ATRIUM ECONOMICS
Centered on Energy

Ronald J. Amen

Managing Partner

Mr. Amen has over 40 years of combined experience in utility management and consulting in the areas of regulatory support, resource planning, organizational development, distribution operations and customer service, marketing, and systems administration.

He has advised gas, electric and water utility clients in the following areas: regulatory policy, strategy, and analysis; cost of service studies (embedded and marginal cost analyses); rate design and pricing issues including time- of-use rates, revenue decoupling, weather normalization and other cost tracking mechanisms; resource strategy, planning and financial analysis; and business process design, evaluation, and organizational structures. Mr. Amen has provided expert testimony in numerous state and provincial regulatory agencies, and the Federal Energy Regulatory Commission. Prior to establishing Atrium Economics in 2020, Mr. Amen's consulting experience included Director Advisory & Planning at Black & Veatch Management Consulting, LLC, Vice President of Concentric Energy Advisors, Inc. and Director with Navigant Consulting, Inc. His prior utility experience includes leadership of State and Federal Regulatory Affairs at two electric and gas utilities, and management positions in Regulatory Affairs, Information Systems and Distribution Operations.

EDUCATION

Bachelor of Science with Distinction, Business Administration, Finance and Economics, University of Nebraska, United States

YEARS EXPERIENCE

42

PROFESSIONAL ASSOCIATIONS

American Gas Association

Southern Gas Association

RELEVANT EXPERTISE

Financial Analysis; Litigation Support; Regulatory Support; Strategy; Utility Operations

REPRESENTATIVE PROJECT EXPERIENCE

REGULATORY POLICY, STRATEGY AND ANALYSIS

Western Export Group (2019)

In a Nova Gas Transmission, LTD. (NGTL) Rate Design and Service Application before the Canadian National Energy Board, Mr. Amen led a consulting team supporting the interests of the Western Export Group, a group of nine utility companies located in the Western U.S. and British Columbia who are export shippers on the NGTL system.

Regulatory Commission of Alaska (2019 – 2020)

Part of a multi-functional team that assisted the Regulatory Commission of Alaska (RCA) in its evaluation of the Chugach Electric Association, Inc's acquisition of the Municipal of Anchorage d/b/a Municipal Light & Power Department. Assisted the RCA with its evaluation of the long-term benefits of the transaction to ML&P and Chugach customers, the implication of terms and assumptions in various agreements, and the careful balance of the fiscal and regulatory implications for the customers of the combined entity.

CPS Energy (2017 – 2018)

Provided an overall review of the client's Strategic Roadmap to prioritize its multi-year regulatory initiatives. (e.g., changes in product and service offerings, restructuring of current rate classes, introduction of new rate structures, rate levels, and tariff provisions). Current pricing processes and platforms assessed to identify recommended enhancements to enable the development and implementation of dynamic pricing concepts. Assisted client with preparation of next rate case (e.g., costing and pricing analyses, load forecasting, internal communications, and stakeholder engagement).

FortisBC Energy, Inc. (2016 – 2018)

Performed an overall review of the client's Transportation Service Model. Analyzed the client's various midstream transportation and storage capacity resources used in providing balancing of transportation customers' loads. Review included the physical diversity, functionality and flexibility provided by the various capacity resources, and the cost impact caused by transportation customers' imbalance levels. Conducted an industry-wide benchmarking study of current industry-wide best practices, by regulatory jurisdiction, related to transportation balancing tariff provisions. Participated in stakeholder workshops and testified before the BCUC.

McDowell Rackner & Gibson Law Firm (2015 – 2016)

Provided due diligence services to the law firm in connection with a state utility commission investigation into the law firm client's gas storage and optimization activities. Provided an independent opinion as to the likely outcome of the Commission's ongoing investigation.

Gulfport Energy Corporation (2016)

Provided regulatory analysis and support to Gulfport Energy Corporation in the ANR Pipeline Company Natural Gas Act §4 rate proceeding before the Federal Energy Regulatory Commission (FERC). Analyzed as-filed cost of service and rate design to identify key cost of service, cost allocation, rate design and service related/tariff issues. Developed an integrated cost of service and rate design model to prepare studies on client issues. Prepared best/worst case litigation outcomes, discovery, and evaluations of discovery of other parties. Analyzed FERC staff top sheets and settlement offers; and assisted in the preparation of settlement positions.

Confidential Financial / Energy Partners (2015)

Provided regulatory due diligence support for client related to a proposed merger with a multijurisdictional gas/electric company including an evaluation of the regulatory landscape in the various applicable state jurisdictions, recent regulatory decisions, and current regulatory issues.

Confidential International Energy Company (2014)

Provided regulatory due diligence support for client related to a proposed merger with a multijurisdictional gas company including an evaluation of the regulatory landscape in the various applicable state jurisdictions, recent regulatory decisions, and current regulatory issues.

Pacific Gas & Electric Company (2014)

Developed an extensive industrywide benchmarking study to determine the cost allocation and ratemaking treatment utilized by Local Distribution Companies (LDCs) in the United States for recovery of gas transmission costs. Benchmarked cost allocation and rate design utilized by Interstate/Intrastate Pipelines. Benchmarked how Industrial & Electric Generation customers are served with natural gas.

Public Service Company of New Mexico (2009-2010)

Provided case management, revenue requirement, cost of service and rate design support for general rate cases in the utility's two state regulatory jurisdictions. Issue management and policy development included an electric fuel and purchased power cost mechanism, recovery of environmental remediation costs for a coal fired power plant, and the valuation of renewable energy credits related to a wind power facility.

Confidential International Energy Company (2009)

Provided due diligence on behalf of client related to the purchase of a gas/electric utility, including a review of the regulatory and market-related assumptions underlying the client's valuation model, resulting in the validation of the model and identification of key business risks and opportunities.

RESOURCE PLANNING, STRATEGY AND FINANCIAL ANALYSIS

Fortis BC Energy, Inc. (2011)

Retained to help develop a gas supply incentive mechanism in cooperation with the British Columbia Utilities Commission staff and the company's other stakeholders. Provided an independent analysis of the utility's management of pipeline and storage capacity and supply. Part of this work entailed a review of the major markets in which the utility transacted, reviewing the size of trading activity at the major market hubs, and reviewing the price indices for these markets.

Black Hills Colorado Electric Utility (2009)

Engaged as a member of a consultant team that served as the independent evaluator in a competitive solicitation for non-intermittent generation resources. Jointly recommended by the utility client, the staff of the utility commission and the state attorney general, the consulting team acted as an agent of the public utility commission monitoring and overseeing the solicitation, which included reviewing the request for proposals and solicitation process, including provisions of the power purchase agreement, preliminary review (economic and contractual) of bids received from the request for proposals, initial modeling of bids for screening, selection of bidders with whom to conduct negotiations and oversight of the negotiation process, and the ultimate selection of the winning bid. Provided due diligence review of all input data, preliminary and final model output, and output summaries. The team produced biweekly confidential reports to the commission regarding the process and its results.

NW Natural (2007-2008)

Assisted with the development of its long-term Integrated Resource Plan (IRP) for its Oregon and Washington service territories. The IRP included the evaluation of incremental inter- and intra-state pipeline capacity, underground storage, and two proposed LNG plants under development in the region.

Puget Sound Energy (2007)

Engaged to assist the client with the development of a natural gas resource efficiency and direct end-use strategy, an interdepartmental initiative focused on preparing a natural gas resource efficiency plan that optimizes customers' end-use energy consumption while furthering corporate customer, financial, environmental, and social responsibilities.

Puget Sound Energy (2002 – 2 003)

Provided resource planning strategy and analysis for the company's Least Cost Plan, including a review of the company's underlying 20-year electric and gas demand forecasts. As a member of a consulting team, served as the client's financial advisor for the acquisition of new electric power supply resources. Conducted a multitrack solicitation process for evaluation of generation assets and purchase power agreements. Provided regulatory support for the acquisition.

COST ALLOCATION, PRICING ISSUES AND RATE DESIGN

Montana-Dakota Utilities (2020 – 2021) (Pending)

Provided cost of service, class revenue apportionment, rate design, and expert witness support for the gas utility's general rate cases before the Montana Public Service Commission and the North Dakota Public Service Commission, filed in 2020. Testimony included theoretical principals and practical application of cost allocation, and rate design principles or objectives that have broad acceptance in utility regulatory and policy literature. Supported the continuation of a Straight Fixed-Variable rate design for the residential customer class in North Dakota.

Kansas City, KS Board of Public Utilities (2019 – 2020)

Provided expert witness testimony supporting the basis for a Green Energy Program, its objectives, and overall benefits. Provide an assessment of how the program is aligned with best practices in design of Green Energy tariff programs nationally. Testimony also provided an assessment of how the program mitigates potential risks the to the Board of Public Utilities and protects against subsidization of other rate classes.

NW Natural (2018 – 2019)

Provided cost of service, class revenue apportionment, rate design, and expert witness support for the gas utility's general rate case before the Washington Utility and Transportation Commission (WUTC), filed in December 2018. Testimony included theoretical principals and practical application of cost allocation, and rate design principles or objectives that have broad acceptance in utility regulatory and policy literature.

Chesapeake Utilities Corporation (2018 – 2019)

Developed a Weather Normalization Adjustment (WNA) mechanism applicable to the monthly billings of Chesapeake's residential and general service customers. Sponsored the WNA mechanism through expert testimony filed with the Delaware Public Service Commission in January 2019. The testimony included a description of the WNA calculations; back-casting performance analyses, with bill impacts; a WNA tariff; and conceptual and evidentiary support for this ratemaking mechanism.

Louisville Gas & Electric Company and Kentucky Utilities Company (2018)

Engaged by LG&E and KU to a conduct a study in support of a joint utility and stakeholder collaborative concerning economical deployment of electric bus infrastructure by the transit authorities in the Louisville and Lexington KY areas, as well as possible cost-based rate structures related to charging stations and other infrastructure needed for electric buses.

Summit Utilities – Colorado Natural Gas, Inc. (2018)

Engaged by Summit Utilities to develop and support with expert testimony an appropriate normal weather period for the client's five Colorado temperature zones, resulting normalized billing determinants, and a Weather Normalization Adjustment ("WNA") proposal in conjunction with the filing of a general rate case for its Colorado Natural Gas, Inc. subsidiary.

