of Hedging Time Horizon and Volumes Hedged

Reevaluate long-term pricing decisions. While low prices warrant coverage, it has been justified to trim volumes due to internal/external uncertainties.

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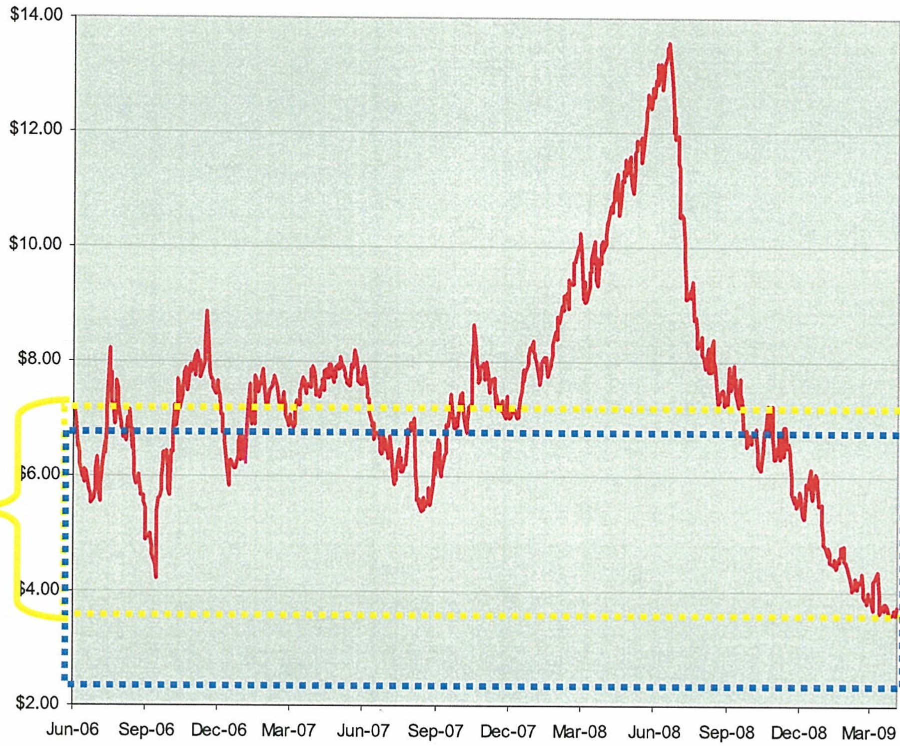
SPF-7

ENERGY MARKET OVERVIEW

Long Term Pricing Decisions in Natural Gas

NATURAL GAS - NYMEX 4-YEAR CALCULATION	
Mean	7.63
Median	7.20
90% - MAX	10.68 - 15.05
80% - 90%	8.97 - 10.68
70% - 80%	8.16 - 8.97
60% - 70%	7.49 - 8.16
50% - 60%	7.20 - 7.49
40% - 50%	6.88 - 7.20
30% - 40%	6.55 - 6.88
20% - 30%	6.01 - 6.55
10% - 20%	5.44 - 6.01
MIN - 10%	3.63 - 5.44



NATURAL GAS - NYMEX 8-YEAR CALCULATION	
Mean	6.79
Median	6.78
90% - MAX	9.05 - 15.99
80% - 90%	7.88 - 9.05
70% - 80%	7.48 - 7.88
60% - 70%	7.10 - 7.48
50% - 60%	6.78 - 7.10
40% - 50%	6.40 - 6.78
30% - 40%	5.94 - 6.40
20% - 30%	5.09 - 5.94
10% - 20%	4.04 - 5.09
MIN - 10%	2.33 - 4.04

Source: Mark-It View™ & RMI WebTools

- **Buying associated with historic prices should be done using a "scaled down" approach with small amounts of volumes at multiple price points**
- **A portfolio approach should always be used**
- **If price levels continue to fall then the company may continue to buy lower prices with greater volumes**

OPTIONS PRICING

Options Pricing Added to Daily Energy Market Update...

April 17, 2009

DAILY FORWARD OPTION ENERGY PRICES

	Strip Period	Summer 2009	Winter 2009/2010	Summer 2010	Winter 2010/2011	Summer 2011	Winter 2011/2012	Summer 2012	Winter 2012/2013
	Settlement	$4.12	$5.70	$5.94	$6.94	$6.68	$7.43	$6.92	$7.63
CALLS	**$5.00**	$0.22							
	$5.50	$0.15	$0.95	$1.21					
	$6.00	$0.10	$0.74	$0.99		$1.51			
	$6.50	$0.07	$0.58	$0.81		$1.28		$1.45	
	$7.00	$0.05	$0.46	$0.66	$1.25	$1.10	$1.58	$1.26	
	$7.50	$0.04	$0.36	$0.55	$1.08	$0.95	$1.38	$1.10	$1.52
	$8.00	$0.03	$0.29	$0.45	$0.93	$0.82	$1.22	$0.96	$1.36
	$9.00	$0.02	$0.18	$0.31	$0.70	$0.62	$0.97	$0.74	$1.10
	$10.00	$0.01	$0.12	$0.22	$0.55	$0.48	$0.77	$0.57	$0.91
	$11.00	$0.01	$0.08	$0.16	$0.44	$0.38	$0.62	$0.45	$0.76
	$12.00	$0.01	$0.06	$0.11	$0.35	$0.30	$0.51	$0.36	$0.64

	Strip Period	Summer 2009	Winter 2009/2010	Summer 2010	Winter 2010/2011	Summer 2011	Winter 2011/2012	Summer 2012	Winter 2012/2013
	Settlement	$4.12	$5.70	$5.94	$6.94	$6.68	$7.43	$6.92	$7.63
PUTS	**$3.00**	$0.09	$0.04	$0.06	$0.03	$0.04			
	$3.50	$0.21	$0.09	$0.12	$0.07		$0.07		
	$4.00	$0.44	$0.18	$0.22	$0.13	$0.17	$0.14		
	$4.50	$0.77	$0.32	$0.36	$0.23	$0.28			
	$5.00	$1.16	$0.51	$0.55	$0.37	$0.43	$0.35	$0.42	$0.34
	$5.50	$1.59	$0.75	$0.78	$0.54	$0.62	$0.50	$0.60	$0.48
	$6.00	$2.05	$1.04	$1.05	$0.76	$0.85	$0.69	$0.82	$0.66

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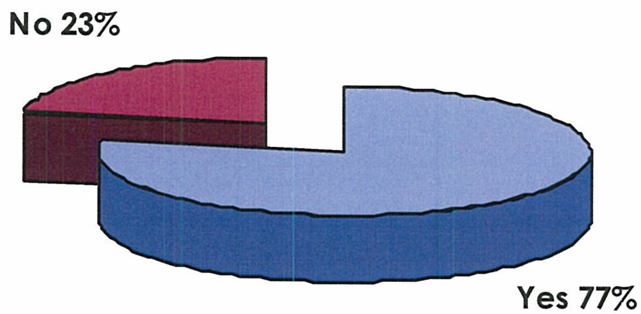
RMI

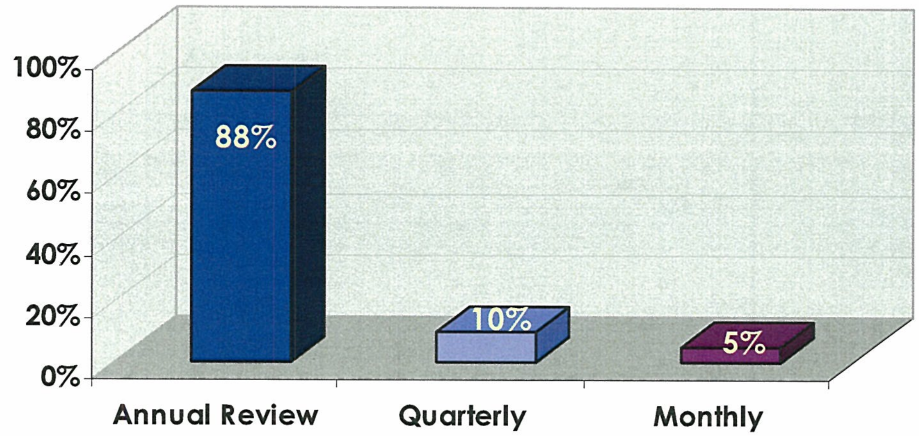
HEDGE PLAN REVIEW REQUIREMENTS & DEVIATIONS

HEDGE PLAN REVIEW REQUIRED PER YOUR POLICY & PROCEDURES?

Periodic Review Required?

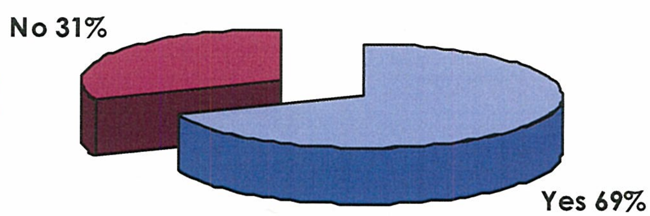


Review Interval Required



DOES HEDGE PLAN HAVE A PROCEDURE/ PROCESS TO ALLOW COMPANY TO DEVIATE FROM ORIGINAL PLAN?

Hedge Plan Deviations Allowed?



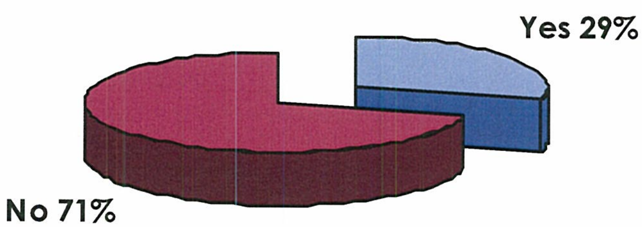
COMMENTS TO NOTE:

- ***Board, Oversight Committee and/or Senior Mgmt Approval Required***
- ***Timing of Execution has element of Discretion***
- ***Acceleration of Execution Allowed when Value-Triggers are Hit***
- ***Maximum Hedge Volume Cap Has +/- % Band up to 10%***

REGULATORY OVERSIGHT

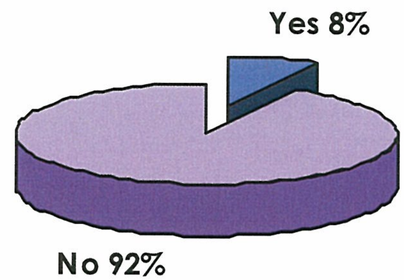
RECENT DISCUSSIONS WITH REGULATORS REGARDING HEDGE/PLAN STRATEGY?

Recent Regulator Discussions?



IF YES, DID REGULATORS GIVE DIRECTION?

