REDACTED

UNITIL ENERGY SYSTEMS, INC.

JOINT DIRECT TESTIMONY

OF

ANDRE J. FRANCOEUR

TODD R. DIGGINS

CHRISTOPHER J. GOULDING

AND

JEFFREY M. PENTZ

EXHIBIT FDGP-1

New Hampshire Public Utilities Commission

Docket No. DE 22-_____

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Exhibits

I. INTRODUCTION

Q. Mr. Francoeur, would you please state your name and business address?

A. My name is Andre J. Francoeur. My business address is 6 Liberty Lane West, Hampton, New Hampshire 03842.

Q. What is your position and what are your responsibilities?

A. I am the Financial Planning and Analysis Manager for Unitil Service Corp. ("Unitil Service"), which provides services to Unitil Energy Systems, Inc. ("UES" or the "Company"). My responsibilities are primarily in the areas of strategic planning and budgeting, supporting investor relations, and assisting with various regulatory and treasury projects.

Q. Please describe your business and educational background.

A. I have approximately 7 years of professional experience within the finance and accounting areas. I began working for Unitil Service in 2017 as a Financial Analyst, was promoted to Senior Financial Analyst in 2020, and promoted to my current role in 2021. I graduated with honors from the State University of New York at Plattsburgh with a Bachelor of Science degree. I am currently pursuing a Master's degree in Business Administration from the University of New Hampshire.

Q. Mr. Francoeur, do you hold any professional certifications?

A. Yes, I am a Certified Management Accountant.

Q. Have you previously testified before the Commission, or other regulatory agencies?

A. Yes, I recently testified before the New Hampshire Public Utilities Commission (the "Commission") in DG 21-104, Northern Utilities' most recent base distribution rate case.

Q. Mr. Diggins, please state your name and business address.

A. My name is Todd R. Diggins. My business address is 6 Liberty Lane West, Hampton, New Hampshire 03842.

Q. Mr. Diggins, what is your position and what are your responsibilities?

A. I am the Treasurer and Director of Finance for Unitil Service, a subsidiary of Unitil Corporation that provides managerial, financial, accounting, regulatory, engineering and information technology services to Unitil Corporation's subsidiaries. I am also the Treasurer of UES and Unitil Corporation's other utility subsidiaries. My responsibilities are primarily in the areas of financial planning and analyses, regulatory projects, treasury operations, investor relations, and insurance and loss control programs.

Q. Mr. Diggins, please describe your business and educational background.

A. I have over 20 years of professional experience in the utility industry focused within the finance, accounting, and regulatory areas. I joined Unitil Service in 1998 as a Systems Financial Analyst. In 2004, I accepted a position within the Accounting

Department as a General Accountant and was promoted to Corporate Accounting Manager in 2009. In 2018, I was promoted to Director of Finance and in 2020 became Treasurer and Director of Finance. I hold a Bachelor of Science degree from the University of New Hampshire, a Master's Degree of Science in Finance from Southern New Hampshire University, and a Masters of Global Business Administration from Southern New Hampshire University.

Q. Do you hold any professional licenses?

A. Yes, I am a Certified Public Accountant in the State of New Hampshire.

Q. Have you previously testified before the Commission, or other regulatory agencies?

A. Yes, I recently testified before the Commission in DE 21-030, UES's most recent base distribution rate case.

Q. Mr. Goulding, please state your name and business addresses.

A. My name is Christopher J. Goulding, and my business address is 6 Liberty Lane West, Hampton, New Hampshire 03842.

Q. What is your position and what are your responsibilities?

A. I am the Director of Rates and Revenue Requirements for Unitil Service, a subsidiary of Unitil Corporation that provides managerial, financial, regulatory and engineering services to Unitil Corporation's utility subsidiaries including UES. My responsibilities include all rate and regulatory filings related to the financial requirements of UES and its affiliates.

Q. Please describe your business and educational background.

A. In 2000, I was hired by NSTAR Electric & Gas Company and held various positions with increasing responsibilities in Accounting, Corporate Finance, and Regulatory. I was hired by Unitil Service in early 2019 to perform my current job responsibilities. I earned a Bachelor of Science degree in Business Administration from Northeastern University in 2000 and a Master of Business Administration from Boston College in 2009.

Q. Mr. Goulding, have you previously testified before the Department or other regulatory agencies?

A. Yes, I have testified before the Commission on various financial, ratemaking and utility regulation matters, including utility cost of service and revenue requirements analysis. I have also testified before the Maine Public Utilities Commission and Massachusetts Department of Public Utilities on similar matters on several occasions.

