

Evaluation of Net Metering in Vermont Conducted Pursuant to Act 125 of 2012

Public Service Department
January 15, 2013

1 Introduction

Act 125 of the 2012 Vermont legislative session directed the Public Service Department (Department) to complete an evaluation of net metering in Vermont:

No later than January 15, 2013, the department of public service (the department) shall perform a general evaluation of Vermont's net metering statute, rules, and procedures and shall submit the evaluation and any accompanying recommendations to the general assembly. Among any other issues related to net metering that the department may deem relevant, the report shall include an analysis of whether and to what extent customers using net metering systems under 30 V.S.A. § 219a are subsidized by other retail electric customers who do not employ net metering. The analysis also shall include an examination of any benefits or costs of net metering systems to Vermont's electric distribution and transmission systems and the extent to which customers owning net metering systems do or do not contribute to the fixed costs of Vermont's retail electric utilities. Prior to completing the evaluation and submitting the report, the department shall offer an opportunity for interested persons such as the retail electric utilities and renewable energy developers and advocates to submit information and comment.

The Department undertook several steps to address the legislative request and evaluate Vermont's net metering statute, rules, and procedures. Background and current statistics regarding net metering in Vermont are presented in Section 2 of this report. Section 3 describes the analysis the Department conducted to evaluate whether, and to what extent, customers employing net metering are subsidized by other customers. Section 4 concludes the report with a general assessment of the state's net metering statute, rules, and procedures.

The Department issued a Request for Information, focused on the cross-subsidization analysis but welcoming comments on all aspects of the study, on September 17, 2012. The results and analysis reported here were informed by comments submitted by eleven interested persons, organizations, and businesses (including utilities and renewable energy advocates). The Department also held several meetings with commenters to better understand their comments and solicit further information. The Department also received stakeholder comments on both the draft report document and draft spreadsheet tool, both of which were released on December 21, 2012.

2 Background

2.1 A Brief History of Net Metering in Vermont

The 1998 legislative session enacted a net metering law (30 V.S.A. §219a), requiring electric utilities to permit customers to generate their own power using small-scale renewable energy systems of 15 kW or less (including fuel cells using a renewable fuel). Farm systems were allowed to be larger, with a cap of 100 kW. Any power generated by these systems could be fed back to the utility, running the electric meter backwards, if generation exceeded load at any given time.

Amendments in 1999, 2002 and 2008 permitted the installation of more net metered capacity, increased the allowable size of systems, and added the use of non-renewably fueled combined heat and

power units of 20 kW or less. Beginning in 2002 “group net metering” was allowed, but was restricted to farmers. The 2008 amendments lifted this restriction, increased the permissible size per installation to 250 kW, simplified the permitting process for systems under 150 kW, and raised the ceiling on the total installed capacity from one percent to two percent of peak load. In 2011, the Vermont General Assembly expanded the permissible size limit per installation to 500 kW, simplified the administration for net metering groups, allowed a registration process for photovoltaic (PV) systems 5 kW and under, increased the overall net metering capacity cap per utility to 4 percent of the 1996 utility system peak or previous year’s peak (whichever is higher), and created a solar credit payment for all customers who have installed PV net metered systems. The solar credit payment has the effect of increasing the value of generation to net metered customers up to 20 cents per kWh in the year the system is installed.

During the 2012 session the registration process was expanded to PV projects 10 kW and under, and the process for group net metering billing and monetization of credits was clarified.

2.2 Status of Net Metering in Vermont

Net metering has experienced rapid growth over the last four years as the demand for local renewable energy has grown, costs have come down, and access to renewables has broadened. As can be seen in Figure 1, solar PV has had the most substantial growth of all the renewable technologies. The number of PV systems applying for net metering permits annually has grown by a factor of more than four since 2008.

Net Metering Applications Per Year

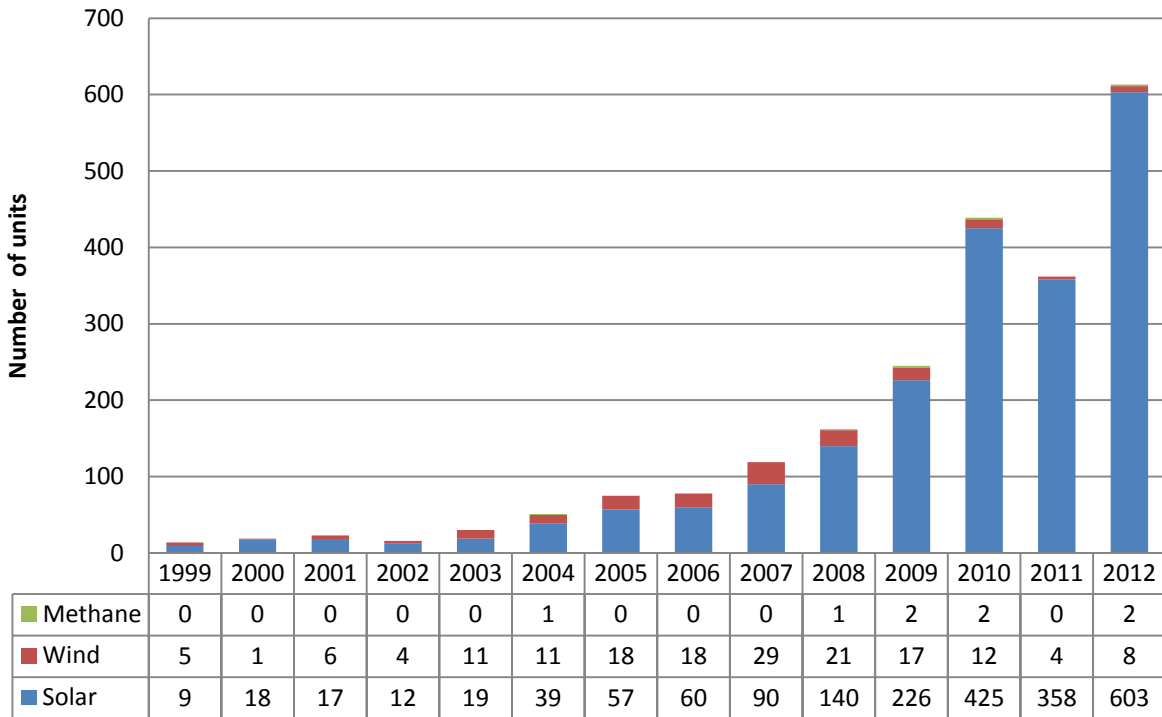


Figure 1. Number of net metering applications & registrations annually. (2012 data as of 12/5/12.)

With the recent rise in number of PV installations, solar now accounts for almost 88% of all net metering systems. Wind turbines represent under 8% of the systems and hydro just 3% (see figure 2.)

Net Metered Capacity by Type

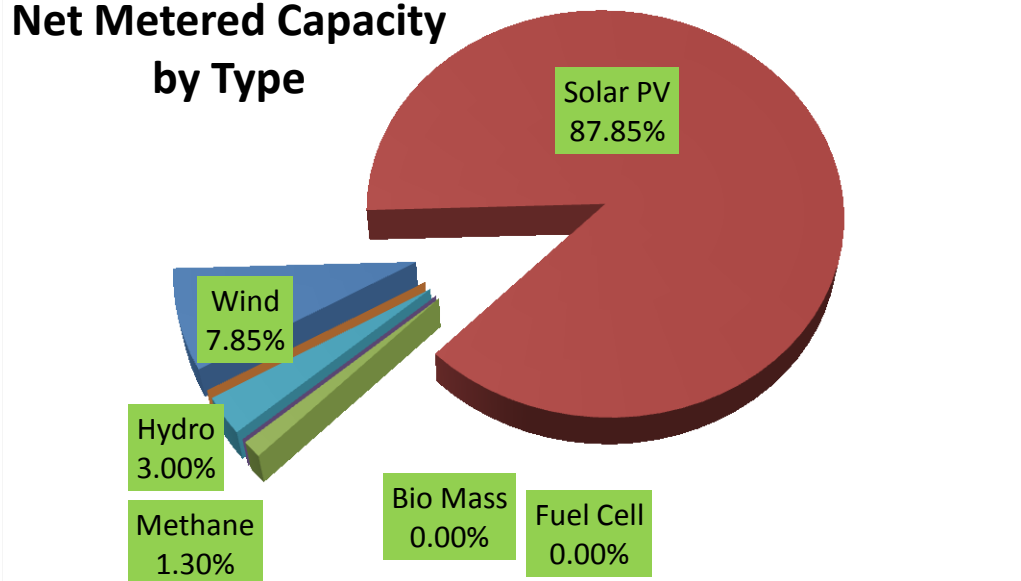


Figure 2. Net metering applications & registrations by technology type.

To date, there have been no net metered fuel cells or combined heat and power systems in Vermont.

The exponential increase in the number of PV system installations has driven not only the overall number of net metered systems but also the total growth of net metered system capacity¹ to over 20 MW (see figure 3).

