

BEFORE THE
STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

DOCKET DE 22-060

IN THE MATTER OF: Electric Distribution Utilities
 Consideration of Changes to the Current Net Metering
 Tariff Structure, Including Compensation of Customer-
 Generators

DIRECT TESTIMONY

OF

Alex Hill and Anirudh Kshemendranath

December 6, 2023

Table of Contents

| | |
|------------------------------------|----|
| Introduction..... | 3 |
| Purpose..... | 5 |
| Focus and Scope of VDER Study..... | 5 |
| VDER Study Methodology..... | 8 |
| VDER Data and Data Sources | 12 |
| VDER Sensitivity Analyses..... | 13 |
| VDER Study Findings | 16 |
| VDER Study Model..... | 20 |
| Net Metering Compensation..... | 22 |

1 **Introduction**

2 **Alexander James Hill**

3 **Q. Mr Hill, Please state your full name?**

4 A. My name is Alexander James Hill.

5 **Q. By whom are you employed, and what is your business address?**

6 A. I am employed by 6893449 CANADA INC (doing business as Dunsky Energy + Climate
7 Advisors), and my business address is 50 Ste-Catherine St. West, Suite 420 Montreal, QC,
8 H2X 3V4.

9 **Q. Please summarize your education and professional work experience.**

10 A. I have a Bachelor's degree in Chemical Engineering from McGill University in Montreal,
11 Quebec, Canada (Graduated 1996) and a Master's degree in Civil Engineering also from
12 McGill University (Graduated 2000). I joined Dunsky Energy + Climate Advisors (Dunsky)
13 as a Senior Consultant in 2012, and I became a Partner in the company in 2015. At Dunsky,
14 I lead two areas of practice: our Opportunity Assessment practice, which includes our various
15 distributed energy resources modelling and analytics work, as well as our Financing Practice,
16 through which we assist clients in providing strategic analysis, feasibility studies, program
17 designs and program evaluations. Prior to joining Dunsky, I performed various independent
18 renewable energy and energy efficiency consulting contracts over the 2009 to 2012 period.
19 From 2005 to 2010, I was the General Manager of Green Energy Benny Farm in Montreal,
20 Quebec, and in parallel, from 2007 to 2009, I was a Project Manager for Ecocité
21 Development in Montreal, Quebec. From 2000 to 2005, I worked as the Environmental
22 Program Manager at Alternatives Inc. in Montreal, Quebec.

23

1 **Anirudh Kshemendranath**

2 **Q. Mr. Kshemendranath, please state your full name.**

3 A. My name is Anirudh Kshemendranath.

4 **Q. By whom are you employed, and what is your business address?**

5 A. I am employed by 6893449 CANADA INC (doing business as Dunsky Energy + Climate
6 Advisors), and my business address is 555 Richmond St W #1110, Toronto, ON M5V 3B1.

7 **Q. Please summarize your education and professional work experience.**

8 A. I completed a Bachelor of Technology in Metallurgy and Material Science from the National
9 Institute of Technology, Nagpur, India, in 2013. I also obtained a Master of Science Degree
10 in Energy Science Technology and Policy from Carnegie Mellon University, Pittsburgh,
11 Pennsylvania, USA, completed in 2014. I have obtained a Master of Business Administration
12 (MBA) degree from Quantic School of Business and Technology, licensed by the District of
13 Columbia Higher Education Licensure Commission in Washington, DC, completed in 2021.
14 I have been a Consultant at Dunsky Energy and Climate Advisors since April 2022 and a
15 Senior Principal Analyst since August 2021. At Dunsky, I provide analytical and strategic
16 consultation on energy storage, solar adoption, the value of DERs, utility planning, and rate
17 design. Before that, I worked as an Independent Senior Principal Analyst with Dunsky
18 Energy and Climate Advisors from August 2019 to July 2022. Between November 2018 and
19 March 2019, I worked as a senior consultant at Fractal Energy Storage Consultants based in
20 Austin, Texas. From November 2015 to October 2018, I worked as a Consultant at Strategen
21 Consulting, Inc., a clean energy strategy consulting firm based in Berkeley, California.
22 During that time, I have supported policymakers in creating clean energy roadmaps, helped
23 energy developers evaluate the financial viability of their projects, and advised corporate

1 clients on market entry strategies for new or existing energy products. From February 2015
2 to October 2015, I worked at Robert Bosch Research and Technology Center North America
3 as Business Development Intern on both the direct current microgrids and the battery and
4 energy storage systems teams.

