

UNITIL ENERGY SYSTEMS, INC.

DIRECT TESTIMONY OF

LISA S. GLOVER

New Hampshire Public Utilities Commission

Docket No.: DE 19-

June 14, 2019

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LIST OF SCHEDULES

Schedule LSG-1: Stranded Cost Charge Costs

Schedule LSG-2: External Delivery Charge Costs

Schedule LSG-3: Contract Release Payments and Administrative Service Charges

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Schedule LSG-5: HQ Payments and Revenues

1 **I. INTRODUCTION**

2 **Q. Please state your name and business address.**

3 A. My name is Lisa S. Glover. My business address is 6 Liberty Lane West,
4 Hampton, NH.

5

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

7 A. I am a Senior Energy Analyst for Unitil Service Corp. ("USC"). USC provides
8 management and administrative services to Unitil Energy Systems, Inc. ("UES")
9 and Unitil Power Corp. ("UPC").

10

11 **Q. Please describe your relevant educational and work experience.**

12 A. I received my Bachelor of Science degree in Environmental Science from the
13 University of Massachusetts Amherst and a Master of Public Administration from
14 Norwich University in Vermont. I joined Unitil Service Corp. in February 2003
15 and have held various positions within the company prior to joining Energy
16 Contracts in May 2014 in my current position as Senior Energy Analyst. I have
17 primary responsibilities in the areas of default service budgeting, administration,
18 and procurement; long-term renewable energy procurement; electric market
19 operation and data reporting; and Renewable Portfolio Standard compliance.

20

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

23 A. Yes.

1 **II. SUMMARY OF TESTIMONY**

2 **Q. Please summarize your testimony in this proceeding.**

3 A. My testimony presents the cost data and explains the reasons for the proposed
4 changes to UES's Stranded Cost Charge ("SCC"), and External Delivery Charge
5 ("EDC"), effective August 1, 2019. Ms. Linda S. McNamara is sponsoring
6 testimony on the reconciliation and rate development for the SCC and EDC,
7 based on the cost data included in my testimony. Mr. Douglas Debski has
8 provided testimony to explain the calculation of displaced distribution revenue
9 associated with net metering for 2018, which is included in the proposed EDC.

10

11 **III. STRANDED COST CHARGE COSTS**

12 **Q. What costs are included in the SCC?**

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

16

17 Schedule LSG-1, page 1, provides a description of the CRP. Page 2 provides the
18 CRP by month reflecting actual data from August 2017 through April 2019 and
19 estimated data from May 2019 through July 2020.

20

21 **Q. Please describe the Amended Unitil System Agreement.**

22 A. The purpose of the Amended Unitil System Agreement was to restructure UES's
23 power supply in order to implement retail choice. Prior to the implementation of

1 the Amended Unitil System Agreement on May 1, 2003, UES purchased full-
2 requirements power supply from UPC at fully reconciling, cost-of-service rates.

3

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

10

11 **Q. Please describe the CRP.**

12 A. The CRP is calculated in accordance with Appendix 1 of the Amended Unitil
13 System Agreement. The CRP is equal to the sum of the Portfolio Sales Charge,
14 the Residual Contract Obligations, the Hydro-Quebec Support Payments, and
15 True-Ups from Prior Periods. The Portfolio Sales Charge and the Residual
16 Contract Obligations have ended. The CRP estimates in this filing, therefore,
17 include only the Hydro-Quebec Support Payments.

