nationalgrid

Jennifer Brooks Hutchinson
Senior Counsel

January 29, 2016

VIA HAND DELIVERY AND ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket 4556 – 2016 Standard Offer Service Procurement Plan
<u>Compliance Filing</u>

Dear Ms. Massaro:

Enclosed please find ten (10) copies of the Company's[1] filing of a report from The Northbridge Group, Inc., regarding its review and analysis of procurement methods for Rhode Island Standard Offer Service. This filing is made in compliance with the Rhode Island Public Utilities Commission's (PUC) decision at the July 1, 2015 Open Meeting, in which the PUC stated:

> National Grid shall conduct an analysis of whether and to what extent its SOS procurement plan addresses current wholesale electricity market conditions. To be consistent with R.I.G.L. Section 39-1-27.8 and least cost procurement, such analysis shall include the extent to which current market conditions are conducive to discretionary hedge of the spot market with FRS contracts in the SOS procurement process. The analysis should refer to, and expand upon, the Northbridge Study filed by National Grid on January 22, 2010 in Docket 4041. National Grid shall file this analysis with the PUC on or before January 29, 2016.[2]

Thank you for your attention to this transmittal. If you have any questions, please contact me at 401-784-7288.

Very truly yours,

Jennifer Brooks Hutchinson

Enclosure
cc: Docket 4556 Service List
Leo Wold, Esq.
Steve Scialabba, Division

[1] The Narragansett Electric Company d/b/a National Grid (Narragansett or the Company)
[2] Docket No. 4556, Decision Summary, dated July 2, 2015.

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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

January 29, 2016
Date

Docket No. 4556 - National Grid – 2016 Standard Offer Service (SOS) and Renewable Energy Standard (RES) Procurement Plans
Service List updated 5/29/15

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Analysis of Rhode Island Standard Offer Service Supply Procurement

Prepared for National Grid

Re: RI PUC Docket 4556

January 29, 2016

NORTHBRIDGE

This report was authored by Scott Fisher, Neil Fisher, and David Coleman, all Principals of The NorthBridge Group, Inc. ("NorthBridge"). NorthBridge is an economic and strategic consulting firm serving the electric and natural gas industries, including regulated utilities and companies active in the competitive wholesale and retail markets. NorthBridge clients include vertically integrated utilities, restructured utilities, and other electricity market participants. As Principals of NorthBridge, the authors have assisted clients with wholesale market design issues, competitive market analysis and strategy, regulated power supply procurement, state regulatory initiatives and strategy, and mergers and acquisitions. The authors have significant experience with issues pertaining to the procurement of standard offer service supply, having advised regulated utilities (as purchasers) and competitive suppliers (as sellers) on such matters. The views expressed in this report reflect the authors' independent evaluation of the issues discussed herein.

This report presents an analysis of the relative costs and risks of different approaches to serve Rhode Island residential 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 also will change.

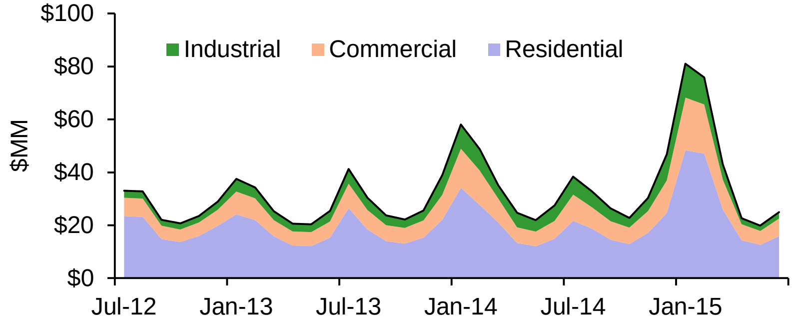
Rhode Island General Laws §§ 39-1-27.3 and 39-1-27.8 require National Grid to arrange for power supply for customers who are not otherwise receiving electric service from a Non-Regulated Power Producer. Specifically, pursuant to RIGL § 39-1-27.8, from 2009 through 2018, the Company must file an annual supply procurement plan with the Rhode Island Public Utility Commission ("PUC") that includes the procurement procedure, the pricing options being sought, and a proposed term of service for which Standard Offer Service ("SOS") will be acquired. In its July 2, 2015 Decision Summary, the PUC decided:

> "National Grid shall conduct an analysis of whether and to what extent its SOS procurement plan addresses current wholesale electricity market conditions. To be consistent with R.I.G.L. §39-1-27.8 and least cost procurement, such analysis shall include the extent to which current market conditions are conducive to discretionary hedging of the spot market with FRS contracts in the SOS procurement process. The analysis should refer to, and expand upon, the Northbridge Study filed by National Grid on January 22, 2010 in Docket 4041. National Grid shall file this analysis with the PUC on or before January 29, 2016."
>
> *-- RI PUC Decision Summary, Docket 4556, July 2, 2015.*

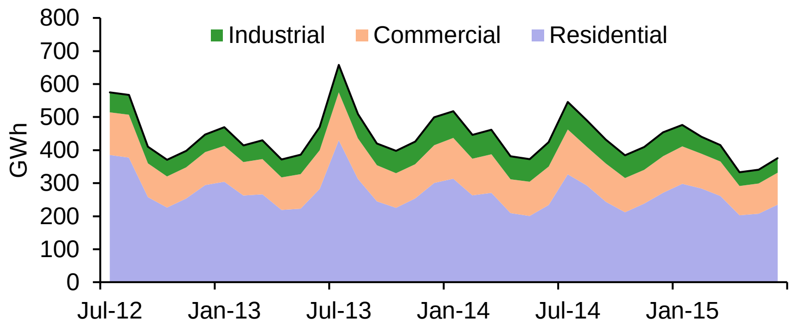
In response to the PUC's decision, National Grid engaged NorthBridge to update its previous analysis taking into account current market conditions and new information since its original report was completed in January 2010.

Electric SOS supply procurement decisions impact many customers and involve substantial amounts of money:

Monthly Supply Cost by Procurement Group



Monthly SOS Load by Procurement Group



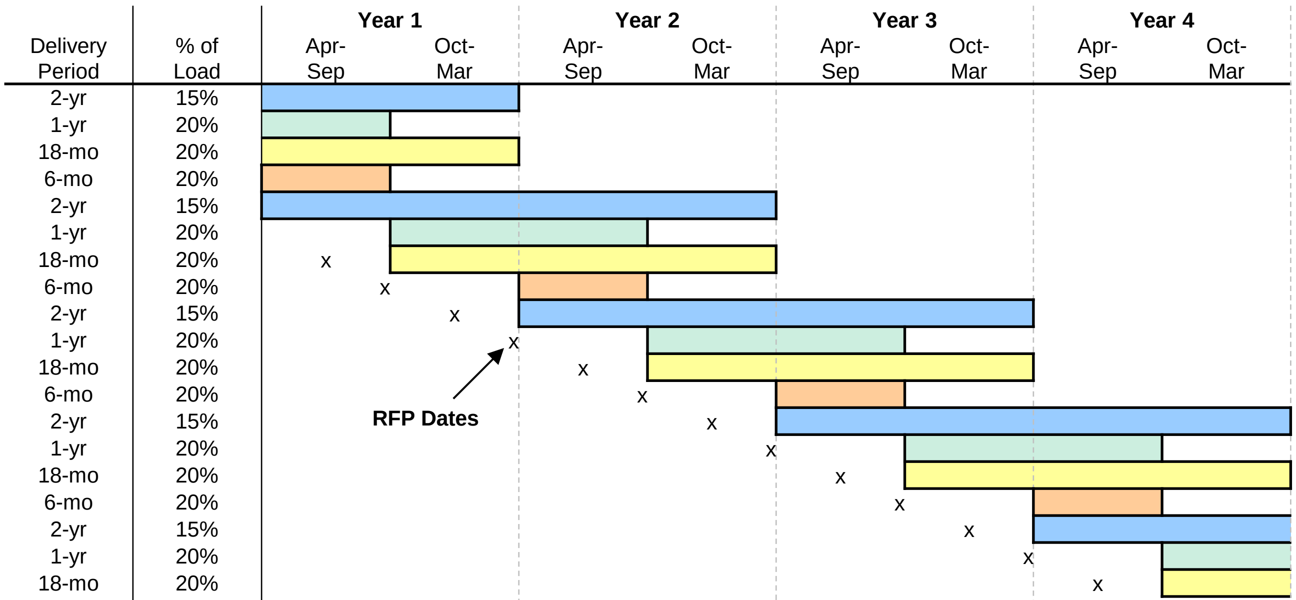
- National Grid currently spends about $465 million for 5,000 GWh annually.[1]
- This includes about 390,000 residential customers representing about 3,000 GWh or 60% of the total SOS load.[2]
- The need for SOS is likely to continue for the foreseeable future.

This presentation, including our forward-looking analysis of SOS procurement approaches, focuses on residential customer load in Rhode Island.

[1] Numbers represent the 12-month period ending June 2015.
[2] "Residential" consists of customers receiving service on Basic Residential Rate A-16 and Low Income Discount Rate A-60.

OVERVIEW Current Procurement Approach

National Grid currently procures supply for the Residential Group using a repeating procurement schedule that consists of quarterly solicitations for overlapping Full Requirements Service ("FRS") products with four different delivery period durations:[1]



	Delivery Period	Year 1 Apr-Sep	Year 1 Oct-Mar	Year 2 Apr-Sep	Year 2 Oct-Mar	Year 3 Apr-Sep	Year 3 Oct-Mar	Year 4 Apr-Sep	Year 4 Oct-Mar
Four Delivery Period Durations	2-yr	30%	30%	30%	30%	30%	30%	30%	30%
	1-yr	20%	20%	20%	20%	20%	20%	20%	20%
	18-mo	20%	40%	20%	40%	20%	40%	20%	40%
	6-mo	20%	0%	20%	0%	20%	0%	20%	0%
	Total	90%	90%	90%	90%	90%	90%	90%	90%

- Winning suppliers for each six-month segment are paid based on monthly bid prices.
- Rates adjust every six months (April 1 and October 1).
- Rates and costs are reconciled for the prior calendar year starting April 1 with deferral balances recovered over 12 months from SOS customers.

FRS products satisfy 90% of the Residential load requirements, and the remaining 10% of the load requirements are satisfied through ISO-NE spot market purchases.

[1] Under the current approach, for each product that is solicited, that product's delivery period is separated into six-month periods. The supply associated with a given six-month period within a given product is known as a "segment" or "block" (not to be confused with "block products" discussed later in this presentation), and different bidders can be awarded different segments of the product. While bidders may "shape" their bids by bidding a different $/MWh supply price for each month within a given segment, customer rates are set at a single $/MWh value for the corresponding six months, in which the customer rate reflects an estimated overall supply cost for that period (plus adjustments such as reconciliations from prior periods).

An important aspect of our analysis involves understanding the relative costs and risks associated with alternative SOS procurement approaches to serve Rhode Island residential customers. In particular, we seek to determine:

1. Do the FRS products under the current procurement approach protect customers from market price risks given current wholesale electricity market conditions?

2. Is the pricing for FRS products reasonable given current wholesale electricity market conditions?

3. What changes could be made to the current procurement approach to provide greater rate stability, reduce accumulation of cost recovery deferrals, and/or enhance supply cost predictability?

