Andrew S. Marcaccio, Counsel
PPL Services Corporation
AMarcaccio@pplweb.com

280 Melrose Street
Providence, RI 02907
Phone 401-784-7263

Rhode Island Energy™
a PPL company

September 25, 2024

VIA ELECTRONIC MAIL AND HAND DELIVERY

Stephanie De La Rosa, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket No. 24-20-EL - The Narragansett Electric Company d/b/a Rhode Island Energy's 2025 Last Resort Service Procurement Plan <u>Responses to CLF Data Requests – Set 1 (Complete Set)</u>

Dear Ms. De La Rosa:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), enclosed please find the Company's responses to the First Set of Data Requests issued by the Conservation Law Foundation ("CLF") in the above-referenced matter.

This transmittal contains the Company's response to CLF 1-2 and completes the Company's responses to CLF Set 1.

Thank you for your attention to this matter. If you have any questions, please contact me at 401-784-4263.

Sincerely,

Andrew S. Marcaccio

Enclosures

cc: Docket No. 24-20-EL Service List

CLF 1-1

Request:

Referring to testimony on pages 13 in response to the question to give a general overview of LRS procurement plan from 2023, witnesses state that "[b]ecause it is effective in mitigating price volatility in all market environments, the Company is not proposing changes to a laddered and layered FRS procurement approach in the 2025 LRS Plan."

a. Is mitigation of price volatility the primary purpose of this procurement strategy?

b. Are there any other public policy goals, PUC precedent, or other regulatory or statutory requirement that the Company is seeking to meet by utilizing the laddered and layered approach?

Response:

a. The mitigation of price volatility is a primary purpose of the procurement strategy. It would add risk to procure the entire load period for Last Resort Service customers into only one purchase. To draw a comparison as an example, procuring energy with a single purchase could be considered analogous to having one stock or security in a personal retirement account. To mitigate this risk in a retirement account it is common practice to hold mutual funds with multiple securities to diversify risk. This is the same concept as the laddered and layered procedure in the energy markets.

b. Rhode Island General Laws §§ 39-1-27.3 and 39-1-27.8 requires Rhode Island Energy to arrange for power supply for customers who are not otherwise receiving electric service from a Non-Regulated Power Producer (NPP). Pursuant to R.I. Gen. Laws § 39-1-27.3(c), the Company must file a supply procurement plan with the PUC that includes the procurement procedure, the pricing options being sought, and a proposed term of service for which LRS will be acquired. All components of the procurement plan are subject to the PUC's review and approval. While there may not be legal limitations on utilizing only a laddered and layered strategy, this strategy lowers risk and volatility and has historically achieved lower rates versus peer utilities.

Prepared by or under the supervision of: Jonathan Bausch

CLF 1-2

Request:

On pages 13-14 of testimony, witnesses describe the different pricing options available for Commercial customers taking LRS, the "Fixed Price Option" and the "Variable Price Option."

a. Does the company maintain NAICS codes of the commercial customers that chose each option? If so, please provide a breakdown of which NAICS codes are represented in each pricing option and the number of entities that identify under each code in each pricing option.

b. Please provide a statistical breakdown of the electric load for customers in each pricing option -- including at least the mean load, median load, and a standard deviation within each pricing option -- for calendar years 2021, 2022, and 2023.

c. Please provide any other analysis that the Company has done with respect to types of commercial customers that select each pricing option, e.g. geographic breakdown, non-profit vs. for-profit customers, etc.

Response:

a. Yes, please see the Excel version of Attachment CLF 1-2. Please note, the data is limited to the information that was input previously by National Grid.

b. Please see below. The Company would need additional time to scrub and validate the data; however, it believes the data represents a fair estimated breakdown.

Commercial Fixed Price Customers			
Year	Mean Monthly kWh	Median Monthly kWh	Standard Deviation
2021	42,435,965	41,717,913	1,234,144
2022	46,920,057	45,337,658	1,605,160
2023	37,135,939	35,947,929	1,473,891

Prepared by or under the supervision of: Jonathan Bausch

CLF 1-2, page 2

Commercial Variable Price Customers			
Year	Mean Monthly kWh	Median Monthly kWh	Standard Deviation
2021	38,500,802	38,501,694	7,847,236
2022	35,944,114	34,865,156	9,288,067
2023	29,078,833	28,474,730	8,103,916

b. The Company has not completed any other analysis in respect to the types of commercial customers that select each pricing option.

Prepared by or under the supervision of: Jonathan Bausch

CLF 1-3

Request:

On page 17 of testimony, witnesses do a retrospective analysis of the financial impact of increasing the spot market purchase by 5%. They indicate that "…there were periods of volatility in the spot market vs. FRS…" Can you explain what is meant by volatility between these two price points? Additionally, please provide any analysis done as to the cause(s) of this volatility.

Response:

Periods of volatility between the spot market vs. FRS means that there were periods where the spot market outperformed FRS, and there were periods where FRS outperformed the spot market. However, the trend over time was that spot market procurements were lower. There was not an analysis per say directed towards the cause of volatility. Volatility is inherent in the energy market. The Excel version of the analysis is provided as Attachment CLF 1-3 which contains the breakout of the FRS and Spot rate components on the 'Spot Market Increase' and 'RIPUC Source Data' tabs.

CLF 1-4

Request:

With respect to the retrospective analysis that is represented in the Figures 1 through 4 – Corrected:

a. Why was 2016 used as a starting point in the analysis?

b. Wouldn't it be a more logical data point to start with the 2023 LRS Procurement Plan (Docket 22-02-EL) which was the first plan over which PPL exercised control over Narragansett Electric's operations?

c. Please provide the formula used to determine the "Cumulative Spot Savings" that is represented by the dotted red line in Figure 1 - Corrected.

d. Please provide the formula used to determine the "FRS Block Chage Cumulative Savings" that is represented by the dotted blue line in Figure 3- Corrected.

Response:

a. 2016 was an appropriate year because it allowed for the consideration of the lower market conditions prior to 2021, and the subsequent higher market conditions of 2022 - 2023. The reason for the differing markets is largely related to natural gas supply constraints.

b. Examining different circumstances and time periods when analyzing energy markets can be beneficial for different reasons. Consideration of the 2023 plan is included in the analysis, albeit perhaps not specifically called out. Nevertheless, because it takes almost two years to complete the procurements for one rate period, it was beneficial to show a longer period.

c. Please see the 'Summary Data' tab on Excel Attachment CLF 1-3.

d. Please see the 'FPR Savings' tab on the Confidential Excel Attachment Division 1-6-1.

Prepared by or under the supervision of: Jonathan Bausch

CLF 1-5

Request:

On page 18 of testimony witnesses indicate that keeping 85% of energy procurement "…via FRS transactions and quarterly auctions serve as risk mitigation against market volatility."

a. Please confirm CLF's understanding that the risk being mitigated is market volatility.

b. What motivates the Company to mitigate against this risk, i.e. is it public policy in statute, is there a PUC precedent, or is there some other guidance as to why this risk needs to be mitigated?

Response:

a. Confirmed. Volatility risk is being mitigated via the procurement methodology.

b. R.I. Gen. Laws § 39-1-27.3 states that the Company is required to provide Last Resort Service and that the PUC has the authority to approve or reject the rates based on what's best in the public interest. In addition, please see CLF Attachment 1-5, which contains the findings of the Northbridge Report from 2010. It was determined that a 100% spot market would expose mass market customers to significant rate volatility. Also, it was determined that a managed portfolio and full requirements products would reduce customers' exposure to rate volatility. Though 2010 was approximately 14 years ago, the inherent energy market volatility that existed then still exists.

Prepared by or under the supervision of: Jonathan Bausch

nationalgrid

Thomas R. Teehan
Senior Counsel

January 22, 2010

VIA HAND DELIVERY & ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02889

RE: Docket 4041: Standard Offer Service Procurement Plan Compliance Filing

Dear Ms. Massaro:

On behalf of National Grid,[1] I am filing ten copies of the Company's report regarding its review and analysis of procurement methods for Rhode Island. This filing consists of the report as well as supporting analysis as attachments. This filing is made in compliance with the Commission's direction in Commission Order 19839 that the Company file a report regarding the Company's review of procurement options and discussing the relative merits of a managed portfolio approach and an FRS approach including a comparison of gas and electric procurement activities and also including an analysis of administrative cost considerations. The Company intends to incorporate the results of this supply procurement analysis as it attempts to balance the relative strengths and weaknesses of the various procurement methods in fashioning a recommended approach for Commission consideration in the Company's upcoming Standard Offer Service filing on March 1, 2010.

Thank you for your attention to this transmittal. If you have any questions, please feel free to contact me at (401) 784-7667.

Very truly yours,

Thomas R. Teehan

Enclosure

cc: Docket 4041 Service List
Leo Wold, Esq.
Steve Scialabba, Division

[1] National Grid d/b/a Narragansett Electric Company ("National Grid" or "Company")

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

RHODE ISLAND PUBLIC UTILITIES COMMISSION

National Grid Standard Offer Service Procurement Plan	Docket No. 4041

NATIONAL GRID'S REPORT REGARDING ITS COMPREHENSIVE REVIEW OF STANDARD OFFER SERVICE PROCUREMENT STRATEGIES

National Grid [1] submits this report in compliance with Commission Order #19839 regarding its comprehensive review of Standard Offer Service procurement strategies.

Introduction

During the course of this docket, the Rhode Island Public Utilities Commission ("Commission") has prompted, and the parties have begun to engage in, a discussion regarding the advisability of a transition to a fully managed portfolio approach ("MPA") to procure energy supply for mass market customers (residential and small commercial). The Company indicated that it would conduct a review and analysis of its procurement methods in Rhode Island, taking into account its experience with different procurement methods in its affiliates' service territories, to determine the best procurement approach for its customers. As part of its analysis, the Company also considered the balance between the key goals associated with Standard Offer Service, including rate stability and

[1] The Narragansett Electric Company d/b/a National Grid hereinafter referred to as "National Grid" or "Company."

low rate level. This report summarizes the analysis of various procurement approaches and is responsive to the following inquiries, as ordered by the Commission:

(1) an assessment of the comprehensive review;

(2) empirical proof of savings of the managed portfolio approach or the full requirements service ("FRS") approach;

(3) the merits or lack thereof of a managed portfolio approach;

(4) an in-depth, detailed comparison of procurement of natural gas and electricity, reviewing symmetries and differences that might drive different policy approaches for each commodity; and

(5) an administrative cost analysis.

1. Assessment of the comprehensive review

The Company has completed an extensive study of procurement approaches, from which the strengths and weaknesses of the different approaches can be evaluated and insights can be developed. The Company engaged The NorthBridge Group ("NorthBridge"), a consulting firm with extensive expertise regarding electricity market pricing and standard offer service procurement, in order to assist with the comprehensive review of procurement approaches for Standard Offer Service for mass market customers. Specifically, NorthBridge analyzed the costs and risks associated with various procurement approaches. NorthBridge's quantitative analysis utilized a Monte Carlo simulation approach to replicate market uncertainty based on actual market data, including the prices for many different standard offer service products recently solicited by different utilities. Exhibit A is a presentation of the NorthBridge analysis as it relates to Rhode Island. Each procurement approach was evaluated using various metrics that pertain to objectives with respect to Standard Offer Service, including expected rate level, supply cost surprise, and rate volatility. Numerous portfolio approaches were reviewed, but three representative approaches were identified in order to illustrate conclusions drawn from NorthBridge's analysis:

(a) "Spot" Procurement: 100% spot market purchases;

(b) "Full Requirements" Product Procurement: 100% full requirements contracts (one-year contracts, half procured every six months); and

(c) "Block and Spot" Managed Portfolio: Targeted procurement quantities consisting of 25% spot market purchases, and 75% fixed-price predetermined-quantity (i.e., "block") contracts (equally split into 6-month, 2-year and 4-year contracts).

2. Empirical proof of savings of the MPA or FRS approach

As discussed above, the NorthBridge analysis is based on actual market data, rather than conjecture about the relative merits of various procurement approaches; therefore, it represents empirical evidence of the relative benefits of different procurement approaches. Furthermore, the analysis involves a comparison of standard offer service approaches against several metrics that pertain to various objectives with respect to Standard Offer Service, and therefore allows for an assessment of the tradeoffs with respect to key objectives, such as rate stability and low rate level.

The NorthBridge analysis indicates that the expected standard offer service rate under the Spot Procurement approach would be about \$2-3/MWh lower than the expected rate under different procurement approaches, but that the Spot Procurement approach would expose mass market customers to high levels of unexpected changes in supply costs, on the order of \$26/MWh on average in the top 10% of market scenarios. By comparison, the "Block and Spot" Managed Portfolio approach involves an expected standard offer service rate that is about \$2/MWh higher than under the Spot Procurement approach, but the level of supply cost uncertainty is cut significantly, to about \$10/MWh on average in the top 10% of market scenarios. Finally, the Full Requirements Product approach involves an expected standard offer service rate that is about \$1/MWh higher than under the "Block and Spot" Managed Portfolio approach, but the level of supply cost uncertainty is about \$3/MWh on average in the top 10% of market scenarios, which is much lower than the supply cost uncertainty value associated with the "Block and Spot" Managed Portfolio approach.

3. Discussion of the merits or weaknesses of a managed portfolio approach

The managed portfolio approach has advantages with regards to the inclusion of spot market purchasing. The Company believes that the utility should stay engaged in the power markets in order to provide the least cost supply that maintains rates within a reasonable degree of volatility. This level of engagement in the energy markets can be achieved by the Company's conducting some level of spot purchases through the ISO-NE, as it is doing currently since January 1, 2010. This direct involvement in the power markets also allows the Company to retain the ability to purchase replacement power in the event of a supplier default.

As indicated above, however, an approach that is entirely reliant upon purchases from the spot market involves a level of supply cost uncertainty (on a $/MWh basis) that is arguably too large for mass market Standard Offer service customers. The "Block and Spot" managed portfolio involves much less supply cost uncertainty, because the purchased structured products help to reduce the risks associated with spot market purchases, but this comes at a higher expected rate. On the other hand, a procurement approach based solely on full requirements products significantly reduces the supply cost uncertainty as compared to the "Block and Spot" approach. This reduction in supply cost uncertainty results because full requirements suppliers are responsible for assuming, managing, and covering costs and risks (such as those associated with customer migration, transmission congestion, usage patterns, changes in laws and regulations, etc.), rather than leaving these risks to be managed by the Company on behalf of customers and exposing customers to the uncertain supply costs incurred by the Company. Although the full requirements product approach involves a higher expected rate, the analysis shows that the difference in the expected rate under the full requirements product approach versus under the "Block and Spot" approach is small (i.e., about $1/MWh). In summary, the higher costs for full requirements products was found to be relatively small compared to the lower supply cost uncertainty and therefore added value for mass market customers.

