RAPPORT DU CONSULTANT MERRIMACK ENERGY GROUP INC. RELATIF À COMPARAISON DES PRIX DE LA COMBINAISON SÉLECTIONNÉE AVEC LES PRIX DES PRINCIPAUX PRODUITS DISPONIBLES DANS LES MARCHÉS DU NORD-EST DE L'AMÉRIQUE ET LES COÛTS DE TRANSPORT APPLICABLES

Final REPORT OF Merrimack Energy Group, Inc.

1/31/2023

Benchmarking the Cost of Supplying Electricity from Renewable Energy Sources Relative to Hydro-Quebec Distribution's December 2021 Call for Tenders

prepared by

MERRIMACK ENERGY GROUP, INC.

WWW.MERRIMACKENERGY.COM

Table of Contents

1. Executive Summary

Merrimack Energy Group, Inc. ("Merrimack Energy") was retained by Hydro-Quebec to undertake a benchmark cost assessment of the comparative costs of renewable energy resources in the Northeast United States ("US") and eastern Canadian markets relative to the costs of the proposals submitted to and selected by Hydro-Quebec in its distribution activities under its most recent December 2021 Call for Tenders.

Hydro-Quebec is required, based on regulations, to demonstrate to the Regie de l'energie du Quebec ("Regie") that the contract pricing from the Call for Tenders is competitive and represents lowest reasonable cost when compared with market options in neighboring markets as part of the contract approval process by the Regie. For this assignment, Merrimack Energy is required to provide two deliverables.

Deliverable 1 includes a benchmark cost assessment of renewable energy resources in the Northeast US and eastern Canadian markets in terms of unit costs per energy source and the expected prices in those of the future for a specified list of renewable resources. The list of renewable resources required includes:

- Wind power
- Wind power with energy storage
- Hydro
- Solar Power
- Solar power with energy storage
- Biomass power
- Renewable natural gas

This report serves as the benchmark assessment for calculating the competitive cost of renewable resources in neighboring markets to Quebec. Merrimack Energy notes in this report the significant increases in market prices experienced by most renewable resources over the past eighteen months driven by supply chain constraints, inflationary pressures, the war in Ukraine, increases in the costs of inputs to the production of wind, solar and storage resources, and regulatory and legislative initiatives. Due to the volatility in market prices, Merrimack Energy has focused its efforts to the development of benchmark prices that correspond as closely as possible to the timing for submission of proposals in July 2022 in response to Hydro-Quebec's 2021 Call for Tenders.

To develop benchmark costs for the renewable resources identified above, Merrimack Energy has utilized publicly available reports, generic market information based on projects proposed, and our knowledge of market trends for specific renewable resource types based on real-time market involvement as Independent Evaluator or Independent Monitor in a number of power procurement processes. This information has been used to develop estimates of the cost of power for each resource technology in the Northeast US markets and eastern Canadian markets.

Merrimack Energy prepared a sample of proposals based on contract prices or unit costs but also developed a sample of proposal costs based on capital costs for specific resource types and then calculated annualized costs using a capital cost recovery factor plus O&M costs divided by the capacity factor[1] of the resource technology for the applicable markets. Merrimack Energy's methodology is designed to calculate the Levelized Cost of Energy ("LCOE")[2] for each resource type as the initial calculation and then calculate the real levelized cost of energy consistent with Hydro-Quebec's input assumptions and methodology for evaluating proposals received through its December 2021 Call for Tenders. For US projects, Merrimack Energy initially calculated the LCOE and real levelized cost[3] values in US dollars and then converted the cost streams to Canadian dollars, using Hydro-Quebec's projected exchange rates for Canadian and US dollars.

Table ES-1 provides a summary of the levelized cost of energy and real levelized benchmark costs in Canadian dollars for each renewable resource evaluated. As noted in this table, Merrimack Energy has provided a range of costs due to volatility and increases in the cost of constructing renewable projects including solar, wind and storage resources. Merrimack Energy was able to compile a significant amount of data on US projects for the mid-2022 timeframe required but was not able to find much real time data for eastern Canadian markets. As a result, the cost calculations rely heavily on US data and associated calculations of costs in northeast US markets. The report provides a detailed description regarding the basis for calculation of benchmark costs for each resource type.

[1] Use of capacity factors for generation resources in specific markets is important to appropriately evaluate the costs of these resources. For example, the levelized cost of solar PV projects would likely be much lower in western and southern US markets given the higher capacity factors of solar resources relative to the northeast where capacity factors for solar resources are much lower.

[2] The LCOE is a measurement used to assess and compare alternative methods of generating electricity. The LCOE of an energy-generating asset can be thought of as the average total cost of building and operating the asset per unit of total electricity generated over an assumed lifetime of the asset. The LCOE can be calculated by first taking the net present value of the total cost of building and operating the power generating asset. This number is then divided by the net present value of total electricity generation over its lifetime.

[3] Real levelized cost is based on the determination of the initial year price escalated by inflation that results in the same net present value of the stream of dollars generated by the LCOE calculation.

Table ES-1: Summary of LCOE and Real Levelized Cost Calculations ($/MWh Cn$)

Resource Cost Assessment	Levelized Cost of Energy ($/MWh Cn$)	Real Levelized Cost of Energy (2022 $/MWh Cn$)
Wind		
Capital Cost - $2,000/kW	$86.27	$62.11
Capital Cost - $2,250/kW	$94.22	$67.82
Capital Cost - $2,500/kW	102.17	$73.56
New England/New York LCOE	$96.10	$69.17
Solar 17% CF		
Capital Cost - $1,800/kW	$146.70	$113.77
Capital Cost - $2,000/kW	$160.31	$124.29
Capital Cost - $2,200/kW	$173.92	$134.84
Solar 22% CF		
Capital Cost - $1,800/kW	$113.36	$87.91
Capital Cost - $2,000/kW	$123.88	$96.05
Capital Cost - $2,200/kW	$134.39	$104.19
New England LCOE[4]	$101.27	$78.54
New York LCOE	$92.11	$71.43
Standalone Storage		
Capital Cost - $1,600/kW	$155.17	$129.76
Capital Cost - $1,900/kW	$176.23	$147.55
Capital Cost - $1,600/kW – LCOE ($/kW-month)	$16.05	$13.43
Capital Cost - $1,900/kW – LCOE ($/kW-month)	$18.22	$15.27
Solar + Storage		
4-hr duration BESS at 10% ($4/MWh Adder)	$129.08	$98.59
4-hr duration BESS at 100% ($25/MWh Adder)	$156.38	$119.44
Biomass		
Capital Cost - $2,500/kW	$85.79	$61.35
Capital Cost - $5,000/kW	$126.95	$90.76
Capital Cost – NREL - $4,360/kW	$116.41	$83.23
Capital Cost -NE - $5,372/kW	$133.35	$95.33
Capital Cost -NY - $5,389/kW	$133.07	$95.15
Hydropower[5]		

[4] While Table ES-1 includes the data for solar projects in New England and New York plus the increase in $/MWh (US$) based on the LevelTen analysis, in Merrimack Energy's view these costs are unreasonably low and are not supported by current capital costs for solar. Please see Section 4 of this report for more details.