Q. Mr. Pentz, would you please state your name and business address?

A. My name is Jeffrey M. Pentz. My business address is 6 Liberty Lane West, Hampton, New Hampshire 03842.

Q. What is your position?

A. I am employed by Unitil Service as a Senior Energy Analyst.

Q. Please describe your business and educational background.

A. I received my Bachelor of Arts degree in Economics from the University of Massachusetts. Before joining Unitil Service, I worked as a Contracting and Transaction Analyst with Mint Energy, a retail electric supplier. My range of responsibilities included contract negotiation with brokers and customers, retail billing, and sales. Prior to Mint Energy, I worked as a data analyst for Energy Services Group. My responsibilities included supplier business transaction testing and integration with regulated utilities. I joined Unitil Service in February 2016 as an Energy Analyst with the Energy Contracts department. In January 2019 I was promoted to my current position as Senior Energy Analyst. I have primary responsibilities in the areas of load settlement, renewable energy credit procurement, renewable portfolio standard compliance, default service procurement, market research and operations, and monitoring renewable energy policy.

Q. Have you previously testified before the Commission?

A. Yes, I have testified before the Commission in Default Service Solicitation proceedings.

Q. What is the purpose of your testimony and how is it organized?

A. As discussed in the testimonies of Messrs. Sprague and Dusling, the Company is proposing to construct, own, and operate a 4.99 megawatt ("MW") alternating current ("AC" or "ac") utility-scale solar generating facility in Kingston, New Hampshire pursuant to New Hampshire Revised Statutes Annotated ("RSA") 374-G (the "Kingston Solar Project" or the "Project"). Among other things, RSA 374-G requires electric utilities to provide an analysis of the benefits and costs ("Benefit-Cost") of proposed Distributed Energy Resource ("DER") projects, and the associated rate implications. The purpose of our testimony is to present the Company's Benefit-Cost Analysis and the estimated bill impacts associated with the Kingston Solar Project.

Section II provides an overview of the Company's methodological approach to the Benefit-Cost Analysis. Section III provides a detailed discussion of the estimated costs for the Project. Section IV provides a detailed discussion of the estimated benefits of the Kingston Solar Project. Section V discusses the results of the Benefit-Cost analysis. Section VI presents the Company's cost recovery proposal and the estimated bill impacts for the Project. Lastly, Section VII is the conclusion.

II. OVERVIEW OF BENEFIT-COST ANALYSIS

Q. Please provide an overview of the methodology the Company employed in its Benefit-Cost Analysis.

A. Whether it be explicit or implicit, investment decisions generally involve a comparison of benefits and costs. A Benefit-Cost Analysis is a systematic approach for calculating and comparing the estimated benefits and costs of a project to determine the extent of net benefits (the excess of benefits over costs). In many cases, project benefits accrue over many years while capital costs, which often represent a significant portion of total costs, are incurred primarily in the initial years. Therefore, the benefits and costs estimated over an analysis period are discounted to calculate the net present value ("NPV") of benefits and costs so they may be compared. The present value of the benefits and costs can be compared to calculate a benefit-cost ratio and if this ratio is greater than 1.00, it generally indicates the proposed investment is worth undertaking. The Company applied this methodological approach in the Benefit-Cost Analysis discussed below. The benefits and costs included in this analysis were viewed from the vantage point of the Company's customers.

Q. Does RSA 374-G require a Benefit-Cost Analysis?

A. As part of the minimum filing requirements for a DER investment, RSA 374-G:5, I(b) requires a discussion of the costs, benefits, and risks of the proposal, with specific reference to the public interest factors (set forth in RSA 374-G:5, II) that must be considered by the Commission. This discussion should include an analysis of the costs and benefits of the project to participating customers, the utility's default service customers, and its distribution customers. The public interest factors that must be considered by the Commission include a quantitative analysis of the benefits and costs to the utility's customers (RSA 374-G:5, II(g)), whether the expected economic benefits outweigh the economic costs (RSA 374-G:5, II(h)), and the costs and benefits to any participating customers (RSA 374-G:5, II(i)).

Q. Please briefly explain the benefits and costs included in the Benefit-Cost Analysis.

A. In brief, the benefits included in the economic analysis are direct benefits that will accrue to all customers. The costs included in the model (Exhibit FDGP-2) reflect the revenue requirement associated with owning and operating the Project. Partially offsetting the revenue requirement is the benefit of the Investment Tax Credit ("ITC"), which is discussed in further detail later in this testimony.

Q. Please describe the classification of benefits reflected in the Company's filing.

A. For purposes of analysis and discussion, the Company has divided the Project's expected benefits into two categories: (1) "direct benefits" and (2) "indirect benefits." Direct benefits are readily quantifiable because there are well-established markets or indices with accessible data and/or prices that can be relied upon to monetize benefits that will accrue directly to customers. Indirect benefits, on the other hand, seek to quantify benefits that flow to society more broadly. Although indirect benefits may be more complicated to quantify, they are as real and valid as those that are readily quantifiable.