Regulator Direction Received?



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SPECIAL NOTE: MARYLAND PSC DIRECTIVE ISSUED

- The Maryland PSC, given low wholesale gas prices, ordered the state's largest LDCs to purchase, by March 31st, 40% of supply planned for summer storage.
- PSC comments included that ratepayers will be better protected against uncertainties affecting gas and power prices with a portion of summer injection needs purchased at current low market prices.
- The PSC also said that while "there will yet be opportunities" for utilities to take advantage of further price declines, it is "prudent and appropriate to lock in substantial savings over last summer's prices now."

MARYLAND PSC ANNOUCEMENT

Maryland Utilities Ordered to Lock In Prices Now

Excerpt from Gas Daily 3.19.09

- **The Maryland Public Service Commission has ordered the state's largest gas distribution utilities to purchase, by March 31, 40% of the supply they plan to add to storage from April through October to take advantage of low wholesale gas prices.**
- In a series of orders issued Tuesday, the PSC directed the state's gas utilities, including Baltimore Gas & Electric, Washington Gas Light and Columbia Gas of Maryland, to "take the actions necessary to assure" that 40% of their summer injection volumes, between April and October, reflect a Henry Hub price of $4.32/MMBtu or less, plus basis delivery cost, by month's end.
- In issuing the orders, the PSC overruled a staff recommendation that the commission "stand pat" and allow the utilities to proceed with their existing purchasing programs, under which they would gradually buy gas for storage from April through October.
- PSC staff and utilities argued that any order directing the utilities to lock in gas supply now for the summer storage period would preclude them from taking advantage of even better deals should gas prices continue to fall over the spring and summer.
- The PSC, however, said both the utilities and staff acknowledged that "nobody can predict future gas prices with precision and that nobody predicted the summer 2008 gas price spikes before they happened." "Everyone agreed," the commission said in its orders, "that gas bought now, at or about the current futures price in the low [$4/MMBtu] range would be bought well below the prices at which summer injection gas was purchased in 2008.
- Put another way, ... if the gas utilities fail to take advantage of current natural gas prices, they may lose an opportunity to lock in lower costs for ratepayers in the 2009-2010 winter heating season."
- The PSC added that "given the unprecedented volatility of natural gas prices... ratepayers will benefit and will be better protected against price spikes due to heat, hurricanes, cold weather and many other uncertainties affecting gas and power prices by a strategy of purchasing a portion of ... summer injection need sat the current low market prices."
- The PSC said that while "there will yet be opportunities" for utilities to take advantage of further price declines, it believes it is "prudent and appropriate to lock in substantial savings over last summer's prices now."

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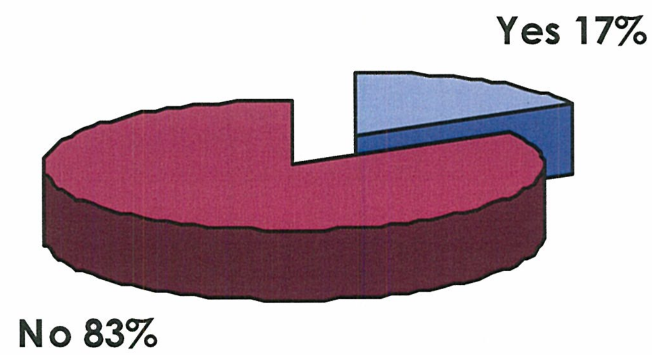
UTILITY CUSTOMER RISK SURVEY

SURVEYED UTILITY CUSTOMERS DIRECTLY REGARDING RISK APPETITES?

Customer Risk Surveyed?



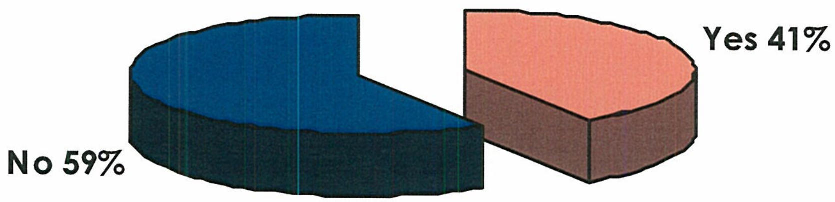
COMMENTS TO NOTE:

- ***Done as part of an ongoing process by which information/proposals are presented, discussed, and acted upon in accordance with direction received***
- ***Preliminary findings indicate a mixed response on hedging for customers, due somewhat to the complex subject matter***

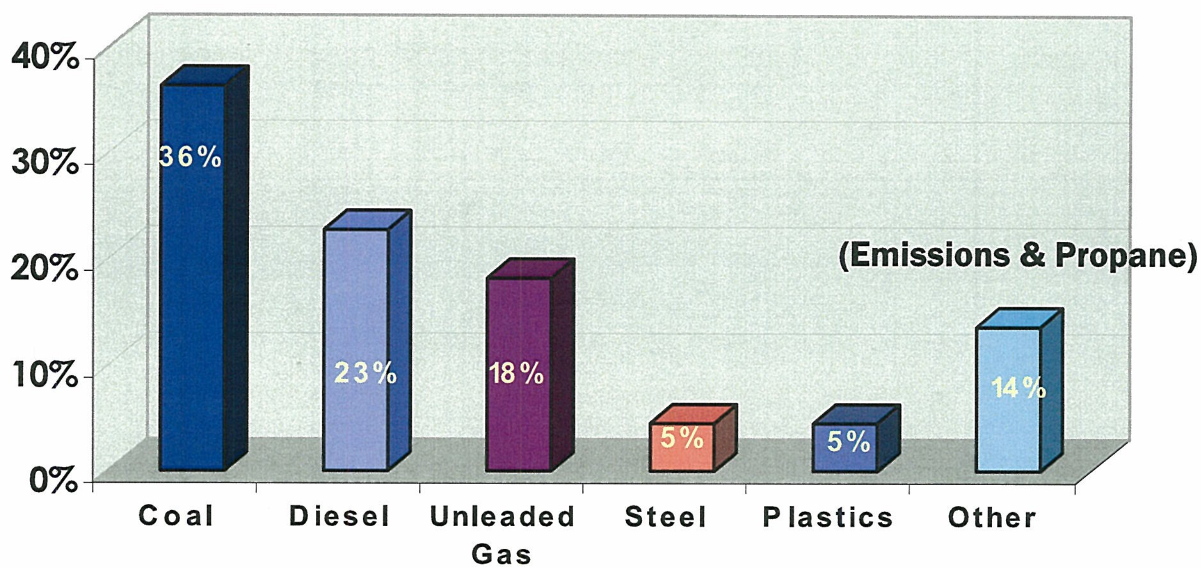
HEDGING OTHER COMMODITIES

WITH MANY COMMODITIES HITTING EXTREMELY LOW PRICES, ARE THERE OTHER EXPOSURES YOU ARE HEDGING OR CONSIDERING TO HEDGE?

Additional Commodities Considered for Hedging?

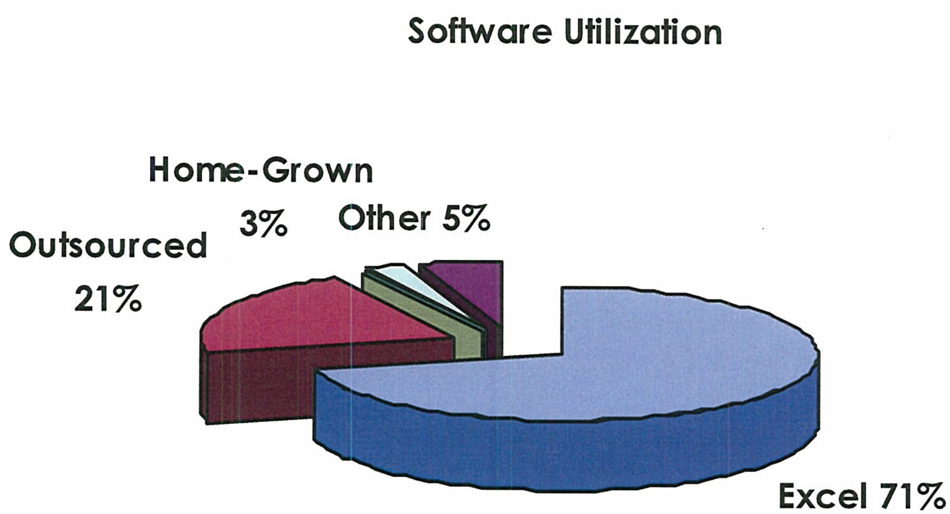


Commodities Considered

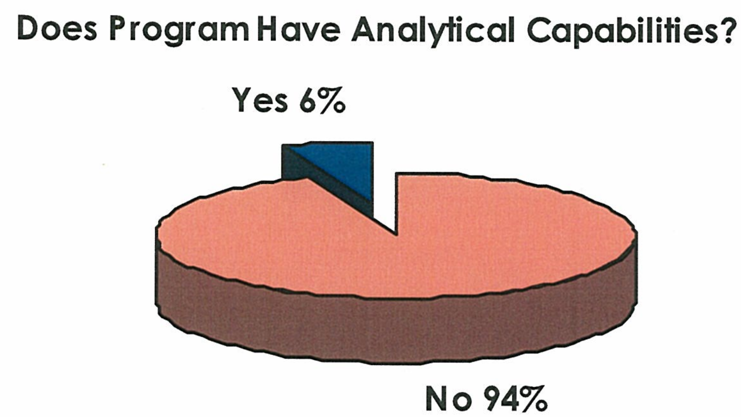


TRACKING & REPORTING HEDGE POSITIONS

WHAT ARE YOU USING FOR TRACKING & REPORTING HEDGE POSITIONS?



DOES IT HAVE ANALYTICAL CAPABILITIES?