5

6 **Purpose**

7 **Q. What is the purpose of your testimony in this proceeding?**

8 A. The purpose of our testimony is to provide an overview of the Value of Distributed Energy
9 Resources study and its findings, along with the associated analytical tools.

10 **Q. Did you prepare the Final Report on the New Hampshire Value of Distributed Energy
11 Resources and Appendices (VDER Study) resources filed in this matter on October 31,
12 2022, at Docket Tab 9?**

13 A. We each played a central role in preparing the VDER study, alongside other colleagues who
14 worked at Dunskey at the time. Mr. Kshemendranath built the VDER analytical tools behind
15 the study, conducted the analysis, and contributed to the quantitative and narrative. Mr. Hill
16 acted as the internal project sponsor (titled Project Director at Dunskey) and, through that role,
17 led the team to develop the report outline and logical structure and conducted a full editorial
18 review of each iteration of the VDER report, providing input and direction to the content.

19

20 **Focus and Scope of VDER Study**

21 **Q. Please describe in brief terms the overall focus of the VDER Study.**

22 A. The VDER study assesses the value of behind-the-meter (BTM) Distributed Energy
23 Resources (DERs) that are owned by customers-generators and are eligible to participate in

1 net energy metering (NEM) programs within the service territories of the regulated
2 distribution utilities in New Hampshire. It provides an assessment of the relative benefits and
3 costs of net-metered distributed generation (DG) from the perspectives of the utility system
4 as a whole, DG customer-generators, and non-DG customers.

5 **Q. Did you perform the VDER Study in accordance with a predetermined scope?**

6 A. Yes.

7 **Q. Where did the predetermined VDER Study scope come from?**

8 A. The scope for the VDER Study was formally established in the New Hampshire Public
9 Utilities Commission (Commission) Order No. 26,316 (December 2019 Order). It was then
10 provided as Appendix A in REQUEST FOR PROPOSALS (RFP) RFP #2020-001 issued by
11 the Commission on March 27, 2020, to which Dunsky submitted a proposal to conduct the
12 VDER Study to meet the predetermined scope.

13 **Q. Please describe in brief terms the scope of the VDER Study.**

14 A. The VDER Study scope prescribes developing net present value avoided cost estimates over
15 a 15-year forward-looking period resulting from NEM-eligible DERs that are interconnected
16 to a New Hampshire-regulated distribution utility. The assessment provides an estimate of
17 the direction and magnitude of net avoided costs as well as the direction and magnitude of
18 rate and bill impacts of DG deployment to identify any potential cost-shifting between DG
19 customer-generators and non-DG customer. It does not propose to represent an exact
20 projection of future electricity rates and utility cost recovery, nor provide proposed exact
21 compensation rates for NEM DG-customer-generators. The scope dictates that the study
22 assesses the relative benefits and costs of NEM DERs from the perspective of the utility
23 system as a whole and utility ratepayers' perspective (both NEM DG customer-generator and

1 non-DG customers). The study was to focus on load reduction values and maintain
2 consistency with standard benefit-cost analysis criteria as applied for energy efficiency
3 resources in the state, applying the Utility Cost Test (UCT) and a customer rate and bill
4 impact analysis.

5 The VDER Study scope outlines nineteen (19) Avoided Cost criteria to be evaluated through
6 a value-stack approach, as determined through a stakeholder process and approved by the
7 Commission. The scope prescribes that 3-5 years of historical data be applied where possible
8 to validate future projections, along with data from the most recent Avoided Energy Supply
9 Cost (AESC) in New England study and the Locational Value of Distributed Generation
10 study, to formulate inputs as appropriate. The avoided costs also include a number of “hard-
11 to-quantify” criteria proposed to be evaluated through either quantitative proxy values or
12 qualitative review. Net avoided costs were to be presented on a net present value basis using
13 appropriate discount rates.