18

19 The Hydro-Quebec Phase II Agreements require UPC to support the Hydro-Quebec
20 Phase II facilities through October 2020. These facilities are part of one high-voltage,
21 direct-current ("HVDC") interconnection between New England and Quebec. UPC
22 has no obligation to support Phase I of these facilities. Currently, the costs for
23 maintenance and construction of these facilities are paid by Interconnection Rights

1 Holders (“IRH”) through support agreements between the IRH members and the
2 owners of the HVDC transmission facilities. The Hydro-Quebec Support Payments
3 include all costs incurred by UPC pursuant to the Hydro-Quebec Phase II
4 Agreements, offset by any revenues received by UPC for sales of UPC’s Hydro-
5 Quebec Phase II entitlement. The Hydro-Quebec Support Payments are not a known
6 payment stream because they are based on the cost-of-service of the Hydro-Quebec
7 Phase II transmission facilities. As discussed below, UPC receives revenue for short-
8 term sales of transmission rights and capacity rights. These revenues operate to offset
9 the expense of the Hydro-Quebec Support Payments.

10

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

18

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

20 A. Details regarding the CRP are provided in Schedule LSG-3. This shows the
21 actual itemized CRP and ASC charges as billed by UPC to UES for the period
22 beginning August 2017 through April 2019 under the Amended Unitil System
23 Agreement. Beginning on page 2 of Schedule LSG-3, estimated CRP and ASC

1 for the 15-month period beginning May 2019 and ending July 2020 are presented.
2 UPC bills UES on estimated data, prior to the beginning of the month of service.
3 These estimates are trued-up to actuals on a two-month lag.

4

5 **Q. Please provide a comparison of the estimated CRP for the upcoming SCC**
6 **rate period (August 2019 through July 2020) to the projected CRP for the**
7 **current SCC rate period (August 2018 through July 2019).**

8 A. Table 1 below provides a comparison of the estimated CRP for the upcoming
9 SCC rate period to the projected CRP for the current SCC rate period. At the time
10 of the preparation of this estimate of the CRP, actual CRP expense data was
11 available through April 2019. As such, the projected actual CRP for the current
12 SCC rate period (August 2018 through July 2019) is comprised of nine months of
13 actual data and three months of estimated data.

Table 1. Comparison of Estimated CRP for August 2018 through July 2019 to Projected CRP for August 2019 through July 2020 Unitil Power Corp.				
Line No.	Line Item Description	Aug 2018 - July 2019 9 Months Act. and 3 Months Est.	Aug 2019 - July 2020 Estimate	Variance (Aug 2018 - July 2019 Costs minus Aug 2019 - July 2020 Costs)
1.	Portfolio Sales Charge	\$0	\$0	\$0
2.	Residual Contract Obligations	\$0	\$0	\$0
3.	Hydro-Quebec Support Payments	(\$771,145)	(\$355,232)	\$415,913
4.	Subtotal (L. 2 through 4)	(\$771,145)	(\$355,232)	\$415,913
5.	True-up for estimate	\$214,087	\$0	(\$214,087)
6.	Obligations prior to May 1, 2003	\$0	\$0	\$0
7.	Total CRP as billed by Unitil Power Corp.	(\$557,058)	(\$355,232)	\$201,826

14

15

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

3 A. UPC mitigates these costs through short-term sales of the transmission rights and
4 capacity, which UPC is entitled to through its support of the Hydro-Quebec Phase
5 II facilities. Currently, UPC resells its transmission rights on a short-term basis
6 through a brokering agreement with Green Mountain Power (“GMP”). Under this
7 brokering agreement, which was amended November 1, 2015, to increase the
8 maximum duration of transmission sales from one month to one year, GMP offers
9 UPC’s transmission rights associated with the Hydro-Quebec Phase II facilities
10 for sale on a short-term basis through GMP’s OASIS website. GMP has authority
11 under this amended agreement to enter into binding sales of UPC’s Hydro-
12 Quebec transmission rights for firm and non-firm transactions for a maximum
13 term of one year. UPC also has rights to Hydro-Quebec Interconnection
14 Capability Credit (“HQICC”), pursuant to the ISO Tariff. UPC is reimbursed by
15 GMP for its HQICC at a price equal to the ISO Net Regional Clearing Price.¹
16 Please refer to Schedule LSG-5 for itemized cost and revenue offsets, related to
17 the Hydro-Quebec Phase II Support Agreements.