4. Is there convincing market evidence to suggest that a departure from the FRS product approach is warranted?

5. Are current market conditions conducive to discretionary hedging of the spot market with FRS products?

1. **FRS products under the current procurement approach protect customers from significant market price risks.**
   a) The *expected* SOS rate under 100% spot procurement is about $3/MWh (i.e., about 4% of the supply rate) lower than the current procurement approach, but spot procurement would expose customers to disproportionate rate volatility.
   b) While the current approach provides notable protection, our simulation modeling indicates that there is a 93% probability that at some point in a given year there will be a supply rate increase of at least 25% and a 14% probability of a supply rate increase of at least 50%.[1]
2. **FRS product pricing remains reasonable given the potential value of this "insurance."**
   a) FRS product pricing levels have been reasonable overall.
   b) Increased market uncertainty, which FRS suppliers must manage to the benefit of customers, may be a factor in instances in which the residual compensation values were higher than previously expected (in 2010).
   c) Bidder participation in solicitations for Rhode Island's residential FRS products has been consistently high, providing further evidence that the FRS product pricing is competitive.
3. **Changes to the current approach could be made to provide greater rate stability, reduce deferral balance risks, and enhance supply cost predictability.**
   a) Incorporate flat pricing over the entire product delivery periods (or for at least 12-month segments).[2]
   b) Eliminate the 10% spot component.
   c) Reduce the portion of shorter-term products.
4. **Market evidence does not convincingly support a departure from the FRS product approach.**
5. **Adoption of a "discretionary hedging" approach, in which procurement decisions are made based on judgments about future market price levels, likely would increase risks for customers without a corresponding benefit. However, it may be appropriate to allow some discretion in situations in which an extraordinary event results in a high likelihood that competitively-priced bids would not be obtained on the scheduled bid date.**

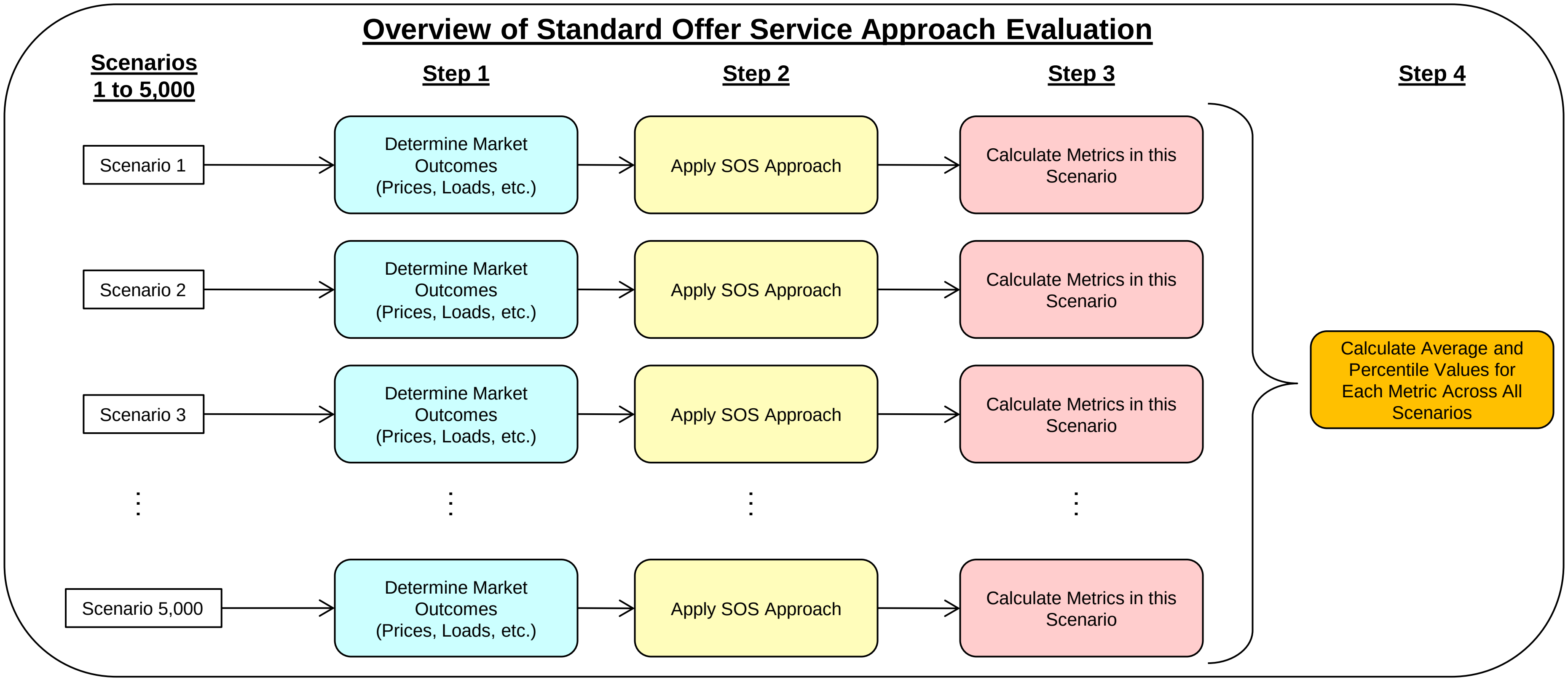
[1] Furthermore, the actual probabilities of these rate increases could be higher to the extent that the model does not capture all of the (anticipated or unanticipated) risks.

[2] However, if the Commission opts for some seasonality in SOS prices, it could either (1) apply administratively-determined seasonal factors, or (2) incorporate some six-month products into the portfolio. But, this would increase the potential for rate shock.

Overview of Analysis

ANALYSIS OVERVIEW — Monte Carlo Simulation

In order to analyze various SOS approaches, 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 under a wide range of market scenarios:



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

Procurement — **Linkage** — **Cost Recovery**

Procurement

Product Duration
- 20-year
- ↑
- 3-year
- 2-year
- 1.5-year
- 1-year
- 6-month
- ↓
- Hourly (spot)

Product Type
- Mix of Products
- ↑
- Full Requirements
- Block
- ↓
- Spot

Hedge Target
- 100%
- ↑
- 90%
- 75%
- 50%
- ↓
- 0%

Supplier Price Structure
- Flat price for product duration
- ↑
- 12-month flat price
- 6-month flat price
- Shaped (FRS)
- ↓
- Hourly (spot)

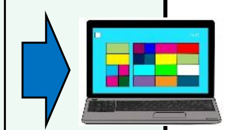
Maximum Turnover[1]
- 100%
- ↑
- 50%
- ↓
- 0%

Cost Recovery

Retail Rate Adjustments
- Annually or Longer
- ↑
- Semi-Annually
- Quarterly
- Monthly
- ↓
- Hourly

Deferral Balance Accruals
- Annually (cal-year)
- ↑
- Monthly
- ↓
- None

Recovery Period
- Annually (w/ 3-month lag)
- ↑
- Monthly
- ↓
- None



Note: Current approach is highlighted in red.

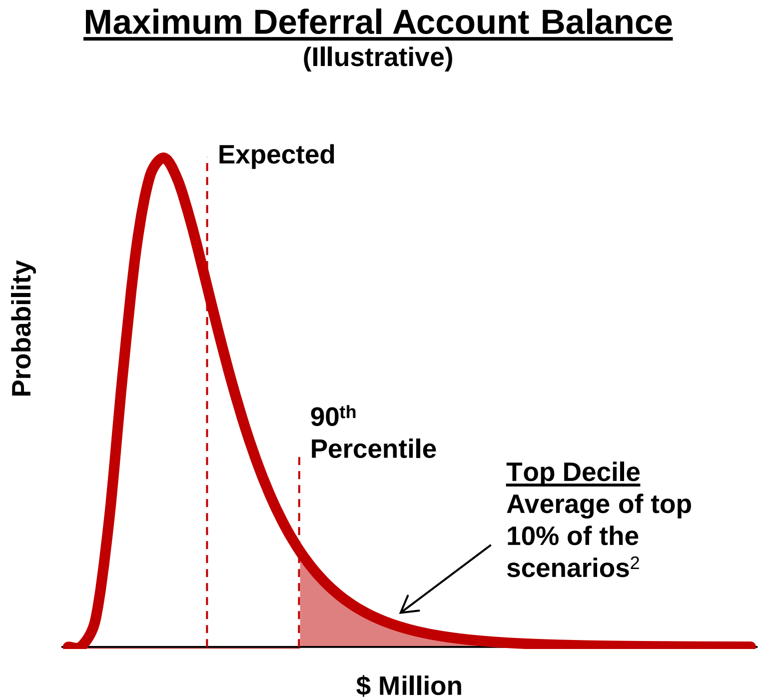
[1] Maximum percentage of the supply replaced at any point in time.

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

Results were evaluated using the following metrics:

Metric
Rate Shock Distribution of the maximum rate change from one six-month period to the next (during a given year)
Annual Rate Movement Distribution of changes in the average SOS rate paid from one year to the next
Maximum Deferral Account Balance Distribution of maximum accumulated under/(over) collections due to differences between SOS rates and actual supply costs
Oct-Mar Supply Cost Surprise Distribution of the difference between actual (ex post) and forecasted (ex ante) October-March supply costs (i.e., how do actual supply costs during this critical period compare to expectations three months before the period began)
Expected Rate Level[1] Average SOS rate level across scenarios

To assess risks, distributions of the metrics were analyzed:



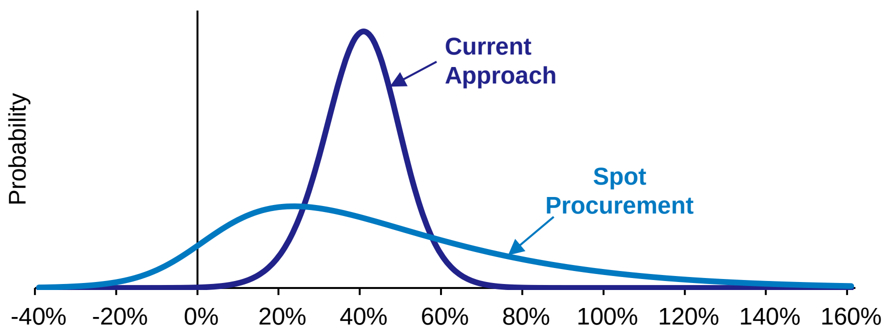
[1] Unless otherwise noted, rates in this presentation refer to the supply rate (including any related deferral account reconciliations), not including the delivery services portion of a customer's bill, and not including gross-ups for line losses, retail taxes, and other administrative costs.

[2] The risk measurements are expressed in terms of the averages of the top 10% of values across the scenarios modeled. Actual outcomes could be larger than these figures. Furthermore, the probabilities of values similar to or greater than the top decile values are even higher to the extent that the model does not capture all of the (anticipated or unanticipated) risks.

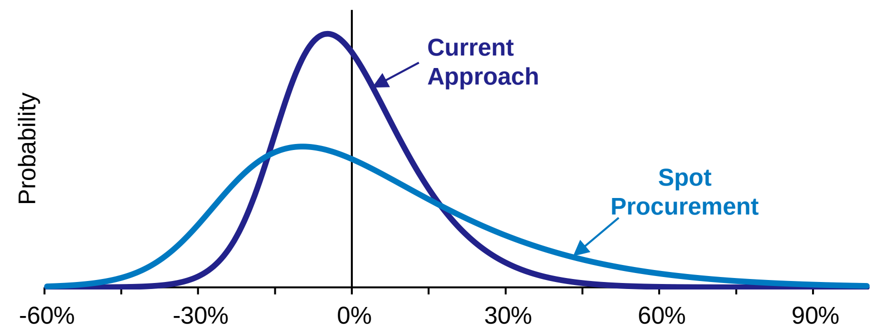
1. **Do the FRS products under the current procurement approach protect customers from market price risks given current wholesale electricity market conditions?**

FRS products under the current procurement approach protect customers from significant market price risks. The *expected* SOS rate under 100% spot procurement is about \$3/MWh lower than the current procurement approach, but spot procurement would expose customers to disproportionate rate volatility:[1]

Rate Shock (%)



Annual Rate Movement (%)



	Rate Shock (top decile, %)	Annual Rate Movement (top decile, %)	Maximum Deferral Account Balance (top decile, \$)	Oct-Mar Supply Cost Surprise (top decile, \$/MWh)	Expected Rate Level (average, \$/MWh)
Spot Procurement	116.5%	55.2%	\$0MM[1]	\$39.07	\$66.84
Current Approach	57.1%	26.5%	\$31MM	\$4.06	\$70.11
Difference	-59.4%	-28.7%	+\$31MM	-\$35.01	+\$3.27

While the current approach provides notable protection, our simulation modeling indicates that there is a 93% probability that the rate shock in a given year will be at least 25% and a 14% probability that it will be at least 50%.[2]

[1] For the purposes of the charts and table above, the specific values for the "Spot Procurement" approach assume that rates are set monthly based on actual ex-post spot costs. The top decile value for "Rate Shock" under this approach is calculated by load weighting the monthly rates across six-month periods, and the "Rate Shock" value is measured off of those six-month load-weighted rate levels.

[2] Furthermore, the actual probabilities of these rate shocks could be higher to the extent that the model does not capture all of the (anticipated or unanticipated) risks.

A previous study by the Division also indicated that National Grid's procurement strategy has been effective in mitigating rate increases relative to other states:[1]

- "According to the Division's research, the standard offer service rate increases in Massachusetts and New Hampshire have surpassed Rhode Island's standard offer rate increase, in some cases by as much as 45%."
- "The Division noted that Rhode Island's comparatively low standard offer service rates reflect that National Grid has already mitigated the impact of winter price volatility to some extent by establishing a rate that reflects an average of six different price points and by procuring power over longer and more varied time periods."

The PUC recently reaffirmed the value of reasonable and stable SOS rates:[2]

- "The Commission will expect the Company to provide assurances at this time that its procurement practices have been designed to the fullest extent possible to mitigate winter price volatility and strive to achieve reasonable and stable standard offer service rates for all customer classes."
- "[I]n light of the size of the increase proposed in this matter and the level of public opinion waged in this docket, the Commission is compelled to exercise its authority to mitigate the impact of this rate increase to the greatest extent possible."
- "[T]he legislature has expressly recognized the limitation of retail competition and the importance of rate stability to a viable economy."

