REDUCING THE COST OF SOLAR ENERGY IN MAINE

FINAL REPORT

Prepared for

Maine Office of the Public Advocate

By

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March 14, 2024

Reducing the cost of solar energy in Maine

Prepared for Maine Office of the Public Advocate ("OPA") by London Economics International LLC

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London Economics International LLC ("LEI") was engaged to provide consulting services to the Maine Office of the Public Advocate ("OPA") to assist in examining the costs of Maine's Net Energy Billing ("NEB") program. Maine offers two options within the NEB program: the NEB kWh Netting program, which serves as a decrement to wholesale load, and the NEB Tariff Rate program, which is connected to the distribution system but is treated as a supply of energy to the ISO-NE wholesale market.

LEI examined i) the direct additional ratepayer costs of the programs (i.e., the costs which would not be incurred if the programs did not exist), ii) the indirect impact of the programs on the economics of Maine's standard offer service, and iii) cross-subsidies from non-participating ratepayers not included in the first two categories. LEI also examined the opportunity cost of the NEB programs—the cost of the next-best alternative, including adjusting for an apples-to-apples comparison of benefits. LEI found that the total cost to ratepayers in 2023 of all these categories of cost for the two programs was an estimated $284 million; and that costs are likely to increase to over $300 million for 2024.

LEI's findings indicate that the benefits of the NEB programs can be achieved much less expensively. Considering the benefits of the NEB programs compared to the benefits of Maine's utility-scale procurements, the compensation to NEB sponsors is far more than the cost of Maine's utility-scale projects, some of which are similar in size to the maximum size allowed in the NEB program.

LEI is not arguing that the benefits of solar or other renewable energy do not accrue to the NEB projects, just that such benefits can be had at a far lower cost. Neither is LEI arguing that the NEB program should be replaced by utility-scale procurements. LEI's findings simply demonstrate that there is ample leeway for the compensation to NEB program sponsors to be designed to be much less costly to ratepayers, while still incentivizing solar generation and receiving the benefits thereof.

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List of Acronyms

A/S	Ancillary services
AEO	Annual energy outlook
ATC	Around the clock
BHD	Bangor Hydro District
BTM	Behind the meter
CEP	Competitive electricity provider
CMP	Central Maine Power
EIA	Energy Information Administration
ISO-NE	New England Independent System Operator
LEI	London Economics International
LMP	Locational marginal price
LSE	Load serving entity
MPD	Maine Public District
MPUC	Maine Public Utility Commission
MW(h)	Megawatt(hour)
NEB	Net energy billing
NECEC	New England Clean Energy Connect
OPA	Office of the Public Advocate
OTC	Over the counter
PPA	Power purchase agreement
REC	Renewable energy credit
RFP	Request for proposal
RPS	Renewable portfolio standard
SOP	Standard offer provider
SOS	Standard offer service
SSA	Standard service agreement
T&D	Transmission and distribution utility

1 Introduction and executive summary

The Maine Office of the Public Advocate ("OPA") engaged London Economics International ("LEI") to examine the costs of Maine's Net Energy Billing ("NEB") program. LEI is a US-owned and operated firm based in Boston, specializing in economic and financial advisory services for energy and infrastructure industries around the world. LEI has a wealth of knowledge and solid experience in regulatory economics and deregulation, has a strong track record of analysis and support for clients in the ISO-NE market, and has testified and provided expert opinions in front of state public utilities commissions, including in Maine (see Section 6 (Appendix 1) for more information on LEI).

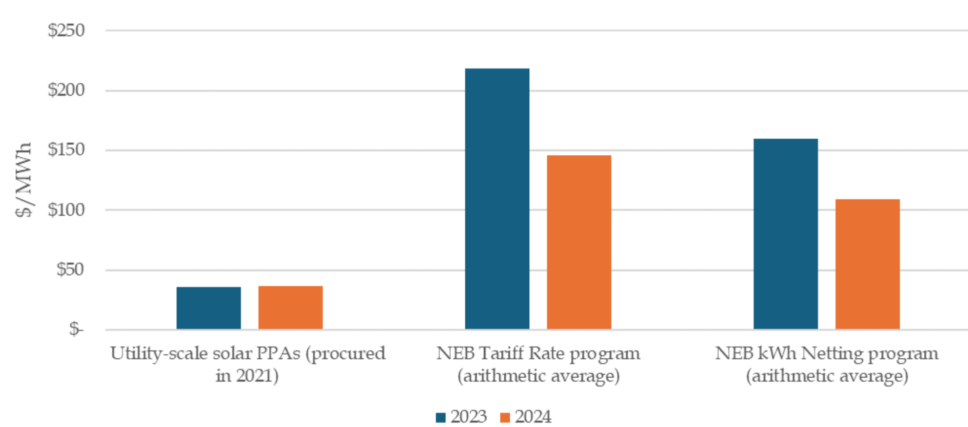
The OPA asked LEI to examine the efficacy of the NEB programs and whether:

1) developers of renewable energy projects have been potentially over-compensated under the NEB program; and

2) utility customers not participating in the NEB program must pay an unfairly higher portion of the cost of other bill components which are not covered by NEB participants.

As demonstrated in detail in this report, LEI found that, yes, project sponsors are over-compensated by the NEB program. Compensation to sponsors is far higher for the two NEB programs (the kWh Netting program and the Tariff Rate program, whose characteristics are discussed in detail in Section 2) than for the utility-scale solar projects that Maine has recently procured under power purchase agreements ("PPAs") (see Figure 1).

Figure 1. Compensation to project sponsors across Maine's solar energy support programs



Notes: NEB Tariff Rate program compensation is assumed to be 85% of the arithmetic average tariff rate, from MPUC <https://www.maine.gov/mpuc/regulated-utilities/electricity/neb>; NEB kWh Netting price is assumed to be 85% of the arithmetic average residential standard offer service price, from MPUC <https://www.maine.gov/mpuc/regulated-utilities/electricity/standard-offer-rates/cmp>; Average utility-scale PPA price: see details in Figure 11 of this report.

Even considering the benefits of the NEB programs compared to the benefits of Maine's utility-scale PPAs (which LEI discusses in Section 4 of this report), compensation to sponsors is far more expensive than procurement of utility-scale projects (some of which are small and similar in size to the maximum size allowed in the NEB program).

LEI is not arguing that benefits of solar or other renewable energy do not accrue to the NEB projects, simply that such benefits can be had at a far lower cost. As noted by the Maine Public Utility Commission ("MPUC") *"… [I]ncentive programs should not be evaluated solely on whether costs to ratepayers are simply lower than that value, but also on whether the program design achieves that value at the lowest possible cost. An important question the Legislature may want to consider is whether the value sought from the NEB program can be obtained at a lower cost."*[1] Maine can achieve the benefits of solar generation at a much lower cost than it is currently paying, by adjusting the compensation to sponsors of NEB program facilities.

As LEI demonstrates in Section 4, compensation for NEB community solar, as distinct from behind-the-meter ("BTM") projects, should reflect the additional value of avoided transmission cost, but apart from that, the benefits are the same as from utility-scale PPA projects. For example, a tariff rate and/or kWh Netting rate which reflected PPA prices plus a premium for transmission cost savings, would reflect the benefits of the NEB projects, but would cost Maine ratepayers far less than they are now paying for NEB projects.

LEI also found substantial cross-subsidies from non-participating customers to participating customers, to cover the costs of the NEB program.

1.1 Methodology

LEI categorized the costs of the NEB program conceptually as **ratepayer costs** (of which we identified three categories) and **opportunity costs:**

1. **Direct additional ratepayer costs**: The NEB Tariff Rate program compensates projects based on tariff rates set annually by the MPUC, based on a formula which reflects retail prices. The output of these projects is sold at wholesale market prices. The difference between the tariff rate and the wholesale market price is the net cost of the program—this net cost is an **additional cost** from the program, compared to not having the program at all. It is a cross-subsidy by other ratepayers because it is collected by the transmission and distribution utilities ("T&Ds") from all ratepayers. LEI discusses this in detail in Section 2.

2. **Indirect additional ratepayer costs:** As LEI demonstrates in detail in Section 3, the NEB kWh Netting program puts upward pressure on Maine standard offer service ("SOS") prices for all Maine ratepayers taking SOS. This is a cross-subsidy from non-participants to NEB program participants.

[1] MPUC *Report on the Effectiveness of Net Energy Billing in Achieving State Policy Goals and Providing Benefits to Ratepayers*. November 10, 2020. P. 12.

3. **Cross-subsidies from non-participating ratepayers not included in 1 or 2 above**: The cost to Maine T&Ds in terms of lost delivery revenues from the NEB kWh Netting program is recovered from all ratepayers. There is no increase in the total cost recovery allowed for transmission and distribution assets, nor are there any assets identified as stranded (so there is no additional cost to the system), but the NEB kWh Netting program results in less energy over which to recover the T&Ds' delivery costs. It shifts the cost to ratepayers who are not subscribers to the NEB kWh Netting program. This is discussed in detail in Section 2.

4. **Opportunity cost of the NEB Tariff Rate program:** The cost of any economic choice is the opportunity cost—in other words, the cost of alternatives. An alternative to the NEB program for incentivizing solar and other renewable energy in Maine has been a program in which the utilities are directed to procure utility-scale contracts for renewable energy. The net opportunity cost of the NEB program is positive in the amount by which it is more expensive than the net cost of recent utility-scale procurements in Maine. This methodology, including adjustments for differences in benefits from the types of programs to ensure apples-to-apples comparison, is discussed in detail in Section 4.

1.2 Summary of findings

LEI discusses the details of its methodology, data, assumptions, and numerical findings throughout this report. LEI made conservative assumptions where judgement was required—in other words, we made assumptions which allowed the NEB program net costs to be estimated as low as possible. These are identified throughout the report.

LEI arrived at an estimate of total cost of $284.1 million in 2023 (see Figure 1). Of this total, costs compared to not having the NEB program in place amount to $118.6 million, and cross-subsidization from the kWh Netting program (not an additional cost) is an estimated $24.1 million. As discussed in detail in Section 4, because peak period energy prices were high in 2023, the cost of Maine's utility-scale solar power purchase agreements ("PPAs") was ***negative***—PPA prices were lower than the price of energy, so the contracts had positive energy market earnings. This resulted in an additional opportunity cost for NEB projects compared to the PPAs.

For 2024, some costs are likely to be lower, driven by lower expected costs for wholesale energy and lower SOS rates. SOS and tariff rates for 2024 are already determined, and this information is available from the MPUC, indicating lower tariff rates. On the other hand, the NEB programs are on track to grow strongly from 2023 levels, which increases total costs. Overall, we project 2024 costs to be higher than in 2023, at $330 million.

Figure 2. Total estimated costs of Maine NEB programs

Cost category	Description	Unit costs $/MWh 2023	Unit costs $/MWh 2024	Estimated applicable MWh 2023	Estimated applicable MWh 2024	Total costs 2023	Total costs 2024
Total ratepayer cost							
Additional cost							
	Direct: Tariff Rate program net supply cost (cost above wholesale energy + capacity)	$ 167.19	$ 117.72	645,679	867,076	$ 107,950,997	$ 102,072,269
	Indirect: kWh Netting program impact on SOS prices	$ 1.80	$ 5.89	5,913,969	5,913,969	$ 10,643,214	$ 34,815,655
	Total					$ 118,594,212	$ 136,887,924
Cross-subsidization not included above							
	kWh Netting program shift of T&D costs	$ 88.10	$ 81.48	274,000	536,038	$ 24,138,720	$ 43,673,839
Opportunity cost							
NEB Tariff Rate program		$ 168.40	$ 136.80	645,679	867,076	$ 108,732,268	$ 118,614,991
NEB kWh Netting		$ 119.11	$ 57.58	274,000	536,038	$ 32,637,345	$ 30,863,355
Total cost						**$ 284,102,545**	**$ 330,040,109**

All details of assumptions underlying the cost per megawatt ("MW") and generation in megawatt hours ("MWh") are found in this report, in the detailed sections.

2 Maine's Net Energy Billing program

2.1 Overview of the NEB program

Maine's NEB program is defined in LD 1711 *"An Act to Promote Solar Energy Projects and Distributed Generation Resources in Maine"* P.L. 2019, Chapter 478 ("Act"). Part A of the Act, now codified at 35-A M.R.S. §§ 3209-A, 3209-B, defined the NEB program.[2] The NEB program is available for residential and non-residential customers of Maine's T&Ds (Versant and CMP) for service from small solar facilities (up to 5 MW) and other renewable energy projects. Within the NEB program, there are two options:[3]

1. **NEB Kilowatt-hour ("kWh") Netting program**: This program is available to residential, commercial, and industrial customers. Customers may choose to have their own project or to share a project with other customers. The NEB developer retains ownership of the renewable energy credits ("RECs") generated by the facility. The program provides kWh credits on participating customers' electricity bills regardless of when the energy is produced (as discussed in more detail below), so that the entire retail rate is avoided. From the perspective of the ISO-NE system operator, projects in the NEB kWh Netting program serve to reduce load.