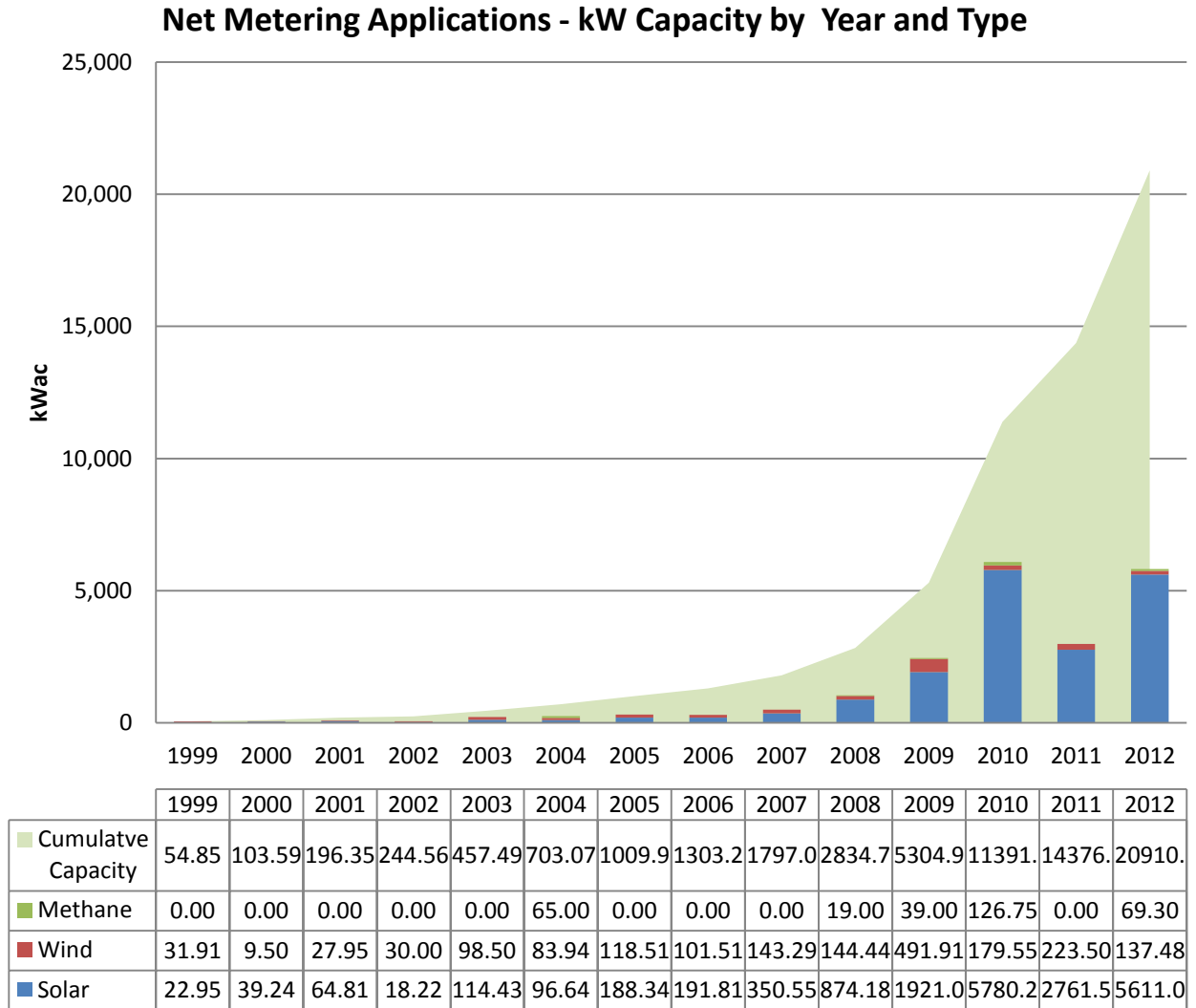


Figure 3. Capacity of net metering applications by type. (2012 data as of 12/5/12.)

The capacity histogram (figure 4) shows that 59% of net metering systems permitted to date are less than 5 kW, 26% are between 5-10 kW and fewer than two percent are larger than 100kW.

¹ The capacity of a generator is the maximum output that the generator is capable of producing. It is an instantaneous measure, and measured in Watts, kilowatts (kW), megawatts (MW), etc. Energy production is measured over time – a 1 kW generator operating at that level for an hour produces one kilowatt-hour (kWh) of energy. Vermont’s summer peak load is near 1000 MW, and the state uses about 5.5 terawatt-hours each year.

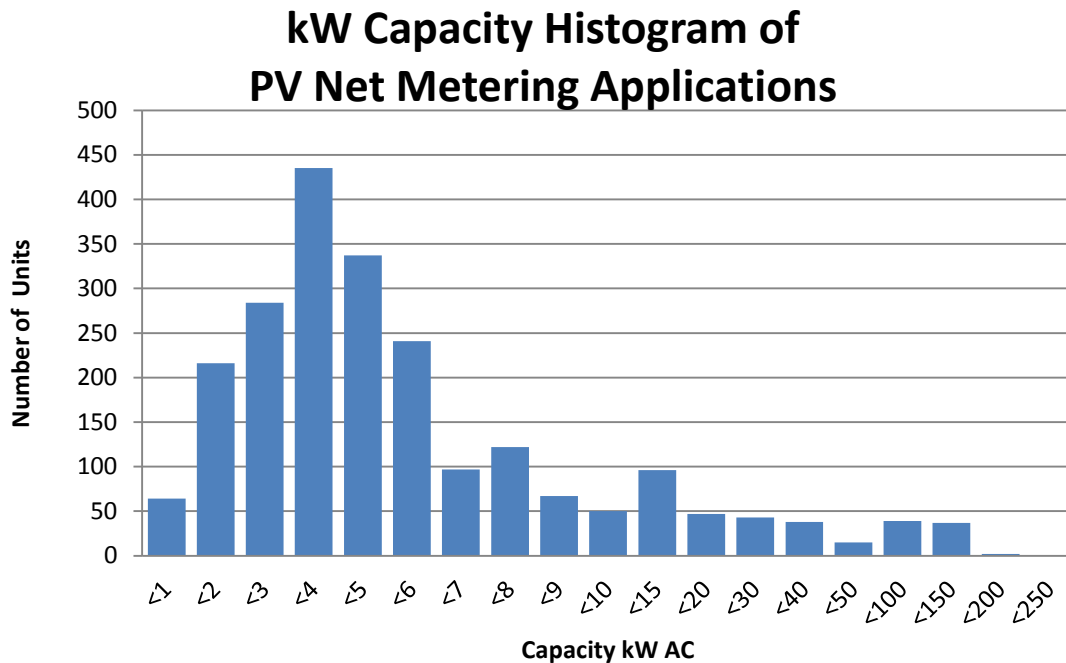


Figure 4. Capacity (in kW AC) of all net metered PV system applications

While the growth has been rapid and 20MW of small net metered systems represents a level of success that some didn't think would be achieved, it represents a very small fraction of Vermont's overall electrical portfolio. Only one utility (Washington Electric Cooperative) has more than 1% of their customers participating in net metering. There are some smaller utilities that are approaching the 4% capacity cap, but it is important to remember that the cap is based on capacity and not power production. Net metering systems produce less than 1% of the power Vermont uses each year or about 35 GWh per year².

3 Cross-Subsidization Analysis

This section describes the quantitative analysis conducted by the Department to examine the question raised explicitly in Act 125: "... the report shall include an analysis of whether and to what extent customers using net metering systems under 30 V.S.A. § 219a are subsidized by other retail electric customers who do not employ net metering." In conducting this analysis, the Department was greatly aided by information and suggestions received from numerous stakeholders through written comments, data submittals, and meetings.

3.1 Literature review

In order to frame the analysis for determining whether net metering represents a "cost-shift" from non-participating ratepayers to net metering customers, the Department conducted a broad-based literature review of relevant papers and studies. This review included over two dozen publications from a wide variety of sources, including the National Renewable Energy Laboratory (NREL), the Solar America Board

² In 2011, Vermont utilities sold 5,554 GWh of electricity to their customers.

for Codes and Standards (Solar ABCs), and a number of states and utilities on either the subject of net metering benefits generally, or specifically on the rate impacts of net metering. Few of the publications reviewed were directly comparable with each other, or with the specific net metering rules and regulations in Vermont. However, information gleaned from these publications provided context that informed assumptions made in the Department model.

One of the challenges facing Vermont is that the only one other state – California – has conducted a full analysis of the cost-shift question (i.e., a full cost-benefit analysis) from a utility and ratepayer perspective. The California study³ (and its subsequent updates^{4,5}), along with two prior values-only studies performed for specific utilities (Arizona Public Service⁶ and Austin Energy^{7,8}) form the basis for a generalized methodology for analyzing the costs and benefits of net metering proposed by the Solar America Board for Codes and Standards⁹. This methodology, however, only looks at exported (rather than gross) generation from net-metered solar photovoltaic systems. For reasons explained below, Vermont has chosen to look at gross generation, and at generation from a number of allowed types of net metering technologies – not only solar. Therefore, the methodology serves as a good guidepost and checkpoint for our work, but not an exact template.

Three other relevant statewide studies have been performed: two in New York and one in Pennsylvania/New Jersey. One of the New York studies is a broad review of the benefits and costs to ratepayers of increasing in-state solar capacity to 5,000 MW by 2025¹⁰; while the other looks at the overall costs and benefits of distributed solar to ratepayers and taxpayers in the New York City area¹¹. The PA/NJ study is similar to the latter¹². The assumptions and methodologies used in these studies were also helpful in framing our analysis.

Table 1 below summarizes the results of relevant publications. Each study is unique, with distinct definitions for the costs and benefits analyzed. In many cases, costs and benefits not included in this

³ Energy and Environmental Economics, Inc. (2010). *Net energy metering (NEM) cost effectiveness evaluation (E3 study)*. Available at http://www.cpuc.ca.gov/PUC/energy/DistGen/nem_eval.htm.

⁴ Beach, Thomas R. and Patrick G. McGuire (2012). *Re-evaluating the Cost-Effectiveness of Net Energy Metering in California*. Berkeley, CA: Crossborder Energy.

⁵ Beach, Thomas R. and Patrick G. McGuire (2012). *Evaluating the Benefits and Costs of Net Energy Metering for Residential Customers in California*. Berkeley, CA: Crossborder Energy.

⁶ *Distributed Renewable Energy Operating Impacts and Valuation Study* (2009). Seattle, WA: R.W. Beck.

⁷ Braun, Jerry, Thomas E. Hoff, Michael Kuhn, Benjamin Norris, and Richard Perez (2006). *The Value of Distributed Photovoltaics to Austin Energy and the City of Austin*. Napa, CA: Clean Power Research, LLC.

⁸ Harvey, Tim, Thomas E. Hoff, Leslie Libby, Benjamin L. Norris, and Karl R. Rabago (2012): *Designing Austin Energy's Solar Tariff Using a Distributed PV Value Calculator*. Austin, TX and Napa, CA: Austin Energy and Clean Power Research.

⁹ Keyes, Jason B. and Joseph F. Wiedman (2012). *A Generalized Approach to Assessing the Rate Impacts of Net Energy Metering*. Solar America Board for Codes and Standards, http://www.solarabcs.org/about/publications/reports/rateimpact/pdfs/rateimpact_full.pdf.

¹⁰ *New York Solar Study: An Analysis of the Benefits and Costs of Increasing Generation from Photovoltaic Devices in New York* (2012). Albany, NY: New York State Energy Research and Development Authority.

¹¹ Hoff, Thomas E., Richard Perez, and Ken Zweibel (2011). *Solar Power Generation in the US: Too Expensive, or a Bargain?* Albany, NY: Clean Power Research, LLC.

¹² Hoff, Thomas E., Benjamin L. Norris, and Richard Perez (2012). *The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania*. Albany, NY: Clean Power Research, LLC.

table are discussed. Additional details of select studies are provided in a more extensive literature review document, posted at http://publicservice.vermont.gov/topics/renewable_energy/net_metering. Details of this Public Service Department study are included in Table 1 for comparison purposes.

Table 1: Comparison of methodology and included costs and benefits in the relevant literature.