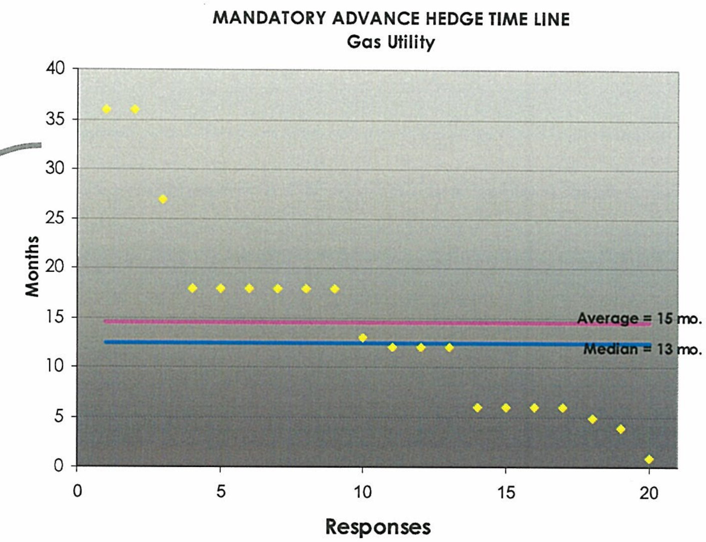


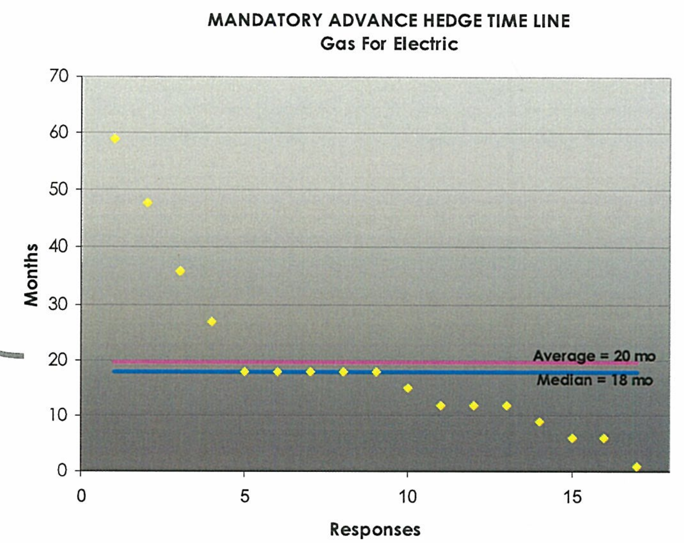
ONE RESPONDENT'S NOTE *"Need recommendations for canned, easy, cheap!"*

MANDATORY LENGTH OF TIME

MANDATORY LENGTH OF TIME IN ADVANCE THAT YOU MUST BEGIN TO HEDGE NATURAL GAS PRIOR TO A SEASON OR MONTH?

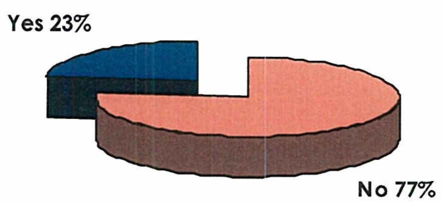
Mandatory Advance	LDC Months	Gas for Elec Months
Average	15	20
Median	13	18
High	36	59
Low	1	1





Given the recent economic situation, has this timeframe changed or are you considering a change?

Change to Mandatory Horizon Under Consideration?



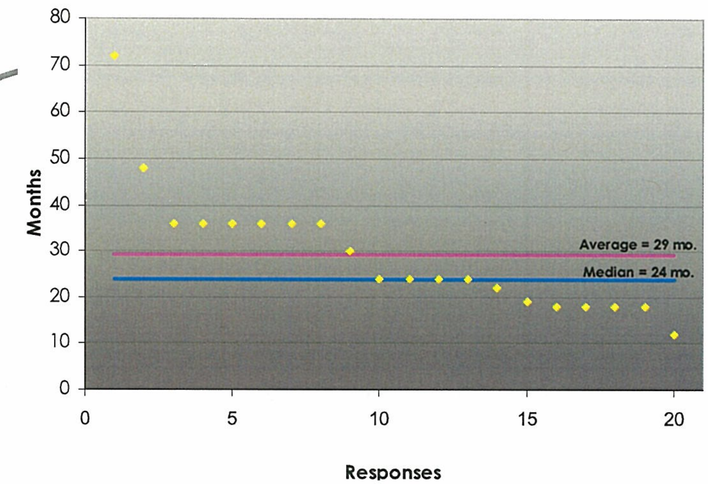
Of those that answered yes, roughly over 50% are considering an increase in the mandatory time line and just under half are considering a reduction in the lead time a hedge must be implemented prior to a given month or season.

MAXIMUM LENGTH OF TIME

MAXIMUM LENGTH OF TIME IN ADVANCE THAT YOU CAN ESTABLISH A HEDGE WITHOUT EXTRAORDINARY APPROVAL?

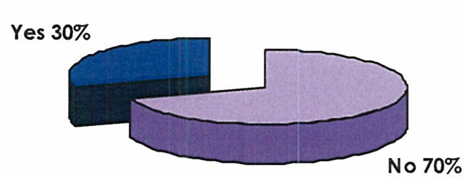
Max Advance	LDC Months	Gas for Elec Months
Average	29	42
Median	24	36
High	72	72
Low	12	12

Maximum Hedge Advance Time Line
Gas Utility



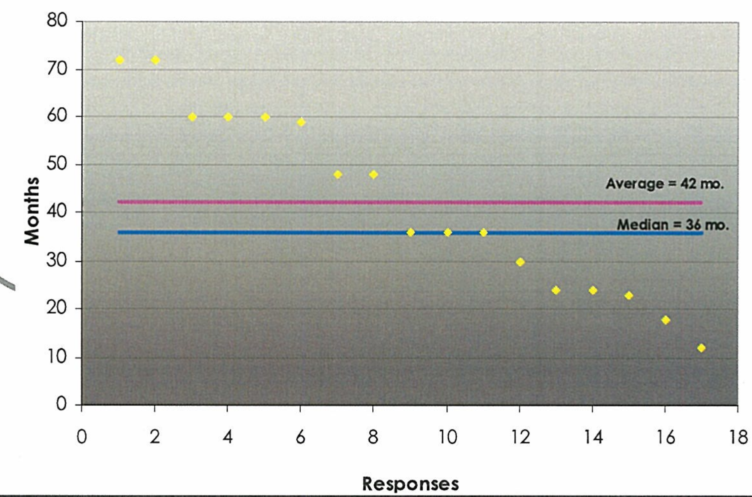
Given the recent economic situation, has this timeframe changed or are you considering a change?

Change to Max Horizon Under Consideration?



Of those that answered yes, 50% are considering an increase in the maximum time line and just under half are considering or have recently made a reduction in the lead time a hedge can be implemented prior to a given month or season.

Maximum Hedge Advance Time Line
Gas For Electric

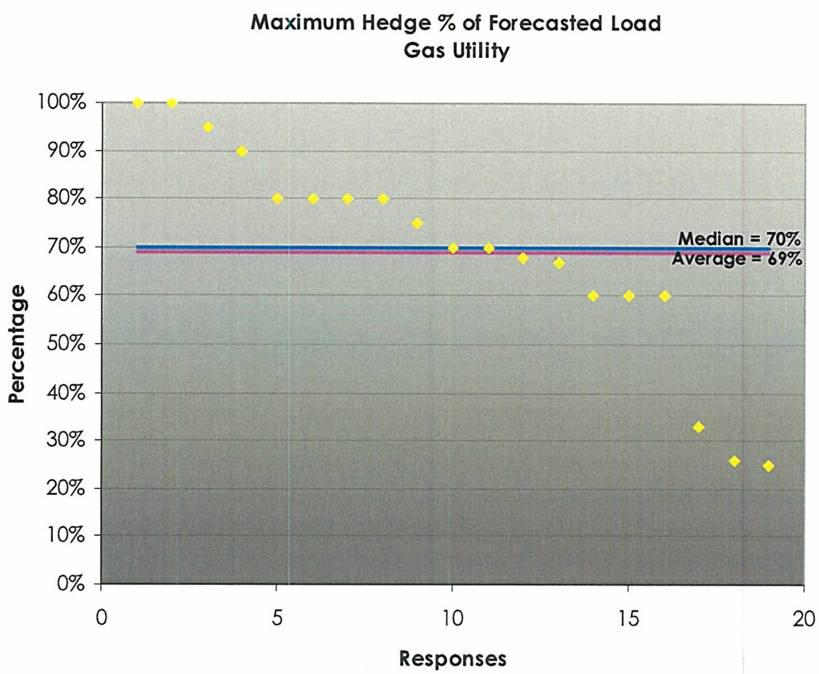


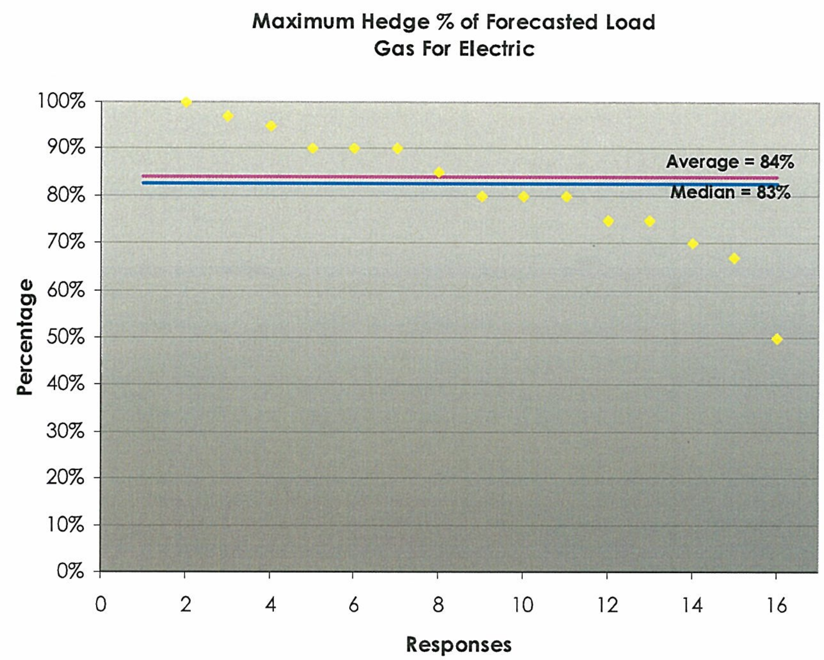
HEDGE QUANTITY - MAXIMUM

MAXIMUM PERCENTAGE OF FORECASTED LOAD THAT CAN BE HEDGED PRIOR TO A GIVEN MONTH OR SEASON?