And PUC staff has commented on the relative value of providing price signals for customers:

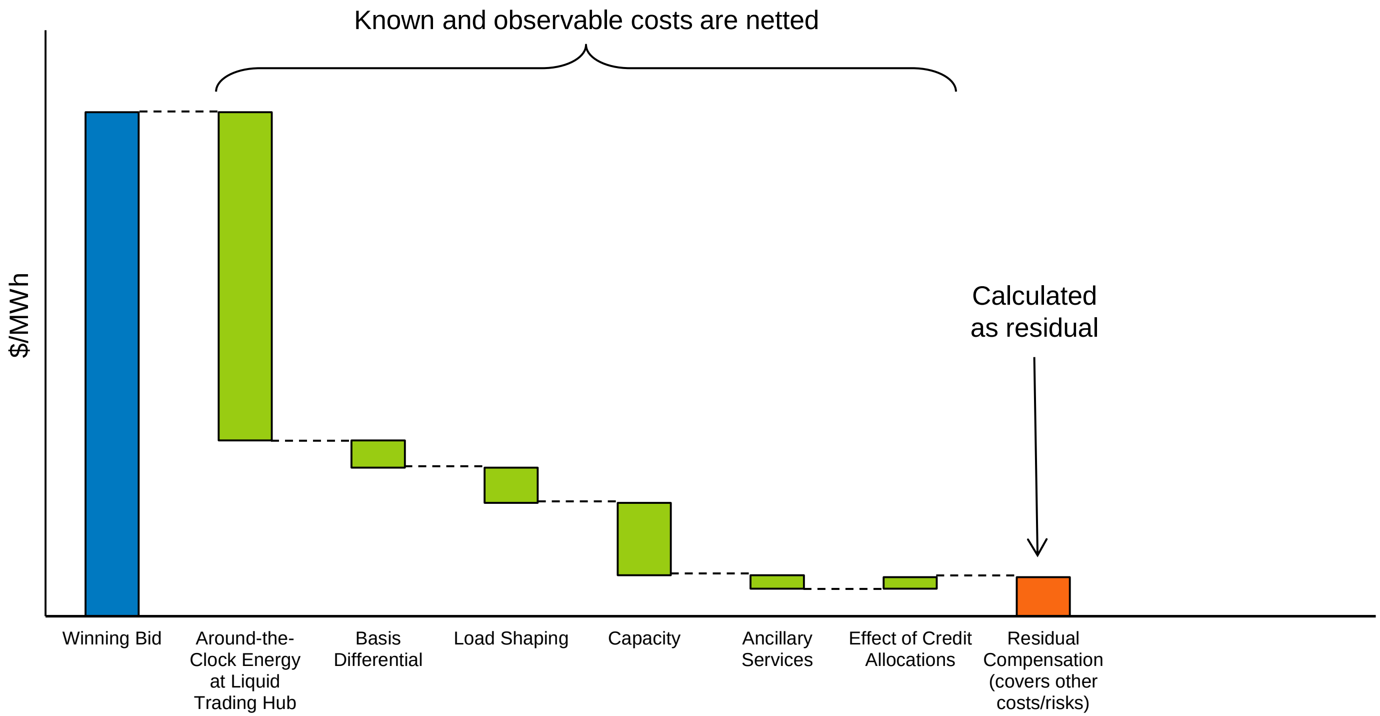
- Regarding a decision to shift the timing of National Grid's six-month rate periods…"There may be a little bit more volatility [from the rate period shift], but it goes toward giving customers a price signal."

[1] RI PUC Order No. 21827, Docket 4393, February 23, 2015, p. 6.
[2] Ibid., pp. 17-18.
[3] "National Grid Seeks Electric Rate Reduction," Providence Journal, October 16, 2015. (Quote from Alan Nault, RI PUC Analyst.)

2. Is the pricing for FRS products reasonable given current wholesale electricity market conditions?

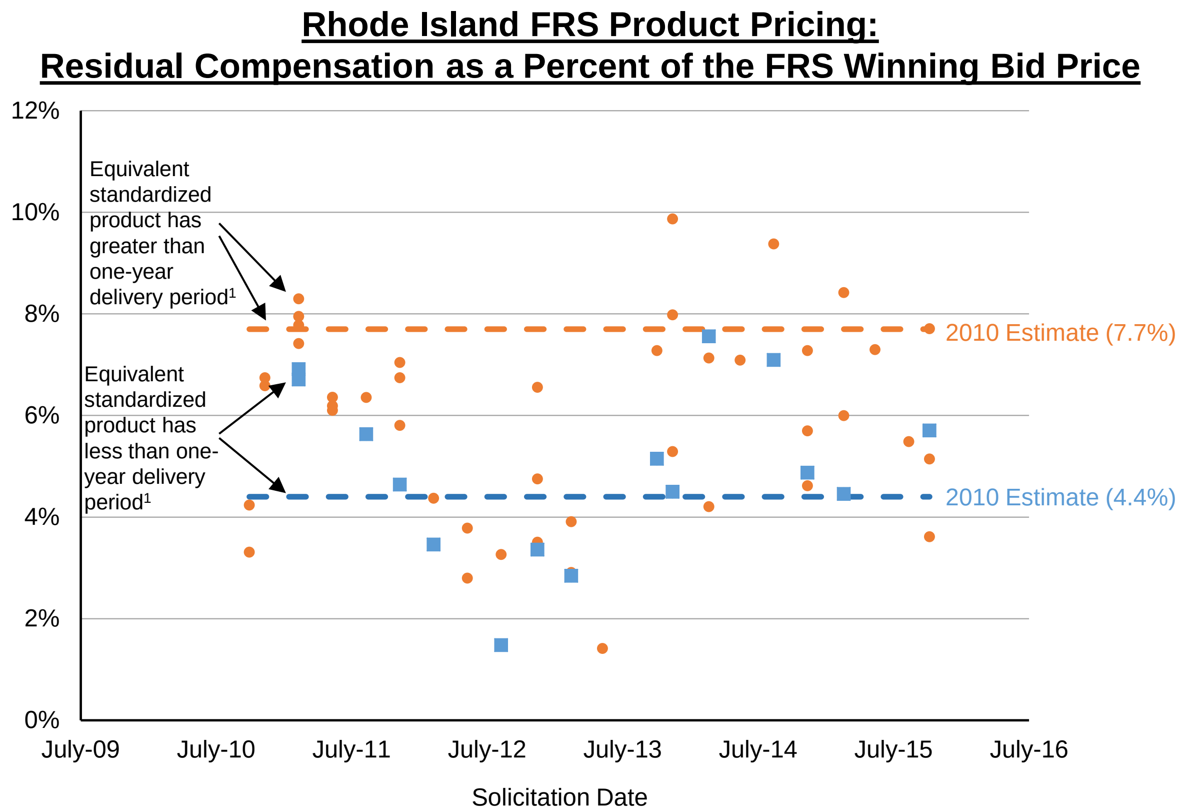
In order to evaluate FRS product pricing for SOS supply products solicited by National Grid in Rhode Island, we used market information to develop estimates of expectations (at the time of each solicitation) regarding the costs of various components of the FRS supply product, and compared these costs to the actual winning bid prices for each FRS product:

Illustrative Full Requirements Product Price Analysis



The residual compensation required by FRS product suppliers (to cover the other costs and risks that were not individually quantified), which was observed through our study of actual Rhode Island solicitations, was incorporated in our simulation analysis.[1]

[1] The residual compensation assumptions in the simulation analysis are based on the actual solicitation results during 2013-2015, as the first significant price spike occurred in January 2013.



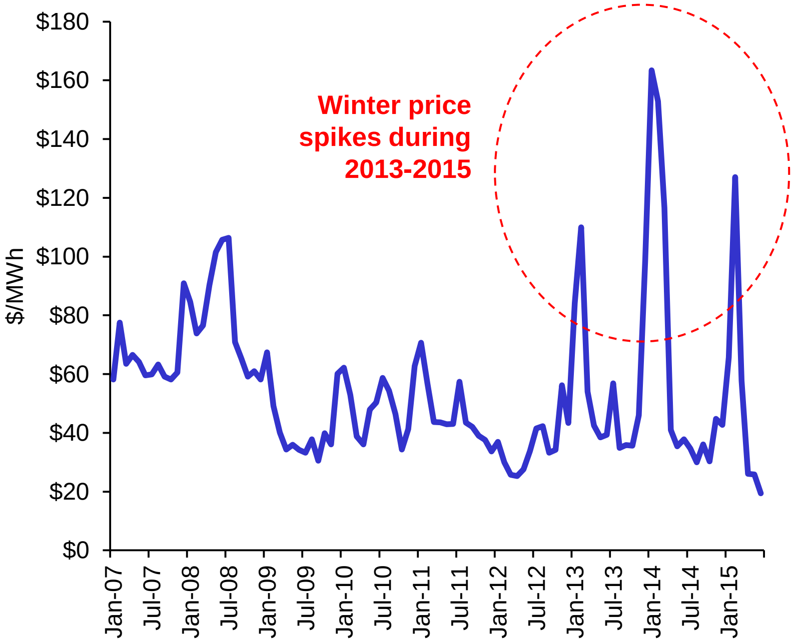
- FRS product pricing levels have been reasonable overall.
- Residual compensation tends to be somewhat higher for products that are solicited further away from delivery, as these products protect against greater market uncertainty.
- FRS pricing for longer-term products has been generally lower than estimated in our 2010 analysis, yet for shorter-term products the pricing has been somewhat higher than previously estimated.[2]

[1] A one-year equivalent standardized product refers to a product for which there is nine months from the bid date to the midpoint of the delivery period, because a one-year product has six months from the start of delivery to the midpoint of the delivery period and this equivalent standard assumes a lead time (from the bid date to the start of delivery) of three months.

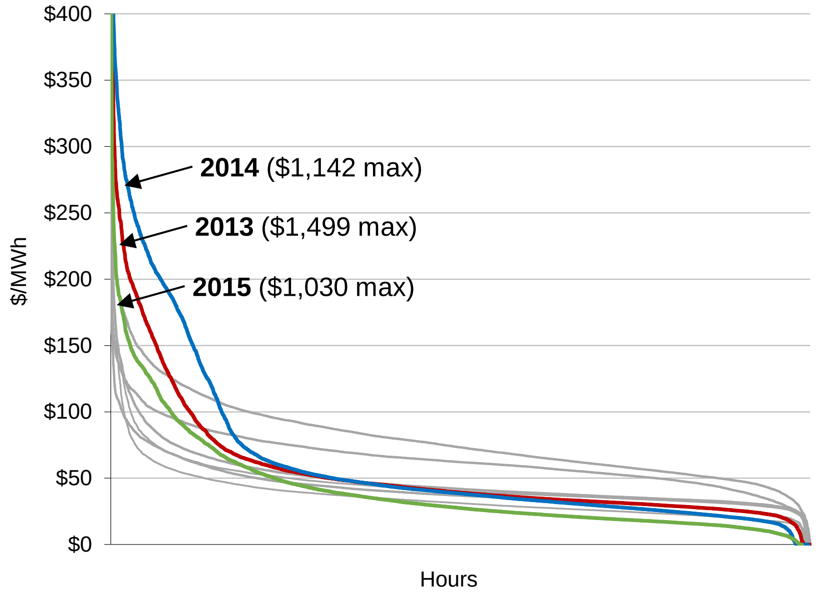
[2] For solicitations held during the period September 2010 through October 2015, residual compensation for products less than nine months from the bid date to the midpoint of the delivery period has averaged 5.0% of the winning bid price. During the same period, residual compensation for products greater than nine months from the bid date to the midpoint of the delivery period has averaged 5.9% of the winning bid price.

Increased market price volatility (that FRS suppliers must manage) may be a factor in instances in which the residual compensation values were higher than previously expected (in 2010):

RI Zone Around-the-Clock (7x24) Energy Price
(monthly)



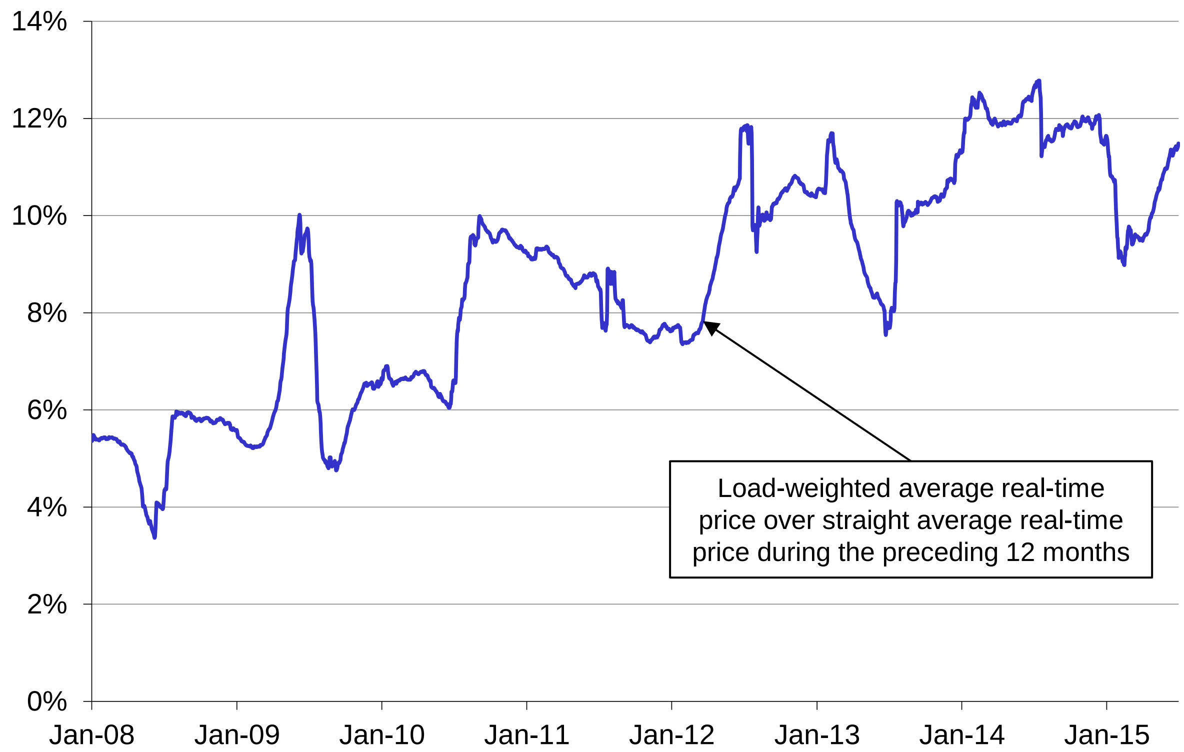
2007-2015 RI Zone Spot Price Duration Curves



Price uncertainty, evidenced by the spot price spikes during the 2013-2015 winters and the changing price duration curves, translate into increased risks for FRS product suppliers who provide price protection for customers.