Study	Test Perspective	Generation analyzed	Costs Analyzed		Benefits Analyzed								Notes
			Net metering bill credits	Program administration costs	Avoided energy purchases	Avoided capacity purchases	Avoided T&D line losses	Avoided T&D investments /O&M	Environmental benefits	Natural gas price hedge	Avoided RPS purchases	Reliability benefits (ancillary services and VAR support)	
Solar ABCs 2012 (generalized methodology)	Utility/non-participating ratepayers	Exported energy only	X	X	X	X	X	X	X	X	X	X	Generalized methodology based on E3, Austin, and APS studies
E3 for CA CPUC (2010)	Utility/non-participating ratepayers	Exported energy only	X	X	X	X	X	X	X		X	X	Benchmark study for cross-subsidization evaluations
Crossborder (update to E3 study, 2012)	Utility/non-participating ratepayers	Exported energy only	X	X	X	X	X	X	X		X	X	Updated to E3 based on interim restructuring of PG&E rate structures; results net cost of 7¢ that found in 2010
Crossborder (2nd update, October 2012)	Utility/non-participating ratepayers	Exported energy only	X	X	X	X	X	X	X		X	X	Second update using same methodology as first but instead looking at three OU territories; still small net cost in PG&E but more than offset by net benefits in SCE and DG&E
Austin Energy (Clean Power Research, 2006, updated in 2012)	Utility/non-participating ratepayers	Gross output	N/A	N/A	X	X	X	X	X	X			Values-only study looking at distributed (not just net metered) PV; looked at reactive power control and disaster recovery values but not included in final results
APS (R.W. Beck, 2008)	Utility/non-participating ratepayers	Gross output	N/A	N/A	X	X	X	X				X	Values-only study looking at distributed (not just net metered) PV and also residential solar hot water & commercial daylighting systems
Perez (for NYC area, 2011)	Utility/non-participating ratepayers AND state/society	Gross output	N/A	N/A	X	X	X	X	X	X		X	For distributed PV; other costs analyzed: stream of revenues for developer to break even, and costs to manage non-controllable solar for reliability. Other benefits analyzed: long-term societal value, economic growth value
NYSDA/NYDPS (2012)	Utility/non-participating ratepayers	Gross output	N/A	N/A	X	X	X	X	X		X		Costs/benefits of achieving 2,500 MW PV by 2020 and 5,000 MW by 2025; other costs analyzed: lifetime average energy costs in all sales of PV, plus admin costs of state solar incentive program; other benefits analyzed: prices suppression, macroeconomic/jobs impacts
Clean Power Research (Perez for NJ & PA, 2012)	Utility/non-participating ratepayers AND state/society	Gross output	N/A	N/A	X	X	X	X	X	X		X	For distributed PV; other costs analyzed: costs to manage non-controllable solar for reliability. Other benefits analyzed: long-term societal value, economic growth value
This/TS study	Utility/non-participating ratepayers	Gross output	X	X	X	X	X	X	X	X			

NOTE: The Department is aware of at least three additional, potentially relevant studies that will be published sometime in 2013.

3.2 Cross-subsidization analysis decisions

Based upon the landscape of methodologies revealed in the broad literature review, the Department made three threshold decisions regarding its cross-subsidization analysis framework, each described in greater detail below:

- To examine the cost-benefit from a statewide ratepayer perspective, with consideration of two scenarios which include and do not include monetary value for reductions in greenhouse gas emissions;
- To include a clear, defined set of assumptions of the costs and benefits of net metering; and
- To include costs and benefits associated with all generation by net metering systems, rather than only that generation that is exported to the electric grid.

The following subsections describe the conclusions the Department reached on each of these points.

The Department modeled the costs and benefits of net metered generation from three technologies: fixed solar photovoltaic (PV), 2-axis tracking solar PV, and wind power. While there are a handful of net-metered generators in Vermont that use agricultural methane or hydropower, over 95% of net-metered generation uses either solar or wind power. In addition, the Legislature has made special allowance for agricultural methane in the Standard Offer program. The Department expects that the vast majority of new net metering generation will continue to be powered by solar and wind energy.

3.2.1 Ratepayer perspective

There are a number of different cost-benefit tests that an analysis could pursue to determine the impact of net metering, each reflecting the different perspective.¹³ The Department concluded that Act 125 requires a statewide ratepayer perspective. This is the appropriate analysis to evaluate any potential subsidization of net metering participants by other Vermont retail electric customers. For simplicity and clarity, the Department decided to consider the weighted average costs and benefits across all of the state's utilities rather than model the costs and benefits for each utility separately.

In addition, the Department supplements the state utility ratepayer perspective by the avoided costs of greenhouse gas emissions that are currently externalized due to market failures. This calculation attempts to quantify what the ratepayer costs and benefits would be if these costs were internalized in

¹³ One perspective is that of the participant (net metered customer), who receives lower electric bills in exchange for expending the capital for the project. A ratepayer cost-benefit test captures costs and benefits to a utility's ratepayers (including both those who install net metered systems and those who do not). This perspective depends on the regulatory structure where utility recovers the costs from, and shares the benefits with, its customers. Moving to a larger universe of impacted people, a study can examine the impact on all the ratepayers in the state of Vermont. The largest scale is society as a whole.

Depending on the perspective considered for a cost-benefit analysis, a particular flow of value could be considered a cost, a benefit, or a transfer. For example, the utility's cost from lost bill revenue is the participant's benefit from reduced electric bills. Reduced Vermont contribution to regional transmission costs (for transmission already built) is a benefit if the boundary is drawn at the utility or state level, but is simply a transfer of burden to other New England ratepayers if society as a whole is considered. Under current policies, costs due to many environmental impacts, such as greenhouse gas emissions, are borne by society as a whole, not just by Vermont or any single utility's ratepayers.

the electricity market. The Department finds this addition appropriate given the State’s emphasis on greenhouse gas emission reductions, exemplified in statutory priorities (see, for example, 10 V.S.A. § 578 and 30 V.S.A. § 8001), and especially the statutory guidance in 30 V.S.A. § 218c to consider “the value of the financial risks associated with greenhouse gas emissions from various power sources.”

3.2.2 Costs and benefits

The Department examined the relevant literature, as well as the structure of New England and Vermont electricity markets and regulation to identify the following costs:

- Lost revenue (due to participants paying smaller electric bills)
- The Vermont solar credit, for solar PV systems
- Net metering-related administrative costs (engineering, billing, etc.)

The Department identified the following benefits:

- Avoided energy costs, including avoided costs of line losses and avoided internalized greenhouse gas emission costs
- Avoided capacity costs, including avoided costs of line losses
- Avoided regional transmission costs (costs for built or un-built pooled transmission facilities, or PTF, embodied in the ISO-NE Regional Network Service charge and other regional charges allocated in a similar fashion)
- Avoided in-state transmission and distribution costs (avoiding the construction of new non-PTF facilities)
- Market price suppression
- Value associated with SPEED generation

Net costs and benefits were calculated both including and excluding the value of avoided greenhouse gas emissions that are currently not internalized in the cost of energy. Ratepayers face a risk that more greenhouse gas costs will be internalized in the future, potentially leading to stranded assets.

Costs and benefits are determined from a Vermont ratepayer perspective; transfers from entities which are not Vermont ratepayers to Vermont ratepayers are included; any potential transfers between Vermont ratepayers are not included.

The assumptions used for each of these costs and benefits are described in more detail in Section 3.3 below.

3.2.3 Generation to include

The literature review conducted for this study revealed one particular analytic choice made by the Department that is different from some similar studies undertaken elsewhere: other analyses consider the costs and benefits of only the generation that is exported to the grid from the site of the net metering generator. That is, they do not consider the costs and benefits to the consumer, utility, or society of generation that offsets load on-site. The Department considered the analytical option used by others, but determined that this choice is not appropriate for Vermont because it would have been unresponsive to the charge from Act 125 which asks for an evaluation and analysis of 30 V.S.A. § 219a as

a whole. Instead, the Department's analysis considers all generation from net metering systems. Other reasons for this choice include:

- The net metering solar credit is based on all generation;
- Simplified permitting is allowed for small net metering generators whether they produce enough to spin their host's meter backwards or not;
- Generation from a net metering system can offset not only a customer's load but also service and other charges;
- Group net metering and virtual group net metering options are available in Vermont. In these instances, generators are likely to be connected directly to the grid, and balancing of production with load is only accounted for on paper each billing period rather than physically in net electric energy flow through a meter.

3.3 Modeling assumptions

The spreadsheet model¹⁴ estimates the costs and benefits incurred as a result of any single net metering installation installed in 2013 or a later year. It projects costs and benefits over the 20-year period following installation, allowing examination of the potential changing costs and benefits over that period as well as calculation of a levelized net benefit or cost per kWh over 20 years.

3.3.1 What the model does not do

While model calculations are precise, and reflect the Department's best point estimate, they do not estimate the width of the range of uncertainty surrounding each estimate due to the compounding effect of multiple assumptions, each of which has its own uncertainty. In addition, the model does not:

- Capture economic impacts outside of the utility-ratepayer context, such as job or economic impacts from the renewable electricity industry or changes to the economics of energy consumption among net metering participants or non-participants.
- Identify impacts on energy prices, load shapes, or other inputs to the analysis that may have already occurred due to deployment of net metering systems in Vermont. For systems modeled as installed in years after 2013, the model does not account for potential changes in Vermont's load shape or other inputs that may occur prior to installation.
- Capture potential changes in rate structures or regional costs, including those due to net metering. It models only the marginal impact of net metering under a "current policy" baseline scenario. That is, it does not model a situation in which rate structures change over time (such as adoption of time-of-use rates), or the impact that increasing net metering may have on future rates or rate structures.
- Capture nonlinear or feedback effects in which additional deployment of net metering in subsequent years may change marginal costs or benefits attributable to systems installed in earlier years (such as through changes in load shape and resulting peak coincidence). For example, it does not capture changes in the costs or benefits (such as avoided infrastructure costs) attributed to systems deployed in 2013 that might occur if future net metering, or other

¹⁴ Available for download from http://publicservicedept.vermont.gov/topics/renewable_energy/net_metering.

generation or efficiency deployment, changes the state's load shape and therefore the need for or cost of infrastructure.

- Include impact from advanced metering infrastructure or other grid modernization technologies, and the resulting potential changes to rate structures.
- Account for integration costs (incremental costs due to the need to change the output of other resources to account for intermittency). These costs are expected to be very small for systems of the size eligible for net metering in Vermont.
- Include monetary values for environmental impacts other than avoided greenhouse gas emissions or value as SPEED resources.
- Capture differences between utilities. All numbers used are weighted statewide or region-wide averages.
- Capture potential cross-subsidization between utilities. This should be very small as the costs and benefits studied are utility-specific. Second-order effects of net metering are possible if net metering penetration or the distribution of net metering technologies is very different between utility service territories.

3.3.2 Economic assumptions

3.3.2.1 Inflation

The baseline expected long-term inflation estimate is 2.45%. This is based on the market expectations for inflation, measured by the difference between the return on inflation-protected and non-inflation-protected long-term (>10 year) U.S. Treasury bonds (as measured in late November, 2012).