Westar Energy (2018)

Provided cost of service and expert witness support for the electric utility's general rate case filing before the Kansas Corporation Commission (KCC). The cost of service study determined the cost components for a new Residential Distributed Generation (DG) customer class that provided the basis for recommendations for establishing components of a sound, modern three-part rate design for this new Residential DG (roof-top solar) service, which was approved by the KCC.

Florida Public Utilities (Chesapeake Utilities) (2017 – 2018)

Provided a rate stratification study of the utility's commercial and industrial customer classes to facilitate the reconfiguration of the classes by size of service facilities, annual volume, and load factor. Reviewed the cost allocation bases and recommended alternatives for recovery of capital investments related to the utility's Gas Reliability Investment Program (GRIP).

Tacoma Power (2016 – 2018)

Provided cost of service and rate design support for the electric utility's general rate case filings, including support for recovery of fixed costs through fixed charges and impacts on low-income customers. Provided recommendations as to specifications in the client's cost of service analysis (COSA) model for deriving Open Access Transmission Tariff rates, using FERC approved standards to guide the evaluation. Conducted an electric utility costing and pricing workshop for the PUB in October 2017; and participated with Tacoma Utilities staff in a comprehensive electric and water Rates and Financial Planning workshop in February 2018. Engagement was extended for the 2019 – 2020 rate filing, which will incorporate the Black & Veatch municipal COSA model for costing and ratemaking purposes. Currently working with Tacoma Power for the potential incorporation of financial forecasting capabilities and revenue requirements development into the COSA model. Future project work involves working on the re-design of the general service and industrial rate schedules, economic development rate strategies, demand response rates, and other innovative rate programs.

Tacoma Power (2017)

Engaged to review and assess current rates for 3rd Party Pole Attachments (PA), and more specifically, to determine and recommend if any rate adjustments were needed. Performed several tasks:

- Performed a market survey of rates charged by comparable utilities
- Reviewed current regulations on rate setting and practice for 3rd Party Pole Attachments as set forth by the Federal Communications Commission (FCC) and the State of Washington (WA), and the interpretation of such regulations in court decisions
- Reviewed industry best practices under the FCC, WA, and the American Public Power Association (APPA)
- Collected and reviewed data for cost-based fees including:
- Application Fees
- Non-Compliance Fees
- Reviewed cost data supplied by the City of Tacoma as relates to determining pole costs; and
- Performed modeling of rates under the FCC Model, the APPA model and the State of Washington shared model (50 % FCC Rate/ 50% APPA Rate).

BC Hydro (2016)

Provided research and analysis of the line extension policies of a select group of peer utilities in Canada with similar regulatory regimes as well as U.S. utilities based on their geographic relationship to the client. Conducted interviews with peer utilities to gather comparative information regarding their line extension policies and related internal procedures. Performed a comparative analysis of the various line extension policies from the selected peer group.

Cascade Natural Gas Corporation (2015 – 2019)

Provided cost of service and rate design support for several of the company's general rate case filings in its two state jurisdictions, 3 in Oregon and 2 in Washington. Conducted Long-run Incremental Cost Studies in the Oregon jurisdiction and embedded class allocated cost of service studies in the Washington jurisdiction. Performed benchmark analyses to compare each of the client's administrative and general (A&G) and operations and management (O&M) expenses, on a per-customer basis, to various peer groups. Analyses were performed for natural gas utilities and combination utilities with both electric and gas operations. Various iterations of the analyses were prepared to make the peer group of utilities more comparable to the characteristics of the client's utility operations. Represented the client's interests in a Washington generic rulemaking proceeding on the subject of electric and gas cost of service methodologies and minimum filing requirements.

Chesapeake Utilities (2015 – 2016)

For its Delaware jurisdiction, provided cost of service and rate design support in the client's general rate case proceeding, including expert witness testimony in support of the utility's proposed gas revenue decoupling mechanism.

Homer Electric Association / Alaska Electric and Energy Cooperatives (2015)

Represented clients in an ENSTAR gas general rate proceeding. Testimony discusses accepted industry principles of revenue allocation and rate design, including the applicability to and alignment with ENSTAR's revenue allocation and rate design proposals for large power and industrial customers. Provided a critique of certain methodological aspects of ENSTAR's Cost of Service study, proposed revenue allocation, and rate design relating to the various large power and industrial customers.

Arkansas Oklahoma Gas Corporation (2002, 2003, 2004, 2007, 2012, 2013)

Provided cost of service and rate design support for several of the company's general rate case filings in its two state jurisdictions and in support of Section 311 transportation filings (2007, 2010) before the Federal Energy Regulatory Commission. Provided related research, design, and expert witness testimony in support of a Revenue Decoupling mechanism in one jurisdiction and a Weather Normalization Adjustment mechanism in the other jurisdiction, along with a significant increase in fixed charges and the introduction of demand charges for the company's largest customer classes. Conducted a pre-filing "decoupling" workshop for the utility commission staff.

Northern Indiana Public Service Company (NiSource) (2009 – 2010, 2013, 2017)

Conducted class allocated cost of service studies for the client's natural gas (including two other affiliate gas utilities) and electric operations. Work included reconfiguring the Company's commercial and industrial customer classes according to size of load and customer-related facilities. Rate design was modernized to recover a greater portion of fixed costs via fixed monthly customer and demand-based charges, a transition to a "Straight-Fixed Variable" form of rate design. Industry research was provided on alternative rate designs for the electric service, including Time-of-Use rates and Critical Peak Pricing. Served as an expert witness on behalf of the client in four general rate cases before the Indiana Utility Regulatory Commission.

Southwestern Public Service Company (Xcel) (2012)

Retained to conduct a study to estimate the conservation effect of replacing its existing electric residential rate design with an alternative rate design such as an inverted block rate design. Reviewed inclining block rate structures that have actively been employed in other jurisdictions and also reviewed technical and academic literature to assess the elasticity of electricity demand for residential customers in the southwestern U.S. Analyzed 2009-2011 residential data to determine what sort of conservation effect the company may expect by implementing an inclining block rate structure. Provided an overview of alternative rate structures which may also promote conservation effects, such as seasonal rates, three-part rates, and time-of-use (TOU) rates and considered the competing incentives of promoting conservation and cost recovery, without specific rate mechanisms to address this conflict.

Atlantic Wallboard LP and Flakeboard Company Limited (JD Irving) (2012)

Represented clients in an Enbridge Gas New Brunswick Limited Partnership ("EGNB") general rate proceeding. Testimony responded to the 2012 allocated cost of service study and rate design that was submitted to the New Brunswick Energy and Utilities Board by EGNB. Testimony also provided benchmark information regarding EGNB's distribution pipeline infrastructure in New Brunswick. CA.

Western Massachusetts Electric Company (Northeast Utilities) (2010 – 2011)

Supported utility in its decoupling proposal for the company's general rate case. Work included: 1) research on the financial implications of decoupling; 2) identification of decoupling mechanism details to address company and regulatory requirements and objectives; 3) identification of rate adjustment mechanisms that would work together with the company's proposed decoupling mechanism; and 4) preparing pre-filed testimony and testifying at hearings in support of the company's decoupling and rate adjustment proposals. The proposed rate adjustment mechanisms included an inflation adjustment mechanism based on a statistical analysis, and a capital spending mechanism to recover the costs associated with capital plant investment targeted to improving service reliability.

Interstate Power & Light (Alliant Energy) (2010 – 2011)

Conducted class allocated cost of service studies for a Midwestern electric utility's Minnesota electric system. Work included reconfiguring the company's customer classes for cost of service purposes to collapse end-use based classes with the classes to which they would be eligible. Cost of service studies were performed on a before-and-after basis for the existing and proposed classes. The cost of service studies included a fixed/variable study for production costs, and a primary/secondary study for poles, transformers, and conductors. Performed a TOU analysis to determine the appropriate rate differentials for its peak and off-peak rates. Served as an expert witness on behalf of the client in a general rate case before the Minnesota Public Service Commission.

National Grid (2010)

Conducted class allocated cost of service studies for the client's Massachusetts natural gas operations. This task included combined gas cost of service studies for the consolidation of four gas service territories into two gas utility subsidiaries. During interrogatories, performed four separate allocated cost of service studies for each gas service territory. Work included reconfiguring the company's commercial and industrial customer classes according to size of load and customer-related facilities. Served as an expert witness on behalf of the client in consolidated general rate cases before the Massachusetts Department of Public Utilities.

Puget Sound Energy (2001 – 2002, 2006 – 2007, 2019 – 2020)

In three Washington general rate proceedings, provided cost of service and rate design support, including expert witness testimony in support of the utility's proposed revenue decoupling mechanism. Conducted research on accelerated cost recovery mechanisms for infrastructure replacement, and electric power cost adjustment mechanisms. In a pending general rate case, Mr. Amen is sponsoring expert testimony on a proposed revenue attrition adjustment to the client's revenue requirement.

UTILITY SYSTEM OPERATIONS AND ORGANIZATIONAL DEVELOPMENT

Philadelphia Gas Works (2017, 2020)

Engaged to provide an independent consulting engineer's report to be included as an appendix to the official statement prepared in connection with the issuance of the City of Philadelphia, Pennsylvania Gas Works Revenue Bonds. The evaluation of the PGW system included a discussion of organization, management, and staffing; system service area; supply facilities; distribution facilities; and the utility's Capital Improvement Plan (CIP). Our report also contained: (a) financial feasibility information, including analyses of gas rates and rate methodology; (b) projection of future operation and maintenance expenses; (c) CIP financing plans; (d) projection of revenue requirements as a determinant of future revenues; (e) an assessment of PGW's ability to satisfy the covenants in the General Gas Works Revenue Bond Ordinance of 1998 authorizing the issuance of the Bonds; and (f) information regarding potential liquefied natural gas ("LNG") expansion opportunities.