The cost of the load following "gross-up" – the ratio of National Grid's hourly residential load-weighted spot price to the average spot price over a 12-month period – has more than doubled since 2008:

Historical National Grid Residential 12-Month Load Following "Gross-Up"



This variability and unpredictability adds to the costs and risks that FRS product suppliers must cover to supply SOS customers.

FRS PRODUCT PRICING High Market Risks Going Forward?

The PUC found that recent price spikes and rate increases reflect issues that are broader than Rhode Island, and that underlying factors such as increasing natural gas dependency and power plant retirements over the next five years may make the region even more susceptible to price spikes:

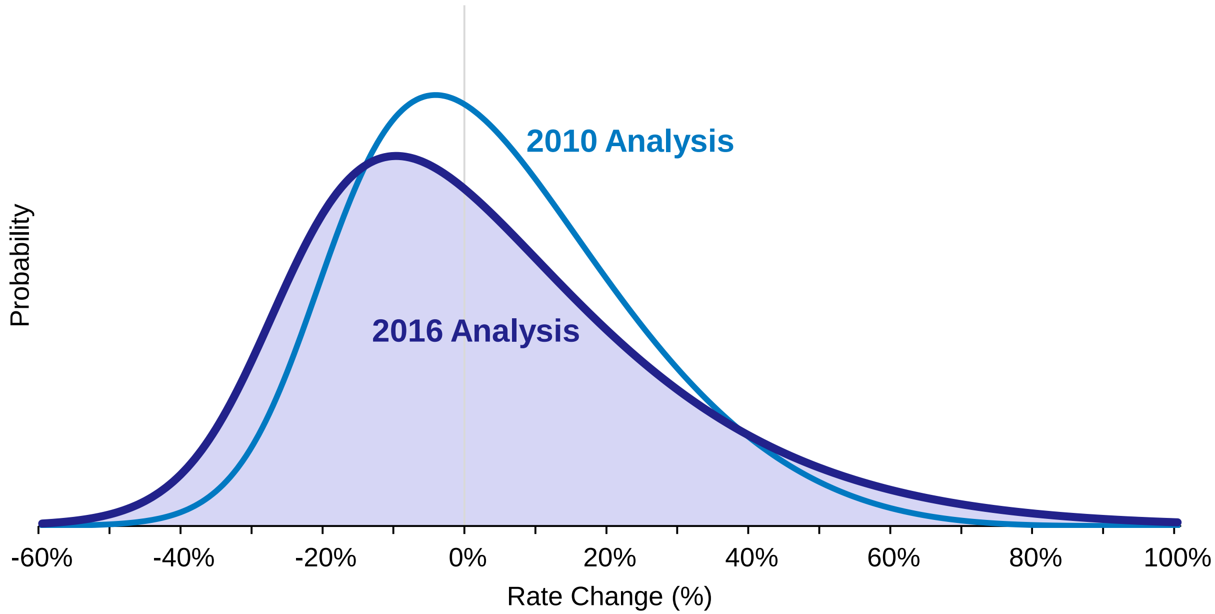
> National Grid's proposed 26.1% standard offer service rate increase reflects a problem that extends beyond the R.I. Public Utilities Commission, National Grid and the State of Rhode Island. It is a problem faced by the entire New England region which policymakers, utility experts and the regional system operator have been grappling with for years. The Independent System Operator of New England (ISO-NE) recognized the gas constraint issue in 2010 when it launched the Strategic Planning Initiative (SPI). SPI, supported by stakeholders from around the region, identified three problems facing the region which threatened the reliability of the grid and the efficiency of electricity wholesale markets. To suggest that the rising cost of power is attributable to National Grid or this Commission ignores what is common knowledge in the utility industry…
>
> Factors contributing to winter price spikes in New England, including Rhode Island, are natural gas dependency and power plant retirements. Natural gas has become the favored source of energy generation in the region due to its low cost and comparatively appealing environmental attributes. Half of the electricity generated in New England is from gas-fired plants, and with ninety-five percent (95%) of proposed new generation coming from gas and wind resources, the trend is toward more, not less, natural gas. During periods of peak demand, i.e. the coldest days of winter, New England suffers from the inability to import needed natural gas from neighboring states like Pennsylvania, which are plentiful in natural gas. This constraint has led to increasingly high wholesale electricity prices. It is these increasingly high wholesale electricity prices which distribution companies from around the region, including National Grid, must pay to supply standard offer service to customers…The gas constraint problem is exacerbated by the retirement of baseload power plants and expansion of renewable energy resources. The retirement of four major power plants over the next five years, equivalent to an estimated 3,300 MW, will make the region even more reliant on natural gas.

-- RI PUC Order No. 21827, Docket 4393, February 23, 2015, pp. 10-12, emphasis added.

Greater price volatility and associated risks observed since our 2010 analysis are reflected in our updated simulation model of future market scenarios, as illustrated below by the wider range of potential annual rate changes absent any hedging:

Forecasted Distribution of Annual Rate Changes with No Hedging

(100% Spot Procurement)

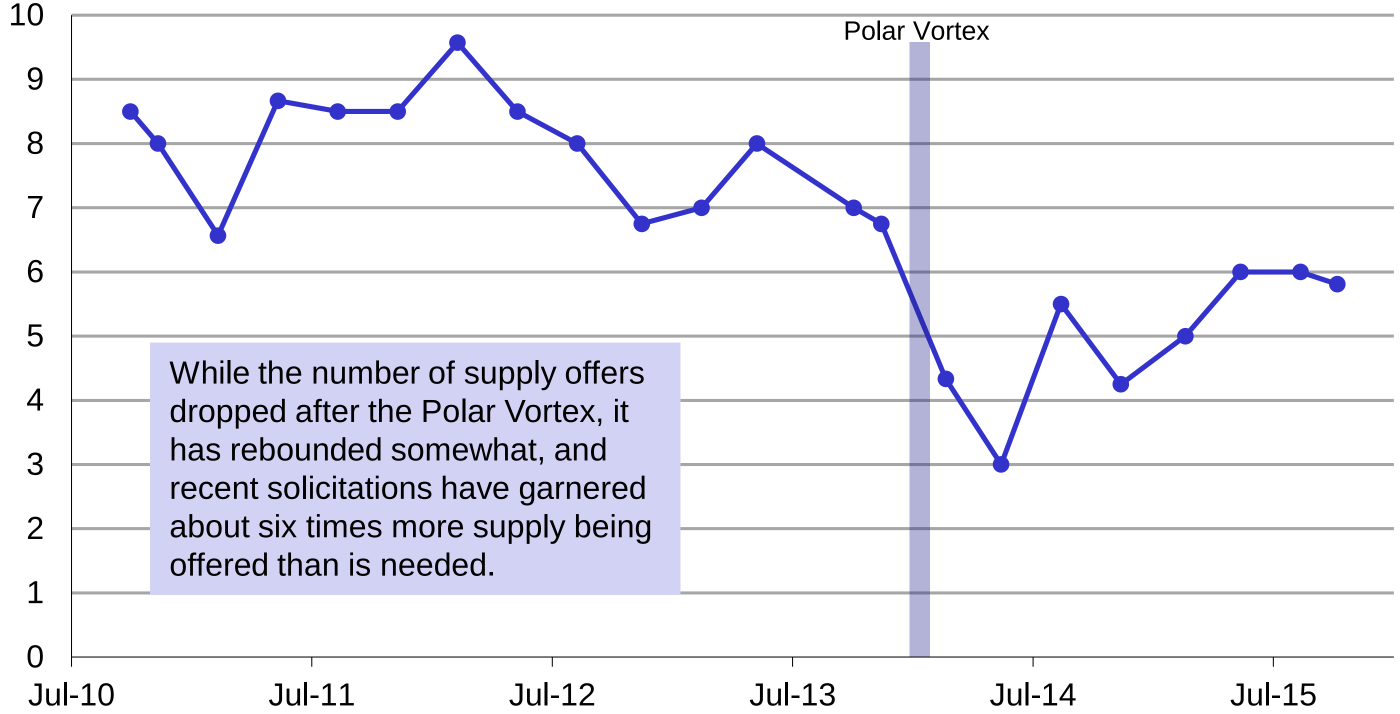


Annual Rate Movement (%)	
	Average of Top Decile
2010 Analysis	42.1%
2016 Analysis	55.2%
Difference	+13.1%

In sum, our historical residual compensation analysis indicates that Rhode Island FRS product pricing has been reasonable given the increased market risks against which FRS suppliers protect customers, and we have reflected more current (since 2010) underlying market uncertainty in our simulation analysis.

While product pricing can reflect competitive levels with only one bidder,[1] robust bidder participation is a good indication of competitive product pricing. Bidder participation in solicitations for Rhode Island's residential FRS products has been consistently high, providing further evidence that the FRS product pricing is competitive:

Rhode Island Residential FRS Product Bid-to-Cover Ratio by Solicitation Date



[1] In National Grid's 2015 SOS Procurement Plan, the Company originally proposed an automatic rejection of single bids followed by subsequent RFPs and spot purchases but later amended its proposal to accommodate the Division's position that National Grid ought to review single bids with the Division and evaluate their competitiveness based on a comparison with market estimates. (RI PUC Order No. 21826, Docket 4490, February 23, 2015, p. 7.)

3. **What changes could be made to the current procurement approach to provide greater rate stability, reduce accumulation of cost recovery deferrals, and/or enhance supply cost predictability?**

Changes to the current approach could be made to provide greater rate stability, reduce deferral balance risks, and enhance supply cost predictability:

1. **Incorporate flat pricing over the entire product delivery periods (or for at least 12-month segments)**
   Replacing the shaped supplier pricing with flat pricing over the entire delivery periods of the products procured would significantly reduce the potential for rate shock and the risks associated with deferral balance accumulation.[1]

2. **Eliminate the 10% spot component**
   Relying on 100% FRS products would reduce the risks associated with supply cost surprise and deferral balances.

3. **Reduce the portion of shorter-term products[2]**
   With flat pricing incorporated across entire product delivery periods (or for at least 12-month segments), further rate stability could be achieved by replacing shorter-term FRS products in the portfolio with more of the longer-term FRS products.

[1] Alternatively, if the flat pricing is limited to periods of 12 months for each product, risk reductions would be achieved, but to a lesser extent. In contrast, only extending the flat pricing from the current monthly frequency to six-month periods would do little to alleviate rate shock.

[2] However, if the Commission decides that some seasonality in SOS prices would be appropriate, it could either (1) apply administratively-determined seasonal factors (to products with delivery periods of at least 12 months and flat product term pricing) to calculate the prices paid to FRS suppliers and charged in customer rates, or (2) incorporate some six-month products into a portfolio of otherwise longer-term products (with flat product term pricing). But, this would increase the potential for rate shock.

Overview of Pricing Structures

As explained on the following slides, certain changes to the pricing structure of National Grid's FRS products would provide greater rate stability and reduce the risks associated with deferral balances. As such, an overview of different pricing structures is appropriate. Using a product with a two-year delivery period starting in April as an illustrative example:

	Year 1		Year 2		
Structure Name	**Apr-Sep**	**Oct-Mar**	**Apr-Sep**	**Oct-Mar**	
"Flat Product Term" Pricing	Flat Price				The supplier bids and receives a flat price throughout the entire delivery period of the product (in this case, 24 months).
"Flat 12-Month" Pricing	Flat Price		Flat Price		The product is broken into 12-month segments and bidders may submit (and be paid) separate flat bid prices for each segment.[1]
"Flat 6-Month" Pricing	Flat Price	Flat Price	Flat Price	Flat Price	The product is broken into 6-month segments and bidders may submit (and be paid) separate flat bid prices for each segment.
"Shaped" Pricing					The product is broken into months and bidders may submit (and be paid) separate bid prices for each month.