4. Comparison of procurement of natural gas and electricity

The following section reviews the symmetries and differences that might drive different policy approaches for natural gas and electricity commodity. The differences in the gas and electric procurement activities performed by the Company are attributable to the differences in their respective wholesale markets. There are two key differences that affect the Company's procurement practices for these two commodities. First, the ability to store gas commodity is a key difference from electric commodity and changes the procurement approach. Second, electric wholesale markets are administered by regional Independent System Operators ("ISOs") that ensure the day-to-day reliable operation of the region's bulk power generation and transmission system, by overseeing and ensuring the fair administration of the region's wholesale electricity markets, and by managing comprehensive, regional planning processes. Due to the existence of the ISO, the Company's role is to engage in electricity purchases that balance competing concerns, such as rate stability and low rate level. By comparison, in the natural gas market, there is no analog to the ISO, so the Company's role also directly involves ensuring sufficient gas transmission capacity, storage, and peak supplies.

A. Description of the Rhode Island Gas Portfolio

The fundamental goal of the Company's gas supply planning process is to ensure that there are adequate gas supplies to reliably meet the needs of customers under design winter conditions. In order to meet the load requirements under such conditions, the Company maintains a resource portfolio consisting of supply contracts, pipeline transportation, underground storage and peaking resources. In addition to pipeline capacity, the Company relies on underground storage capacity to meet fluctuations in customer requirements throughout the winter season. Similarly, peaking resources are used to meet winter requirements not met by pipeline and underground storage resources. Peaking resources are composed of both third-party delivered supplies as well as the Company's on-system liquefied natural gas ("LNG") facilities. In addition to serving as a supply source, the on-system LNG facilities are a critical resource used to meet hourly load fluctuations and to balance pressures across portions of the distribution system during periods of high demand.

In addition, the Company manages the gas supply cost to Rhode Island customers through a hedging program. The Company is required to hedge 60% of forecasted normal weather gas purchases for April and October and 70% of the forecasted purchases the remaining ten months. These are mandatory hedge volumes which are a regulatory requirement of the Gas Procurement Incentive Plan. In addition to the mandatory purchases the Company is required to hedge incremental discretionary volumes.

The management of the gas supply portfolio provides opportunities to optimize the value of the assets when they are not being fully utilized to meet customers' peak demand. The value derived from these optimization efforts is shared between the customers and the Company.

B. Comparison of Gas to the Electric Portfolio

Unlike the gas business, long-term electric supply adequacy is the responsibility of the regional ISO and not that of the individual utility. The ISOs address this requirement by ensuring that there is adequate generation capacity and interconnecting markets that can meet the potential demand. It is the responsibility of the New England ISO ("ISO-NE") to determine the installed capacity requirements for the New England region, which includes Rhode Island. The ISO-NE is also responsible for the administration of comprehensive regional system planning processes to identify reliability needs, consider and evaluate potential solutions, and establish market rules for ensuring resource adequacy. National Grid, on behalf of its affiliates, is active in these planning processes. In contrast, as noted, the natural gas market involves no regional ISO or Regional Transmission Organizations, and thus reliability is the primary concern of the individual utility, which must acquire all resources in order to meet customer requirements.

In summary, there are two primary goals for the gas supply portfolio. First, on the delivery side, the goal is to reliably meet the design load requirements in a least-cost manner with a portfolio of resources including transmission capacity, storage assets and peaking supplies. The second goal is to reduce monthly volatility while providing the customer with low monthly gas supply costs. On the electric side, the Company has the primary goal of providing Standard Offer Service mass market customers with a supply portfolio that balances the level and volatility of rates, striving to keep both as low as can be reasonably achieved, consistent with the directive of least-cost procurement.

5. Administrative Cost Analysis

It is National Grid's experience that certain characteristics of a supply portfolio will drive the overall administrative costs, such as solicitation frequency and the regulatory approval process. On the other hand, portfolio size and contract types are minor drivers of administrative costs (i.e., there is no difference in administrative costs to conduct solicitations for full requirements versus block contracts). More resources may be required for specific aspects of the supply portfolio, such as:

- Increased quantity of contracts (i.e., how many contracts are layered in each month);
- Increased variation in the type of contracts (i.e., all one type or a mixture of products);
- Performing load bidding into the ISO for any portion of specific customer groups;
- The frequency of the solicitations, as well as conducting the solicitation separately from other National Grid distribution company solicitations; and
- The frequency of regulatory approvals (i.e., are individual contracts approved or are the final retail rates approved).

These characteristics not only increase the efforts required by the Electric Supply staff to procure Standard Offer Service, but will also increase the labor costs associated with the support necessary from accounting and risk management staff. In addition, increased uncertainty in cost recovery and prudency reviews would require more legal and regulation-related staff activity, as well as increased senior management involvement.

The range in administrative costs could vary significantly depending on the procurement approach. Table A, Estimation of Standard Offer Service Administrative Costs, shows the estimated annual costs of labor and supervision associated with administering various supply portfolios. The administrative costs for procuring Standard Offer Service under a FRS approach, based on semi-annual solicitations for FRS contracts, are estimated to be $340,000, or $0.055/MWh on a unitized basis (using the estimated 2010 deliveries related to Standard Offer Service of 6,200 GWh). Table A also shows a preliminary estimate for the administrative cost associated with a Block and Spot managed portfolio approach for mass market customers. This managed portfolio would include spot purchases (ISO-NE load bidding) and quarterly solicitations for block contracts, in addition to monitoring and reporting. The estimated costs of $450,000, or $0.072/MWh on a unitized basis, also include an increased level of activity required from support staff.

Table A

Estimation of Standard Offer Service Administrative Costs

Different procurement approaches	Annual administrative cost estimate	Unitized cost per MWh
FRS approach	$340,000	$0.055
“Block and Spot” MPA approach	$450,000	$0.072

Conclusion

The Company, with the assistance of an experienced electric-market consulting firm, has completed an analysis of the various procurement methods available for obtaining electric supply for the Rhode Island mass market customers. This analysis has addressed the dual procurement goals of commodity cost and cost volatility. The Company also considered procurement methods that would best allow for continued or increased Company engagement in the energy markets.

As a general statement, the spot market approach produced the lowest expected supply rate while the FRS approach best controlled price volatility. However, the increase in expected supply rates for FRS products was relatively small as compared to the MPA or even to the spot approach, particularly when considering the much lower supply cost uncertainty. The Company also determined that spot market purchasing is effective in continuing to keep the Company engaged in the energy markets. The Company intends to incorporate the results of this supply procurement analysis as it attempts to balance the relative strengths and weaknesses of these procurement methods in fashioning a recommended approach for Commission consideration in the Company's upcoming Standard Offer Service filing on March 1, 2010.

Exhibit A

Analysis of Standard Offer Service Approaches for Mass Market Customers

by The Northbridge Group

Analysis of Standard Offer Service Approaches for Mass Market Customers

Prepared for National Grid

Re: RI PUC Order #19839

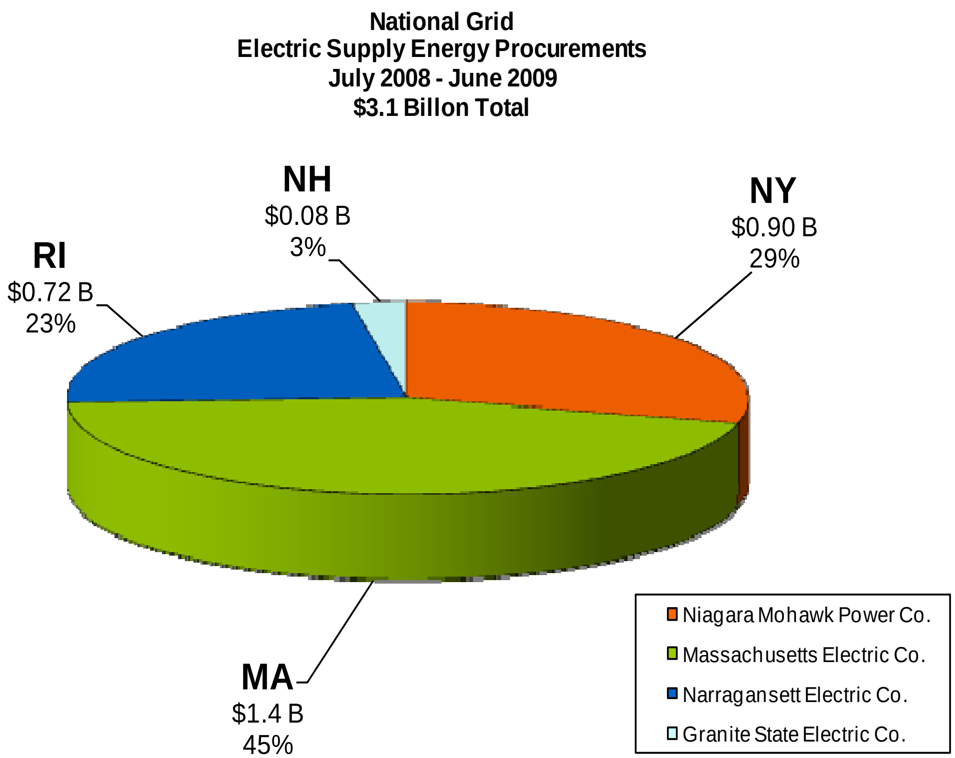
January 2010

NORTHBRIDGE

This report presents an analysis of the relative costs and risks of different approaches to serve mass market standard offer service customers, and how different approaches could impact customers' standard offer service supply rates. While this report depicts potential future supply costs and rate levels, it is not intended to provide a prediction of absolute levels in the future associated with any particular approach for standard offer service supply procurement and ratemaking. As market prices and conditions change over time, expected absolute supply costs and rate levels would also change.

SOS OVERVIEW — Large Impacts

Electric standard offer service (SOS) supply procurement decisions impact many customers and involve substantial amounts of money:



- Currently spending about $3.1 billion annually for 38,000 GWh
- The need for SOS is likely to continue for the foreseeable future

Our forward-looking quantitative analysis of SOS procurement approaches reflects mass market customer load in Rhode Island.

SOS APPROACHES — Full Requirements Products

Most electric utilities in restructured states primarily use full requirements products to secure SOS supply for residential customers:

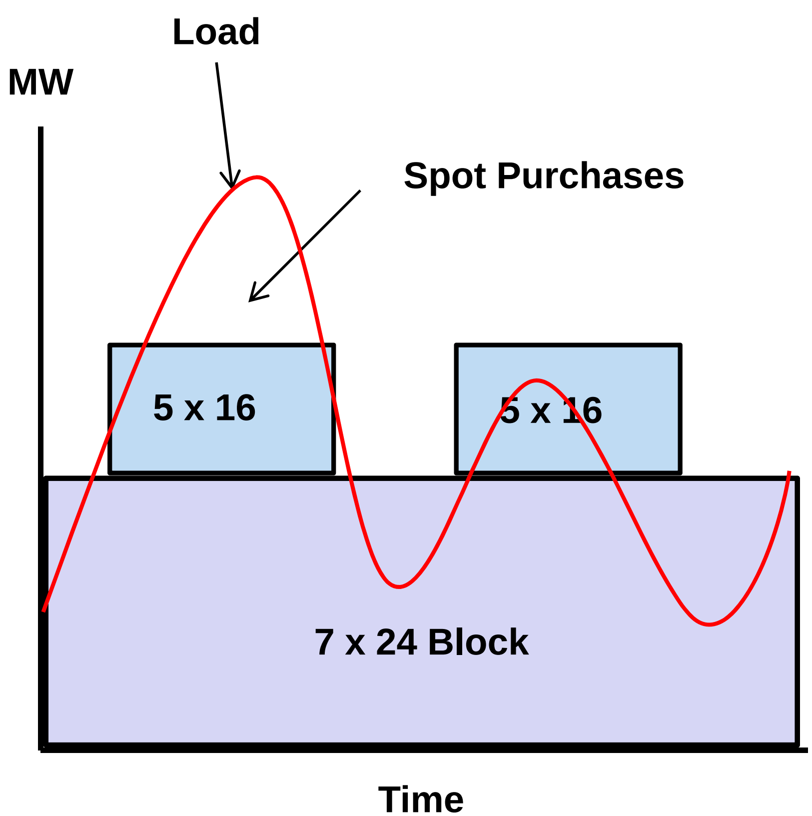
State	Utility
CT	CLP, UI
DC	PEPCO
ME	BHE, CMP
MD	AP, BGE, DPL, PEPCO
MA	NG, NSTAR, WMECO
NJ	ACE, JCPL, PSEG, RECO
PA	FE, PPL, PECO, WPP

Key Features

- RFP/auction process
- Bundles energy, capacity, ancillary services, and often RECs
- Third party supplier assumes volume, price, and regulatory risks during the contract period
- Contracts vary in length and are typically “laddered” to provide rate stability
- Details regarding the procurement process, products, and timing are pre-approved
- Cost recovery process is approved by the Commission in advance
- Results are approved within 1-3 business days of solicitation
- Products do not require utility to post collateral
- Usually no significant cost deferrals
- Relatively easy to implement
- Sellers require compensation for the costs and risks that they bear

SOS APPROACHES — Managed Portfolio

Another approach to SOS procurement involves the use of a "managed portfolio," which generally entails purchases of component products of the full requirements supply obligation, most commonly involving block products for energy supplemented with spot market purchases:



Key Features

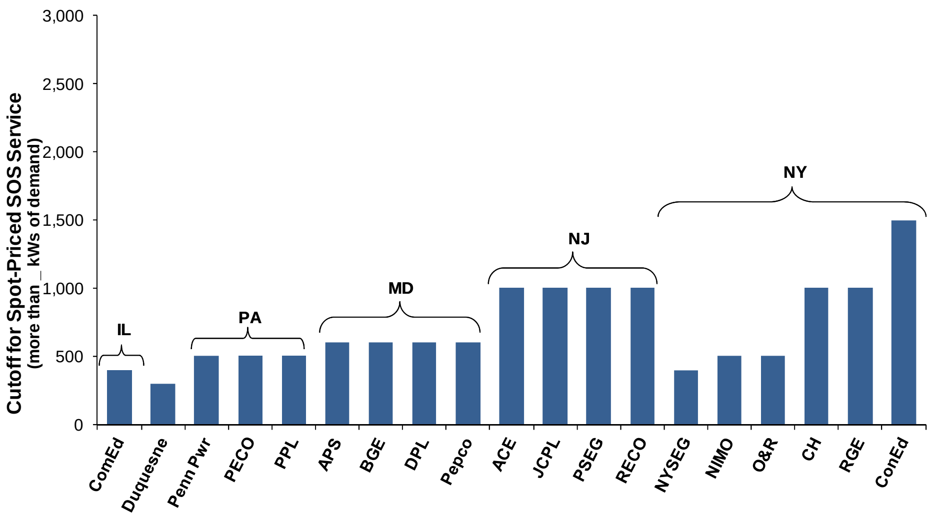
- Utility purchases component products
- Customers assume a degree of volume, price, and regulatory risks
- Contracts vary in length and are typically "laddered" to provide rate stability
- Cost recovery process is approved by the Commission in advance
- Standard NYMEX block products may require utility to post collateral
- Potential mismatch of supply and demand (i.e., "too much" or "too little"), especially when unfavorable

Note: Some parties consider some portfolios that include full requirements products to be "managed portfolios." For the purpose of clarity in this presentation, the term "managed portfolio" here refers to portfolios that do not include full requirements products and that are not entirely based on spot procurement.