2. **NEB Tariff Rate program**: This program is available only to non-residential customers. Customers may choose to have their own project or to share a project with other customers. The NEB developer retains ownership of the RECs. The program provides dollar credits on participating customers' electricity bills based on rates established annually by the MPUC. From the perspective of the ISO-NE system operator, projects in the Tariff Rate program operate as generators.

Both these options credit customers for more than simply the cost of energy (which is the supply portion of a utility bill). The NEB kWh Netting program credits the entire cost of supply, delivery, and other bill charges to participants, because it decreases monthly billed energy consumption on a kWh basis. The Tariff Rate program provides a Commission-determined tariff rate which reflects the cost of standard offer service, and in addition partly encompasses the cost of transmission and distribution.[4] This tariff is a discount to the participating customer's bill. The distinguishing features of these programs, and current size and uptake, are discussed in detail below.

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[2] MPUC. *Report on the Effectiveness of Net Energy Billing in Achieving State Policy Goals and Providing Benefits to Ratepayers Pursuant to An Act to Promote Solar Energy Projects and Distributed Generation Resources in Maine*. Maine.Gov. Published November 10th, 2020. <https://www.maine.gov/mpuc/legislative/reports>

[3] MPUC. *Programs for Small Solar, Community and Other Renewable Energy Projects*. Maine.Gov. <https://www.maine.gov/mpuc/regulated-utilities/electricity/renewable-programs> Accessed January 20, 2024.

[4] Ibid.

2.2 NEB kWh Netting program

The NEB kWh Netting program includes BTM rooftop solar as well as community solar projects, which are not behind the customer's meter. In the early years of the NEB kWh Netting program, most of the solar capacity was behind the meter, with an estimated 60 MW of installed BTM capacity in 2020, and an estimated production of 77,000 MWh for the year.[5] Since that time, most of the NEB kWh Netting projects which have come online or have been proposed have been community solar projects.

Unlike rooftop solar, NEB community solar projects do not reduce physical demand for energy at the customer's meter. Metered retail demand – the demand that a load-serving entity ("LSE") must supply— is the same. NEB projects are supply projects connected to the distribution system. They can result in less demand for transmission services, but not for distribution services.

Community solar projects are marketed to potential participants ("subscribers") by project sponsors registered with the MPUC. Project sponsors provide subscribers with a disclosure document outlining the fuel source, facility output subscription percentage, term, and other conditions of participating in the shared project. NEB kWh Netting project sponsors are paid pursuant to an individual contract with a subscriber. This is a separate bill from the bills sent by the T&D and the standard offer service provider ("SOP") (the LSE for customers on standard offer service) The project sponsor acts on the subscriber's behalf by requesting, executing, and complying with the provisions of NEB and informing the T&D of the allocation of credits among the accounts of all the subscribers.[6] The NEB kWh Netting project sponsor and the subscriber must both be on the same T&D system. All utility customers in Maine have smart meters and customer consumption data is sent daily to ISO-NE for settlement. The information is also passed from the T&D to the SOP, to settle the SOP's load obligation.

The NEB kWh Netting program has been growing steadily but it is still a small portion of retail consumption in Maine. As of June 2023, kWh credits accounted for about 2.5% of all T&D customer load served by competitive energy providers ("CEPs") and SOPs (see Figure 3).[7]

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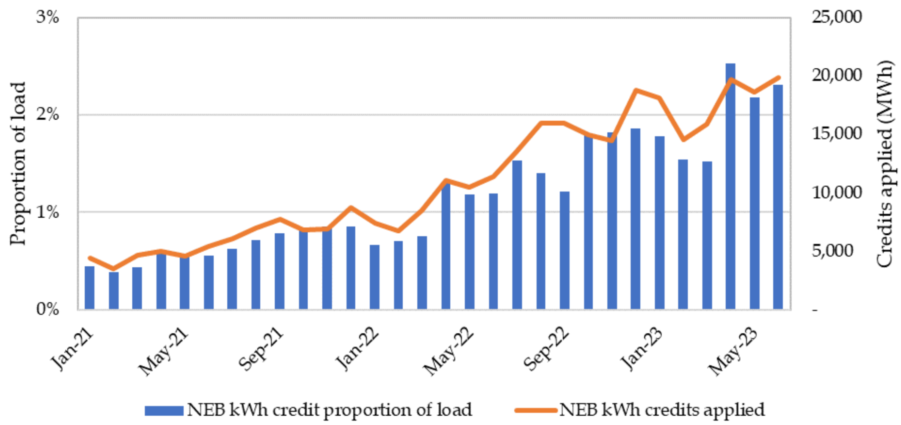
[5] ISO-NE. "Final 2021 PV Forecast." April 29, 2021. P. 59. <https://www.iso-ne.com/static-assets/documents/2021/04/final_2021_pv_forecast.pdf>

[6] MPUC. *Code of Maine Rule 65 – Department of Public Utilities Commission 407 – Public Utilities Commission Chapter 313*. Maine.Gov. <https://www.maine.gov/mpuc/sites/maine.gov.mpuc/files/inline-files/Chapter313NEB.pdf> Accessed January 23, 2024.

[7] MPUC. *Migration statistics*. Maine.Gov <https://www.maine.gov/mpuc/regulated-utilities/electricity/choosing-supplier/migration-statistics> Accessed February 28, 2024; *Applied NEB kWh by Month*. Maine.Gov. <https://www.maine.gov/mpuc/regulated-utilities/electricity/rfps/standard-offer/2023-00092/cmp> Accessed February 28, 2024; and *kWh Credit Net Energy Billing Data*. Maine.Gov. <https://www.maine.gov/mpuc/regulated-utilities/electricity/rfps/standard-offer/2023-00092/bhd> Accessed February 28, 2024.

Figure 3. NEB kWh Netting credits, compared to total CMP and Versant retail consumption



Source: MPUC. "Migration statistics". Maine.Gov <https://www.maine.gov/mpuc/regulated-utilities/electricity/choosing-supplier/migration-statistics> Accessed February 28, 2024; Public Utility Commission. "Applied NEB kWh by Month". Maine.Gov. <https://www.maine.gov/mpuc/regulated-utilities/electricity/rfps/standard-offer/2023-00092/cmp> Accessed February 28, 2024; and Public Utility Commission. "kWh Credit Net Energy Billing Data". Maine.Gov. <https://www.maine.gov/mpuc/regulated-utilities/electricity/rfps/standard-offer/2023-00092/bhd> Accessed February 28, 2024.

Though in terms of consumption it is a small share, in terms of capacity the NEB kWh Netting program is relatively much larger. CMP projects the capacity of the kWh Netting program on its system to reach 399 MW by the end of 2024.[8] This is more than 25% of CMP's total system peak load of 1,500 MW.[9]

2.2.1 kWh Netting credits are applied to customer's metered usage

Maine's T&Ds are required to offer net energy billing, whether the customer takes generation service from an SOP or a CEP. If the customer takes SOS, the SOP is required to provide net energy billing; whereas a CEP may or may not agree to provide service on a net energy basis.[10] In practice, CEPs in Maine have not provided a net energy billing option. Therefore, LEI's analysis of the impact of the NEB kWh Netting program on retail prices, discussed in Section 3, focuses on SOS prices, not competitive retail energy prices.

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[8] MPUC. *kWh Credit Net Energy Billing Data.* <https://www.maine.gov/mpuc/regulated-utilities/electricity/rfps/standard-offer/2023-00092/cmp>. Accessed March 12, 2024.

[9] CMP. <https://www.cmpco.com/w/system-information>. Accessed March 12, 2024.

[10] Versant Power. *Net Energy Billing*. Versant Power.com. <https://www.versantpower.com/residential/rates/bhe-net-energy-billing/#3> Accessed January 23, 2024.

The kWh Netting program provides kWh credits on subscribers' electricity bills. Maine PUC 65-407, Chapter 313: *Customer Net Energy Billing,* specifies the way in which an NEB customer must be billed by the T&D. A Maine ratepayer receives two separate bills—one from the T&D, which covers delivery charges (netting out the NEB program credits if applicable), and the other from the SOP (assuming the customer takes standard offer service) which is included in the customer's paper or electronic bill, but which is a separate page on which it is made clear that that portion of the bill is not for T&D services, but for the energy supplied by the SOP, which also nets out the NEB credits if applicable.

A simplified example of a single residential customer (Customer X) subscribing versus not subscribing to the NEB program provides a helpful illustration. Customer X consumed a metered 7,520 kWh over six months in 2023 (see the blue column in Figure 4). If they had not subscribed to the NEB kWh Netting program, their total bill (delivery charges plus supply charges) would have been $1,931, for the 7,520 kWh of metered consumption (also in blue in Figure 4). If they had subscribed to a hypothetical NEB facility and received a hypothetical 6,100 kWh credits (in the orange column) over the six months, their billed kWh would have been 1,420 (in the green column). They would have saved the supply charge and the delivery charge for each kWh credit, and their bill for the six months would have totaled $365 (in the green column). The customer is not allowed to have negative billed kWhs, so in months in which NEB credits are greater than metered consumption, the credits are banked for use in later months (see yellow column in Figure 4). Banked credits can be rolled forward for 12 months, after which they expire.

Figure 4. Customer X in NEB kWh Netting program

	NEB facility	Customer X		
Month	Generation allocated to Customer X (kWh)	Customer's metered kWhs	Net kWhs billed to customer (metered kWh less NEB allocation)	Banked credits (kWh)
July	1,500	1,400	-	100
Aug	1,600	1,700	-	-
Sept	1,100	1,000	-	100
Oct	700	1,120	320	-
Nov	750	1,200	450	-
Dec	450	1,100	650	-
Total	**6,100**	**7,520**	**1,420**	
Supply price ($/kWh)		$ 0.16631	$ 0.16631	
Delivery charge ($/kWh)		$ 0.0905	$ 0.0905	
Customer bill for 6 months		**$ 1,931**	**$ 365**	

Separately, the subscriber pays the NEB project sponsor an agreed contract price for the 6,100 kWh.

2.2.2 kWh Netting credits result in cross-subsidies

As shown in the example of Customer X above, the NEB kWh Netting program results in fewer kWh over which to recover the costs of transmission and distribution assets. There is no increase in the total cost recovery for transmission and distribution assets, and no assets are assumed to be no longer used or useful, but the T&Ds are allowed to collect the costs which are not paid for by the NEB subscribers from all ratepayers. These costs are not additional costs to the overall system but are a shift in the cost of the kWh Netting program participants to all ratepayers. They are a cross-subsidy.

The T&Ds file annual "stranded cost" filings, in which they estimate these costs going forward.[11] The costs are not stranded in the usual sense, because they are not the result of T&D assets no longer used or useful. The costs are cross-subsidies collected from non-participants. As of January 2024, the T&Ds estimated that annual production reached 536,038 MWh from operational projects (see Figure 5). The corresponding delivery (transmission and distribution) cost for operational kWh Netting agreements which the T&Ds are allowed to collect from other ratepayers is an estimated $43,673,839, an average of $0.08148/kWh ($81.48/MWh) for each kWh of kWh Netting solar generation.

Figure 5. Estimated delivery costs cross-subsidy from kWh Netting program based on 2024 production

		Project capacity (kW)	Estimated annual production (kWh)	Delivery rate ($/kWh)	Estimated delivery revenue Loss
CMP kWh Netting Agreements	Operational	288,952.76	462,121,312	$ 0.081796	$ 37,799,675
	Active Non-Operational	300,708.40	524,648,927	$ 0.081796	$ 42,914,184
	Pending	141,283.85	234,396,595	$ 0.081796	$ 19,172,704
	Total	**730,945.01**	**1,221,166,834**		**$ 99,886,562**
Versant kWh Netting Agreements	Operational	46,708.66	73,916,751	$ 0.07947	$ 5,874,164
	Active Non-Operational	157,647.20	220,958,316	$ 0.07947	$ 17,559,557
	Pending	49,369.89	66,027,820	$ 0.07947	$ 5,247,231
	Total	**253,726**	**360,902,887**		**$ 28,680,952**
Total CMP + Versant	Operational	335,661	536,038,063	$ 0.08148	$ 43,673,839
	Active Non-Operational	458,356	745,607,243	$ 0.08111	$ 60,473,741
	Pending	190,654	300,424,415	$ 0.08128	$ 24,419,935
	Total	**984,671**	**1,582,069,721**		**$ 128,567,515**

Note: Entries highlighted in blue correspond to entries in Figure 2 of this report.