Q. What is the analysis period over which the Company discounted the estimated costs and benefits of the Project?

A. The Company assumed a 30-year life, based on input from the contractors who responded to the Company's Request for Information ("RFI") and the preliminary engineering, procurement, and construction Request for Proposals ("Preliminary EPC RFP"), which are discussed in the testimony of Mr. Dusling.

Q. What discount rate was used in the Benefit-Cost Analysis?

A. The Company used its weighted average after tax cost of capital of 6.71 percent as the discount rate for the estimated costs and the direct benefits of the Project. The weighted average after tax cost of capital of 6.71 percent incorporates the most recently approved capital structure and cost of capital by the Commission as part of a settlement agreement in the Company's most recent base distribution rate case.[1] The Company's consultant, Daymark Energy Advisors ("Daymark"), presents the quantification of indirect benefits in Exhibits GPP-1 and GPP-2, as well as the discount rates applied in those calculations.

Q. Has the Commission provided any guidance with respect to the discount rate that should be used in the Benefit-Cost Analysis?

A. Yes, the Commission has. In DE 09-137, the Commission held that, as a general

[1] *See*, *Unitil Energy Systems Inc.*, DE 21-030, Order No. 26,623, at 32-33 (May 3, 2022); Settlement Agreement Attachment, Schedule RevReq-5; Schedule RevReq-3-21, page 1 of 4.

matter, the same discount rate should be used to calculate the present value of both costs and benefits.[2] The Commission further held that, for consistency, it is appropriate to use the after tax cost of capital as the discount rate.[3]

In DE 09-137, the Commission further held that there may be times when it is appropriate to use other discount rates as part of a secondary analysis provided the petition provides justification for such alternative discount rate analyses.[4] As Daymark explains, that is the case in calculating the present value of indirect benefits.

Q. Has the Commission provided any guidance with respect to the incorporation of indirect benefits into a Benefit-Cost Analysis?

A. Yes. In DE 09-137, the Commission held that it is appropriate to include indirect benefits in the Benefit-Cost Analysis after first considering direct and readily quantifiable benefits. In addition, the Commission held that in situations where projects may be marginally uneconomic based on direct benefits alone, it will allow reasonable estimates of indirect benefits to be considered and, if appropriate, to support a public interest finding.[5]

The indirect benefits associated with the Project are discussed in detail in the joint testimony of Ms. Gilbert and Mr. Pierce. As discussed below, the Project's Benefit-

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[2] Order No. 25,111, at 33.
[3] Order No. 25,111, at 33.
[4] Order No. 25,111, at 33.
[5] Order No. 25,111, at 35.

Cost ratio exceeds 1.00 without considering indirect benefits—therefore, those (indirect) benefits serve to further increase the Project's already positive benefits and reinforce a finding that the Project is in the public interest.

Q. Is the Company's Benefit-Cost Analysis approach consistent with past practice before the Commission?

A. Yes. In the context of the DE 09-137 proceeding, the Company and Commission Staff agreed that an accurate estimate of project economics would be achieved by comparing lifetime benefits to lifetime revenue requirements.[6] The Company employed the same approach in this filing.

Q. Do the benefits of the Project outweigh the costs?

A. Yes, the direct benefits outweigh the costs over the Project's 30-year investment horizon.[7] As explained in greater detail in Section V of this testimony, the Project yields a positive NPV of approximately $1.4 million and a Benefit-Cost Ratio of greater than 1.0.[8]

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[6] *Unitil Energy Systems Inc.*, Order No. 25,111, at 10, 20, 33 (June 11, 2010).
[7] As discussed below, the Project's useful life may exceed 30 years.
[8] Here, the positive Net Present Value may be seen as a positive Present Value of net benefits.

III. KINGSTON SOLAR PROJECT COST ESTIMATES

Q. How is the Company calculating the total costs of the Kingston Solar Project in the context of its Benefit-Cost Analysis?

A. The cost included in the analysis is the 30-year revenue requirement associated with owning and operating the PV facility.

As shown in Exhibit FDGP-2, Schedule 1, UES has calculated a Year 1 revenue requirement of $1.82 million which declines over the life of the Project to a cost of $0.55 million in Year 30. The annual revenue requirement steadily declines due to ongoing depreciation, which has the effect of reducing Rate Base.

Q. Does RSA 374-G provide direction regarding the project-related costs that may be recovered?

A. Yes. RSA 374-G:5, III provides that recovery for authorized and prudently incurred costs shall include recovery of depreciation, a return on investment, taxes, and operating and maintenance ("O&M") expenses directly associated with the investment, net of any offsetting revenues directly attributable to the investment.