Puget Sound Energy (2013 – 2014)

Engaged to perform a review of its project management and capital spending authorization processes (CSA). The overall project objectives were to educate project management (PM) staff as to the importance and relevance of regulatory prudence standards, evaluate existing PM processes along with newly introduced corporate CSA processes, and propose PM and corporate process and documentation efficiencies. This task was accomplished through 1) a situational assessment and risk review; 2) analysis of project management practices; and 3) development of common documentation for the CSA and PM processes.

Puget Sound Energy (2012 – 2013)

Engaged to perform a review of how the company compares to similarly situated utilities in the areas of the underlying capitalized costs related to new customer additions ("new business investment") and the management policies and practices that influence the new business capital investment. Examined the interrelationships of our client's management policies and practices in the functional areas related to new business investment and developed an understanding of the nature of the costs captured by the new business investment process. Benchmarked those costs relative to peers' cost factors and management capital expenditure practices and performed targeted peer group interviews on our client's behalf. The review identified certain trends and/or interrelationships between management policies and practices, as well as other exogenous factors, and the resulting impact on new business investment.

Puget Sound Energy (2011 – 2012)

Engaged to perform a review of its electric transmission planning and project prioritization process. The emphasis of the review was to determine if the process implemented by the client could be expected to meet the regulatory standard of prudence, as adopted by the state regulatory commission. Reviewed the prudence standard adopted by the commission in several recent regulatory proceedings, supplemented by our knowledge of the prudence standard adopted at a national level and in other states. The engagement included two phases: 1) an initial situation assessment of the existing process employed by the client, and 2) a review of the historic implementation of that process by reviewing a sampling of transmission projects. Compiled and provided examples of capital planning documents and procedures, viewed as "best practices," from other electric utilities and other relevant transmission entities.

Alliant Energy (2011 – 2012)

Provided audit support for one of the company's gas and electric utilities, Interstate Power & Light, during a management audit ordered by one of its two regulatory jurisdictions. Conducted a pre-audit of distribution operations and resource planning processes to provide the client with potential audit issues. Assisted the client throughout the audit process in responding to information requests, preparing company executives and management personnel for audit interviews, and management of preliminary audit issues and findings by the independent audit firm.

Ameren Illinois Utilities (2009 – 2010)

Performed a number of benchmark analyses to compare each of the client's A&G and O&M expenses, on a per-customer basis, to various peer groups conducted for the client's natural gas and electric operations. Analyses were performed for natural gas, electric and combination utilities with both electric and gas operations. Various iterations of the analyses were prepared to make the peer group of utilities more comparable to the characteristics of the client's utility operations. Served as an expert witness on behalf of the client in a consolidated general rate case proceeding of its three utility subsidiaries before the Illinois Commerce Commission.

EXPERT WITNESS TESTIMONY PRESENTATION

- Alaska Regulatory Commission
- Arkansas Public Service Commission
- British Columbia Utility Commission (Canada)
- Colorado Public Utility Commission
- Connecticut Department of Public Utility Control
- Delaware Public Service Commission
- Illinois Commerce Commission
- Indiana Utility Regulatory Commission
- Kansas Corporation Commission
- Massachusetts Department of Utilities
- Minnesota Public Utilities Commission
- Missouri Public Service Commission
- Montana Public Service Commission
- New Brunswick Energy and Utilities Board (Canada)
- North Dakota Public Service Commission
- Oklahoma Corporation Commission
- Oregon Public Utility Commission
- Pennsylvania Public Utility Commission
- Washington Utilities and Transportation Commission
- Federal Energy Regulatory Commission

SELECTED PUBLICATIONS / PRESENTATIONS

"Enhancing the Profitability of Growth," American Gas Association, Rate and Regulatory Issues Seminar, April 4 - 7, 2004

"Regulatory Treatment of New Generation Resource Acquisition: Key Aspects of Resource Policy, Procurement and New Resource Acquisition," Law Seminars International, Managing the Modern Utility Rate Case, February 17 - 18, 2005

"Managing Regulatory Risk – The Risk Associated with Uncertain Regulatory Outcomes,"

Western Energy Institute, Spring Energy Management Meeting, May 18 - 20, 2005

"Capital Asset Optimization – An Integrated Approach to Optimizing Utilization and Return on Utility Assets," Southern Gas Association, July 18 - 20, 2005

"Resource Planning as a Cost Recovery Tool," Law Seminars International, Utility Rate Case Issues & Strategies, February 22 - 23, 2007

"Natural Gas Infrastructure Development and Regulatory Challenges," Southeastern Association of Regulatory Utility Commissioners, Annual Conference, June 4 – 6, 2007

"Resource Planning in a Changing Regulatory Environment," Law Seminars International, Utility Rate Cases – Current Issues & Strategies, February 7 - 8, 2008

"Natural Gas Distribution Infrastructure Replacement," American Gas Association, Rate Committee Meeting and Regulatory Issues Seminar, April 11 – 13, 2010

"Building a T&D Investment Program to Satisfy Customers, Regulators and Shareholders," SNL Webinar, March 27, 2014

"Utility Infrastructure Replacement; Trends in Aging Infrastructure, Replacement Programs and Rate Treatment," Large Public Power Council, Rates Committee Meeting, August 14, 2014

"Natural Gas in the Decarbonization Era, Gas Resource Planning for Electric Generation," EUCI, January 22-23, 2020

Unitil NH - Electric Division
12 Months Ended December 31, 2020
Summary of Cost of Service Study Results

	REVENUE REQUIREMENT SUMMARY	ACCOUNT BALANCE	D - Domestic Delivery Service	G2 - Regular General Service	G1 - Large General Service	Outdoor Lighting
1	**Rate Base**					
2	Plant in Service	407,914,122	286,045,852	79,128,205	34,863,113	7,876,951
3	Accumulated Reserve	(138,059,087)	(97,321,043)	(26,485,481)	(9,931,826)	(4,320,737)
4	Other Rate Base Items	(43,824,954)	(30,663,230)	(8,604,323)	(3,718,307)	(839,094)
5	Total Rate Base	226,030,081	158,061,579	44,038,401	21,212,979	2,717,121
6	**Total Revenue at Current Rates**					
7	Total Distribution Margin	58,056,553	31,580,284	16,916,360	7,736,414	1,823,495
8	Late Payment Charges (450)	275,537	249,040	21,925	3,573	999
9	Misc. Service Revenues (451)	194,996	137,978	37,091	16,096	3,831
10	Rent-elect. Property (454)	585,200	410,366	113,519	50,015	11,300
11	Other Electric Rev (456)	143,733	101,704	27,340	11,864	2,824
12	New DOC Rent Revenue	313,007	221,481	59,539	25,837	6,150
13	Total Revenue	59,569,025	32,700,853	17,175,775	7,843,798	1,848,599
14	**Expenses at Current Rates**					
15	O&M and A&G Expenses	26,051,337	18,853,556	4,658,497	1,765,392	773,892
16	Other Power Generation Expense	284,252	126,390	77,665	78,329	1,868
17	Depreciation and Amortization Expense	14,241,708	9,971,023	2,848,036	1,227,802	194,847
18	Taxes Other Than Income	8,072,185	5,663,185	1,563,956	685,135	159,909
19	Income Taxes	1,852,866	(324,656)	1,362,155	693,520	121,847
20	Total Expenses - Current	50,502,348	34,289,498	10,510,309	4,450,179	1,252,362
21	Operating Income - Current	9,066,677	(1,588,645)	6,665,466	3,393,620	596,237
22	Current Rate of Return	4.01%	-1.01%	15.14%	16.00%	21.94%
23	**Present Revenue at Equal Rates of Return**					
24	Present Return	4.01%	4.01%	4.01%	4.01%	4.01%
25	Present Operating Income @ Equal Return	9,066,677	6,340,277	1,766,499	850,910	108,991
26	Income Taxes	1,852,866	1,295,699	361,002	173,892	22,273
27	Other Expenses	48,649,481	34,614,153	9,148,154	3,756,659	1,130,515
28	Total Revenue @ Equal Rates of Return	59,569,025	42,250,129	11,275,656	4,781,461	1,261,780
29	Present (Subsidies)/Excesses	-	(9,549,277)	5,900,119	3,062,338	586,820

Unitil NH - Electric Division
12 Months Ended December 31, 2020
Summary of Cost of Service Study Results

	REVENUE REQUIREMENT SUMMARY	ACCOUNT BALANCE	D - Domestic Delivery Service	G2 - Regular General Service	G1 - Large General Service	Outdoor Lighting
30	**Revenue Requirement at Equal Rates of Return**					
31	Required Return	7.88%	7.88%	7.88%	7.88%	7.88%
32	Required Operating Income	17,811,170	12,455,252	3,470,226	1,671,583	214,109
33	**Expenses at Required Return**					
34	O&M and A&G Expenses	26,051,337	18,853,556	4,658,497	1,765,392	773,892
35	Other Power Generation Expense	284,252	126,390	77,665	78,329	1,868
36	Depreciation and Amortization Expense	14,241,708	9,971,023	2,848,036	1,227,802	194,847
37	Taxes Other Than Income	8,072,185	5,663,185	1,563,956	685,135	159,909
38	Income Taxes	1,852,866	1,295,699	361,002	173,892	22,273
39	Gross Up - Income Taxes	3,247,900	2,271,238	632,802	304,816	39,043
40	Gross Up - Gross Receipts & Uncollectibles	-	-	-	-	-
41	Total Expenses - Required	53,750,248	38,181,091	10,141,958	4,235,367	1,191,832
42	Total Revenue Requirement at Equal Return	71,561,418	50,636,343	13,612,184	5,906,950	1,405,941
43	Current Miscellaneous Revenue	1,512,473	1,120,569	259,415	107,385	25,104
44	Total Revenue @ Equal Rates of Return	70,048,945	49,515,774	13,352,769	5,799,565	1,380,837
45	Revenue (Deficiency)/Surplus	(11,992,393)	(17,935,490)	3,563,590	1,936,849	442,658
46	Total Base Revenue as Proposed	70,048,945	41,026,489	18,663,515	8,535,446	1,823,495
47	Miscellaneous Revenue	1,512,473	1,120,569	259,415	107,385	25,104
48	Total Revenue as Proposed	71,561,418	42,147,058	18,922,930	8,642,831	1,848,599
49	Total Distribution Margin Increase as Proposed	11,992,393	9,446,205	1,747,155	799,032	-
50	Miscellaneous Revenues Change	-	-	-	-	-
51	Total Revenue Increase as Proposed	11,992,393	9,446,205	1,747,155	799,032	-
52	Precent Base Revenue Change (Line 51/Line 7)	20.13%	29.91%	10.33%	10.33%	0.00%
53	Income Prior to Taxes	22,911,936	7,532,905	9,774,776	4,886,172	718,084
54	Income Taxes	5,100,766	1,677,012	2,176,108	1,087,783	159,863
55	Operating Income	17,811,170	5,855,893	7,598,668	3,798,389	558,221
56	**Proposed Return**	7.88%	3.70%	17.25%	17.91%	20.54%