[5] The first two hydro cases evaluated are based on US Department of Energy, "Energy Information Administration Annual Energy Outlook 2022" estimated capital and O&M costs for hydropower projects in New England and New York respectively. The third case, (NSD4) reflects the estimated cost for a new hydro project greater than 10 MW

Capital Cost - $2,025/kW	$47.95	$34.08
Capital Cost - $4,244/kW	$85.27	$60.62
Capital Cost – NSD4 10+ MW - $6,269/kW	$105.10	$74.71
Capital Cost – NPD2 – Medium - $5,514/kW	$171.49	$121.92
Capital Cost – NPD6 – Medium - $6,873/kW	$172.37	$122.54

with a 30+ foot head. The fourth project, (NPD2) is defined as a lake-based project. The fifth project, (NPD6) is defined as a lock-based project. The lake-based option includes non-lock dams, while the lock-based option is based on navigation dams with locks.

2. INTRODUCTION

2.1 BACKGROUND & OBJECTIVE

Merrimack Energy Group, Inc. ("Merrimack Energy") was retained by Hydro-Quebec to undertake a benchmark cost assessment of the comparative costs of renewable energy resources in the Northeast United States ("US") and eastern Canadian markets relative to the costs of the proposals submitted to and selected by Hydro-Quebec in its distribution activities under its most recent December 2021 Call for Tenders. Hydro-Quebec issued two Call for Tenders, including one which calls for the purchase of a block of renewable energy with a 480 MW capacity contribution to the winter peak with energy needs of 4.2 TWh on an annual basis and a second which requires a block of wind energy having 300 MW of installed capacity. The new long-term supply contracts expected from the December 2021 Calls for Tenders are required to meet the energy and power needs of Hydro-Quebec. The new supplies solicited will have to be available no later than December 1, 2026.

Hydro-Quebec is required, based on regulations, to demonstrate to the Regie de l'energie du Quebec ("Regie") that the contract pricing from the Call for Tenders is competitive and represents lowest reasonable cost when compared with market options in neighboring markets as part of the contract approval process by the Regie. For this assignment, Merrimack Energy is required to provide two deliverables.

Deliverable 1 includes a benchmark cost assessment of renewable energy resources in the Northeast US and eastern Canadian markets in terms of unit costs per energy source and the expected prices in those of the future for a specified list of renewable resources. The list of renewable resources required includes:

- Wind power
- Wind power with energy storage
- Hydro
- Solar Power
- Solar power with energy storage
- Biomass power
- Renewable natural gas

For the first deliverable, Merrimack Energy is required to present the comparison in Canadian dollars and in 2022 constant dollar prices. In addition, the results obtained should be adjusted to reflect Quebec's business, economic, and regulatory context, and document the main characteristics that differentiate

North American Call for Tenders (or Request for Proposals) to those in the Quebec market. The main factors to be considered include:

- Climate
- Labor
- The regional market
- Local sourcing requirements
- Involvement of local communities and First Nations (where applicable)
- Topography of the land
- No tax credits offered for renewable energy projects
- Limited interconnection capacity
- Scale of the projects

Deliverable 2 requires Merrimack Energy to provide a comparison of the unit costs of winning bids in Hydro-Quebec's Call for Tenders issued in December, 2021 to benchmark resources potentially available in northeast power markets, including the cost of transporting the power to Quebec and factoring in the Quebec business, economic and regulatory context. Hydro-Quebec wishes to obtain an assessment of the anticipated real unit cost (in real levelized $/MWh in Cn$) per originating renewable energy source as the basis for comparison.

Under its regulations, the Regie requires that Hydro-Quebec undertake a comparative analysis of the cost of power for similar products from neighboring Northeast power markets. The "similar products" standard is important to define in undertaking the benchmark study and can be identified to reflect project technology, size, product specifications, contract term, timing for the Call for Tenders and project in-service date. For example, as will be described in this report, the similar product standard should include size of the resource, timing of the solicitation process for Hydro-Quebec, and commercial operation date of the project, if possible. Based on recent dramatic changes in electric power project costs resulting from such factors as: (1) supply chain constraints affecting the availability and cost of generating equipment; (2) project input commodity costs for a wide range of raw materials; required in the production process such as steel, copper, cement, etc.; (3) inflationary trends affecting labor and other costs; (4) increases in interest rates in the US and other markets which affects the cost of borrowing to construct such projects; (5) worldwide competition for renewable resources; (6) exchange rate impacts; and (7) legislative and regulatory initiatives to increase subsidies for renewable projects, it is important that the cost of benchmark resources should be assessed in conjunction with Hydro-Quebec's timing for its Call for Tenders in which bids were due in July 2022 and projects are expected to come on-line in 2026.

The timing for the comparative assessment based on July 2022 cost information presents unique challenges for collecting primary data for each market as the basis for comparison. For example, the most recent publicly available studies on renewable project costs rely largely on 2021 data or before with little or no data available for mid-2022. Reliance on the data in these studies, in many cases, show a continued decline in project costs through 2022 and beyond which is totally contrary to experiences in the current market, which started experiencing increases in project costs beginning in Q2 or Q3 2021 and continuing through and beyond Q3 2022. As a result, any studies which do not capture current market trends in cost increases for a number of renewable and other generation resources are reporting out-of-date information which is not consistent with the current market conditions in 2022, as will be described in this report.[6] While the long-term cost trends may revert back to declining costs for a number of resources as many analysts project, for the appropriate comparison of market costs to the costs of resources selected by Hydro Quebec through its December 2021 Call for Tenders, it is required that consistent information at that point in time when bids were submitted, evaluated, and selected should be utilized.

As Independent Evaluator or Independent Monitor for a large number of Request for Proposal processes for renewable resources and energy storage projects in many regions of the United States, Merrimack Energy can attest to the significant volatility in project pricing for most renewable resources and storage projects and the implications on power procurement activities, which have been driven by multiple factors as described above. Section 3 of this report will provide in more detail a description of the factors that have driven increases in power project costs and their implications on current and near-term future power markets.

As described in its Request for Proposals underlying this assignment, Hydro-Quebec requests the consultant provide a table of 5 comparisons for each of the following renewable energy sources: wind, wind power with energy storage, hydro, solar power, solar power with energy storage, biomass power, and renewable natural gas. Hydro-Quebec also requires that the consultant limit its analysis to the North American market, ideally the eastern Canadian provinces and northeastern US regions/markets. In undertaking the assessment in previous benchmarking studies for Hydro-Quebec in its distribution activities[7], Merrimack Energy also considered project size, location, technology, generation profile and capacity factors based on location. As an example of the importance of these

[6] Several of the reports which Merrimack Energy has reviewed project costs for most renewable resources, including battery energy storage projects, to continue to decline into the future. This raises the question whether the recent cost increases are temporary and represent an anomaly relative to previous trends regarding declining renewable resource costs or counteract the projected longer-term decline in resource costs.
[7] Merrimack Energy prepared and submitted at least seven reports on the competitive cost of electricity associated with Hydro-Quebec Call for Tenders between 2004 to 2015.

factors in the analysis, the levelized cost of solar projects based on contract pricing is generally much lower in areas such as Arizona or California due to much higher capacity factors for solar resources than would be realized in the US Northeast or eastern Canada even if the capital cost of such projects may be reasonably similar in the above markets, adjusted only by differences in construction and labor costs and the regulatory environment. Given the potential impact on Levelized Cost of Energy ("LCOE") values, this may lead to the use of capital costs as a starting point for assessing levelized cost or as verification of the levelized contract costs as an appropriate methodology.

