UNITIL ENERGY SYSTEMS, INC.

DIRECT TESTIMONY OF

FRANCIS X. WELLS

New Hampshire Public Utilities Commission

Docket No.: DE 08-

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Francis X. Wells. My business address is 6 Liberty Lane West, Hampton, NH.

Q. What is your relationship with Unitil Energy Systems, Inc.?

A. I am employed by Unitil Service Corp. ("USC") as Senior Energy Trader. USC provides management and administrative services to Unitil Energy Systems, Inc. ("UES") and Unitil Power Corp. ("UPC"). UES provides Default Service to its retail electric customers. UES also secures the necessary transmission arrangements for the wheeling of power through the New England bulk transmission grid for all of its retail customers, including both Default Service customers and customers who have taken advantage of retail choice opportunities, either through an approved retail supplier or through self-supply. UPC, pursuant to the Amended Unitil System Agreement, recovers its remaining wholesale power supply costs from UES in accordance with terms approved by the Federal Energy Regulatory Commission ("FERC") and the New Hampshire Public Utilities Commission ("Commission"). UPC incurred these power supply costs in order to perform its obligations to supply full requirement power supply to UES under the original Unitil System Agreement. UES, UPC and USC are wholly owned subsidiaries of Unitil Corporation.

Q. Please summarize your educational background and professional qualifications.

1 A. I received my Bachelor of Arts Degree in both Economics and History from the
2 University of Maine in 1995. I joined USC in September 1996 as an Analyst,
3 assisting in the planning and operation of both electric power and natural gas
4 supply portfolios. Since January 2001 I have worked as a Senior Energy Trader
5 in the Energy Contracts Department. I have responsibilities in the area of energy
6 supply acquisition, including default service purchasing, regulatory reporting,
7 budgeting, and long-term supply planning.
8
9 Q. Have you previously testified before the Commission?
10 A. Yes. I have testified on numerous occasions before the Commission.
11
12 **II. SUMMARY OF TESTIMONY**
13 Q. Please summarize your testimony in this proceeding.
14 A. My testimony will first review the changes in the relationship between UPC and
15 UES, which were necessary to implement retail choice. I will then present an
16 overview of the Portfolio Sale and Assignment and Transition Service and
17 Default Service Supply Agreement by and among UPC, UES, and Mirant
18 Americas Energy Marketing, LP ("Mirant Agreement") and explain how the
19 Mirant Agreement directly affects the underlying costs for the current Stranded
20 Cost Charge ("SCC").
21
22 Next, I will present and explain the cost data and underlying reasons for the
23 proposed changes to UES' Stranded Cost Charge ("SCC"), and External Delivery

Charge ("EDC"), effective May 1, 2008. Ms. Asbury presents the reconciliation for the SCC and EDC through April 2008 and the rate development for the SCC and EDC for the period beginning May 1, 2008 and ending April 30, 2009, based on the cost data I discuss in my testimony.

Finally, I will report on UPC's on-going efforts to mitigate the cost of its HQ Phase II Support Payment obligations, which UES recovers through the SCC.

III. RESTRUCTURING OF UES' POWER SUPPLY

Q. Please describe UES' relationship with UPC before and after May 1, 2003.

A. The Unitil System Agreement defined the relationship between UPC and UES, prior to May 1, 2003. UPC provided full-requirements power supply to UES at fully reconciling, cost-of-service rates. UES met all of its wholesale power supply requirements through the Unitil System Agreement with UPC. The Unitil System Agreement was a FERC-regulated rate schedule.

Effective May 1, 2003, the Unitil System Agreement between UPC and UES was replaced with the Amended Unitil System Agreement. The purpose of this Amended Unitil System Agreement was to restructure UES' power supply in order to implement retail choice. The major provisions of the Amended Unitil System Agreement included the termination of power sales from UPC to UES effective May 1, 2003, and the provision for payment of UPC's on-going costs by UES. These on-going costs are defined in the Amended Unitil System Agreement

as Contract Release Payments ("CRP") and Administrative Service Charges ("ASC"). The Amended Unitil System Agreement is also a FERC-regulated rate schedule. UES recovers the CRP costs through the SCC and recovers the ASC charges through the EDC.

Initially, UES purchased its power supply requirements via the Mirant Agreement. Currently, UES purchases its power supply requirements via periodic Default Service Requests-for-Proposals, the results of which are submitted to the Commission for review and approval.