Unitil NH - Electric Division
12 Months Ended December 31, 2020

Proposed Revenues
Revenue Apportionment

		Total Company	D - Domestic Delivery Service	G2 - Regular General Service	G1 - Large General Service	Outdoor Lighting
1	**Current Margin Revenue**	58,056,553	31,580,284	16,916,360	7,736,414	1,823,495
2	**Revenue to Cost Ratio Under Current Rates**	0.83	0.64	1.27	1.33	1.32
3	**Revenues at Equalized Rates of Return**					
4	Revenue Increase	11,992,393	17,935,490	(3,563,590)	(1,936,849)	(442,658)
5	Total revenue at equalized rates of return	70,048,945	49,515,774	13,352,769	5,799,565	1,380,837
6	Percent Increase	20.66%	56.79%	(21.07%)	(25.04%)	(24.28%)
7	Parity Ratio	1.00	1.00	1.00	1.00	1.00
8	**Secnario A: Equal Percentage Increase**					
9	Revenue Increase	11,992,393	6,523,349	3,494,311	1,598,064	376,668
10	Total revenue at equal percentage increase	70,048,945	38,103,633	20,410,670	9,334,478	2,200,164
11	Percent Increase	20.66%	20.66%	20.66%	20.66%	20.66%
12	Parity Ratio	1.00	0.77	1.53	1.61	1.59
13	**Secnario B: No Class Increase Above Parity**					
14	Revenue Increase	11,992,393	11,992,393	0	0	0
15	Total revenue with no increase to classes above parity	70,048,945	43,572,677	16,916,360	7,736,414	1,823,495
16	Percent Increase	20.66%	37.97%	0.00%	0.00%	0.00%
17	Parity Ratio	1.00	0.88	1.27	1.33	1.32
18	**Secnario C: Minimum Class Increase of 50% of System Average**					
19	Minimum 50% of system average increase		145%	50%	50%	0%
20	Revenue Increase	11,992,393	9,446,205	1,747,155	799,032	0
21	Total revenue at 25% system average minimum	70,048,945	41,026,489	18,663,515	8,535,446	1,823,495
22	Percent Increase	20.66%	29.91%	10.33%	10.33%	0.00%
23	Parity Ratio	1.00	0.83	1.40	1.47	1.32

Unitil NH - Electric Division
12 Months Ended December 31, 2020

Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line	Description	TOTAL RATE BASE	D - Domestic Delivery Service	G2 - Regular General Service	G1 - Large General Service	Outdoor Lighting
	Functional Rate Base					
1	**Electric Procurement Supply**					
2	Demand	$ 13,797	$ 7,216	$ 3,637	$ 2,944	$ -
3	Energy	$ 687,195	$ 305,554	$ 187,760	$ 189,365	$ 4,516
4	Customer	$ -	$ -	$ -	$ -	$ -
5	Subtotal	$ 700,992	$ 312,771	$ 191,397	$ 192,309	$ 4,516
6	**Radial Transmission**					
7	Demand	$ 206,652	$ 111,284	$ 50,295	$ 43,653	$ 1,420
8	Energy	$ -	$ -	$ -	$ -	$ -
9	Customer	$ -	$ -	$ -	$ -	$ -
10	Subtotal	$ 206,652	$ 111,284	$ 50,295	$ 43,653	$ 1,420
11	**Distribution Sub-Transmission**					
12	Demand	$ 38,899,578	$ 20,947,864	$ 9,467,411	$ 8,217,073	$ 267,230
13	Energy	$ -	$ -	$ -	$ -	$ -
14	Customer	$ -	$ -	$ -	$ -	$ -
15	Subtotal	$ 38,899,578	$ 20,947,864	$ 9,467,411	$ 8,217,073	$ 267,230
16	**Distribution Primary**					
17	Demand	$ 49,191,543	$ 26,490,204	$ 11,972,277	$ 10,391,128	$ 337,933
18	Energy	$ -	$ -	$ -	$ -	$ -
19	Customer	$ 53,279,692	$ 45,152,087	$ 7,440,286	$ 111,319	$ 576,001
20	Subtotal	$ 102,471,235	$ 71,642,291	$ 19,412,563	$ 10,502,447	$ 913,934
21	**Distribution Secondary**					
22	Demand	$ 21,364,641	$ 15,028,715	$ 4,280,211	$ 1,970,355	$ 85,361
23	Energy	$ -	$ -	$ -	$ -	$ -
24	Customer	$ 31,732,680	$ 26,523,290	$ 4,866,892	$ 49,153	$ 293,345
25	Subtotal	$ 53,097,322	$ 41,552,005	$ 9,147,103	$ 2,019,508	$ 378,706
26	**Onsite & Metering**					
27	Demand	$ -	$ -	$ -	$ -	$ -
28	Energy	$ -	$ -	$ -	$ -	$ -
29	Customer	$ 17,245,355	$ 12,107,537	$ 4,036,630	$ 213,948	$ 887,241
30	Subtotal	$ 17,245,355	$ 12,107,537	$ 4,036,630	$ 213,948	$ 887,241
31	**Customer Accounts & Service**					
32	Demand	$ -	$ -	$ -	$ -	$ -
33	Energy	$ -	$ -	$ -	$ -	$ -
34	Customer	$ 13,408,947	$ 11,387,828	$ 1,733,003	$ 24,041	$ 264,075
35	Subtotal	$ 13,408,947	$ 11,387,828	$ 1,733,003	$ 24,041	$ 264,075
36	**Total**					
37	Demand	$ 109,676,211	$ 62,585,284	$ 25,773,831	$ 20,625,153	$ 691,943
38	Energy	$ 687,195	$ 305,554	$ 187,760	$ 189,365	$ 4,516
39	Customer	$ 115,666,675	$ 95,170,741	$ 18,076,811	$ 398,461	$ 2,020,661
40	**Total Rate Base**	$ 226,030,081	$ 158,061,579	$ 44,038,401	$ 21,212,979	$ 2,717,121

Unitil NH - Electric Division
12 Months Ended December 31, 2020

Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line	Description	TOTAL	D - Domestic Delivery Service	G2 - Regular General Service	G1 - Large General Service	Outdoor Lighting
	Functional Revenue Requirement					
41	**Electric Procurement Supply**					
41	Demand	$ 13,322	$ 6,968	$ 3,512	$ 2,843	$ -
42	Energy	$ 671,094	$ 298,395	$ 183,361	$ 184,928	$ 4,410
42	Customer	$ -	$ -	$ -	$ -	$ -
43	Subtotal	$ 684,417	$ 305,363	$ 186,872	$ 187,771	$ 4,410
44	**Radial Transmission**					
44	Demand	$ 183,848	$ 99,004	$ 44,745	$ 38,836	$ 1,263
45	Energy	$ -	$ -	$ -	$ -	$ -
45	Customer	$ -	$ -	$ -	$ -	$ -
46	Subtotal	$ 183,848	$ 99,004	$ 44,745	$ 38,836	$ 1,263
47	**Distribution Sub-Transmission**					
47	Demand	$ 7,919,614	$ 4,264,802	$ 1,927,482	$ 1,672,924	$ 54,406
48	Energy	$ -	$ -	$ -	$ -	$ -
48	Customer	$ -	$ -	$ -	$ -	$ -
49	Subtotal	$ 7,919,614	$ 4,264,802	$ 1,927,482	$ 1,672,924	$ 54,406
50	**Distribution Primary**					
51	Demand	$ 15,496,200	$ 8,344,880	$ 3,771,478	$ 3,273,388	$ 106,455
52	Energy	$ -	$ -	$ -	$ -	$ -
53	Customer	$ 16,732,641	$ 14,180,143	$ 2,336,643	$ 34,960	$ 180,895
54	Subtotal	$ 32,228,841	$ 22,525,022	$ 6,108,121	$ 3,308,348	$ 287,350
55	**Distribution Secondary**					
56	Demand	$ 4,724,920	$ 3,323,691	$ 946,595	$ 435,756	$ 18,878
57	Energy	$ -	$ -	$ -	$ -	$ -
58	Customer	$ 8,347,837	$ 6,934,418	$ 1,329,335	$ 12,469	$ 71,615
59	Subtotal	$ 13,072,757	$ 10,258,110	$ 2,275,929	$ 448,225	$ 90,493
60	**Onsite & Metering**					
61	Demand	$ -	$ -	$ -	$ -	$ -
62	Energy	$ -	$ -	$ -	$ -	$ -
63	Customer	$ 8,033,403	$ 5,346,092	$ 1,782,377	$ 94,469	$ 810,466
64	Subtotal	$ 8,033,403	$ 5,346,092	$ 1,782,377	$ 94,469	$ 810,466
65	**Customer Accounts & Service**					
66	Demand	$ -	$ -	$ -	$ -	$ -
67	Energy	$ -	$ -	$ -	$ -	$ -
68	Customer	$ 9,438,538	$ 7,837,949	$ 1,286,658	$ 156,377	$ 157,553
69	Subtotal	$ 9,438,538	$ 7,837,949	$ 1,286,658	$ 156,377	$ 157,553
70	**Total**					
71	Demand	$ 28,337,905	$ 16,039,345	$ 6,693,811	$ 5,423,747	$ 181,002
72	Energy	$ 671,094	$ 298,395	$ 183,361	$ 184,928	$ 4,410
73	Customer	$ 42,552,419	$ 34,298,602	$ 6,735,013	$ 298,275	$ 1,220,529
74	**Total Revenue Requirement**	$ 71,561,418	$ 50,636,343	$ 13,612,184	$ 5,906,950	$ 1,405,941
75	Demand	39.60%	31.68%	49.18%	91.82%	12.87%
76	Energy	0.94%	0.59%	1.35%	3.13%	0.31%
77	Customer	59.46%	67.74%	49.48%	5.05%	86.81%