3.3.2.2 Discount rate

The Department's analysis uses two discount rates. One, referred to as the "ratepayer" discount rate, is based on the cost of capital to individual ratepayers. The other, referred to as the "statewide" discount rate, is based on a societal perspective on time preference in which the state as a whole has less strong time preference than do individual ratepayers.

The ratepayer discount rate assumed in the Department's analysis is 8.03%. This rate was derived based on analysis conducted by the U.S. Department of Energy for use in analysis of the cost-effectiveness of appliance energy conservation standards.¹⁵ The analysis that U.S. DOE conducts for these standards includes examination of the cost of capital faced by U.S. residential, commercial, and industrial energy consumers. The Department weighted the three average values used in recent U.S. DOE rulemaking proceedings by the three sectors' share of Vermont load, then adjusted for inflation.

The statewide discount rate assumed in the Department's analysis is 5.52%. The Department assumes that the state as a whole has a time preference similar to that of society at large. The Public Service

¹⁵ See, for example, analysis conducted for the standards of furnace fans (https://www1.eere.energy.gov/buildings/appliance_standards/residential/furnace_fans.html) and electric motors (https://www1.eere.energy.gov/buildings/appliance_standards/commercial/electric_motors.html).

Board has adopted a value of 3% in real terms for societal screening of energy efficiency measures; this value is 3% adjusted for inflation.¹⁶

3.3.3 Costs and Benefits

In the context of this study, “costs” and “benefits” are measured from the ratepayer standpoint. The utility regulatory structure in Vermont (including GMP’s alternative regulation plan, the co-op structure of VEC and WEC, and the municipal structure of the state’s other utilities) results in the relevant set of costs and benefits faced by the state’s utilities being passed to the state’s ratepayers. For example, utility costs include lost revenue, the solar credit, and administrative costs. Benefits include avoided energy, capacity, transmission, and distribution costs. As a result, the proposed analytical framework treats utility costs as ratepayer costs, and utility benefits as ratepayer benefits.¹⁷

3.3.3.1 Costs

3.3.3.1.1 Reduction in utility revenue

Net metering reduces utility revenue by enabling a participating customer to provide some of their own electricity (including, at times, spinning their meter backward while exporting energy), which reduces their monthly bill. In order to calculate the size of this reduction due to a modeled net metering installation, the model requires the energy produced per year, along with the expected average customer rate, and any solar credit. The current average electric rate applicable to most net metering installations is 14.7 cents/kWh. This is the average residential electric rate; after the passage of Act 125 in the 2012 legislative session the vast majority of net metering installations in the state should be credited at the residential rate. This is because these installations are in fact residential, or because they are commercial accounts billed under a demand or time-of-use tariff – Act 125 established that such commercial customers receive credit for net metered generation at the residential rate.

Generally speaking, electric rates are composed of energy, capacity, transmission, and other costs. (Other costs include personnel/O&M and the carrying costs of the utility’s investments in poles and wires.) In order to project costs and benefits into the future, the Department has built a simple tool to build a self-consistent projection of rates based on forecast market costs of energy and capacity, forecast transmission costs, and an assumption that other utility costs will rise at some rate, for which the Department chose to use the rate of inflation.

The analysis assumes that energy costs in rates are composed of a mixture of the market energy costs seen in New England over the preceding 10 years: 20% based on market energy prices in the year in question, 40% based on the average of the previous 5 years, and 40% based on the average of the previous 10 years. Vermont’s utilities enter into contracts of varying lengths, and the prices they are willing to pay are based on the energy prices at the time, as well as projected energy prices. See the discussion of “avoided energy costs” below for detail regarding the market energy price forecast.

¹⁶ The discount rate is 5.52% rather than 5.45% because the two rates are most appropriately multiplied rather than added. $1.0245 \times 1.03 = 1.0552$.

¹⁷ Externalities, such as the externalized portion of the value of greenhouse gas emission reductions, do not follow this pattern.

The analysis assumes that market capacity costs equivalent to 60% of Vermont's peak are included in rates; the remainder of capacity is self-supplied and therefore not subject to market fluctuations. (These self-supplied capacity costs are included in the "other" category for utility infrastructure, O&M, etc.) See the discussion of "avoided capacity costs" below for detail regarding the market capacity price forecast.

Regional transmission costs, embodied in the ISO-NE administered Regional Network Service charge, account for the independent transmission portion of electric rates. The analysis assumes that these costs are distributed in an even fashion across all of Vermont's kWh. See the discussion of "avoided regional transmission costs" below for detail regarding the RNS forecast.

Once 2012 energy, capacity, and transmission costs are removed from 2012 rates, the remainder must reflect other costs.¹⁸ The Department assumed that these costs rise at the rate of general inflation. The analysis makes one adjustment to account for known current circumstances: the guaranteed merger savings resulting from the merger of GMP and CVPS. These savings come out of the "other" category, and are assumed to total \$144 million in nominal dollars in 2012 to 2021, then to continue at the same annual nominal level in 2022 and later that they achieve in 2021.

The rate forecast resulting from this analysis is shown in Table 2, located in Section 3.3.3.2.1.

Solar photovoltaic net metering systems are eligible for a "solar credit" in addition to the value of their rates. This credit is calculated by subtracting the residential rate from 20 cents/kWh. Therefore, the state average solar credit in 2013 should be 5.3 cents per kWh generated. The value of this credit is fixed for ten years for each installation at the value it had at the time the system was commissioned. As a result, by the end of ten years the cost of each kWh provided by the solar net metering system could significantly exceed 20 cents. The solar credit is guaranteed to each system for ten years. For systems installed in later years, when rates are expected to be higher in nominal terms, the solar credit is assumed to be correspondingly smaller.

3.3.3.1.2 Administrative costs

The Department did not receive quantitative data from any commenter regarding appropriate administrative costs. The Department developed a set of assumed costs based on qualitative comments that the current administrative burden on distribution utilities is split between two main tasks: evaluating systems as they are submitted (a one-time cost related to engineering assessment and other setup costs) and billing (which is predominantly a cost for group net metered systems, as billing individual net metering is already or very easily automated). Based on qualitative comments, the Department assumed that the total cost for these two tasks is approximately \$200,000 dollars per year for the current pace and scale of net metering in Vermont, split roughly in half between initial costs and on-going costs. To a rough approximation, this corresponds to a setup cost of approximately \$20 per kW of net metering system capacity, ongoing costs of about \$20 per kW per year for billing group net metered systems, and no on-going billing cost for individual net metered systems. The Department also assumed that efficiencies in billing systems (aided by the standardization resulting from the Board's

¹⁸ These other costs are also reflected in the monthly customer charge, which does not play a significant role in the determination of net metering costs and benefits.

order regarding billing standards and procedures) would result in billing costs per kW falling at a rate of 20% per year.

3.3.3.2 Benefits

3.3.3.2.1 Avoided energy cost

From the perspective of the regional electric grid or a utility purchasing power to meet its load, net metering looks like a load reduction. A utility therefore purchases somewhat less power to meet the needs of their customers. While Vermont utilities purchase much of their energy through long-term contracts, this kind of moment-by-moment change in load is reflected in changes in purchases or sales on the ISO-NE day-ahead or spot markets. As a result, the Department assumes that the energy source displaced or avoided by the use of net metering is energy purchased on these ISO-NE markets (the difference between day-ahead and spot markets over the course of the year is minor).

Variable generators, like many of the types of generators deployed in Vermont for net metering, may exhibit some correlation with the weather and therefore with market prices. For example, the season and time of most solar irradiance is correlated (although imperfectly) with the peak summer loads, and therefore somewhat higher regional electricity prices. In order to capture this real correlation, the Department calculated a hypothetical 2011 avoided energy cost on an hourly basis by multiplying the production of real Vermont generators by the hourly price set in the ISO-NE market. This 2011 annual total value was then updated to 2013 and beyond by scaling the annual total price according to a market price forecast. The Department used hourly generation data from the Standard Offer program and net metering systems deployed around Vermont.¹⁹ Significant deployment of such systems has continued this year, but relatively few systems operated for all of 2011. These calculations indicate that fixed solar PV has a weighted average avoided energy price 10% higher than the annual ISO-NE average spot market price, 2-axis tracking solar PV is 13% higher, and small wind is 5% lower.

The Department assumed that the capacity factor for each solar technology is projected capacity factor using the NREL PVWatts tool for a location in Montpelier, using all PVWatts default settings. The assumed capacity factor for wind is the 2011 capacity factor of the real Vermont generator used to calculate the correlation. Separating the capacity factor from the price-performance correlation allows the analysis to correct for differences between the typical capacity factors expected over many years for a generic facility and the capacity factors exhibited for a limited number of generators in only one year.

Output from net-metered generators is expected to decay at a low rate as the generator ages. The Department has assumed a rate of 0.5% per year; this is based on typical degradation rates for solar PV systems.

The Department's market energy price forecast is based on known forward market energy prices for the first five years, then known forward natural gas prices for years 5 to 10. Natural gas prices are an

¹⁹ Including a fixed solar array in Ferrisburgh, a two-axis solar tracker array in Shelburne, and a 100 kW wind turbine near the Burlington airport.

appropriate proxy for scaling electricity prices because the marginal generator in New England, which sets the price, is almost always a natural gas generator. Prices beyond 10 years are based on extrapolation of the electricity and natural gas price trends seen in the market-derived forecast for years 1-10. Using forward market prices implicitly includes the value of net metering as a known-price hedge against a volatile price of energy or natural gas. This is because the prices used in developing the Department's fit are the known prices to lock in supply years into the future; these prices already have a market-determined price risk adjustment included. The resulting energy price forecast (in nominal dollars) is shown in Table 2. The values used in this analysis are averages of the market price forecast conducted on three separate dates in October and November, 2012.

Energy generated by net metering systems on distribution circuits in Vermont is used locally, often on the same property or within a few miles. Therefore, line losses from this energy are insignificant. The energy being displaced, however, would be purchased on the bulk system and then transported to load, with resulting line losses. Analysis conducted by utilities and the Department for the development of the Vermont energy efficiency screening tool concluded that typical marginal line losses are about 9%. A very similar line loss factor applies to capacity; the Department has assumed it to be the same factor of 9%.

Table 2: Department assumptions and forecasts of avoided energy, capacity, regional transmission, and in-state transmission and distribution costs, along with assumed self-consistent residential rate forecast, developed for this study. Values are in nominal dollars.