SOS APPROACHES — Spot Procurement

Spot market procurement and pricing based on customer-specific hourly usage has become more prevalent for large C&I customers:

Utilities with Spot-Priced SOS Service for Large C&I Customers



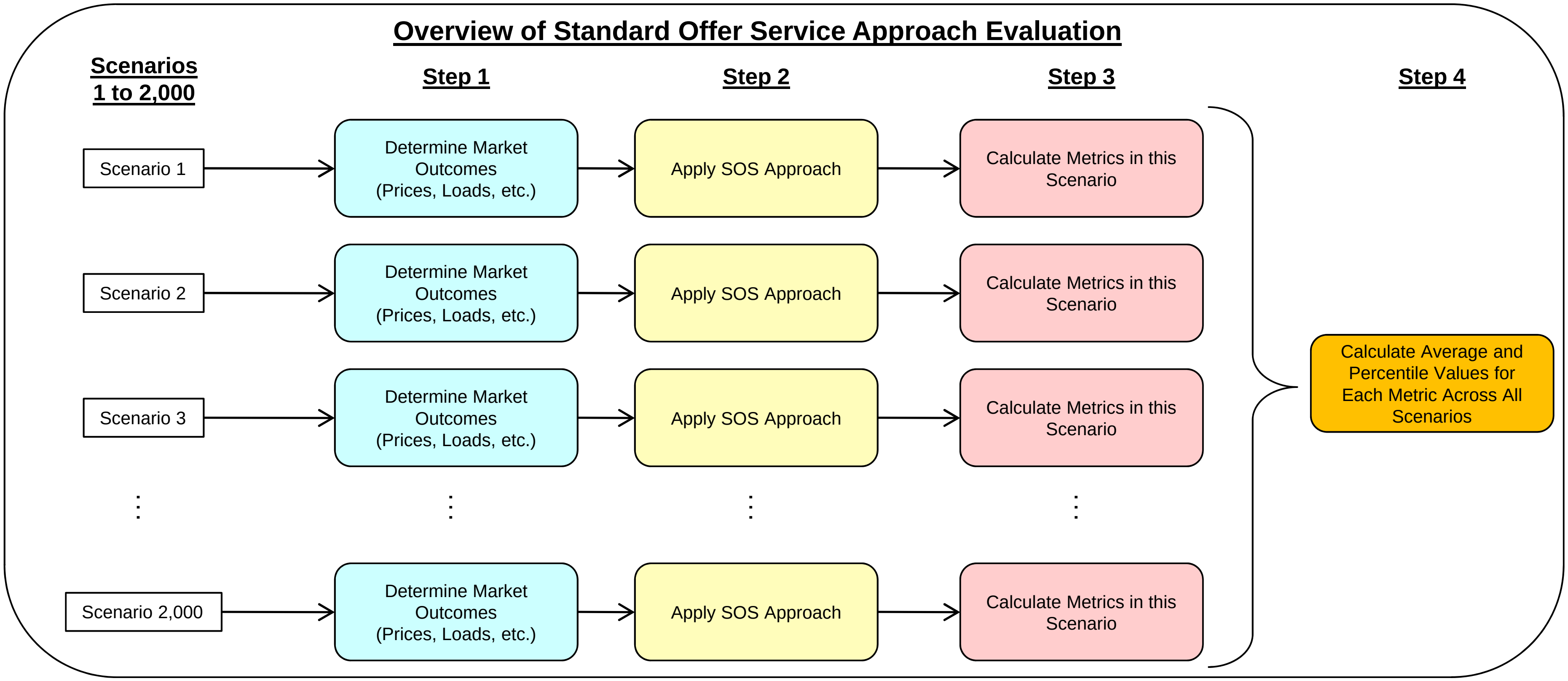
Note: For the purposes of this chart, "spot" includes both day-ahead and real-time pricing.
Note: PECO's spot-priced service has been approved, but is not yet effective.

Key Features

- Real-time or day-ahead energy spot prices
- Promotes efficient customer consumption decisions (e.g., EE and DR)
- Supports retail market development
- Usually no significant cost deferrals
- Generally not considered “acceptable” for small customers due to rate volatility concerns
- Not feasible absent metering / communications / data management

OUR ANALYSIS Overview

In order to analyze various SOS approaches for mass market customers, we utilized a proprietary Monte Carlo simulation approach to replicate market uncertainty based on actual market data, and modeled and measured the performance of the various SOS approaches:



As part of this analysis, we studied bid prices and component costs for SOS products recently solicited by different utilities.

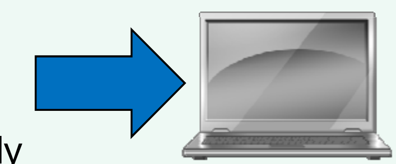
OUR ANALYSIS — Application Of Approaches

Our model allows for evaluation of a wide variety of SOS procurement and cost recovery approaches, including:

← **Procurement** → **Linkage** ← **Cost Recovery** →

Product Duration	Product Type	Hedge Target	Laddering*	Retail Rate Adjustments	Deferral Balance Accruals
20 yr.	Mix of Products	100%	100%	Annually or Longer	Annually
3 yr.	Full Requirements	75%	50%	Quarterly	Monthly
1 yr.	Block	50%	33.3%	Monthly	None
6 month	Spot	0%	0%	Hourly	
Hourly					

Recovered over X months @ Y% interest with or without deferral recovery cap



* Amount of supply procured at any point in time.

Procurement events, rate adjustments, customer switching decisions, and deferral balance recovery can be modeled to occur at different times.

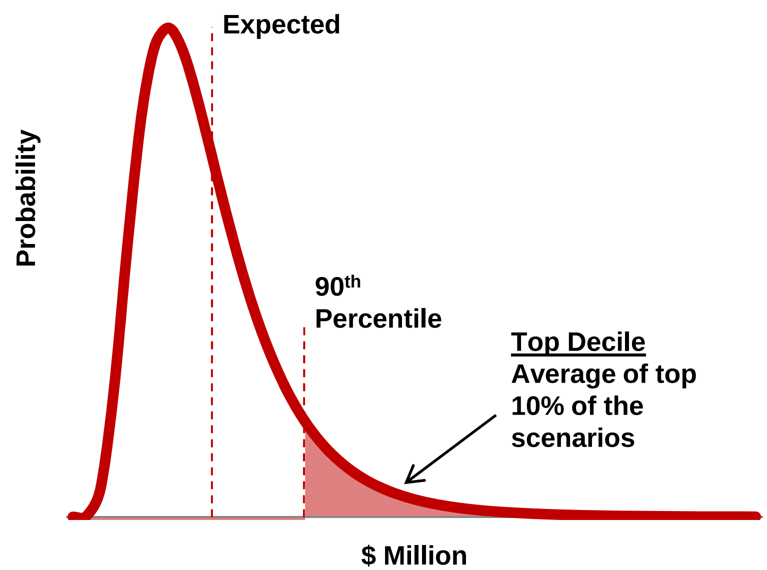
OUR ANALYSIS — Metrics

Each SOS approach was evaluated using the following metrics:

Category	Metric
Metrics Directly Related to Rates	**Expected Rate Level** Average SOS rate level across scenarios
	Supply Cost Surprise Distribution of difference between actual (ex post) and forecasted (ex ante) supply costs ($MM, $/MWh, %)
	Rate Volatility Distribution of SOS rate movements: • From one year to the next • "Coefficient of variance" (similar to New York)
Metrics Directly Related to Financing/ Liquidity	**Deferral Account Balance** Distribution of accumulated under/(over) collections due to differences between SOS rates and actual supply costs
	Mark-to-Market Exposure Exposure on block energy contracts (how far fixed-quantity commitments are out-of-market; also potentially relevant to credit requirements)

- To assess risks, distributions of the metrics were analyzed:

Deferral Account Balance



Note: Rates in this presentation refer to the rate for the supply procured, not including gross-ups for line losses, retail taxes, and other administrative costs.

OUR ANALYSIS — Representative Approaches

While we analyzed many specific SOS approaches/portfolios, our findings can be conveyed through a discussion of three representative SOS approaches/portfolios:

Type of Approach	Description	Standard Offer Service Rate Determination	Treatment of Deferrals
Full Requirements	1-year full requirements products, in which 1/2 is procured every 6 months	Rates reset every 6 months (ex ante)	No deferrals; rates based on actual costs
Managed Portfolio (Block and Spot)	Block energy 25% 4-year (1/4 per year), 25% 2-year (1/2 per year), 25% 6-month, Spot (25%)	Rates reset every 6 months (ex ante)	Prior month balance recovered with 2 month lag; \$5/MWh recovery cap (i.e., deferral rate adjustment in any month cannot exceed \$5/MWh)
Spot	Procurement based entirely on spot	Rates reset each month (ex post)	No deferrals[1]; rates based on actual costs

[1] Deferrals may exist to the degree that RTO settlement adjustments are not available when customers' bills are sent.

SUMMARY OF FINDINGS — Spot Procurement

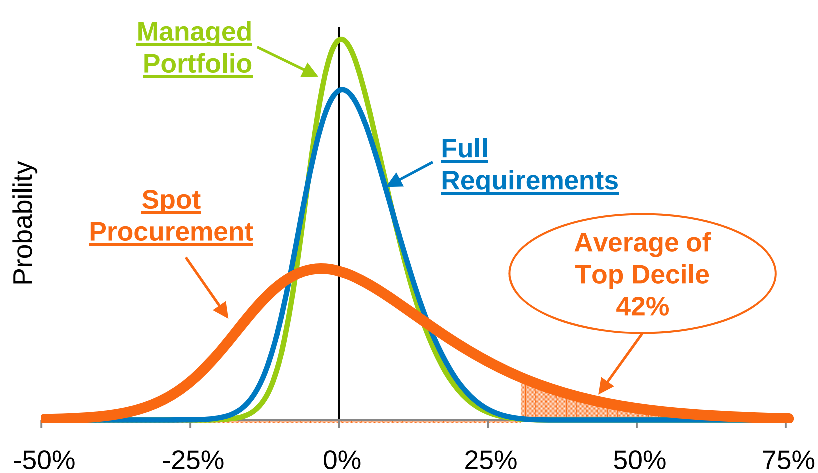
The expected SOS rate under spot procurement is about $2-3/MWh lower than under other approaches, but spot procurement exposes customers to significant rate volatility – annual rate increases across 10 percent of the market scenarios average over 40%:

Expected Rate Levels

Approach	Expected Rate ($ / MWh)	Difference Versus Spot
Spot	$86.01	NA
Managed Portfolio	$88.22	+$2.21
Full Requirements	$88.94	+$2.93

Spot Procurement – High Rate Volatility

Distribution of Annual Rate Changes (%)



Spot Procurement	
Top Decile Supply Cost Surprise ($MM)	$123 MM
Expected Coefficient of Variance (%)	17%
Top Decile Coefficient of Variance (%)	28%

Most regulators and small customer representatives consider 100% spot procurement for mass market customers to be "unacceptable":

- Our studies indicate that no U.S. utilities only offer spot-priced SOS without some form of hedging for mass market customers
- "Unacceptable rate increases" for mass market customers with few competitive alternatives could result in significant cost deferrals

SUMMARY OF FINDINGS MP vs. FR

Both managed portfolio (MP) and full requirements (FR) approaches can reduce customers' exposure to rate volatility, but key differences exist:

Key Differences	Managed Portfolio	Full Requirements
Risks Allocated to Customers	**Higher**, cost of mistakes/bad market outcomes borne by customers	**Lower**, cost of mistakes/bad market outcomes borne by FR suppliers during delivery period
Expected Rate Level	**Lower**	**Higher**, by about $1/MWh
Supply Cost Surprise	**Higher**, supply costs exceed ex ante forecasts by over $40 MM on average across 10 percent of the scenarios due to unhedged positions and load uncertainty	**Lower**, FR suppliers assume more risks
Deferral Account Balances	**Higher**, could become large ($50 MM or more) depending on several key variables	**Minimal** (if no spot included)
Effect of Additional Costs and Risks Not Modeled	**Higher**, would increase costs and risks of an MP approach (e.g., uncertainty regarding capacity, ancillary services, and RPS costs, greater-than-assumed customer switching, etc.)	**Lower,** risks assumed by FR suppliers
Internal Resources	**Higher**, may require additional staff to manage portfolio and ongoing Commission oversight	**Lower**, risk management functions put out for competitive bid

MP vs. FR — Allocation Of Risks

SOS costs and risks remain in either approach, but who bears these costs and risks is different in each approach:

Standard offer service involves many costs and risks:

- Mismatch between revenues and supply costs
- Customer migration
- Unexpected congestion
- Uncertain load and price levels
- Uncertain load and price shapes
- Adverse selection (competitors can select who they serve; SOS supplier cannot)
- Collateral requirements (potentially)
- Potential changes in laws and regulations
- Administrative expenses

These costs and risks remain in either approach.