The analysis undertaken by Merrimack Energy is intended to validate whether or not the costs of the projects selected by Hydro-Quebec for contract execution are competitive to similar resource options in other neighboring markets. [8]

2.2 Methodology for Preparing Benchmark Costs in Neighboring Markets

The methodology and workplan proposed by Merrimack Energy is generally consistent with the methodology used by Merrimack Energy in the previous Benchmark studies prepared for Hydro-Quebec in its distribution activities, including presenting cost estimates in constant Canadian dollars.[9] However, as highlighted in the Scope of Work for the consultant, Merrimack Energy would anticipate including more details and documentation on the unique differences in Quebec and other markets that may affect the competitive assessments as well as broader project samples if available. Although it can be difficult to conduct a consistent and equivalent evaluation of proposals by technology type, particularly given the current volatile market conditions, Merrimack Energy has developed a reasonable approach for conducting the comparative cost assessment required by the Regie.

The methodology proposed by Merrimack Energy is designed to assess the competitive cost of long-term power from the winning bids from Hydro-Quebec's recent Call for Tenders with general industry cost data as well as a sample of other

[8] For purposes of this analysis, Merrimack Energy will provide a range of costs for several technologies designed to reflect average costs in the market as well as first and second quartile prices in the applicable markets, if possible, as representative of the most competitive projects which reflects a reasonable sample from which to compare the prices of the projects selected by Hydro-Quebec from the Call for Tenders processes.

[9] This methodology is often referred to as real levelized cost analysis, which is, in simple terms, the initial year cost of a project (i.e., 2026 if the project is expected to come on-line in 2026) which, when escalated by inflation results in the same Net Present Value ("NPV") as the cost stream proposed by the bidder. If the offer was submitted as a fixed price for the contract term, the Net Present Value of that cost stream could be compared to an "alternative" cost stream that calculates the initial year price escalated by inflation that results in the same NPV. The real levelized cost approach is effective for comparing costs of projects with different contract start dates and contract terms.

similar project types proposed and under development in neighboring North American markets on a real levelized cost basis over consistent contract terms (e.g., 30-year contract terms for wind and biomass resources and 20-year terms for solar and storage resources) based on the expected useful life of such resources. The analysis will also include the cost of transmission from neighboring Northeast markets assuming the power would be purchased in the neighboring market and delivered to Quebec. In cases where multiple data points exist for project proposals, as noted, Merrimack Energy will focus on the cost of projects in the first and second quartiles as the most competitive options relative to the bids selected by Hydro Quebec, which would likely be the most competitive proposals as well. In addition, Merrimack Energy will strive to use publicly available data inputs for each market as a primary source of data if available. If publicly available sources of data are not readily available, Merrimack Energy will attempt to correlate data in other markets with the data in question for the local markets and apply trends in costs to develop capital cost and other cost inputs and assumptions and apply the expected cost changes over time.

For this assignment, Hydro-Quebec has identified two deliverables to be provided by the consultant:

1. Provide a written Benchmarking report assessing the market of the various resources listed in Objective 1 of the mandate. This will include costs of resources in northeast Canadian and US energy markets;
2. Provide a separate written report for the two calls for tenders issued by Hydro-Quebec in December 2021 regarding the price comparisons prepared by the consultant relative to the winning bids from the Hydro-Quebec's December 2021Call for Tenders.

For the previous benchmark reports Merrimack Energy prepared for previous Hydro-Quebec Call for Tenders solicitations, Merrimack Energy conducted research on project specific cost information in regional markets, if available and developed a list of similarly sized projects to the projects being considered by Hydro-Quebec. Merrimack Energy supplemented this information with information included in publicly available power project cost studies and competitive procurement processes,[10] and also attempted to compile information on contracts for projects in each market or reported levelized cost information from recent studies for applicable markets.

Merrimack Energy has found in preparing such benchmark studies that use of only levelized cost of energy studies can be misleading based on differences in location, capacity factor, project size, contract term, and market cost structure.

[10] Data from competitive procurement processes is generally confidential but average costs can be calculated without identifying project names or the specific procurement processes.

When capital cost information was available, Merrimack Energy calculated the annualized costs associated with the amortization of the capital costs and added estimates of O&M costs and transmission costs for delivering the power from the select market into Quebec, assuming Hydro-Quebec could procure similar resources in other northeast markets and deliver the power to Quebec. Merrimack Energy then relied upon data from other Call for Tenders or Requests for Proposals as a check on the reasonableness of the comparative costs generated.[11] As we did in previous benchmark reports, Merrimack Energy will compare the costs of renewable or other projects bid into Hydro-Quebec's Call for Tenders with similar resources in New Brunswick, Ontario, Nova Scotia, New York and New England. Merrimack Energy also addressed other factors in preparing the sample costs including tax credits and incentives in the US and Canada, capacity factor differences, and local conditions for adjusting benchmark costs.[12] We intend to conduct a similar assessment for this assignment but including a more extensive list of renewable resources, as required.

As a starting point, Merrimack Energy has initially focused on developing a reasonable sample of similar projects as required based on the resource types selected by Hydro-Quebec in neighboring northeast markets. For developing the sample of project costs, Merrimack Energy has focused on cost information for recent projects (i.e., 2022 project costs) given the market volatility consistent with the timing of submission of proposals in response to Hydro-Quebec's Call for Tenders. To develop the sample, Merrimack Energy has reviewed recent studies on renewable project costs, public information from trade associations and local sources regarding specific project costs, results from any local Call for Tenders or Request for Proposals ("RFPs), regulatory filings and approvals for contracts submitted, and similar information. In addition, Merrimack Energy utilized bid data from recent RFPs to validate cost information as required. For example, while Merrimack Energy expects the capital cost and operating cost of renewable projects to be somewhat similar within the applicable North American markets, unit costs could vary much more dramatically between different markets based on local conditions. As an example, while we would expect that capital and operating costs for wind and solar projects would not vary dramatically for

[11] Section 3 of the Mandate includes as Objective 1 identification and analysis of the results of recent North American Calls for Tenders in terms of the unit cost per energy source. However, based on our role as Independent Evaluator for utility solicitations, it is very difficult to gain access to such bid data immediately after completion of a solicitation process given the confidential nature of the data and the market timing associated with Hydro-Quebec's Call for Tenders. Some data may be available from solicitations after contracts are executed and filed for approval with regulatory Commissions but the timing of such solicitations with Hydro-Quebec's Call for Tenders may not correlate, particularly in light of recent price volatility.

[12] In previous Call for Tenders, Hydro-Quebec in its distribution activities generally conducted a procurement process designed to procure a targeted resource (i.e., wind only, or biomass only). As a result, Merrimack Energy's previous benchmark studies focused on one specific resource type for comparison purposes. The technologies and resource types are much broader for this assessment.

projects in high-cost markets such as California or the northeast US (i.e., New England and New York), given that these markets are high-cost markets with labor market dominated by requirements for union labor, the generation profiles will be very different with the capacity factor for solar projects in California or similar markets exceeding 30%, compared to lower than or slightly over 20% in most northeast markets. These differences will definitely affect unit costs in the different markets, while capital costs would likely be similar. As noted, while our original objective will be to develop a sample of similar projects in northeast Canadian and US markets on a unit cost basis, Merrimack Energy will also utilize capital costs for projects and the relationship between the actual costs in different markets to develop a sample of projects as a validation check.