14 Certain avoided costs contributing to the VDER are time and/or location dependent. For each
15 avoided cost criterion applied, hourly avoided cost values accounting for time and locational
16 dependencies (where appropriate) were to be developed, thereby enabling a technology-
17 neutral analysis of marginal avoided cost components. After developing a technology neutral
18 avoided cost analysis for hourly load reduction across the study time period, distributed
19 generation (DG) production curves were to be used to determine avoided costs for various
20 DG technologies, specifically solar photovoltaic and hydroelectric as contemplated by Order
21 No. 26,029. The scope also includes sensitivity analyses to determine the demonstrable and
22 quantifiable net benefits associated with relevant externalities, such as environmental benefit,
23 while adequately mitigating the potential for double-counting such externalities. The scope

1 also included development of net DG customer-generator installed costs (including
2 incentives) which could be used in future proceedings to evaluate how NEM compensation
3 rates may impact opportunities to invest in DG in the state and receive fair compensation.
4 The VDER study scope also included a consumer rate and bill impact (RBI) assessment, to
5 determine the effects on utility ratepayers and the potential for cost-shifting between
6 customers participating and those not participating in net metering.

7
8 **VDER Study Methodology**

9 **Q. Please provide a brief overview of the methodology used in conducting the VDER**
10 **Study.**

11 A. The VDER study methodology framework can be summarized by five high-level steps,
12 outlined below: First, technology-neutral avoided cost values were established (step 1). Next,
13 DER production curves were developed for each resource type (step 2), and the technology-
14 neutral avoided costs were applied to the resulting production curves to calculate the avoided
15 cost value of DERs by system type (step 3). Avoided cost values were also calculated under
16 sensitivity cases, including consideration of environmental externalities, high load growth
17 scenarios, and a market resource value scenario (step 4). In addition to the value stack
18 components, we calculated the net present cost for each system type, considering upfront and
19 operational costs to DG customer-generator as well as available incentives. Because this
20 study focuses on avoided utility system costs, these DG customer-generator costs are not
21 included in base values, however the study scope contemplated that in the future, those
22 estimated costs could be used to assess the cost-effectiveness of DER systems from the
23 perspective of DG customer-generators against alignment with a reasonable compensation

1 rate. Finally, the rate and bill impacts were assessed, determining how DER deployment and
2 compensation will affect New Hampshire rates and customer bills (step 5).

3 The RBI assessment provides high-level insight into the impact of DG deployment in New
4 Hampshire on ratepayers, considering the benefits received and the costs incurred by the
5 utilities as a result of incremental DG additions (which, for the purpose of this analysis, are
6 limited to solar PV systems), and considering how those values are passed on to ratepayers.

7 The RBI methodology can be summarized by four high-level steps. As the first step, solar PV
8 system archetypes are defined for each utility (Eversource, Unitil, and Liberty) and for
9 representative rate classes (residential, small commercial, and large commercial). Next, the
10 incremental impacts associated with future DG deployment were evaluated, applying
11 forecasts from the Independent System Operator-New England (ISO-NE), which assumes
12 that 140 MW of additional DG (solar PV) will be deployed in New Hampshire between 2021
13 and 2030. The future deployment of DG is expected to create both upward pressure on rates
14 (due to lost utility revenues and program cost recovery, and downward pressure on rates (due
15 to avoided utility costs). As the third step, the impact on retail rates was assessed. To
16 illustrate the impacts of different potential DG program designs on ratepayers, changes to
17 rates were assessed under two scenarios for DG compensation:

18 (1) Alternative NEM Tariff Scenario: Assumes DG exports are compensated at a rate that is
19 in alignment with the current alternative NEM tariff compensation rates in the state

20 (2) Avoided Cost Value Stack (ACV) Tariff Scenario: Assumes that DG exports are
21 compensated at an avoided cost rate that is in alignment with the calculated value stack
22 assessment.