Full Requirements
Suppliers bear costs and risks during the delivery period, but require compensation to do so

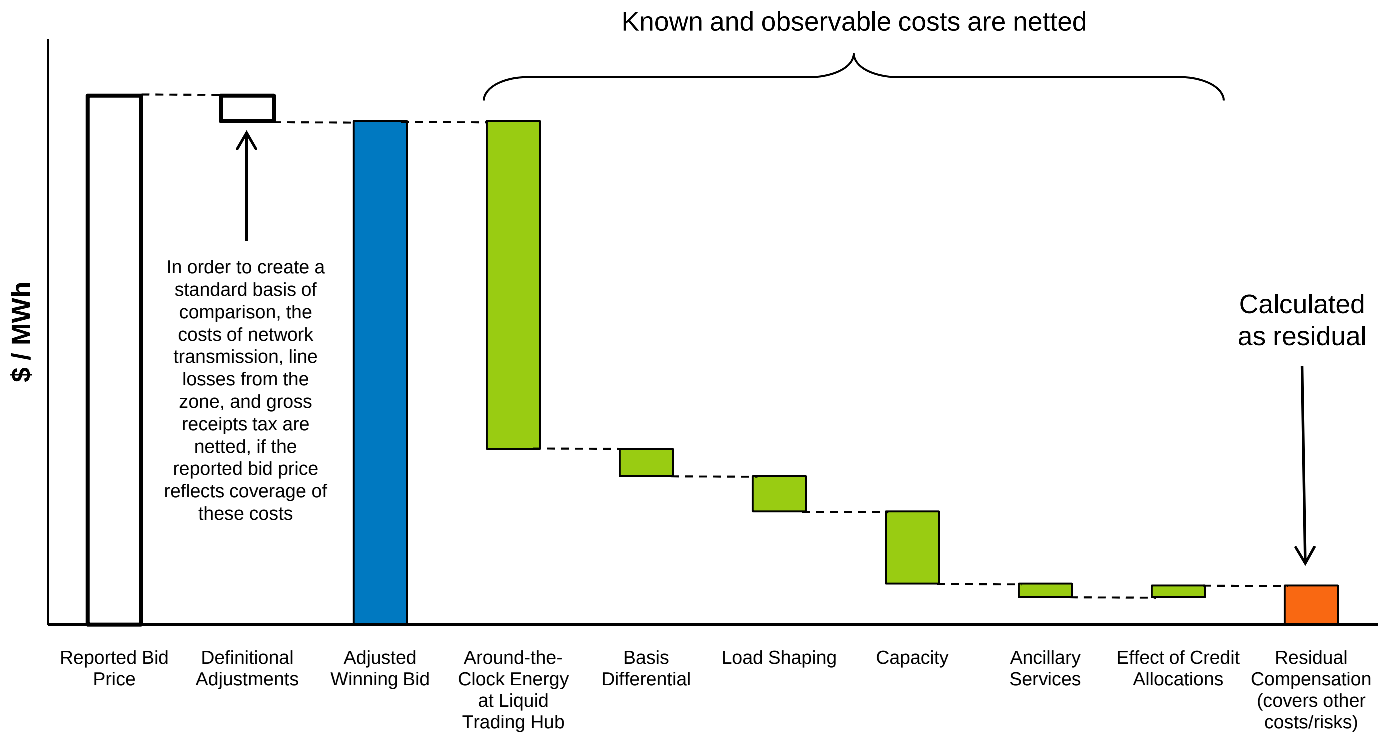
Managed Portfolio
Customers are exposed to costs and risks to a higher degree

Our analysis involved a thorough look at the trade-off between compensation and risk.

FULL REQUIREMENTS — Modeling FR Product Pricing

In order to incorporate full requirements product pricing in our analysis, for full requirements SOS supply products recently solicited by different utilities, we used market information to develop estimates of expectations (at the time of the solicitation) regarding the costs of components of the full requirements supply product and compared these costs to the actual prices of the full requirements product:

Illustrative Full Requirements Product Price Analysis

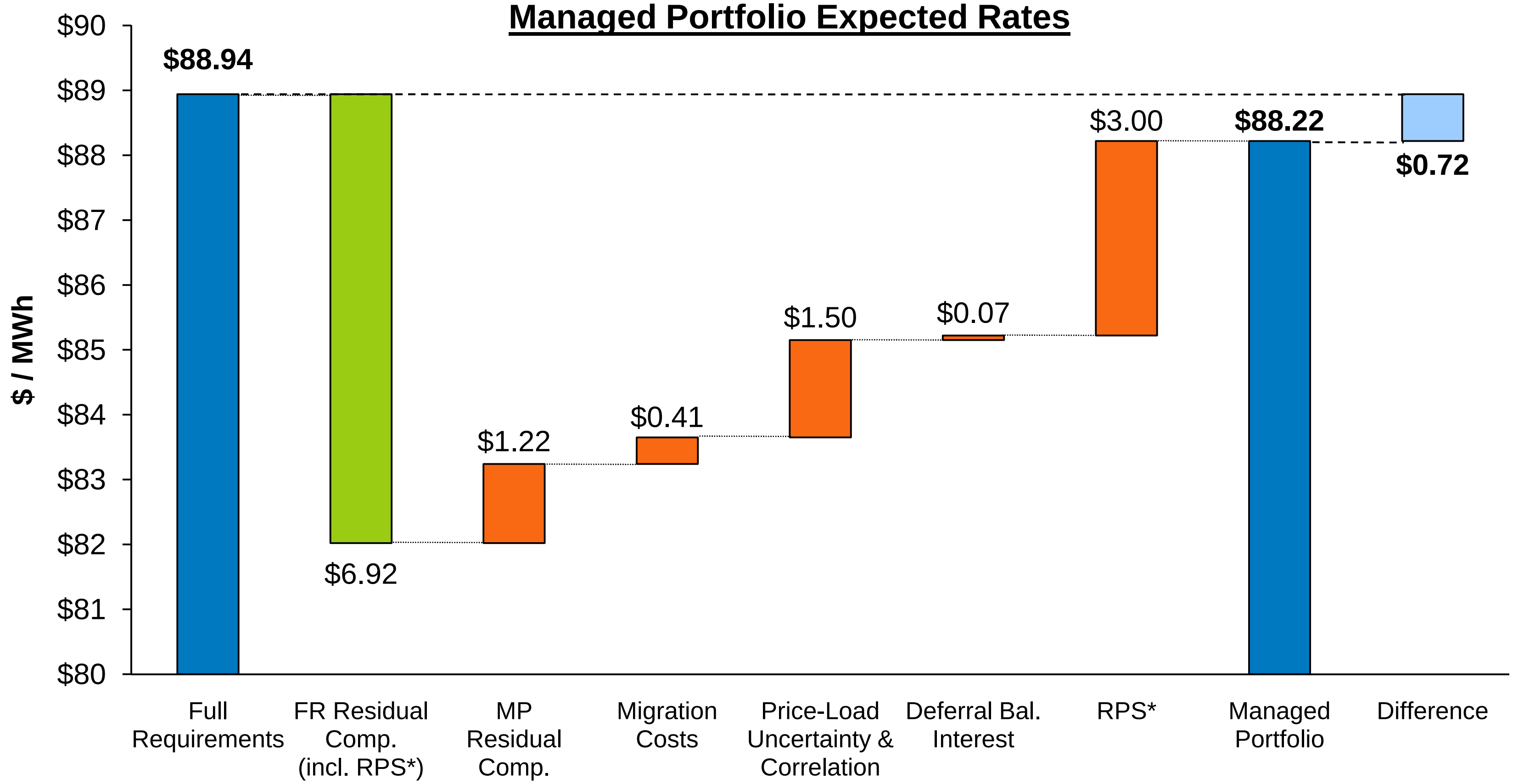


The residual compensation required by full requirements product suppliers, observed through this study of actual product solicitations, was incorporated in our quantitative analysis of SOS approaches.

MP vs. FR — Expected Rate

The difference between the expected SOS rate under the FR approach versus under the MP approach is about $1/MWh:

Comparison of Full Requirements and Managed Portfolio Expected Rates

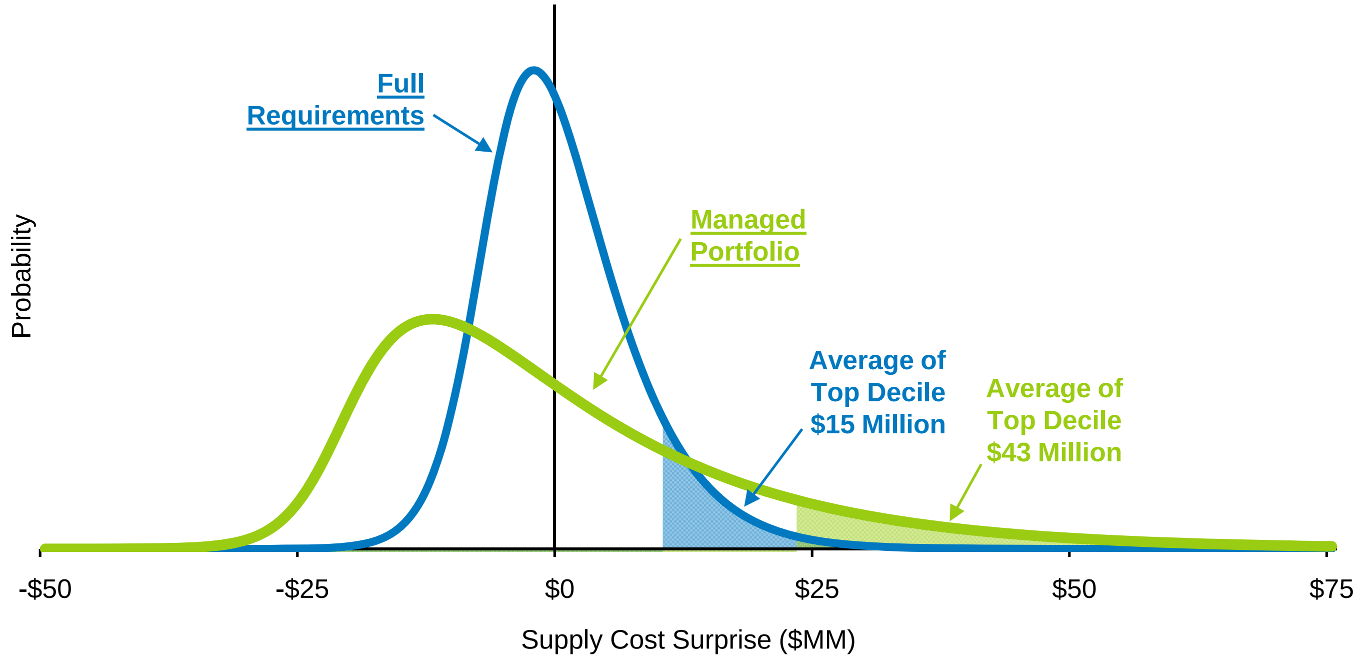


* Under *all* of the procurement approaches that were modeled, the model adjusts the pricing of the supply procured to reflect an RPS cost of $3/MWh *going forward*.

MP vs. FR — Supply Cost Surprise

But the MP approach could result in higher unexpected increases in SOS costs, due to unhedged positions and/or unpredictable SOS load levels:

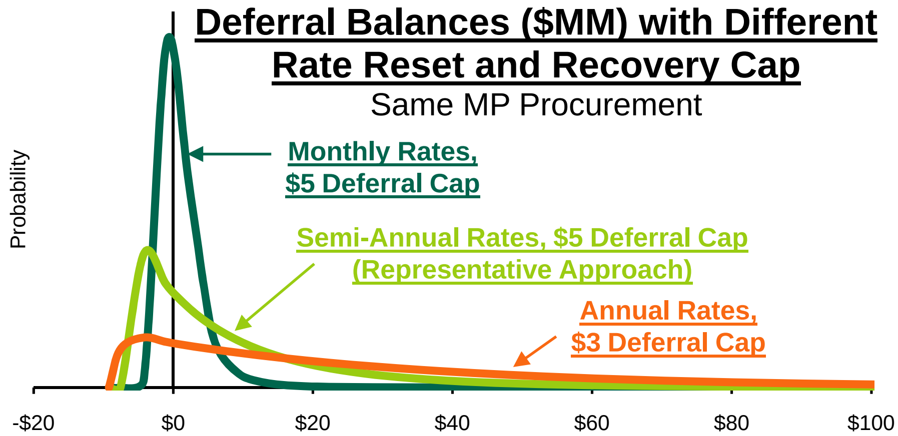
Distribution of Supply Cost Surprise ($MM)



For example, risks associated with price movements such as the 2000 price spikes in California or the 1998-1999 price spikes in the Eastern U.S. would be absorbed by FR suppliers during the supply product delivery period, but customers would absorb more of this risk under an MP approach.

MP vs. FR — Deferral Balances

MP approaches also involve deferral balances that could become large, and are impacted by how the deferral recovery mechanisms are designed, approved, and implemented:



Deferral Account Balances ($MM)			
	Semi-Annual Rates, $5 Deferral Recovery Cap	Annual Rates, $3 Deferral Recovery Cap	Monthly Rates, $5 Deferral Recovery Cap
Expected Value ($MM)	$10 MM	$28 MM	$1 MM
Average of Top Decile ($MM)	$57 MM	$113 MM	$9 MM

Key Variables in Mechanism Design

- Frequency of rate reset (based on forecasted future costs)
- Frequency of rate reconciliation (based on actual costs and revenues)
- Recovery period
- Interest on deferral balances
- Deferral recovery cap
- Maximum deferral balance

Wellsboro Example

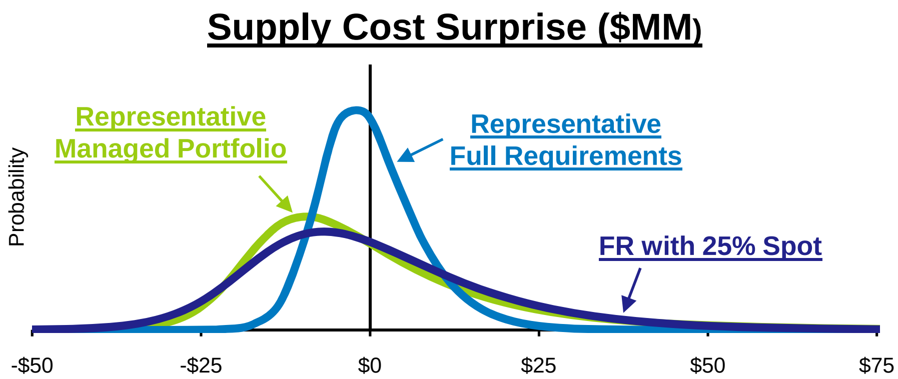
- Based on its unexpected costs incurred under its MP approach in early 2008, Wellsboro Electric reported that supply rates could be twice expected levels without deferrals. As a result, the period for recovery of the unexpected costs was extended from three to twelve months.

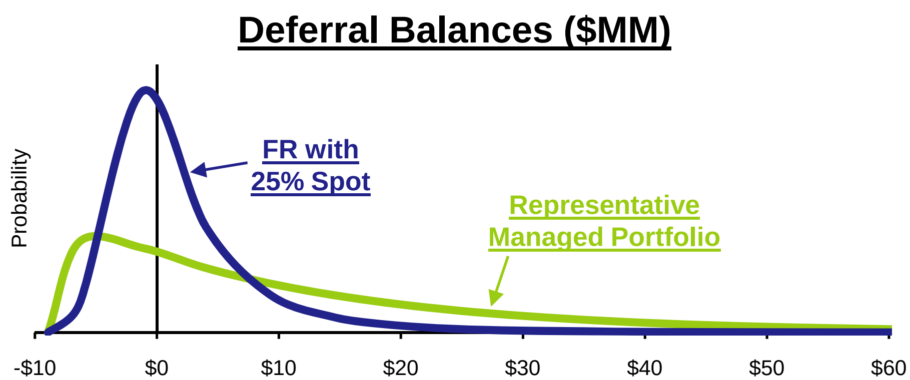
Using an FR approach, supply costs are known when rates are established, therefore no (or minimal) deferrals are required unless spot purchases are also included in the plan.