Unitil NH - Electric Division
12 Months Ended December 31, 2020

Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line	Description	TOTAL	D - Domestic Delivery Service	G2 - Regular General Service	G1 - Large General Service	Outdoor Lighting
	Unit Costs					
78	**Electric Procurement Supply**					
79	Demand	$ 0.05	$ 0.04	$ 0.05	$ 0.05	$ -
80	Energy	$ 0.5783	$ 0.5783	$ 0.5783	$ 0.5783	$ 0.5783
81	Customer	$ -	$ -	$ -	$ -	$ -
82	**Radial Transmission**					
83	Demand	$ 0.63	$ 0.63	$ 0.63	$ 0.62	$ 0.63
84	Energy	$ -	$ -	$ -	$ -	$ -
85	Customer	$ -	$ -	$ -	$ -	$ -
86	**Distribution Sub-Transmission**					
87	Demand	$ 26.93	$ 26.99	$ 26.98	$ 26.73	$ 26.99
88	Energy	$ -	$ -	$ -	$ -	$ -
89	Customer	$ -	$ -	$ -	$ -	$ -
90	**Distribution Primary**					
91	Demand	$ 52.69	$ 52.80	$ 52.79	$ 52.30	$ 52.80
92	Energy	$ -	$ -	$ -	$ -	$ -
93	Customer	$ 15.78	$ 17.39	$ 17.39	$ 17.39	$ 1.67
94	**Distribution Secondary**					
95	Demand	$ 16.07	$ 21.03	$ 13.25	$ 6.96	$ 9.36
96	Energy	$ -	$ -	$ -	$ -	$ -
97	Customer	$ 7.87	$ 8.51	$ 9.90	$ 6.20	$ 0.66
98	**Onsite & Metering**					
99	Demand	$ -	$ -	$ -	$ -	$ -
100	Energy	$ -	$ -	$ -	$ -	$ -
101	Customer	$ 7.58	$ 6.56	$ 13.27	$ 47.00	$ 7.46
102	**Customer Accounts & Service**					
103	Demand	$ -	$ -	$ -	$ -	$ -
104	Energy	$ -	$ -	$ -	$ -	$ -
105	Customer	$ 8.90	$ 9.61	$ 9.58	$ 77.80	$ 1.45
106	**TOTAL**					
107	Demand (per kW)	$ 96.36	$ 101.49	$ 93.70	$ 86.66	$ 89.78
108	Energy (per kWh)	$ 0.57832	$ 0.57832	$ 0.57832	$ 0.57832	$ 0.57832
109	Customer (per cust month)	$ 40.13	$ 42.07	$ 50.13	$ 148.40	$ 11.24
110	Demand & Customer (per cust mo.)	$ 66.86	$ 61.74	$ 99.96	$ 2,846.78	$ 12.91
111	**BILLING DETERMINANTS**					
112	Demand (kW)	294,079	158,032	71,441	62,590	2,016
113	Energy (kWh)	1,160,419	515,969	317,057	319,767	7,626
114	Customer Bills	1,060,234	815,280	134,344	2,010	108,600

Unitil Energy Systems, Inc.

External Class Allocation Factors Summary

Line No.	Name	Description	Total	D - Domestic Delivery Service	G2 - Regular General Service	G1 - Large General Service	Outdoor Lighting
1	**DEMAND ALLOCATORS**						
2	CP @ Supply						
3		Coincident Peaks @ Generation	286,670	149,935	75,569	61,167	-
4		Adjustment Factor		100%	100%	100%	100%
5	CP_DEMAND	CP Demand Allocator	286,670	149,935	75,569	61,167	-
6			100%	52.30%	26.36%	21.34%	0.00%
7	NCPs @ Supply						
8		NCPs @ Generation	311,871	168,254	76,007	65,464	2,146
9		Adjustment Factor		100%	100%	100%	100%
10	PROCURE_DEMAND	Supply Demand Allocator	311,871	168,254	76,007	65,464	2,146
11			100%	53.95%	24.37%	20.99%	0.69%
12	NCPs @ Sub-Transmission						
13		NCPs @ Sub-Transmission	308,811	166,603	75,261	64,821	2,125
14		Adjustment Factor		100%	100%	100%	100%
15	SUB-TRANS_DEMAND	Sub-Transmission Demand Allocator	308,811	166,603	75,261	64,821	2,125
16			100%	53.95%	24.37%	20.99%	0.69%
17	NCPs @ Primary						
18		NCPs @ Primary	301,451	162,335	73,367	63,678	2,071
19		Adjustment Factor		100%	100%	100%	100%
20	PRI_DEMAND	Primary Demand Allocator	301,451	162,335	73,367	63,678	2,071
21			100%	53.85%	24.34%	21.12%	0.69%
22	NCPs @ Secondary						
23		Max Customer NCPs @ Secondary	504,576	354,939	101,087	46,535	2,016
24		Adjustment Factor		100%	100%	100%	100%
25	SEC_DEMAND	Secondary Demand Allocator	504,576	354,939	101,087	46,535	2,016
26			100%	70.34%	20.03%	9.22%	0.40%
27	NCPs @ Meter						
28		Metered NCPs	294,079	158,032	71,441	62,590	2,016
29		Adjustment Factor		100%	100%	100%	100%
30	METERED_DEMAND	Metered Demand Allocator	294,079	158,032	71,441	62,590	2,016
31			100%	53.74%	24.29%	21.28%	0.69%

Unitil Energy Systems, Inc.

External Class Allocation Factors Summary

Line No.	Name	Description	Total	D - Domestic Delivery Service	G2 - Regular General Service	G1 - Large General Service	Outdoor Lighting
32	**CUSTOMER ALLOCATORS**						
33	Customer Count - billing						
34	CUSTOMERS	Test Year 2020 Customer Count	80,852	67,940	11,195	168	1,549
35			100%	84.03%	13.85%	0.21%	1.92%
36	Number of Customers Using Primary System						
37	PRI_CUST	Test Year 2020 Customer Count	80,169	67,940	11,195	168	867
38			100%	84.75%	13.96%	0.21%	1.08%
39	Number of Customers Using Secondary System						
40	SEC_CUST	Test Year 2020 Customer Count	80,116	67,940	11,175	135	867
41			100%	84.80%	13.95%	0.17%	1.08%
42	Number of Customers Billed at Primary Voltage						
43	LARGE_CUST	Test Year 2020 Customer Count	53	-	21	33	-
44			100%	0.00%	38.38%	61.62%	0.00%
45	Number of Customers and Light Fixtures						
46	ONSITE_CUST	Test Year 2020 Customer Count	88,353	67,940	11,195	168	9,050
47			100%	76.90%	12.67%	0.19%	10.24%
48	Allocation of Meter Investments						
49		Average Cost per Meter		$ 356.53	$ 721.36	$ 2,555.42	$ -
50		Relative Weighting Factor		1.00	2.02	7.17	-
51	METERS	Weighted Meter Count	91,792	67,940	22,651	1,201	-
52			100%	74.02%	24.68%	1.31%	0.00%
53	Allocation of Services						
54		Service Cost per Service		$ 708.28	$ 1,321.35	$ 293.31	$ -
55		Relative Weighting Factor		1.00	1.87	0.41	-
56	SERVICES	Weighted Customers	88,895	67,940	20,886	69	-
57			100%	76.43%	23.49%	0.08%	0.00%
58	Uncollectible						
59	UNCOLLECT	Uncollectibles	$ 972,322	$ 878,816	$ 77,371	$ 12,608	$ 3,527
60			100%	90.38%	7.96%	1.30%	0.36%
61	Customer Deposits						
62	CUST_DEPOSITS	Customer Deposits	$ 371,830	$ 192,145	$ 175,177	$ 4,508	$ -
63			100%	51.68%	47.11%	1.21%	0.00%

Unitil Energy Systems, Inc.

External Class Allocation Factors Summary

Line No.	Name	Description	Total	D - Domestic Delivery Service	G2 - Regular General Service	G1 - Large General Service	Outdoor Lighting
64	Meter Reading						
65	ACCT_902	Meter Reading	$ 63,751	$ 47,185	$ 15,732	$ 834	$ -
66			100%	74.02%	24.68%	1.31%	0.00%
67	Cutomer Records and Collections						
68	ACCT_903	Cutomer Records and Collections	$ 3,226,861	$ 2,723,565	$ 442,139	$ 7,584	$ 53,573
69			100%	84.40%	13.70%	0.24%	1.66%
70	Customer Assistance						
71	ACCT_909	Customer Assistance	$ 28,775	$ 24,897	$ 3,362	$ 50	$ 465
72			100%	86.52%	11.68%	0.17%	1.62%
73	Direct Assignment of Lighting						
74	LIGHT		1	-	-	-	1
75			100%	0.00%	0.00%	0.00%	100.00%
76	**ENERGY ALLOCATORS**						
77	MWh Sales						
78	ENERGY	MWh Sales	1,160,419	515,969	317,057	319,767	7,626
79			100.00%	44.46%	27.32%	27.56%	0.66%
80	**REVENUE ALLOCATORS**						
81	Distribution Revenue						
82	DIST_REVENUE	Total Revenue	58,056,553	31,580,284	16,916,360	7,736,414	1,823,495
83			100%	54.40%	29.14%	13.33%	3.14%
84	***FUNCTIONAL PLANT ALLOCATORS***						
85	Misc. Intangible Plant Split						
86	Plant Related	Account 303 related to plant	2.90%				
87	Customer Related	Account 303 related to billing, meter reading, customer accounts	66.81%				
88	Labor Related	Account 303 related to operations, IT, finance accounting, employees	30.28%				

Unitil Energy Systems, Inc.