(Includes options and fixed price positions, but does not include first of the month or daily purchases)

Maximum %	LDC %	Gas for Elec %	Combined %
Average	69%	84%	75%
Median	70%	83%	80%
High	100%	115%	115%
Low	25%	50%	25%





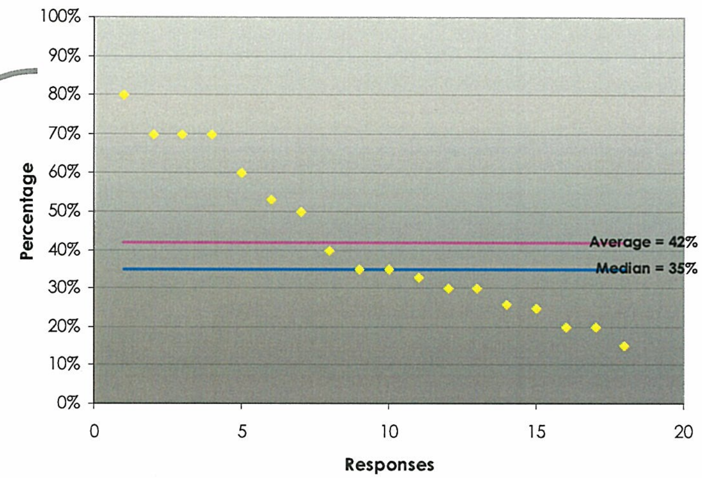
HEDGE QUANTITY - MINIMUM

MINIMUM PERCENTAGE OF NATURAL GAS REQUIRED TO BE HEDGED PRIOR TO A GIVEN MONTH OR SEASON?

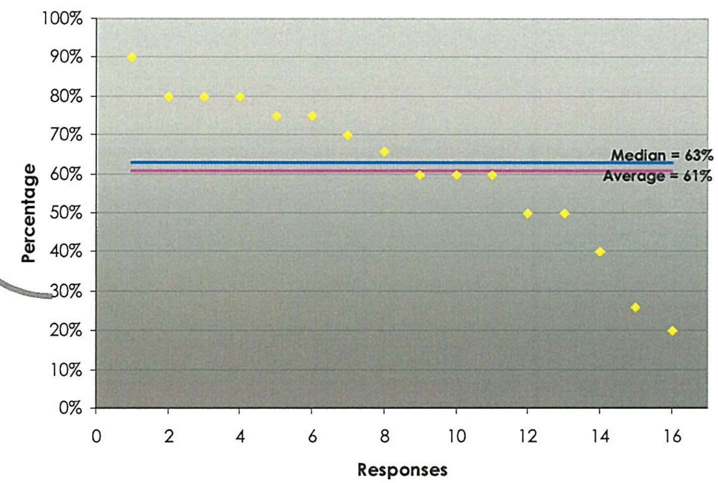
(Does not include first of the month or daily purchases)

Minimum %	LDC %	Gas for Elec %	Combined %
Average	42%	61%	51%
Median	35%	63%	52%
High	80%	90%	90%
Low	15%	20%	15%

Minimum Allowable Hedge % Forecast Load
Gas Utility

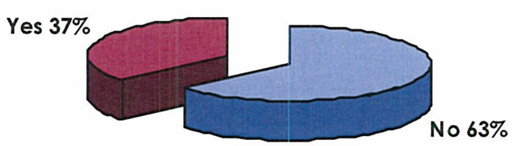


Minimum Allowable Hedge % Forecast Load
Gas For Electric



Given the current economic situation, has your utility revised or considered revising the volumes to be hedged?

Hedge Volume Change Made or Considered?

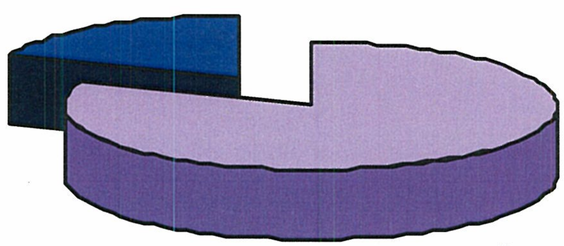


Of the respondents who noted hedge % volume under the plan is under review for change, roughly over 50% are considering a decrease in the volumes allowed and just under half are considering an increase in allowable hedge volume percentages.

SUMMER/WINTER AND LONG TERM MATRIX

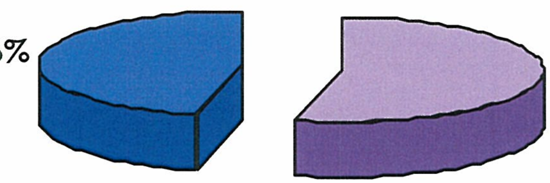
IF YOU ARE AN LDC, DO YOU HEDGE SUMMER AND WINTER VOLUMES?

Summer/Winter Versus Winter Only



RMI INTRODUCED THE 8 YEAR MATRIX IN OCTOBER. HAS YOUR UTILITY REVISED OR CONSIDERED REVISING PRICING TARGETS?

Hedge Target Change Made or Considered?

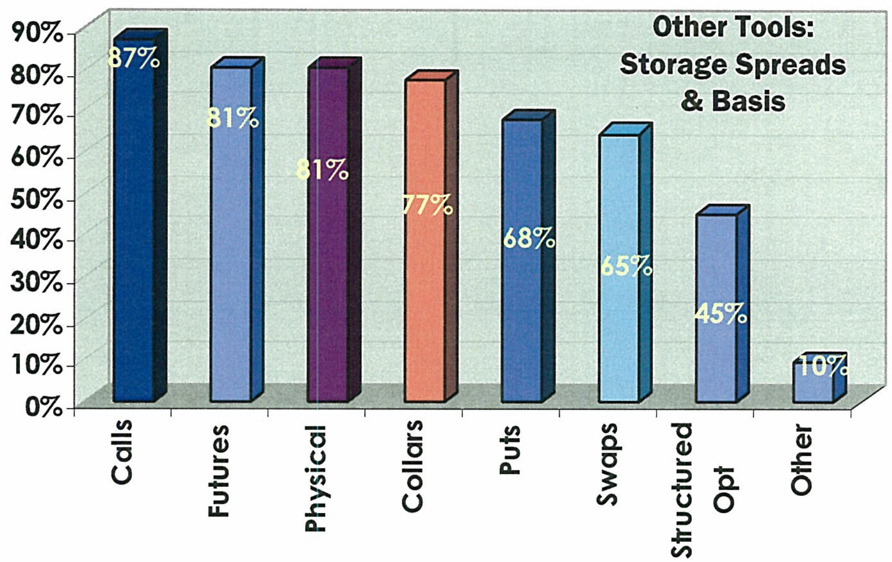


COMMENTS TO NOTE:

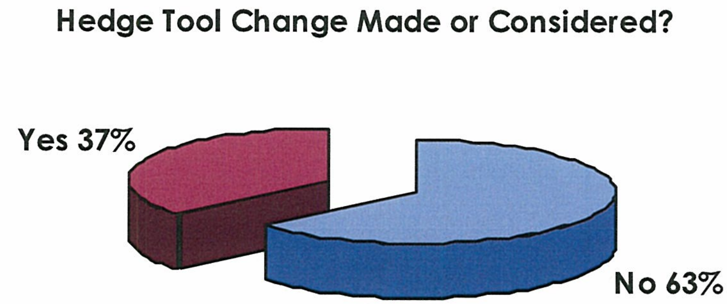
- ***More conservatism toward longer-term price driven purchases.***
- ***Consideration ongoing as to establishing upper limit price cap for adding additional hedges combined with a lower limit trigger in which incremental hedges will be added for substantial volumes.***
- ***Excluding peak price when gas reached @$14.***

PHYSICAL AND FINANCIAL TOOLS

WHICH TOOLS CAN YOU EXECUTE?



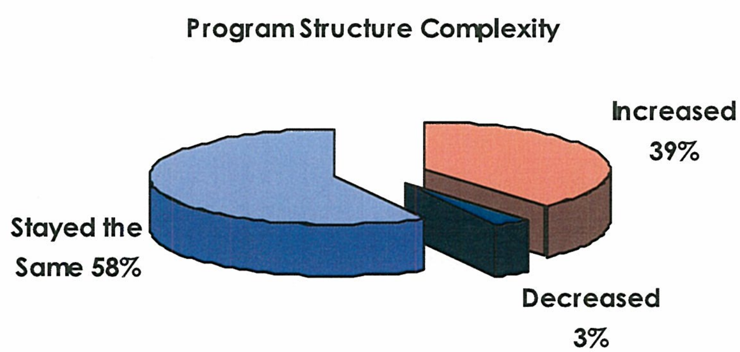
GIVEN CURRENT ECONOMY, TOOL BOX CHANGE OR CONSIDERING CHANGE?



COMMENT TO NOTE:

Considering the use of more "call/put options"

COMPLEXITY OF FINANCIAL PRODUCTS UTILIZED IN LAST TWO YEARS...



Most qualitative responses indicated a more sophisticated use of options.

ANALYTICAL TOOLS

WHICH OF THE FOLLOWING DO YOU UTILIZE IN DETERMINING WHEN AND HOW TO BUY?

1=Most Important. When not used, left blank.

Ranking	Analytical Tool	% Responding to Tool Type
1	Dollar Cost Averaging	93%
2	Historic Pricing	93%
3	Budget #s	63%
4	Fundamentals/Weather	59%
5	Private Forecasts	37%
6	Internal Price Forecasts	41%
7	Technical Analysis	48%

Response frequency for each analytical tool type is noted to demonstrate which areas have the most focus.

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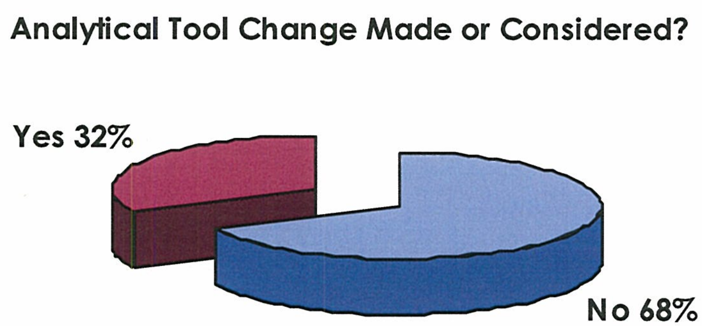
GIVEN ECONOMIC SITUATION, HAS THE ANALYTICAL TOOL BOX CHANGED OR IS CHANGE BEING CONSIDERED?



