UNITIL ENERGY SYSTEMS, INC.

DIRECT TESTIMONY OF

TODD M. BOHAN

New Hampshire Public Utilities Commission

Docket No.: DE 15-

June 17, 2015

TABLE OF CONTENTS

LIST OF SCHEDULES

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Todd M. Bohan. My business address is 6 Liberty Lane West, Hampton, NH.

Q. For whom do you work and in what capacity?

A. I am employed by Unitil Service Corp. (”USC”) as a Senior Energy Analyst. USC provides management and administrative services to Unitil Energy Systems, Inc. (“UES”) and Unitil Power Corp. (“UPC”).

Q. Please describe your relevant educational and work experience.

A. I graduated *magna cum laude* from Saint Anselm College, Manchester, New Hampshire in 1987 with a Bachelor of Arts degree in Financial Economics. I earned a Masters in Economics from Clark University, Worcester, Massachusetts in May 1990. In September 1995, I earned a Ph.D. in Economics from Clark University. Before joining Unitil, I worked for Bay State Gas Company as a Rate Analyst. Prior to working for Bay State, I was employed as a Utility Analyst and an Economist in the Economics Department of the New Hampshire Public Utilities Commission. I joined Unitil Service Corp. in November 1998, and have been involved in various regulatory proceedings. In August of 2010, I joined the Energy Contracts group and have primary responsibilities in the areas of electric market operation and data reporting, default service administration and budgeting, and competitive electric supplier operations.

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

A. Yes. I have testified before the Commission on various regulatory matters, most recently in UES's Default Service Solicitation proceeding, Docket No. DE 15-079 and UES's Stranded Cost Recovery and External Delivery Charge Reconciliation and Rate Filing, Docket No. DE 14-170.

II. SUMMARY OF TESTIMONY

Q. Please summarize your testimony in this proceeding.

A. My testimony presents the cost data and explains the reasons for the proposed changes to UES's Stranded Cost Charge ("SCC"), and External Delivery Charge ("EDC"), effective August 1, 2015. Ms. Linda S. McNamara presents the reconciliation for the SCC and EDC through July 2015 and the rate development for the SCC and EDC for the period beginning August 1, 2015 and ending July 31, 2016, based on the cost data included in my testimony.

III. STRANDED COST CHARGE COSTS

Q. What costs are included in the SCC?

A. The SCC includes the Contract Release Payments ("CRP") from Unitil Power Corp., charged in accordance with the Amended Unitil System Agreement, approved by both the Commission in Docket No. DE 01-247 and by the FERC.

Schedule TMB-1, page 1, provides a description of the CRP. Page 2 provides the CRP by month reflecting actual data from August 2013 through April 2015 and estimated data from May 2015 through July 2016. These include costs associated with the recovery of a customer billing adjustment as approved in docket DE 11-105 and as discussed in the testimony of Ms. McNamara.

Q. Please describe the Amended Unitil System Agreement.

A. The purpose of the Amended Unitil System Agreement was to restructure UES's power supply in order to implement retail choice. Prior to the implementation of the Amended Unitil System Agreement on May 1, 2003, UES purchased full-requirements power supply from UPC at fully reconciling, cost-of-service rates.

The Amended Unitil System Agreement provides for termination of power sales from UPC to UES and the payment of UPC's on-going costs by UES. These on-going costs are defined in the Amended Unitil System Agreement as either CRP or Administrative Service Charges ("ASC"). UES recovers the CRP through the SCC and the ASC through the EDC. The ASC will be discussed later under the EDC costs.

Q. Please describe the CRP.

A. The CRP is calculated in accordance with Appendix 1 of the Amended Unitil System Agreement. The CRP is equal to the sum of the Portfolio Sales Charge, the Residual Contract Obligations, the Hydro-Quebec Support Payments, and True-Ups from Prior Periods.

The Portfolio Sales Charge and the Residual Contract Obligations have ended. The CRP estimates in this filing include no Portfolio Sales Charge and no Residual Contract Obligations. UPC's last Portfolio Sales Charge payment under the Mirant Agreement was made in October 2010, and UPC's last Residual Contract Obligation buyout payment (Indeck contract buyout) was made in September 2009.

