STATE OF NEW HAMPSHIRE
BEFORE THE PUBLIC UTILITIES COMMISSION

Public Service Company of New Hampshire
Reconciliation of Energy Service and Stranded Costs for
Calendar Year 2017

DIRECT TESTIMONY OF CHRISTOPHER J. GOULDING

I. INTRODUCTION

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

A. My name is Christopher J. Goulding. My business address is 780 North Commercial Street, Manchester, NH. I am employed by Eversource Energy Service Company as the Manager of New Hampshire Revenue Requirements and in that position, I provide service to Public Service Company of New Hampshire d/b/a Eversource Energy ("Eversource" or the "Company").

Q. Have you previously testified before the Commission?

A. Yes, I have.

Q. What are your current responsibilities?

A. I am currently responsible for the coordination and implementation of revenue requirements calculations for Eversource, as well as the filings associated with Eversource's Energy Service ("ES") rate, Stranded Cost Recovery Charge ("SCRC"), and the Transmission Cost Adjustment Mechanism ("TCAM").

Q. What is the purpose of your testimony?

A. The primary purpose of my testimony is to provide an overview of this filing and to seek approval of the reconciliation between the revenues and expenses contained within Eversource's ES and SCRC rate filings for the twelve-month reporting period January 1, 2017 through December 31, 2017 ("reporting period").

Q. Will anyone else be providing testimony in support of this filing?

A. Yes. William H. Smagula, Vice President of Generation for Eversource, will review the performance of Eversource's fossil-hydro generation units and Frederick B. White, Supervisor - Power Supply Analysis and Policy, will review how Eversource met its energy and capacity requirements during this reporting period.

Q. Have you calculated replacement power costs as a result of outages incurred during the period as discussed in Mr. Smagula's testimony?

A. Yes. Attachment CJG-2 summarizes the replacement power costs incurred as a result of forced outages during the period.

Q. Please describe the ratemaking framework that began on May 1, 2001.

A. On May 1, 2001 (Competition Day), Eversource began to recover costs under the Restructuring Settlement. Under the terms of the Restructuring Settlement, Eversource continues to recover costs related to the generation and delivery of electricity, but the specific rate structure now in place segments recovery into various components. The four major components of that segmentation are the Delivery Charge, the TCAM, the SCRC, and the ES rate. Two of the major interrelated rate components, the SCRC and the ES rate, are the subject of this proceeding.

II. <u>Energy Service Charge</u>

Q. Please describe the ES recovery mechanism.

A. Under restructuring, customers have a choice regarding their energy supplier. Customers may contract for and obtain energy on their own, or they may choose to continue to receive their energy from Eversource.

Under the terms of the Restructuring Settlement and subsequent legislation, Eversource is required to provide ES to those customers who request it. Initially, ES rates were set by statute. Beginning in February 2003, the ES rate for large commercial and industrial customers was based on Eversource's forecast of "actual, prudent and reasonable costs." Beginning in February 2004, the ES rate for all retail customers was based on a forecast of Eversource's "actual, prudent, and reasonable cost of service." The chart below shows the ES rates per kWh which have been in effect since Competition Day.