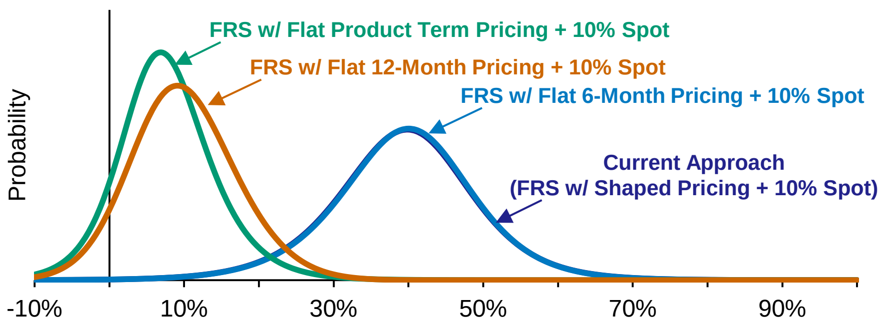
National Grid's Current Approach

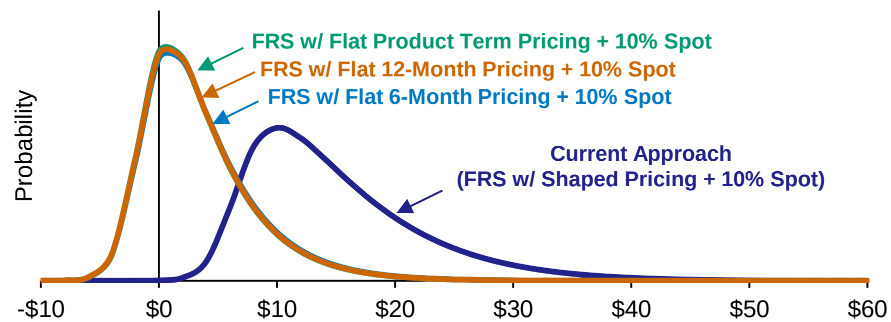
- National Grid's current FRS products have a "shaped" pricing structure.
- For a given product, different bidders can win different six-month (Apr-Sep, Oct-Mar) segments.
- In order to evaluate a given bidder's bid for a given six-month segment, that bidder's six monthly bid prices are weighted by respective monthly loads to develop a six-month, load-weighted, benchmark price.

[1] Under this structure, products with overall delivery periods that are not integer multiples of 12 months would need to have one segment be less than 12 months. For example, an 18-month product would be split into a 6-month segment followed by a 12-month segment, or a 12-month segment followed by a 6-month segment.

POTENTIAL CHANGES — Flat Product Term Pricing (1)

Replacing the shaped supplier pricing with flat pricing over the entire delivery periods of the products procured (i.e., flat product term pricing) would significantly reduce the potential for rate shock and the risks associated with deferral balance accumulation:[1]





	Rate Shock (top decile, %)	Annual Rate Movement (top decile, %)	Maximum Deferral Account Balance (top decile, $)	Oct-Mar Supply Cost Surprise (top decile, $/MWh)
Current Approach	57.1%	26.5%	$31MM	$4.06
FRS w/ Flat 6-Month Pricing + 10% Spot[1]	57.0%	28.4%	$14MM	$3.91
Difference vs. Current Approach	*-0.1%*	*+1.9%*	*-$17MM*	*-$0.15*
FRS w/ Flat 12-Month Pricing + 10% Spot[1]	23.1%	25.8%	$14MM	$3.91
Difference vs. Current Approach	*-34.0%*	*-0.7%*	*-$17MM*	*-$0.15*
FRS w/ Flat Product Term Pricing + 10% Spot[1]	20.3%	20.2%	$14MM	$3.91
Difference vs. Current Approach	*-36.8%*	*-6.3%*	*-$17MM*	*-$0.15*

In contrast, only extending the flat pricing from the current monthly frequency to six-month periods (i.e., flat 6-month pricing) would reduce deferral balance risks (due to the improved matching of supply prices with the flat six-month customer rates), but it would do little to alleviate rate shock.

[1] In the analysis shown here, the pricing structure is changed as described, but the overall product delivery periods remain the same.

When given a choice, SOS supply bidders may generally choose to submit shaped bids rather than flat price bids:

- Shaped bids expose SOS suppliers to less financial risk associated with monthly loads varying from expectations.
- However, with shaped bids, customers assume these risks in the form of potentially greater deferred cost recoveries when loads inevitably vary from expectations.
- Furthermore, flat price bids may afford customers greater economic benefits to switch on or off of SOS, at the expense of SOS suppliers.

In sum, all else equal, most suppliers may prefer a shaped price structure because this structure shifts certain risks from the suppliers to customers, and because it may reduce certain economic benefits to customers afforded at the expense of SOS suppliers.

But, our analysis indicates that reductions in rate volatility and deferral balance risks under the flat product term pricing approach are substantial, and the same is true to a lesser extent if the flat pricing is limited to segments of 12 months for each product (i.e., flat 12-month pricing).

Furthermore, while Rhode Island has not requested flat price bids to date, FRS product solicitations requiring flat product term bid prices consistently have produced competitive and satisfactory results in other jurisdictions:

FRS Bid Price Structures in Restructured States

State	Utilities	Dominant Bid Price Structure
CT	Eversource, UI	Shaped[1]
DC	PEPCO	Summer/Non-Summer[2]
DE	DP	Summer/Non-Summer[2]
ME	BHE, CMP, MPS	Flat Product Term
MD	BGE, DP, PEPCO, PotEd	Summer/Non-Summer[2]
MA	Eversource, NG, Unitil	Shaped[1]
NH	Eversource, Liberty, Unitil	Shaped[1]
NJ	ACE, JCPL, PSEG, RECO	Flat Product Term[3]
OH	AEP, DP&L, Duke, FE	Flat Product Term[3]
PA	DLC, FE,[3] PPL, PECO	Flat Product Term

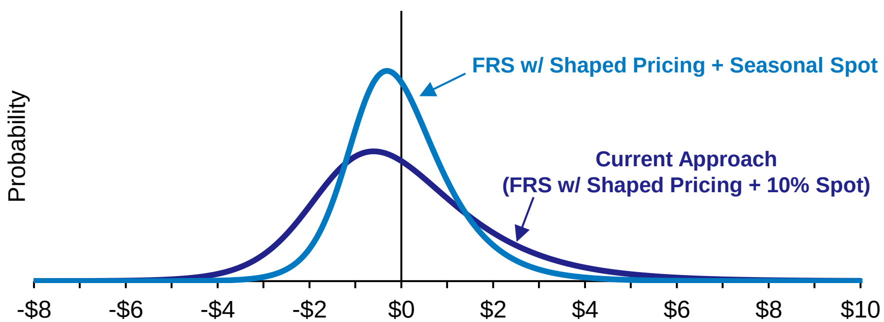
[1] Suppliers bid monthly prices, which are then combined into one benchmark price for bid evaluation.

[2] Suppliers bid flat summer and flat non-summer prices, which are then combined into one benchmark price for bid evaluation.

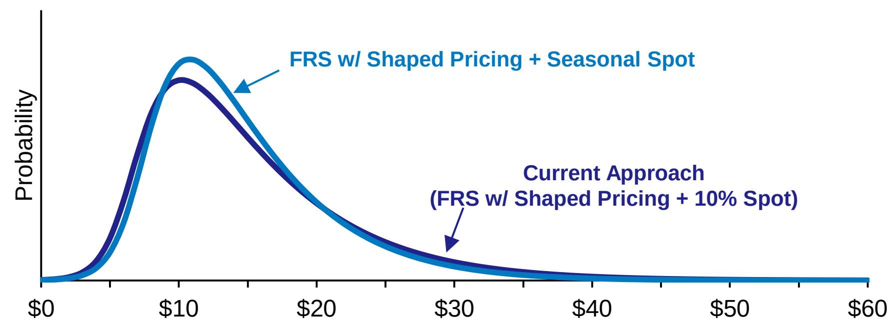
[3] Suppliers bid flat product prices for the product term, and seasonal factors are applied to calculate supplier payments and customer rates. However, in some cases, the factors have been set at a value of 1.000 for all seasons.

We also investigated the possibility of incorporating seasonal variation in the percentage of the spot position. Seasonally allocating the 10% spot position[1] could reduce supply cost surprise but it would provide little benefit on other metrics:

Oct-Mar Supply Cost Surprise ($/MWh)



Maximum Deferral Balance ($MM)



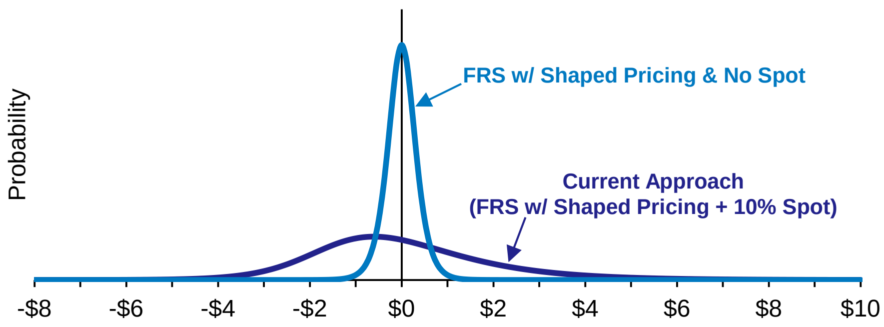
	Rate Shock (top decile, %)	Annual Rate Movement (top decile, %)	Maximum Deferral Account Balance (top decile, $)	Oct-Mar Supply Cost Surprise (top decile, $/MWh)
Current Approach	57.1%	26.5%	$31MM	$4.06
FRS w/ Shaped Pricing + Seasonal Spot[2]	57.0%	26.4%	$28MM	$2.44
Difference vs. Current Approach	*-0.1%*	*-0.1%*	*-$3MM*	*-$1.62*

1 The seasonal spot approach depicted here preserves the 10% overall spot position by having no spot during peak summer and winter months and 23% spot during other months. Peak summer months refer to June, July, and August. Peak winter months refer to December, January, and February.

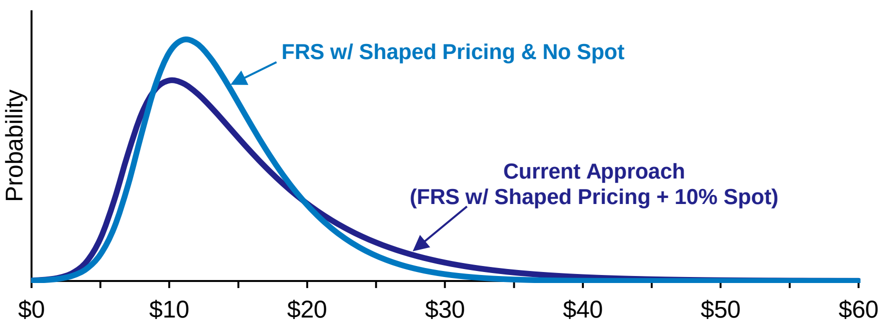
2 The difference in the expected rate level versus the "Current Approach" is estimated to be about +$0.07/MWh.

A more impactful approach with regard to the spot percentage would be to eliminate it altogether and entirely use FRS products to supply residential load requirements:

Oct-Mar Supply Cost Surprise ($/MWh)



Maximum Deferral Balance ($MM)



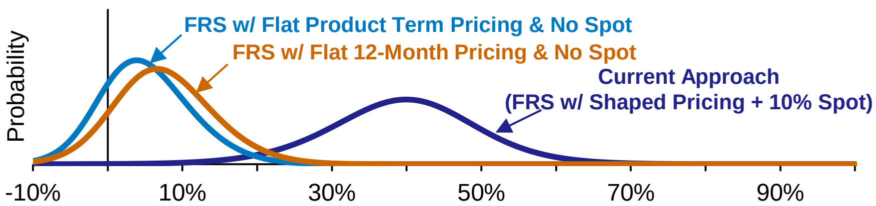
	Rate Shock (top decile, %)	Annual Rate Movement (top decile, %)	Maximum Deferral Account Balance (top decile, $)	Oct-Mar Supply Cost Surprise (top decile, $/MWh)
Current Approach	57.1%	26.5%	$31MM	$4.06
FRS w/ Shaped Pricing & No Spot[1]	56.9%	25.9%	$24MM	$0.62
Difference vs. Current Approach	*-0.2%*	*-0.6%*	*-$7MM*	*-$3.44*

[1] The difference in the expected rate level versus the "Current Approach" is estimated to be about +$0.38/MWh.