Description of ACOSS Functionalization and Classification of Accounts

FERC	Description	Functionalization	Classification
Intangible Plant			
301-303	Intangible Plant		
301	Organization	Labor expense	Labor expense
303	Miscellaneous Intangible Plant, Plant-related	Total plant in service	Total plant in service
303	Miscellaneous Intangible Plant, Customer-related	Accounts & Services	Customer-related
303	Miscellaneous Intangible Plant, Labor-related	Labor expense	Labor expense
Production Plant and Expenses			
340-348	Other Production Plant		
343	Prime Movers	Supply	Demand-related
555-557	Other Power Generation Expense		
555	Purchased Power Expenses	Supply	Energy-related
557	Other Purchased Power	Supply	Energy-related
Transmission Plant and Expenses			
350-359	Transmission Plant	No transmission plant	N/A
560-571	Transmission Expenses		
560	Supervision and Engineering	Transmission	Demand-related
562	Station Expenses	Transmission	Demand-related
563	Overhead Line Expenses	Transmission	Demand-related
567	Rents	Transmission	Demand-related
568	Supervision and Engineering	Transmission	Demand-related
571	Maintenance of Overhead Lines	Transmission	Demand-related

FERC	Description	Functionalization	Classification
Distribution Plant and Expenses			
360-373	*Distribution Plant*		
360	Land and Land Rights	Accounts 361 through 364	Accounts 361 through 364
361	Structures and Improvements	Sub-transmission	Demand-related
362	Station Equipment	Sub-transmission	Demand-related
364	Poles, Towers and Fixtures - Primary	Primary distribution	Demand-Customer split based on the minimum system analysis
364	Poles, Towers and Fixtures - Secondary	Secondary distribution	Demand-Customer split based on the minimum system analysis
365	Overhead Conductors and Devices - Primary	Primary distribution	Demand-Customer split based on the minimum system analysis
365	Overhead Conductors and Devices - Secondary	Secondary distribution	Demand-Customer split based on the minimum system analysis
366	Underground Conduit - Primary	Primary distribution	Demand-Customer split based on the minimum system analysis
366	Underground Conduit - Secondary	Secondary distribution	Demand-Customer split based on the minimum system analysis
367	Underground Conductors and Devices - Primary	Primary distribution	Demand-Customer split based on the minimum system analysis
367	Underground Conductors and Devices - Secondary	Secondary distribution	Demand-Customer split based on the minimum system analysis
368	Line Transformers	Line transformers	Demand-Customer split based on the minimum system analysis
368.1	Line Transformer Installations	Line transformers	Demand-Customer split based on the minimum system analysis
369	Services	Secondary distribution	Customer-related
370	Meters	Onsite	Customer-related

FERC	Description	Functionalization	Classification
370.1	Meter Installations	Onsite	Customer-related
371	Installations on Cust Premises	Onsite	Customer-related
373	Street Lighting and Signal Systems	Onsite	Customer-related
580-598	*Distribution Expenses*		
580	Operation Supervision & Engineering	Accounts 582-589	Accounts 582-589
581	Load Dispatching	Accounts 582-589	Accounts 582-589
582	Station Expenses	Sub-transmission	Demand-related
583	Overhead Line Expenses	Account 365	Account 365
584	Underground Line Expenses	Account 367	Account 367
585	Street Lighting and Signal Systems	Onsite	Customer-related
586	Meter Expenses	Onsite	Customer-related
587	Customer Installation Expenses	Onsite	Customer-related
588	Misc. Distribution Expenses	Distribution plant	Distribution plant
589	Rents	Distribution plant	Distribution plant
590	Maintenance Supervision & Engineering	Accounts 591-598	Accounts 591-598
591	Maintenance of Structures	Sub-transmission	Demand-related
592	Maintenance of Station Equipment	Sub-transmission	Demand-related
593	Maintenance of Overhead Lines	Account 365	Account 365
594	Maintenance of Underground Lines	Account 367	Account 367
595	Maintenance of Line Transformers	Account 368	Account 368
596	Maintenance of Street Lights	Onsite	Customer-related
597	Maintenance of Meters	Onsite	Customer-related
598	Maintenance of Misc. Plant	Distribution plant	Distribution plant
General Plant			
389-399	General & Common Plant	Labor expense	Labor expense

FERC	Description	Functionalization	Classification
Depreciation Reserve			
108	Accumulated Depreciation	Corresponding plant accts.	Corresponding plant accts.
Other Rate Base Items			
165	Prepayments	Total plant in service	Total plant in service
131	Cash Working Capital	Total plant in service	Total plant in service
154	Materials and Supplies	Total plant in service	Total plant in service
182, 254	Regulatory Assets	Total plant in service	Total plant in service
235	Customer Deposits	Accounts & Services	Customer-related
190	Net Deferred Income Taxes	Total plant in service	Total plant in service
	Excess Deferred Income Taxes	Total plant in service	Total plant in service
	Deferred Income Taxes Debit	Total plant in service	Total plant in service
Customer Expenses			
901-905	Customer Accounts Expense	Accounts & Services	Customer-related
906-910	Customer Service & Information Expense	Accounts & Services	Customer-related
911-917	Sales Expense	N/A	N/A
Administrative and General Expenses			
920	Administrative & General Salaries	Labor expense	Labor expense
921	Office Supplies & Expenses	Labor expense	Labor expense
923	Outside Services Employed	Labor expense	Labor expense
923-D	Key Account Management	Accounts & Services	Customer-related
926	Employee Pensions and Benefits	Labor expense	Labor expense
924	Property Insurance	Total plant in service	Total plant in service
925	Injuries and Damages	Total plant in service	Total plant in service
935	Maintenance of General Plant	Total plant in service	Total plant in service
927	Franchise Requirements	O&M expense allocation	O&M expense allocation

FERC	Description	Functionalization	Classification
928	Regulatory Commission Expenses	O&M expense allocation	O&M expense allocation
930	General/Miscellaneous. Expenses	O&M expense allocation	O&M expense allocation
931	Rents	O&M expense allocation	O&M expense allocation
	Test year Inflation Allowance	O&M expense allocation	O&M expense allocation
Depreciation and Amortization Expenses			
403	Depreciation Expense	Accumulated depreciation	Accumulated depreciation
404-407	Amortization Expense	Total plant in service	Total plant in service
Taxes Other Than Income			
408	Payroll Taxes	Labor expense	Labor expense
408	Unemployment Tax	Labor expense	Labor expense
408	Property Taxes	Total plant in service	Total plant in service
408	NH BET Taxes	Total plant in service	Total plant in service
408	NH Surcharge Taxes	Total plant in service	Total plant in service
Income Taxes			
409-410	Income Taxes	Rate base	Rate base
Revenues			
440-449	Distribution Revenue	Revenue requirement	Revenue requirement
454	Rent from Electric Property	Total plant in service	Total plant in service
450-457	All Other Revenues	Revenue requirement	Revenue requirement

UNITIL ENERGY SYSTEMS, INC.

SUBFUNCTIONALIZATION/CLASSIFICATION OF DISTRIBUTION PLANT

SUMMARY OF RESULTS

FOR COST ALLOCATION PURPOSES

		FUNCTIONALIZATION		PRIMARY SPLIT		SECONDARY SPLIT	
DIST. ACCT. NO.	DESCRIPTION	PRIMARY % OF ACCOUNT TOTAL	SECONDARY % OF ACCOUNT TOTAL	CUSTOMER COMPONENT % OF	DEMAND COMPONENT % OF	CUSTOMER COMPONENT % OF	DEMAND COMPONENT % OF
364	POLES, TOWERS AND FIXTURES	84.32%	15.68%	45.45%	54.55%	46.21%	53.79%
365	OVERHEAD CONDUCTORS AND DEVICES	84.59%	15.41%	50.98%	49.02%	70.80%	29.20%
367	UNDERGROUND CONDUCTORS	93.46%	6.54%	69.31%	30.69%	35.73%	64.27%
368	TRANSFORMERS	0.00%	100.00%	NA	NA	54.14%	45.86%

UES Minimum Size System Study

Primary

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
			Minimum Size			Expand to Total Account				
Account	Minimum Size (Asset Description)	Unit	Total Installed Cost	Total Installed Units	Average Unit Cost (4)/(5)	Total Units	Total Customer Component	Account Total	% Customer (8)/(9)	% Demand 100-(10)
364	30 FOOT	Pole			$ 530.96	48,517	$ 25,760,813	$ 56,678,749	**45.45%**	**54.55%**
365	365-00/ 31/2 : #6 WIRE	Feet	$ 5,896,066	2,475,090	$ 2.38	19,113,164	$ 45,530,657	$ 89,315,929	**50.98%**	**49.02%**
367	367-00/ 8/2 : #2 URD CABLE	Feet	$ 1,561,231	255,636	$ 6.11	2,918,153	$ 17,821,863	$ 25,714,356	**69.31%**	**30.69%**

Secondary

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
			Minimum Size			Expand to Total Account				
Account	Minimum Size (Asset Description)	Unit	Total Installed Cost	Total Installed Units	Average Unit Cost (4)/(5)	Total Units	Total Customer Component	Account Total	% Customer (8)/(9)	% Demand 100-(10)
364	30 FOOT	Pole			$ 530.96	9,095	$ 4,829,087	$ 10,451,423	**46.21%**	**53.79%**
365	365-00/ 70/2 : #4 TRIPLEX (3W #4)	Feet	$ 233,330	42,022	$ 5.55	3,583,740	$ 19,898,940	$ 28,105,481	**70.80%**	**29.20%**
367	367-00/ 49/2 : #500 MCM	Feet	$ 35,711	11,214	$ 3.18	21,853	$ 69,590	$ 194,770	**35.73%**	**64.27%**
368 Material	368-00/ 68/2 : 15 KVA	KVA	$ 10,756,584	4,622	$ 2,327.26	22,980	$ 53,480,374	$ 93,399,648	57.26%	42.74%
368 Install	368-01/ 2/2 : 10-25 KVA INSTALL	KVA	$ 3,152,146	4,077	$ 773.15	21,282	$ 16,454,251	$ 35,779,296	45.99%	54.01%
368							$ 69,934,625	$ 129,178,944	**54.14%**	**45.86%**