	Residential Rates (\$/kWh)	Energy (\$/MWh)	Capacity (\$/kW-month)	Regional transmission (PTF) (\$/kW-month)	Vermont T&D (non-PTF) (\$/kW-month)
2012	\$0.147	\$35.28	\$2.89	\$6.27	\$13.17
2013	\$0.147	\$47.22	\$2.84	\$7.08	\$13.43
2014	\$0.150	\$46.80	\$2.84	\$7.83	\$13.71
2015	\$0.151	\$46.83	\$2.84	\$8.71	\$13.88
2016	\$0.150	\$47.12	\$1.16	\$9.58	\$14.14
2017	\$0.154	\$47.75	\$1.71	\$10.06	\$14.48
2018	\$0.157	\$48.56	\$2.39	\$10.56	\$14.58
2019	\$0.162	\$50.60	\$2.68	\$11.09	\$14.95
2020	\$0.168	\$52.90	\$3.76	\$11.64	\$15.33
2021	\$0.170	\$55.44	\$3.83	\$12.23	\$15.64
2022	\$0.179	\$58.15	\$5.75	\$12.84	\$15.95
2023	\$0.186	\$60.97	\$6.92	\$13.48	\$16.19
2024	\$0.193	\$63.85	\$7.57	\$14.15	\$16.50
2025	\$0.201	\$67.62	\$7.86	\$14.86	\$16.86
2026	\$0.208	\$71.72	\$8.03	\$15.60	\$17.18
2027	\$0.216	\$76.16	\$8.20	\$16.38	\$17.50
2028	\$0.225	\$80.93	\$8.38	\$17.19	\$17.82
2029	\$0.234	\$86.02	\$8.56	\$18.05	\$18.14
2030	\$0.244	\$91.44	\$8.75	\$18.95	\$18.46
2031	\$0.254	\$97.18	\$8.94	\$19.89	\$18.78
2032	\$0.265	\$103.25	\$9.13	\$20.88	\$19.10
2033	\$0.276	\$109.69	\$9.33	\$21.92	\$19.42
2034	\$0.288	\$116.54	\$9.53	\$23.01	\$19.74
2035	\$0.301	\$123.82	\$9.74	\$24.16	\$20.07
2036	\$0.314	\$131.54	\$9.95	\$25.36	\$20.39
2037	\$0.328	\$139.75	\$10.16	\$26.62	\$20.71
2038	\$0.342	\$148.48	\$10.38	\$27.95	\$21.02
2039	\$0.357	\$157.74	\$10.61	\$29.34	\$21.34
2040	\$0.373	\$167.59	\$10.83	\$30.80	\$21.65

3.3.3.2.2 Avoided capacity cost

Capacity costs are charged by ISO-NE to each of the region’s utilities in order to offset the region’s payments to generators through the Forward Capacity Market. (This market assures that enough capacity is available in the region to meet load during extreme weather or grid emergencies.) These

costs are allocated to each utility based on its share of the ISO-NE regional peak load. The value provided by net metering systems is based on average performance (power output) during the time of peak system demand. For the bulk grid perspective, net metering systems look like a reduction in demand, and therefore reduce the utility’s cost for capacity.

There are multiple potential methods to measure the effective capacity of generators with respect to different purposes. In determining the peak coincidence factors described in this or following subsections, the Department used the average performance of real in-state generators during particular times of day and particular months, as it determined were appropriate for the purpose at hand based on known cost allocation mechanisms or parallels with the treatment of energy efficiency. For example, the Department estimated economic peak coincidence for each generation technology by examining 2010, 2011 and 2012 performance of examples of each technology during afternoons in the month of July; ISO-NE peaks typically occur during July afternoons. These values were calculated based on the output of ten 2-axis tracking solar PV generators, four fixed solar PV generators, and two small wind generators. The resulting capacity peak coincidence values are shown in Table 3.

The capacity price forecast assumed by the Department, and used by default in the model, is based on recent electric utility regulatory filings including Integrated Resource Plans and purchase power acquisitions. The resulting capacity price forecast (in nominal dollars) is shown in Table 2.

Table 3: Department assumptions of net-metered generators’ performance during peak times used to calculate values of avoided capacity, avoided regional RNS cost, and avoided in-state transmission and distribution infrastructure. Each value shows the fraction of the system’s rated capacity that is assumed in the calculation of the value of the three avoided costs. For example, in calculating the value of avoided capacity costs due to a fixed solar PV system with a nameplate capacity of 100 kW, the system is assumed to reduce capacity costs by the same amount as a system that can output 49.5 kW and is always running or perfectly dispatchable. These values were calculated based on the output of ten 2-axis tracking solar PV generators, four fixed solar PV generators, and two small wind generators.

	Capacity	RNS	In-state T&D
Fixed PV	0.495	0.216	0.476
Tracking PV	0.595	0.263	0.562
Wind	0.045	0.069	0.050

3.3.3.2.3 Avoided regional transmission costs

Regional Network Service (RNS) costs are charged by ISO-NE to each of the region’s utilities to pay for the cost of upgrades to the region’s bulk transmission infrastructure. These are costs that have already been incurred, or are required to meet reliability standards, and thus cannot be entirely avoided – only their allocation among New England ratepayers can be changed. Avoiding these costs through net metering shifts the costs to ratepayers in other states. These costs are allocated to each utility based on its share of the monthly peak load within Vermont. The model uses values calculated by examining performance of Vermont generators during hour ranges when monthly peaks have occurred in Vermont over the last 5 years. The resulting average monthly peak coincidence values are shown in Table 3.

The values assigned to this cost are based on the ISO-NE forecast of the next 5 years' worth of RNS costs, and escalated based on historical increases in the Handy-Whitman Index of public utility construction costs. ISO-NE forecast RNS costs increase at 10% or more per year from 2012 to 2017, but the Department assumes that flattening regional peak loads, including demand response and distributed generation, will reduce this growth rate. The resulting regional transmission price forecast (in nominal dollars) is shown in Table 2.

3.3.3.2.4 Avoided in-state transmission and distribution costs

In-state transmission and distribution costs are those costs incurred by the state's distribution utilities or VELCO and which are not subject to regional cost allocation. The values used in this model are derived from those in the recently completed avoided transmission and distribution cost working group for the update to the electric energy efficiency cost-effectiveness screening tool. This working group consisted of representatives from the state's distribution, transmission, and efficiency utilities, and the Department. The values used in the model have been converted to nominal dollars using the assumed rate of inflation.

The in-state transmission and distribution upgrades deferred due to load reduction or on-site generation (such as net metering) are driven by reliability concerns. Therefore, rather than average peak coincidence for a net metering technology, the critical value is how much generation the grid can rely on seeing at peak times. Therefore, the Department calculated a "reliability" peak coincidence value, separate from the "economic" peak coincidence used in avoided capacity and regional transmission cost calculations. The Department calculated a reliability peak coincidence by calculating the average generator performance of several Vermont generators during June, July, and August afternoons. This corresponds to the methodology that ISO-NE uses to value energy efficiency in the Forward Capacity Market, results of which are used for transmission planning purposes. The resulting reliability peak coincidence values are shown in Table 3.

3.3.3.2.5 Market price suppression

Reductions in load shift the relationship between the supply curve and demand curve for both energy and capacity, resulting in changes in market price.²⁰ Because net metering looks like load reduction, the Department has approximated the market price suppression effect using analysis based on the 2011 Avoided Energy Supply Cost (AESC) study's calculation of the demand reduction induced price effect ("DRIPE") for Vermont. Energy DRIPE is a fraction of the value of avoided energy supply (starting at 9% and decaying over time), while capacity DRIPE has varying values over time, averaging to between \$2 and \$3 per kW-year. The assumptions regarding load, prices, and other factors used in the AESC study do not correspond directly to the assumptions used in this study, and load reduction with the particular load shapes corresponding to solar PV or wind generation are likely dissimilar from those from energy efficiency. As a result, the value attributed to net metering generation from this mechanism is very much approximate.

²⁰ This kind of market price suppression is a transfer between generators and ratepayers, so it is a benefit from a ratepayer perspective but would not be included in a societal cost-benefit analysis.

3.3.3.2.6 Value associated with meeting SPEED goals

The model allows for assignment of a value that ratepayers see that is attributable to the type of generation used by net metering systems installed by other customers. The analysis does not include, or attempt to quantify, the value of renewable attributes (such as RECs) to the participating customer, who is assumed to retain ownership of those attributes. Ratepayers see monetary value associated with the type of net metering technology and resource used by other customers' net metering through the fact that net-metered generation would help the state's utilities meet their SPEED goals. (The state has goals of 20% new SPEED resources by 2017 and 75% renewable electricity by 2032.) If a utility were to acquire SPEED resources elsewhere, there would likely be a small premium cost compared to market costs. This avoided premium is a benefit to all utility ratepayers from net-metered generation. Based on conversations with commenters the Department assumes this value is \$5/MWh (fixed in nominal dollar terms).

3.3.3.2.7 Climate change

The Department's analysis calculates the costs and benefits of net metering to the state's non-participating ratepayers both with and without the estimated externalized cost of greenhouse gas emissions. It should be noted that these benefits from a marginal net metering installation in Vermont do not flow to Vermonter ratepayers in direct monetary terms. Instead, they reflect both a societal cost that is avoided and the size of potential risk that Vermont ratepayers avoid by reducing greenhouse gas emissions. If these environmental costs were fully internalized, for example into the cost of energy, ratepayers would bear those costs. The Department is assuming a value of \$80 per metric ton of CO₂ emissions reduced (in \$2011); this is the societal value adopted by the Public Service Board for use in energy efficiency screening, and is intended to reflect the marginal cost of abatement. About \$2 of the \$80 is internalized in utility costs through the Regional Greenhouse Gas Initiative, so the analysis incorporates an additional cost of about \$78 (in \$2011) for cases in which costs of environmental externalities are included.

CO₂ emission reductions are calculated by using the 2010 ISO-New England marginal emission rate of 943 lbs/MWh.²¹ ISO-NE grid operations and markets almost always result in a gas generator dispatched as the marginal plant, so this value is comparable to the emissions from a natural gas generator. The Department's analysis does not track or account for emission or abatement of other greenhouse gasses.

3.4 Results of Cross-Subsidization Analysis

3.4.1 Systems Examined

This report presents the results of the cross-subsidization analysis for 6 systems, representing typical cases in Vermont:

- A 4 kW fixed solar PV system, net metered by a single residence
- A 4 kW 2-axis tracking solar PV system, net metered by a single residence
- A 4 kW wind generator, net metered by a single residence
- A 100 kW fixed solar PV system, net metered by a group

²¹ http://www.iso-ne.com/genrtion_resrcs/reports/emission/final_2010_emissions_report_v2.pdf

- A 100 kW 2-axis tracking solar PV system, net metered by a group
- A 100 kW wind generator, net metered by a group

3.4.2 Results for Systems Installed in 2013

The methodology described in section 3.3 allows the model to calculate costs incurred and benefits received from each typical net-metered generator on an annual basis. These values may also be combined into a 20-year levelized value. A levelized value is the constant value per kWh generated that has the same present value as the projected string of costs and/or benefits over the 20-year study period. This section presents graphs of the annual costs and benefits along with levelized costs, benefits, and net costs (costs minus benefits). Benefits are presented both with and without externalized carbon emission costs; levelized values are also presented from both an individual ratepayer and statewide perspective (corresponding to different discount rates).