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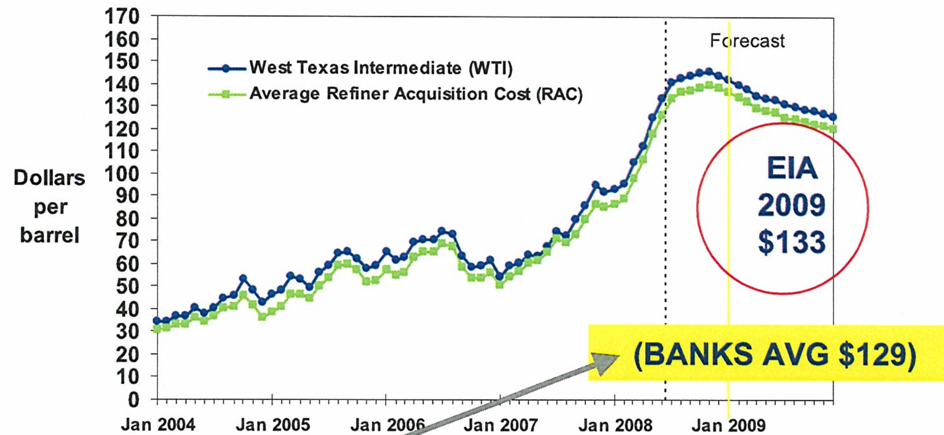
PREVIOUS 2009 CRUDE OIL PRICE FORECASTS

2009 CRUDE OIL PRICE FORECASTS – SELECT BANKS	2009 Crude Oil Price Forecast as of JUL 10TH, 2008	2009 Crude Oil Price Forecast as of NOV 26TH, 2008
Barclays	$123	$101
Citigroup	$123	$65
Credit Suisse	$110	$60
Fortis	$172	$73
Goldman Sachs	$148	$80
Merrill Lynch	$107	$90
Raymond James	$130	$90
Societe Generale	$129	$73
UBS	$120	$60
AVERAGE	$129	$77

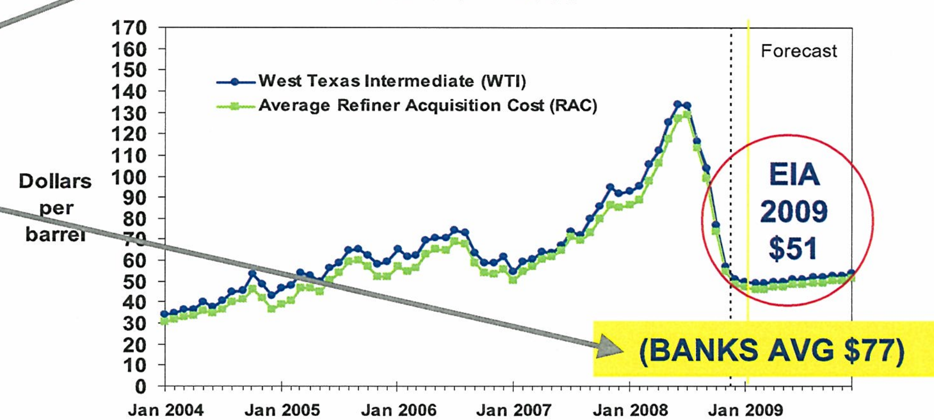
Source: Reuters

EIA AS OF JUL 08...



Short-Term Energy Outlook, July 2008

EIA AS OF DEC 08...

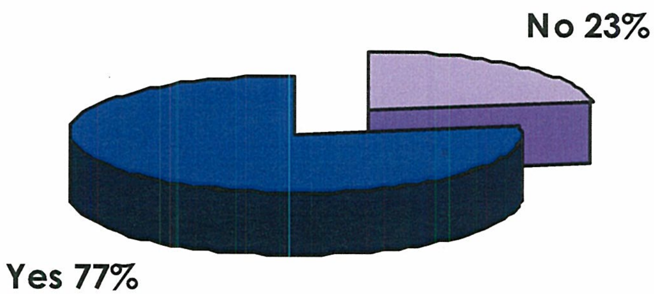


Short-Term Energy Outlook, December 2008

DISCRETION

IS THERE A DISCRETIONARY ELEMENT TO YOUR HEDGE PROGRAM IN REGARDS TO THE TIMING OF YOUR EXECUTION?

Timing Discretion in Plan?



WHAT DETERMINES WHEN DISCRETIONARY PURCHASES ARE MADE?

- ***Term coverage duration reviewed periodically under time parameters***
- ***Percentage coverage based on value compared to historic pricing***
- ***Timing of trade execution within the month is discretionary***
- ***Oversight Committee/Senior Management directives***
- ***Upcoming regulatory change that could impact the market***

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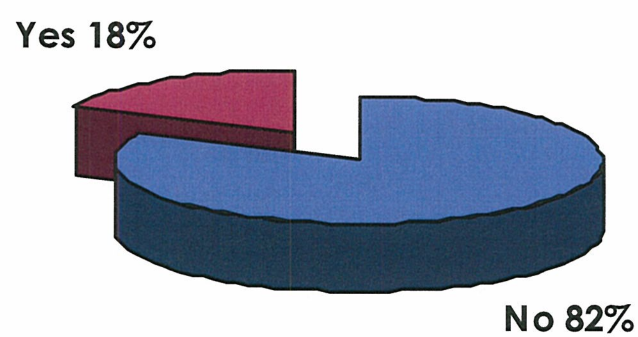
GIVEN ECONOMIC SITUATION, HAS THIS CHANGED OR IS CHANGE BEING CONSIDERED?

Timing Discretion Under Review?



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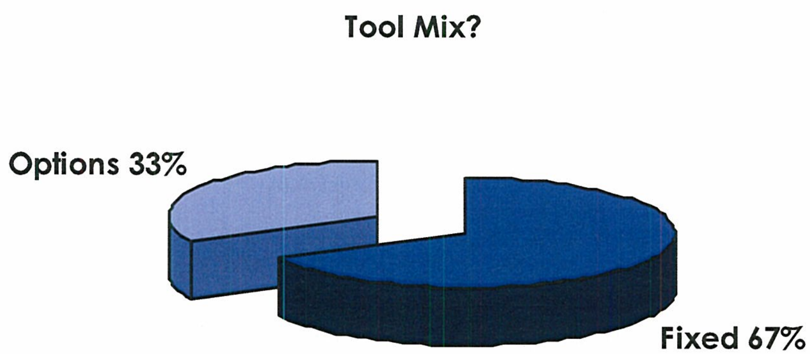
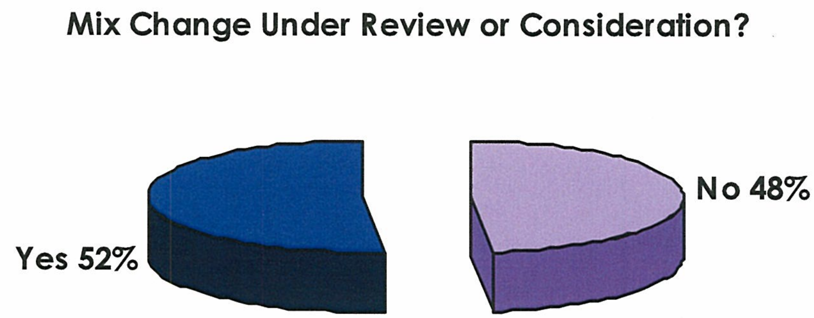
OPTIONS VS. FIXED CONTRACTS

TOOL MIX OVER THE LAST YEAR?



OPTIONS VS. FIXED CHANGED OR CHANGED BEING CONSIDERED?



COMMENTS TO NOTE:

MORE OPTIONS

- *More options to protect downside*

FEWER OPTIONS

- *During a period of increasing prices, options were more heavily utilized. Now, fixed hedges are almost 100%.*

CHANGES…

MORE OR LESS OPTIONS? DIFFERENT STRATEGIES?

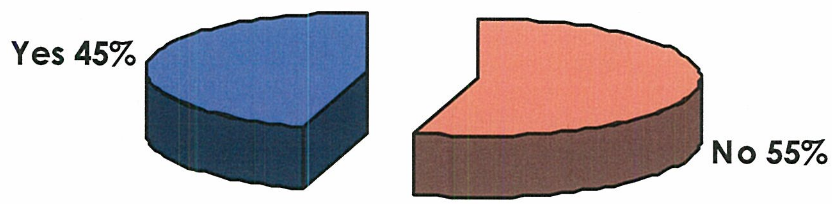
Almost 70% of respondents providing additional commentary noted the use of additional options products is under consideration.

A minority provided commentary on using more fixed pricing or swaps.

OPTION BUDGETS & PREMIUMS

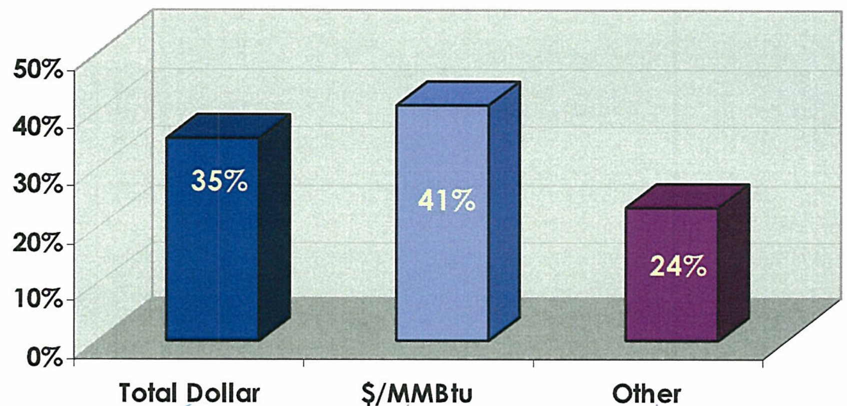
ESTABLISHED OPTION PREMIUM BUDGET?

Established Premium Budget in Place?



HOW IS YOUR OPTION PREMIUM BUDGET ALLOCATED?

Option Budget Structure



PERCENT OF TOTAL GAS COSTS

Only two quantified numbers in the 1%-1.25% of total gas cost range

PER MMBTU COST LIMIT

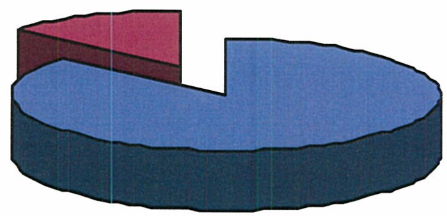
Only two quantified numbers in the premium range of $.30-$.50/Dth

OTHER

Two responded the amount is set by the Commission

PUT PURCHASES FOR STORED GAS

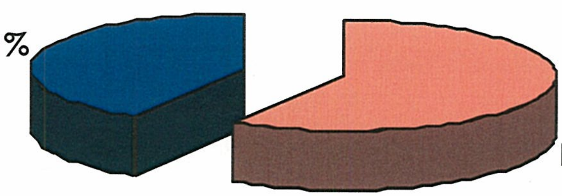
INTEREST IN BUYING PUTS AGAINST GAS IN STORAGE?



COMMENTS TO NOTE:

- *If gas stays where it is now, around $5.00 for 2009 Summer, it may be difficult to ask regulators to sign off a hedging strategy to protect $5.00 storage gas (it represents almost 50% reduction from last 2008 Summer)*
- *Company is showing a renewed interest*
- *Use spreads - hedge both injection and withdrawal at same time*

HAS YOUR UTILITY BENEFITED FROM HAVING HEDGING MECHANISMS THAT HAVE DOWN-SIDE PARTICIPATION IN THE MARKET, SUCH AS BUYING PUT OPTIONS?