18
19 **IV. TERMINATION OF PHASE II SUPPORT AGREEMENTS**

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.

1 **Q. Please provide background on the Hydro-Quebec Phase II Support**
2 **Agreements.**

3 A. The Hydro-Quebec high voltage direct current (“HVDC”) transmission facilities
4 were supported by two sets of agreements signed in the 1980s. The Support
5 Agreements pre-dated electric industry restructuring and were entered into on a
6 pro rata basis by all or nearly all members of the New England Power Pool
7 (“NEPOOL”). The Phase I Support Agreements were signed in 1980, and
8 brought interconnection and transmission facilities with approximately 690 MW
9 of transfer capability from the Hydro-Quebec system to New England into service
10 in 1986. The Phase II Support Agreements were signed in 1985 and increased the
11 total transfer capability from Hydro-Quebec to New England to approximately
12 2,000 MW. A Restated Use Agreement² defines the rights (“Use Rights”) of
13 parties to the Support Agreements, also known as Interconnection Rights Holders
14 (“IRH”). The term of the Phase I and Phase II Support Agreements is 30 years
15 after the Phase II facilities went into service. The Phase II facilities went into
16 service in the fall of 1990 and the agreements are set to expire October 31, 2020.

17

18 **Q. What is Unitil Power Corp.’s share of the Phase II Support Agreements?**

² New England Power Pool FERC Electric Third Revised Rate Schedule No. 4.

1 A. UPC's share of Phase II is 1.227 percent, which provides Use Rights for
2 approximately 16 MW of transfer capability. The Phase II Support Agreements
3 include four separate agreements.³ UPC does not have a share of Phase I.

4

5 **Q. Why didn't Unitil Power Corp. divest its Phase II entitlement during**
6 **restructuring?**

7 A. UPC sought to divest its Phase II entitlement early in the divestiture process, but
8 did not find market interest so the entitlement was retained in Unitil Energy
9 Systems, Inc's power supply restructuring plan. UPC has mitigated the costs of
10 the Phase II Support Agreements since restructuring began and recovered costs
11 from and credited revenues to UES under the Unitil System Agreement. In turn,
12 UES has recovered the net costs in the SCC. As documented in the prior section,
13 mitigation has taken the form of transmission sales and HQICC.

14

15 **Q. What are the renewal rights associated with the Support Agreements?**

16 A. The Support Agreements include a right to renew for an additional period of up to
17 20 years. The right must be exercised no later than two years before the
18 termination date, or by October 31, 2018. There is a requirement that 100 percent
19 of the entitlements must be renewed or the renewal right is forfeited. Thus, if an

³Phase II Boston Edison AC Facilities Support Agreement, dated June 1, 1985. Phase II Massachusetts Transmission Facilities Support Agreement, dated June 1, 1985. Phase II New England Power AC Facilities Support Agreement, dated June 1, 1985. Phase II New Hampshire Transmission Facilities Support Agreement, dated June 1, 1985.

1 individual IRH decides not to renew, then their shares would need to be allocated
2 among those IRH who choose to renew.

3

4 **Q. Has UPC decided to exercise the renewal right or to let its share of the**
5 **Support Agreements terminate?**

6 A. UPC has decided not to renew its share of the Phase II Support Agreements and to
7 let its share terminate.

8

9 **Q. Why has UPC elected not to renew the Phase II Support Agreements and the**
10 **Restated Use Rights Agreement?**

11 A. As stated in its previous filing (D.E. 18-096) these agreements are not needed to
12 provide service to UES' customers. UES is a distribution company that purchases
13 electric default service power from the market as directed by the Commission.
14 The purpose of the Support Agreements, which pre-dated industry restructuring,
15 was to build the HVDC transmission line for the benefit of the New England
16 region. The facilities are now in service and there is no indication that UPC not
17 renewing its share of the support agreement will lead to the abandonment of the
18 facilities. Lastly, although mitigation revenues from UPC's Phase II entitlement
19 have been higher than costs in recent years, the level of such revenues is largely
20 outside of UPC's control. If mitigation revenues were to fall below the cost of
21 support payments in the future, UPC would incur net costs that are not related to
22 the services required by UES.