Rate in Effect:	**Rate Set By: Statute or Docket No.**	**Residential, Small Commercial/Industrial Customers (RSCI)**	**Large Commercial/ Industrial Customers (LCI)**
May 1, 2001 – January 31, 2003	Statute	4.40 cents	4.40 cents
February 1, 2003 - January 31, 2004	RSCI – Statute LCI-DE 02-166	4.60 cents	4.67 cents
February 1, 2004 - July 31, 2004	DE 03-175	5.36 cents	5.36 cents
August 1, 2004 - January 31, 2005	DE 03-175	5.79 cents	5.79 cents
February 1, 2005 - July 31, 2005	DE 04-177	6.49 cents	6.49 cents
August 1, 2005 - January 31, 2006	DE 04-177	7.24 cents	7.24 cents
February 1, 2006 - June 30, 2006	DE 05-164	9.13 cents	9.13 cents
July 1, 2006 - December 31, 2006	DE 05-164	8.18 cents	8.18 cents
January 1, 2007 - June 30, 2007	DE 06-125	8.59 cents	8.59 cents
July 1, 2007 – December 31, 2007	DE 06-125	7.83 cents	7.83 cents
January 1, 2008 - June 30, 2008	DE 07-096	8.82 cents	8.82 cents
July 1, 2008 - December 31, 2008	DE 07-096	9.57 cents	9.57 cents
January 1, 2009 - July 31, 2009	DE 08-113	9.92 cents	9.92 cents
August 1, 2009 - December 31, 2009	DE 08-113	9.03 cents	9.03 cents
January 1, 2010 - June 30, 2010	DE 09-180	8.96 cents	8.96 cents
July 1, 2010 - December 31, 2010	DE 09-180	8.78 cents	8.78 cents
January 1, 2011 - June 30, 2011	DE 10-257	8.67 cents	8.67 cents
July 1, 2011 - December 31, 2011	DE 10-257	8.89 cents	8.89 cents
January 1, 2012 – April 15, 2012	DE 11-215	8.31 cents	8.31 cents
April 16, 2012 – June 30, 2012	DE 11-250	8.75 cents	8.75 cents
July 1, 2012 - December 31, 2012	DE 11-215	7.11 cents	7.11 cents
January 1, 2013 – June 30, 2013	DE 12-292	9.54 cents	9.54 cents
July 1, 2013 - December 31, 2013	DE 12-292	8.62 cents	8.62 cents

Rate in Effect:	Rate Set By: Statute or Docket No.	Residential, Small Commercial/Industrial Customers (RSCI)	Large Commercial/ Industrial Customers (LCI)
January 1, 2014 – June 30, 2014	DE 13-275	9.23 cents	9.23 cents
July 1, 2014 – December 31, 2014	DE 13-275	9.87 cents	9.87 cents
January 1, 2015 – June 30, 2015	DE 14-235	10.56 cents	10.56 cents
July 1, 2015 – December 31, 2015	DE 14-235	8.98 cents	8.98 cents
January 1, 2016 – June 30, 2016	DE 15-415	9.99 cents	9.99 cents
July 1, 2016 – December 31, 2016	DE 15-415	10.95 cents	10.95 cents
January 1, 2017 – June 30, 2017	DE 16-822	11.17 cents	11.17 cents
July 1, 2017 – December 31, 2017	DE 16-822	11.66 cents	11.66 cents

Q. Please describe the costs incurred in providing ES to customers during the twelve-month reporting period.

A. ES costs include the fuel costs associated with Eversource's generation as well as costs and revenues from energy and capacity purchases and sales. Also included are costs related to the New Hampshire Renewable Portfolio Standard ("RPS") and the Regional Greenhouse Gas Initiative ("RGGI"). Finally, additional costs include those associated with IPP power valued at market prices, revenue requirements of generation such as: non-fuel O&M, depreciation, property taxes and payroll taxes, and a return on the net generation investment. Detailed information on the cost of generation is included in Attachment CJG-3 and Attachment CJG-4, page 6.

Q. How were the costs of the Scrubber recovered over the period of January 1, 2017 through December 31, 2017?

A. By Order No. 25,854 (December 22, 2015), the Commission approved a temporary Scrubber rate of 1.72 cents per kWh which converted to a permanent rate by operation of Order No. 25,920 (July 1, 2016) in Docket No. DE 14-238. Due primarily to increases in customer migration, the 1.72 cents per kWh rate fell short of recovering all 2017 Scrubber related costs as well as one-seventh of previously deferred Scrubber costs.

Q. What are the final results for ES in the 2017 reporting period?

A. As shown on Attachment CJG-4, page 5, line 9, last column, the ES had a net adjusted under-recovery balance of $133.6 million at December 31, 2017. This net adjusted under-recovery was due primarily to deferred Scrubber costs of $104.1 million (i.e., Scrubber costs incurred in excess of the permanent rate recovery). The $29.5 million non-Scrubber under-recovery was due to actual revenues that were $4.5 million lower than forecasted, $9.2 of fossil fuel expenses higher than forecasted, RPS Costs that were $6.4 million higher than forecasted, Capacity credits that were $5.6 million lower than forecasted, O&M expenses that were $3.2 million higher than forecasted, along with the $3.4 million CSL contract settlement (currently being reviewed as part of Docket No. DE 17-075) that was not included in 2017 ES rates, offset by ($2.3) million in other expenses that were lower than forecasted. And, the Company notes that the rates in effect in 2017 took into account the amount included relative to a coal delivery contract payment, which had been explained in the May 9, 2017 Joint Technical Statement of Christopher J. Goulding and Frederick B. White in Docket No. DE 16-822, and which was also discussed at the hearing on June 22, 2017 in that docket.