RSA 374-G:5 further provides that the Commission may add an incentive to the return on investment component as it deems appropriate to encourage investments in DERs.

Q. What cost elements are included in the Company's revenue requirement?

A. The revenue requirement consists of the pre-tax return on Rate Base, O&M expense, Depreciation expense, Property Tax expense, and activity associated with crediting the benefit of the ITC to customers. The cost components of the revenue requirement are summarized on Exhibit FDGP-2, Schedule 3.

Q. Has the Company requested an incentive return?

A. No, it has not.

Q. Please provide an overview of the Project's Rate Base.

A. The determination of Rate Base for the Project begins with gross plant, which consists of the estimated capital spending explained below. Net plant is then calculated as gross plant less accumulated depreciation. Lastly, rate base is calculated by reducing net plant by accumulated deferred income taxes.

Q. Please explain the capital costs included in the Benefit-Cost Analysis.

A. The capital costs included in the analysis are discussed in detail in the testimony of Mr. Dusling. For economic modeling purposes, the Project's capital costs are categorized as follows: PV Facility Installation, Solar Inverter 1, Solar Inverter 2, Electric System Upgrades, Land Improvements, and Land Acquisition costs.

KINGSTON SOLAR PROJECT CAPITAL COST CATEGORIES
• PV Facility Installation • Solar Inverter 1 • Solar Inverter 2 • Electric System Upgrades • Land Improvements • Land Acquisition

Unlike the other PV Facility Installation costs, the Solar Inverters have an assumed 15-year life and as such must be modeled differently than the other Facility Installation costs which have a 30-year life. Solar Inverter 2 represents the replacement cost of Solar Inverter 1 at the end of its useful life in Year 15. The economic modeling also assumes that 50 percent of the Land Acquisition costs will be transferred to UES for the Project, which is explained in the testimony of Mr. Dusling. The total capital costs included in the Benefit-Cost Analysis in Year 1 are $13.2 million and are detailed in Exhibit FDGP-2, Schedule 11. As noted above, this capital spending serves as the basis for gross plant in the rate base calculation.

Q. Please explain the calculation for Return and Taxes on Rate Base.

A. We calculate the Return and Taxes on Rate Base by applying a pre-tax rate of return of 9.18 percent to the average Rate Base balance. Average rate base is the simple average of current and prior year balances. The pre-tax rate of return represents the Company's most recently approved capital structure and cost of capital in DE 21-030. Income tax expense is included in this calculation by grossing up the cost of equity by a factor of 1.3685 to account for the effective tax rate of 26.93 percent associated with both state and Federal taxes (*See* Exhibit FDGP-2, Schedule 12).

Q. Please explain the Operating Expenses included in the Revenue Requirement in the Benefit-Cost Analysis.

<u>O&M Expense</u>

Based on information provided in response to the Preliminary EPC RFP, the

Company estimates Year 1 O&M expense at [redacted] escalated at 2.5 percent annually (*See* Exhibit FDGP-2, Schedule 4).

<u>Depreciation Expense</u>

Book depreciation expense is calculated using the straight-line depreciation method. As noted above, the PV facility and system upgrades are assumed to be 30-year property and the inverters are assumed to be 15-year property. The forecasted capital spending in each respective 30-year and 15-year asset category is multiplied by the annual depreciation rate, 3.33 percent in the case of the 30-year property and 6.66 percent for the 15-year property. In Year 16, depreciation expense increases slightly to account for the cost of the replacement inverter (Solar Inverter 2).

The Land Improvements and Land Acquisition costs are non-depreciable plant additions. As noted above, Accumulated Depreciation is derived by the calculation of Depreciation expense and is included in the calculation of Net Plant and Rate Base. Exhibit FDGP-2, Schedule 7.

<u>Property Tax Expense</u>

The Property Tax expense included in the model is a function of Net Plant multiplied by an assumed Property Tax Rate of $27.88 (per $1,000 of value).

The assumed tax rate is the sum of the current property tax rate in Kingston of $21.28 and the current State Rate of $6.60 (*See* Exhibit FDGP-2, Schedule 5).

Q. Please discuss the Investment Tax Credit and how it is reflected in the Revenue Requirement.

A. The Company expects the Project, under current guidance, to qualify for a 30 percent federal ITC for certain eligible facilities. The Inflation Reduction Act ("IRA"), signed into law on August 16, 2022, extended the energy ITC for solar electricity production facilities beginning construction before January 1, 2025. The ITC begins at 30 percent and steps down to 26 percent in 2033 and 22 percent in 2034.