1 Finally, the impact on customers' bills was assessed as an indication of the overall impact to
2 customers, and to determine any potential cost-shifting. Changes to bills are assessed under
3 two scenarios: the NEM scenario and the ACV scenario described above. The results are
4 largely focused on presenting the average percent increase/decrease in customers' monthly
5 bills attributable to DG from 2021 to 2035 for each of the typical customer archetypes to
6 indicate the long-term impacts of DG on utility customers.

7 In keeping with the study goals of maintaining consistency with energy efficiency cost-
8 effectiveness evaluation, avoided cost values from the AESC study (2021 edition) were used
9 wherever possible. For avoided cost criteria that are not included in the AESC study, relevant
10 inputs were gathered through a combination of New Hampshire utility data requests, utility
11 interviews, and literature reviews. In the updated addendum (submitted on 8th June 2023, Tab
12 43 in DE 22-060), across all criteria, prices were adjusted to real 2024 dollars and \$/kWh
13 values were calculated for each hour of the study (8,760 hours per year, years 2024-2035).
14 Based on data availability, value stack components were evaluated using 1) AESC study, 2)
15 Quantitative methods unrelated to AESC, or 3) Qualitative review. The following cost
16 components were assessed using the AESC data, methods, and results: Avoided Energy,
17 Avoided Capacity, Avoided Ancillary Services and Load Obligation Charges, Avoided RPS
18 Compliance Charges, Avoided Transmission and Distribution Line Losses, Wholesale
19 Market Price Suppression Benefits, Avoided Wholesale Risk Premium and Environmental
20 Externality Benefits. Other value stack components were evaluated using quantitative
21 methods unrelated to AESC; these include Avoided Transmission Charges, Avoided
22 Distribution Capacity Costs, Distribution System Operating Expenses, and Distribution
23 Utility Administration Costs. Due to data limitations, four value components were not

1 quantified; instead, a qualitative review was applied as per the predetermined scope
2 description discussed earlier in this testimony. These include the Avoided Transmission
3 Capacity, Avoided Transmission and Distribution System Upgrades, Distribution Grid
4 Support Services and Resiliency Services, and as a result, they were not captured in the
5 technology-neutral avoided value stack.

6 Eight distributed energy resources were assessed in this study. These include small hydro,
7 behind-the-meter residential south-facing solar, behind-the-meter residential west-facing
8 solar, behind-the-meter commercial south-facing solar, behind-the-meter commercial west-
9 facing solar, front-of-the-meter solar, behind-the-meter residential south-facing solar coupled
10 with energy storage, and behind-the-meter commercial south-facing solar coupled with
11 energy storage.

12 Some criteria were not included in the total avoided cost value stack but were assessed to
13 contribute to other aspects of the VDER study. The Environmental Externalities were
14 applied as a sensitivity to the avoided cost value stack; these represent benefits/costs not
15 already included in energy prices and external to utility system valuation and are not
16 currently included in NEM tariff design. The Utility Lost Revenue was assessed as part of the
17 Rate and Bill Impact analysis to determine the potential cost-shifting effects and was not
18 included in the avoided costs stack. Customer Net Installed Costs were assessed to evaluate
19 how NEM compensation may impact opportunities to invest in DG in the state. In the
20 future, it may be used to assess the cost-effectiveness of the DG systems from the perspective
21 of customer generators with net-metered DG systems.

22

1 **VDER Data and Data Sources**

2 **Q. What were the data and sources of the data you analyzed in the VDER Study?**