23

1 **Q. What other benefits derive from UPC's decision not to renew the Phase II**
2 **Support Agreements?**

3 A. Allowing the Phase II Support Agreements to terminate will allow the
4 elimination of the Stranded Cost Charge, the opportunity to dissolve UPC and the
5 opportunity to terminate the Unitil System Agreement. These changes would also
6 better align UES's energy supply related commitments with its energy
7 procurement practices and reduce associated administrative costs.

8

9 **IV. EXTERNAL DELIVERY CHARGE COSTS**

10 **Q. What costs are included in the EDC?**

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

- 12 1) Third Party Transmission Providers (Eversource Network Integration
- 13 Transmission Service);
- 14 2) Regional Transmission and Operating Entities;
- 15 3) Third Party Transmission Providers (Eversource Wholesale Distribution);
- 16 4) Working Capital Associated with Other Flow-Through Operating Expenses-
- 17 transmission costs only;
- 18 5) Transmission-Based Assessments and Fees;
- 19 6) Load Estimation and Reporting System and EDI Communication Costs;
- 20 7) Unmetered Purchased Power;
- 21 8) Data and Information Services;
- 22 9) Legal Charges;
- 23 10) Consulting Outside Service Charges;
- 24 11) Administrative Service Charges;
- 25 12) EDC Portion of the Annual PUC Assessment;
- 26 13) Net Metering Credits
- 27 14) Net Metering Costs
- 28 15) Regional Greenhouse Gas Initiative Auction Proceeds;
- 29 16) Rate Case Expenses;
- 30 17) Other Regulatory Expenses;

1 18) Working Capital Associated with Other Flow-Through Operating Expenses-
2 excluding transmission costs; and
3 19) Displaced Distribution Revenue.

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

5 The Third Party Transmission Providers (Eversource Network Integration
6 Transmission Service) component of the EDC consists of Network Integration
7 Transmission Service taken by UES and provided by the Eversource Energy
8 companies⁴ (“Eversource”) pursuant to Schedule 21-ES of the ISO New England
9 Inc. Transmission, Markets and Services Tariff (FERC Electric Tariff No.3)
10 (“ISO Tariff”).

11
12 The Regional Transmission and Operating Entities component of the EDC
13 consists of all charges from ISO New England Inc. (“ISO”). These charges
14 consist primarily of Regional Network Service, taken pursuant to the ISO Tariff.
15 Other major costs (which are also billed by the ISO to UES) are various ancillary
16 services allocated to transmission customers, such as VAR support, dispatch
17 service, and black-start capability.

18
19 The Third Party Transmission Providers (Eversource Wholesale Distribution)
20 component consists of Distribution Delivery Service (“DDS”) charges with
21 Eversource. DDS compensates Eversource for the wheeling of power from the
22 Eversource transmission system to UES’s distribution system over certain

⁴ Northeast Utilities formerly changed its name and those of all its subsidiaries in January 2015 to Eversource Energy.

1 facilities, which are classified as distribution facilities for accounting purposes
2 and, therefore, are not included in the Eversource transmission system rate base.
3

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

6 A. Schedule LSG-2 provides the External Delivery cost data used in the calculation
7 of the EDC. Page 2 provides actual historic External Delivery cost data for the
8 year beginning August 2017 through July 2018. Actual External Delivery cost
9 data for the months of August 2017 through April 2018 was included in UES's
10 last EDC rate and reconciliation filing, Docket No. DE 18-096. In that docket,
11 UES provided estimated External Delivery costs for May 2018 through July 2019.
12 Rather than present partial data beginning with May 2018, UES is presenting the
13 full period. Page 3 of Schedule 2 provides External Delivery cost data for the
14 current EDC rate period, August 2018 through July 2019. Actual cost data is
15 available through April 2019, and estimated cost data is provided for May 2019
16 through July 2020. Finally, page 4 of Schedule LSG-2 provides estimated
17 External Delivery costs for the upcoming EDC rate period, August 2019 through
18 July 2020.