The next step in the process for developing a sample of similar projects is to assess the implications of other factors which could influence costs of different projects by region. This could include implications of tax credits in the US relative to Canada, labor costs and requirements, local or regional content requirements, initiatives to benefit local communities and First Nations in Quebec, cost of transmission between regions, project sizes as noted previously, expected capacity factors for projects in different markets, and other unique requirements in the various markets which could impact project cost comparisons. Our objective would be to control for these factors as much as possible in preparing a sample of project costs as the basis for comparison. Table 1 below presents Merrimack Energy's perspective for how each of these factors may influence costs in each region relative to Quebec.

Table 1: Cost Factor Considerations in Northeast US and Eastern Canada

Factor	Considerations	Implications on Cost Comparisons
Climate	All Northeast markets would likely experience similar impacts regarding shorter project construction timeframes, capacity factors, peak period requirements and cost implications.	From a wind perspective, projects would appear to be smaller in the Northeast US and some other Canadian markets than the experience in Quebec. Larger wind projects would have some economies of scale. Limited land availability and reasonable access could impact the ability to construct large scale solar PV projects in the Northeast US. For this factor, we are generally assuming no significant difference or cost impact.
Labor costs	Labor costs are likely higher in all Northeast US and Canadian markets considered due to union labor requirements.	US markets may experience higher labor costs based on market structure and competition but no major differences. Differences are generally associated with comparison to other markets in the US such as Southwest or Southeast markets where non-union labor is allowed and cost of construction and operations is lower.

		Merrimack Energy would expect that labor costs would not vary significantly between Quebec and other northeast markets.
Regional Market	Studies reviewed indicate that the cost of wind projects in Ontario are much higher than in the US. Certainly, tax credits can be one factor but it appears that market inefficiencies and regulatory issues could also have an impact.	For wind, we have assumed that all regional markets are similar with the exception of Ontario that appears to be a higher cost market for wind. As will be discussed later in this report, it also appears that the recent solicitation in Nova Scotia resulted in fairly low prices for wind projects selected.
Local Sourcing Requirements	In previous Call for Tenders, Hydro-Quebec included a local or regional content requirement that bidders had to meet regarding the sourcing of inputs, equipment and labor	Merrimack Energy would expect that local and regional requirements would result in higher costs for projects, particularly in cases where equipment is in short supply and supply chain issues are present. Assume 5% cost disadvantage.
Involvement of Local Communities and First Nations	Merrimack Energy consulted to Hydro-Quebec on Call for Tenders which allocated capacity to local communities and First Nations. As we recall, the project costs were more diverse but that on the whole project costs were generally higher for those projects associated with local communities and First Nations. Nova Scotia's 2022 RFP apparently included involvement of First Nations organizations in the projects, which may contribute to lower costs resulting from tax benefits or lower cost of capital?	As Merrimack Energy recalls from previous Hydro-Quebec Call for Tenders that involved local communities there was a range of costs, some higher and lower than broader Call for Tenders. Slightly higher costs are likely to result due to the additional requirements which may limit market participation.
Topography	For Northeast US markets for wind, the best projects are generally in mountainous areas away from population centers. The topography likely results in higher cost construction in these areas. For solar, Merrimack Energy would expect smaller projects given land availability in the Northeast US, in particular.	Due to the topography overall in the Northeast, we would expect that costs for construction and operations would be higher due to the topography relative to other markets such as Texas and the Southwest US with mesas and flat lands that are conducive to wind project development at a lower cost and the benefits associated with a large amount of available land for solar development. One of the other important issues associated with topography in northeast US and Canadian markets is the cost of constructing transmission facilities to connect the projects to the utility system.
Tax Credits	US markets for wind, solar and other renewables as well solar combined with storage have enjoyed Production Tax Credits and Investment Tax Credits for a number of years. The recent Inflation Reduction Act has extended and expanded tax credits for renewables and has also added an investment tax credit for standalone storage. US projects have had an advantage over Canadian projects	In the US, the rules and regulations for accessibility to the available tax credits under the Inflation Reduction Act are still being developed. While we have recently seen in trade publications that tax credits are being considered in Canada, we are not certain of the potential impacts. The tax benefits associated with renewable energy projects depend on how competitive the market is and what percentage of the tax

	which have not had tax credits but that may be changing given recent discussions in Canada about adopting tax credits for renewable resources.	credits are passed along to utility customers or retained by the project developer or tax equity participants.
Limited Interconnection capacity	This is an issue that every region generally experiences. In the Northeast US, the presence of large offshore wind contracts could absorb much of the available interconnection capacity and result in significant costs for system expansion. The most economic wind projects in New England and New York are in the northern tier areas where system access may be limited	Merrimack Energy expects no difference because all regions are likely affected by interconnection constraints. Major cost differences are primarily dependent on project location within the transmission system.
Scale of the projects	There are generally smaller scale wind and solar projects in the Northeast markets for the most part with the possible exception of Quebec and Ontario. New York has also experienced a limited number of larger projects for solar and wind, but not of the level consistently seen in other states or Provinces	The scale of projects is generally affected by the available land for such projects and the topography that supports the highest levels of output for the technology. .

As noted above, in developing Merrimack Energy's benchmark reports for previous Hydro-Quebec Call for Tenders, Merrimack Energy not only prepared a sample of proposals based on unit costs but also developed a sample of proposal based on capital costs and then calculated annualized costs using a capital cost recovery factor that reflected the market cost of capital initially for consistency purposes but ultimately adjusted to reflect Hydro-Quebec's discount rate or cost of capital. Merrimack Energy's methodology is designed to calculate the LCOE[13] for each resource type as the initial calculation and then calculate the real levelized cost of energy consistent with Hydro-Quebec's methodology. For US projects, Merrimack Energy will initially calculate the LCOE and real levelized cost[14] values in US dollars and then convert to Canadian dollars using Hydro-Quebec's projected exchange rates for Canadian and US dollars. We intend to also include such costs for purposes of preparing the project cost sample for this assignment.

In terms of developing the database for projects in other regional markets there are additional issues to keep in mind that could affect the evaluation. First of all,

[13] The LCOE is a measurement used to assess and compare alternative methods of generating electricity. The LCOE of an energy-generating asset can be thought of as the average total cost of building and operating the asset per unit of total electricity generated over an assumed lifetime of the asset. The LCOE can be calculated by first taking the net present value of the total cost of building and operating the power generating asset. This number is then divided by the net present value of total electricity generation over its lifetime.

[14] Real levelized cost is based on the determination of the initial year price escalated by inflation that results in the same net present value of the stream of dollars generated by the LCOE calculation.

it is challenging for consultants to gain access to the results of Request for Proposals and Call for Tenders, particularly recent solicitations in neighboring markets consistent with the timeframe for Hydro-Quebec's Call for Tenders, since the data is generally confidential. A second factor of importance to consider, especially at this time in the renewable energy industry, is the implications of supply chain constraints, inflationary factors, and legislative and regulatory policy changes. It has been our experience that costs for solar, wind, and storage resources have increased significantly since the middle of 2021. Hydro-Quebec's Call for Tenders occurred in the middle of 2022. As Independent Evaluator, we are seeing project developers request higher pricing for their proposals during contract negotiations (or even after contracts have been executed and approved by regulatory agencies) as well as including indexed pricing, either for submitting proposals or as part of the contract negotiation process. Many projects are having challenges securing wind, solar, and storage equipment in the current market, which is delaying the expected Commercial Operation Date ("COD") of the project and driving up costs. Combined with these issues is the recent increase in interest rates which are also driving up bidder costs and associated pricing due to increased financing costs.[15] As a result, one of our objectives has been to place similar resources on an equal basis when developing a benchmark analysis of pricing of these resources. For this process, we also intend to rely upon actual proposals in other regions of the US and adjust the local market costs based on historical relationships to costs in the northeast markets as another data point for comparison. We have seen many cases in which government or other publicly available studies addressing pricing of various electric generation resources are out of date the minute they are released because the market has changed, and the study has not included the impacts of market volatility or pertinent changing market conditions. For a number of years costs for solar, wind and storage equipment and resource costs were flat or declining. However, that is not currently the case as virtually all factors are leading to an increase in cost of these resources.[16] The market is currently in an increasing cost state and one has to tread lightly regarding the reliance on such studies, although recent studies could add value as a starting point for incorporating adjustments in cost as Merrimack Energy has attempted in this report.