3 A. The following data and sources were leveraged to conduct the VDER study:

- 4 1) From the 2021 Avoided Energy Supply Cost Study, we used the hourly ISO-NE and New
5 Hampshire system load curves, wholesale hourly energy prices, forecasted capacity
6 prices, reserve margin, RPS compliance costs, transmission line losses, price elasticity
7 curves, gross demand reduction induced price effect (DRIPE) energy price forecasts,
8 uncleared capacity DRIPE Forecast, electric-gas-electric (E-G-E) cross DRIPE
9 coefficients, wholesale risk premium, carbon dioxide (CO₂) marginal emissions rates,
10 societal cost of carbon, nitrogen oxide (NO_x) marginal emissions rates and short ton price
11 of NO_x.
- 12 2) From the ISO-NE website, we leveraged the wholesale ancillary and load charges, ISO-
13 NE forward capacity market (FCM) net regional clearing price reports, effective charge-
14 rate forecast, ISO-NE wholesale monthly reports by zone, New England Power Pool
15 (NEPOOL) reliability committee/transmission Committee regional network service
16 (RNS) Rates: 2020-2024 pooled transmission facilities (PTF) Forecast, ISO-NE regional
17 network load (RNL) Reports.
- 18 3) Additionally, we also leveraged data such as the Henry Hub Natural Gas Futures Prices
19 from NYMEX, Distribution Capital Expenditure Proxy Value from the Locational Value
20 of Distributed Generation (LVDG) study and societal cost of carbon from the New York
21 state website (NYS SCC)¹.

¹ [New York DPS Societal Cost of Carbon](#)

1 For data that was not publicly available, we gathered the relevant inputs through a
2 combination of utility data requests and interviews.

3

4 **VDER Sensitivity Analyses**

5 **Q. Please describe any sensitivity analyses you performed concerning the VDER Study.**

6 A. As part of the VDER study, we conducted a sensitivity analysis to assess the impact of three
7 factors on the DER avoided cost value stack. These sensitivities included (1) the impact of
8 including consideration of environmental externalities, (2) the impact of high-load growth
9 scenarios (HLGS) based on increased levels of building heating and transportation
10 electrification, and (3) the market rate value scenario (MRVS) to determine the value of
11 DERs that participate directly in the ISO-NE market (MRVS).

12 Environmental externalities are not currently applied in New Hampshire's utility system
13 valuation and, therefore, are not currently included in the NEM tariff design. The Granite
14 State Test (Primary) and the NH Utility Cost Test do not consider the impacts of non-
15 embedded environmental externality. Thus, this avoided cost value was assessed as a
16 sensitivity to the overall VDER assessment to determine how accounting for environmental
17 externalities could impact the VDER results.

18 The AESC wholesale energy price forecasts include the costs of compliance with the
19 Regional Greenhouse Gas Initiative (RGGI), therefore this cost was not included within the
20 environmental externality sensitivity. For this analysis, the full social cost of CO2 emissions
21 (net of RGGI compliance costs to avoid double-counting) is included in the environmental
22 externalities value. Additionally, the AESC wholesale energy forecasts do not include any

1 costs associated with NOx emissions. Therefore, the analysis assumes the full social cost of
2 NOx emissions in the environmental externalities value.

3 The environmental externalities value does not include sulfur dioxide (SO2) emissions,
4 particulate matter, and methane. The AESC assumes that coal-fired power generation, which
5 is the primary source of SO2 emissions and particulate matter from electricity generation,
6 will be phased out by 2025. Therefore, the environmental externalities value of these
7 emissions is expected to be minimal. Although there may be potential significant costs
8 related to methane emissions, as forecasting methane emissions for ISO-NE poses
9 challenges, it was not included in the value of environmental externalities.

10 The HLGS sensitivity analysis assessed the incremental impact of varying the deployment of
11 building and transportation electrification technologies on the avoided costs. The base-case
12 value stack avoided costs are derived using the AESC 2021 study, counterfactual #2
13 scenario, which does not include programmatic resource impacts of building electrification
14 but does include a projection of transportation electrification. As summarized in Table 1,
15 three HLGS treatments were applied, accounting for (1) the impact of building electrification
16 (derived from the AESC study counterfactuals #3 and #4) coupled with base-case projections
17 of transportation, (2) the impact of building electrification coupled with more rapid
18 electrification of transportation, and (3) further increased levels of building electrification
19 coupled with more rapid electrification of transportation.