3.4.2.1 4 kW fixed solar PV system, net metered by a single residence

A 4 kW fixed solar PV system would generate about 4,500 kWh annually with a capacity factor of 13.0%.

Figure 5. Annual costs and benefits associated with a 4 kW fixed solar PV residential system installed in 2013.

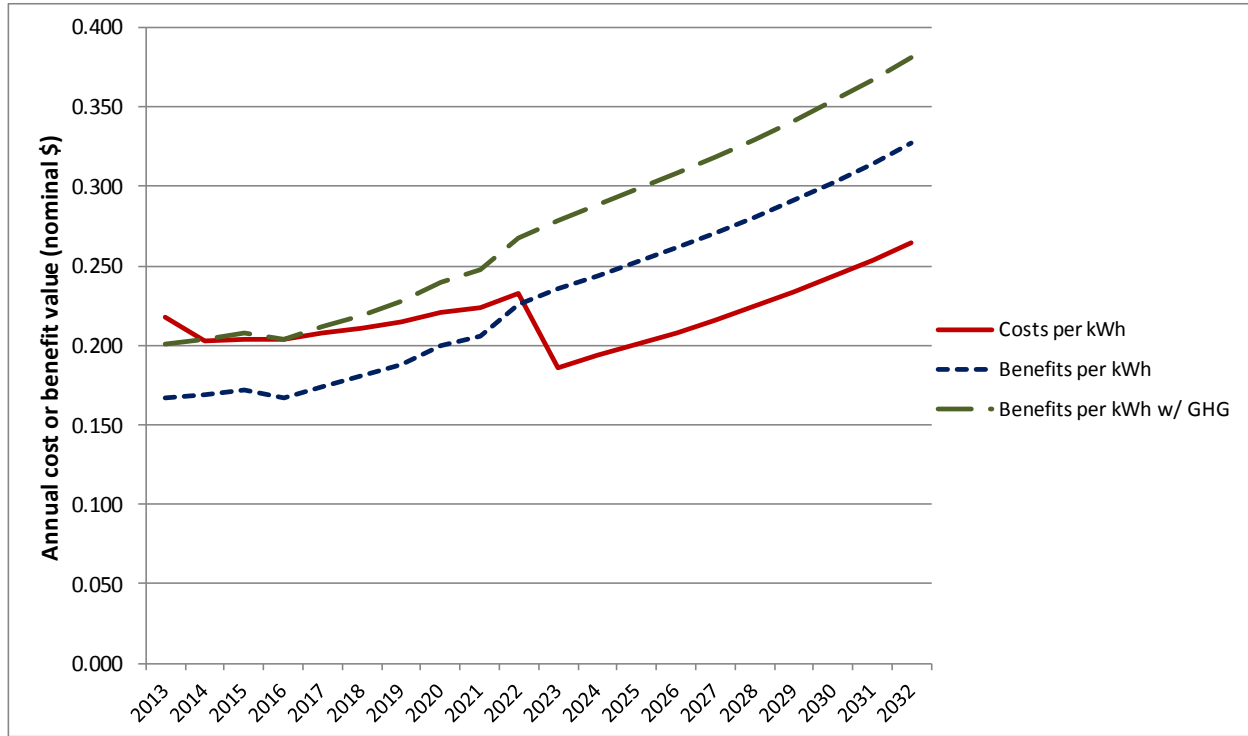


Table 4. Levelized cost, benefit, and net benefit of a 4 kW fixed solar PV residential system installed in 2013 to other ratepayers individually (“ratepayer”) or statewide.

Units: \$ per kWh generated	No GHG value included			GHG value included	
Cost	Benefit	Net Benefit	Benefit	Net Benefit	
Ratepayer	0.221	0.215	(\$0.006)	\$0.257	\$0.036
Statewide	0.222	0.222	\$0.000	\$0.264	\$0.043

3.4.2.2 4 kW tracking solar PV system, net metered by a single residence

A 4 kW 2-axis tracking solar PV system would generate about 6,000 kWh annually with a capacity factor of 17.1%.

Figure 6. Annual costs and benefits associated with a 4 kW tracking solar PV residential system installed in 2013.

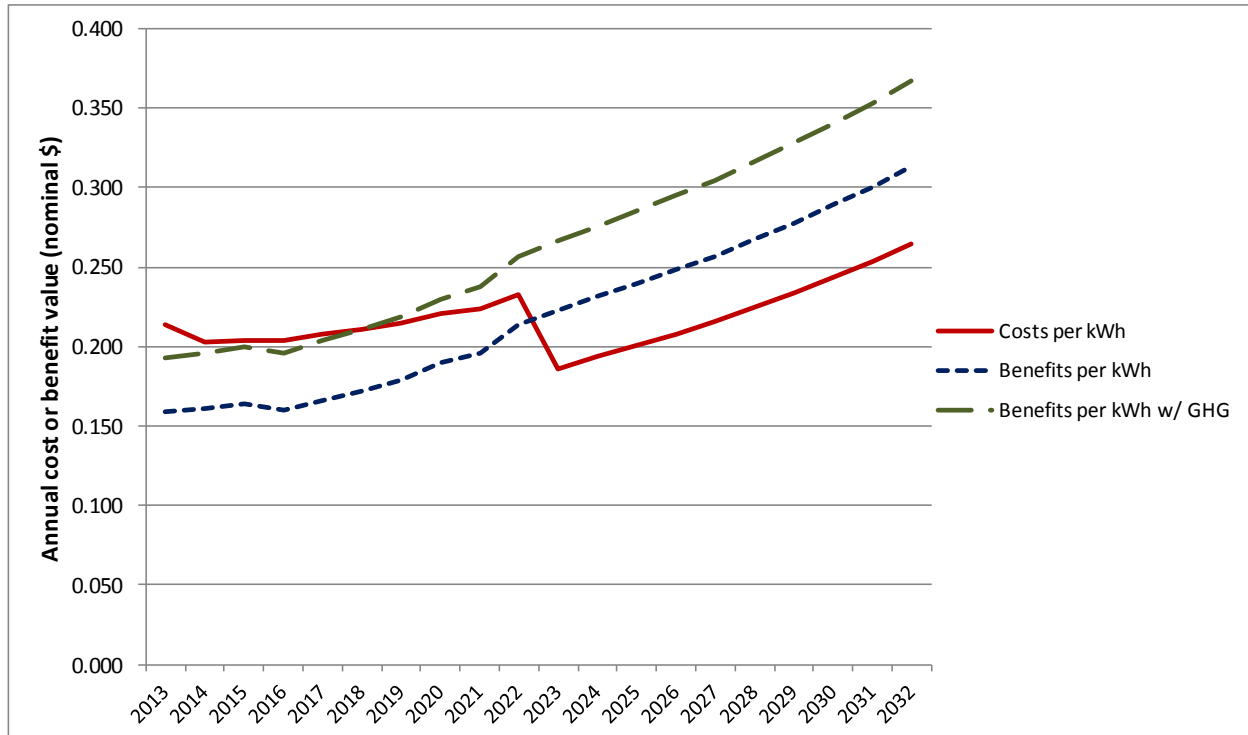


Table 5. Levelized cost, benefit, and net benefit of a 4 kW tracking solar PV residential system installed in 2013 to other ratepayers individually (“ratepayer”) or statewide.

Units: \$ per kWh generated	No GHG value included			GHG value included	
Cost	Benefit	Net Benefit	Benefit	Net Benefit	
Ratepayer	0.220	0.205	(\$0.016)	\$0.247	\$0.026
Statewide	0.221	0.211	(\$0.010)	\$0.254	\$0.033

3.4.2.3 4 kW wind generator, net metered by a single residence

A 4 kW wind generator generates approximately 2,600 kWh per year, with a capacity factor of 7.4%. If such a generator were sited optimally, it could have a significantly higher capacity factor and generate more electricity. However, the per-kWh costs and benefits described here would be unlikely to change significantly.

Figure 7. Annual costs and benefits associated with a 4 kW residential wind generator installed in 2013.

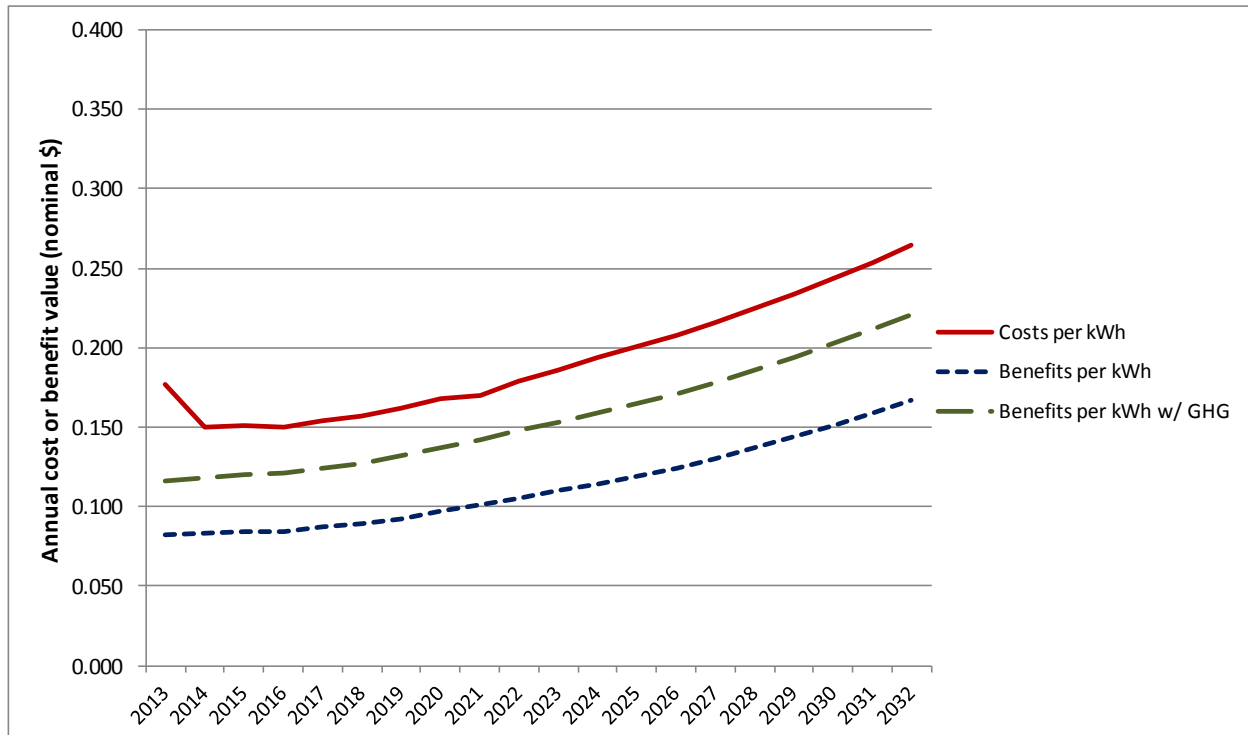


Table 6. Levelized cost, benefit, and net benefit of a 4 kW residential wind generator installed in 2013 to other ratepayers individually (“ratepayer”) or statewide.