Finally, it is important to note that the recent passage of the Inflation Reduction Act ("IRA") in the United States could have an offsetting cost impact for US projects based on the potential for higher tax incentives and other benefits which

[15] Merrimack Energy has also seen delays in project development being affected by transmission constraints and interconnection challenges. However, these issues are consistent in all markets considered.
[16] Sellers are generally the beneficiary of declining cost markets since the seller will submit its proposal based on its expectations of equipment and EPC costs but may enjoy the benefits associated with continued cost declines once the seller executes contracts for such equipment.

could lower the cost of these resources for future projects. However, the details underlying this legislation are being worked out and the message we are hearing from bidders in power procurement solicitations is that there is still quite a bit of uncertainty how the rules regarding tax credits will be developed and implemented.[17] Merrimack Energy will also address these implications once more market information becomes available. Table 2 presents a comparison of the recent tax credits in the US for renewable resources compared to the proposed tax credits expected to be implemented through the Inflation Reduction Act.

Table 2: US Renewable Energy Tax Credits Before and with IRA[18]

Tax Incentives by Resource Type	Recent Tax Incentives in the United States for Renewable Resources	Proposed Tax Incentives from the Inflation Reduction Act
Wind	Up to \$26/MWh US\$ Production Tax Credit ("PTC") depending on the in-service date.	Projects will be able to choose the ITC or PTC. Both credits come with potential adders for meeting certain domestic requirements (labor and domestic content), located in energy communities, or for being a low-income property.[19] ITC could range from 24% up to 40% if special adders are reached. PTC starts at \$26/MWh in 2024 and escalates by inflation each year.
Solar	Up to 26% Investment Tax Credit ("ITC") depending on the in-service date. For example, projects that begin construction in 2022 and are online before the end of 2025 and eligible for 26%. Projects that begin construction in 2023 and are online before the end of 2025 are eligible for 22%. Projects that begin construction after 2023 are eligible for 10%.	Projects will be able to choose the ITC or PTC. Both credits come with potential adders for meeting certain domestic requirements, located in energy communities, or for being a low-income property. ITC could range from 24% up to 40% if special adders are reached. PTC starts at \$26/MWh in 2024 and escalates by inflation each year.
Storage	No tax benefits	Standalone storage will be eligible for a 30% ITC and up to 40% with additional incentives including location, US equipment, and labor requirements.
Hybrid	Battery systems that are charged by a renewable energy system more than 75%	It appears that hybrid projects can receive tax credits for both the renewable system and the

[17] Merrimack Energy's experience in recent Request for Proposals is that pricing for renewable and storage resources are not yet declining with the passage of the IRA but are still increasing. For solar, the recent US Department of Commerce preliminary decision in its investigation may be one major factor contributing to the increase in solar costs.

[18] All costs reported in Table 2 are in US\$.

[19] Labor requirements entail certain prevailing wage and apprenticeship conditions being met. To qualify for the domestic content bonus, all steel or iron used must be produced in the US and a "required percentage" of the total costs of manufactured products (including components) of the facility need to be mined, produced, or manufactured in the United States. An "Energy Community" is defined in the legislation as applying to a brownfield site or an area that has had energy production facilities closed and has an unemployment rate at or above the national average. Projects sited in an energy community are eligible for a 10 percentage point increase in value of the ITC (e.g., an additional 10% for a 30% ITC equals 40%) or a 10 percent increase in the value of the PTC.

	of the time are eligible for the ITC. Battery Systems that are charged by a renewable energy system 75% to 99.9% of the time are eligible for that portion of the value of the ITC.	storage component as well based on the individual benefits for each technology as provided through the IRA.
Hydro	Qualifying hydro power projects were allowed half-credit PTC or nearly $13/MWh adjusted for inflation.	Qualifying hydro power projects will now be allowed the full PTC as well as bonus credit amounts that meet domestic content requirements to certify that certain steel, iron, and manufactured products used in the facility were domestically produced. The bonus credit amount would be 10% of the credit amount.
Biomass	PTC benefits	Biomass along with geothermal, landfill gas and hydro power is eligible for PTC up to $26/MWh
Biogas		Eligible for ITC benefits

3. Current Conditions in Renewable Energy Markets in North America

Although there have been signs of issues with power pricing and the ability of power project developers to bring projects to commercial operations in the time expected by utility buyers since 2020, Merrimack Energy in its role as Independent Evaluator began to hear serious concerns expressed by project developers in the summer of 2021. Developers of solar projects began to warn utility buyers that if the United States Department of Commerce initiated a case against Chinese solar manufacturers for assembling Chinese solar components and modules in southeast Asian countries to avoid payment of tariffs, that the availability of solar equipment, such as modules and panels, would likely decrease dramatically and availability would be limited, which would drive up the cost to secure modules and panels. The US Department of Commerce did not initiate such an investigation in 2021 which as a result did not shock the market as warned.

However, Merrimack Energy began to see price increases for solar, wind and storage projects, including solar plus storage options, beginning in the Q3/Q4 timeframe in 2021. Merrimack Energy first noticed the trend toward higher prices when in response to a request to bidders in an All Source solicitation involving a large amount of MWs shortlisted, bidders submitted best and final prices that were generally higher than the original offer price. Usually, best and final pricing has led to a decrease in the pricing of proposals as project developers usually focus on "sharpening their pencils" to lower prices to remain competitive in a solicitation process.

In Q4 of 2021, the United States Congress proposed a package of tax incentives for renewable resources, labeled the "Build Back Better Act", to encourage the development of renewable resources to meet emission reduction objectives. Several utilities requested bidders in solicitation processes to price their bids assuming the Build Back Better legislation was passed into law to assess the potential price reduction that could be expected if the law passed based on the identified proposed incentive package. However, the Build Back Better legislation was not passed by the US Congress in 2021. As a result, proposals reflecting the potential impact of Build Back Better were not considered and instead any discussions between bidders and the utility focused on existing market conditions and originally proposed pricing.

A report issued by the International Energy Agency ("IEA") in late 2021 entitled *"Renewables 2021 Analysis and Forecast to 2026"* and associated articles regarding the report confirmed the trends in pricing of renewable resources that

Merrimack Energy had begun to witness in project bid pricing in its role as Independent Evaluator or Monitor on a number of renewable energy and storage resource procurements in the US. The Executive Summary of the IEA 2021 report provides graphs highlighting the trends in renewable resource prices which illustrates that prices for renewable projects had continued to decline through 2020 but were beginning to increase in 2021.