Based on the current capital cost estimates, the Company expects the Project will generate ITCs totaling approximately $3.5 million. For purposes of the Benefit-Cost model, the Company reduces the Revenue Requirement by amortizing the ITC over the life of the facilities that generated the credits. There is also a tax Gross Up associated with the amortization of the ITC. In Year 1, the ITC Amortization and Gross Up reduces the Revenue Requirement by approximately $160,000. Also included in the Revenue Requirement is the ITC Tax Effect and associated tax Gross Up. The ITC Tax Effect is included to recover the tax impact of the permanent book-tax difference that arises due to the ITC. The federal investment tax basis is reduced by 50 percent of the ITC resulting in lower book depreciation expense than federal tax depreciation. In Year 1, the ITC Tax Effect and Gross Up increases the Revenue Requirement by approximately $17,000.

This approach is consistent with the methodology for flowing back the ITC to customers pursuant to Generally Accepted Accounting Principles and prevailing tax laws. The Company also is exploring options to further maximize the value of the ITC for customers. Specifically, the IRA authorizes taxpayers to transfer the ITC to other taxpayers in exchange for cash. In addition, if components of a qualified facility are deemed to have been produced in the United States, the ITC can be increased above 30 percent. These potential structures could reduce the amount of capital that UES would otherwise include in rate base, which in turn would reduce the Project's overall revenue requirement and increase its Benefit-Cost ratio.

IV. KINGSTON SOLAR PROJECT BENEFITS

Q. How is the Company measuring the total benefits of the Kingston Solar Project in the context of its Benefit-Cost Analysis?

A. The Company is including direct benefits (summarized in the table below) that will accrue to customers over the course of the 30-year Project. In Year 1, the Company estimates customers will realize direct benefits of approximately $1.5 million.

KINGSTON SOLAR PROJECT BENEFITS
Direct Benefits
• Avoided Energy Costs
• Avoided Capacity Costs
• Local Transmission Benefits
• Regional Transmission Benefits
• Renewable Energy Certificate ("REC") Savings

Q. Please discuss each direct benefit the Company has included in the Benefit-Cost Analysis.

A. **Avoided Energy Costs**

As discussed in the testimony of Mr. Dusling, the Company's estimate of the annual electricity production from the Kingston Solar Project is shaped by two factors: (1) the capacity factor and (2) the degradation factor.

The capacity factor is the ratio of actual electricity produced to the electricity that could have been produced at continuous full power operation during the same period. For purposes of the Benefit-Cost Analysis, the Company assumed the Project will operate at an approximately 22 percent capacity factor.

The degradation factor represents the percentage by which the energy production of the solar panels is expected to decrease over time. For purposes of the Benefit-Cost Analysis, the Company assumed an annual degradation factor of 0.5 percent.

As shown in Exhibit FDGP-2, Schedule 2, by applying those capacity and degradation factors to the Project, the Company has calculated energy output of 9,600,000 kWh in Year 1 declining to 8,208,000 kWh by Year 30.

As Mr. Dusling explains, the Kingston Solar Project will operate as a load reducer, meaning the facility will not participate in wholesale markets. Rather, the electricity output will offset energy that otherwise would be received by UES from the transmission system. The avoided energy costs represent the avoided cost of purchasing power from the market to meet the needs of customers that now would be generated by the Project.

The Company calculated this benefit as the product of the annual electricity production and an annual estimate of the price of electricity. As shown in Exhibit FDGP-2, Schedule 2, the Company used the "ISO New England MASS HUB 5 MW LMP Futures" to extrapolate electricity prices for the first four years of the Project. For the balance of the project life, the Company escalated the ISO New England ("ISO-NE") futures prices beginning in Year 5 by 2 percent, which is the long-run annual growth rate included in Energy Information Administration's 2022 Annual Energy Outlook for end-use prices ("Escalation Rate"). This escalation also is consistent with the Federal Reserve's target inflation rate. As shown in Exhibit FDGP-2, Schedule 2, the avoided energy costs are the most significant quantitative benefit generated by the Kingston Solar Project.

Avoided Capacity Costs

As a load reducer, the Kingston Solar Project will reduce capacity from the perspective of the ISO-NE market. Based on information provided in response to the Preliminary EPC RFP, the Company estimated that the generating capacity of the Project would be 1,850 kW (i.e., approximately 37 percent of nameplate capacity) during the annual historical ISO-NE peak hour. As shown on Exhibit-FDGP-2, Schedule 2, the Company calculated the avoided capacity costs as the product of the generation output at the peak hour and the estimated capacity clearing price. The Company's estimated capacity clearing prices for years 1 through 12 are the levelized rate from the 2021 Avoided Energy Supply Components in New England Report (the "AESC Report").[9]

As shown in Exhibit FDGP-2, Schedule 2, from Year 13 through Year 30, the Company escalated the levelized capacity value from the AESC Report using the previously described Escalation Rate.