Source: Versant, <https://mpuc-cms.maine.gov/CQM.Public.WebUI/MatterManagement/MatterFilingItem.aspx?FilingSeq=122429&CaseNumber=2020-00199> Accessed March 1, 2024; CMP, <https://mpuc-cms.maine.gov/CQM.Public.WebUI/MatterManagement/MatterFilingItem.aspx?FilingSeq=122302&CaseNumber=2020-00199> Accessed March 1, 2024.

As noted above, these costs are not additional costs to the power system, they are a subsidy to ratepayers who subscribe to the kWh Netting program, from ratepayers who do not subscribe.

[11] These costs are referred to as stranded costs for the purposes of the T&D utilities' regulatory filings but are not the result of T&D assets no longer to be used at all (which is the classic definition of a stranded asset). If the NEB kWh projects caused some assets to no longer be used at all, then that would be a stranded cost. In this case, however, the costs are cross-subsidies from program participants to non-participants, and are not stranded costs in the classical sense.

2.3 NEB Tariff Rate program

Under the NEB Tariff Rate program, the T&D takes title to the generation from the NEB project and immediately sells it into the ISO-NE system. Therefore, from the perspective of the ISO-NE system operator, projects in the Tariff Rate program operate as generators, and are not a decrement to the subscriber's load. The Tariff Rate program gives participants a dollar amount bill credit equal to the applicable tariff rate multiplied by the customer's share of the facility output during the applicable period. Bill credits are not allowed to result in a negative customer bill; customers can accumulate unused bill credits and apply them over a 12-month rolling period.[12]

For 2023, the T&Ds estimated that currently operational Tariff Rate facilities produced 645,679 MWh annually.[13] This amounts to about 11% of total non-residential energy consumed in 2023 (an estimated 6,011,197 MWh).[14] As noted above, however, the Tariff Rate program is not a decrement to load, it is a source of supply.

Tariff rates are set by MPUC each year, for each T&D and customer class. Tariff rates are based on SOS prices and include a percentage for delivery (transmission and distribution). Specifically (emphasis added): [15]

> *"A. The tariff rate for a customer participating in net energy billing with a distributed generation resource described in this paragraph must* ***equal the standard-offer service rate*** *established under section 3212 that is applicable to the customer receiving the credit* ***plus 75% of the effective transmission and distribution*** *rate for the rate class that includes the smallest commercial*

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12 MPUC. *Code of Maine Rule 65 – Department of Public Utilities Commission 407 – Public Utilities Commission Chapter 313*. Maine.Gov. <https://www.maine.gov/mpuc/sites/maine.gov.mpuc/files/inline-files/Chapter313NEB.pdf> Accessed January 23, 2024.

13 CMP, MPUC. https://mpuc-cms.maine.gov/CQM.Public.WebUI/MatterManagement/MatterFilingItem.aspx?FilingSeq=122302&CaseNumber=2020-00199, January 2024; Versant, MPUC. https://mpuc-cms.maine.gov/CQM.Public.WebUI/MatterManagement/MatterFilingItem.aspx?FilingSeq=122429&CaseNumber=2020-00199, January, 2024.

14 MPUC. RFP for CMP - Appendix E - Small, Medium and Large Customer Class. Published November 13, 2023. <https://www.maine.gov/mpuc/regulated-utilities/electricity/rfps/standard-offer/2023-00092/cmp> Accessed March 11 2024; MPUC. RFP for BHD - Appendix E - Small, Medium and Large Customer Class. Published November 14, 2023. <https://www.maine.gov/mpuc/regulated-utilities/electricity/rfps/standard-offer/2023-00092/bhd> Accessed March 11 2024. MPUC. RFP for MPD - Appendix E - Small, Medium and Large Customer Class. Published November 14, 2023. <https://www.maine.gov/mpuc/regulated-utilities/electricity/rfps/standard-offer/2023-00092/mpd> Accessed March 11, 2024.

15 Maine State Legislature. *Title 35-A: Public Utilities Part 3: Electric Power Chapter 32: Electric Industry Restructuring §3209-A. Net Energy Billing*. <https://legislature.maine.gov/legis/statutes/35-A/title35-Asec3209-B.html> Accessed January 20, 2024.

customers of the investor-owned transmission and distribution utility. The tariff rate under this paragraph applies to net energy billing with a distributed generation resource:

(1) With a nameplate ***capacity of greater than one megawatt if****:*

> *(a) The entity developing the distributed generation resource certifies by affidavit with accompanying documentation to the commission that the entity,* ***before September 1, 2022, commenced on-site physical work*** *of a significant nature on the distributed generation resource and the entity has made and will continue to make continuous on-site construction…;*
>
> *or*
>
> *(b) The distributed generation resource is* ***collocated with a net energy billing customer*** *that is or net energy billing customers that are subscribed to at least 50% of the facility's output; or*

(2) With a nameplate ***capacity of one megawatt or less****. [PL 2021, c. 659, §19 (AMD).]"*

And, if the resource is not covered in paragraph A above (i.e., if it is one megawatt or more and is neither collocated nor under construction by September 1, 2022): [16]

"A-1. ***The tariff rate*** *for a customer participating in net energy billing under this section with a distributed generation resource not governed by paragraph A must:*

> *(1)* ***In 2022, equal the standard-offer service rate*** *established pursuant to section 3212 that was applicable to the rate class of the customer receiving the credit* ***on December 31, 2020 plus 75% of the effective transmission and distribution rate that was in effect on December 31, 2020*** *for the rate class that includes the smallest commercial customers of the investor-owned transmission and distribution utility; and*
>
> *(2)* ***Increase by 2.25% on January 1st of each subsequent year, beginning January 1, 2023****. [PL 2021, c. 659, §19 (NEW).]*

CMP uses the term "Tariff rate" for qualifying projects, and "Alternate Tariff Rate" for non-qualifying projects; Versant refers to "Tariff Rate 1" for qualifying projects, and "Tariff Rate 2" for non-qualifying projects. For both T&Ds, the Alternative Tariff Rate and Rate 2 were lower than the rate for qualifying projects in 2023 and 2024 (see Figure 6).[17]

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[16] Ibid.

[17] Ibid.

Figure 6. Tariff rates offered in NEB Tariff Rate program

Period	Customer Class	Central Maine Power Company	Versant Power – Bangor Hydro District	Versant Power – Maine Public District
Calendar Year 2022 (January 19, 2022 Order in Docket No. 2019-00197)	Small Commercial	$0.192834 per kWh	$0.207552 per kWh	$0.184707 per kWh
	Medium Commercial or Industrial	$0.188937 per kWh	$0.202088 per kWh	$0.178505 per kWh
	Large Commercial or Industrial	$0.145562 per kWh	$0.174322 per kWh	$0.205990 per kWh

Period	Customer Class	Central Maine Power Company	Versant Power – Bangor Hydro District	Versant Power – Maine Public District
Calendar Year 2023 Tariff Rates for Facilities that Qualify under Ch. 313 Section 3(K)(4)(a) (December 9, 2022 Order in Docket No. 2019-00197)	Small Commercial	$0.246922 per kWh	$0.250467 per kWh	$0.230652 per kWh
	Medium Commercial or Industrial	$0.235503 per kWh	$0.243196 per kWh	$0.225255 per kWh
	Large Commercial or Industrial	$0.206838 per kWh	$0.223903 per kWh	$0.255255 per kWh

Period	Customer Class	Central Maine Power Company	Versant Power – Bangor Hydro District	Versant Power – Maine Public District
Calendar Year 2023 Tariff Rates for Facilities that **do not** Qualify under Ch. 313 Section 3(K)(4)(a) (December 9, 2022 Order in Docket No. 2019-00197)	Small Commercial	$0.132952 per kWh	$0.149972 per kWh	$0.124374 per kWh
	Medium Commercial or Industrial	$0.130468 per kWh	$0.152627 per kWh	$0.120656 per kWh
	Large Commercial or Industrial	$0.144042 per kWh	$0.154547 per kWh	$0.142478 per kWh

Period	Customer Class	Central Maine Power Company	Versant Power – Bangor Hydro District	Versant Power – Maine Public District
Calendar Year 2024 Tariff Rates for Facilities that **do not** Qualify under Ch. 313 Section 3(K)(4)(a) (December 18, 2023 Order in Docket No. 2019-00197)	Small Commercial	$0.135943 per kWh	$0.0.153346 per kWh	$0.127172 per kWh
	Medium Commercial or Industrial	$0.133404 per kWh	$0.156061 per kWh	$0.123371 per kWh
	Large Commercial or Industrial	$0.147283 per kWh	$0.158024 per kWh	$0.145684 per kWh

Period	Customer Class	Central Maine Power Company	Versant Power – Bangor Hydro District	Versant Power – Maine Public District
Calendar Year 2024 Tariff Rates for Facilities that Qualify under Ch. 313 Section 3(K)(4)(a) (December 18, 2023 Order in Docket No. 2019-00197)	Small Commercial	$0.179475 per kWh	$0.215267 per kWh	$0.212602 per kWh
	Medium Commercial or Industrial	$0.172905 per kWh	$0.208935 per kWh	$0.227715 per kWh
	Large Commercial or Industrial	$0.180986 per kWh	$0.216214 per kWh	$0.257715 per kWh

Source: MPUC. <https://www.maine.gov/mpuc/regulated-utilities/electricity/neb>.

For both T&Ds, most of the operational Tariff Rate program facilities qualify under Ch. 313 Section 3(K)(4)(a), and earn the higher tariff rates; whereas most of the active non-operational facilities are non-qualifying facilities and earn the lower non-qualifying rates, based on the T&D's projections (see Figure 7).

Figure 7. T&Ds' estimates of NEB Tariff rate project energy production, and LEI estimate for 2024

		Estimated annual production from qualifying projects (kWh)	Estimated annual production from non-qualifying projects (kWh)	Total qualifying and non-qualifying production (kWh)
CMP Tariff Rate agreements	Operational	450,642,235	93,080,291	543,722,526
	Active Non-Operational	52,828,582	458,246,813	511,075,395
	Pending	91,386,218	34,255,104	125,641,322
	Total	**594,857,035**	**585,582,208**	**1,180,439,243**
Versant Tariff Rate agreements	Operational	82,210,287	19,745,741	101,956,028
	Active Non-Operational	84,668,133	133,694,419	218,362,552
	Pending	25,083,174	5,426,294	30,509,468
	Total	**191,961,594**	**158,866,454**	**350,828,048**
CMP + Versant Tariff Rate agreements	Operational	532,852,522	112,826,032	645,678,554
	Active Non-Operational	68,748,358	295,970,616	364,718,974
	Pending	58,234,696	19,840,699	78,075,395
	Total	**659,835,576**	**428,637,347**	**1,088,472,923**
LEI estimate	Operational	532,852,522	112,826,032	645,678,554
	1/2 Active Non-Operationa	34,374,179	147,985,308	182,359,487
	1/2 Pending	29,117,348	9,920,350	39,037,698
	Total	**596,344,049**	**270,731,690**	**867,075,738**

Note: Entries highlighted in blue correspond to entries in Figure 2 of this report.

Source: CMP, https://mpuc-cms.maine.gov/CQM.Public.WebUI/MatterManagement/MatterFilingItem.aspx?FilingSeq=122302&CaseNumber=2020-00199, January 2024; Versant, https://mpuc-cms.maine.gov/CQM.Public.WebUI/MatterManagement/MatterFilingItem.aspx?FilingSeq=122429&CaseNumber=2020-00199, January 2024.

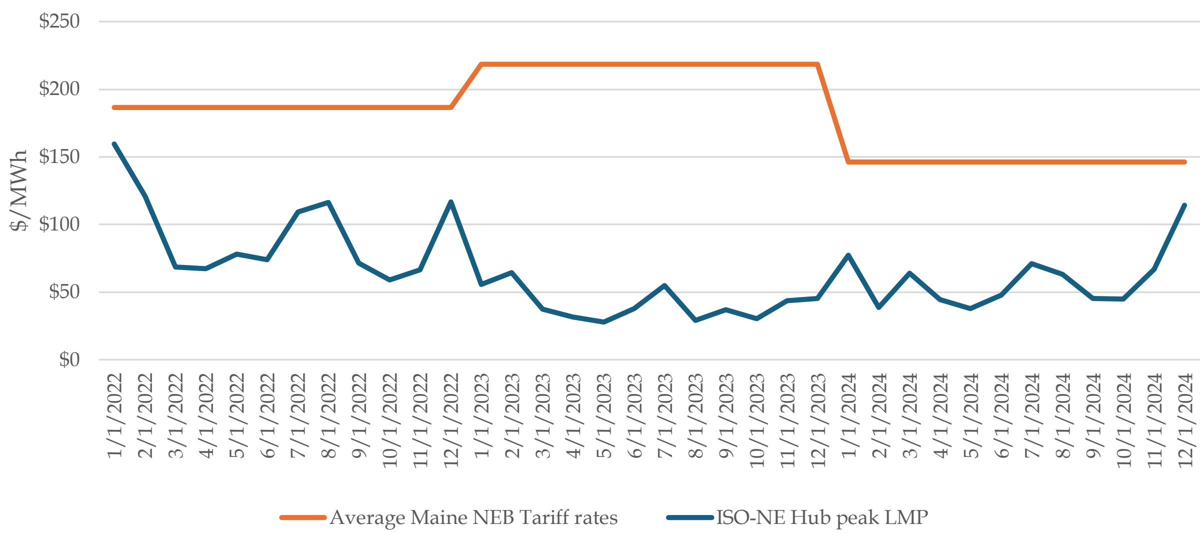
2.3.1 The Tariff Rate program directly increases energy supply costs

In 2023, tariff rates were much higher than the peak period wholesale locational marginal price ("LMP") for which the T&D would have sold the energy entitlements (see Figure 8). In 2023, the weighted average tariff rate was $218.52/MWh for operational projects, compared to the average peak wholesale LMP of $41.36/MWh.[18] This increment of $177.16/MWh over wholesale prices is the estimated additional cost

[18] LEI's calculation of the average NEB Tariff rates are the tariff rates shown in Figure 6, weighted by the share of qualifying versus non-qualifying operational generation shown in Figure 7.

of the energy from the Tariff Rate program. The Tariff Rate projects do not necessarily provide capacity value, but if they did, accounting for LEI's estimated value of capacity at $9.97/MWh in 2023[19] reduces the increment to $167.19/MWh.