Several of the findings of the report with regard to renewable resource pricing conform to the trends Merrimack Energy had been witnessing in the power market via involvement in power procurement processes. This information serves as background information to the preparation of this report notably the following conclusions:

- Rising commodity prices have increased the cost of producing solar PV modules, wind turbines and biofuels worldwide. Higher prices for solar PV and wind equipment have reversed the cost reduction trends that the industry has been seeing for more than a decade and may delay the financing of some projects already in the pipeline;
- Prices for many industrial materials and freight costs have been on an increasing trajectory since Q1 2021, pushing up wind turbine and solar PV costs. Since the beginning of 2020 the price of PV-grade polysilicon has more than quadrupled, steel has increased by 50%, copper by 60% and aluminum by 80%. In addition, freight fees have increased almost six-fold, resulting in additional costs for the geographically dispersed supply chain of renewables;
- The reversal of the long-term trend of decreasing costs is already visible in the price of wind turbines and PV modules, which have increased by 10-25% depending on country and region, erasing two to three years of cost reductions since 2018 from technology improvements;
- In addition, restrictive trade measures have brought additional price increases to solar PV modules and wind turbines in key markets such as the United States, India and European Union;
- Biofuel prices have increased between 70% and 150% across the United States, Europe, Brazil and Indonesia by October 2021, depending on the market and fuel.

In Q1of 2022, Merrimack Energy had heard from project developers and utilities in the project evaluation and negotiation process that the solar module market was facing regulatory uncertainty leading to cancellation and delays in project development. In the United States, the passage of the Uyghur Forced Labor Prevention Act ("UFLPA") in December 2021 added potential concerns associated with module delivery. The Act gives United States authorities increased power to block the imports of goods linked to forced labor practices in China. The law was expected to create project delays resulting from bans on importing cells and modules containing silicon from certain companies. The new law means it is no longer business as usual for imports associated with forced labor in China and the Xinjiang Province especially.[20]

On April 1, 2022 the US Department of Commerce ("DOC") initiated an anti-dumping and tariff circumvention investigation into solar module imports from Malaysia, Thailand, Vietnam, and Cambodia following a petition filed by Auxin Solar. A positive ruling by the Department of Commerce would mean any anti-dumping duties imposed in such a ruling would be retroactively applied to any shipments made as of the initiation date (i.e., April 1 2022) which has already impacted availability and shipment of modules. The DOC investigation froze imports and stalled the development of projects immediately. It has been estimated that this investigation could impact over 80% of the solar panels imported and could lead to retroactive tariffs of up to 250%. In addition, the investigation could take over six months to complete. In early June 2022, President Joe Biden deployed the Defense Protection Act to enact a 24-month tariff exemption in order to mitigate the massive disruption to the industry that the investigation had caused. With that said, many developers have sought solar panel supplies from other manufacturers which oftentimes would come at a higher price, particularly due to constraints from unaffected manufacturers.[21]

In addition to the regulatory changes and inflationary pressures associated with commodity inputs for solar PV and wind projects such as steel, copper, and aluminum, as well as semi-conductor chip shortages and increases in lithium carbonate prices, a key input in battery energy storage costs, have all had a negative impact on pricing. Also, recent increases in interest rates due to Federal Reserve policies to reduce inflation are also impacting overall energy project prices and driving up costs to finance a project. Finally, the cost of shipping and increasing freight costs are all negatively affecting resource costs. This analysis will

---

[20] As background, since 2017 Chinese authorities have committed crimes against humanity against Uyghurs and other Turkic Muslims in the northwest Xinjiang region subjecting detainees and others to forced labor. The Xinjiang region in China is home to 50% of the global supply of polysilicon which is a key element in the production of solar modules. According to articles, China produced more than 80% of the world's solar-grade polysilicon in 2021.

[21] On December 2, 2022, the US Department of Commerce rendered a preliminary decision in its anti-dumping investigation to impose anti-circumvention duties on solar panels and cells produced in Vietnam, Malaysia, Thailand, and Cambodia. The DOC named four panel suppliers that it said are circumventing US duties on Chinese solar panels by routing them through factories in Southeast Asia. The four are BYD (Cambodia), Canadian Solar (Thailand), Trina (Thailand) and Vina Solar (Vietnam). The DOC also released the names of another 22 companies that it concluded are circumventing US duties because they failed to respond to information requests. An article by the Law Firm of Norton Rose Fulbright noted that 80% of solar panels imported into the United States during 2021 came from the four Southeast Asian countries mentioned and fewer than 1% came from China. The article noted that while the China-wide rate for anti-dumping duties is 238.95% and for countervailing duties is 15.87%, many manufacturers are subject to significantly lower anti-dumping duties after demonstrating to the DOC that their dumping margins are low. Commerce will issue a final determination on its findings around May 1, 2023.

reflect the changes we are seeing in the market and the implications of these factors on project costs as actually experienced in power procurement activities in the US.

3.1 Power Markets in the Northeast US and Eastern Canada

For the comparative analysis of costs of electricity by resource type identified by Hydro-Quebec, Merrimack Energy's objective is to prepare a database of generating resource options for renewable resources and energy storage projects in both the northeast US and eastern Canadian markets. In the Northeast US this includes the New York ISO ("NYISO) and ISO New England (ISO-NE), the entities that operate the power market in New York and New England, respectively.

For eastern Canadian Markets, Merrimack Energy assessed the Ontario, New Brunswick and Nova Scotia markets. While all three regions have experienced an increase in renewable generation, there is little available recent data on the cost of generating electricity from renewable resources in these three regions compared to the US. There does not appear to be much recent publicly available cost information and limited results from recent solicitations. Merrimack Energy has been able to find some cost information from specific wind projects over the past three to four years but we could find no information regarding the recent implications of increases in costs for all the different renewable generation technologies. Merrimack Energy is providing the information we have gathered below in an attempt to inform our view of the cost of different renewable resources.

3.2 Market Costs & Structure in New York and New England

The Northeast US markets have a number of similarities regarding market structure, resource mix, procurement initiatives, and underlying resource characteristics. For example, both New England and New York wholesale electric markets are operated by an Independent System Operator ("ISO") – ISO New England and the New York ISO respectively. Both markets have a generation mix primarily dependent on natural gas, with renewable resources a small but growing component. Both regions can be classified as high-cost markets and regional areas with a heavy presence of union labor. Both regions have similar resource plans with a projected significant reliance on offshore wind to make up an increasing portion of the generation mix in each region going forward. Given the climate in each region, the capacity factors for wind and solar are lower than many other regions of the US. These factors will affect the levelized cost of energy calculations, which will reflect relatively lower levels of output for wind and solar projects.