MP vs. FR — FR with Spot

If the FR approach were modified to include 25% spot purchases, the expected rate level would decrease, but the risk associated with supply cost surprise and deferral balances would increase:

Expected Rate Level ($/MWh)	
Approach	Average of Top Decile
Representative MP	$88.22
Representative FR	$88.94
FR with 25% Spot	$88.21





Supply Cost Surprise ($MM)	
Approach	Average of Top Decile
Representative MP	$43 MM
Representative FR	$15 MM
FR with 25% Spot	$37 MM

Deferral Account Balances ($MM)	
Approach	Average of Top Decile
Representative MP	$57 MM
Representative FR	$0 MM
FR with 25% Spot	$18 MM

Some utilities have adopted an approach involving a mix of full requirements products and spot purchases (although 25% spot is higher than levels generally adopted for mass market customers).

MP vs. FR — Additional Risks

There are additional costs and risks that were not modeled in the quantitative evaluation that would increase the costs and risks of an MP approach:

- Increased administrative costs (e.g., portfolio management staff and systems, regulatory proceedings and/or interaction with regulators, etc.)
- Uncertainty regarding capacity, ancillary services, and RPS costs[1]
- Greater-than-assumed customer switching (e.g., due to additional potential for new technologies, regulatory policies, opt-out customer aggregation, etc.)
- Imputed debt costs

In contrast, full requirements product suppliers compete on price to manage these and other risks, and absorb the costs of any mistakes.

[1] The model assumes constant $/MWh capacity, RPS, and ancillary services costs across all scenarios. Modeling uncertainty around these other variables would make an MP approach less attractive relative to what was quantified in this presentation.

SUMMARY OF FINDINGS

- 100% spot procurement would expose mass market customers to significant rate volatility and is not acceptable to most regulators at this time
- Both a managed portfolio and a full requirements approach can reduce customers' exposure to rate volatility, but key differences exist:

Key Differences	Managed Portfolio	Full Requirements
Risks Allocated to Customers	**Higher**	**Lower**
Expected Rate Level	**Lower**	**Higher**
Supply Cost Surprise	**Higher**	**Lower**
Deferral Account Balances	**Higher**	**Minimal** (if no spot included)
Effect of Additional Costs and Risks Not Modeled	**Higher**	**Lower**
Internal Resources	**Higher**	**Lower**

Appendix

SUMMARY OF METRICS More Approaches

Description of Approach				Comparison of Performance Metrics								
Product Term	Product Type	Hedge Target	Rate Period	2014 SOS Rate Level ($ / MWh)	Supply Cost Surprise ($MM)	Supply Cost Surprise ($/MWh)	Supply Cost Surprise (%)	Deferral Account Balance ($MM)	Annual Rate Movement (%)	Coefficient of Variance (%)	Customer Switching (%)	Mark-to-Market Exposure ($MM)
Ten-Year Laddered	Block Energy	100%	Annual	$92.37 ($84.06 / $105.89)	$0 (-$14 / $29)	$0.00 (-$4.03 / $10.51)	0.0% (-4.5% / 11.8%)	$9 (-$1 / $51)	1.8% (-3.7% / 8.8%)	2.0% (0.0% / 3.5%)	16% (0% / 57%)	-$31 (-$421 / $213)
Five-Year Laddered	Block Energy	100%	Annual	$89.90 ($76.28 / $108.77)	$0 (-$13 / $28)	$0.00 (-$3.48 / $8.63)	0.0% (-4.0% / 10.0%)	$7 (-$1 / $41)	2.0% (-5.2% / 10.6%)	2.1% (0.0% / 3.6%)	12% (0% / 44%)	-$5 (-$169 / $113)
		75%	Annual	$88.60 ($72.41 / $111.25)	$0 (-$23 / $43)	$0.00 (-$6.00 / $10.14)	0.0% (-6.5% / 11.4%)	$14 (-$4 / $77)	2.1% (-6.6% / 13.2%)	2.7% (0.0% / 5.3%)	11% (0% / 40%)	-$4 (-$126 / $84)
Three-Year Laddered	Full Requirements	100%	Annual	$92.19 ($71.87 / $118.74)	$0 ($0 / $0)	$0.00 ($0.00 / $0.00)	0.0% (0.0% / 0.0%)	$0 ($0 / $0)	1.8% (-7.2% / 12.4%)	0.0% (0.0% / 0.0%)	13% (1% / 36%)	$0 ($0 / $0)
		75%	Annual	$90.65 ($69.47 / $119.18)	$0 (-$20 / $29)	$0.00 (-$5.33 / $6.46)	0.0% (-5.6% / 7.0%)	$3 (-$4 / $24)	1.9% (-8.8% / 14.0%)	3.3% (0.5% / 5.7%)	10% (1% / 31%)	$0 ($0 / $0)
	Block Energy	100%	Annual	$89.61 ($69.67 / $115.89)	$0 (-$12 / $27)	$0.00 (-$3.20 / $8.09)	0.0% (-3.7% / 9.2%)	$7 (-$1 / $39)	1.8% (-8.2% / 13.1%)	2.1% (0.0% / 3.6%)	10% (0% / 38%)	$4 (-$82 / $74)
		75%	Annual	$88.63 ($67.69 / $116.87)	$0 (-$22 / $43)	$0.00 (-$5.65 / $10.03)	0.0% (-6.2% / 11.3%)	$14 (-$3 / $77)	2.1% (-8.4% / 14.9%)	2.7% (0.0% / 5.1%)	11% (0% / 41%)	$3 (-$61 / $55)
One-Year Laddered	Full Requirements	100%	Semi-Annual	$88.94 ($65.66 / $121.55)	$0 (-$11 / $15)	$0.00 (-$2.91 / $3.46)	0.0% (-3.3% / 3.7%)	$0 ($0 / $0)	2.0% (-11.2% / 17.0%)	2.1% (0.2% / 5.6%)	8% (0% / 24%)	$0 ($0 / $0)
		100%	Annual	$88.99 ($65.43 / $122.45)	$0 (-$11 / $15)	$0.00 (-$2.87 / $3.47)	0.0% (-3.2% / 3.7%)	$2 (-$3 / $15)	2.1% (-12.8% / 20.2%)	2.3% (0.3% / 4.7%)	8% (1% / 24%)	$0 ($0 / $0)
		100%	Monthly	$88.94 ($65.66 / $121.55)	$0 (-$11 / $15)	$0.00 (-$2.91 / $3.46)	0.0% (-3.3% / 3.7%)	$0 ($0 / $0)	2.0% (-11.2% / 17.0%)	2.1% (0.2% / 5.6%)	8% (0% / 24%)	$0 ($0 / $0)
		75%	Semi-Annual	$88.21 ($64.12 / $121.76)	$0 (-$26 / $37)	$0.00 (-$6.94 / $8.30)	0.0% (-7.6% / 9.2%)	$2 (-$4 / $18)	2.1% (-12.7% / 18.7%)	4.1% (1.9% / 7.3%)	6% (0% / 21%)	$0 ($0 / $0)
	Block Energy	100%	Semi-Annual	$88.02 ($64.75 / $120.65)	$0 (-$17 / $30)	$0.00 (-$4.25 / $7.03)	0.0% (-4.9% / 7.7%)	$4 (-$1 / $26)	2.0% (-11.3% / 17.2%)	3.3% (1.3% / 6.6%)	6% (0% / 25%)	$6 (-$27 / $37)
		75%	Semi-Annual	$87.59 ($63.51 / $121.02)	$0 (-$28 / $49)	$0.00 (-$7.11 / $10.90)	0.0% (-8.0% / 12.4%)	$11 (-$3 / $62)	2.2% (-12.2% / 19.1%)	4.0% (1.1% / 7.2%)	8% (0% / 35%)	$5 (-$20 / $28)
Spot	None	0%	Monthly Ex Post	$86.01 ($56.77 / $127.32)	$0 (-$90 / $123)	$0.00 (-$21.36 / $25.78)	0.0% (-23.7% / 29.8%)	$0 ($0 / $0)	3.5% (-26.0% / 42.1%)	16.9% (9.4% / 27.6%)	0% (0% / 0%)	$0 ($0 / $0)
		0%	Monthly Ex Ante	$86.03 ($56.68 / $126.55)	$0 (-$87 / $118)	$0.00 (-$21.37 / $25.81)	0.0% (-23.8% / 29.9%)	$8 (-$4 / $34)	3.6% (-26.3% / 41.2%)	19.0% (10.6% / 29.9%)	3% (0% / 15%)	$0 ($0 / $0)
		0%	Quarterly Ex Ante	$86.11 ($56.74 / $125.11)	$0 (-$82 / $108)	$0.00 (-$21.41 / $25.89)	0.0% (-23.8% / 30.0%)	$18 (-$9 / $76)	3.6% (-24.7% / 40.1%)	16.1% (6.0% / 29.9%)	9% (0% / 42%)	$0 ($0 / $0)
Hybrid / Mixed	Block Energy[1]	75%	Semi-Annual	$88.22 ($66.68 / $117.88)	$0 (-$23 / $43)	$0.00 (-$5.92 / $9.83)	0.0% (-6.6% / 11.1%)	$10 (-$3 / $57)	2.2% (-9.0% / 16.1%)	3.6% (1.1% / 6.6%)	9% (0% / 36%)	$5 (-$47 / $47)
	Block Energy[1]	75%	Annual	$88.23 ($66.58 / $117.88)	$0 (-$22 / $42)	$0.00 (-$5.76 / $9.83)	0.0% (-6.5% / 11.0%)	$16 (-$4 / $86)	2.3% (-9.7% / 16.9%)	2.6% (0.0% / 5.5%)	12% (0% / 46%)	$5 (-$46 / $46)
	Block Energy[1]	75%	Monthly	$88.04 ($66.63 / $117.86)	$0 (-$24 / $44)	$0.00 (-$5.89 / $9.59)	0.0% (-6.5% / 10.8%)	$1 (-$2 / $9)	2.2% (-8.8% / 16.6%)	5.9% (2.6% / 10.8%)	5% (0% / 18%)	$5 (-$48 / $49)
	Block Energy[2]	75%	Annual	$88.98 ($70.98 / $114.13)	$0 (-$24 / $42)	$0.00 (-$6.42 / $9.85)	0.0% (-7.1% / 11.0%)	$16 (-$3 / $85)	3.6% (-9.3% / 19.0%)	3.4% (0.6% / 6.6%)	14% (0% / 56%)	-$7 (-$129 / $78)

[1] 25% four-year block energy, 25% two-year block energy, 25% six-month block energy, 25% spot.
[2] 25% ten-year block energy, 25% four-year block energy, 25%, one-year block energy, 25% spot.

MARKET OUTCOMES — Monte Carlo Approach

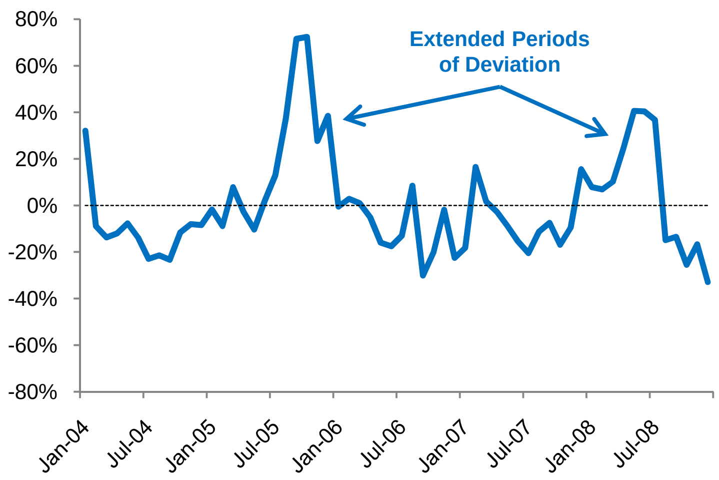
- Each SOS approach is evaluated by examining how the approach would perform under a wide variety of market conditions
- Creating these potential 'states of the world' is a critical part of the evaluation process
  - NorthBridge utilizes a proprietary Monte Carlo simulation approach to replicate the types of uncertainty in energy prices, total load, and load-weighting gross-ups we have seen historically[1]
  - This approach generates correlated[2] scenarios of potential outcomes for energy prices, total load, and load-weighting gross-ups to which we can apply different SOS approaches and observe the range of risks and benefits
- Scenarios of market outcomes are centered around current forecasts or expectations for energy prices, total load, and load-weighting gross-ups, but the intent behind the quantitative evaluation of SOS approaches is to illustrate the relative differences in cost and risk between different approaches rather than identify the precise costs associated with a specific approach

[1] Capacity prices, ancillary services costs, and RPS costs were not modeled to be uncertain in this analysis.
[2] Correlations between energy prices, total load, and load-weighting gross-ups are based on historical relationships.

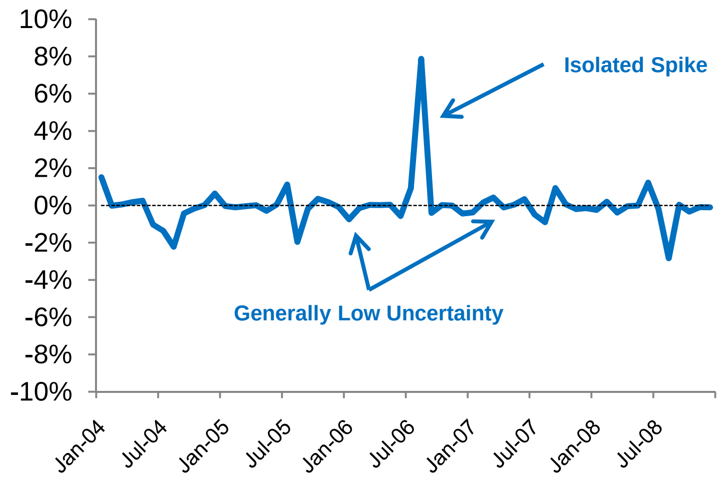
MARKET OUTCOMES — Characteristics of Volatility

- We generate scenarios to help us observe how different SOS approaches would perform under different conditions (i.e. what sort of rate volatility, rate levels, deferral balances, etc. would they yield?)
- We need scenarios to exhibit the same types of characteristics (e.g. volatility and mean reversion) we have seen in the past:

% Deviation of the Monthly Mass-Hub Peak Energy Price From Seasonal Pattern and Long-Term Trend



% Deviation of the Monthly Mass-Hub Peak Load-Weighting Gross-Up From Seasonal Pattern and Long-Term Trend



- Energy prices tend to be quite volatile and may take considerable time to mean-revert back to a long-term trend
- Gross-up levels are generally far less volatile and mean revert to long-term trends very quickly, but can also exhibit some extreme 'events'

MARKET OUTCOMES — Underlying Model

- In order to create scenarios of what might happen in the future, we use a model of how the underlying process (i.e. prices or load) evolve over time
- The model used in this analysis is a three factor mean reverting model with stochastic volatility, and is a variant of the Random Walk / Geometric Brownian Motion (GBM) model commonly used in quantitative finance