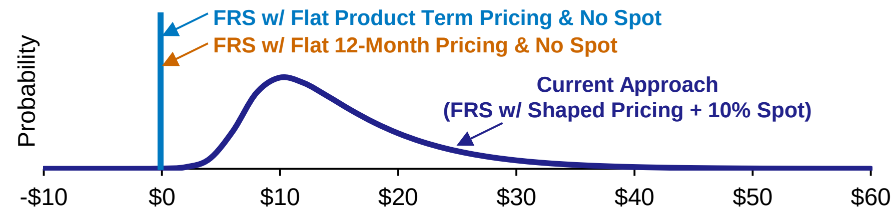
POTENTIAL CHANGES Flat Product Term Pricing & No Spot

Doing both – replacing the shaped supplier pricing with flat product term pricing *and* eliminating the spot component – would significantly reduce the risks associated with rate volatility, deferral balances, and supply cost surprise:

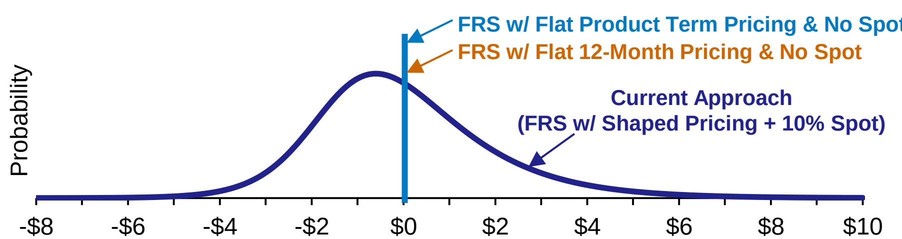
Rate Shock (%)



Maximum Deferral Balance ($MM)



Oct-Mar Supply Cost Surprise ($/MWh)



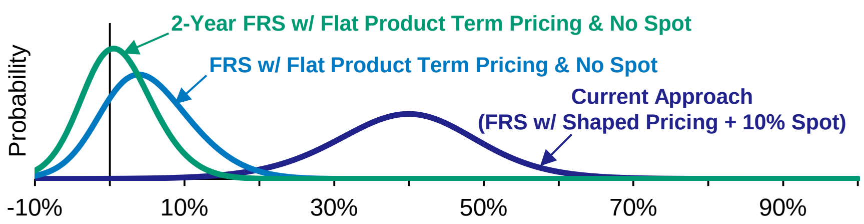
	Rate Shock (top decile, %)	Annual Rate Movement (top decile, %)	Maximum Deferral Account Balance (top decile, $)	Oct-Mar Supply Cost Surprise (top decile, $/MWh)
Current Approach	57.1%	26.5%	$31MM	$4.06
FRS w/ Flat 12-Month Pricing & No Spot[1]	19.9%	25.1%	$0MM[2]	$0.00
Difference vs. Current Approach	*-37.2%*	*-1.4%*	*-$31MM*	*-$4.06*
FRS w/ Flat Product Term Pricing & No Spot[1]	16.7%	19.0%	$0MM[2]	$0.00
Difference vs. Current Approach	*-40.4%*	*-7.5%*	*-$31MM*	*-$4.06*

[1] The difference in the expected rate level versus the "Current Approach" is estimated to be about +$0.38/MWh due to the elimination of the spot component, plus any effect due to the switch to flat pricing.

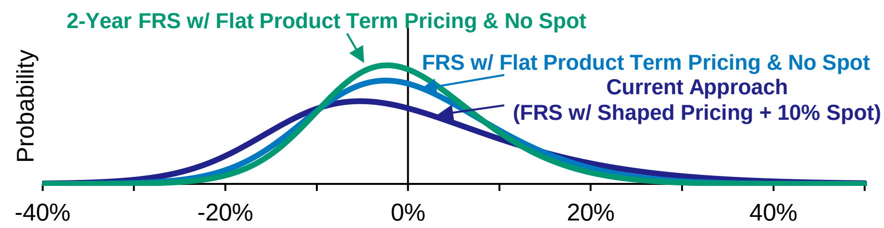
[2] While the deferral balance is shown as zero, small deferrals still may remain due to other factors such as accruals versus customer billings, etc.

Further rate stability could be achieved by replacing shorter-term products in the current portfolio with two-year FRS products:

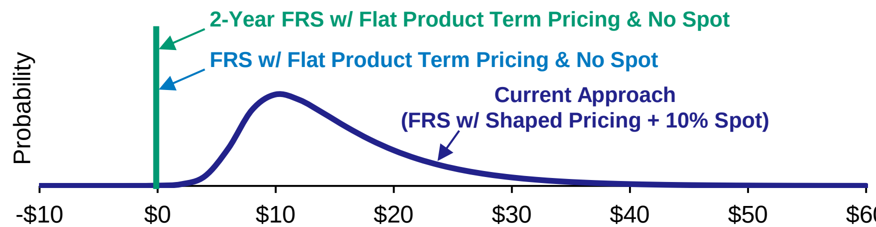
Rate Shock (%)



Annual Rate Movement (%)



Maximum Deferral Balance ($MM)



	Rate Shock (top decile, %)	Annual Rate Movement (top decile, %)	Maximum Deferral Account Balance (top decile, $)	Oct-Mar Supply Cost Surprise (top decile, $/MWh)
Current Approach	57.1%	26.5%	$31MM	$4.06
FRS w/ Flat Product Term Pricing & No Spot[1]	16.7%	19.0%	$0MM[3]	$0.00
Difference vs. Current Approach	*-40.4%*	*-7.5%*	*-$31MM*	*-$4.06*
2-Yr FRS w/ Flat Product Term Pricing & No Spot[2]	10.3%	16.8%	$0MM[3]	$0.00
Difference vs. Current Approach	*-46.8%*	*-9.7%*	*-$31MM*	*-$4.06*

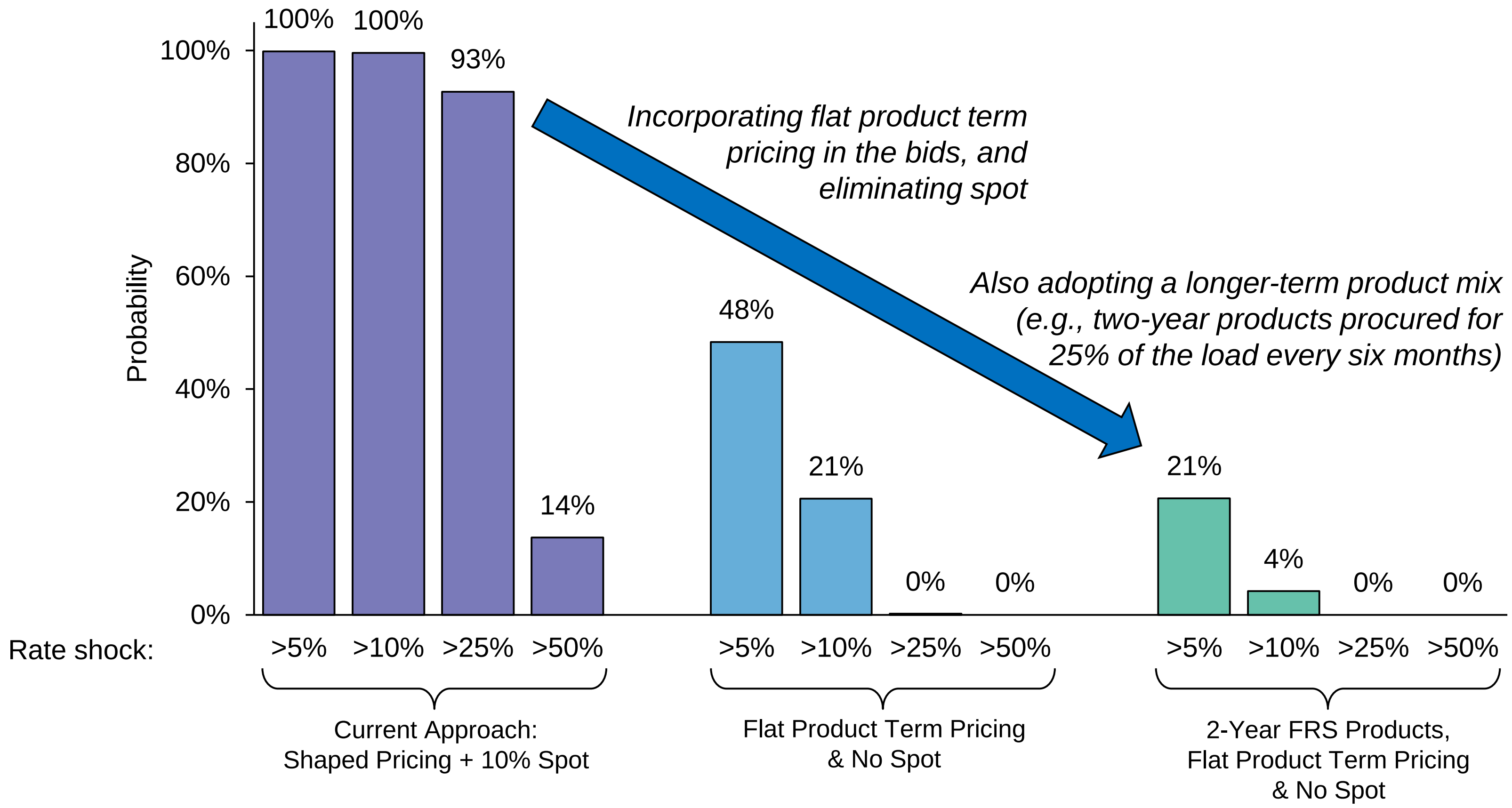
1 The difference in the expected rate level versus the "Current Approach" is estimated to be about +$0.38/MWh due to the elimination of the spot component, plus any effect due to the switch to flat pricing.

2 For illustrative purposes, semiannual procurements were assumed in modeling this particular approach. The difference in the expected rate level versus "FRS w/ Flat Product Term Pricing & No Spot" is estimated to be about +$0.20/MWh.

3 While the deferral balance is shown as zero, small deferrals still may remain due to other factors such as accruals versus customer billings, etc.

Adopting flat pricing for the full product delivery periods, eliminating the spot component, and possibly extending the delivery periods, would significantly reduce potential rate shock to which customers are exposed:

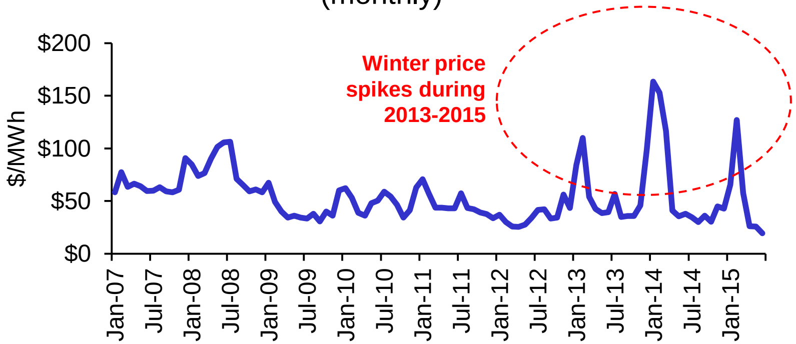
Likelihood of Rate Shock[1]



[1] Based on modeled risks. Probabilities across the board could be higher to the extent that the model does not capture all of the (anticipated or unanticipated) risks.

The potential changes that we have described (especially adoption of flat product term pricing) would reduce customers' exposure to price volatility witnessed in the underlying market:

Around-the-Clock (7x24) Energy Price
(monthly)



Contributing Factors

- Increased reliance on natural gas
- Gas pipeline constraints
- Retirement of non-gas generators
- Cold weather

And thereby lessen the chances of situations like those experienced recently:

Recent Public Outcry Regarding Rate Shock[1]

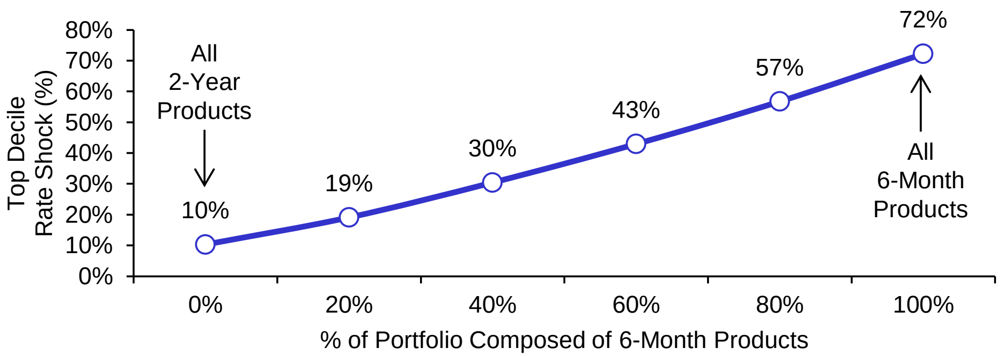
- On November 19, 2014, National Grid filed a 52.0% increase in residential SOS rates (i.e., a 26.1% increase on an aggregated supply plus delivery rate basis, for a typical bill).
- There was considerable public comment in protest of the proposed increase.
- The PUC found that the proposed SOS rates for the Residential and Commercial Groups, for the period January to June 2015, as filed, would pose a significant hardship to residential and commercial customers and ordered National Grid to defer portions of the rate increases.

[1] RI PUC Order No. 21827, Docket 4393, February 23, 2015; "Proposed Standard Offer Service Rates…," National Grid, RI PUC Docket 4393, November 19, 2014.