20
21
22
23

1 Table 1. Summary of HLGS Sensitivity Analyses and Data Sources

| Scenario | Building Electrification (BE) | Transportation Electrification (TE) |
|---|-------------------------------|-------------------------------------|
| Scenario 1: Impact of BE | AESC ² | AESC ³ |
| Scenario 2: Impact of BE and high TE | AESC ² | High ⁴ |
| Scenario 3: Impact of high BE and high TE | High ⁵ | High ⁴ |

2

3 In Table 1 above, building and transportation electrification rates are varied under multiple

4 scenarios under the HLGS sensitivity analysis. The sensitivity analysis assumed two levels of

5 electrification: 1) Aligned with the AESC and 2) High case that assumes higher

6 electrification rates than assumed in the AESC.

7 Each HLGS treatment applied volumetric and capacity avoided cost impacts as derived from

8 the AESC counterfactual values and applied elasticity factors to extrapolate the avoided cost

9 impacts for electrification levels that exceeded those presented in the AESC 2021 study

² **Building Electrification (AESC):** The AESC counterfactual #2 did not include the programmatic resource impacts of building electrification measures, but these impacts were included in counterfactuals #3 and #4. The building electrification measure impact included in counterfactuals #3 and #4 was added to counterfactual #2 to derive Scenario 1.

³ **Transportation Electrification (AESC):** The AESC included transportation electrification impacts across all four counterfactual scenarios, so some degree of transportation electrification was considered in the base avoided cost values taken from the AESC counterfactual #2 scenario.

⁴ **Transportation Electrification (High):** For HLGS scenarios 2 and 3, transportation electrification was assumed to exceed the AESC assumptions such that light-duty vehicle uptake aligned with a market share target of 26% by 2026, 90% by 2030, and 100% by 2035. Data availability on medium- and heavy-duty vehicle stocks and sales in New Hampshire was limited, so market share targets could not be established. Deployment was instead accelerated over AESC assumptions to align with the modified uptake trends in the light-duty sector, resulting in load impacts that exceeded AESC values by up to 58% at the mid-point of the study, but were approximately aligned with AESC assumptions by 2035.

⁵ **Building Electrification (High):** The high building electrification assumptions included an accelerated timeline for heat pump installations in residential buildings, exceeding AESC assumptions by up to 30% at the study mid-point and 14% by the study end point.

1 results. HLGS impacts on environmental externalities were also assessed, applying
2 regression analysis to the marginal emissions rates as published in the AESC 2021 study.
3 Unlike the other two sensitivity analyses, the MRVS did not assess the sensitivity to potential
4 variability in the avoided costs. The MRVS assessed the impact on the compensation
5 received by a DER provider by participating directly in the wholesale power market operated
6 by the ISO-NE rather than being compensated by the NEM tariff. The MRVS analysis
7 quantified the resulting compensation the DER provider would receive based on the
8 wholesale values of energy, capacity, and ancillary services.

9
10 **VDER Study Findings**

11 **Q. Please provide a brief summary of the findings of the VDER Study.**

12 A. In New Hampshire, DERs are forecasted to achieve a total average annual net avoided cost
13 value of \$0.13 to \$0.19 per kWh of electricity produced in 2024 and \$0.10 to \$0.23 per kWh
14 produced in 2035 (all values in 2024 \$), varying by DER system type and excluding
15 environmental externalities.

16 The two largest drivers of total technology-neutral value are avoided energy costs and
17 avoided transmission charges. Avoided energy cost contributes up to 50% of the total
18 technology-neutral value, and the contribution of this value declines over time. Transmission
19 charges are forecasted to increase over time, increasing from 20% of the value stack (\$0.02
20 per kWh) in 2024 to 38% (\$0.05 per kWh) by 2035.

21 Net-metered DERs are expected to provide some additional value beyond what was shown in
22 graphs and charts in the report, notably for those value stack criteria addressed qualitatively

1 in this study: transmission capacity (for non-pool transmission facilities), transmission and
2 distribution system upgrades, distribution grid support services, and resiliency.