Stochastic Differential Equations Defining the Underlying Processes[1]

$$dP = (P - \overline{P}) \cdot h_p \cdot dt + \sigma_p \cdot V \cdot P \cdot dW + drift$$

$$dV = (V - \overline{V}) \cdot h_v \cdot dt + \sigma_v \cdot V \cdot dZ$$

$$r(dW, dZ) = \beta$$

(*dW* and *dZ* are correlated normally-distributed random variables)

dP = Change in price
P = Price in prior period
$\overline{P}$ = Long term average price
h_p = Rate of mean reversion of price
dt = Time elapsed since prior period
σ_p = Basecase marginal volatility of price
dW = Normally distributed random variable
dV = Change in volatility
V = Volatility in prior period
$\overline{V}$ = Long term average volatility
h_v = Rate of mean reversion in volatility
σ_v = Basecase marginal volatility of volatility
dZ = Normally distributed random variable
β = Correlation between dW and dZ

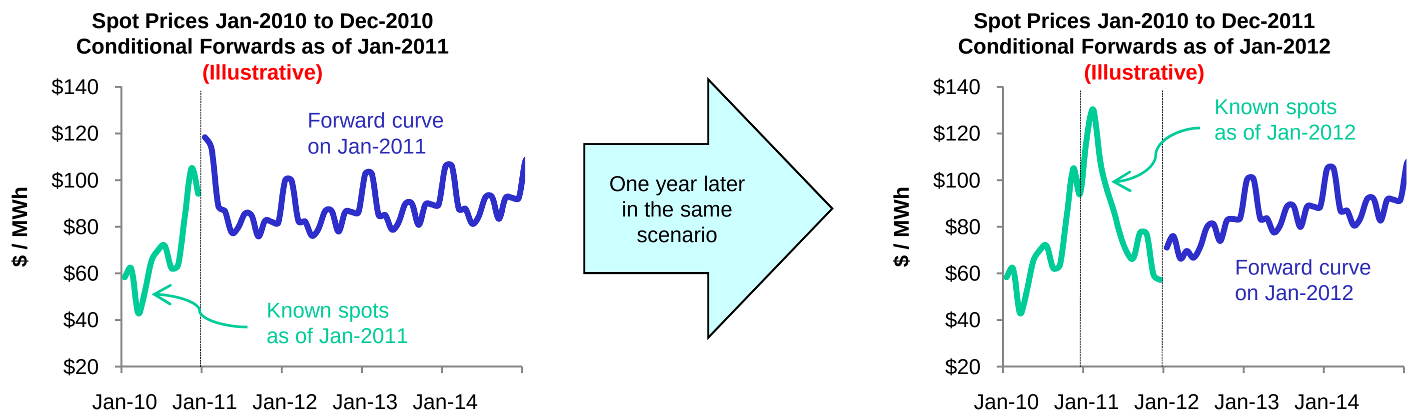
- NorthBridge has developed a proprietary set of tools using a maximum likelihood estimation technique to 'fit' the model above to match price / load characteristics and properties observed historically

[1] This model is a variation of the Dixit-Pindyck mean-reverting random walk model used for simulating commodity price movements. The principal difference is the addition of the term for stochastic volatility.

MARKET OUTCOMES — Scenario Components

- Scenarios illustrate the uncertainty associated with variables such as wholesale market prices, total load levels, and load-weighting gross-up factors
- Each scenario consists of (1) a time-series of ultimate spot outcomes, and (2) conditional forecasts (i.e. in a given scenario, what would most likely be the forecast at a specific observation date for future delivery periods)

- We might observe spot prices from Jan-2010 through Dec-2010 and then ask what the forward curve might look like as of Jan-2011:
- In that same scenario, we can then track what might have happened during 2011 and then reassess the forward curve as of Jan-2012:



APPLICATION OF APPROACHES — Model Overview

Several steps are needed to analyze the performance of SOS approaches under the scenarios:

Analysis of Standard Offer Service Solicitations
Evaluation of residual compensation for full requirements and block energy products

Market Model
2,000 scenarios using a three-factor stochastic volatility model of how the expectations of price, load, and gross-up may vary over time, and what spot prices, and actual loads and gross-ups might result

1) Specify Procurement Volumes and Prices
Calculate product prices at the time of procurement

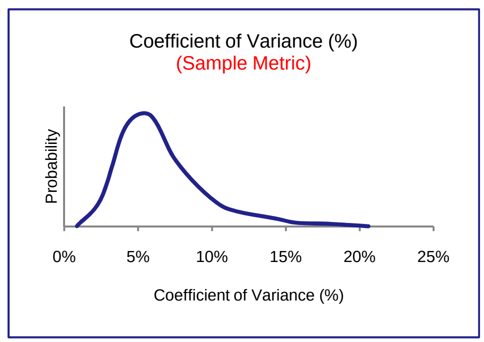
2. Calculate Retail Rates
Rates are based on known costs of completed procurements plus costs of remaining open exposure at forecasted cost

3. Estimate Switching
Customers switch based on knowledge of SOS rates and market price levels

4. Determine Actual Supply Costs
Actual costs to serve SOS customers are based on price of hedged volumes and remainder at spot

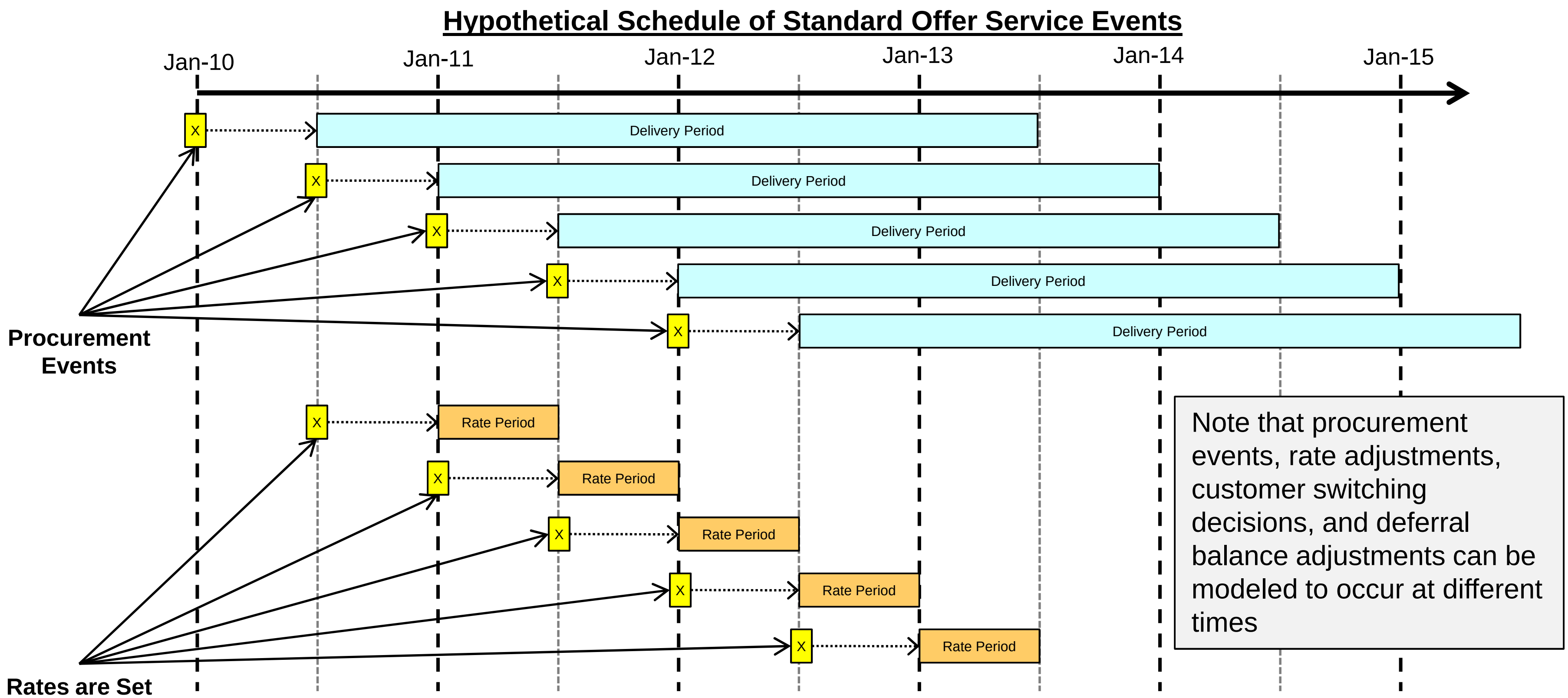
5. Determine Under / Over Recovery
Determine over / under recovery of costs and amortization schedule for full recovery

Calculate Evaluation Metrics for Each of 2,000 Scenarios



APPLICATION OF APPROACHES — Model Methodology

In each scenario, the model applies the SOS approach, procuring products, setting rates, calculating actual costs and amortizing over/under recoveries as appropriate:



All actions (e.g. entering into hedges or setting rates) are done only with the information available at the time (i.e. using conditional forecasts), just as would be the case in the real world.

APPLICATION OF APPROACHES Determine Procurements

- Each time a procurement event is scheduled, hedge targets and conditional forecasts of retained load are compared to existing hedges; incremental purchases are made at conditional forward prices:

Illustrative Block Energy Procurement Product Price Calculation

Delivery Month	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
Total Forecasted Load (MWh)	354,272	291,862	286,682	256,802	246,598	440,393	436,106	388,879	327,210	269,360	304,062	365,284
Hedge Target (%)	100%	100%	100%	100%	100%	100%	50%	50%	50%	50%	50%	50%
Existing Hedges (MWh)	159,400	131,300	129,000	115,600	111,000	198,200	0	0	0	0	0	0
Incremental Purchases (MWh)	194,872	160,562	157,682	141,202	135,598	242,193	218,053	194,439	163,605	134,680	152,031	182,642
Market Price ($ / MWh)	$60.34	$60.34	$51.62	$51.62	$48.74	$50.43	$55.92	$55.92	$50.10	$56.24	$56.24	$56.24

Total Cost ($MM)	$113.4
Total Volume (TWh)	2.1
Product Price ($ / MWh)	**$54.56**

- The prices received for different products may include residual compensation (for costs/risks) consistent with historical market evidence for similar transactions

APPLICATION OF APPROACHES — Determine Rates

- Rates are determined by calculating the total forecasted cost attributable to SOS customers during the delivery period, including any cost/benefit from hedged volumes:

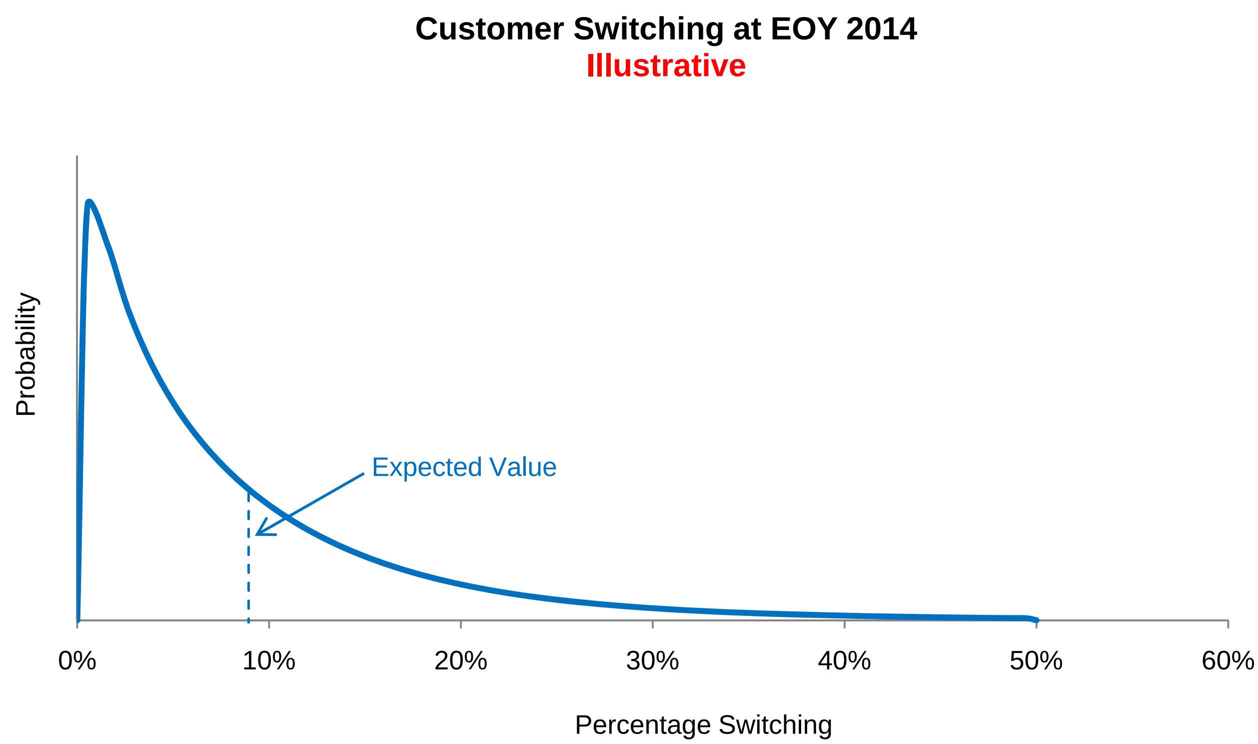
Illustrative Standard Offer Service Rate Calculation

Delivery Month	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
Total Forecasted Load (MWh)	336,559	277,269	272,348	243,962	234,268	418,374	414,301	369,435	310,850	255,892	288,859	347,020
Forecasted ATC Price ($ / MWh)	$54.31	$54.31	$46.45	$46.45	$43.86	$45.38	$50.33	$50.33	$45.09	$50.62	$50.62	$50.62
Forecasted Price-Load Gross Up (%)	5.79%	11.95%	7.94%	7.28%	6.09%	10.56%	9.87%	11.52%	10.95%	10.98%	8.54%	9.23%
Forecasted Spot Cost ($MM)	$19.34	$16.86	$13.66	$12.16	$10.90	$20.99	$22.91	$20.74	$15.55	$14.37	$15.87	$19.19
Hedged Volume (MWh)	354,272	291,862	286,682	256,802	246,598	440,393	218,053	194,439	163,605	134,680	152,031	182,642
Hedged Price ($ / MWh)	$54.56	$54.56	$54.56	$54.56	$54.56	$54.56	$54.56	$54.56	$54.56	$54.56	$54.56	$54.56
Benefit (Cost) of Hedge ($MM)	-$0.09	-$0.07	-$2.32	-$2.08	-$2.64	-$4.04	-$0.92	-$0.82	-$1.55	-$0.53	-$0.60	-$0.72
Total Forecasted Cost ($MM)	$218.92											
Total Forecasted Volume (TWh)	3.77											
Energy ($ / MWh)	$58.08											
Capacity ($ / MWh)	$10.00											
Ancillary ($ / MWh)	$3.00											
Renewable Energy Credits ($ / MWh)	$3.00											
SOS Rate ($ / MWh)	**$74.08**											

- This rate only includes forward-looking cost components; recovery of deferral balances is handled separately