If the Commission decides that some seasonality in SOS prices would be appropriate, it could either:

- Apply administratively-determined seasonal factors (to products with delivery periods of at least 12 months and flat product term pricing) to calculate the prices paid to FRS suppliers and charged in customer rates:
  - The benefit of this approach is that it allows for some control over the seasonal differences in prices.
  - Prior to the solicitation for a given set of SOS supply products, National Grid would alert bidders to the fact that the prices that they will be paid will be adjusted by predetermined and publicly known seasonal factors (e.g., x% increase for supply during specific months throughout the year and y% decrease for supply during other months).
  - In any given month, each supplier would be paid its bid price multiplied by the appropriate seasonal factor.
  - SOS rates would be designed to vary seasonally based on the prices paid to suppliers.
  - This type of approach is employed in New Jersey and Ohio.
- Or, incorporate some six-month products into a portfolio of otherwise longer-term products (with flat product term pricing):
  - However, the potential for rate shock increases with the percentage of six-month products, as shown below for portfolios comprised of six-month products and two-year products (all with flat product term pricing):[1]

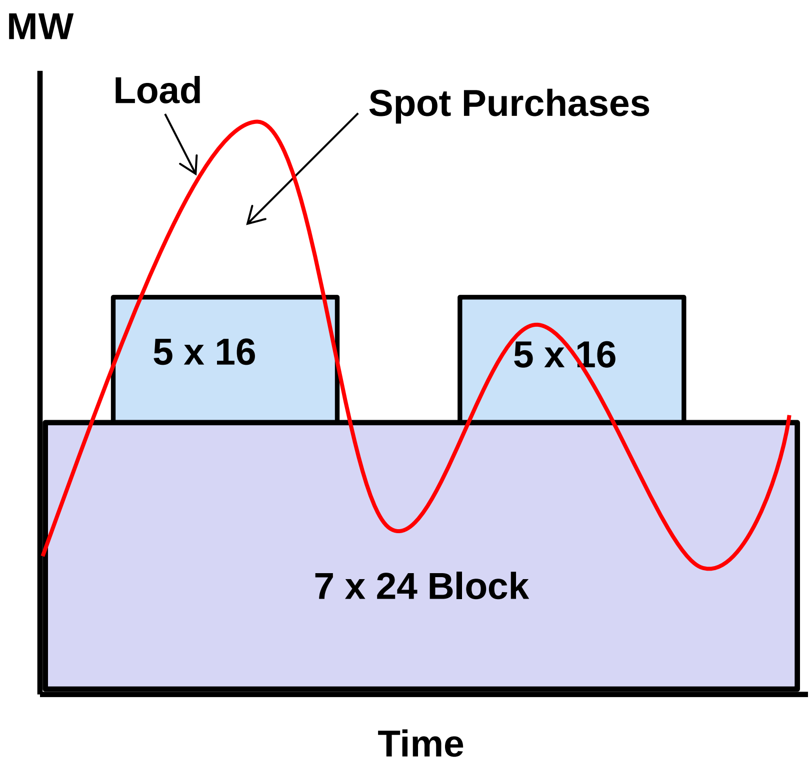
Portfolios of Six-Month and Two-Year FRS Products
With Flat Product Term Pricing and No Spot
(semiannual overlapping of two-year products)



[1] The top decile rate shock values shown here would be higher if the two-year products were replaced by shorter-term products or pricing terms.

4. **Is there convincing market evidence to suggest that a departure from the FRS product approach is warranted?**

In our 2010 analysis, we considered another SOS procurement approach based on purchases of component products of the full requirements supply obligation, involving block products for energy supplemented with spot market purchases (sometimes referred to as a "managed portfolio"):[1]



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 facilitate 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
- Quantity and timing of purchases could be decided with or without utility discretion

[1] 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.

However, as competitive markets have evolved, most electric utilities in restructured states primarily use FRS products to secure SOS supply for residential customers:

State	Utilities
CT	Eversource, UI
DC	PEPCO
DE	DP
ME	BHE, CMP, MPS
MD	BGE, DP, PEPCO, PotEd
MA	Eversource, NG, Unitil
NH	Eversource, Liberty, Unitil
NJ	ACE, JCPL, PSEG, RECO
OH	AEP, DP&L, Duke, FE
PA	DLC, FE, PPL, PECO

Key Features

- RFP/auction process
- Bundles energy, capacity, ancillary services, and sometimes 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

Rhode Island has relied primarily on FRS products for residential customers since 1998.

SOS APPROACHES — 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

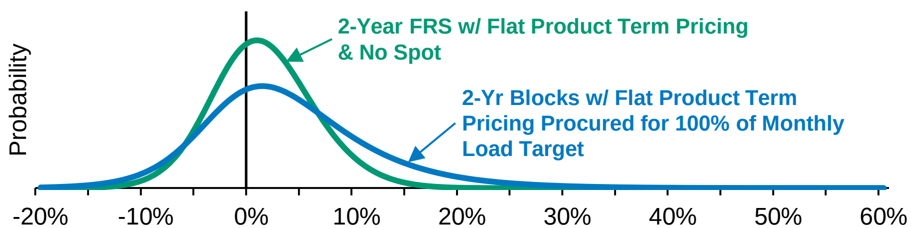
Managed Portfolio
Customers are exposed to costs and risks to a higher degree

Given the changes in market conditions since 2010, we evaluated the trade-off between compensation and risk to determine whether there is convincing market evidence to suggest that a departure from the FRS product approach is now warranted.

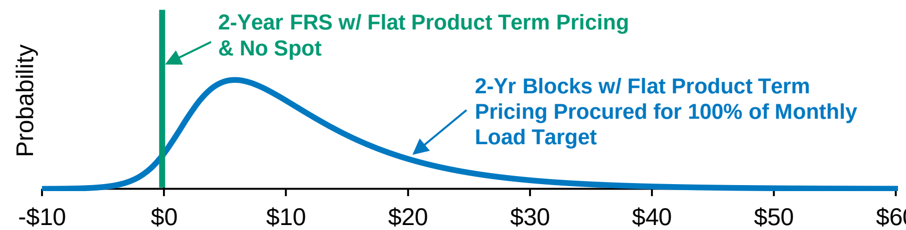
SOS APPROACHES FRS Provides a Reasonable Balance

Market evidence does not convincingly support a departure from the FRS product approach:

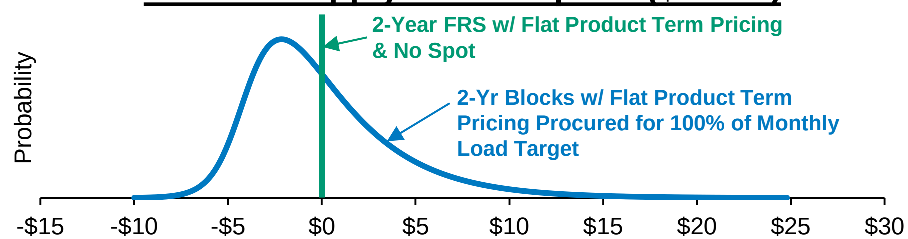
Potential Rate Shock (%)



Maximum Deferral Balance ($MM)



Oct-Mar Supply Cost Surprise ($/MWh)



	Rate Shock (top decile, %)	Annual Rate Movement (top decile, %)	Maximum Deferral Account Balance (top decile, $)	Oct-Mar Supply Cost Surprise (top decile, $/MWh)
FRS Product Approach 2-Yr FRS w/ Flat Product Term Pricing & No Spot	10.3%	16.8%	$0MM[1]	$0.00
Managed Portfolio (Block & Spot) 2-Yr Blocks w/ Flat Product Term Pricing Procured for 100% Monthly Load Target[2]	20.2%	28.1%	$30MM	$8.83
Difference	+9.9%	+11.3%	+$30MM	+$8.83

These significant increases would come with an estimated reduction in the expected rate level of only about $1.68/MWh.

[1] While the deferral balance is shown as zero, small deferrals still may remain due to other factors such as accruals versus customer billings, etc.

[2] Certain simplifying technical modeling assumptions may tend to underestimate the risks associated with this approach. Also, while having a block quantity hedge target of 100% of the load as shown above (versus having a lower hedge target) may increase the block & spot portfolio's performance with respect to certain metrics, there are other issues with this level of block hedges including stranded cost risk and a possibly increasing supply cost (on a $ per SOS MWh basis) if market prices decrease and customers switch to competitive retail suppliers.

There are additional costs and risks that were not fully (or at all) captured in the simulation analysis, and these would increase the costs and risks under a managed portfolio approach:

- Increased administrative costs (e.g., portfolio management staff and systems, regulatory proceedings and/or interaction with regulators, etc.).
- Greater-than-assumed customer switching (e.g., due to additional potential for new technologies, regulatory policies to encourage switching, etc.) causing stranded costs.
- Imputed debt costs.
- The potential for changes in market rules and legislation.[1]
- Other risks that we may not be able to identify or anticipate at this time.

In contrast, FRS product pricing is fully captured in the analysis, and FRS suppliers compete on the basis of lowest price to manage these and other risks, and absorb the costs of any mistakes.

[1] For example, rules related to ISO-NE's forward capacity markets and/or energy markets are subject to change, and federal energy legislation could impact future capacity and/or energy costs.

5. **Are current market conditions conducive to discretionary hedging of the spot market with FRS products?**

It is sometimes suggested that "discretionary hedging" could be used to analyze then-current market trends, compare forward prices to historical price levels or other assessments, and exercise judgments in an effort to lower overall supply costs and rates. Such discretionary hedging strategies often involve the following decisions:

Examples of Market Judgments with Discretionary Hedging

- **When to buy** – Defer product purchases when forward prices appear high and accelerate them when forward prices appear low.
- **How much to buy** – Leave a greater portion of the supply requirement unhedged, to be procured in shorter-term markets (e.g., spot) when forward prices appear high, and leave a smaller portion unhedged when forward prices appear low.
- **What types of products to buy** – Purchase shorter-term products when forward prices appear high and purchase longer-term products when forward prices appear low; consider different types of products (FRS products versus spot versus other).

In the context of the SOS supply portfolio, either the utility or a third-party agent would make these decisions about how "best" to manage the supply portfolio.

Adoption of a "discretionary hedging" approach to Rhode Island's SOS supply procurement, in which procurement decisions are made based on judgments about future market price levels, likely would increase risks for customers without a corresponding benefit:

- Such approaches equate to market speculation, as they involve efforts to "second guess," "time," or "beat the market."
- There is no evidence that the utility or a third-party agent systematically would have better insights regarding future market price levels than the broad universe of participants competing in the wholesale electricity market (e.g., the FRS product bidders).
- This type of approach could result in unnecessary costs and risks imposed on customers:
  - A one-off discretionary decision, to defer or abstain from a previously scheduled purchase that is part of a pre-established risk management strategy, would result in excess market exposure that could increase costs to customers if market prices then increase.
  - On the flip side, a one-off discretionary decision, to purchase more forward supply at a given time than was previously planned as part of a pre-established risk management strategy, would result in unnecessary costs to customers if market prices then decrease.
  - Customers would bear additional costs associated with (1) the market evaluation and the recommendation formulation, whether they be in the form of increased utility administrative costs or the fees charged by the third-party agent; (2) establishing the governing parameters for discretionary decisions; (3) any RI PUC approvals of discretionary decisions; (4) ongoing RI PUC evaluation of discretionary decisions that have been made; (5) regulatory costs associated with challenges made by any party regarding the process or subjective judgment pertaining to a previous discretionary decision that later proved to be costly.

However, it may be appropriate to allow some discretion to postpone a solicitation in situations in which an extraordinary event, such as the advent of war, terrorism, natural catastrophe, or other crisis, results in a high likelihood that competitively-priced bids for the products solicited would not be obtained on the scheduled bid date.

Appendix

REPRESENTATIVE APPROACHES Description

We used representative SOS approaches/portfolios to summarize our findings:

Type of Approach	Product Portfolio	Supplier Price Structure	Standard Offer Service Rate Determination	Treatment of Deferrals
100% Spot	Procurement based entirely on spot	Hourly	Rates reset each month (ex post)	No deferrals;[1] rates based on actual costs
90% Full Requirements / 10% Spot	Full Requirements[2] 30% 2-year (1/2 per year), 30% 18-month (1/2 per year), 20% 12-month (1 per year), 10% 6-month (1 every other year), Spot (10%)	Shaped	Rates reset every 6 months on April 1st and October 1st (ex ante 3 months prior)	Prior calendar year deferral balance recovered with 3-month lag over 12-month period
90% Full Requirements / 10% Spot	Full Requirements[2] 30% 2-year (1/2 per year), 30% 18-month (1/2 per year), 20% 12-month (1 per year), 10% 6-month (1 every other year), Spot (10%)	Flat 6-month, 12-month, or product term pricing (each modeled as a separate approach)	Rates reset every 6 months on April 1st and October 1st (ex ante 3 months prior)	Prior calendar year deferral balance recovered with 3-month lag over 12-month period
90% Full Requirements / 10% Spot	Same as current RI approach except that percentage of supply served by spot varies seasonally	Shaped	Rates reset every 6 months on April 1st and October 1st (ex ante 3 months prior)	Prior calendar year deferral balance recovered with 3-month lag over 12-month period
100% Full Requirements	Same as current RI approach, but scaled up without any spot	Shaped	Rates reset every 6 months on April 1st and October 1st (ex ante 3 months prior)	No deferrals;[1] rates based on actual costs
100% Full Requirements	Same as current RI approach, but scaled up without any spot	Flat 6-month, 12-month, or product term pricing (each modeled as a separate approach)	Rates reset every 6 months on April 1st and October 1st (ex ante 3 months prior)	No deferrals;[1] rates based on actual costs
100% Full Requirements	Semiannually overlapping 2-year products	Flat product term pricing	Rates reset every 6 months on April 1st and October 1st (ex ante 3 months prior)	No deferrals;[1] rates based on actual costs
Managed Portfolio (100% Block Target with Spot Balancing)	Semiannually overlapping 2-year products	Flat product term pricing	Rates reset every 6 months on April 1st and October 1st (ex ante 3 months prior)	Prior calendar year deferral balance recovered with 3-month lag over 12-month period

Current RI SOS Approach (row 2)

Red type represents changes versus the current approach.