3 **Q. Please provide a brief summary of the findings in the VDER Study regarding rate and**
4 **bill impacts.**

5 A. The Rate and Bill Impact (RBI) analysis provides insight into the impact of DG deployment
6 in New Hampshire on ratepayers, considering both the benefits and the costs that would be
7 incurred by the utilities. The assessment is intended to serve as a future-looking estimate of
8 the direction and magnitude of the impacts of DG deployment on all ratepayers and any
9 potential cost-shifting between DG customer-generator and non-DG customer. It is not
10 intended to represent an exact projection of future electricity rates and cost recovery. Instead,
11 it serves as a future-looking approximation of the impacts on ratepayers attributable to DG.
12 The RBI assessment highlights the impacts across the three regulated electric utilities serving
13 New Hampshire - Public Service Company of New Hampshire d/b/a Eversource Energy
14 (Eversource), Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities (Liberty)
15 and Unitil Energy Systems, Inc. (UES) across three representative rate classes for each utility
16 (residential, small general service, large general service) and three representative customer
17 groups (typical DG customer-generators, typical non-DG customers, average utility
18 customers). The average utility customer is not a customer class *per se* but is used to
19 represent the resulting bill impacts in aggregate for all DG customer-generators and non-DG
20 customers combined. The analysis considers the impacts under two scenarios for DG
21 compensation: (1) Net Energy Metering (NEM), the existing alternative net metering tariff
22 (effective September 2017), and (2) Avoided Cost Value (ACV) Tariff: a hypothetical tariff
23 structure based on the outcomes of the VDER study where DG customer-generators are

1 compensated for grid exports at the value of the avoided cost values. The RBI assessment
2 was not updated to reflect the latest avoided costs published in the addendum.

3 Under the current NEM scenario, based on the forecasted DG adoption over the 2021 to 2035
4 period, on average, residential customers across the state are projected to experience a
5 decrease of 1.0% in their monthly bills, while on average across small general service and
6 larger general service customers are projected to experience a 0.5% and 1.8% reduction in
7 their monthly bills.

8 While DG customer-generators will experience notable decreases in their monthly bills
9 resulting from the NEM tariffs, non-DG customers are expected to experience a slight
10 increase in their monthly bills, averaging 1.0% for residential customers and 0.5% for small
11 and large general service customers. These bill increases for non-DG customers are driven
12 by progressive increases in rates, which by 2035 results in a 1.2% to 1.8% increase in rates
13 for residential customers, a 0.3% to 1.1% increase for small general service customers, and a
14 0.2% to 1.1% increase for large general service customers, depending on the utility service
15 territory.

16 The ACV Tariff scenario yielded similar results to the NEM scenario, with the avoided cost-
17 based compensation slightly reducing the bill impact on non-DG customers.

18 **Q. Please describe any findings in the VDER Study regarding potential cost-shifting**
19 **between net metering customers and non-net metering customers.**

20 A. Under both RBI scenarios, non-DG customers are expected to experience minimum bill
21 increases over the 15-year period, while DG customer-generators will experience notable bill
22 reductions, suggesting the potential for relatively limited cost-shifting between these two
23 customer groups. Note that if the avoided cost criteria identified as unable to be quantified

1 were included and/or the environmental externality avoided costs were included, the bill
2 impacts to non-DG customers are expected to be even smaller or reversed.

3 **Q. Please provide a brief summary of the VDER Study Addendum that was filed in this**
4 **docket on June 8, 2023, at Docket Tab 43.**

5 A. Since the completion of the New Hampshire Value of Distributed Energy Resources Study
6 Report in October 2022, natural gas prices have experienced a much higher increase than had
7 been projected at the time of the study, driven to a large degree by the Russian invasion of
8 Ukraine. The Addendum applies updated natural gas prices to adjust the Avoided Energy
9 Costs, Ancillary Services and Load Obligation Charges, Transmission and Distribution Line
10 Losses, Wholesale Market Price Suppression, and Wholesale Risk Premium to factor in the
11 higher natural gas prices and convert them to the real \$2024 values. The remaining avoided
12 cost components were updated to reflect \$2024 values. Compared to the original technology-
13 neutral value stack, the total avoided costs (excluding environmental benefits) are, on
14 average, about 17% higher in 2025 and about 5% higher by 2035.