Local Transmission Benefits

Based on information provided in response to the Preliminary EPC RFP, the Company estimated the Kingston Solar Project's generation output during the monthly peak hour to be approximately 600 kW (i.e., approximately 12 percent of nameplate capacity). As shown on Exhibit FDGP-2, Schedule 2, the Company calculated the Year 1 local transmission benefits as the total of: (1) the product of the generation output at the monthly peak hour and the annualized transmission rate ($/MWh) and (2) the product of the generation output at the monthly peak hour and the annualized ancillary services rate ($/MWh). The Company escalated the

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[9] AESC Report, at 13, *available at* https://www.synapse-energy.com/avoided-energy-supply-costs-new-england-aesc. The AESC Report calculated four "counterfactuals", each of which represents a hypothetical future that lacks some amount of anticipated demand-side measures. AESC Report, at 1. For purposes of the capacity value assumption, the Company utilized the AESC's Counterfactual #1 prices. Counterfactual #1 represents a future in which program administrators install no new energy efficiency, building electrification, or active demand management (demand response and energy storage) resources in 2021 or later years. Id. For the current program year (and upcoming Program Year), the New Hampshire Energy Efficiency programs are using the 2021 AESC Counterfactual #1 for the avoided capacity costs.

transmission and ancillary services rates for the remaining 29 years of the projected life of the facility by the previously described Escalation Rate.

The transmission and ancillary service rates are based on the most recent bill from Eversource to UES setting forth the local service rate for Schedule 21-ES (Part A) Tariff Service. Eversource is the transmission provider to UES for the Kingston, New Hampshire service area.

Regional Transmission Benefits

To quantify regional transmission benefits, the Company used the same production assumptions described above for local transmission – that is, it – assumed production of 600 kW during the monthly system peak hour. As shown on Exhibit FDGP-2, Schedule 2, the Company calculated the Year 1 regional transmission benefits as the total of: (1) the product of the generation output at the monthly peak hour and the Open Access Transmission Tariff (“OATT”) Schedule 1 Regional Network Service Rate; (2) the product of the generation output at the monthly peak hour and the OATT Schedule 5 Regional Network Service Rate; (3) the product of the generation output at the monthly peak hour and the ISO Schedule 1 Regional Network Service (“RNS”) Rate; and (4) the OATT Schedule 9 Rate. The Company escalated the ISO-NE transmission rates for the remaining 29 years of the facility using the previously described Escalation Rate.

Renewable Energy Certificates

The New Hampshire Renewable Portfolio Standard ("RPS") was created to stimulate investment in low-emission, renewable energy generation, like the Kingston Solar Project. The RPS requires retail electricity suppliers, including UES with respect to providing Default Service, to purchase a certain percentage of the electricity they supply from renewable energy sources every year. A REC represents one megawatt hour of energy generated by an eligible renewable source. Providers of electricity may acquire RECs either by generating energy from a qualified renewable generation unit or by purchasing RECs in the market. Alternative Compliance Payments can be made to satisfy RPS obligations in the absence of RECs being generated or procured.

The Kingston Solar Project will generate RECs that will be retained to either meet UES's Default Service RPS obligations or sold into the market and credited back to customers. The Company will first apply any RECs produced by the Project to the Company's RPS obligations associated with its default service load. Applying the RECs produced by the facility to RPS obligations results in administrative savings by reducing the management and transaction fees that would result if the Company were to sell the RECs produced by the Kingston Solar Project into the market and separately purchase comparable RECs from the market. Any RECs produced by the facility in excess of Default Service RPS requirements would be sold into the market. In any case, as explained later in our testimony, the revenue received from the sale of RECs generated by the Project will be credited to all UES customers, regardless of whether they purchase delivery service supply from UES or competitive supply from a Competitive Electric Power Supplier.

New Hampshire's RPS statute divides renewable energy sources into four separate classes with solar generation like the Kingston Solar Project, falling into the Class II category. The Company estimated REC revenues as the product of the facility's electricity (MWh) output and the estimated value of RECs. The Company estimated the REC value at [redacted], which is based on a recent quote from a REC broker. The Company assumed the [redacted] REC value remains fixed over the Project's 30 year life.

Q. Does the Company's filing also contain a discussion of indirect benefits?

A. Yes. As noted above, the joint testimony of Ms. Gilbert and Mr. Pierce provides a discussion of the methods used to quantify the indirect benefits.

Q. Please briefly summarize the Indirect Customer benefits.

A. As discussed in Exhibits GPP-1 and GPP-2, Daymark has quantified three indirect benefits: economic benefits, emissions reduction benefits, and Demand Reduction Induced Price Effects ("DRIPE") benefits. Daymark estimates the Project will generate $11.2 million dollars of direct, indirect, and induced economic benefits, on an NPV basis. For CO_2 and NOx benefits, Daymark estimates a total benefit of $1.8 million on an NPV basis. Lastly, Daymark's DRIPE analysis shows the aggregate benefits to New Hampshire load would be $566,963 on an NPV basis. These indirect benefits reinforce the viability of the Kingston Solar Project.