Q. Did Eversource file a summary of 2017 benefits for the Northern Wood Power Project (NWPP)?

A. Yes. Attachment CJG-4, page 10 provides the NWPP revenue target as well as the projected incremental revenues based on Schiller Unit 5 generation, consisting of Renewable Energy Certificates (RECs), Production Tax Credit ("PTCs") and RGGI avoided costs. Due to timing of the REC sales, these 2017 credits will be trued up to actuals in the final 2018 ES reconciliation filing.

Q. Was there activity through the Seabrook Power Contracts in 2017 that affected the Seabrook net proceeds figure?

A. Yes. There were credits to NAEC of $0.1M in 2017 reported on Attachment CJG-4, page 6. While there may be additional charges and credits in 2018 that will further impact the net proceeds figure, we do not expect these amounts to be significant. However, we are unable to quantify these charges and credits at this time.

Q. Will these Seabrook-related subsequent charges and credits be passed on to Eversource?

A. Yes, the Seabrook Power Contracts between Eversource and NAEC are still in place for Seabrook sale reconciliation purposes.

Q. Did Eversource incorporate the results of the lead/lag study ordered in Docket No. DE 15-415 into this filing?

A. Yes. In Order No. 25,914 issued on June 28, 2016 in Docket No. DE 15-415, the Commission required Eversource to conduct a Lead/Lag study, in consultation with the Staff and the Office of Consumer Advocate ("OCA"), for inclusion in Eversource's 2017 energy service rate calculation. In its September 30, 2016 ES Rate filing in Docket No. DE 16-822, Eversource provided testimony and schedules describing the methodology and results of a lead-lag study prepared to determine the cash working capital requirement included in the Company's calculation of energy service revenue requirements. Staff subsequently issued numerous data requests to review the lead/lag study calculation to which Eversource submitted responses. At the request of the Staff, the Commission issued a secretarial letter on November 28, 2016 in Docket No. DE 16-822 requiring Eversource to remove the results of the lead/lag study from its ES rate calculation pending the completion of Staff's review. While Eversource removed the calculation for purposes of rate setting, and has now added it back to the ES calculation, Eversource believes it is appropriate to include it here to reflect the true cost of providing ES in 2017 and is consistent with Order No. 25,914. The lead/lag analysis incorporated in this submission is substantially the same as that provided in Docket No. DE 16-822, which related to ES rates for 2017. Accordingly, it uses the same data set as that initial analysis. The same lead/lag analysis was incorporated into Eversource's TCAM rate effective July 1, 2017 by Order No. 26,031 (June 28, 2017).

Q. What is cash working capital?

A. Cash working capital is the amount of money that is needed by Eversource to fund operations in the time period between when expenditures are incurred to provide service to customers and when payment is actually received from customers for that service.

Q. How has the Company historically estimated its cash working capital requirement?

A. The Company has historically estimated cash working capital to equal 45 days, or 12.3 percent (45/365), of annual operation and maintenance expense, which is the method that had been used in Eversource's last rate case in 2009 and which was consistent with the method described in Puc 1604.07(t) before it was amended in 2015 in Docket No. DRM 14-362.

Q. How is cash working capital estimated through a lead-lag study?

A. A lead/lag study identifies the amount of time it typically takes for the Company to collect revenue from customers, as well as the amount of time the Company takes to make payment for applicable operating costs. The difference between those two numbers is used as the basis to estimate cash working capital requirements.