Unitil Energy
2021 Rate Case Electric Marginal Cost of Service Study
Marginal Cost Summary

A	B	C	D	E	F	G	H	I
No.	FERC A/C	Description	Units	Total System	Domestic	G2	G1	OL
				MARGINAL COST BASED REVENUE REQUIREMENTS REPORT				
1		**Demand Related Carrying Costs**						
2	362	Station Equipment		$ 5,790,215	$ 3,118,096	$ 1,409,227	$ 1,223,114	$ 39,777
3	364-367	Primary System		$ 1,860,253	$ 1,001,768	$ 452,750	$ 392,956	$ 12,779
4	368	Line Transformers		$ 6,604,803	$ 4,646,074	$ 1,323,212	$ 609,128	$ 26,389
5	364-367	Secondary System		$ 3,323,459	$ 2,337,850	$ 665,825	$ 306,506	$ 13,279
6	389-398	General Plant - Demand Related		$ 656,266	$ 361,786	$ 157,536	$ 132,582	$ 4,362
7		Subtotal: Demand Related Carrying Costs		$ 18,234,997	$ 11,465,574	$ 4,008,550	$ 2,664,287	$ 96,587
8		**Demand Related O&M Costs**						
9	920-935	A&G Expense - Demand Related		$ 2,545,690	$ 1,408,958	$ 609,637	$ 510,271	$ 16,824
10		Subtotal: Demand O&M Costs		$ 2,545,690	$ 1,408,958	$ 609,637	$ 510,271	$ 16,824
11		**Total: Demand Related Costs**		**$ 20,780,688**	**$ 12,874,531**	**$ 4,618,187**	**$ 3,174,558**	**$ 113,411**
12		**Customer Related Carrying Costs**						
13	364-367	Primary System		$ 4,003,233	$ 3,392,555	$ 559,035	$ 8,364	$ 43,278
14	368	Line Transformers		$ 9,284,520	$ 7,873,450	$ 1,295,033	$ 15,597	$ 100,441
15	364-367	Secondary System		$ 7,033,214	$ 5,964,299	$ 981,014	$ 11,815	$ 76,086
16	369	Services		$ 7,089,387	$ 5,421,293	$ 1,663,535	$ 4,560	$ -
17	370-371	Meters & Installations		$ 5,795,383	$ 4,289,643	$ 1,430,159	$ 75,581	$ -
18	373	Street Lighting and Signal Systems		$ 514,709	$ -	$ -	$ -	$ 514,709
19	389-398	General Plant - Customer Related		$ 1,936,254	$ 1,512,216	$ 313,300	$ 9,445	$ 101,294
20		Subtotal: Demand Related Carrying Costs		$ 35,656,701	$ 28,453,456	$ 6,242,076	$ 125,361	$ 835,808
21		**Customer Related O&M Costs**						
22	902	Meter Reading Expenses		$ 63,751	$ 47,185	$ 15,732	$ 834	$ -
23	903	Customer Records & Collection Expenses		$ 3,226,861	$ 2,711,528	$ 446,813	$ 6,685	$ 61,835
24	904	Uncollectible Accounts		$ 1,124,573	$ 1,016,425	$ 89,486	$ 14,582	$ 4,079
25	905	Customer Accounts Expenses Supervision		$ 17,026	$ 8,798	$ 8,021	$ 206	$ -
26	908	Customer Assistance Expenses		$ -	$ -	$ -	$ -	$ -
27	909	Informational and Instructional Advertising Exp.		$ 28,775	$ 24,179	$ 3,984	$ 60	$ 551
28	910	Misc. Customer Service & Informational Exp.		$ -	$ -	$ -	$ -	$ -
29	920-935	Customer A&G Costs		$ 7,124,894	$ 5,440,000	$ 1,185,246	$ 156,734	$ 342,914
30		Subtotal: Customer O&M Costs		$ 11,585,879	$ 9,248,116	$ 1,749,283	$ 179,101	$ 409,379
31		**Total: Customer Related Costs**		**$ 47,242,580**	**$ 37,701,572**	**$ 7,991,358**	**$ 304,462**	**$ 1,245,188**
32		**Total LRIC Based Revenue Requirement**		**$ 68,023,268**	**$ 50,576,103**	**$ 12,609,545**	**$ 3,479,020**	**$ 1,358,599**
33		**Actual Revenue Requirement**		**$ 70,048,945**				
34		**True-up Factor**		**1.0298**				
35		**Allocated Actual Revenue Requirement**		**$ 70,048,945**	**$ 52,082,219**	**$ 12,985,047**	**$ 3,582,623**	**$ 1,399,057**
36		**Revenue to Cost Ratio**		0.83	0.61	1.30	2.16	1.30

Unitil Energy
2021 Rate Case Electric Marginal Cost of Service Study
Marginal Cost Summary

A No.	B FERC A/C	C Description	D Units	E Total System	F Domestic	G G2	H G1	I OL
					MARGINAL UNIT COST REPORT			
37		**Demand Related Carrying Costs**						
38	362	Station Equipment		$ 19.21	$ 19.21	$ 19.21	$ 19.21	$ 19.21
39	364-367	Primary System		$ 6.17	$ 6.17	$ 6.17	$ 6.17	$ 6.17
40	368	Line Transformers		$ 21.91	$ 28.62	$ 18.04	$ 9.57	$ 12.74
41	364-367	Secondary System		$ 11.02	$ 14.40	$ 9.08	$ 4.81	$ 6.41
42	389-398	General Plant - Demand Related		$ 2.18	$ 2.23	$ 2.15	$ 2.08	$ 2.11
43		Subtotal: Demand Related Carrying Costs		$ 60.49	$ 70.63	$ 54.64	$ 41.84	$ 46.64
44		**Demand Related O&M Costs**						
45	920-935	A&G Expense - Demand Related		$ 8.44	$ 8.68	$ 8.31	$ 8.01	$ 8.12
46		Subtotal: Demand O&M Costs		$ 8.44	$ 8.68	$ 8.31	$ 8.01	$ 8.12
47		**Total: Demand Related Costs**		**$ 68.94**	**$ 79.31**	**$ 62.95**	**$ 49.85**	**$ 54.76**
48		**$/kW-Month**		**$ 5.74**	**$ 6.61**	**$ 5.25**	**$ 4.15**	**$ 4.56**
49		**Customer Related Carrying Costs**						
50	364-367	Primary System		$ 45.31	$ 49.93	$ 49.93	$ 49.93	$ 4.78
51	368	Line Transformers		$ 105.08	$ 115.89	$ 115.68	$ 93.11	$ 11.10
52	364-367	Secondary System		$ 79.60	$ 87.79	$ 87.63	$ 70.54	$ 8.41
53	369	Services		$ 80.24	$ 79.80	$ 148.59	$ 27.22	$ -
54	370-371	Meters & Installations		$ 65.59	$ 63.14	$ 127.75	$ 451.23	$ -
55	389-398	General Plant - Customer Related		$ 21.92	$ 22.26	$ 27.98	$ 56.39	$ 11.19
56		Subtotal: Customer Related Carrying Costs		$ 397.75	$ 418.80	$ 557.56	$ 748.42	$ 35.48
57		**Customer Related O&M Costs**						
58	902	Meter Reading Expenses		$ 0.72	$ 0.69	$ 1.41	$ 4.98	$ -
59	903	Customer Records & Collection Expenses		$ 36.52	$ 39.91	$ 39.91	$ 39.91	$ 6.83
60	904	Uncollectible Accounts		$ 12.73	$ 14.96	$ 7.99	$ 87.06	$ 0.45
61	905	Customer Accounts Expenses Supervision		$ 0.19	$ 0.13	$ 0.72	$ 1.23	$ -
62	908	Customer Assistance Expenses		$ -	$ -	$ -	$ -	$ -
63	909	Informational and Instructional Advertising Exp.		$ 0.33	$ 0.36	$ 0.36	$ 0.36	$ 0.06
64	910	Misc. Customer Service & Informational Exp.		$ -	$ -	$ -	$ -	$ -
65	920-935	Customer A&G Costs		$ 80.64	$ 80.07	$ 105.87	$ 935.73	$ 37.89
66		Subtotal: Customer O&M Costs		$ 131.13	$ 136.12	$ 156.25	$ 1,069.26	$ 45.24
67		**Total: Customer Related Costs**		**$ 528.88**	**$ 554.92**	**$ 713.81**	**$ 1,817.68**	**$ 80.72**
68		Monthly Costs		$ 44.07	$ 46.24	$ 59.48	$ 151.47	$ 6.73

Unitil Energy
2021 Rate Case Electric Marginal Cost of Service Study
Plant Investment

A No.	B FERC A/C	C Description	D Units	E Total	F Domestic	G G2	H G1	I OL
1		**Billing Determenants**						
2		No. of Customers/Fixtures		88,353	67,940	11,195	168	9,050
3		No. of Customers/Fixtures - Primary		80,169	67,940	11,195	168	867
4		No. of Customers/Fixtures - Secondary		80,116	67,940	11,175	135	867
5		NCP-Demand - Primary	kW	301,451	162,335	73,367	63,678	2,071
6		NCP-Demand - Secondary	kW	504,576	354,939	101,087	46,535	2,016
7		Energy	kWh	1,160,419	515,969	317,057	319,767	7,626
8		Revenue		$ 58,056,553	$ 31,580,284	$ 16,916,360	$ 7,736,414	$ 1,823,495
9		**Demand Related Additions**						
10	362	Station Equipment						
11		Investment per unit capacity	$/kW		$159.83	$159.83	$159.83	$159.83
12		Class investment	$	$ 48,181,591	$25,946,334	$11,726,474	$10,177,788	$330,995
13		ECCR	%		12.02%	12.02%	12.02%	12.02%
14		Annual Carrying Charge	$	$ 5,790,215	$3,118,096	$1,409,227	$1,223,114	$39,777
15		Unit Annual Carrying Costs	$/kW		$19.21	$19.21	$19.21	$19.21
16	364-367	Primary System						
17		Investment per unit capacity	$/kW		$36.45	$36.45	$36.45	$36.45
18		Class investment	$	$ 10,988,967	$5,917,684	$2,674,504	$2,321,289	$75,491
19		ECCR			16.93%	16.93%	16.93%	16.93%
20		Annual Carrying Charge	$	$ 1,860,253	$1,001,768	$452,750	$392,956	$12,779
21		Unit Annual Carrying Costs	$/kW		$6.17	$6.17	$6.17	$6.17
22	368	Line Transformers						
23		Investment per unit capacity	$/kW		$117.41	$117.41	$117.41	$117.41
24		Class investment	$	$ 59,244,319	$41,674,744	$11,869,058	$5,463,810	$236,707
25		ECCR			11.15%	11.15%	11.15%	11.15%
26		Annual Carrying Charge	$	$ 6,604,803	$4,646,074	$1,323,212	$609,128	$26,389
27		Unit Annual Carrying Costs	$/kW		$28.62	$18.04	$9.57	$12.74
28	364-367	Secondary System						
29		Investment per unit capacity			$38.91	$38.91	$38.91	$38.91
30		Class investment	$	$ 19,632,477	$13,810,244	$3,933,188	$1,810,606	$78,440
31		ECCR			16.93%	16.93%	16.93%	16.93%
32		Annual Carrying Charge	$	$ 3,323,459	$2,337,850	$665,825	$306,506	$13,279
33		Unit Annual Carrying Costs	$/kW		$14.40	$9.08	$4.81	$6.41