APPLICATION OF APPROACHES — Customer Switching

- The modeled customer switching dynamic produces a distribution of switching outcomes as follows under one of the SOS approaches:



APPLICATION OF APPROACHES — Deferral Accounts

- At the end of each simulated month, the model calculates the amount by which the utility's costs differ from revenues:

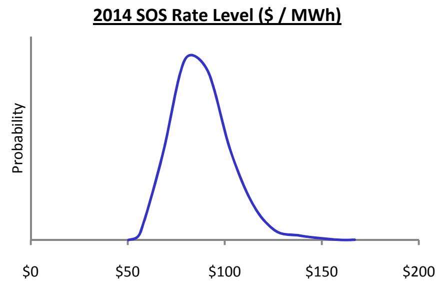
Illustrative Cost Under / (Over) Recovery

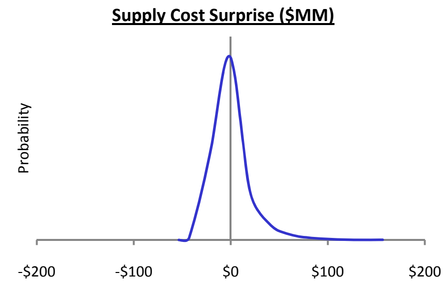
Month	Jan-11
Actual SOS Load (TWh)	371,986
SOS Rate ($ / MWh)	$74.08
Actual Revenue ($MM)	$27.6
ATC Energy ($ / MWh)	$66.37
Price-Load Gross-Up (%)	6.03%
Shaped Energy ($ / MWh)	$70.38
Capacity ($ / MWh)	$10.00
Ancillary ($ / MWh)	$3.00
Renewable Energy Credits ($ / MWh)	$3.00
Actual Cost ($ / MWh)	$86.38
Actual Cost ($MM)	$32.1
Under / (Over) Collection ($MM)	$4.6

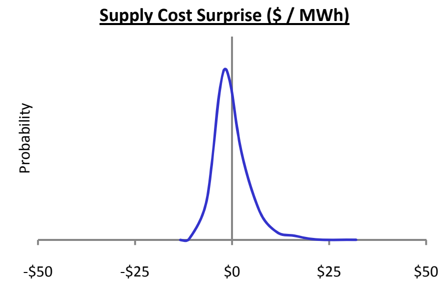
- In this month, actual costs exceeded revenues by $4.6MM
- Any over / under recovery is amortized over future months based on an established schedule as a separate rate rider (e.g. prior month balance recovery with two month delay, potentially subject to a recovery cap)
- This rider is independent of the rates set on the basis of forecasted future costs

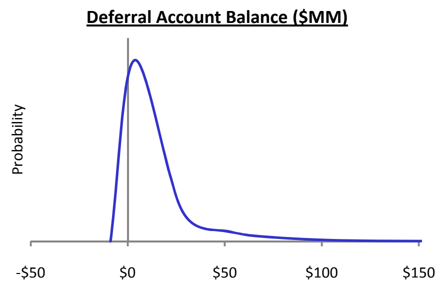
METRICS — Distributions

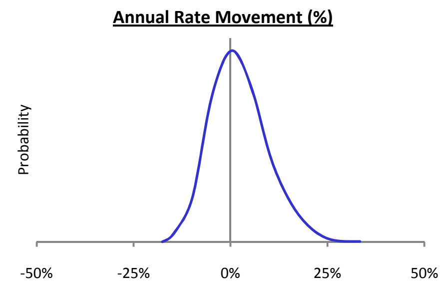
Metrics are calculated in each scenario and transformed into distributions which are used to calculate expected values and percentiles:

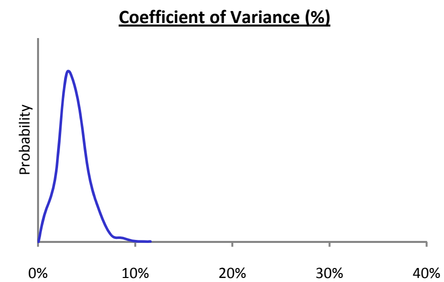


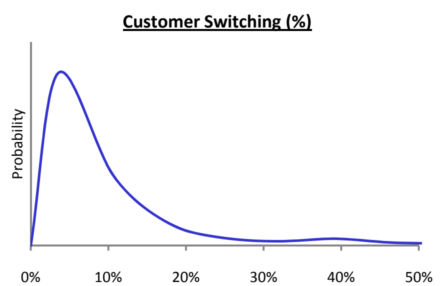


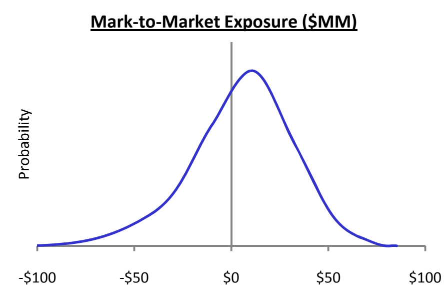












Note: Metrics are based on 2014 results (i.e., enough time for the procurement cycle to reach equilibrium).

METRICS — Expected Rate Level

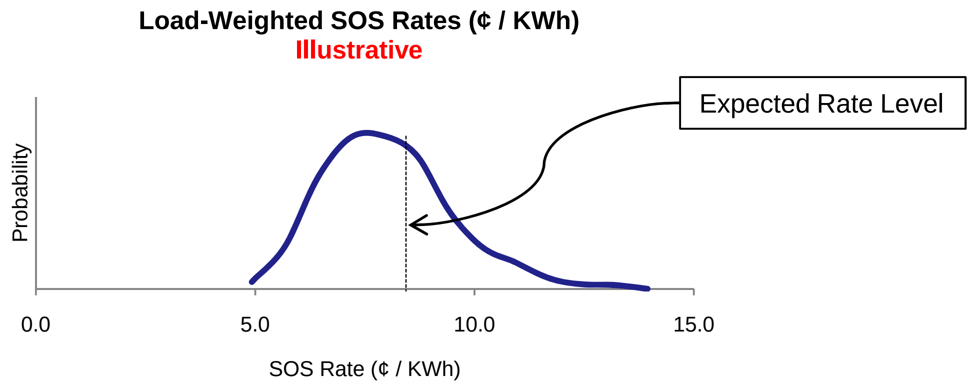
- The expected rate level is the average load-weighted rate that an SOS customer would face in a year:

Illustrative Standard Offer Service Rate Level

Delivery Month	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
SOS Rate (¢ / KWh)	7.74	8.04	7.94	8.65	7.81	8.09	7.96	8.37	9.96	10.40	9.36	8.85
Total Eligible Load (MWh)	371,833	327,861	340,913	288,822	293,588	385,558	480,899	412,442	333,331	305,243	323,969	365,015

Load-Weighted SOS Rate (¢ / KWh)	**8.55**

- Each scenario will yield a different rate; the mean across all scenarios is the expected rate level:



METRICS — Supply Cost Surprise Calculation

- Supply cost surprise refers to the difference between ex ante known or forecasted SOS supply costs and the actual cost to serve:[1]

Illustrative Supply Cost 'Surprise' Calculation

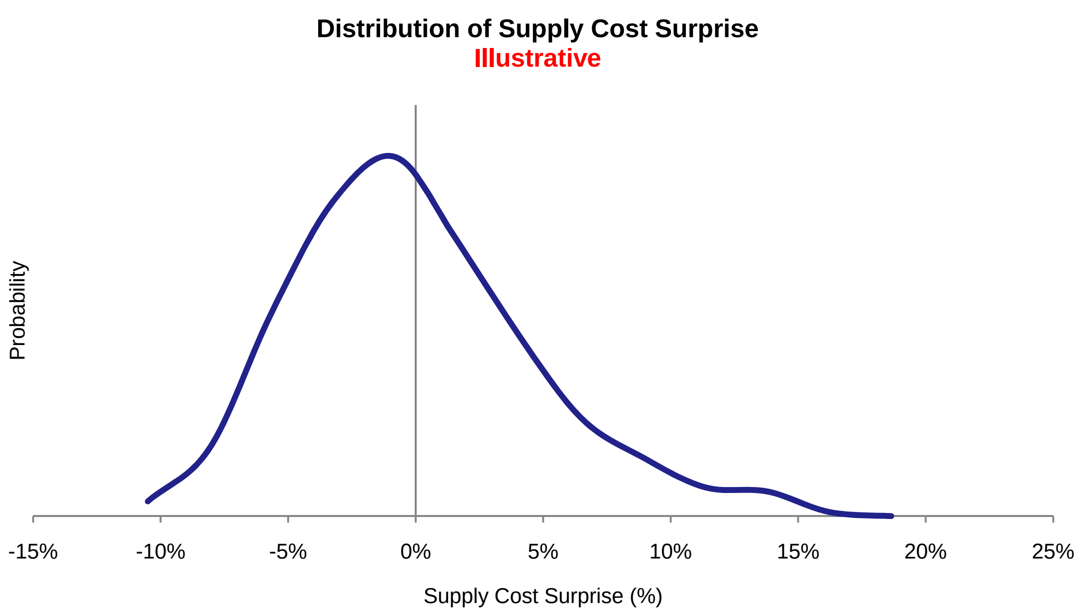
Month	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
Forecasted Supply Costs												
ATC Energy ($ / MWh)	$78.93	$78.93	$65.44	$65.44	$60.71	$63.19	$69.37	$69.37	$62.28	$68.96	$68.96	$68.96
Gross Up (%)	4%	11%	7%	6%	4%	9%	10%	11%	10%	9%	7%	8%
Shaped Energy ($ / MWh)	$81.69	$87.21	$70.02	$69.03	$62.83	$68.88	$76.30	$77.00	$68.20	$74.82	$73.78	$74.13
Capacity ($ / MWh)	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00
Ancillary ($ / MWh)	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
RECs ($ / MWh)	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
Total Rate ($ / MWh)	$97.69	$103.21	$86.02	$85.03	$78.83	$84.88	$92.30	$93.00	$84.20	$90.82	$89.78	$90.13
Load (MWh)	375,714	329,604	341,612	283,764	291,208	375,872	472,194	388,716	324,172	301,542	327,487	381,201
Forecasted Supply Cost ($ / MWh)	$89.97 ($ / MWh)											
Actual Supply Costs												
ATC Energy ($ / MWh)	$94.71	$94.71	$78.52	$78.52	$72.85	$75.83	$83.24	$83.24	$74.74	$82.75	$82.75	$82.75
Gross Up (%)	4%	12%	8%	6%	4%	10%	11%	12%	10%	9%	8%	8%
Shaped Energy ($ / MWh)	$98.36	$105.65	$84.57	$83.27	$75.65	$83.33	$92.39	$93.31	$82.55	$90.48	$89.12	$89.57
Capacity ($ / MWh)	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00
Ancillary ($ / MWh)	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
RECs ($ / MWh)	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
Total Rate ($ / MWh)	$114.36	$121.65	$100.57	$99.27	$91.65	$99.33	$108.39	$109.31	$98.55	$106.48	$105.12	$105.57
Load (MWh)	394,499	346,084	358,693	297,953	305,768	394,665	495,803	408,152	340,381	316,619	343,861	400,261
Actual Supply Cost ($ / MWh)	$105.41 ($ / MWh)											
Supply Cost Surprise ($ / MWh)	$15.44 ($ / MWh)											
Supply Cost Surprise (%)	+17% (%)											

[1] Forecast is for a twelve-month period as of three months prior. While not shown, the supply cost surprise is calculated to ensure an expected surprise of zero.

Note: When the metric for supply cost surprise is expressed in terms of $MM, the calculation is performed by multiplying the $/MWh supply cost surprise by the actual SOS load.

METRICS — Supply Cost Surprise Risk

- In this case, the supply cost surprise was +17%. This means the cost per MWh of SOS supply was 17% greater than had been forecasted
- We perform this same calculation in each scenario and create a distribution of supply cost surprise:



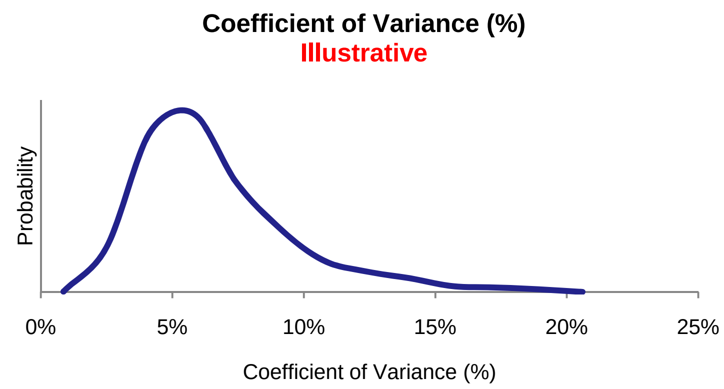
METRICS — Coefficient of Variance

- The coefficient of variance is a metric used by the New York PSC and relates to the volatility of the SOS rate measured on a monthly scale over the prior 12 months:

Illustrative Coefficient of Variance Calculation

Delivery Month	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
SOS Rate (¢ / KWh)	7.74	8.04	7.94	8.65	7.81	8.09	7.96	8.37	9.96	10.40	9.36	8.85
Standard Deviation of Rate (¢ / KWh)	0.74											
Average Rate Level (¢ / KWh)	8.60											
Coefficient of Variance (%)	**8.6%**											

- This statistic is calculated in each scenario, allowing us to create a distribution of values:



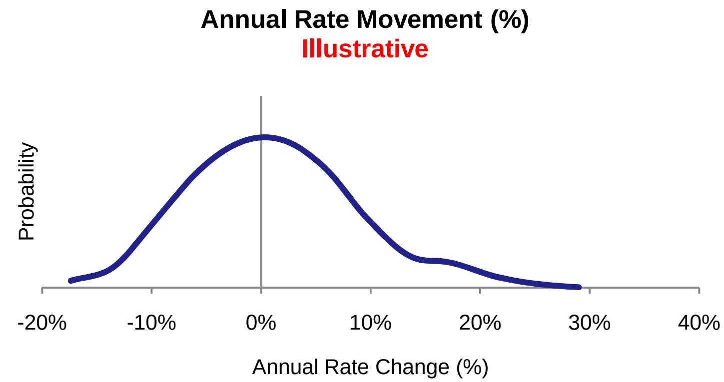
METRICS — Annual Rate Movement

- A variant of the coefficient of variance involves looking at the volatility of year-over-year rate movements:

Illustrative Annual Rate Movement Calculation

Scenario	2013 Rate[1]	2014 Rate[1]	Delta
1	$73.44	$85.51	16.4%
2	$79.97	$84.16	5.2%
3	$76.96	$82.44	7.1%
4	$83.57	$73.11	-12.5%
5	$65.62	$69.12	5.3%
6	$73.08	$75.07	2.7%
7	$77.88	$78.63	1.0%
8	$81.64	$84.54	3.6%
…	…	…	…
2,000	$71.93	$80.77	12.3%

- This statistic is calculated in each scenario, allowing us to create a distribution of values:



[1] Monthly SOS rate is weighted by total eligible load to determine the average rate a customer would face during the year.