Q. Please define the terms "revenue lag days" and "expense lead days."

A. Revenue lag is the time, measured in days, between delivery of a service to Eversource customers and the receipt by Eversource of the payment for such service. Similarly, expense lead is the time, again measured in days, between the performance of a service on behalf of Eversource by a vendor or employee and payment for such service by Eversource. Since base rates are based on revenue and expenses booked on an accrual basis, the revenue lag results in a need for capital while the expense lead offsets this need to the extent the Company is typically not required to reimburse its vendors until after a service is provided.

Q. Please describe the Lead/Lag Study (Attachment CJG-5) and its findings.

A. The Lead/Lag Study consists of 29 pages of calculations and supporting schedules to separately calculate lag days for operations and maintenance ("O&M") expense and Purchased Power expense. The Lead/Lag Study produced an O&M net lag of 17.5 days or 4.8% percent (17.5/365), and 19.4 days or 5.3 percent (19.4/365) for Purchased Power expense.

Q. How is the revenue lag determined?

A. First, total revenue was disaggregated between revenue from retail and wholesale customers. The significant majority of energy service revenue is collected from retail customers. However, Eversource recovers annual proceeds from the sale of renewable energy certificates ("RECs") from the Northern Wood Power Project ("NWPP") and a net surplus of capacity sold into the market overseen by the Independent System Operator for New England ("ISO-NE"). These annual proceeds are credited to customers, offsetting a portion of the energy service revenue requirement and displacing revenue that would otherwise be collected from retail customers. Collections were reviewed, and the lag days were calculated for each category. Once the lag days for each category were determined, they were summarized and dollar weighted to arrive at Total Revenue lag days. See, Attachment CJG-5, page 2. The lag days for each category were weighted based on actual annual amounts reflected in the Company's 2016 Energy Service Reconciliation. However, the lag days associated with sale of NWPP RECs were excluded from the calculation of revenue lag applied to Purchased Power expense because those expenses do not support the production of RECs from NWPP.

Q. How is the retail revenue lag computed?

A. The retail revenue lag consists of a "meter reading or service lag," "collection lag" and a "billing lag." The sum of the days associated with these three lag components is the total retail revenue lag experienced by Eversource. See Attachment CJG-5, Page 3 of 29.

Q. What lag does the Lead/Lag Study reveal for the component "meter reading or service lag?"

A. The Lead/Lag Study reveals 15.2 days. This lag was obtained by dividing the number of billing days in the test year by 12 months and then in half to arrive at the midpoint of the monthly service periods.

Q. How was the "collection lag" calculated and what was the result?

A. The "collection lag" for energy service totaled 26.2 days. This lag reflects the time delay between the mailing of customer bills and the receipt of the billed revenues from customers. The 26.2 days lag was arrived at by a thorough examination of energy service accounts receivable balances using the accounts receivable turnover method. End of month balances were utilized as the measure of customer accounts receivable. Attachment CJG-5, Page 4 details monthly balances for the majority of the accounts receivable accounts (Customer Accounts). Attachment CJG-5, Page 5 summarizes the month end reserve balances for uncollectible accounts. Attachment CJG-5, Page 3 shows the net sum of the average customer balances and Reserve for Uncollectible accounts of $26,067,355. Attachment CJG-5, Page 6 calculated the average daily revenue amount by dividing total revenue by 365 days ($995,608). The resulting Collection Lag is derived by dividing the average daily accounts receivable balance by the average daily revenue amount to arrive at the Collection lag of 26.2 days.

Q. How did you arrive at the 1.00 day "billing lag"?

A. Nearly all of the Company's customers are billed the evening after the meters are read. Therefore, I have included a 1.00 day billing lag. I have not made an exception for large customers which may require additional time to process.

Q. **Is the total retail revenue lag computed from these separate lag calculations?**

A. Yes. The total retail revenue lag of 42.4 days is computed by adding the number of days associated with each of the three retail revenue lag components. See, Attachment CJG-5, Page 3. This total number of lag days represents the amount of time between the recorded delivery of service to retail customers and the receipt of the related revenues from retail customers.