Figure 8. ISO-NE monthly average peak wholesale LMPs, and NEB tariff rates



Source: MPUC. *Net Energy Tariff Rates,* <https://www.maine.gov/mpuc/regulated-utilities/electricity/neb>; third-party data provider, accessed March 6, 2024.

CMP and Versant reported an estimated annual production of 645,679 MWh from operational NEB Tariff rate projects by the end of 2023 (as shown previously in Figure 7).[20] To arrive at a rough estimate of the additional cost of the NEB Tariff Rate program, LEI multiplied the annual production by the $167.19/MWh incremental cost in 2023, resulting in an estimated $107,950,997 in additional supply costs from the Tariff Rate program in 2023.

For 2024, tariff rates have already been determined (as shown in Figure 6 above). 2024 average tariff rates were calculated by LEI as the weighted average of 2024 rates for operational projects, and ½ of non-operational and pending projects. The Maine wholesale LMP price for the 2024 year is not yet known. Therefore, LEI referred to publicly available forward prices as of March 6, 2024. For 2024, the average

[19] Based on capacity market revenues earned in 2023 in ISO-NE, and average around-the-clock energy prices in 2023. Source: ISO-NE <https://www.iso-ne.com/about/key-stats/markets#fcaresults>.

[20] Maine PUC. https://mpuc-cms.maine.gov/CQM.Public.WebUI/MatterManagement/MatterFilingItem.aspx?FilingSeq=122302&CaseNumber=2020-00199, and https://mpuc-cms.maine.gov/CQM.Public.WebUI/MatterManagement/MatterFilingItem.aspx?FilingSeq=122429&CaseNumber=2020-00199.

tariff rate is an estimated $187.46/MWh, compared to the forward monthly wholesale peak LMP of $59.74/MWh as seen in Figure 5. LEI assumed a capacity cost of $10/MWh. The increment of $117.72/MWh over wholesale prices is the estimated additional cost of NEB projects. In 2024 the total estimated cost would be $102,072,269 assuming ½ of non-operational and pending projects are included.

This increment of direct supply costs is collected from non-participating ratepayers; it is a cross-subsidy which is paid for by non-participating ratepayers.

3 The impact of the NEB kWh Netting program on SOS prices

LEI examined the structure of Maine's SOS, and the structure of the NEB kWh Netting program to derive the indirect impact of the NEB kWh Netting program on SOS prices. Because the Tariff Rates are not applied to metered kWh and therefore do not reduce billed kWh consumption, the Tariff Rate program does not impact SOP margins.

3.1 Overview of Maine's SOS

Maine's restructured electricity market allows a retail electricity customer to purchase their electricity supply from a competitive energy provider. Electric consumers that are not served by a CEP automatically have their electricity supplied by the standard offer provider. SOPs provide all or a specified portion of electric generation service to consumers receiving SOS.[21] The SOS product is a load-following, all-requirements product (energy, capacity, and ancillary services ("A/S")), for all hours. The T&Ds deliver SOS but are not responsible for procuring it.

Each year, the MPUC purchases SOS on behalf of SOS customers, using a competitive solicitation for a contract which is characterized by the following:[22]

- **Typically, a year-long obligation:** The SOP usually commits to a year-long contract, but proposals for commitment periods of six months, eighteen months, and two years are acceptable. For the small customer class (which includes residential customers), the winning SOS prices are fixed for the whole calendar year (or commitment period). Prices for the medium and large customer classes generally vary by month.

- **Minimum percentages of retail load, at fixed increments:** A provider of SOS is required to serve a minimum percent of retail load for a given T&D's customer class. According to the most recent procurement, for service starting in 2024, in the CMP and Versant-Bangor Hydro District area bids can be submitted in 25% increments for the small class load.[23] For the medium class, bids may be submitted for 20% increments, and for the large class bids may only be submitted for

[21] Maine State Legislature. *Code of Maine Rule 65 – Department of Public Utilities Commission 407 – Public Utilities Commission Chapter 301*. Maine.Gov. <https://www.maine.gov/mpuc/electricity/rfps/standard_offer/sosmall0306/BHE/Appendix%20A%20Chapter%20301%20407c301.pdf>. Page 9. Accessed January 20, 2024.

[22]MPUC. *Standard Offer Bid Solicitations*. Maine.Gov. <https://www.maine.gov/mpuc/regulated-utilities/electricity/rfps/standard-offer>. Accessed January 23, 2024.

[23] MPUC. *Request for Proposals to Provide Standard Offer Service to Central Maine Power Company Customers*. Maine.Gov. Published September 13, 2023. <https://www.maine.gov/mpuc/sites/maine.gov.mpuc/files/inline-files/CMP%20SO%20RFP%202024%20FINAL%2020230913.pdf> and MPUC. *Request for Proposals to Provide Standard Offer Service to Versant Power – Bangor Hydro District Customer*. Maine.Gov. Published September 13, 2023. <https://www.maine.gov/mpuc/sites/maine.gov.mpuc/files/inline-files/BHD%20SO%20RFP%202024%20FINAL%2020230913.pdf>.

100% of the service requirement.[24] For the Versant-Maine Power District, all customer classes require bidders to commit to 100% of the service requirement.[25]

- **The actual load in kWh that the SOP must serve is not known at the time it submits its bid:** The SOP knows only the share of load that it will have to serve if it is awarded an SOS contract. The SOP can refer to historical load information provided by MPUC to help it determine the share it wishes to bid.

3.1.1 Payments to SOPs are based on billed kWh

SOPs are paid the SOS rate based on the share (the percentage) of the SOS load which they win, and the contract price per kWh they offered. According to the SOP Standard Service Agreement ("SSA") documents, the T&D pays the SOP a daily payment for SOS during the term of the agreement in an amount equal to the product of:

- The daily aggregate amount of kWhs ***billed*** (emphasis added) to retail SOS customers (small, medium and large customers);
- The provider's share thereof;
- The applicable contract price (in $/kWh);
- Minus the uncollectible allowance percentage of the amount calculated.[26]

The SOS is paid based on the percentage of load **billed** to a retail SOS customer, not the actual load it **delivers** to the retail customer as measured at the customer's meter.

The NEB kWh Netting program reduces **billed** kWh for a participating NEB customer. This reduction in billed kWh will not correspond to a reduction in the SOP's load obligation to that customer, which is measured in **metered** kWh.[27] This disconnect gives rise to a price-increasing effect of the NEB kWh Netting program on the SOS price, as discussed next.

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[24] Ibid.

[25] Ibid.

[26] MPUC. *Contract Exhibit D - Providers Shares and Rates*. Maine.Gov. <https://www.maine.gov/mpuc/regulated-utilities/electricity/rfps/standard-offer/2023-00092/cmp>. Accessed January 23, 2024.

[27] MPUC. *Contract Exhibit A - T&D Specific Provisions*. Maine.Gov. <https://www.maine.gov/mpuc/regulated-utilities/electricity/rfps/standard-offer/2023-00092/cmp> Accessed February 28, 2024, and conference call January 30, 2023, with CMP representatives.

3.1.2 The metered-versus-billed kWh gap

As explained above, SOPs are paid based on billed kWh, not metered kWh. The SOP forgoes the retail price it would have earned from meeting the customer's energy demand, but it saves only the wholesale cost of the energy. The SOP must still deliver the same number of kWhs to the customer's meter – recall that neither the kWh Netting program nor the Tariff Rate program reduce retail energy demand.

To illustrate this impact, we turn again to the simplified example of Customer X subscribing versus not subscribing to the NEB kWh Netting program. As assumed previously, Customer X consumed a metered 7,520 kWh over six months in 2023 (see the blue column in Figure 9). If Customer X did not participate in the NEB kWh Netting program, the SOP earns revenues of $1,250.65 (7,520 kWh multiplied by the SOS rate of $0.16631 per kWh) for serving this customer (also in blue in Figure 9).

The cost that the SOS incurred to serve this load is the wholesale price of energy ($0.0334/kWh) and the estimated price of capacity ($0.00997/kWh)[28] times the metered consumption of 7,520 kWh, i.e., $251.46 (in blue in Figure 9). The SOP would have no kWh credits against its load obligation to Customer X if Customer X were not in the NEB program. Thus, the total cost to serve this customer's load is $326.44 (highlighted in grey in Figure 9).

The SOP's revenue of $1,250.65 less its energy cost of $251.46 is $924.21 (in grey), which LEI refers to as the SOP's gross margin.[29] The SOP's gross margin per metered kWh supplied is $0.12/kWh.

[28] Based on capacity market revenues earned in 2023 in ISO-NE, and average around-the-clock energy prices in 2023. Source: <https://www.iso-ne.com/about/key-stats/markets#fcaresu>.

[29] To simplify the analysis, LEI assumed the cost of ancillary services are zero; however, the SOP is responsible for these costs, and to provide these services as part of the standard offer, on the basis of metered load.

Figure 9. Single-customer example of metered-versus-billed kWh gap

	NEB facility	Customer X			SOP
Month	Generation allocated to Customer X	Customer's metered kWhs	Net kWhs billed to customer	Banked credits	Reduction in overall load obligation
July	1,500	1,400	-	100	1,500
Aug	1,600	1,700	-	-	1,600
Sept	1,100	1,000	-	100	1,100
Oct	700	1,120	320	-	700
Nov	750	1,200	450	-	750
Dec	450	1,100	650	-	450
Total	**6,100**	**7,520**	**1,420**		**6,100**
SOS price, (2023) $/kWh		$ 0.16631	$ 0.16631		
		if customer did not participate in NEB	if customer participated in NEB		
SOS revenue		**$ 1,250.65**	**$ 236.16**		
Wholesale energy price*		$ 0.0334	$ 0.0334		
Estimated wholesale capacity price		$ 0.00997	$ 0.00997		
SOP cost to serve metered load		326.44	326.44		
SOP savings from load credits		$ -	264.80		
SOP cost to serve load**		**$ 326.44**	**$ 61.64**		
Gross margin for SOP (revenue less cost)		**$ 924.21**	**$ 174.52**		
Gross margin/metered kWh supplied		$ 0.12	0.02		
Gross margin/metered MWh supplied		$ 122.90	$ 23.21		

*Average ISO-NE ATC wholesale energy price in Maine zone in 2023.

**LEI simplified the analysis by assuming ancillary service costs are zero, and there are no internal costs to the SOP.

Compare this result to the SOP's gross margin if Customer X subscribes to a hypothetical NEB project. In that case, the customer's total **billed** consumption is 1,420 kWh (the green column in Figure 9). This billed consumption is the sum of metered consumption, less kWh credits from the NEB project (orange column) to which Customer X subscribes. Note that in July and September, Customer X's billed consumption was zero because their NEB credits were greater than their metered consumption. Customer X banked their credits and used them in subsequent months. However, from the perspective of the SOP, there is no banking. The SOP's load obligation is reduced by the total generation from the

NEB kWh Netting in the same month the energy is generated.[30] The revenues earned by the SOP are equal to the SOS rate of $0.16631/kWh multiplied by the **billed** consumption of 1,420 kWh, i.e., $236.16 (highlighted in green in Figure 9). The SOP gets credit against its total load obligation for the 6,100 kWh from the NEB program at the wholesale price of energy and capacity, equal to $264.80 (in pink), so the net cost to serve the load is $61.64 (in grey). The SOP's gross margin is $174,52. Its gross margin per metered kWh is $0.02/kWh. The SOP's gross margin is therefore $0.10/kWh less from Customer X than it was without the NEB program.