The Hydro-Quebec Phase II Agreements require UPC to support the Hydro-Quebec Phase II facilities through October 2020. These facilities are part of one high-voltage, direct-current ("HVDC") interconnection between New England and Quebec. UPC has no obligation to support Phase I of these facilities. Currently, the costs for maintenance and construction of these facilities are paid by Interconnection Rights Holders ("IRH") through support agreements between the IRH members and the owners of the HVDC transmission facilities. The Hydro-Quebec Support Payments include all costs incurred by UPC pursuant to the Hydro-Quebec Phase II Agreements, offset by any revenues received by UPC for sales of UPC's Hydro-Quebec Phase II entitlement. The Hydro-Quebec Support Payments are not a known payment stream because they are based on the cost-of-service of the Hydro-Quebec Phase II transmission facilities. As discussed below, UPC receives revenue for short-term sales of transmission rights and capacity rights. These revenues operate to offset the expense of the Hydro-Quebec Support Payments.

The True-ups from Prior Periods reflect any differences in costs resulting from the reconciliation of estimated costs to actual costs under the CRP component of the Amended Unitil System Agreement. The True-ups from Prior Periods also provide for the reconciliation of costs billed to UPC for services purchased in UPC's performance of the Unitil System Agreement, prior to May 1, 2003. The CRP estimates in the current filing reflect no True-ups from Prior Periods.

Q. Please provide an estimate of each of the components of the CRP.

A. Details regarding the CRP are provided in Schedule TMB-3. This shows the actual itemized CRP and ASC charges as billed by UPC to UES for the period beginning August 2013 through April 2015 under the Amended Unitil System Agreement. Beginning on page 2 of Schedule TMB-3, estimated CRP and ASC for the 15-month period beginning May 2015 and ending July 2016 are presented. UPC bills UES on estimated data, prior to the beginning of the month of service. These estimates are trued-up to actuals on a two-month lag.

Q. Please provide a comparison of the estimated CRP for the upcoming SCC rate period (August 2015 through July 2016) to the projected CRP for the current SCC rate period (August 2014 through July 2015).

A. Table 1 below provides a comparison of the estimated CRP for the upcoming SCC rate period (August 2015 through July 2016) to the projected actual CRP for the current SCC rate period (August 2014 through July 2015).

Table 1. Comparison of Estimated CRP for August 2015 through July 2016 to Projected CRP for August 2014 through July 2015 Unitil Power Corp.				
Line No.	Line Item Description	Aug 2014 - July 2015 9 Months Act. and 3 Months Est.	Aug 2015 - July 2016 Estimate	Variance (Aug 2015 - July 2016 Costs minus Aug 2014 - July 2015 Costs)
1.	Portfolio Sales Charge	$0	$0	$0
2.	Residual Contract Obligations	$0	$0	$0
3.	Hydro-Quebec Support Payments	$190,301	$201,684	$11,383
4.	Subtotal (L. 2 through 4)	$190,301	$201,684	$11,383
5.	True-up for estimate	($7,634)	$0	$7,634
6.	Obligations prior to May 1, 2003	$0	$0	$0
7.	Total Contract Release Payments as billed by Unitil Power Corp.	$182,667	$201,684	$19,017

At the time of the preparation of this estimate of the CRP, actual CRP expense data was available through April 2015. As such, the projected actual CRP for the current SCC rate period (August 2014 through July 2015) presented in Table 1 is comprised of nine months of actual data and three months of estimated data.

Q. Please report on the efforts by UPC to mitigate the stranded cost associated with the Hydro-Quebec Phase II Agreements.

A. UPC mitigates these costs through short-term sales of the transmission rights and capacity, which UPC is entitled to through its support of the Hydro-Quebec Phase II facilities. Currently, UPC resells its transmission rights on a short-term basis through a brokering agreement with Central Vermont Public Service Corporation ("CVPS"). Under this brokering agreement, CVPS offers UPC's transmission rights associated with the Hydro-Quebec Phase II facilities for sale on a short-term basis through the CVPS' OASIS website. CVPS has authority under this agreement to enter into binding sales of UPC's Hydro-Quebec transmission rights for transactions of one month or less in duration. UPC also has rights to Hydro-Quebec Interconnection Capability Credit ("HQICC"), pursuant to the ISO Tariff. UPC is reimbursed by CVPS for its HQICC at a price equal to the ISO Net Regional Clearing Price.[1] Please refer to Schedule TMB-5 for itemized cost and revenue offsets, related to the Hydro-Quebec Phase II Support Agreements.