Units: \$ per kWh generated	No GHG value included		GHG value included		
Cost	Benefit	Net Benefit	Benefit	Net Benefit	
Ratepayer	0.184	0.105	(\$0.079)	\$0.147	(\$0.037)
Statewide	0.187	0.108	(\$0.079)	\$0.151	(\$0.037)

3.4.2.4 100 kW fixed solar PV system, group net metered

A 100 kW fixed solar PV system would generate about 114,000 kWh annually with a capacity factor of 13.0%.

Figure 8. Annual costs and benefits associated with a 100 kW fixed solar PV group net-metered system installed in 2013.

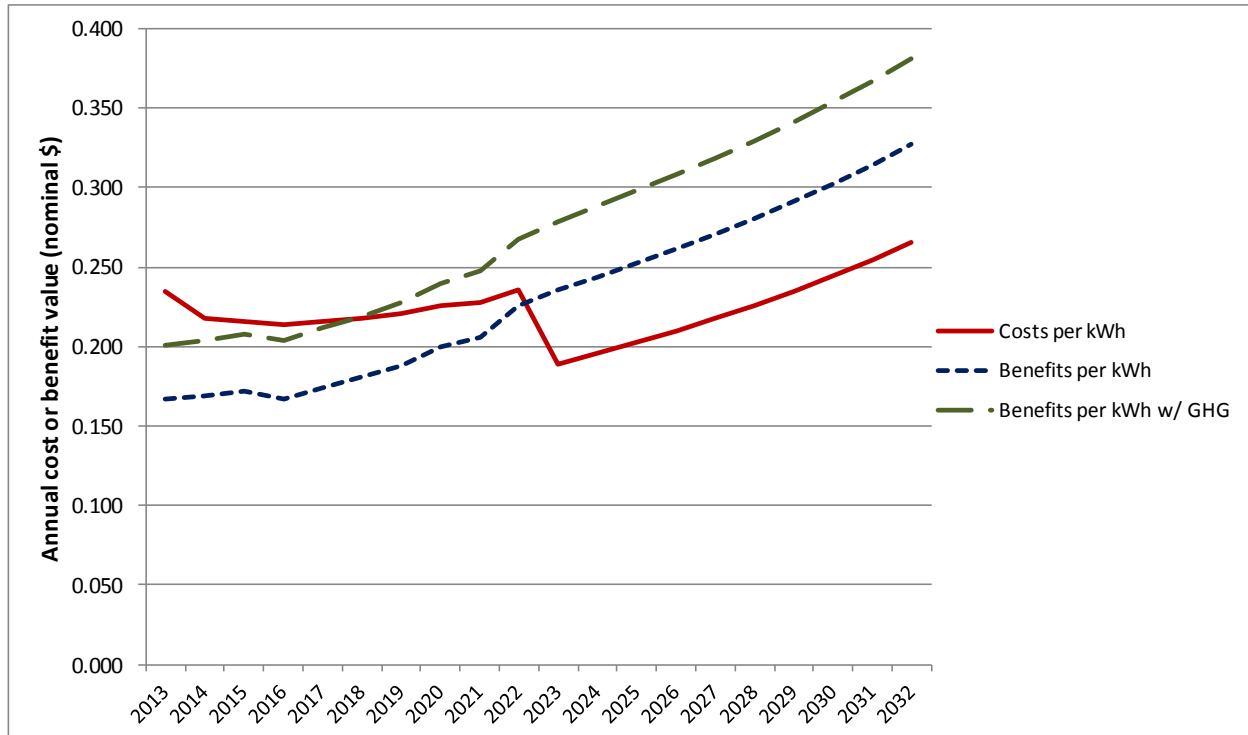


Table 7. Levelized cost, benefit, and net benefit of a 100 kW fixed solar PV group net-metered system installed in 2013 to other ratepayers individually (“ratepayer”) or statewide.

Units: \$ per kWh generated	No GHG value included			GHG value included	
Cost	Benefit	Net Benefit	Benefit	Net Benefit	
Ratepayer	0.228	0.215	(\$0.013)	\$0.257	\$0.029
Statewide	0.228	0.222	(\$0.006)	\$0.264	\$0.036

3.4.2.5 100 kW tracking solar PV system, group net metered

A 100 kW 2-axis tracking solar PV system would generate about 150,000 kWh annually with a capacity factor of 17.1%.

Figure 9. Annual costs and benefits associated with a 100 kW tracking solar PV group net-metered system installed in 2013.

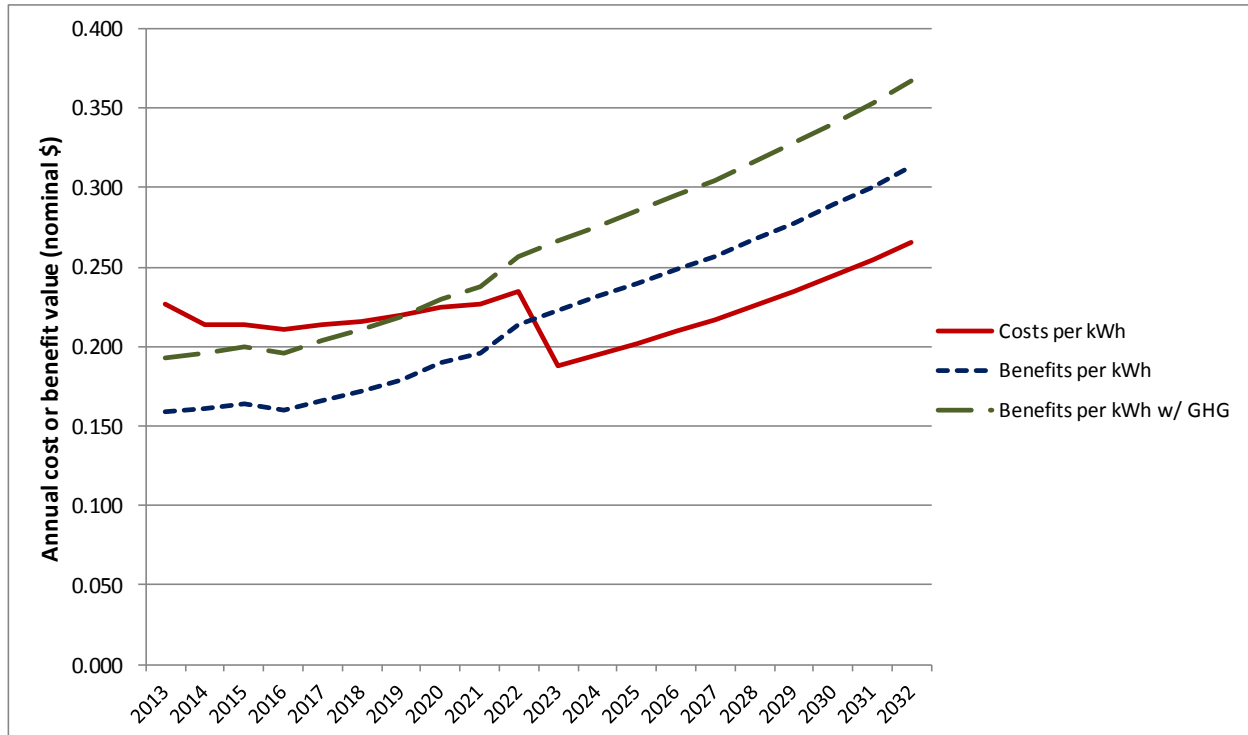


Table 8. Levelized cost, benefit, and net benefit of a 100 kW tracking solar PV group net-metered system installed in 2013 to other ratepayers individually (“ratepayer”) or statewide.

Units: \$ per kWh generated	No GHG value included			GHG value included	
Cost	Benefit	Net Benefit	Benefit	Net Benefit	
Ratepayer	0.226	0.205	(\$0.021)	\$0.247	\$0.021
Statewide	0.226	0.211	(\$0.015)	\$0.254	\$0.028

3.4.2.6 100 kW wind generator, group net metered

A 100 kW wind generator generates approximately 65,000 kWh per year, with a capacity factor of 7.4%. If such a generator were sited optimally, it could have a significantly higher capacity factor and generate more electricity. However, the per-kWh costs and benefits described here would be unlikely to change significantly.

Figure 10. Annual costs and benefits associated with a 100 kW group net-metered wind generator installed in 2013.

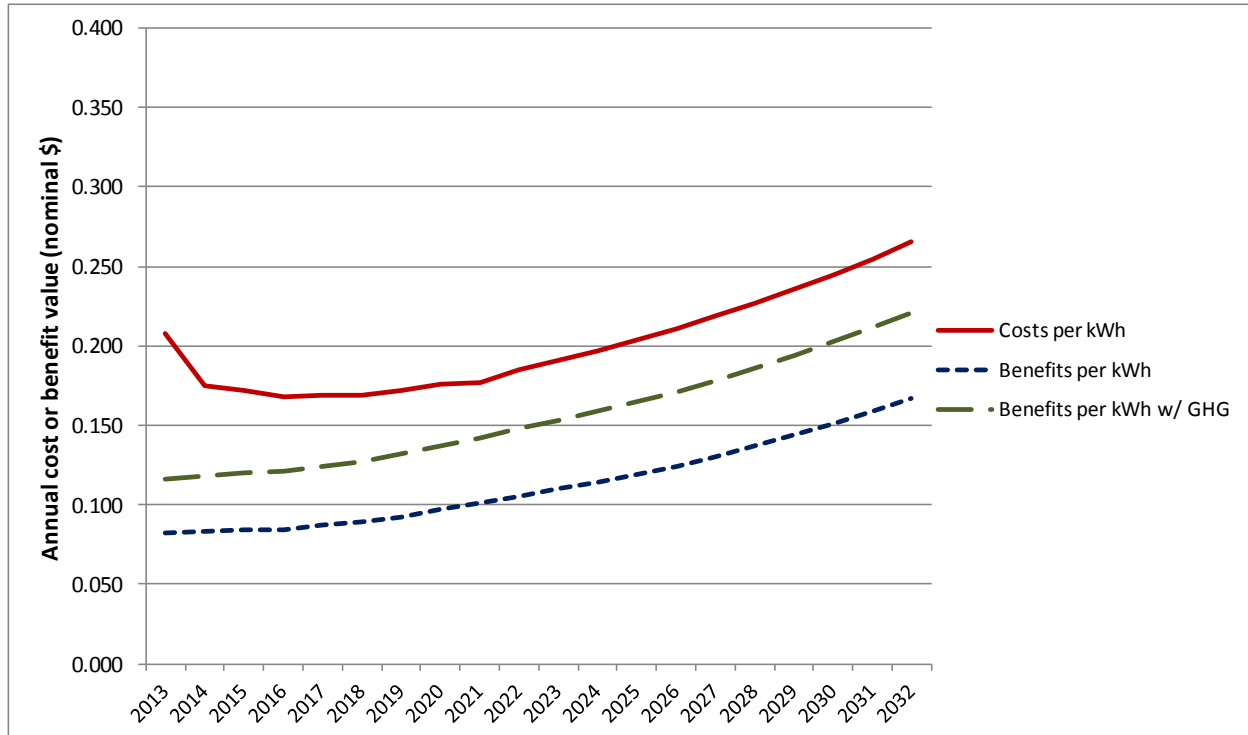


Table 9. Levelized cost, benefit, and net benefit of a 100 kW group net-metered wind generator installed in 2013 to other ratepayers individually (“ratepayer”) or statewide.