Q. Please describe the Mirant Agreement.

A. The Mirant Agreement provided for the transfer of most of UPC's purchase power obligations to Mirant Americas Energy Marketing, LP ("MAEM") and for the purchase of Transition Service ("TS") and Default Service ("DS") power by UES from MAEM through April 30, 2006. Under the Mirant Agreement, UPC makes fixed monthly payments and until May 1, 2006, UES purchased TS and DS power at specified, annual prices per kilowatt-hour for its energy purchases. Although the TS and DS power supply component of the Mirant Agreement ended effective May 1, 2006, coincident with the termination of Transition Service, UPC's fixed monthly payment obligation continues until October 2010.

On July 14, 2003, MAEM filed a voluntary petition for protection under chapter 11 of the bankruptcy code. On December 11, 2003, a Settlement Agreement including

MAEM, UPC, and UES was approved by the bankruptcy court, which provided for the assumption of the Mirant Agreement by MAEM. On January 3, 2006 MAEM emerged from bankruptcy. On February 1, 2006 MAEM transferred the Mirant Agreement to Mirant Energy Trading, LLC ("MET"). MET is currently meeting all of its obligations under the Mirant Agreement, which are now limited to the performance of all UPC's purchase power obligations.

Q. Has the Commission approved the recovery of costs under the Mirant Agreement?

A. Yes. The Commission approved the recovery of costs under the Mirant Agreement in Phase III of DE 01-247, subject to reconciliation.

VI. STRANDED COST CHARGE COSTS

Q. What is UES' estimate for SCC Costs, which was used in the reconciliation and calculation of the SCC rate, presented by Ms. Asbury?

A. Schedule FXW-1, page 1, provides a description of Contract Release Payments ("CRP"), which is the only cost included in the SCC. Page 2 provides the CRP by month reflecting actual data from May 2006 through January 2008 and estimated data from February 2008 through April 2009.

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 is equal to the Monthly Payment made by UPC to MET, pursuant to the sale of the majority of the remaining UPC portfolio of power supply contracts. Pursuant to the Mirant Agreement, the Portfolio Sales Charge is a specified monthly payment stream, which continues through October 2010.

The Residual Contract Obligations currently include buyout payments to Indeck and Bay State Gas Company ("Bay State"). The Residual Contract Obligations are also a known monthly payment stream. The Indeck buyout payments continue through September 2009. The Bay State buyout payments continue through December 2008.

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, which are offset by the short-term sales UPC is able to enter into. The Hydro-Quebec Support Payments continue into 2020.

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 provides 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 current filing does not reflect any such costs.

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

A. Details regarding the CRP are provided in Schedule FXW-3. On pages 1, 2, and 3 of Schedule FXW-3, UES presents itemized actual CRP and ASC charges as billed by UPC to UES for the period beginning May 2006 through January 2008 under the Amended Unitil System Agreement. On pages 3 and 4 of Schedule FXW-3, estimates for Febuary 2008 through April 2009 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.

V. EXTERNAL DELIVERY CHARGE COSTS

Q. What costs are included in the EDC?

A. Schedule FXW-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; 6) Legal Charges; 7) Consulting Outside Service Charges; and, 8) Administrative Service Charges.

I would like to expand on the descriptions of items 1), 2), and 3) of the Schedule.

The Third Party Transmission Providers (NU Network Integration Transmission Service) component of the EDC consists of Network Integration Transmission Service taken by UES and provided by the Northeast Utilities Companies 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.

Third Party Transmission Providers (NU Wholesale Distribution) became effective upon the implementation of a Distribution Delivery Service with NU ("DDS") on June 1, 2005. This component is in addition to the Network Integration Transmission Service UES currently purchases under Schedule 21-NU of the ISO Tariff. DDS compensates Public Service Company of New Hampshire for the wheeling of power from the NU transmission system to UES' distribution system over certain facilities, which are classified as distribution facilities for

accounting purposes and therefore not included in the NU transmission system rate base.

Q. What is UES' estimate for External Delivery costs, which is used in the calculation of the EDC rate, presented by Ms. Asbury?

A. Pages 2 through 4 provide the External Delivery costs by month reflecting actual data from May 2006 through January 2008 and estimated data from February 2008 through April 2009. Actual data for the months May 2006 through January 2007 was included in UES' last rate and reconciliation filing, Docket No. DE 07-035. Rather than present partial data beginning with February 2007, UES is presenting the full period.