METRICS — Deferral Account Balance

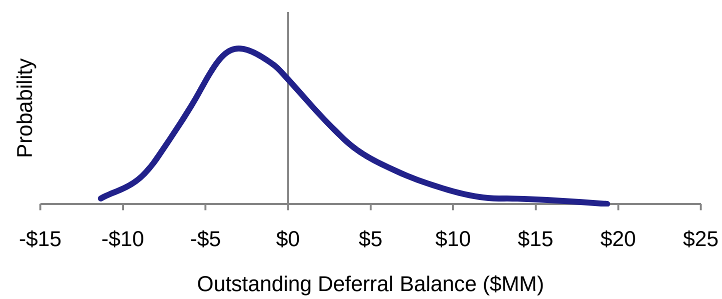
- The deferral account balance metric measures the size of the balance sheet item tracking the accumulated over/under level of cost recovery:

Illustrative Deferral Balance Calculations

Month	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
SOS Rate Revenues ($MM)	$30.0	$30.0	$30.0	$30.0	$30.0	$30.0	$30.0	$30.0	$30.0	$30.0	$30.0	$30.0
Deferral Rider ($MM)			-$0.4	$0.1	$1.7	-$2.5	$1.6	$3.8	-$0.4	-$2.9	$2.7	$1.2
Actual Costs ($MM)	$29.6	$30.1	$31.3	$27.6	$33.3	$31.3	$31.3	$30.9	$32.3	$28.3	$32.2	$29.7
Under / (Over) ($MM)	-$0.4	$0.1	$1.7	-$2.5	$1.6	$3.8	-$0.4	-$2.9	$2.7	$1.2	-$0.5	-$1.5
Interest ($MM)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Deferral Balance ($MM)	-$0.4	-$0.4	$1.3	-$1.1	$0.5	$4.3	$3.9	$1.1	$3.8	$5.0	$4.5	**$3.1**

- This statistic is calculated in each scenario, allowing us to create a distribution of values

Outstanding Deferral Balance EOY 2014 ($MM) Illustrative



Note: Interest of 6% accrues on deferral balances.

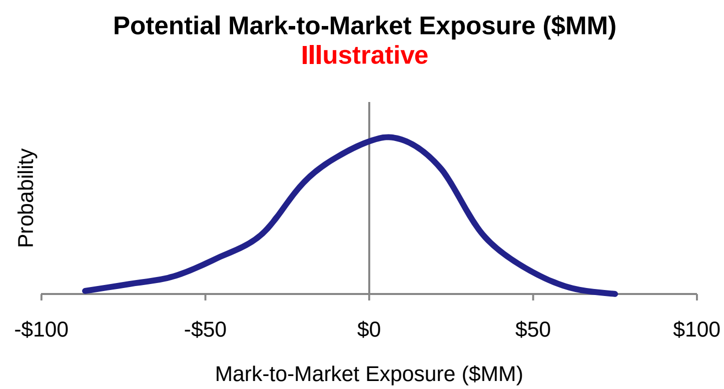
METRICS — Mark-to-Market Exposure

- Mark-to-market exposure indicates how far fixed-quantity commitments are out-of-market, and may be relevant for collateral requirements on block energy products:

Illustrative Mark-to-Market Exposure[1]

Scenario	PV of Payments at Initial Mark	PV of Payments at Market Price	Potential Exposure
1	$11.0	$10.4	$0.6
2	$9.8	$9.9	-$0.1
3	$9.0	$10.3	-$1.3
4	$8.8	$9.4	-$0.6
5	$8.7	$8.8	$0.0
6	$9.5	$9.6	-$0.2
7	$9.5	$8.2	$1.3
8	$8.6	$11.0	-$2.4
…	…	…	…
2,000	$10.2	$9.1	$1.1

- This statistic is calculated in each scenario, allowing us to create a distribution of values:



[1] Mark-to-market exposure can change over the course of the year. Therefore, this metric is calculated by identifying the month during which the average top decile exposure is greatest and then examining the mark-to-market exposure during that month. The calculation involves application of a discount rate of 10%.

CLF 1-6

Request:

On page 22 of testimony witnesses indicate that since ~ 95% of Industrial Group customers are served by the retail supply market they "do not need to rely on LRS to provide them with price stability to the same degree as Commercial and Residential customers." What is the connection between the percentage of accounts served by the retail market and the need for price stability?

Response:

Industrial customers are generally the most willing and/or able to access the competitive retail supply market to meet their needs. As a result, these customers do not need to rely upon Last Resort Service to provide them with price stability to the same degree that commercial and residential customers do. See *Direct Testimony of Margaret M. Janzen*, March 1, 2010, at Page 8 of 42.[1]

Furthermore, the deregulated electric supply market in ISO-NE has historically had concerns with supplier participation. For the same reason that municipal aggregations are successful in offering rates at or lower than LRS, the greater the MWh load value of a customer, the more purchasing power exists. Residential customers and small businesses individually have less purchasing power with smaller loads.

[1] The link to the testimony is: https://ripuc.ri.gov/sites/g/files/xkgbur841/files/eventsactions/docket/4149-NGrid-2011SOS-RES-Plans%283-1-10%29.pdf, See PDF Page 17.

CLF 1-7

Request:

On the subsequent page witnesses assert that 64% of the Commercial Group and 25% of the Residential Group are served by the retail supply market and therefore it is appropriate to procure supply separately.

a. What is the connection between the percentage of customers served by the competitive market and the decision to procure supply separately?

b. Does this imply that there is a point where there is sufficient service by the retail supply market to no longer justify separate procurement?

Response:

a. Since 2011 LRS customers have been grouped into three categories: Industrial, Commercial and Residential. Residential customers pay a fixed price for the six-month period. Commercial customers (except C-06) are under variable default pricing option. Having commercial customers under the variable price option better reflects the underlying monthly supply contract prices. Thus, there is closer alignment of cost incurrence and revenue collection for customers who choose this pricing option than for customers who choose to pay a fixed price for the six-month period. This dynamic is a factor in the decision to procure supply separately because it ensures best procurement practices.

   Furthermore, Residential, Commercial and Industrial customers have different load profiles. For example, Industrial customers often use electricity for processing and other manufacturing related functions. Hence, the load profile of an Industrial customer is different than a Residential customer. Suppliers pricing load based on similar load shape will be able to better forecast loads by group – which would contribute to better results.

b. This probably depends on the number of supplier participation for residential and commercial blocks. Having adequate load to encourage supplier participation is important in the ISO-NE energy market. In addition, having commercial customers under the variable price option well reflects the underlying monthly supply contract prices. Thus, there is closer alignment of cost incurrence and revenue collection for customers who choose this pricing option than for customers who choose to pay a fixed price for the six-month period.

Prepared by or under the supervision of: Jonathan Bausch

CLF 1-8

Request:

On page 32 of testimony the witnesses describe a change in its contingency plan for insufficient participation in the quarterly auctions.

a. For what purpose would the Company consult with the Division to determine if the rates are too high? It is presumed that the open order referenced in Docket 23-50-B did not require consultation.

b. If these changes were made, would the Company have exercised it any of its historic procurement auctions?

Response:

a. The purpose would be if the Company had reason to believe that there is a better procurement option available other than a bid received during the said RFP.

b. The Company cannot say because National Grid had historically been making those decisions at the time. The Company believes it is prudent to consult and analyze alternative procurements if rates are deemed too high. The Company is continuously procuring energy quarterly so there is a strong sense of when market movements are abnormal.

Prepared by or under the supervision of: Jonathan Bausch

CLF 1-9

Request:

In review of the BCA and aligned testimony, the Company asserts that there is "positive, but minimal, benefit impact on Energy Demand Reduction Induced Price Effect and utility Low-Income categories."

a. Is reduced usage uniformly considered a benefit in the Company's analysis?

b. Is there any consideration of what a customer may be forgoing in reducing their usage when determining if it is a benefit – e.g. lowering heat to potentially unsafe levels?

c. Does the Company account for the inability of low-income customers to access energy efficiency programs when determining if seasonally higher prices are a benefit?

d. How is budget billing either a quantitative or qualitative benefit, rather than just a temporal shift of financial liability?

Response:

a. Reduced energy consumption should have a positive impact on the Energy Demand Reduction Induced Price Effect. However, no detailed analysis was conducted to quantify these benefits.

b. The Company believes the well-being of individuals should be considered in reducing their usage and does not recommend lowering heat to potential unsafe levels.

c. The Company has two programs specifically for Income Eligible customers: Single Family and Multifamily. Evaluation studies have been conducted to determine the barriers to participation, and actions have been taken to attempt to overcome the barriers. The Company typically increases its marketing and outreach activities in the fall, leading up to price increases, to help customers undertake energy efficiency activities before they encounter higher bills.

d. Budget billing makes monthly utility bills more predictable and reduces the possibility of late payment penalties or possible disconnection. However, no analysis was conducted to quantify these benefits.

Prepared by or under the supervision of: Jonathan Bausch

CLF 1-10

Request:

On page 37 of testimony, the Company asserts that "[t]he 2025 LRS Plan results in LRS rates that reflect futures market pricing, therefore creating a market for NPPs to compete for customers. Please explain why futures market pricing allows for competition, when an NPP, to gain a new customer, would be offering current market prices which would be compared to a futures market price.

Response:

The LRS Plan having positive net benefits on Consumer Empowerment & Choice means that the LRS Plan will bring supplier participation into the ISO-NE deregulated energy market. The deregulated energy market has competition based on what level of risk a deregulated supplier or NPP is willing to take in providing that service to customers. Electric suppliers do not necessarily offer the same futures market prices when gaining on a new customer. Indeed, there are indices used to determine futures energy pricing – but there are usually premiums on top of whatever index a supplier is using to forecast their price offerings. Deregulated suppliers are for profit and their intent is to be profitable from whatever position they offer, relative to the futures curve. The unknown between what futures pricing is, and what actual pricing will be is what suppliers are offering a premium for. This provides customers with a certainty or insurance on how high their rates could go. Electric generation assets or NPPs are involved in setting the futures pricing, and that competition is reinforced when customers participate in that market.

CLF 1-11

Request:

On page 37 when providing a cost comparison between LRS and competitive supply, what competitive supply rates were used as a point of comparison? Did it the analysis consider any variation in the products in determining value, i.e. customer incentives, increased renewables, etc.?

Response:

The competitive supply rates used as a point of comparison were derived from the Company's billing system. The Company's billing system records which customers are being served through competitive supply and which customers are served by LRS. The comparisons were determined both by analyzing the cost and kWh consumption for each customer class. The analysis did not consider the variation in products, customer incentives or increased renewables.

CLF 1-12

Request:

On page 38 in reviewing Societal Level costs, the Company asserts that the "LRS Plan is not intended to address these issues, and therefore most of the category is not applicable." Does this mean that the Company's threshold for analysis is intent of the program? Is the Company aware of any unintended impacts on societal level costs and benefits that are not included?

Response:

In its evaluation the Company follows Docket No. 4600 Benefit-Cost Framework. The evaluators were not aware of any other impacts at the societal level that were not included in the Framework.

Prepared by or under the supervision of: Jonathan Bausch

CLF 1-13

Request:

On page 39 witnesses indicate that they considered the State's ability to achieve its Climate Mandates followed by recognition that it is a legal obligation to provide LRS. What was the Company's analysis? Did the Company identify a conflict between Climate Mandates and provision of LRS?

Response:

The Company did not identify a conflict between Climate Mandates and the provision of LRS. The Company is obligated to provide electricity supply to customers who do not select competitive suppliers through Last Resort Service. Renewable energy mandates are met through the Renewable Energy Standard program. The Company has an obligation to meet both requirements. The Company did not complete a specific analysis related to this section on page 39.

Prepared by or under the supervision of: Jonathan Bausch

Certificate of Service

I hereby certify that a copy of the cover letter and any materials accompanying this certificate was electronically transmitted to the individuals listed below.

The paper copies of this filing are being hand delivered to the Rhode Island Public Utilities Commission and to the Rhode Island Division of Public Utilities and Carriers.

Joanne M. Scanlon

September 26, 2024
Date

Docket No. 24-20-EL – The Narragansett Electric Co. d/b/a Rhode Island Energy – 2025 Last Resort Service Procurement Plan
Service List updated 8/12/2024

Name/Address	E-mail Distribution	Phone
The Narragansett Electric Company d/b/a Rhode Island Energy Andrew Marcaccio, Esq. Celia B. O'Brien, Esq. 280 Melrose Street Providence, RI 02907	AMarcaccio@pplweb.com; COBrien@pplweb.com; JHutchinson@pplweb.com; JScanlon@pplweb.com; JWBausch@pplweb.com; SBriggs@pplweb.com; ACastanaro@pplweb.com; JOliveira@pplweb.com;	401-784-4263
Division of Public Utilities Margaret L. Hogan, Esq.	Margaret.L.Hogan@dpuc.ri.gov; Christy.Hetherington@dpuc.ri.gov; John.Bell@dpuc.ri.gov; Al.Mancini@dpuc.ri.gov; Al.Contente@dpuc.ri.gov; Paul.Roberti@dpuc.ri.gov; Machaela.Seaton@dpuc.ri.gov; Ellen.Golde@dpuc.ri.gov;	401-274-4400
James Rouland Kathleen Kelly Aliea Afnan Daymark Energy Advisors	jrouland@daymarkea.com; kkelly@DaymarkEA.com; aafnan@daymarkea.com;	

File an original & 9 copies w/: Stephanie DeLaRosa Commission Clerk Public Utilities Commission 89 Jefferson Blvd. Warwick, RI 02888	Stephanie.DeLaRosa@puc.ri.gov; Alan.Nault@puc.ri.gov; John.Harrington@puc.ri.gov; Todd.Bianco@puc.ri.gov; Christopher.Caramello@puc.ri.gov; Kristen.L.Masse@puc.ri.gov	401-780-2017
INTERESTED PARTIES:		
Victoria Scott, Governor's Office	Victoria.Scott@governor.ri.gov;	
Marc Hanks, Direct Energy	Marc.Hanks@directenergy.com;	
Good Energy, Inc. Laura S. Olton, Esq. Patrick Roche	laura@lsoenergyadvisors.com; patrick@goodenergy.com;	
Office of Energy Resources Albert Vitali, Esq. Division of Legal Services One Capitol Hill, Fourth Floor Providence, RI 02908 Christopher Kearns	Albert.vitali@doa.ri.gov; Christopher.Kearns@energy.ri.gov; steven.chybowski@energy.ri.gov; Nancy.Russolino@doa.ri.gov; jdalton@poweradvisoryllc.com;	401-724-3600
RI Attorney General Office Nicholas Vaz, Esq. 150 South Main St. Providence, RI 02903	nvaz@riag.ri.gov; mbedell@riag.ri.gov;;	