19

20 **Q. Please provide a comparison of the External Delivery costs for the upcoming**
21 **EDC rate period (August 2019 through July 2020) to the projected External**
22 **Delivery costs for the current EDC rate period (August 2018 through July**
23 **2019).**

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

4

Table 2. Comparison of Estimated External Delivery costs for August 2019 through July 2020 to projected External Delivery costs for August 2018 through July 2019 Unitil Energy Systems, Inc.				
Line No.	Line Item Description	Aug 2018 – July 2019 9 Months Act. and 3 Months Est.	Aug 2019 – July 2020 Estimate	Variance (Aug 2019 - July 2020 Costs minus Aug 2018 - July 2019 Costs)
1.	Third Party Transmission Providers (Eversource Network Integration Transmission Service)	\$1,562,631	\$2,479,324	\$916,693
2.	Regional Transmission and Operating Entities	\$24,437,578	\$24,383,319	(\$54,259)
3.	Third Party Transmission Providers (Eversource Wholesale Distribution)	\$3,271,091	\$2,857,088	(\$414,003)
4.	Working Capital Associated w/ Other Flow-Through Operating Expenses-transmission costs only	\$366,653	\$372,270	\$5,617
5.	Transmission-based Assessments and Fees	\$12,500	\$12,500	\$0
6.	Load Estimation and Reporting System and EDI Communication Costs	\$289,565	\$292,800	\$3,235
7.	Unmetered Purchased Power	(\$13,580)	\$0	\$13,580
8.	Data and Information Services	\$15,000	\$15,000	\$0
9.	Legal Charges	\$2,573	\$28,000	\$25,427
10.	Consulting Outside Service Charges	\$7,764	\$40,000	\$32,236
11.	Administrative Service Charges	\$4,895	\$1,640	(\$3,255)
12.	EDC Portion of the Annual PUC Assessment	\$25,977	\$30,432	\$4,455
13.	Net Metering Credits	\$15,025	\$31,325	\$16,300
14.	Net Metering Costs	\$0	\$0	\$0
15.	Regional Greenhouse Gas Initiative Rebates	(\$1,352,110)	(\$1,352,110)	\$0

16.	Rate Case Expenses	\$0	\$0	\$0
17.	Other Regulatory Expenses	\$142,742	\$142,742	\$0
18.	Working Capital Associated w/ Other Flow-Through Operating Expenses-excluding transmission costs	\$39,708	\$39,708	\$0
19.	Displaced Distribution Revenue	\$187,746	\$218,008	\$30,262
20.	Total External Delivery Costs	\$29,015,758	\$29,592,044	\$576,286

1

2 **Q. Please explain the projected increase in External Delivery costs for the**
3 **upcoming EDC rate period (August 2019 through July 2020) over the**
4 **current EDC rate period (August 2018 through July 2019).**

5 A. The External Delivery costs for the upcoming EDC rate period are projected to be
6 \$576,286 higher than those in the current rate period. The largest contributor to
7 the increase is the projected Third Party Transmission Providers (Eversource
8 Network Integration Transmission Service) costs due to higher forecasted annual
9 revenue requirements from Eversource which are used for billing. The estimated
10 annual revenue requirements will be trued up in June 2020. The increase is offset
11 by lower projected costs associated with Third Party Transmission Providers
12 (Eversource Wholesale Distribution) for interconnection and distribution delivery
13 services compared to the prior period. Regional Transmission and Operating
14 Entities costs are also projected to be slightly lower which are calculated based on
15 historical retail sales and the ISO Schedule 1 rate as well as the Regional Network
16 Service (“RNS”) rate.