Q. What portion of the $1.1 million under-recovery in the EDC is attributable to higher than estimated costs?

A. EDC Costs beginning February 2007 through April 2008 are projected to be $636,000 higher than estimated costs. Table 1 provides a break-out of this variance. Estimated costs are those which are the basis for the current EDC rate. Projected costs are equal to the actual costs beginning February 2007 through January 2008 and new estimated cost for February 2008 through April 2008, which are provided in this filing.

Table 1: February 2007 through April 2008 EDC Cost Estimates				
	External Delivery Costs	Estimated	Projected	Variance
(a)	Third Party Transmission Providers (NU Network Integration Transmission Service)	$1,174,570	$1,420,292	$245,722
(b)	Regional Transmission and Operating Entities	$8,529,428	$8,711,141	$181,713
(c)	Third Party Transmission Providers (NU Wholesale Distribution)	$2,453,278	$2,754,756	$301,478
(d)	Transmission-based Assessments and Fees	$9,000	$8,378	($622)
(e)	Load Estimation and Reporting System Costs	$160,650	$152,436	($8,214)
(f)	Data and Information Services	$3,750	$18,750	$15,000
(g)	Legal Charges	$121,500	$63,219	($58,282)
(h)	Consulting Outside Service Charges	$195	$195	$0
(i)	Administrative Service Charges (1)	($23,545)	($64,656)	($41,111)
(j)	Total External Delivery Costs	$12,428,826	$13,064,511	$635,685

Q. Please explain why projected costs are higher than estimated costs.

A. The variance is driven by NU Network Integration Transmission Service and Regional Transmission and Operating Entities costs, and NU Wholesale Distribution.

Projected February 2007 through April 2008 costs for NU Network Integration Transmission Service were higher than estimated costs for this item by $245,722. The reason for this significant variance is that the NU Network Integration

Transmission Service rate was significantly higher than estimated for the June 2007 through December 2007 period.

Projected costs for the Regional Transmission and Operating Entities line item were higher than estimated costs by $181,713. VAR Support charges to UES were significantly higher than that which was estimated when preparing the Regional Transmission and Operating Entities cost estimate. These higher levels of VAR Support charges are included in the estimates of EDC costs in the upcoming period.

In addition, the cost of the NU Wholesale Distribution increased effective January 1, 2008 pursuant to a settlement agreement with PSNH. This settlement agreement was filed at FERC for approval under docket number ER08-349-000. The need for new DDS rates was driven by PSNH's substantial investment in improving the reliability of facilities between UES' distribution system and NU's transmission system. As a result of this rate change, NU Wholesale Distribution costs were $301,478 higher than previously estimated.

The higher levels of transmission costs for each of the major components of EDC costs have created the increase in projected cost over estimated costs, which this filing reflects.

Q. How do estimated EDC Costs beginning February 2008 through April 2009 compare to those which were estimated for February 2007 through April 2008 in Docket No. DE 07-035?

A. Please refer to the Table 2 on the next page for an itemized comparison of cost projections. Total projected costs are approximately $4,000,000 higher than cost projections made last year. Pages 3 and 4 of Schedule FXW-2 break the estimated cost data out by month for February 2008 through April 2009.

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Table 2: EDC Cost Estimates				
	External Delivery Costs	February 2007 through April 2008	February 2008 through April 2009	Change
(a)	Third Party Transmission Providers (NU Network Integration Transmission Service)	$1,174,570	$1,916,633	$742,063
(b)	Regional Transmission and Operating Entities	$8,529,428	$10,420,899	$1,891,471
(c)	Third Party Transmission Providers (NU Wholesale Distribution)	$2,453,278	$3,841,187	$1,387,909
(d)	Transmission-based Assessments and Fees	$9,000	$8,389	($611)
(e)	Load Estimation and Reporting System Costs	$160,650	$156,000	($4,650)
(f)	Data and Information Services	$3,750	$18,750	$15,000
(g)	Legal Charges	$121,500	$90,000	($31,500)
(h)	Consulting Outside Service Charges	$195	$0	($195)
(i)	Administrative Service Charges (1)	($23,545)	($22,075)	$1,470
(j)	Total External Delivery Costs	$12,428,826	$16,429,783	$4,000,957

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3 Q. Please explain the major increase in projected EDC costs.