Q. How were lag days for net capacity sales determined?

A. Capacity lag days were based on ISO-NE procedures discussed in more detail in the purchased power section of this testimony. Capacity market charges are settled each month and included in the invoice issued on the first Monday after the 10th calendar day of the month following the service period. This results in a lag of 28.8 days as shown in Attachment CJG-5, page 7.

Q. How were the lag days for NWPP RECs determined?

A. The lag days for NWPP RECs were calculated based on the amount of time between when the value of RECs are credited to customers and when cash payment for RECs is received by the Company. The customer share of the value of RECs produced at Schiller Station is credited to customers in the month in which the RPS eligible energy is produced. However, the schedule for the issuance and trading of RECs in the New England Power Pool Generation Information System ("NEPOOL GIS") results in a considerable delay in receipt of the cash value of those RECs. RECs are not available for transfer in NEPOOL GIS until 4-6 months after they are generated and most purchase agreements for RECs only provide payment after RECs have been transferred to a buyer. Additionally, a larger volume of RECs are generally transferred in later trading periods, adding to the revenue lag. As shown in Attachment CJG-5, page 9, Eversource did not receive cash payment for 2016 RECs until, on average, 156.9 days after they were generated.

Q. Please explain Other O&M Cash Working Capital?

A. The Other O&M Cash Working Capital component is composed of O&M expense, payroll taxes and property taxes. These are types of expenses that Eversource pays to underwrite the activities conducted in service to customers before it receives payment from customers for those services.

Q. In determining the expense lead period, how were the weighted lead days in payment of O&M costs determined?

A. First, total O&M expense was disaggregated between payroll, other O&M expense and taxes other than income. Payments were reviewed and the lead days were calculated for each category. Once the lead days for each category were determined, the lead days were summarized and dollar weighted according to 2015 actual annual amounts to arrive at O&M and Tax expense lead days. See, Attachment CJG-5, page 11.

Q. Briefly describe the lead days calculated for each category.

A. The payroll lead is shown in Attachment CJG-5, page 12. Eversource employees are paid every other Thursday for the previous two weeks' work (based on a work week of Sunday-Saturday). This results in an overall weighted lead of 25.7 days.

Q. How was the lead related to other O&M expenses which were not individually studied determined?

A. A random selection of 40 vendor payments was chosen from a complete list of vendor payments made by Eversource during calendar year 2015 directly from the Company's Accounts Payable system. The amount of time between the date the invoice was submitted and when the payment for the service was actually made was then calculated. This calculation resulted in an average lead of 36.6 days as shown on Attachment CJG-5, Page 13.

Q. Would you briefly describe the lead days associated with taxes?

A. Yes. The (4.9) property tax lead days were calculated based on a query of tax payments made by Eversource to New Hampshire municipalities in 2015. The FICA & Medicare tax leads of 12.6 days were calculated based on the 2015 payments made to the government for these payroll related taxes. The leads for other taxes are presented in Attachment CJG-5, page 22 and 23.

Q. How is the total O&M and Taxes Lag determined?

A. The lead in payment for the cost of goods and services purchased of 28.1days is subtracted from the lag in receipt of revenue of 45.6 days to produce the total O&M Lag of 17.5 days. See, Attachment CJG-5, page 1.

Q. What expense is Purchased Power Cash Working Capital intended to address?

A. Purchased Power Cash Working Capital provides cash working capital for expenses paid by Eversource to wholesale energy suppliers and ISO-NE on behalf of customers. Net purchases of wholesale energy, ancillary services and RECs supplement the operation of power generation facilities owned by the Company to provide energy service to customers.

Q. In determining the expense lead period, how were the weighted lead days in payment of Purchased Power costs determined?

A. First, total Purchased Power expense was disaggregated into 5 major cost categories, as shown on Attachment CJG-5, page 24. Payments were reviewed and the lead days were calculated for each category. Once the lead days for each category were determined, they were summarized and dollar weighted based on 2015 actual annual amounts to arrive at Purchased Power expense lead days. See, Attachment CJG-5, page 24.