V. DISCUSSION OF BENEFIT-COST ANALYSIS RESULTS

Q. Please summarize the results of the Company's Benefit-Cost Analysis.

A. As shown in Exhibit FDGP-2, Schedule 1, the present value of the Project's benefits is approximately $17.7 million and the present value of the costs is approximately $16.3 million. This produces a Benefit-Cost ratio of 1.09. The Project has a strong Internal Rate of Return of 11.15 percent, indicating a positive NPV.

Q. Earlier you mentioned that the IRA may provide the ability to transfer the Project's ITCs to a third party. How might such a transaction affect the Benefit-Cost Analysis and the results?

A. Tax normalization rules from the IRS have limited the ability of utilities to maximize the ITC benefit for their customers. Normalization requires the utility to pass the value of the ITC back over the life of the asset that generated the credit rather than immediately realizing the benefit. Without normalization, customers could receive immediate economic value as initial Rate Base would be lowered by the ITC. For illustrative purposes, if the Company were able to reduce Rate Base by the expected ITC at the outset of the Project, the NPV would increase by approximately $2.8 million, the Benefit-Cost ratio would increase to approximately 1.3, and the discounted payback period would significantly shorten. As mentioned earlier, the IRA will allow companies to transfer the ITC to other tax payers in exchange for cash. Because the IRA was only recently passed, it is unclear whether transferring the ITC will allow utilities to avoid IRS normalization rules. The Company will continue to investigate this potential pathway to ensure ratepayers receive the maximum economic value.

Q. Is it reasonable that the PV facility could continue to provide customer benefits after Year 30?

A. Yes. Based on conversations with PV contractors it is reasonable to assume a useful life greater than thirty years. Thirty years represents the length of solar module warranties, not necessarily when they become obsolete. System efficiency is modeled to be reduced to 85.5 percent in Year 30 and still producing customer benefits in excess of $1.6 million. It is likely that the Project will continue to provide benefits to customers even past its warranty period, further supporting the Project's value proposition.

Q. In addition to the direct and indirect benefits discussed above, is there any other value this Project could provide to customers?

A. Yes. If the Project is deemed to be in the public interest, the Company will investigate pairing it with an Energy Storage System. Energy storage could positively augment the economic value of the Project by shifting the Project's output closer to the peak periods, further lowering supply and transmission charges.

VI. COST RECOVERY AND BILL IMPACTS

Q. Does RSA 374-G specify how the costs of DER investments made pursuant to the statute should be recovered?

A. Yes. RSA 374-G, III provides that authorized and prudently incurred investments shall be recovered in a utility's base distribution rates as a component of rate base.

Q. What is the Company's proposal with regard to recovering the costs of the Kingston Solar Project?

A. As discussed in the testimony of Mr. Sprague, the Company is seeking the Commission's approval of a two-step regulatory review process. In this filing (Stage One), the Company is requesting that the Commission find that the Kingston Solar Project is in the public interest. In Stage Two, the Company will seek recovery of the Project's costs. The Company plans to request rate recovery in the context of its next base distribution rate case or a subsequent step adjustment.

Q. Does RSA 374-G require project proponents to calculate estimated bill impacts?

A. Yes. RSA 374-G:5, I (b) requires electric utilities to include an analysis of rate implications to participating customers, the company's default customers, and the utility's distribution customers for all proposed projects. In DE 09-137, the Commission reinforced the importance of this minimum filing requirement and stated that all future filings must include the estimated rate impacts required by RSA 374-G:5, I (b).[10]

Q. Have you provided the bill impacts associated with the Kingston Solar Project as required by the statute?

A. Yes, bill impacts by rate class associated with the Kingston Solar Project have been provided as Exhibit FDGP-3.

Q. Please summarize the bill impacts provided in Exhibit FDGP-3.

A. Page 1 of Exhibit FDGP-3 provides the bill impacts for an average customer within each rate class. Bill impacts will vary based on usage above or the below the average usage.

As shown on line 7, in Year 1 an average Residential customer would see an increase in their monthly bill of $0.18 per month after accounting for the cost and the direct benefits of the project. In Year 30, an average Residential customer would see a decrease in their monthly bill of $0.59 per month.

As shown on line 14, in Year 1 an average Regular General Service G2 kWh meter customer would see an increase in their monthly bill of $0.03 per month after accounting for the cost and direct benefits of the project. In Year 30, an average Regular General Service G2 kWh meter customer would see a decrease in their

[10] DE 09-137, Order No. 25,111, at 29.

monthly bill of $0.09 per month.