IV. EXTERNAL DELIVERY CHARGE COSTS

Q. What costs are included in the EDC?

A. Schedule TMB-2, page 1 provides a description of the costs included in the EDC:

1) Third Party Transmission Providers (NU Network Integration Transmission Service);
2) Regional Transmission and Operating Entities;
3) Third Party Transmission Providers (NU Wholesale Distribution);
4) Transmission-Based Assessments and Fees;
5) Load Estimation and Reporting System Costs;
6) Data and Information Services;
7) Legal Charges;
8) Consulting Outside Service Charges;
9) Administrative Service Charges;
10) Non-Distribution Portion of the Annual PUC Assessment;
11) Working Capital Associated with Other Flow-Through Operating Expenses;
12) Regional Greenhouse Gas Initiative Rebates.

Items 1), 2), and 3) of the Schedule are discussed below:

The Third Party Transmission Providers (NU Network Integration Transmission Service) component of the EDC consists of Network Integration Transmission

[1] The Net Regional Clearing Price is calculated by first adding Forward Capacity Auction payments to Net Reconfiguration Auction Credits or Charges and subtracting Peak Energy Rent Adjustments. This total is then divided by the Net Regional Supply Obligation.

Service taken by UES and provided by the Northeast Utilities Companies ("NU") pursuant to Schedule 21-NU of the ISO New England Inc. Transmission, Markets and Services Tariff (FERC Electric Tariff No.3) ("ISO Tariff").

The Regional Transmission and Operating Entities component of the EDC consists of all charges from ISO New England Inc. ("ISO"). These charges consist primarily of Regional Network Service, taken pursuant to the ISO Tariff. Other major costs (which are also billed by the ISO to UES) are various ancillary services allocated to transmission customers, such as VAR support, dispatch service, and black-start capability.

The Third Party Transmission Providers (NU Wholesale Distribution) component consists of Distribution Delivery Service ("DDS") charges with NU. DDS compensates Public Service Company of New Hampshire for the wheeling of power from the NU transmission system to UES's distribution system over certain facilities, which are classified as distribution facilities for accounting purposes and, therefore, are not included in the NU transmission system rate base.

Q. Please provide the External Delivery cost data, which was utilized in the calculation of the EDC.

A. Schedule TMB-2 provides the External Delivery cost data used in the calculation of the EDC. Page 2 provides actual historic External Delivery cost data for the year beginning August 2013 through July 2014. Actual External Delivery cost data for the months of August 2013 through April 2014 was included in UES's last rate and reconciliation filing, Docket No. DE 14-170. In that docket, UES provided estimated External Delivery costs for May 2014 through July 2014. Rather than present partial data beginning with May 2014, UES is presenting the full period. Page 3 of Schedule 2 provides External Delivery cost data for the current EDC rate period, August 2014 through July 2015. Actual cost data is available through April 2015, and estimated cost data is provided for May 2015 through July 2015. These include costs, which end July 31, 2015, associated with the recovery of a customer billing adjustment (column (n)) as approved in docket DE 11-105 and as discussed in the testimony of Ms. McNamara. Finally, page 4 of Schedule TMB-2 provides estimated External Delivery costs for the upcoming EDC rate period, August 2015 through July 2016.

Q. Please provide a comparison of the External Delivery costs for the upcoming EDC rate period (August 2015 through July 2016) to the projected External Delivery costs for the current EDC rate period (August 2014 through July 2015).

A. Please refer to Table 2 below for an itemized comparison of estimated External Delivery cost for the upcoming EDC rate period to the projected External Delivery costs for the current rate period.

Table 2. Comparison of Estimated External Delivery costs for August 2015 through July 2016 to projected External Delivery costs for August 2014 through July 2015
Unitil Energy Systems, Inc.

Line No.	Line Item Description	Aug 2014 - July 2015 9 Months Act. and 3 Months Est.	Aug 2015 - July 2016 Estimate	Variance (Aug 2015 - July 2016 Costs minus Aug 2014 - July 2015 Costs)
1.	Third Party Transmission Providers (NU Network Integration Transmission Service)	$2,303,300	$1,491,209	($812,091)
2.	Regional Transmission and Operating Entities	$19,792,754	$21,915,376	$2,122,621
3.	Third Party Transmission Providers (NU Wholesale Distribution)	$2,923,709	$2,851,668	($72,040)
4.	Transmission-based Assessments and Fees	$12,000	$12,000	$0
5.	Load Estimation and Reporting System Costs	$214,043	$209,340	($4,704)
6.	Data and Information Services	$15,000	$15,000	$0
7.	Legal Charges	$6,573	$15,000	$8,427
8.	Consulting Outside Service Charges	$12,350	$24,000	$11,650
9.	Administrative Service Charges	$5,882	$7,771	$1,889
10.	Non-Distribution Portion of the Annual PUC Assessment	$365,947	$348,570	($17,377)
11.	Working Capital Associated with Other Flow-Through Operating Expenses	$378,560	$378,560	$0
12.	Regional Greenhouse Gas Initiative Rebates	($1,325,343)	($1,317,932)	$7,411
13.	EDC Cost Adjustment	$73,966	$0	($73,966)
14.	Total External Delivery Costs	$24,778,771	$25,950,562	$1,171,791

Q. Please explain the projected increase in External Delivery costs for the upcoming EDC rate period (August 2015 through July 2016) over the current EDC rate period (August 2014 through July 2015).