IF YES, WHAT HAVE YOU DONE?

- *Structured deals such as 3 ways*
- *Purchased put positions*

CASH FLOW CONCERNS

CASH FLOW CONCERNS CAUSING YOU TO ALTER OR DISCUSS ALTERING YOUR PLAN?

Note: Response frequency for each practice change is noted to demonstrate the highest focused areas.

Ranking	Practice Change	% Responding to Potential Change
1	Revise Tools	42%
2	Revise Hedge Horizon	39%
3	Revise Volumes	32%
3	None	32%
4	Other	16%
4	Stop Hedging	16%
5	Unwind Hedges	13%

Other Responses:

- **Replace futures positions with options**
- **Eliminated discretionary hedging**

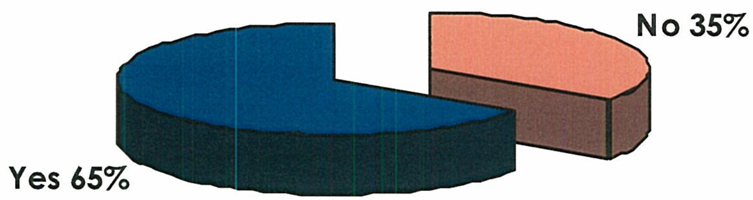
COMMENTS TO NOTE:

- ***Revised tools - increased options use***
- ***Increased hedge horizon***
- ***Decreased hedge horizon***
- ***Only hedged fixed price within credit threshold due to margining***
- ***De-emphasized futures due to margining***
- ***Increased OTC transactions with highly rated ISDA counterparties***

COUNTERPARTY CREDIT CONCERNS

ARE COUNTERPARTY CREDIT CONCERNS AND THE UNCERTAINTY IN THE BANKING INDUSTRY ALTERING YOUR TRADING IN PHYSICAL AND/OR FINANCIAL MARKETS?

Counterparty Credit Concerns Altered Trading Practices?



COMMENTS TO NOTE:

- *Increased physical hedging*
- *Increased counterparty quantity*
- *Become more selective with counterparties*
- *Selling puts primarily to suppliers with very high credit ratings*
- *Using 100% exchange traded products*

-57-

Note: Response frequency for each practice change is noted to demonstrate the highest focused areas.

Ranking	Practice Change	% Responding to Potential Change
1	Reduction in Counterparties	52%
2	Other	22%
3	Modify Hedge Plan	15%
4	None	11%
5	Change Contract Terms	7%
6	Unwind Hedges	4%
No Responses	Stop Hedging	0%

Other Responses:

- **Increased use of NYMEX and ICE Clearing**
- **Delay move to OTC bilateral trading**
- **More through the exchange**

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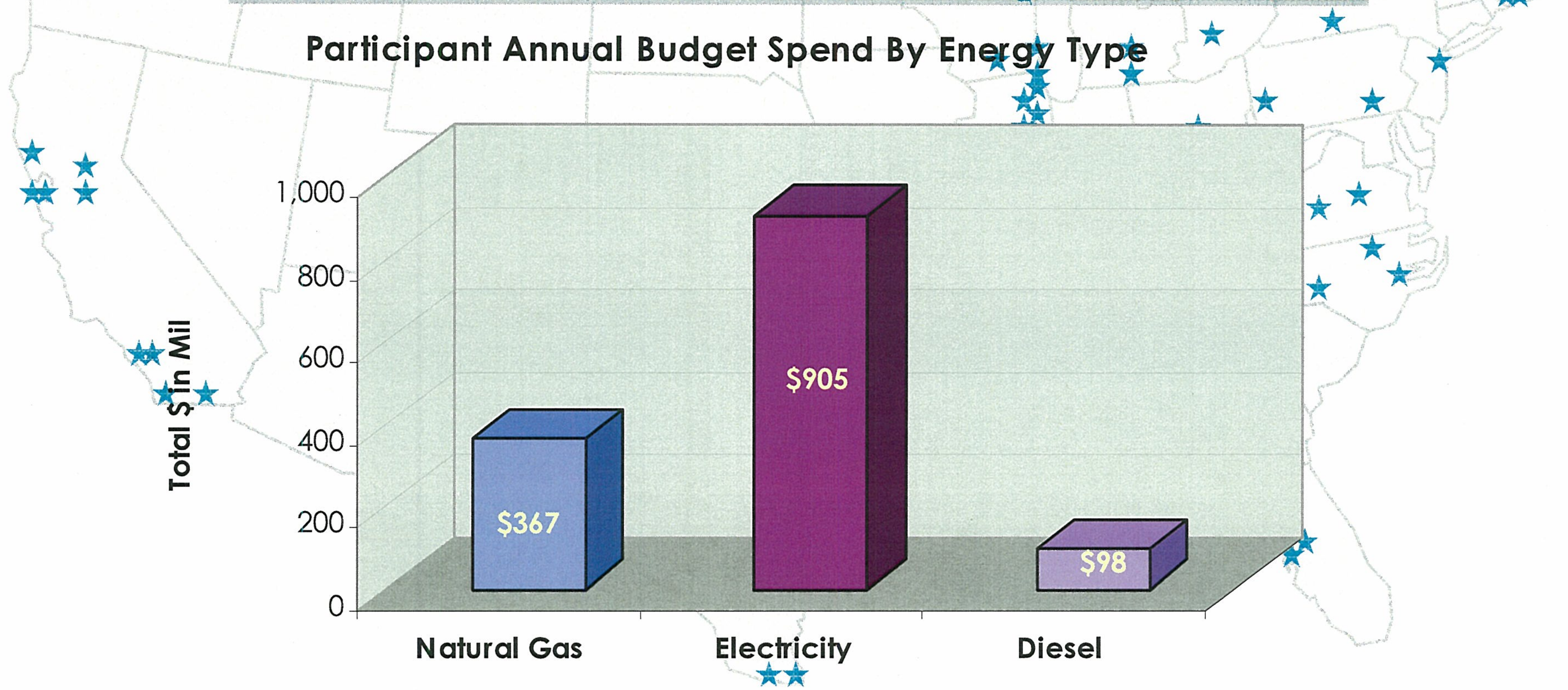
RMI
Commercial & Industrial Hedging Survey

RMI 2009 COMMERCIAL & INDUSTRIAL HEDGING SURVEY

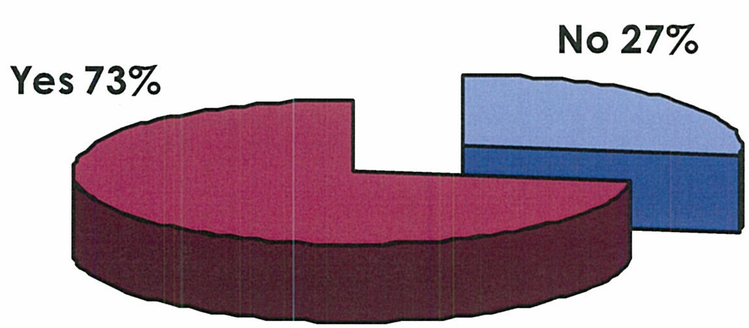
SURVEY CONDUCTED MARCH-APRIL 2009

The total $ spend represented by the survey respondent pool was the following by commodity type:



HEDGE PHILOSOPHY/PROGRAM CHANGES

MADE OR CONSIDERED ANY CHANGES TO YOUR HEDGING PHILOSOPHY/PROGRAM IN THE LAST 6 MONTHS IN RESPONSE TO THE ECONOMIC CRISIS?



Over 70% of respondents noted that their respective companies are either currently reviewing or considering the review of their hedge philosophy/program.

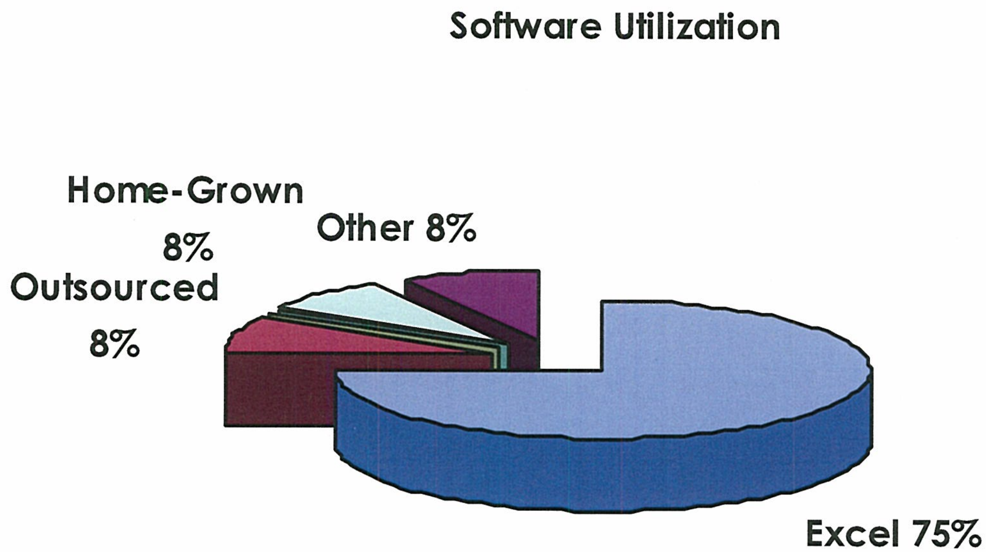
COMMENTS SUMMARY

- **57% More Hedging**
  Coverage Longer Term
- **29% Less Hedging**
  More exposed to spot market and hedging for shorter periods of time
- **14% In-Between**

COMMENT TO NOTE:
"Diesel Hedge Strategies"

TRACKING & REPORTING

WHAT ARE YOU USING FOR TRACKING AND REPORTING?



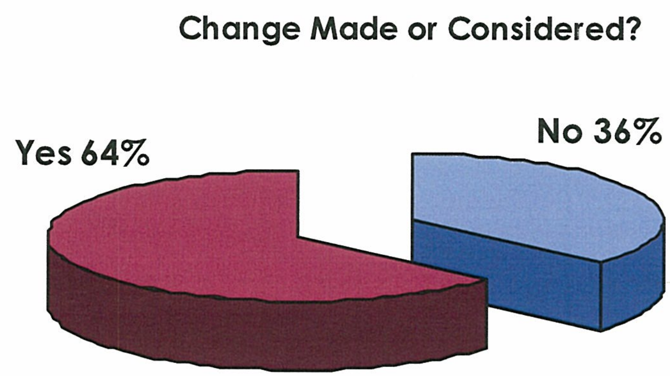
An overwhelming amount, 75% of respondents, currently rely on Excel to track and report hedge positions.