LEI's calculation of gross margin per MWh does not include the cost to the SOP of providing ancillary services or the SOP's own cost of operations. Thus, it overstates the margin—the SOP would actually earn less. However, the calculation which is of interest is not the ***level*** of the gross margin, it is the ***change*** in the gross margin. As this example illustrates, the ***change*** in the SOP's gross margin for Customer X is very large: the gross margin falls from $0.12/kWh ($122.90/MWh) to $0.02/kWh ($23.21/MWh).

The loss of margin from an NEB kWh Netting subscriber puts upward pressure on the SOS rate, because the SOP will seek to make up for the loss of margin by raising the SOS price. The SOP needs to earn a profit margin to be incentivized to participate in Maine's SOS procurements. At the extreme, if the NEB kWh Netting program ever grows to the point that a positive gross margin cannot be maintained, credible SOPs may simply choose to not to participate in the SOS procurements.

LEI expects that the SOP will seek to recover its loss of margin by raising SOS prices. This price increase would impact all SOS customers, which is another cross-subsidy from non-participating ratepayers. How much would SOS prices increase? LEI next quantifies the size of the price increase.

3.2 Impact on Maine SOS prices

LEI developed a methodology that accounts for the key drivers of SOP earnings, and the structure of the NEB kWh Netting program. LEI then populated the methodology using actual reported prices (SOS and wholesale energy and capacity prices) and quantities (SOS metered kWh consumption and NEB kWh Netting credits).

The methodology is as follows:

1) NEB kWh Netting does not physically displace customer load behind the meter. That load must still be served, so metered energy consumption is held constant. (No matter how large or how small the kWh Netting program is, by definition it does not change retail energy consumption, and therefore does not reduce the amount of energy the SOP must deliver to the customer);

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[30] MPUC. *Contract Exhibit A - T&D Specific Provisions*. Maine.Gov. <https://www.maine.gov/mpuc/regulated-utilities/electricity/rfps/standard-offer/2023-00092/cmp> Accessed February 28, 2024, and conference call January 30, 2023, with CMP representatives.

2) LEI assumed that rooftop BTM (as opposed to community solar) accounted for 77,000 MWh of NEB kWh Netting production in 2020 (based on data from ISO-NE)[31] and subtracted this number from the total kWh Netting production supplied in the T&D's filings. This avoids over-estimating the impact of NEB kWh Netting on SOS prices;
3) The SOP must meet metered load;
4) The SOP earns revenue based on billed load, not metered load;
5) Billed load gets smaller and smaller as the NEB kWh Netting program grows;
6) The cost per MWh to serve metered load is the wholesale energy price plus the wholesale cost of capacity;
7) The SOP's total cost to serve metered load is lower by the wholesale energy + capacity price multiplied by the kWh Netting credits.

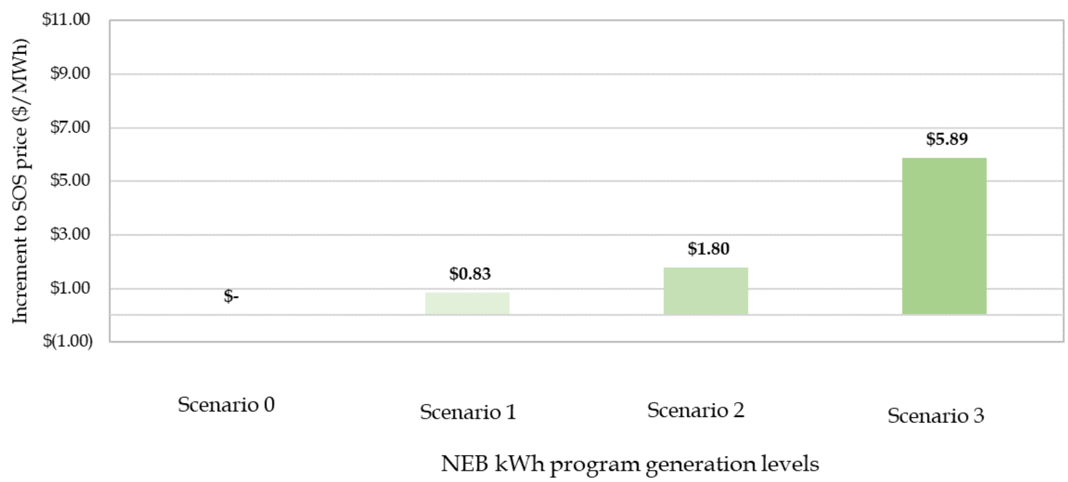
LEI implemented this methodology by comparing four scenarios. LEI used the same approach as for the calculations for the impact on Customer X, as shown in Figure 9 above but included all SOS load and all NEB kWh credits for CMP and Versant; and performed calculations based on MWh rather than kWh. First, LEI calculated the gross margin from SOS assuming no NEB kWh participation (Scenario 0). To do this, LEI used data from 2022 for metered MWh, SOS prices, and wholesale energy and capacity prices. The SOP's gross margin in Scenario 0 is $54.03/MWh (see Figure 10). LEI then defined Scenario 1 assuming that NEB generation is 95,012 MWh for the year (the actual level of NEB kWh credits in 2022 of 172,012 MW less the 77,000 MWh BTM adjustment), with no changes to any other assumptions. In other words, metered consumption is the same, SOS rates are the same, and wholesale energy prices are the same as in Scenario 0. This allows us to isolate the impact of NEB kWh Netting only. In Scenario 1, the SOPs' gross margin is $53.19/MWh (see second column in Figure 10). This is $0.83/MWh less than in Scenario 0 with no NEB kWh solar participation.

[31] ISO-NE. "Final 2021 PV Forecast." April 29, 2021. P. 59. <https://www.iso-ne.com/static-assets/documents/2021/04/final_2021_pv_forecast.pdf>.

Figure 10. Impact of NEB kWh program on SOS prices

	Scenario 0	Scenario 1	Scenario 2	Scenario 3
Metered MWhs	5,913,969	5,913,969	5,913,969	5,913,969
NEB generation (MWh)	0	95,012	197,000	459,038
SOS revenue ($)	$ 689,297,085	$ 678,438,826	$ 666,335,937	$ 625,778,890
Average price received for SOS ($/MWh)	$ 116.55	$ 114.72	$ 112.67	$ 105.81
Cost to serve metered load ($)	$ 369,786,203	$ 369,786,203	$ 369,786,203	$ 369,786,203
Savings from load credits ($)	$ -	$ 5,940,871	$ 12,317,934	$ 28,702,540
Cost to serve load, less credit savings) ($)	$ 369,786,203	$ 363,845,331	$ 357,468,269	$ 341,083,663
Gross margin (revenue - costs) ($)	$ 319,510,883	$ 314,593,495	$ 308,867,668	$ 284,695,228
Gross margin/metered MWh supplied ($/MWh)	$ 54.03	$ 53.19	$ 52.23	$ 48.14
NEB kWh program impact on gross margin	**$ -**	**$ 0.83**	**$ 1.80**	**$ 5.89**
Total required to recover loss of margin	$ -	$ 4,917,388	$ 10,643,214	$ 34,815,655

Note: Entries highlighted in blue above correspond to values in Figure 2.



Details and assumptions:
Metered MWhs are the sum of actual monthly metered MWh for CMP, Versant-BHD, and Versant-MPD SOS customers for 2022;
SOS revenue is based on the weighted average monthly SOS price across all customer classes, for CMP, Versant-BHD, and Versant-MPD for 2022;
Actual NEB generation for 2022 is the sum of monthly NEB kWh credits for CMP, Versant-BHD, and Versant-MPD as reported in <https://www.maine.gov/mpuc/regulated-utilities/electricity/rfps/standard-offer/2023-00092/cmp>, and <https://www.maine.gov/mpuc/regulated-utilities/electricity/rfps/standard-offer/2023-00092/mpd>; to adjust for rooftop solar, which is actually BTM, LEI subtracted 77,000 MWh (2020 BTM generation estimated by ISO-NE) from all the scenarios;
Total metered SOS MWh are left unchanged across the examples;
The wholesale cost to serve load is the monthly average ISO-NE around-the-clock wholesale energy price in Maine zone for 2022 and an estimated $8.26/MWh for capacity, based on 2022 capacity prices and total ISO-NE capacity payments.
The wholesale cost to serve load includes only the cost of energy and capacity (no A/S or operating cost for the SOP).
NEB Generation for 2023 and 2024 NEB kWh Netting program, Versant: MPUC Docket No. 2023-00076, 3.31.23 Exhibit B Versant SC Revenue Requirements 2023 Reconciliation; NEB Generation for 2023 and 2024 NEB kWh Netting program, CMP: Calculated by LEI based on CMP information provided in MPUC Docket No. 2023-00092.

In other words, if the SOP wanted to keep its margin intact, it would have to charge an additional \$0.83/MWh for each metered MWh. Multiplying the \$0.83/MWh by the total metered MWh consumption results in \$4,917,388, the total impact on SOS customers.

LEI then examined implications of growth in NEB kWh Netting on the price of SOS, by defining Scenario 2 and Scenario 3. We based these scenarios on realistic estimates of further NEB kWh Netting program growth, based on publicly available data:

- **Versant:** LEI referred to Versant's stranded cost filing in MPUC Docket No. 2023-00076, 3.31.23 Exhibit B Versant SC Revenue Requirements 2023 Reconciliation. The filing provided Versant's forecasts of NEB kWh program generation for future rate-years.

- **CMP:** CMP's stranded cost filing (in MPUC Docket No 2022-00341) did not refer to NEB kWh Netting program generation (only to the related costs) so, unlike the Versant stranded cost filing, it could not be used for LEI's forecast. Instead, LEI referred to CMP information provided in MPUC Docket No. 2023-00092 (supporting information for standard offer bidders) for which CMP projected total online NEB kWh Netting program nameplate capacity through December 2024.[32] LEI converted CMP's projection in MW to a projection in MWh assuming a capacity factor of 14%, which is the capacity factor derived from comparing another CMP filing in 2023-00092 (historical generation credits by month for the NEB kWh Netting program in 2022) with average NEB kWh Netting program capacity in 2022.[33]

We held constant the number of metered MWh, the SOS rate, and the wholesale energy and capacity prices, so that the results would reflect only the impact of higher kWh Netting. In Scenario 2, the SOP's margin is \$52.23/MWh, so the average SOS price would have to be \$1.80/MWh higher, to offset this decline. In Scenario 3 the margin would be \$48.14/MWh, so a \$5.89/MWh increment would be needed to offset the decline. Recall that the decline in margin is the result of having to supply the same volume of metered energy while being paid based on a lower volume of billed energy. The SOP foregoes the SOS price per kWh for every NEB kWh, but it only saves the wholesale cost of not supplying the energy and capacity.

Multiplying the margin each year that the SOP would have to make up by the metered usage of 5,913,969 MWh (assuming no change in metered MWh usage compared to 2022) results in a cost of \$10,634,214 in Scenario 2, and \$34,815,655 in Scenario 3 (shown in the last row of Figure 10).

3.3 Additional volume risk increases SOP costs

The NEB kWh Netting program imposes additional risks on the SOP in terms of the volume of load it is obligated to serve.

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[32] MPUC. *Applied NEB kWh by Month*. Maine.Gov. <https://www.maine.gov/mpuc/regulated-utilities/electricity/rfps/standard-offer/2023-00092/cmp>

[33] Ibid.

Like the potential for customers to switch to a CEP, or the impact of weather events, the NEB kWh Netting program adds unpredictability to the SOP's actual load obligation on an hourly, daily, and monthly basis. A customer can adopt CEP service at any time during a calendar year—the customer does not have to wait for the beginning of the year—while the SOP has the obligation to serve load for the entire calendar year (or commitment period). A customer can switch back to SOS when their CEP contract expires; again, they do not have to wait until the end of a calendar year. The volume impact of NEB kWh Netting credits is similar. A customer can join an NEB kWh Netting project when it wishes to, at any time during the year. This change in volume interacts with the fact that the SOP commits to a fixed price and therefore needs to match the load it serves with hedges otherwise it may face high risk exposure. The SOP may lose customers and therefore need to shed hedges; or it may gain customers and need to add hedges or face spot market price exposure.

SOPs are familiar with managing this kind of risk. To manage the price risk of their fixed-price load-following obligation, SOPs can hedge using futures contracts. There is a direct cost of engaging in the forwards and posting collateral costs, and if the markets move, it can mean hedges turn out to be more expensive than when the fixed price deal was signed. Hedging volume risk is even more complex and costly. It may involve the use of put and/or call options and perhaps other tools such as swaps with financial counterparties.[34] The SOP must determine the volume of put and/or call options to buy at various strike prices. The larger the potential variance in SOS sales volume, the more puts and calls are needed to reduce the level of risk; thus, the more expensive the cost of reducing risk. To the extent that additional NEB kWh Netting credits add to the volume risk faced by the SOP, the additional volume risk adds cost. See Section 7 (Appendix 2) for a simplified numerical example of price and volume risk management.