A. The External Delivery costs for the upcoming EDC rate period are projected to be $1,171,791 higher than those in the current rate period. This is primarily the result of one factor: higher Regional Transmission and Operating Entities costs for the upcoming period of August 2015 through July 2016. The $2.1 million increase in the Regional Transmission and Operating Entities costs is driven by an increase in the Regional Network Service ("RNS") rate from $87.35/kW-Year to $98.70/kW-Year effective June 1, 2015. A decline in the projected Third Party Transmission Providers (NU Network Integration Transmission Service) costs of approximately ($800,000) is mitigating the impact of the RNS increase. The net impact of these two cost categories is the primary driver of the projected increased costs.

Q. What legal costs does UES expect to incur under the EDC?

A. UES estimates that it will incur approximately $15,000 in legal costs for the upcoming EDC rate period (August 2015 through July 2016). Legal costs include UES's estimates for monitoring FERC issuances and rulemakings and completing FERC tariff filings. The EDC legal costs estimate excludes any charges directly related to the design and implementation of Default Service supply. Any legal costs associated with procurement of Default Service are recovered through the Default Service Charge.[2]

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[2] This is in accordance with the settlement agreement approved in Docket No. DE 05-064.

Q. Please provide the detail behind the estimate for the Administrative Service Charges.

A. Details regarding the ASC are provided in Schedule TMB-3 on lines 10 through 18. The ASC includes any costs incurred by UPC, relative to UPC's obligations under the Amended Unitil System Agreement, which are not otherwise assigned or assumed by UES. These costs include NEPOOL, ISO, and RTO costs, as well as legal, consulting, and other outside services. It does not include any internal costs of USC, UES or UPC.

Q. Has UES included Regional Greenhouse Gas Initiative (RGGI) rebates in the proposed EDC?

A. Yes. UES has included the rebate of excess RGGI auction proceeds applicable to all retail electric customers as a separate line item in the EDC. UES records the rebates in the EDC in the month that the rebate amount is received, and applies carrying charges. For the actual period of August 2013 through April 2015, UES has recorded five rebate amounts totaling ($1,647,415). In accordance with Order No. 25,664, UES has included estimates of auction amounts it expects to receive through July 2016 in order to ensure customers receive the credit, or estimate thereof, in a timely manner. These estimates are shown on Schedule TMB-2, Pages 3 and 4.

Q. Has UES included in this filing the recovery of costs associated with lost distribution revenue due to net metering generation as it did in its previous EDC filing?

A. No, it has not.

Q. Could you please explain why this is the case and discuss how UES plans to recover these costs?

A. Certainly. In its previous EDC filing, in docket DE 14-170, UES proposed to recover lost distribution revenue due to net metering generation through the EDC charge. Through discussion with Commission Staff, UES agreed to withdraw its proposal from its filing and make a separate filing with the Commission in order to allow for a more thorough review process. Subsequent to a technical session with various participants, UES filed its proposal with the Commission on May 13, 2015. The Commission has docketed this matter as DE 15-147 and will review the Company's proposal in that proceeding. At the conclusion of that proceeding, UES plans to recover the cost of lost distribution revenue due to net metering generation through the EDC, unless otherwise directed by the Commission.

V. UPC COSTS AND REVENUES

Q. Has UPC prepared an accounting of the costs and revenues to UPC under the CRP and the ASC?

A. Yes. Schedule TMB-4 provides this accounting for the period beginning August 2013 through April 2015. UPC bills UES estimates of the CRP and ASC on the

25th of the month for the upcoming month. The estimated expenses are trued-up to actual expenses on a two-month lag basis. In order to calculate the true-up, UPC tracks the actual expenses, which comprise both the CRP and the ASC. These actual expenses are compared to the estimated expenses to calculate the true-up for prior period. Schedule TMB-4 provides summary data of actual CRP and ASC expenses and revenues.

VI. CONCLUSION

Q. Does that conclude your testimony?

A. Yes, it does.