Unitil Energy
2021 Rate Case Electric Marginal Cost of Service Study
Plant Investment

A No.	B FERC A/C	C Description	D Units		E Total	F Domestic	G G2	H G1	I OL
34		**Customer Related Additions**							
35	364-367	Primary System							
36		Investment per customer	$/Cust			$294.98	$294.98	$294.98	$294.98
37		Class investment	$	$	23,648,063	$20,040,645	$3,302,353	$49,408	$255,657
38		ECCR				16.93%	16.93%	16.93%	16.93%
39		Annual Carrying Charge	$	$	4,003,233	$3,392,555	$559,035	$8,364	$43,278
40		Unit Annual Carrying Costs	$/Cust			$49.93	$49.93	$49.93	$4.78
41	368	Line Transformers							
42		Investment per customer	$/Cust			$1,039.51	$1,039.51	$1,039.51	$1,039.51
43		Class investment	$	$	83,281,070	$70,623,930	$11,616,297	$139,900	$900,943
44		ECCR				11.15%	11.15%	11.15%	11.15%
45		Annual Carrying Charge	$	$	9,284,520	$7,873,450	$1,295,033	$15,597	$100,441
46		Unit Annual Carrying Costs	$/Cust			$115.89	$115.68	$93.11	$11.10
47	364-367	Secondary System							
48		Investment per customer	$/Cust			$518.58	$518.58	$518.58	$518.58
49		Class investment	$	$	41,546,898	$35,232,559	$5,795,088	$69,793	$449,458
50		ECCR				16.93%	16.93%	16.93%	16.93%
51		Annual Carrying Charge	$	$	7,033,214	$5,964,299	$981,014	$11,815	$76,086
52		Unit Annual Carrying Costs	$/Cust			$87.79	$87.63	$70.54	$8.41
53	369	Services							
54		Investment per customer	$/Cust			$708	$ 1,321.35	$300.71	$0.00
55		Class investment	$	$	62,926,601	$48,120,310	$14,765,820	$40,471	$0
56		ECCR				11.27%	11.27%	11.27%	11.27%
57		Annual Carrying Charge	$	$	7,089,387	$5,421,293	$1,663,535	$4,560	$0
58		Unit Annual Carrying Costs	$/Cust			$79.80	$148.59	$27.22	$0.00
59	370-371	Meters & Installations							
60		Investment per customer	$/Cust			$357	$ 721.36	$2,548.02	$0.00
61		Class investment	$	$	32,725,464	$24,222,826	$8,075,844	$426,794	$0
62		ECCR				17.71%	17.71%	17.71%	17.71%
63		Annual Carrying Charge	$	$	5,795,383	$4,289,643	$1,430,159	$75,581	$0
64		Unit Annual Carrying Costs	$/Cust			$63.14	$127.75	$451.23	$0.00

Unitil Energy
2021 Rate Case Electric Marginal Cost of Service Study
Plant Investment

A	B	C	D		E		F		G		H		I
No.	FERC A/C	Description	Units		Total		Domestic		G2		G1		OL
65		**General Plant**											
66	389-398	Demand Related General Plant											
67		General Plant - ECOSS Demand Allocation		$	7,617,400	$	4,199,315	$	1,828,548	$	1,538,903	$	50,635
68		Less: Accumulated Depreciation		$	(1,917,323)	$	(1,056,981)	$	(460,251)	$	(387,347)	$	(12,745)
69		Net General Plant - Demand Allocation		$	5,700,077	$	3,142,334	$	1,368,297	$	1,151,556	$	37,890
70		Return on Ratebase (Pre Tax)					7.88%		7.88%		7.88%		7.88%
71		Return on Ratebase (Pre Tax)		$	449,166	$	247,616	$	107,822	$	90,743	$	2,986
72		Depreciation Expence		$	207,100	$	114,170	$	49,714	$	41,839	$	1,377
73		Annual Carrying Charge	$	$	656,266.44	$	361,786.08	$	157,536.01	$	132,582.01	$	4,362.35
74		Unit Annual Carrying Costs	$/kW				$2.23		$2.15		$2.08		$2.11
75	389-398	General Plant - Customer Related											
76		General Plant - ECOSS Customer Allocation		$	22,474,444	$	17,552,561	$	3,636,525	$	109,624	$	1,175,733
77		Less: Accumulated Depreciation		$	(5,656,887)	$	(4,418,034)	$	(915,325)	$	(27,593)	$	(295,936)
78		Net General Plant - Demand Allocation		$	16,817,556	$	13,134,527	$	2,721,200	$	82,031	$	879,798
79		Return on Ratebase (Pre Tax)					7.88%		7.88%		7.88%		7.88%
80		Return on Ratebase (Pre Tax)		$	1,325,223	$	1,035,001	$	214,431	$	6,464	$	69,328
81		Depreciation Expence		$	611,031	$	477,216	$	98,869	$	2,980	$	31,966
82		Annual Carrying Charge	$	$	1,936,254	$	1,512,216	$	313,299.72	$	9,444.51	$	101,293.65
83		Unit Annual Carrying Costs	$/Cust				$22.26		$27.98		$56.39		$11.19

Unitil Energy
2021 Rate Case Electric Marginal Cost of Service Study
O&M Expense

A No.	B FERC A/C	C Description	D Units	E Total	F Domestic	G G2	H G1	I OL
1		**Customer Related O&M**						
2	902	Meter Reading Expenses						
3		Meter Reading Expenses			$ 47,185	$ 15,732	$ 834	$ -
4		Expenses per customer			$ 0.69	$ 1.41	$ 4.98	$ -
5	903	Customer Records & Collection Expenses						
6		Customer Records & Collection Expenses			$ 2,711,528	$ 446,813	$ 6,685	$ 61,835
7		Expenses per customer			$ 39.91	$ 39.91	$ 39.91	$ 6.83
8	904	Uncollectible Accounts						
9		Uncollectible Accounts			$ 1,016,425	$ 89,486	$ 14,582	$ 4,079
10		Expenses per customer			$ 14.96	$ 7.99	$ 87.06	$ 0.45
11	905	Customer Accounts Expenses Supervision						
12		Customer Accounts Expenses Supervision			$ 8,798	$ 8,021	$ 206	$ -
13		Expenses per customer			$ 0.13	$ 0.72	$ 1.23	$ -
14	908	Customer Assistance Expenses						
15		Customer Assistance Expenses			$ -	$ -	$ -	$ -
16		Expenses per customer			$ -	$ -	$ -	$ -
17	909	Informational and Instructional Advertising Exp.						
18		Informational and Instructional Advertising Exp.			$ 24,179	$ 3,984	$ 60	$ 551
19		Expenses per customer			$ 0.36	$ 0.36	$ 0.36	$ 0.06
20	910	Misc. Customer Service & Informational Exp.						
21		Misc. Customer Service & Informational Exp.			$ -	$ -	$ -	$ -
22		Expenses per customer			$ -	$ -	$ -	$ -
23	920-935	A&G Expense - Customer Related						
24		A&G Expense - Customer Allocation			$ 5,440,000	$ 1,185,246	$ 156,734	$ 342,914
25		Expenses per customer			$ 80.07	$ 105.87	$ 935.73	$ 37.89
26		**Demand Related O&M**						
27	920-935	A&G Expense - Demand Related						
28		A&G Expense - Demand Allocation			$ 1,408,958	$ 609,637	$ 510,271	$ 16,824
29		Expenses per unit Demand			$ 8.68	$ 8.31	$ 8.01	$ 8.12

Unitil Energy
2021 Rate Case Electric Marginal Cost of Service Study
Lighting Marginal Cost

Unitil Lighting Rate Design - Replacement LED Lights
Estimated Marginal Revenue Requirements

	A	C	D	E
Line No.	Desciption	Count	ECCR on LED Fixtures	Annual Revenue C*D
1	STREETLIGHT LED 30W	4,152	$ 48.22	$ 200,230
2	STREETLIGHT LED 50W	175	$ 45.83	$ 8,030
3	STREETLIGHT LED 100W	498	$ 57.30	$ 28,534
4	STREETLIGHT LED 120W	1,074	$ 57.30	$ 61,561
5	STREETLIGHT LED 140W	228	$ 83.49	$ 19,031
6	STREETLIGHT LED 260W	134	$ 107.43	$ 14,373
7	YARDLIGHT LED 35W	440	$ 77.30	$ 34,017
8	YARDLIGHT LED 47W	122	$ 77.30	$ 9,408
9	FLOODLIGHT LED 70W	280	$ 84.15	$ 23,531
10	FLOODLIGHT LED 90W	391	$ 84.15	$ 32,893
11	FLOODLIGHT LED 110W	461	$ 95.17	$ 43,900
12	FLOODLIGHT LED 370W	206	$ 190.71	$ 39,202
13	Special Agreement Customer Installed LED	889	$ -	$ -
14	Total	9,050		$ 514,709