3.4 Delay in load obligation credits increase the need for working capital

Under the NEB kWh Netting program, there is a timing lag between when the SOP receives the kWh credits to its load obligation versus when it serves the load. By the end of the month, the SOP is made whole, but in the meantime, it must commit more working capital to the SOS program. This is not any longer than the typical lag in the ISO-NE settlements process, but includes the additional decrement to the load obligation from the NEB kWh Netting program. The extra cost to the SOP is the cost of capital for the extra working capital they must carry. This is probably a small cost, as the NEB kWh Netting program is a small share of SOS load, but it could increase over time as the NEB kWh Netting program grows.

3.5 Summary

The quantitative analysis in this section reflects conservative assumptions for the impact of the NEB kWh Netting program on the cost of SOS. LEI excluded the cost of ancillary services and the SOP's internal

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[34] A put option is an option to sell an asset at an agreed price on or before a given date; a call option is an option to buy an asset on an agreed price on or before a given date. A financial swap is a derivative contract whereby two parties exchange the cash flows or liabilities from two different assets; for example, swapping the unknown stream of costs for providing SOS service for a fixed and known stream of costs.

costs of operations; and we also excluded the impact on the cost of managing volume risk, and the impact on working capital needs. These conservative assumptions result in an estimated $1.80/MWh - $5.89/MWh cost impact depending on the uptake of the NEB kWh Netting program. This is a small percentage of the SOS price, but it impacts all SOS customers, and constitutes a cross subsidy from non-participating ratepayers to participants in the NEB kWh Netting program.

4 The opportunity cost of the NEB program

The true cost of any economic choice is the opportunity cost—in other words, the cost of alternatives. An alternative to the NEB program for incentivizing solar and other renewable energy could be a program in which the utilities are directed to procure utility-scale contracts for renewable energy. Development of renewable energy is often incentivized by legislators or regulators utilizing policies such as renewable portfolio standards ("RPS"). RPS incentivize utilities to engage in procurements for renewable energy, supported by power purchase agreements. PPAs provide an offtake contract to cover at least a portion of the plant's output, for a given period (often 20 years for a contract with a utility, usually less for a contract with an individual commercial or industrial customer). With less downside risk from the earnings stream, financiers demand a lower return, which can reduce the cost of the project. Even if there is no binding RPS, legislators often develop policy goals which are met using procurement of utility-scale renewable energy.

Comparing the cost of the NEB facilities to the cost of utility-scale PPAs in Maine is appropriate, because the types of benefits which two kinds of projects create are similar:

- NEB Tariff Rate facilities do not physically displace customer load behind the meter. NEB kWh Netting projects which are not located behind the meter likewise do not physically displace customer load. PPAs are also supply projects and do not displace load;
- Energy market benefits in terms of lower wholesale market prices from NEB projects would be no different than what would result from any other energy bid into the market as a price taker, such as solar energy from a PPA project; and
- NEB projects do not participate in the ISO-NE forward capacity market, and neither, in effect, do Maine's solar PPAs (though both types of projects are allowed to do so), but can be assumed to have capacity benefits.

4.1 Comparing NEB programs to utility-scale solar on an apples-to-apples basis

To compare the costs of the alternatives, it is necessary to recognize and adjust for the differences in any resulting benefits.

- **Transmission benefits:** A utility scale solar project interconnects with the transmission system. An NEB project interconnects to the distribution system, so the transmission cost is avoided. In New England, the Regional Network Service charge ("RNS") cost depends on the amount of load reduction that occurs during the ISO-NE monthly peak. In a report on the net benefits of the Maine NEB program, authors reported a \$10-\$14/MWh savings from avoided RNS charges.[35]

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[35] Daymark Energy Advisors. Costs and *Benefits of Maine's Net Energy Billing Program*. Prepared for Coalition for Community Solar Access. March 11, 2021. P. 32.

- **Distribution benefits:** The NEB program subscribers are on the distribution system and customers still receive metered service. There is no cost adjustment needed for comparability to utility-scale solar.

- **Capacity benefits:** Capacity benefits of both NEB programs and utility-scale PPAs are comparable: Capacity which must be purchased from ISO-NE can decline with additional NEB projects if peak demand on the distribution system declines; capacity offered to ISO-NE wholesale markets can increase as PPA projects grow.

- **RECs:** NEB program facilities do not provide RECs—RECs are retained by the project sponsor; the same is true for the Maine PPAs.

- **GHG emissions reduction:** GHG emissions reduction is the same from a MWh of utility-scale solar energy versus NEB, as far as energy output is concerned. Does one have a lower life-cycle carbon footprint? One study showed that rooftop solar installations have a much lower life-cycle GHG footprint than utility-scale solar of 3.5 MW in size.[36] This is mostly owing to the use of concrete in utility-scale installations; utility-scale installations which did not use concrete had about the same life-cycle GHG emissions as rooftop solar. However, only a small share of the NEB projects (an estimated 60.2 MW, and 77,000 MWh as of 2020)[37] are BTM (rooftop) projects. Therefore, we assume NEB impacts on GHG emissions will be the same as that of utility-scale solar projects.

4.2 Maine's utility-scale PPA net costs are lower than NEB program net costs

In Maine, LD 1494 (*An Act to Reform Maine's Renewable Portfolio Standard, Public Law 2019, Chapter 477*) directed the Commission to procure, in total, 1.715 million MWh of energy or RECs from Class 1A renewable resources.[38] The law gave the Commission the option to procure energy or RECs; the Commission informed bidders that it preferred energy.[39] Most of the contracts which were eventually

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[36] Roy, R., Pearce, J.M. "Is small or big solar better for the environment? Comparative life cycle assessment of solar photovoltaic rooftop vs. ground-mounted systems." *International Journal of Life Cycle Assessment* (2023). <https://doi.org/10.1007/s11367-023-02254-x/ OA journal OA academia>.

[37] ISO-NE. "Final 2021 PV Forecast." April 29, 2021. P. 53. <https://www.iso-ne.com/static-assets/documents/2021/04/final_2021_pv_forecast.pdf>.

[38] MPUC. <https://www.maine.gov/tools/whatsnew/index.php?topic=puc-pressreleases&id=5089377&v=article088> <https://www.maine.gov/mpuc/electricity/rfps/class1a2021/>; and Maine Legislature, LD 1494 (An Act to Reform Maine's Renewable Portfolio Standard, Public Law 2019, Chapter 477) Sec. 2. 35-A MRSA §3210-G <https://www.mainelegislature.org/legis/bills/display_ps.asp?ld=1494&PID=1456&snum=129>.

[39] MPUC. *2021 Request for Proposals for the Sale of Energy or Renewable Energy Credits from Qualifying Renewable Resources*. <https://www.maine.gov/mpuc/electricity/rfps/class1a2021/>; *Bidder's information Session Slide Deck* <https://www.maine.gov/mpuc/electricity/rfps/class1a2021/documents/RPS-Tranche-2-Bidders-Information-Session-slide-show.pdf.>

executed are the result of §3210-C (Capacity resource adequacy) or §3210-G (Renewable portfolio standard) procurement programs. Many contracts were entered into in 2019 and 2021.

LEI examined the 31 legislated PPAs entered into by CMP and Versant, from 1984 through 2021, a total of 750 MW (see Figure 11).[40] The 31 contracts LEI examined included all Maine's legislated PPA contracts except contracts which were executed but later terminated as of the time of LEI's analysis, one contract which was for RECs only, and one which was a contract for differences.

Figure 11. Maine's legislated PPAs examined by LEI

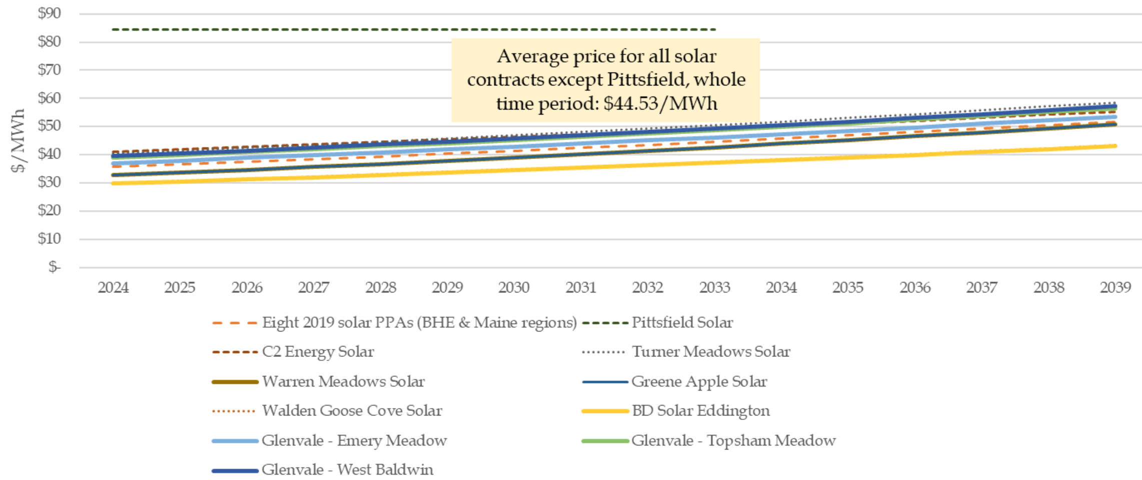
Year	Facility	Resource Type	Nameplate Capacity (MW)	Status	1st year Contract Pricing ($/MWh)	Offer	Term (years)
1984	Green Lake	Hydro	0.4	Operational	$75.00	Energy only	40 (expires in 2024)
1987	West Enfield Hydro	Hydro	16.0	Operational	$7.72/MWh + 1/2 of property taxes and insurance	Energy only	expires May 2024 if buyer chooses
1984	Sebec Hydro	Hydro	0.9	Operational	85% of avoided cost	Energy only	expires 2024
2009	Evergreen Wind - Rollins	Wind	12.0	Operational	Floor price of $55/MWh; ceiling of $110/MWh	Capacity & Energy	20
2009	Evergreen Wind - Rollins	Wind	48.0	Operational	Floor price of $55/MWh; ceiling of $110/MWh	Capacity & Energy	20
2011	Pisgah Mountain Wind	Wind	9.0	Operational	20-year fixed price $93/MWh	Energy only	20
2020	Silver Maple Wind	Wind	20	Operational	34.3	Energy only	20
2013	Athens	Biomass	8.5	Operational	$99.00	Energy only	20
2016	Georges River	Biomass	8.5	Operational	$99.00	Energy only	20
2011	Exeter Phase I	Anaerobic Digester	1.0	Operational	$100.00	Energy only	20 (max)
2013	Exeter Phase II	Anaerobic Digester	2.0	Operational	$85.00	Energy only	20
2017	Pittsfield Solar	Solar	9.9	Operational	$84.50	Energy only	20
2019	BD Solar Eddington	Solar	20	Under Development	$29.75	Energy only	20
2019	BD Solar2 LLC (Winslow)	Solar	7.0	Operational	$34.00	Capacity & Energy	20
2019	BD Solar Augusta LLC	Solar	7.2	Operational	$34.00	Capacity & Energy	20
2019	BD Solar Fairfield LLC	Solar	5.0	Operational	$34.00	Capacity & Energy	20
2019	BD Solar Oxford LLC	Solar	9.2	Operational	$34.00	Capacity & Energy	20
2019	BD Solar Palmyra LLC	Solar	5.0	Operational	$34.00	Capacity & Energy	20
2019	Dirigo Solar - Hancock	Solar	10.2	Operational	$34.00	Capacity & Energy	20
2019	Dirigo Solar - Hancock North	Solar	7.0	Operational	$34.00	Capacity & Energy	20
2019	Dirigo Solar - Milo	Solar	20.0	Operational	$34.00	Capacity & Energy	20
2021	Glenvale Solar - Emery Meadow (EMSS)	Solar	16.3	Under Development	$37.00	Energy only	20
2021	Glenvale Solar - Topsham Meadow	Solar	18.0	Under Development	$39.00	Energy only	20
2021	Glenvale Solar - West Baldwin	Solar	16.2	Under Development	$39.50	Energy only	20
2019	Weaver Wind	Wind	72.6	Operational	$35.00	Energy only	20
2021	C2 Energy Capital LLC	Solar	14.0	Under Development	$39.50	Energy only	20
2021	Glenvale - Turner Meadow Solar Station, LLC	Solar	20.0	Under Development	$38.50	Energy only	20
2021	Glenvale - Warren Meadow Solar Station, LLC	Solar	74.5	Under Development	$32.00	Energy only	20
2021	Walden - Goose Cove	Solar	40.0	Under Development	$28.50	Energy only	20
2021	Greene Apple Solar Power LLC	Solar	120.0	Under Development	$29.89	Energy only	20
2021	Helix - Kibby Mountain Wind	Wind	132.0	Operational	$36.50	Energy only	20

The majority of Maine's solar PPAs are for energy only; some of the solar projects include the option for a portion of the value of capacity, but none of those facilities has qualified for the ISO-NE capacity auction. None of the PPAs includes the RECs—in other words, the ownership (and monetary value) of the RECs is retained by the developer.