HEDGE HORIZON

LENGTH OF TIME IN ADVANCE THAT YOU MIGHT BEGIN TO HEDGE THE FOLLOWING ENERGY COMMODITY PRIOR TO A BUDGET YEAR?

	Natural Gas	Electricity	Diesel
Median	18	18	6
Average	18	20	9
High	48	48	18
Low	0	6	4

GIVEN THE RECENT ECONOMIC SITUATION HAS THIS TIMEFRAME CHANGED OR ARE YOU CONSIDERING A CHANGE?



While the majority of those who noted changes are under consideration or have been made pertained to hedge term increases, a minority indicated that a reduction in hedge horizon is the case.

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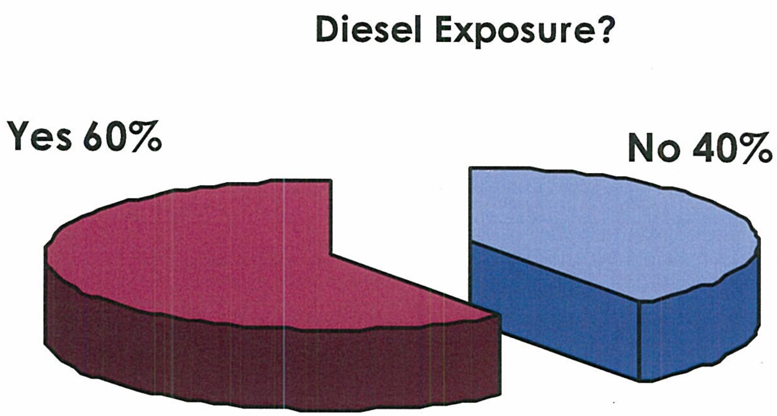
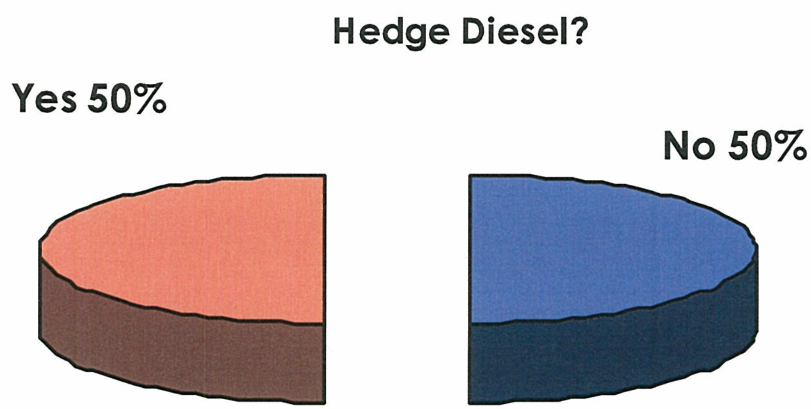
ON-HIGHWAY DIESEL

DIESEL FUEL EXPOSURE?

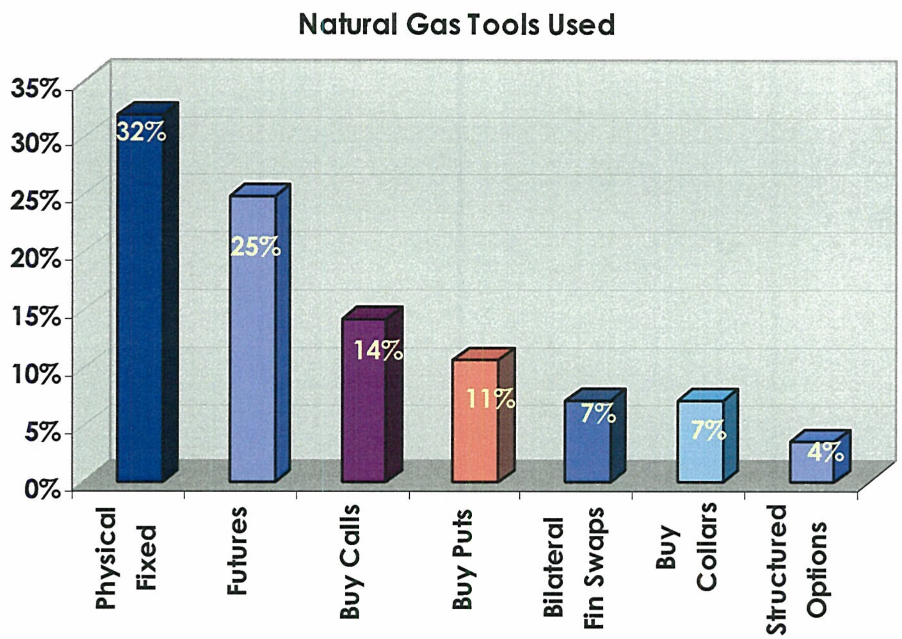


DO YOU HEDGE DIESEL FUEL EXPOSURE?

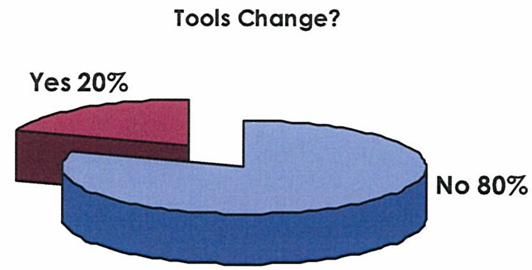


PHYSICAL AND FINANCIAL TOOLS

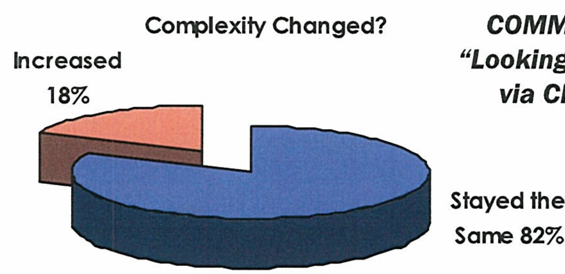
WHICH TOOLS CAN YOUR ORGANIZATION EXECUTE IN THE PHYSICAL OR FINANCIAL MARKETS FOR NATURAL GAS PROCUREMENT?



GIVEN THE RECENT ECONOMIC SITUATION, HAVE THE UTILIZED PRICING TOOLS CHANGED OR IS CHANGE BEING CONSIDERED?



HAS THE COMPLEXITY OF THE FINANCIAL PRODUCTS INCREASED, STAYED THE SAME, OR DECREASED IN THE LAST TWO YEARS?



COMMENT TO NOTE:
"Looking at new offerings via Clearport, etc."

ANALYTICAL TOOLS

WHICH OF THE FOLLOWING DO YOU UTILIZE IN DETERMINING WHEN AND HOW TO BUY?

1=Most Important. When not a factor, left blank

Analytical Tool	Ranking	% Responding
Budget Numbers	1	100%
Internal Price Forecast	2	55%
Historic Pricing	3	100%
Private Forecasts	4	55%
Fund/ Weather	5	73%
Tech Analysis	6	73%
$ Cost Avg	7	64%

Note–Response frequency for each analytical tool type is noted to demonstrate the highest focused areas.

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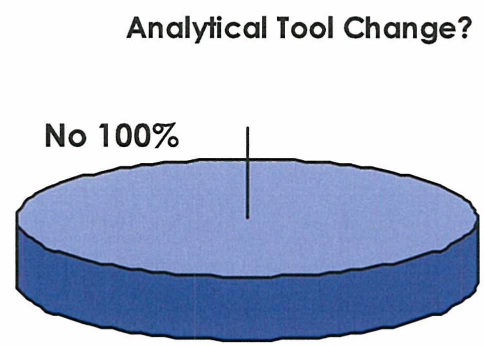
GIVEN THE RECENT ECONOMIC SITUATION HAS THE ANALYTICAL TOOL BOX CHANGED OR IS CHANGE BEING CONSIDERED?



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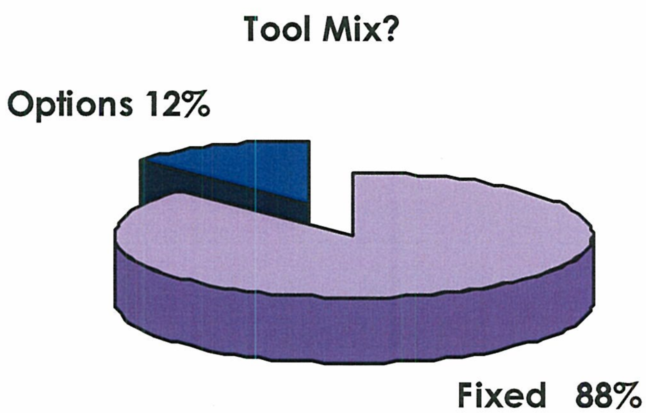
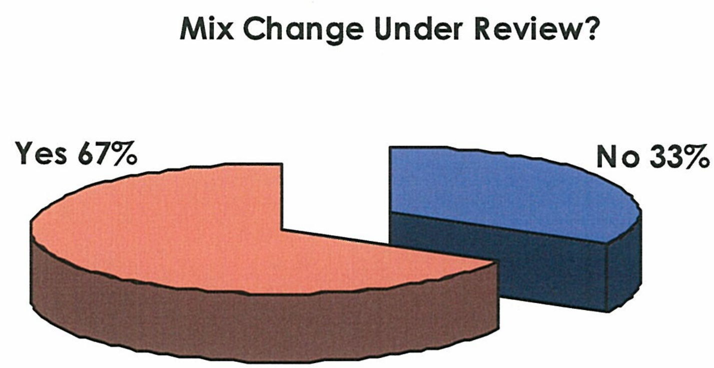
NATURAL GAS AND/OR DIESEL OPTIONS USE

WHAT HAS BEEN, OVER THE LAST YEAR, THE APPROXIMATE MIX OF OPTIONS AND FIXED PRICE IN YOUR PORTFOLIO?



GIVEN THE RECENT ECONOMIC SITUATION HAS THE USE OF OPTIONS VS. FIXED CONTRACTS CHANGED OR IS CHANGE BEING CONSIDERED?