4 A. In general, the cost of transmission service has been increasing due to major
5 investment in transmission infrastructure in New England. This investment has
6 been required for transmission system reliability purposes. This increased
7 investment has the effect of increasing the amount UES pays for NU Network
8 Service and Regional Transmission payments. According to data gathered from

the October 2007 ISO-NE Project Listing Update, projected 2008 total new transmission investment in 2008 will equal $970 million. This will result in major increases in Regional Network Service rates, effective June 1, 2008. Given this environment of major transmission cost increases, the NU Network Service charges are estimated to remain at their current levels, which is significantly higher than what had been forecasted in the prior filing. Finally, the NU Wholesale Distribution Service is estimated to remain at the new rates established in the settlement agreement discussed previously.

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

A. Actual legal costs for the 12-month period beginning February 2007 were $45,219, which was $51,982 lower than estimated costs. Estimated legal costs for the 15-month period beginning February 2008 are $90,000, which is $31,500 lower than estimated legal costs for the 15-month period beginning February 2007.

UES is required to comply with and stay informed about a number of regulatory proceedings. The regulatory proceedings, which UES is or has been actively involved in, include this proceeding, the Regional Transmission Organization return on equity case, compliance with FERC Orders 697, 698, 890 and 890A, the PSNH settlement agreeement related to DDS, and the FERC triennial market power analysis to maintain UES' market-based rate authority. UES expects ongoing involvement in the upcoming 15-month period in this proceeding,

compliance with FERC Orders 697 and 890A and the 2005 Energy Policy Act compliance. It is also expected to be involved in the "Wholesale Competition in Regions with Organized Electric Markets" Notice Of Proposed Rulemaking, which was issued on February 22, 2008 in FERC Docket Nos. RM07-19-000 and AD07-7-000. The EDC legal costs estimate does not include 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, in accordance with the settlement agreement approved in DE 05-064.

Q. Please provide the detail behind the estimate for the ASC.

A. Details regarding the ASC are provided in Schedule FXW-3 on lines 10 through 18. As is the case with the CRP charges to UES, monthly figures are estimates prepared by UPC, which are trued-up to actual costs on a two-month lag. The ASC includes any costs incurred by UPC, relative to UPC's obligations under the Unitil System Agreement or 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.

UPC incurred legal expenses due to its involvement in regulatory proceedings concerning Market Based Rates, and FERC Orders 697, 698, 890 and 890A. In the coming period UPC expects to be involved in Market Based Rate issues and

Order 890/890A issues with Open Access Transmission Tariff requirements associated with its Support rights for the HQ Phase II Agreements.

VI. 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 FXW-4 provides this accounting for the period beginning May 2006 through January 2008. 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.

Page 1 of 2 of the Schedule provides summary data of actual CRP and ASC expenses and revenues. Page 2 of 2 of the Schedule provides account level detail. Account level detail of all expenses pertaining to service under the Unitil System Agreement prior to May 1, 2003 has been excluded since no such charges were paid by UPC for the entire period covered by the Schedule.

VII. HQ REPORT ON MITIGATION EFFORTS

Q. Please provide a report on the efforts by UPC to mitigate the stranded cost associated with the HQ Phase II Agreements.

A. The HQ Phase II Agreements require UPC to support the HQ 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 the 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. UPC recovers these costs through the Amended Unitil System Agreement as a component of the CRP.

UPC mitigates these costs through short-term sales of the transmission rights and capacity, which UPC is entitled to through its support of the HQ 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 HQ 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 HQ 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 sells this capacity in the short-term markets by offering this capacity into the ISO New England Inc. ICAP Supply Auction. Please refer to Schedule FXW-5 for an itemized costs and revenue offsets, related to the HQ Phase II Support Agreements.

Q. Is the cost associated with the HQ Phase I and II facilities included in the ISO New England Inc. transmission rate base?

A. With the exception of certain alternating current facilities, which were determined to be necessary for the reliable operation of the HQ Phase II facilities, the HQ Phase I and II facilities are not currently part of the ISO New England Inc. transmission rate base because they do not qualify as Pool Transmission Facilities ("PTF"), as defined in the ISO Tariff. If the facilities were included in PTF, then UPC would expect to be compensated through the ISO Tariff for all costs it incurs under the HQ Phase II Agreements. This benefit would be passed to UES through the Amended Unitil System Agreement. Currently, UPC is compensated through the ISO Tariff for its support of the alternating current HQ Phase II facilities, since these are included in PTF. These credits are passed to UES through the CRP.

VIII. CONCLUSION

Q. Does that conclude your testimony?

A. Yes, it does.