[1] Deferrals may exist due to other factors such as accruals versus customer billings, etc.

[2] This breakdown is not the same for each delivery month. For April-September, the breakdown is (30% / 20% / 20% / 20%). For October-March, the breakdown is (30% / 40% / 20% / 0%).

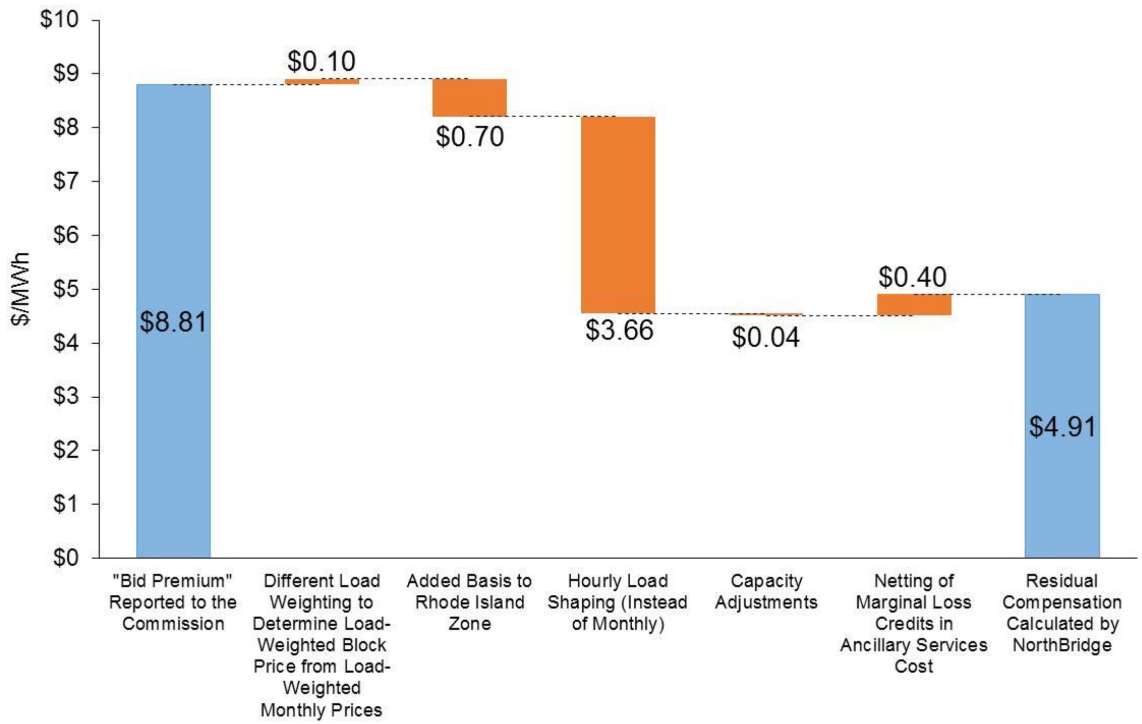
Product Type	Product Pricing	RFP Frequency	Product Delivery Periods	Hedge Target	Rate Shock Top-Decile (%)	Annual Rate Movement Top-Decile ($ / MWh)	Maximum Deferral Account Balance Top-Decile ($ / MWh)	Oct-Mar Supply Cost Surprise Top-Decile ($ / MWh)
Spot Only	-na-	-na-	-na-	0%	116.5%	55.2%	$0	$39.07
FRS	Shaped	Quarterly	RI Mix	90%	57.1%	26.5%	$31	$4.06
FRS	Shaped	Quarterly	RI Mix	100%	56.9%	25.9%	$24	$0.62
FRS	Flat 6-Month	Quarterly	RI Mix	90%	57.0%	28.4%	$14	$3.91
FRS	Flat 6-Month	Quarterly	RI Mix	100%	56.7%	27.9%	$0	$0.00
FRS	Flat 12-Month	Quarterly	RI Mix	90%	23.1%	25.8%	$14	$3.91
FRS	Flat 12-Month	Quarterly	RI Mix	100%	19.9%	25.1%	$0	$0.00
FRS	Flat Product Term	Quarterly	RI Mix	90%	20.3%	20.2%	$14	$3.91
FRS	Flat Product Term	Quarterly	RI Mix	100%	16.7%	19.0%	$0	$0.00
FRS	Flat Product Term	Semi-Annual	2-Year	100%	10.3%	16.8%	$0	$0.00
FRS	Shaped	Quarterly	RI Mix	90%, Seasonal	57.0%	26.4%	$28	$2.44
Block & Spot	Flat Product Term	Semi-Annual	2-Year	100%	20.2%	28.1%	$30	$8.83

Current approach is highlighted in purple.

NorthBridge's calculation of residual compensation in the historical FRS product solicitations is on average about $3.90/MWh lower than the "bid premiums" that were reported to the Rhode Island PUC for the same set of solicitations:

Average Differences in Calculation of Residual Compensation

(for solicitations held during 2013-2015)



Most of the difference is associated with NorthBridge using *hourly* prices and loads to develop the load-shaped energy cost component as opposed to only monthly prices and loads.[1]

[1] The load-shaped energy cost component as calculated here by NorthBridge still may not capture all of the expected load following energy costs (thereby leaving any such additional costs to be included in the residual compensation values), because this methodology weights forward prices (which are indicators of price level expectations) by corresponding *base case* monthly on-peak/off-peak loads and then applies *base case* intra-period hourly load-weighting gross-ups. As such, it does not capture additional expected costs due to unexpected variations in these values and the potentially positive correlations between them.

- Deferred cost recovery balances must be financed by the utility, and this in turn could adversely affect the utility's available credit capacity and/or its cost of financing. These costs of doing business are ultimately passed onto customers.

- Deferred cost recovery may entail higher regulatory and administrative costs which ultimately must be passed onto customers.

- When cost recovery is deferred, customers are often required to pay for power supply from prior periods that they did not consume.

- Deferred cost recovery approaches can cause price distortion issues and reduced price predictability for customers to make economic service decisions.

- 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 loads, and load-weighting gross-ups we have seen historically.
  - This approach generates correlated[1] scenarios of potential outcomes for energy prices, total loads, 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 loads, 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.
- This analysis helps us understand how different SOS approaches would perform under different conditions (i.e., what sort of rate volatility, relative rate levels, deferral balances, etc. would they yield?).

[1] Correlations between energy prices, total loads, and load-weighting gross-ups are based on historical relationships.

- 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) evolves over time.

- The model used in this analysis is a three-factor mean-reverting model, and is a variant of the Random Walk / Geometric Brownian Motion (GBM) model commonly used in quantitative finance.

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

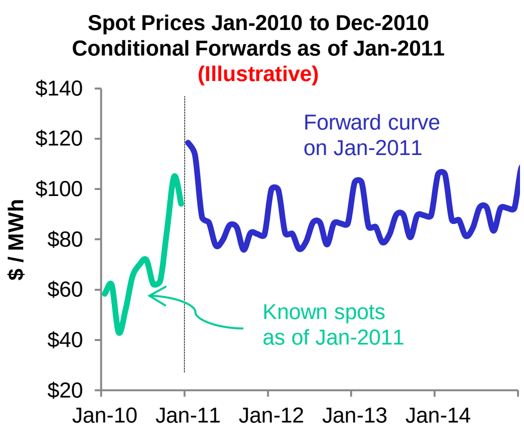
[1] This model is a variation of the Dixit-Pindyck mean-reverting random walk model used for simulating commodity price movements.

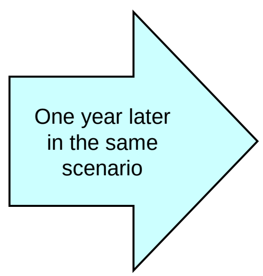
MARKET OUTCOMES — Scenario Components

- Scenarios illustrate the uncertainty associated with variables such as wholesale market prices, total load levels, and load-weighting gross-up factors.

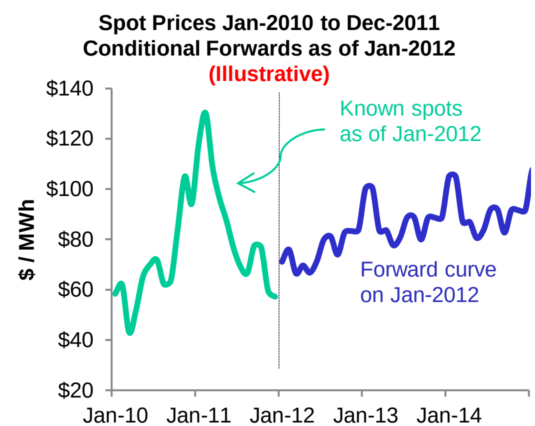
- Each scenario consists of (1) a time-series of ultimate spot outcomes, and (2) conditional forecasts (i.e., in a given scenario, what would most likely be the forecast at a specific observation date for future delivery periods).

- 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:



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
5,000 scenarios using a three-factor model of how the expectations of price, load, and gross-up may vary over time, and what spot prices, actual loads, and gross-ups might result

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

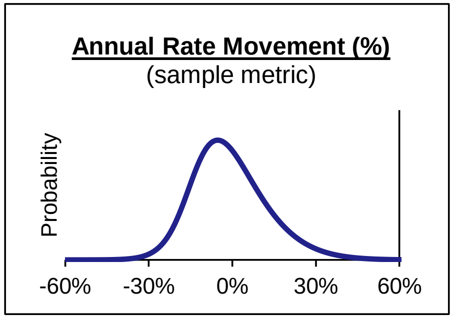
2. Calculate Retail Rates
Rates are based on known costs of completed procurements plus costs of remaining open exposure at forecasted cost

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

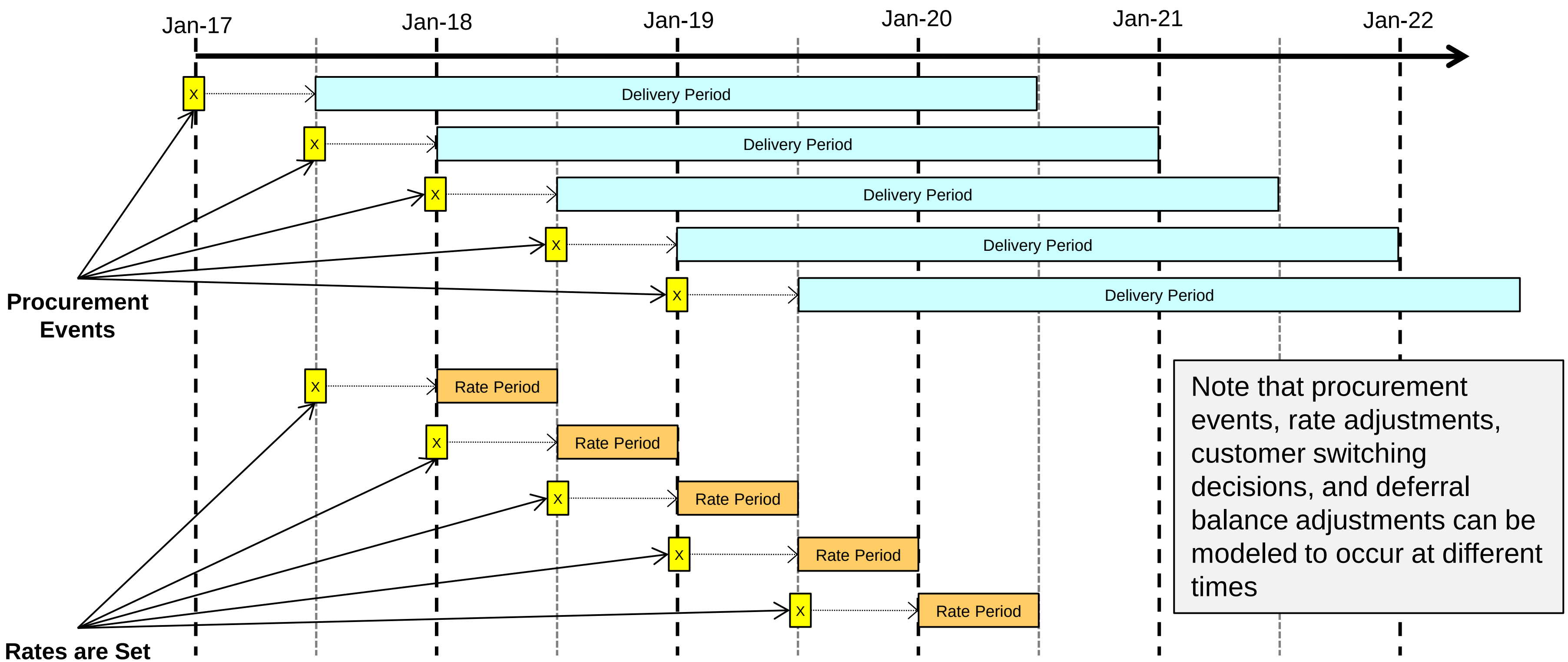
5. Determine Under / Over Recovery
Determine under/over recovery of costs and amortization schedule for full recovery

Calculate Evaluation Metrics for Each of 5,000 Scenarios



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

Hypothetical Schedule of Standard Offer Service Events



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.