All but one of the solar contracts (Pittsfield) are for PPA prices which are currently below $50/MWh (see Figure 12). Including price escalation clauses, prices for the solar PPAs signed in 2021 average an estimated $36.12/MWh in 2023 and $36.66/MWh in 2024. Including price escalation over a 20-year period, the contracts as a whole (except Pittsfield) average $44.53/MWh.

[40] These contracts are publicly available.

Figure 12. Contract prices for Maine's legislated solar PPAs



The solar PPA projects are not necessarily less expensive per MWh because they are larger than NEB projects and therefore benefit from economies of scale. Even the PPA prices for small solar projects such as the 5-MW BD Solar Fairfield and Palmyra facilities are no more costly than a larger 20-MW project such as Dirigo Solar - Milo.

How much more did the Tariff Rate program cost in 2023, compared to the alternative of procuring utility-scale solar? The Tariff Rate was an estimated $218.52/MWh as noted previously. This cost is offset by sales of energy, the value of capacity, and the avoided cost of transmission. To be conservative (i.e., allow NEB Tariff Rate projects to appear as low-cost as possible), LEI assumed i) all energy is sold at peak period ISO-NE Hub prices, ii) all projects are credited with capacity benefits, and iii) the avoided transmission cost is on the high end noted previously, at $14/MWh. These assumptions bring the net cost per MWh of NEB Tariff Rate projects in 2023 to $153.19/MWh (see Figure 13). The same calculations using forward ISO-NE peak period hub energy prices and an assumed capacity price arrive at a projected net cost of $103.72/MWh for 2024.

LEI compared this cost to the cost of recent Maine PPAs. We used average 2023 prices for PPAs signed recently (the 2021 procurement). We assume the PPAs also earn peak period prices for their energy sales, and that they provide a capacity value. However, they do not avoid the need for transmission. The PPAs' prices were lower than energy prices in 2023 (and, by extension lower than energy prices + capacity value), so the PPAs resulted in a ***negative*** cost (i.e., a benefit) of $15.21/MWh in 2023. They result in a projected $33.08/MWh benefit in 2024. The negative cost (i.e., the benefit) of the PPA projects arise because the PPA price is lower than the average peak period energy price. The PPA projects earned more in 2023 than they cost and are projected to do the same in 2024 based on 2024 forward prices.

Figure 13. Estimated net opportunity cost of the NEB programs

			2023		2024
Tariff Rate	Tariff Rate	$	218.52	$	187.46
	Peak period energy price	$	41.36	$	59.74
	Capacity value	$	9.97	$	10.00
	RNS	$	14.00	$	14.00
	Net cost	$	153.19	$	103.72
kWk Netting	Weighted average residential SOS price	$	169.24	$	108.24
	Peak period energy price	$	41.36	$	59.74
	Capacity value	$	9.97	$	10.00
	RNS	$	14.00	$	14.00
	Net cost	$	103.90	$	24.50
Maine PPAs	Average PPA price for projects procured in 2021		$36.12		$36.66
	Peak period energy price	$	41.36	$	59.74
	Capacity value	$	9.97	$	10.00
	Net cost	$	(15.21)	$	(33.08)
Opportunity cost of NEB Tariff Rate program, $/MWh		$	168.40	$	136.80
Tariff rate generation (MWh)			645,679		867,076
Total opportunity cost of NEB Tariff Rate program ($)		**$**	**108,732,020**	**$**	**118,614,991**
Opportunity cost of NEB kWh Netting program, $/MWh		$	119.11	$	57.58
kWh Netting generation (MWh)			274,000		536,038
Total opportunity cost of NEB kWh program ($)		**$**	**32,637,345**	**$**	**30,863,355**
Total opportunity cost of NEB ($)		**$**	**141,369,365**	**$**	**149,478,346**

Note: Entries highlighted in blue correspond to entries in Figure 2 of this report.

Therefore, the opportunity cost of the NEB Tariff Rate program was $168.40/MWh in 2023 (the cost of $153.19/MWh plus the forgone the $15.21/MWh benefit). In 2024, this cost is projected to be $136.80/MWh. Multiplying the costs per MWh by NEB Tariff Rate generation results in an estimated total cost of $108,732,020 in 2023, and a projected $118,614,991 in 2024.

LEI performed a similar calculation for the NEB kWh Netting program. The cost is equal to the forgone SOS charged to residential customers, weighted by the shares of CMP and Versant's SOS load in 2023.

The opportunity cost of the kWh Netting program in 2023 was $119.11/MWh; for 2024 we project $57.58/MWh. Multiplying these costs by the estimated generation in 2023 and projected generation for 2024 arrives at costs of $32,637,345 for 2023, and $30,863,355 for 2024.

The opportunity cost total for both NEB programs is an estimated $141,369,365 in 2023 and $149,478,346 in 2024.

These costs reflect over-compensation to sponsors of NEB projects. NEB projects of 5 MW offer the same benefits as PPAs of 5 MW, except the NEB projects may avoid transmission costs, whereas the PPAs do not. A tariff rate which reflected PPA prices plus a premium for RNS savings would cost Maine ratepayers far less than they are now paying for NEB projects.

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6 Appendix 1: About London Economics International LLC

LEI is a global economic, financial, and strategic advisory professional services firm specializing in energy and infrastructure. The firm combines detailed understanding of specific network and commodity industries, such as gas distribution/transmission, electricity generation and distribution, with a suite of proprietary quantitative models to produce reliable and comprehensible results.

6.1 LEI overview

LEI has in-depth expertise in economic and financial issues related to the gas, electricity, and water sectors, such as asset valuation, procurement, regulatory economics, and market design, assessment and analysis. The firm has its roots in advising on the initial round of privatization of electricity, gas, and water companies in the United Kingdom. Since then, LEI has advised private sector clients, market institutions, and governments on privatization, asset valuation, deregulation, tariff design, market power, strategy, and strategy development in virtually all deregulated markets worldwide, including in North America, Europe, Asia, Latin America, Africa, and the Middle East (see Figure 14).

Figure 14. Selected LEI clients throughout the world

LEI is active across the gas sector and electric sectors and has a comprehensive understanding of the issues faced by investors, utilities, and regulators alike. The following attributes make LEI unique:

- ***clear, readable deliverables*** grounded in substantial topical and quantitative evidence;

- ***internally developed proprietary models*** for electricity price forecasting incorporating game theory, real options valuation, Monte Carlo simulation, and sophisticated statistical techniques;

- ***balance of private sector and governmental clients*** enables LEI to effectively advise both regarding the impact of regulatory initiatives on private investment and the extent of possible regulatory responses to individual firm actions;

- ***experience in rate design and modeling globally*** in which LEI advises on tariffs and designs rates under cost-of-service and performance-based ratemaking; and

- ***worldwide experience*** backed by multilingual and multicultural staff.

LEI has experience working on solar-specific issues, has been engaged by Maine entities on a variety of projects, and is deeply familiar with the ISO-New England electricity markets.

6.2 Solar-specific analysis, and retail rates for special customer classes

LEI has performed a variety of projects which provide it with important context of retail rates and utility solar programs. The following is a brief sample of LEI's work:

- ***Analysis of the true cost of solar:*** LEI was engaged by the single buyer of a major Southeast Asian country to conduct a True Cost of Solar study. The goal of the study was to conduct an in-depth analysis of the costs associated with the integration of solar PV technology into the grid and formulate a tariff for fair allocation and distribution of all costs related to solar PV integration. The study also involved determining the socio-economic impact of the solar PV program, including on land use and on employment and economics growth driven by the solar PV supply chain.
- ***The impact of solar net metering on customer classes:*** LEI demonstrated how the net metering regime in Malaysia impacts different classes of customers (owing to a tariff design that is largely volumetric) and modelled how changing to a more cost reflective tariff with higher fixed charges and lower volumetric charges would result in less unintended cross subsidy between customer classes.
- ***Evaluation of utility green pricing option:*** LEI was engaged by the Louisiana Public Service Commission ("LPSC"), Docket No. U-35916, to serve as the technical consultant evaluating Entergy Louisiana LLC's application for authorization to implement a green pricing option, to be paid for by a Green Pricing Option ("GPO") or Large Volume Green Pricing Option ("LVGPO") rider, and related rate relief. LEI reviewed and examined filings and pre-filed testimony, assisted in drafting, reviewing, and responding to discovery, prepared testimony, and conducted other activities related to the matter.
- ***Examination of solar business models:*** For a client performing due diligence related to a potential investment in business-to-business behind-the-meter solar in the Northeast United States, LEI examined US federal and state incentives for solar adoption, and assessed business models used for targeting commercial, institutional, and industrial sectors. For each business model, LEI

assessed the competitive environment—who is operating in the sector, what is their go-to-market strategy, and in general how these models have been performing. The team also provided a 10-year outlook for solar renewable energy credits ("SRECs") for certain jurisdictions. Finally, LEI developed key questions the client should ask as part of its evaluation of potential transactions in the behind-the-meter solar sector.

6.3 Experience in Maine

LEI has over a decade of experience in working with entities in Maine. This allows LEI to understand, in depth, the circumstances faced by Maine stakeholders, be they ratepayers, utilities, power suppliers, or regulators. Specific examples include:

- ***Investment incentives for electric distribution utility:*** LEI served as independent expert for the Maine Public Utilities Commission ("MPUC") in its investigation of Central Maine Power Company ("CMP") management issues and related ratemaking and performance incentive mechanisms. Ultimately, the Commission's goal was to determine whether the rate plan to be proposed by CMP in a concurrent docket would be more suitable than the current cost-of-service rate plan under which CMP operates, given the parent company's incentives to invest in CMP. The project included a literature review of utility investment incentives and of multi-national entities' ("MNE") incentives to invest in subsidiaries. The project also included detailed case studies of performance-based ratemaking regimes in other US jurisdictions, and the role and effectiveness of performance incentives in the regimes. [Docket No. 2022-00038 (MPUC investigation), and Docket No. 2022-00152 (CMP rate case)].
- ***Analysis of demand reduction-induced price effects ("DRIPE) in the context of avoided energy supply costs ("AESC"):*** LEI was engaged by the MPCU to perform a critical review of the methodology and assumptions which underpinned other consultants' analysis of avoided energy supply costs ("AESC"). LEI performed a careful examination of the economic theory and econometric techniques used by the other consultants to estimate DRIPE. [Docket No. 2018-00321]
- ***Rate impact analysis and study of costs and benefits of municipalization:*** LEI was retained by the MPUC to study proposed legislation that would involve municipalization of the state's transmission and distribution networks. LEI submitted its expert report for the Legislature on February 15, 2020, and testified before the Joint Standing Committee on Energy, Utilities and Technology on February 26, 2020. [MPUC Docket 2019-00280]
- ***Macroeconomic impact of biomass generation:*** LEI examined the macroeconomic impact of biomass generation within the state of Maine (MPUC Docket No. 2016-00084). This included direct, indirect, and induced impacts on: permanent direct jobs, payments to municipalities, payments for fuel harvested in the State, payments for in-state resource access, in-state purchases of goods and services, and construction-related jobs and purchases. LEI used the macroeconomic model known as IMPLAN to capture the economic impacts on industries including logging, sawmills, and other forestry-related industries and well as on state and local taxes.
- ***Independent expert related to Maine Energy Cost Reduction Act:*** LEI was engaged by the MPUC to assist in evaluating options for expansion of natural gas supply into Maine. LEI authored pre-filing reports, responded to discovery from other parties, prepared discovery questions and cross-examined witnesses, reviewed testimony by other parties and provided assessments of the issues

presented, and served as an expert witness in the proceedings. [MPUC Docket No. 2014-071] URL: <https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/CaseMaster.aspx?CaseNumber=2014-00071>

- ***Cost/benefit analysis of transmission line.*** For a utility in Maine, LEI prepared a cost-benefit analysis of a proposed transmission line with the potential to change existing market arrangements. LEI developed a base case and multiple project cases based on different configurations of the transmission project. Using its proprietary modeling tool, POOLMod, LEI simulated energy and capacity prices in each configuration over a 15-year time frame and compared the price differences against various cost allocation scenarios for the transmission line's construction. LEI also tested the statistical significance of the project case results against the base case results, and conducted further analysis on the economic effects of additional renewable generation projects that construction of the transmission line would make possible.
- ***Cost/benefit analysis of Northern Maine joining ISO-NE.*** For a utility in Maine, LEI assessed reliability issues in Northern Maine and performed a cost/benefit analysis of Northern Maine joining ISO-NE.