With regard to New York, the *"2021 State of the Market Report for the New York ISO Markets"* by Potomac Economics[22], May 2022 provides an interesting perspective to help inform the assessment of the benchmark costs for the New York ISO. The Executive Summary provides some interesting observations regarding the market and the expected role of renewable resources. The study notes that at a high level "the NYISO market provides price signals that motivate firms to invest in new resources, retire older plants, and/or maintain their existing generating units. Historically, NYISO has seen entry of efficient fossil generators driven by wholesale market revenues. In recent years, investment has shifted to renewable resources. New York has ambitious clean energy goals under the Climate Leadership and Community Protection Act, including requirements for 70 percent renewable electricity by 2030 and 100 percent zero emissions electricity by 2040. Meeting these mandates will require unprecedented levels of investment in the power sector." The study also provided the following observations with regard to renewables:

- At recent market prices and costs (including state and federal incentives), we estimate that revenues justify investment in land-based wind. This is consistent with current trends that nearly all recent investment has been in land-based wind, although other considerations (such as permitting and siting) may limit the extent of development;
- Other technologies, including solar and offshore wind, do not appear to be economic under prevailing conditions. This may explain why most such projects under contract with the State are significantly delayed.[23] However, the cost of these technologies is expected to fall over the long term. State and federal incentives account for the majority of revenues for all types of renewable generation, although wholesale energy and capacity revenues make up a significant share;
- We find that market revenues are currently below levels that would justify investment in 4-hour and 6-hour batteries. This is not surprising because the conditions that would make battery projects valuable - namely, high levels of intermittent renewable penetration and/or high-capacity prices are not yet present in NYISO. Increased renewable deployment, growing requirements for ancillary services, and retirement of conventional generators will make storage more economic over time;

[22] Potomac Economics is the Market Monitoring Unit for the New York ISO.
[23] New York State Energy Research and Development Authority ("NYSERDA") is the state agency responsible for issuing RFPs to procure offshore wind resources and other land-based renewable resources. Suppliers bid to sell RECs to NYSERDA via the solicitations for offshore and other renewable resources.

- NYISO's energy markets will compensate storage that alleviates curtailment of renewable generation. When renewable resources are curtailed, locational based marginal prices ("LBMPs") are set at negative levels equivalent to the cost of the renewables' foregone Renewable Energy Credit ("REC") payment. Batteries that reduce curtailment of renewable energy by charging at these times are paid for the energy they absorb. Hence, our analysis shows that at any location where renewables are curtailed, storage revenues will increase, creating strong incentives for storage developers to anticipate or respond to renewable integration needs even if they do not receive state and federal incentives;
- Under NYISO's recently approved marginal capacity accreditation rules, capacity revenues of storage units will reflect that they complement the availability of intermittent resources. As deployment of renewables rise, the amount of storage that can receive high-capacity value ratings will naturally tend to grow. Additionally, higher levels of intermittent penetration will lead to more frequent transitory shortages as its output fluctuates, which can significantly increase revenues for storage resources. This should facilitate storage development that efficiently complements the renewable fleet;
- Ancillary service revenues are expected to play a large role in promoting storage investment. However, several aspects of the current market's under-value flexible resources.

As noted in footnote 23, NYSERDA is the primary procurement entity for offshore wind and renewable resources in New York. NYSERDA's webpage contains a list of the Offshore Wind and Renewable RFPs NYSERDA has initiated and completed. NYSERDA issued a Request for Proposals to procure at least 2,000 MW of offshore wind resources on July 27, 2022. Proposals were due on January 26, 2023. Also NYSERDA issued a Large Scale Renewable RFP on September 21, 2022 seeking to procure approximately 4.5 million Tier 1 Renewable Energy Certificates ("RECS") from eligible facilities that enter commercial operations on or before May 31, 2025.

While ISO-NE is responsible for operating the wholesale electric market in New England, long-term procurement activity for renewable resources is managed by each of the states separately. A presentation of Eric Johnson, Director of External Affairs at ISO-NE entitled *"New England Power System Outlook"* at the CBIA 2022 Energy and Environment Conference provided a perspective on the policies of each state regarding their renewable clean energy and CO2 emission reduction goals and recent procurement activity. Table 3 replicates the slide from the presentation regarding New England state's clean energy goals.

Table 3: Clean Energy and Emission Reduction Goals by State

State	Amount of CO2 Emission Reductions Targeted
Massachusetts	MA statewide GHG emission limit – Net-Zero by 2050; MA Clean Energy Standard – 80% by 2050.
Vermont	VT Renewable Energy Requirement – 90% by 2050
Maine	ME Renewable Energy Requirement – 100% by 2050; ME Emission goal – Carbon-Neutral by 2045
Connecticut	CT Zero-Carbon Electricity Goal – 100% by 2040
Rhode Island	RI Renewable Energy Goal – 100% by 2030

As noted, all New England states with the exception of New Hampshire have aggressive clean energy policies in place. In total, the five states listed above have greenhouse gas emission targets that would result in emission reductions of over 80% in aggregate by 2050.

In addition, each of the New England states have implemented renewable power procurement activities and processes via Request for Proposals to procure both offshore wind and other renewable energy resources. Table 4 provides a summary of the procurement activity by state as listed in Mr. Johnson's slide presentation.

Table 4: List of Power Procurement Processes in New England (2017-2022)

State	State Procurement Initiative for Large-Scale Clean Energy Resources	Eligible Resources	RFP Target MW (nameplate)	Projected COD/Selected MW
Maine	2022 Northern Maine Transmission and Renewable RFP	Transmission and newly developed renewables	700 – 1,200 MW	TBD
Massachusetts	2021 Section 83C III [24]Offshore Wind RFP	Offshore Wind	1,632 MW	2028 COD; 1,600 MW
Maine	2020-2021 RPS RFP	ME RPS Class 1A Renewables	2,360,000 MWh	2022-2024
Connecticut	2019 Offshore Wind RFP	Offshore Wind	400 – 2,000 MW	2026 COD; 804 MW
Massachusetts	2019 Section 83C II Offshore Wind RFP	Offshore Wind	800 MW	2025 COD; 804 MW
Rhode Island	2018 Renewable Energy RFP	Solar, Wind, Biomass and other eligible renewable resources	400 MW	2023 COD; 50 MW
Connecticut	2018 Zero-Carbon Resources RFP	Nuclear, Hydro, Class 1 Renewables, Energy Storage	Approximately 1,400 MW (12,000,000 MWh)	2020 – 2026; 11,658,000 MWh

[24] Merrimack Energy has served on the Independent Evaluator team for all three Massachusetts Offshore Wind RFPs.

Connecticut	2018 Clean Energy RFP	Offshore Wind, Fuel Cells, Anaerobic Digestion	252 MW	2019 – 2025; 252 MW
Massachusetts/Rhode Island	2017 Section 83C I Offshore Wind RFP	Offshore Wind	800 MW (MA); 400 MW (RI)	2023 (800 MW); 2025 (400 MW)
Massachusetts	2017 Section 83D Clean Energy RFP	Hydro Imports and other eligible Renewable Resources	Approximately 1,200 MW (9,554,000 MWh)	2022 (9,554940 MWh/yr)

While there has been quite a bit of procurement activity in New England over the past five years, with the exception of Maine, most of the activity has centered on procurement of offshore wind. Interestingly, the Massachusetts utilities contracted for over 1,600 MW from the third offshore wind solicitation from 2021. However, after executing contracts and during the hearing for contract approval at the Massachusetts Department of Public Utilities ("DPU"), both entities selected for contract execution requested that due to increases in market prices they were seeking an increase in the contract price and asked to renegotiate the contract.[25] The utilities refused to renegotiate and the Massachusetts DPU agreed with the utilities position. In early December 2022, one of the project developers who executed contracts for 1,200 MW of offshore wind generation (Avangrid Renewables – Commonwealth Wind) decided to terminate its contract (with a PPA price of $72/MWh US$) due to increased costs for equipment, project development and construction that rendered its project uneconomic at the contract price. It is Merrimack Energy's understanding that the Massachusetts Department of Energy Resources ("DOER") will be initiating another offshore wind solicitation process in early 2023.