Q. How were the lead and lag days in payment of ISO-NE costs determined?

A. Lead and lag days associated with ISO-NE activity were based on ISO-NE procedures for the collection and disbursement of funds among energy market participants. ISO-NE generally issues invoices twice per week, on Monday and Wednesday. The invoice amounts reflect the net total of charges and credits allocated by ISO-NE to a company. The Monday invoice covers all charges recorded in the prior Monday through Wednesday, and the Wednesday invoice covers all activity recorded Thursday through Sunday. Payment from net purchasers are due two business days after the invoice date and disbursement to net sellers is made four business days after the invoice date. Eversource is typically a net purchaser from ISO-NE, so makes payments on Wednesday and Friday. The ISO-NE payment cycle produces a cost of lead 7.1 days for energy and ancillary services as shown in Attachment CJG-5, page 25.

Q. How were the weighted lead days in payment of independent power producers ("IPPs") and contract energy costs determined?

A. Eversource makes payment to IPPs and contracted wholesale energy suppliers on a monthly basis following delivery. The lead days for IPP and contract costs were determined by subtracting the midpoint of a service period from the payment date for that period. A list of payments and payment dates for IPPs recorded for January 2015 is included in Attachment CJG-5, page 26 as a representative sample of payments which produces a cost lead of 34.4 days for IPP Costs. As show in Attachment CJG-5, page 27, the weighted average cost lead for contract purchases from Burgess BioPower and Lempster Wind is 36.5 days.

Q. How were the weighted lead days in payment of Renewable Portfolio Standard ("RPS") costs determined?

A. Lead days for RPS costs were determined by comparing the date of payment for RECs to the load-weighted midpoint of the compliance year to which they were applied for RPS compliance. The schedule of 2015 REC payments in Attachment CJG-5, page 28 includes proceeds from the resale of RECs purchased from Burgess BioPower and Lempster Wind and results in a computed lead of 120.1 days. As discussed previously, transactions for RECs through NEPOOL GIS substantially lag the period in which they are produced and applied for RPS compliance. This schedule creates a cost lead for Purchased Power expense.

Q. How is the total Purchased Power Lag determined?

A. The lead in payment for wholesale energy and related products of 22.8 days is subtracted from the lag in receipt of applicable revenue of 42.2 days to produce the total Purchased Power Lag of 19.4 days as shown in Attachment CJG-5, page 1.

Q. Are there other expenses that could create cash working capital requirements?

A. Yes. The Company has not included any cash working capital requirement associated with its fuel expense at this time due to the 2017 operations of most of its fossil generation fleet. If the fleet was substantially operated as a baseload generation resource, then the Company would likely incur a cash working capital requirement since it would have to make fuel purchases to replenish inventory before it received payment from customers to recover the cost of consumed fuel. However, 2017 seasonal and peak operation of most of the fossil generation permitted greater flexibility of fuel inventory and diminished cash working capital requirements.

Q. Would you summarize the Company's proposal regarding Cash Working Capital?

A. Yes. Based on the results of the lead-lag analysis of Eversource Energy Service Cash Working Capital, the Company identified an O&M working capital component of 17.5 days, or 4.8 percent, and a Purchased Power working capital component of 19.4 days, or 5.3 percent. Application of these values results in a total cash working capital allowance of $12.036 million to be included in generation rate base for 2017.

Q. How do the Lead/Lag Study results compare to the historic 45 day convention?

A. The Lead/Lag Study determined that the Company realizes a net revenue lag of less than 45 days. However, the current convention of determining cash working capital requirements based only upon O&M expense does not capture the working capital required to support Purchased Power expenses incurred to provide Energy Service to customers. The calculation for cash working capital can be found on Attachment CJG-6, Page 1. As referenced in the calculation, the components for both O&M expenses and purchased power expenses were taken from Attachment CJG-4 which reflects actual 2017 expenses. These expense totals were then applied to their respective working capital percentage from Attachment CJG-5, Page 1. The net effect of applying the results of the Lead/Lag study is therefore an increase in cash working capital requirements included in generation rate base from $9.653 million to $12.036 million.

III. Stranded Cost Recovery Charge

Q. Please describe the SCRC and its components in more detail.

A. The SCRC recovers costs categorized as "stranded" by New Hampshire law in RSA Chapters 374-F and 369-B. The initial SCRC average rate of 3.4 cents per kWh was agreed to in the Restructuring Settlement which further defined what Eversource's stranded costs were and categorized them into three different parts (i.e. Parts 1, 2, and 3) based on their priority of recovery. Effective June 30, 2006, Part 3 costs were fully recovered.