6.4 ISO-New England region experience

LEI closely monitors the ISO-NE market for ongoing client work. LEI also produces a semi-annual regional market update and wholesale price forecast for eleven North American power markets, including ISO-NE. LEI's deep understanding of the ISO-NE market serves as a solid foundation for this engagement. LEI has performed hundreds of engagements related to ISO-Ne over the years, the following is a small sample:

- ***Analysis of clean energy market pathways***: in support of a renewable generation owner, LEI engaged in stakeholder consultations (at ISO-NE and NEPOOL committees) involving assessment of various potential market design changes including carbon pricing, integrated clean energy markets, and forward capacity market reforms.

- ***Support for wholesale market design efforts to address fuel security/winter-time energy reliability issues:*** LEI staff assisted the Massachusetts Attorney General's Office ("AGO") to evaluate the problem statement and the market design fixes being proposed by ISO-NE staff as well as other NEPOOL market participants in a FERC-mandated proceeding on energy security issues in the region. LEI presented a counterproposal for an energy storage-based ancillary services product and adjustments to the existing capacity market design at the NEPOOL Markets Committee. LEI also supported the AGO with a review of other stakeholders' proposals and strategy in the run-up to the FERC submissions.

- ***Empirical analysis of proposed change to market design in the Forward Capacity Market to align with states' clean energy initiatives:*** LEI examined the Competitive Auctions with State Policy Resources ("CASPR") proposal from ISO-NE. The CASPR proposal involves adding a second or "substitution" auction to the current Forward Capacity Market ("FCM") framework. LEI evaluated the financial incentives for incumbent (existing) resources to remain in operation versus the financial incentive to retire (and therefore the bidding strategy of these resources). LEI considered the trade-offs that existing generators will be making in the face of the substitution auction, including the opportunity/risk of continuing to operate versus the opportunity/risk of submitting a retirement bid and participating in the substitution auction.

- ***Analysis of merchant market opportunities for a battery energy storage system ("BESS") in New England:*** on behalf of a developer, LEI performed a detailed hourly optimization of operations for different BESS technologies (with varying capacity to energy storage characteristics) to optimize potential energy, capacity and ancillary services revenues and minimize potential for performance penalties. LEI forecasted market prices for the FCM, energy market, regulation service market, and forward reserve market using simulation and statistical techniques.
- ***Analysis of price drivers for gas-fired asset***: LEI was engaged by a private client to conduct a price driver analysis and strategy optimization exercise to enhance the bidding and dispatch strategy on a jointly owned gas-fired asset. This included a report on ISO-New England's Winter Reliability Program to identify and evaluate key wholesale price drivers in the New England region. LEI also examined the generating asset's financial data to help optimize its bidding strategy.
- ***ISO-New England tariff design:*** LEI submitted testimony on behalf of ISO-NE to the FERC to help defend the ISO's self-funding tariff. LEI first defined the basic underlying economic principles for specifying the tariff, and then undertook to show how the tariff should be applied to various system users. The engagement involved intensive financial modeling and frequent interaction with stakeholders. [ER01-316-000]

7 Appendix 2: Managing volume risk for a fixed-price load-following obligation

An electricity provider with a fixed price sales contract who knows the quantity it must deliver can hedge price risk and lock in a predetermined margin on its sale. Futures contracts serve to narrow the distribution of expected profits. In other words, they reduce the variability, or risk, of a given level of profit. Hedging volume risk is more complex and costly, as demonstrated below.

7.1 Futures contracts help manage price risk

The SOP is short energy, because its load obligation is to provide hourly energy for a whole year. It does not know exactly the volume it must provide in each hour; and it does not know the price it will have to pay for that energy. It only knows the fixed price it will receive for the energy. The SOP can buy a futures market contract (or some other derivative, but for simplicity, assume a simple futures contract) to help manage price risk.[41] Using a futures contract, it can lock in a known energy margin which is the difference between the fixed SOS price and the $/MWh cost of the futures contract.

This is shown in Figure 15 which is a simplified analysis of the price risk hedging an SOP would perform.[42] We assumed the SOP must serve 1,000 customers each expected to consume 550 kWh per month (a total of 18.08 MWh per day). The SOS rate is $0.1660/kWh, and the futures contract price at the time the SOP wants to hedge is $0.160/kWh.[43] Part 1 of Figure 15 shows the fixed revenue the SOP will earn from serving the 1,000 customers ($3,001.64) if the customers consume the expected volume of energy. We assume the SOP wishes to hedge all its revenue, so it purchases a futures contract for 18.08 MWh. This costs a total of $2,893.15 (Part 2 of Figure 15).

If the market outcome for the year is that annual market prices are 10% higher than the SOS, the **cost** to the SOP to deliver the 18.08 MWh is $3,182.47 (Part 3 of Figure 15). This is higher than the $3,001.64 it earned from the SOS customers, so the SOP has lost $180.82.

However, this cost and loss is offset by the revenue and profit earned by liquidating the futures contract (Part 4 of Figure 15). The futures contract, which had cost $2,893.15 is sold for $3,182.47, for a margin of $289.32. The net margin is the difference between the profit on the futures contract and the loss on the cash SOS transaction, which amounts to $108.49. The SOP therefore locked in a margin of $108.49 on its

[41] Electricity markets use non-standard forward contracts traded over the counter ("OTC"), not standardized futures contracts. The additional cost of this is not reflected in LEI's simplified assumptions.

[42] This is a simplification of the SOP's risk management process because the SOP will likely only hedge part of its obligation at any given time, the futures contracts prices will be different at different moments in time, and the SOP would use contracts priced at wholesale, not retail prices.

[43] In reality, traded futures contracts are available for only wholesale energy, not retail energy. SOPs would use a more sophisticated hedging strategy which recognizes this. LEI's example is simplified, to illustrate the concept.

SOS transaction, or $6.00/MWh, which is simply the difference between the sale price and the price to hedge the transaction.

Figure 15. Simplified example of hedging price risk for SOP load obligation, no volume risk

	Assumptions				
	SOS commitment		100%		
	SOS rate (2023) $/kWh	$	0.1660		
	Maine residential typical consumption, kWh per month		550		
	Futures contract price, $/kWh	$	0.160		
	Load obligation for serving 1000 customers				
Part 1	**Commitment per day**				
	Load obligation volume (MWh)		18.08		
	P= guranteed price ($/MWh	$	166.00		
	Revenue:	$	3,001.64		
Part 2	**Hedge**				
	Futures purchase volume (MWh)		18.08		
	Futures price ($/MWh)	$	160.00		
	Cost	$	2,893.15		
				Market outcomes	
				Annual market prices 10% higher	Annual market prices 10% lower
Part 3	**Purchase for delivery**				
	Volume			18.08	$ 18.08
	Cash prices at delivery location			$ 176.00	$ 144.00
	Cost			$ 3,182.47	$ 2,603.84
Part 4	**Sale of futures contract**				
	Volume			18.08	$ 18.08
	Futures price to sell contract			$ 176.00	$ 144.00
	Revenue			3,182.47	2,603.84
	Outcome				
	Futures market profit			$ 289.32	($289.32)
	Cash margin			($180.82)	$ 397.81
	Total			**$ 108.49**	**$ 108.49**
	Margin in $/MWh			$ 6.00	$ 6.00

In addition to futures contract on energy, an SOP might also use call options to hedge price risk. These can help mitigate the risk of higher prices when it must deliver the SOS but also allow the SOS to benefit from lower spot prices at delivery time. Unlike futures contracts, options have a cost for their purchase. Other risk management tools include weather derivatives and power/weather derivatives.

As can be seen from the example above, a basic hedging strategy can reduce price risk. Another way to say this is that such a strategy can reduce margin risk. However, this simple strategy does not address volume risk.

7.2 Futures contracts do not help manage volume risk

Reducing volume risk is more complicated and costly. Consider the case in which the assumptions and market price outcomes are the same as shown in Figure 15. The only difference is that the volume to be delivered is not the same as the load obligation expected by the SOP; we assume that volumes to be delivered are 10% higher in the case of higher energy prices, and 10% lower in the case of lower energy prices. In the case with varying volumes, the futures contract cannot lock in an expected margin (see Figure 16).

Figure 16. Simplified example of hedging only price risk for SOP load obligation, 10% volume risk

	Assumptions:			
	SOS commitment	100%		
	SOS rate (2023) $/kWh	$ 0.1660		
	Maine residential typical consumption, kWh per month	550		
	Futures contract price, $/kWh	$ 0.160		
	Load obligation for serving 1000 customers			
Part 1	**Commitment per day**			
	Q = commitment (MWh)	18.08		
	P= guranteed price ($/MWh	$ 166.00		
	Revenue:	$ 3,001.64		
Part 2	**Hedge**			
	Q Futures purchase (MWh)	18.08		
	Futures price on ($/MWh)	$ 160.00		
	Cost	$ 2,893.15		
			Market outcomes	
			Annual market prices and demand are both 10% higher	Annual market prices and demand are both 10% lower
Part 3	**Purchase for delivery**			
	Volume		19.89	$ 16.27
	Cash prices at delivery location		$ 176.00	$ 144.00
	Cost		$ 3,500.71	$ 2,343.45
Part 4	**Sale of futures contract**			
	Volume		18.08	$ 18.08
	Futures price to sell contract		$ 176.00	$ 144.00
	Revenue		3,182.47	2,603.84
	Outcome			
	Futures market profit		$ 289.32	($289.32)
	Cash margin		($499.07)	$ 658.19
	Total		**($209.75)**	**$ 368.88**
	Margin in $/MWh		($11.60)	$ 20.40

The margin if prices and volumes turn out 10% higher than expected is a negative $11.60/MWh; if prices and demand are 10% lower, the margin is $20.40/MWh. The expected value (i.e., average) of this, if both outcomes are equally likely, is $4.40/MWh. This is a lower margin than in the previous "perfect hedge" example in Figure 15. And it is very risky—margins could easily be negative.

Volume risk is not traded in energy markets, which means that such risk does not have a transparent market price.[44] This is unlike price risk, for which the prices of futures, and options costs and strike prices are available to market participants. Sometimes weather derivatives are used to hedge quantity risk, but the effectiveness is based on the correlation of demand and weather.

Using put and call options can help reduce the volatility (i.e., risk) of margins driven by volume risk (see text box). However, unlike futures contracts which have no additional cost (as they are simply traded based on the price of the underlying commodity) options contracts have prices associated with them. Options prices vary depending on the strike price specified by the option and whether the option is "in the money" (when the strike price for a call option is lower than the current market price) or "out of the money" (when the strike price of a call option is higher than current market prices). In ISO-NE, put options for NEPOOL Massachusetts hub wholesale energy with a strike price of $55/MWh traded at about $9/MWh in February 2024; call options at $150 strike prices traded at $0.01/MWh.[45]

Traded options, like futures, reflect wholesale energy prices, not retail prices, so the SOP would need to use other hedging strategies (perhaps swaps with a financial counterparty) to protect itself from wholesale versus retail price risk. Indeed, an SOP may use swaps and other risk management tools

Financial management theory addresses risk strategies for serving fixed-price load-following obligations

Industry practitioners and academics have examined approaches to reducing price and volumetric risk in electric energy provision, and in other commodities. For example, the correlation between load and price can be exploited to develop a combination of futures and options to hedge volume risk. A futures contract is executed for the fixed load obligation that the SOP must provide, at the same price as the SOS price. Then, the SOP must determine the volume of put and call options to buy at various strike prices. As the spot energy price increases, more call options will be in the money, thus providing a hedge for the larger volume that the SOP would need to purchase on the spot market, to serve load. If the spot price falls, more put options are in the money, providing a guaranteed price for excess energy that must be sold on the spot market.

Thus, intuitively, the larger the potential variance in volume, the more puts and calls are needed to achieve the same level of risk reduction in the portfolio.

Source: Oren, Schmuel and Yumi Oum, "Managing Risk under a Fixed Price Load-following Obligation for Electricity Service," IEEE, 2010. 978-1-4244-6551-4/10. <https://ieeexplore.ieee.org/document/5589689>

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[44] Oren, Schmuel and Yumi Oum, "Managing Risk under a Fixed Price Load-following Obligation for Electricity Service," IEEE, 2010. 978-1-4244-6551-4/10. <https://ieeexplore.ieee.org/document/5589689>.

[45] ICE. North American & European Power Futures. <https://www.ice.com/products/6590524/Option-on-ISO-New-England-Massachusetts-Hub-Day-Ahead-Peak-Fixed-Price-Future>, <https://www.ice.com/marketdata/reports>, <https://www.ice.com/report/143>. Accessed February 2, 2024.

tailored to its own specific needs, rather than using options. The point is that any of these strategies reduce risk, but they do so by adding cost. To the extent that additional NEB kWh Netting credits add to the volume risk faced by the SOP, the additional volume risk adds cost.