As shown on line 21, in Year 1 an average Uncontrolled (Quick Recovery) Water Heating customer would see an increase in their monthly bill of $0.41 per month after accounting for the cost and direct benefits of the project. In Year 30, an average Uncontrolled (Quick Recovery) Water Heating customer would see a decrease in their monthly bill of $1.35 per month.

As shown on line 30, in Year 1 an average Regular General Service G2 customer would see an increase in their monthly bill of $0.69 per month after accounting for the cost and direct benefits of the project. In Year 30 an average Regular General Service G2 customer would see a decrease in their monthly bill of $2.29 per month.

As shown on line 39, in Year 1 an average Large General Service G1 customer would see an increase in their monthly bill of $44.58 per month after accounting for the cost and direct benefits of the project. In Year 30 an average Large General Service G1 customer would see a decrease in their monthly bill of $147.94 per month.

As shown on line 46, in Year 1 an average Outdoor Lighting customer would see an increase in their monthly bill of $0.02 per month after accounting for the cost and direct benefits of the project. In Year 30 an average Outdoor Lighting customer would see a decrease in their monthly bill of $0.07 per month.

Q. Please explain the calculation detail that has been provided on page 2 of Exhibit FDGP-2.

A. Page 2 provides the calculation detail that converts the Project's direct benefits into the rate impacts those benefits would produce.

Current transmission costs are collected in Schedule External Delivery Charge ("EDC") as a per kWh charge, so the direct benefit associated with a reduction in allocated transmission costs from Eversource would flow through the EDC by reducing the EDC rate.

To ensure that all customers receive the benefit from the sale of the RECs, the Company proposes that all REC revenue be included in the EDC. As shown on line 5, the impact to the EDC to capture these benefits would be a reduction of $0.00039 per kWh over the project life

The direct benefit associated with the reduction in capacity and energy cost would accrue to customers as lower energy service rates. As mentioned above, the benefits would be realized by all customers whether they are on default service or purchasing their energy service from a competitive supplier. To reflect that all customers would receive these benefits, the total cost reduction was divided by the total kWh sales of the Company. As shown on line 9, the impact on the energy service rate would be a reduction of $0.00090 per kWh in Year 1 with an average reduction over the life of the project of $0.00085 per kWh.

Q. Please further explain how the Company will account for the value of the RECs to ensure that all customers receive the benefit.

A. Earlier it was discussed how RECs would be used to either satisfy the RPS requirements associated with default service or sold into the market. If the RECs are used the satisfy the RPS requirements associated with default service, a transfer price will be established and charged to default service customers and a credit for the transfer price will be included in the EDC. If the RECs are sold into the market, the REC revenue would be included in the EDC. This will ensure that the benefit of the RECs generated by the Project would go to all customers whether they are sold into the market or are used to satisfy the RPS requirements of customers taking default service from the Company.

Q. Please explain the calculations provided on page 3 of Exhibit FDGP-3.

A. The calculations on page 3 adjust currently approved distribution energy rates to account for the revenue requirement associated with the Project. Since customers would realize direct benefits as a reduction to kWh charges, the revenue requirement was first allocated to each rate class based on the share of total company kWh sales. After the rate class allocated revenue requirement amount is determined, currently effective kWh and demand rates for each class were adjusted to recover the rate class share of the revenue requirement. The Company did not adjust the currently effective customer charges for any rate class.

As shown on line 14, in Year 1 the residential rate’s allocated portion of the revenue requirement would increase the distribution kWh charge from the currently effective charge of $0.04511 per kWh to $0.04668 per kWh.

As shown on line 22, in Year 1 the Regular General Service G2 kWh meter rate's allocated portion of the revenue requirement would increase the distribution kWh charge from the currently effective charge of $0.02933 per kWh to $0.03090 per kWh.

As shown on line 30, in Year 1 the Uncontrolled (Quick Recovery) Water Heating rate's allocated portion of the revenue requirement would increase the distribution kWh charge from the currently effective charge of $0.03599 per kWh to $0.03756 per kWh.

As shown on line 39, in Year 1 the Regular General Service G2 rate's allocated portion of the revenue requirement would increase the distribution kW demand charge from the currently effective demand charge of $11.91 per kW to $12.31 per kW. The rate currently has no distribution revenue collected through a kWh charge.

As shown on line 53, in Year 1 the Large General Service G1 rate's allocated portion of the revenue requirement would increase the distribution kVA demand charge from the currently effective demand charge of $8.40 per kVA to $8.90 per kVA. The rate currently has no distribution revenue collected through a kWh charge.

As shown on line 65, in Year 1 the Outdoor Lighting rate's allocated portion of the revenue requirement would increase the current average fixture charge of $16.71 to

$16.82. The rate currently has no distribution revenue collected through a kWh charge.

VII. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.