Q. Please describe the costs that are recovered through the SCRC.

A. The first tier, Part 1 stranded costs, had the highest priority for recovery. All Part 1 costs had been securitized through the issuance of rate reduction bonds ("RRBs"). Part 1 costs consisted of the over-market portion of Seabrook regulatory assets, a portion of Eversource's share of Millstone 3, and certain financing costs that were incurred (i.e. underwriters fees, legal fees, etc.) while obtaining the RRB financing. RRB interest and RRB fees were also recovered as Part 1 costs.

The second tier, Part 2 stranded costs, includes "ongoing" costs consisting of the over-market value of energy purchased from IPPs and the up-front payments made for IPP buy-downs and buyouts previously approved by the Commission, and Eversource's share of the present value of the savings associated with these buy-down and buy-out transactions. Eversource is amortizing these up-front payments over the respective terms of the original IPP rate orders, including a return on the unrecovered costs.

In addition, Part 2 costs include a negative return on the credit for deferred taxes related to the Part 1 securitized stranded costs and a return on the unpaid contract obligations to Connecticut Yankee Atomic Power Co., Maine Yankee Atomic Power Co., and Yankee Atomic Energy Corp., net of related deferred taxes. Page 4 of Attachment CJG-4 shows the detailed Part 2 costs by month.

Q. What is your estimate of how long Eversource will continue to bill the SCRC?

A. That depends on the type of cost. The original Part 1 costs were recovered through the SCRC over the life of the corresponding terms of the rate reduction bonds. The original Part 1 recovery ended in May 2013 since the RRBs were fully amortized as of the end of April 2013. The new part 1 costs related to the issuance of new RRB's in May 2018 are designed to be fully amortized in February 2028.

The timing of Part 2 cost recovery through the SCRC is dependent on the type of cost. There are several types of Part 2 costs: ongoing purchases from the IPPs; the amortization of up-front payments associated with buyouts or buydowns of IPP rate orders or contracts; and various returns, including returns on Part 2 stranded costs and the outstanding Yankee contract obligations, and the return on SCRC deferred balance. Additionally, certain costs related to Eversource's 2018 divestiture of its fossil and hydro generating stations will be recovered through Part 2.

Ongoing IPP purchases are obligations that will end when the various rate orders or contracts expire. The up-front payments associated with buyouts or buydowns of IPP rate orders or contracts are also being amortized over the remaining lives of the respective rate orders or contracts. The last such rate order or contract expires in the early 2020s. However, most wood-burning IPP rate orders expired in late 2006 and the last rate order for a wood-fired IPP expired in 2008.

Q. Please provide an overview of stranded cost recovery during the 2017 reporting period.

A. During the reporting period, the total accumulated balance of Part 2 costs increased by $8.1 million from ($6.6) million at the end of 2016 to $1.5 million at the end of 2017. See Attachment CJG-4, page 1.

Q. What are the final results for the SCRC in the 2017 reporting period?

A. For the SCRC, the net balance as of December 31, 2017 is an over-recovery of $0.2 million as shown on Attachment CJG-4, page 1, line 4, 3rd column. This over-recovery primarily relates to actual Above Market IPP costs higher than forecasted.

Q. Please describe the reduction to Yankee Obligation and Amortization.

A. Periodically, Eversource receives updated Revenue Requirements Forecasts for future decommissioning costs from Maine Yankee Atomic Power Company, Connecticut Yankee Atomic Power Company, and Yankee Atomic Electric Company. The $4.780 million reduction in Yankee Obligation and Amortization costs appearing on CJG-4, Page 4, Line 11, reflects a net reduction in these forecasted decommissioning costs from the three aforementioned companies.

Q. Please summarize your request to the Commission.

A. Eversource is requesting that the Commission approve the 2017 ES and SCRC reconciliations and find that Eversource's generation and purchased power costs were prudently incurred.

Q. Does this conclude your testimony?

A. Yes, it does.