15 The RBI assessment was not updated to reflect the latest avoided costs published in the
16 addendum. Among the updated avoided cost streams, Avoided Energy Costs, Ancillary
17 Services and Load Obligation Charges, Transmission and Distribution Line Losses and
18 Wholesale Risk Premiums are a pass-through to retail customers and any reduction will not
19 affect rates. The post-DG generation rate accounts for the impact of only those avoided-cost
20 components that impact the generation rate; these include Avoided Capacity and Wholesale
21 Market Price Suppression. Since updated Wholesale Market Price Suppression values are
22 slightly higher than those in the original study, theoretically, the total avoided costs would be
23 slightly higher, leading to lower fixed-cost recovery and reducing the upward impact on

1 rates. However, since Wholesale Market Price Suppression benefits are a marginal
2 component in the value stack – the impact on the RBI results would be minimal, which is
3 why we did not update the RBI assessment.

4

5 **VDER Study Model**

6 **Q. Did you provide a model associated with the VDER Study?**

7 A. Yes, an Excel model was provided to the New Hampshire Department of Energy.

8 **Q. What was the purpose of the model provided?**

9 A. The Value of Distributed Energy Resource (VDER) Model is an Excel-based valuation tool
10 that allows users to calculate the avoided costs of various DERs under the base case and three
11 high-load growth scenarios. In line with the study, the model outputs the hourly avoided
12 costs for thirteen components across the study period (2021 to 2035) for distributed energy
13 resources such as solar, energy storage and small hydro as they are deployed for residential,
14 commercial, and front-of-the-meter systems.

15 **Q. Please briefly describe the model associated with the VDER Study.**

16 A. The Value of Distributed Energy Resource (VDER) Model is an Excel-based valuation tool
17 that allows users to calculate hourly, seasonal, or annual avoided costs for thirteen avoided
18 cost components for a DER over a period of 15 years (2021 to 2035). The model can evaluate
19 the avoided costs for a distributed energy resource under various building and transportation
20 electrification scenarios. The following cost components are quantified in the model: avoided
21 energy, avoided capacity, avoided ancillary services and load obligation charges, avoided
22 RPS compliance charges, avoided transmission charges, avoided distribution capacity costs,
23 distribution system operating expenses, avoided transmission and distribution line losses,

1 wholesale market price suppression benefits, avoided wholesale risk premium, distribution
2 utility administration costs and environmental externalities. Avoided transmission capacity,
3 avoided transmission and distribution system upgrades, distribution grid support services,
4 and resiliency services were not quantified but qualitatively addressed in the study report.
5 Customer net installed costs were not quantified in the model but calculated in the report.
6 Eight example DERs are pre-populated in the model: small hydro, behind-the-meter
7 residential south-facing solar, behind-the-meter residential west-facing solar, behind-the-
8 meter commercial south-facing solar, behind-the-meter commercial west-facing solar, front-
9 of-the-meter solar, behind-the-meter residential south-facing solar coupled with energy
10 storage and behind-the-meter commercial south-facing solar coupled with energy storage.
11 For each example DER, the model is populated with representative hourly energy output
12 values for the first eight resources. The model also includes two placeholders for the user to
13 define an additional DER resource and evaluate the avoided cost value associated with a
14 customized DER generation profile.

15 To run the model in the model Dashboard, the user needs to select the preferred DER
16 resource, define the load growth scenario and tweak the sensitivity assumptions. The model
17 allows users to assess the sensitivity of the results to various inputs. For example, the user
18 can adjust the value of each avoided cost component and assess its impact on the total
19 technology-neutral value stack. The user can set reasonable upper and lower values for each
20 avoided cost and see how changes in specific avoided costs, or combinations, affect the
21 overall system value.

22

1 **Net Metering Compensation**

2 **Q. Does the VDER Study take a position on net metering compensation structure?**

3 A. The VDER Study does not take a position on net metering compensation values or structure.

4 **Q. Does this conclude your testimony?**

5 A. Yes.