- ✓ **Almost 70% of respondents providing additional commentary noted the use of additional options products is under consideration.**
- ✓ **A minority provided commentary on using more fixed pricing or swaps.**

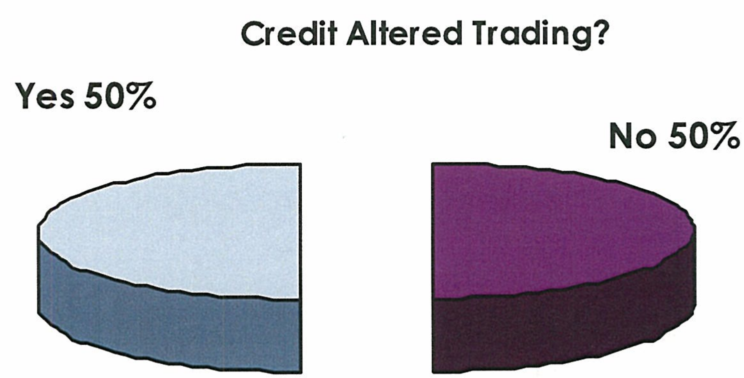
CASH FLOW AND CREDIT ISSUES

GIVEN THE CURRENT ECONOMIC CRISIS, ARE CASH FLOW CONCERNS CAUSING YOU TO ALTER OR DISCUSS ALTERING YOUR PLAN?

Ranking	Practice Change	% Responding to Potential Change
1	None	64%
2	Revise Hedge Horizon	27%
3	Revise Tools	27%
3	Stop Hedging	27%
4	Revise Volumes	18%
4	Unwind Hedges	9%
5	Other	9%

Note–Response frequency for each practice change is noted to demonstrate the highest focused areas.

ARE COUNTERPARTY CREDIT CONCERNS AND THE UNCERTAINTY IN THE BANKING INDUSTRY ALTERING YOUR TRADING IN PHYSICAL AND/OR FINANCIAL MARKETS?



Northern Utilities, Inc.

CASH FLOW AND CREDIT CONCERNS

IF YOU HAVE CHANGED YOUR TRADING PRACTICES DUE TO COUNTERPARTY CREDIT CONCERNS, HOW HAS YOUR TRADING BEEN ALTERED?

Other Responses:

- **Fewer suppliers willing to offer long term deals**
- **Supplier concern with our credit**

Ranking	Practice Change	% Responding to Potential Change
1	Reduction in Counterparties	60%
2	Change Contract Terms	40%
3	Other	40%
4	Modify Hedge Plan	20%
No Responses	Unwind Hedges	0%
No Responses	Stop Hedging	0%
No Responses	None	0%

Note–Response frequency for each analytical tool type is noted to demonstrate the highest focused areas.

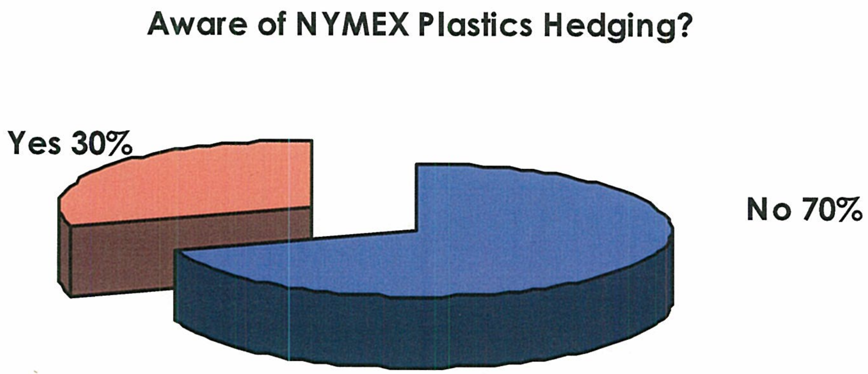
COMMENTS TO NOTE:

- ***We are finding that more suppliers are asking for either cash deposit or letter of credit. It is limiting the suppliers that we are willing to work with.***
- ***We're looking specifically at credit assurance language and only trading with large suppliers.***

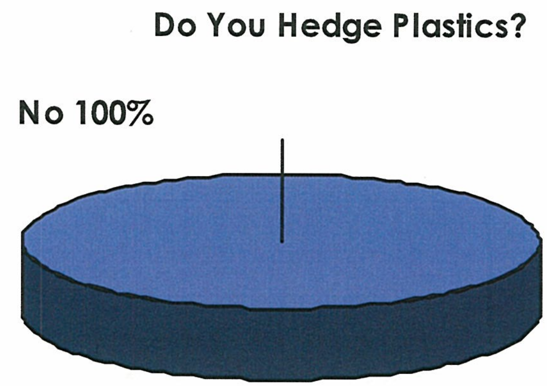
RMI

PLASTICS & GREEN POWER

ARE YOU AWARE NYMEX OFFERS PLASTICS (POLYPROPYLENE AND POLYETHYLENE) FUTURES FOR HEDGING?



HAVE YOU HEDGED FINANCIAL PLASTICS PRODUCTS?



HOW MUCH DOES YOUR COMPANY SPEND VOLUNTARILY ON GREEN POWER?

The range provided of those who do was between $100,000 and $7 mil, anywhere from .3% of spend to 5%.

HAS YOUR COMPANY TRIED TO COMPUTE AN EXPOSURE TO A CARBON TAX?

Only one respondent of the pool has tried to compute this exposure.

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Date Request Received: 11/30/09 **Date of Response: 12/23/09**

Request No. Staff 2-12 **Witness: Robert S. Furino**

Request: Hedging Cost for Customers Switching to Transportation Service

For each summer and winter period that the hedging program has been in place, please provide total throughput, throughput for firm sales, throughput for transportation and the percentages for each.

Response:

Attachment 2-12 lists system throughput, throughput for firm sales and throughput for transportation in the New Hampshire division for each summer and winter period that the hedging program has been in place, and the percentages of each. During the full history, transportation represents 31 percent of winter throughput and 58 percent of summer throughput.

Northern Utilities, Inc.
Total System Throughput, Throughput for Firm Sales and for Transportation, NH Division

	(a)	(b)	(c)=(b)/(a)	(d)=(a)-(b)	(e)=(d)/(a)
Season	Total System Throughput	Throughput for Firm Sales	Firm Sales Throughput as PCT of System Throughput	Throughput for Transportation	Transportation Throughput as PCT of System Throughput
Winter 02/03	4,984,249	4,100,384	82%	883,865	18%
Summer 2003	1,934,174	964,808	50%	969,366	50%
Winter 03/04	5,030,342	3,778,110	75%	1,252,232	25%
Summer 2004	1,924,857	919,128	48%	1,005,729	52%
Winter 04/05	4,888,725	3,620,933	74%	1,267,792	26%
Summer 2005	2,026,859	940,083	46%	1,086,776	54%
Winter 05/06	4,658,418	3,333,146	72%	1,325,272	28%
Summer 2006	2,207,245	933,899	42%	1,273,346	58%
Winter 06/07	5,118,578	3,194,651	62%	1,923,927	38%
Summer 2007	2,193,056	787,513	36%	1,405,543	64%
Winter 07/08	5,223,878	3,140,543	60%	2,083,335	40%
Summer 2008	2,077,706	780,671	38%	1,297,035	62%
Winter 08/09	5,090,192	3,047,157	60%	2,043,035	40%
Summer 2009	2,016,328	761,216	38%	1,255,112	62%
Winter AVG	4,999,197	3,459,275	69%	1,539,923	31%
Summer AVG	2,054,318	869,617	42%	1,184,701	58%

Date Request Received: 11/30/09 **Date of Response: 12/23/2009**

Request No. Staff 2-13 **Witness: Robert S. Furino**

Request:

For each summer and winter period that the hedging program has been in place, please provide the amount and percentage of hedging gains/losses associated with the change in throughput.

Response:

Hedging gains and losses occur under the hedging program regardless of throughput levels and customer migration activity. I believe the question intends to ask how customer migration has impacted the allocation of financial gains and losses between residential and commercial and industrial customers, much like ODR-1 from the peak season cost of gas proceeding, DG 09-167. The Company establishes the volumes to hedge for each season well in advance of actual deliveries. When actual volumes come in differently than planned, the impact of hedging will vary since the gains or losses are allocated to higher or lower volumes. When firm sales are higher than expected, the impact of hedging is diluted, and when firm sales are lower than expected, the impact is increased. The level of throughput and firm sales can change due to weather conditions, economic conditions, conservation and customer migration. As with ODR-1 in DG 09-167, this response focuses on changes in firm sales due to the impact of incremental customer migration from one year to the next.

Attachment 2-13 provides a table showing hedging gains and losses for the New Hampshire division and the impact of customer migration on the allocation of those gains and losses between residential and commercial and industrial customers. The dollar amount and percentage of the reallocated gains and losses are reported for each summer and winter period since the program has been in place.

Please note that an error was found in the calculation provided in ODR-1 in DG 09-167: the Maine division allocators were used rather than the New Hampshire division allocators. The additional financial hedging loss due to incremental customer migration during the winter of 2008/09 was $47,143 rather than $39,124.

Attachment 2-13

Northern Utilities, Inc.
Impact of Migration on Allocation of Financial Hedging Gains/(Losses)
New Hampshire Division

Season	NH Div. Hedging Gain/(Loss)	Impact of Migration on Allocation of Gains/(Losses): Residential	Impact of Migration on Allocation of Gains/(Losses): Commercial & Industrial	Percentage Impact of Migration on Allocation of Gains/(Losses): Residential	Percentage Impact of Migration on Allocation of Gains/(Losses): Commercial & Industrial
Winter 02/03	$ 747,213	$ 12,426	$ (12,426)	1.7%	-1.7%
Summer 2003	$ 54,455	$ 2,875	$ (2,875)	5.3%	-5.3%
Winter 03/04	$ 186,423	$ (1,110)	$ 1,110	-0.6%	0.6%
Summer 2004	$ 256,739	$ (241)	$ 241	-0.1%	0.1%
Winter 04/05	$ 711,504	$ 4,284	$ (4,284)	0.6%	-0.6%
Summer 2005	$ 1,250,387	$ 15,417	$ (15,417)	1.2%	-1.2%
Winter 05/06	$ 1,106,890	$ 2,986	$ (2,986)	0.3%	-0.3%
Summer 2006	$ (712,200)	$ (12,536)	$ 12,536	1.8%	-1.8%
Winter 06/07	$ (1,694,155)	$ (30,670)	$ 30,670	1.8%	-1.8%
Summer 2007	$ (331,527)	$ (12,672)	$ 12,672	3.8%	-3.8%
Winter 07/08	$ (189,643)	$ (3,894)	$ 3,894	2.1%	-2.1%
Summer 2008	$ 354,800	$ 4,060	$ (4,060)	1.1%	-1.1%
Winter 08/09	$ (2,875,319)	$ (47,143)	$ 47,143	1.6%	-1.6%
Summer 2009	$ (1,861,155)	$ (102,348)	$ 102,348	5.5%	-5.5%