17

18 **Q. What legal charges does UES expect to incur under the EDC?**

1 A. UES estimates that it will incur legal charges of \$28,000 for the upcoming EDC
2 rate period (August 2019 through July 2020). These costs include charges for an
3 upcoming FERC wheeling tariff rate filing that the Company expects to make
4 within the upcoming EDC rate period. These costs also cover half of the annual
5 NAESB membership as well as an estimate to cover routine legal costs. Any
6 legal costs associated with procurement of Default Service are recovered through
7 the Default Service Charge.⁵

8

9 **Q. What consulting charges does UES expect to incur under the EDC?**

10 A. UES estimates that it will incur approximately \$40,000 in outside consulting
11 service charges for the upcoming EDC rate period (August 2019 through July
12 2020). These costs include charges associated with the FERC wheeling tariff
13 filing previously referenced.

14

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

17 A. Details regarding the ASC are provided in Schedule LSG-3 on lines 10 through
18 18. The ASC includes any costs incurred by UPC, relative to UPC's obligations
19 under the Amended Unitil System Agreement, which are not otherwise assigned
20 or assumed by UES. These costs include NEPOOL, ISO, and RTO costs, as well

⁵ This is in accordance with the settlement agreement approved in Docket No. DE 05-064.

1 as legal, consulting, and other outside services. It does not include any internal
2 costs of USC, UES or UPC. These costs are projected to be lower compared to
3 the prior period.

4

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

7 A. Yes. UES has included the rebate of excess RGGI auction proceeds applicable to
8 all retail electric customers as a separate line item in the EDC. UES records the
9 rebates in the EDC on the month in which it is received, and applies carrying
10 charges. For the actual period of August 2017 through April 2019, UES has
11 recorded seven rebate amounts totaling \$2,068,119. In accordance with Order
12 No. 25,664, UES has included estimates of auction amounts it expects to receive
13 through July 2020 in order to ensure customers receive the credit, or estimate
14 thereof, in a timely manner. These estimates are shown on Schedule LSG-2,
15 Pages 3 and 4.

16

17 **Q. Has UES included in this filing the recovery of costs associated with lost**
18 **distribution revenue due to net metering?**

19 A. Yes. In accordance with Order No. 25,991 in DE 15-147, UES is allowed to
20 recover displaced distribution revenue through its EDC. Please see the Testimony
21 and Exhibits prepared by Mr. Douglas Debski.

22

1 **Q. Please describe the additional EDC expenses included in Schedule LSG-2 for**
2 **the upcoming rate period.**

3 A. Changes to this schedule include the addition of line items for net metering credit
4 and net metering costs associated with alternative net metering. Prior changes
5 were implemented in the D.E. 18-096 filing that included presenting separate line
6 items that are considered transmission and non-transmission in order to properly
7 bill and credit alternative net metering customers. Those changes can be found in
8 this filing on Page 2 of 4 of Schedule LSG-2, beginning with August 2017,
9 Unmetered Purchased Power has been separately line itemed in order to remove it
10 from the regional transmission line item in which it was previously included.
11 Working Capital associated with Other Flow-Through Operating Expenses has
12 been broken out by transmission costs only and excluding transmission costs; and
13 sub-totals for transmission costs and non-transmission costs have been added to
14 the schedule.

15

16 **V. UPC COSTS AND REVENUES**

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

19 A. Yes. Schedule LSG-4 provides this accounting for the period beginning August
20 2017 through April 2019. UPC bills UES estimates of the CRP and ASC on the
21 25th of the month for the upcoming month. The estimated expenses are trueed-up
22 to actual expenses on a two-month lag basis. In order to calculate the true-up,
23 UPC tracks the actual expenses, which comprise both the CRP and the ASC.

1 These actual expenses are compared to the estimated expenses to calculate the
2 true-up for prior period. Schedule LSG-4 provides summary data of actual CRP
3 and ASC expenses and revenues.

4 **VI. CONCLUSION**

5 **Q. Does that conclude your testimony?**

6 A. Yes, it does.