Units: \$ per kWh generated	No GHG value included		GHG value included		
Cost	Benefit	Net Benefit	Benefit	Net Benefit	
Ratepayer	0.197	0.105	(\$0.092)	\$0.147	(\$0.050)
Statewide	0.199	0.108	(\$0.091)	\$0.151	(\$0.048)

3.4.3 Systems Installed in Coming Years

Costs of energy, capacity, and transmission which contribute to electric rates may also be avoided by a net metered generator. These costs are projected to change over time. In addition, as electric rates rise the solar credit that applies to a newly installed net metered solar generator is expected to fall. This leads to the question of how the analysis of cross-subsidization presented in the previous section is likely to change for systems installed in future years.

While the analysis described in this section is necessarily more uncertain than the analysis presented in the previous section, it does provide some directional information and insights regarding future costs and benefits. The limitations of the model the Department developed for the cross-subsidization analysis also limit this analysis. In particular, the avoided transmission and distribution costs attributable to net metered generation depend on the State’s and utilities’ load shapes (particularly including the timing of monthly and seasonal demand peaks). Load shapes will change as net metering is deployed, saturation of appliances changes, and electric energy efficiency measures are implemented. Projections of costs and benefits are necessarily more uncertain as they reach further into the future.

In order to undertake this secondary analysis, the Department modeled the costs and benefits, as in Section 3.3, but for systems installed in years after 2013. The following figures illustrate the changes in net costs and benefits for residential-scale systems installed in subsequent years. (The results of large-scale systems are similar, as illustrated in the previous section, and are omitted here for brevity.) Qualitatively, the benefits of solar PV net metered generation increase more quickly than the costs (due in large part to the decreasing solar credit), so that solar PV systems installed in later years have greater net benefit than systems installed in 2013. The same is not true for wind generation.

Figure 11. *Levelized net benefit of a 4 kW individual net metered fixed solar PV system installed in each year 2013 to 2018. Four lines show the net benefits from the perspective of a typical Vermont ratepayer, from the statewide perspective of all ratepayers, and both including and excluding the value of GHG emission reductions due to system operation.*

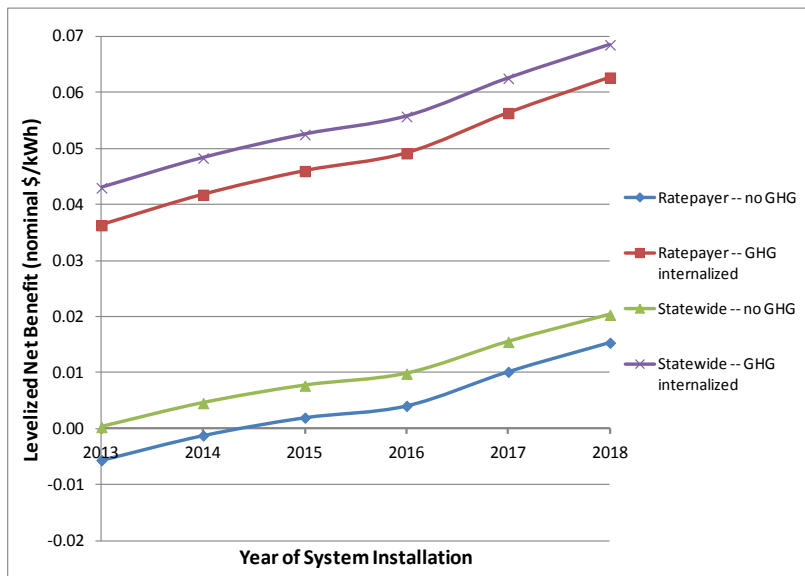


Figure 12. Levelized net benefit of a 4 kW individual net metered 2-axis tracking solar PV system installed in each year 2013 to 2018. Four lines show the net benefits from the perspective of a typical Vermont ratepayer, from the statewide perspective of all ratepayers, and both including and excluding the value of GHG emission reductions due to system operation.

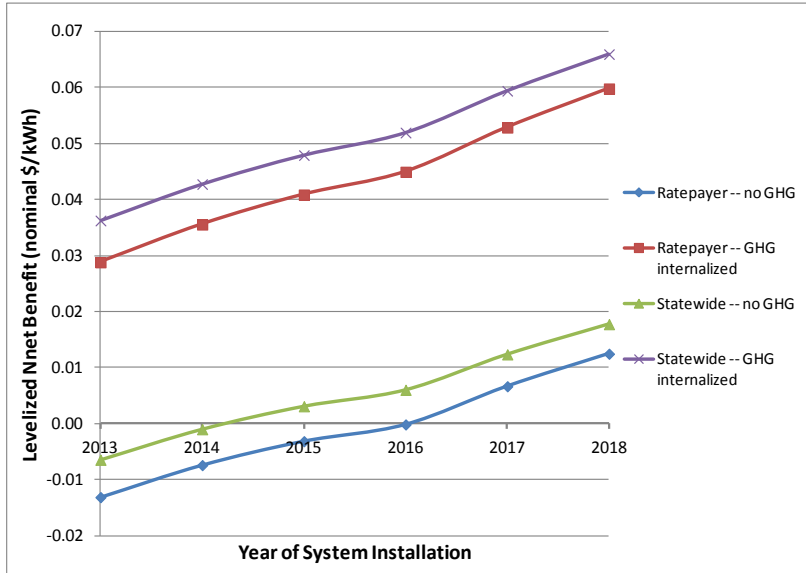
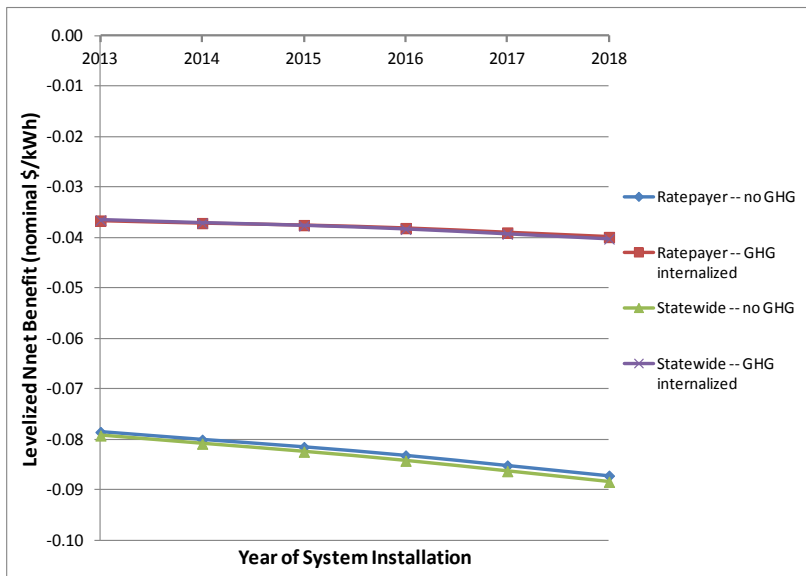


Figure 13. Levelized net benefit of a 4 kW individual net metered wind generator system installed in each year 2013 to 2018. Four lines show the net benefits from the perspective of a typical Vermont ratepayer, from the statewide perspective of all ratepayers, and both including and excluding the value of GHG emission reductions due to system operation.



3.4.4 Concluding Remarks on Cross-Subsidization

The analysis presented in the preceding sections indicates that net metered systems do not impose a significant net cost to ratepayers who are not net metering participants. Net benefits from solar photovoltaic systems, which represent nearly 88% of net metering systems, are either positive or negative depending on the discount rate chosen and whether the value of non-internalized greenhouse gas emissions are included or not included respectively. There would be real long-term risk to ratepayers if decisions were made that assume no increase in the internalization of these costs over the 20-year analysis period for this study. Impacts on transmission and distribution infrastructure costs are a significant component of the value of net-metered systems. Solar PV has much greater coincidence of generation with times of peak demand than does wind power; this results in more net benefits for solar PV than for wind. Wind power has net costs whether greenhouse gas emissions costs are included or not. Given the relatively small scale of wind system net metering in Vermont, the Department does not consider this to be a significant cost to ratepayers.

4 General assessment of Vermont's net metering statute, rules, and procedures

The Department has reviewed the relevant statutes, rules, and general policy in Vermont, and the results of the cross-subsidization analysis described in Section 3. The Department's general assessment is that Vermont's current net metering policy is a successful aspect of State's overall energy strategy that is cost-effectively advancing the state's renewable energy goals. Net metering in Vermont has undergone a significant growth, enabled in part by changes in state policy and statutes, as well as by changes in technology costs and business models. In addition to the costs and benefits discussed in the preceding sections, net metering has enabled the growth of numerous small businesses, which employ hundreds of Vermonters and form an important part of the foundation of Vermont's clean energy economy. Based on this success and the analysis presented in this report, the Department has concluded that there is no need for statutory changes at this time.

The Department highlights the process, led by the Public Service Board (PSB), to clarify and make more uniform the billing standards and practices associated with net metering. The PSB issued an order with billing standards and procedures on November 14, 2012, and has the authority to revise these standards as may be warranted. While additional changes may be required as utilities and regulators understand billing cases and configurations not yet covered in the standards, utilities should expeditiously update their tariffs and procedures to match the Board's order. These efforts should provide clarity and uniformity; lack of clarity and uniformity had been an area of concern to the Department. Stability in utility procedures and state policies would provide an opportunity to better understand the impacts of current policies and allow regulatory processes to come up to date. For example, such stability should allow the PSB to update their net metering rule (5.100) to reflect statutory changes and updated interconnection standards since the rule was last updated. The PSB has the authority to raise the 4% capacity cap for each utility, reducing any future need to raise that cap through statutory change.