3.3 Market Structure in Eastern Canadian Power Markets

Merrimack Energy's goal is to collect and utilize data available for project costs in the three eastern Canadian markets of Ontario, New Brunswick and Nova Scotia. The market structure and role of renewables differ by market, with Ontario having a more complex market structure than either of the smaller systems of New Brunswick and Nova Scotia

[25] Commonwealth Wind, who executed a contract for 1,200 MW of offshore wind generated electricity, maintained that the offshore wind generation project underlying its PPAs with the utilities is no longer viable because of recent global commodity price increases due in part to the war in Ukraine, interest rates, supply chain constraints, and persistent inflation.

A March 2021 report by the Canadian Energy Regulator (CER) entitled *"Canada's Renewable Power: Recent and Near-Term Developments"* provides a review of recent developments for renewable energy by Province. The Report notes that between 2010 and 2017, Ontario added a net 7,152 MW of renewable capacity, comprised primarily in wind (3,668 MW) and solar (2,299 MW). Between 2017 and 2023, Ontario is projected to add 466 MW of new net renewable capacity. The projected increases in wind and solar are offset by decreases in Biomass/Geothermal capacity. The report identified recent and future wind (5 projects), solar (1 project) and hydro (1 project) projects added between 2017 and 2021.

A recent report by the Independent Electricity System Operator ("IESO") in Ontario entitled *"Resource Eligibility Interim Report"*, October 7, 2022 noted that the 2022 Annual Acquisition Report ("AAR") identified a need for 2,500 MW of capacity starting in 2025 and continuing beyond. The report notes that to address this need, the IESO has developed three procurements (Same Technology Upgrades, Expedited LT 1, and LT 1) with a target of approximately 4,000 MW of capacity. The IESO has identified significant reliability risks as a result of potential project delays, given current global supply chain and project development issues. The higher procurement target mitigates against this risk of not having enough resources to meet planning standards and ensure that the system is ready for future growth. This target will also help the IESO manage operability risks stemming from integrating new technologies onto the system. The procurement amounts and timelines are listed in Table 5.

Table 5: Power Procurement Processes in Ontario

Procurement Mechanism	Capacity Target (MW)	Eligibility	Procurement Materials Posted	Proposals Due	Contract Award
Same Technology Upgrades	300	Facility improvements managed through contract amendments	Nov 1, 2022	Dec 20, 2022	Q1 2023
Expedited Long Term 1	1,500	On-site expansions and new greenfield resources	Nov 1, 2022	Dec 20, 2022	Feb 2023
Long Term 1	2,200	On-site expansions and new greenfield resources	Jan 31, 2023	Q2 2023	No later than Oct 2023
Total	4,000				

The CER report notes that approximately one-third of New Brunswick's electricity is generated by renewable sources with hydro the largest source followed by wind and biomass. New Brunswick is reported to have 294 MW of wind and 127 MW of biomass capacity. New Brunswick is projected to add 35 MW of wind by 2023 from 2017 with no change in biomass capacity. Utility solar capacity is currently miniscule in New Brunswick.

Although approximately 36% of Nova Scotia's generating capacity is comprised of renewable resources, only about 26% of its electricity generation is provided by renewables. Nova Scotia generates over 50% of its energy from coal. Renewable energy generation in Nova Scotia is growing, led primarily by wind. Hydro, tidal and biomass also contribute to total generation. Solar is near 0%. Nova Scotia's legislated renewable energy target requires 40% of electricity to be generated from renewable sources by the end of 2020. In 2021, legislation was passed setting an 80% renewable target by 2030. The Province of Nova Scotia issued a Request for Proposals for new large wind and solar projects capable of supplying 10% of the province's electricity from renewable sources in January 2022. This report discusses the results of that solicitation later in the report.

4. Calculation of Benchmark Costs for Renewable Resources

Section 4 of this report discusses general trends in renewable resource costs at a high level. This Section also describes in detail the calculation of benchmark costs for renewable resources, including renewable resources in northeast US and eastern Canadian markets for the purpose of comparing against the pricing of the wind and other bids selected by Hydro Quebec through the recent 2021 Call for Tenders. For purposes of developing benchmark cost estimates, Merrimack Energy initially focuses on renewable energy cost information for the US Northeast markets based on the greater availability of data and information. Following the compilation and calculation of cost and other data for Northeast US markets, Merrimack Energy provides the comparative cost information for eastern Canadian markets that we have been able to gather for comparison purposes.

4.1 Calculation of Wind Benchmark Costs

4.1.1 Background to the Calculation of Wind Benchmark Costs by Market

There are a number of factors that influence the cost of wind-generated electric power and other renewable resources by market area. These include the capital cost of the project, the cost of financing the project, operation and maintenance costs, and other administrative costs (e.g., property taxes, insurance, administration costs, and land lease costs, if applicable). For wind resources, the wind regime at the site, the size of the wind farm, configuration of the turbines, and the presence of government incentives such as production tax credits (US), accelerated depreciation and state subsidy programs also influence the levelized cost of energy.

The strength of the wind resource (i.e., wind regime), including wind speed and wind speed distribution over the course of the year, and the matching of the wind resource to the wind turbine power curve, is also a major determinant of project cost. These factors determine project output and the associated capacity factor of the wind system. Since most of the costs associated with a wind generation facility are fixed costs, the higher the capacity factor, the lower the per-unit cost.

However, since the cost of wind generation is highly site specific, it is very difficult to consistently and equitably compare the economics of various projects since each project has a unique set of local conditions. Unlike other generation technologies, such as combined cycle or combustion turbine facilities that generally have a standard design and fairly consistent cost characteristics, the economics of wind generation can vary considerably by area or market regions.

4.1.2 Sources of Data for Evaluation of Wind Benchmark Costs

Merrimack Energy has focused its efforts in developing a large database of information on renewable resource costs in the US and Canada, with a focus on compiling data in the regions of the Northeast US and eastern Canada, where available. As noted, since Hydro-Quebec's bids were submitted into the Call for Tenders in July, 2022 and therefore pricing submitted by bidders would reflect the changes in project costs experienced in the market in Q1 and Q2 of 2022, our objective was to develop benchmark costs for the same period as the bids received by Hydro-Quebec Distribution. While ideally collection of primary real time data based on contracts executed at the same time or solicitations for bids in these regions at the same time would be preferred, it is very challenging to collect such data. However, we have attempted to compile secondary data sources, such as reports, which include cost trends or to correlate the cost of wind in the northeast markets during the same base period to cost changes in other markets where more recent data is available and extrapolate the change in costs to projects in the northeast markets as an example.

The development of benchmark costs for wind projects defined in this assessment for each market will be supported by the following sources of information:

1. Recent reports, studies, and trade press articles in the US and Canada which focus on trends in wind-generated electricity costs, and may include regional wind prices. Examples of reports include: (1) *"LevelTen Energy 2021 (Q1 - Q4) and 2022 (Q1, Q2, and Q3) PPA Price Index Executive Summary for North America"*[26]; (2) *"US Department of Energy Land-Based Wind Market Report: 2022 Edition"*; (3) *"NREL Annual Technology Baseline: The 2022 Electricity Update"*; and (4) *"CohnReznick Capital Solar & Wind Market Cost of Energy Analysis, July 2022"*.
2. Pricing for wind projects bid into recent Request for Proposal processes where available;[27]
3. Studies which provide estimated installed costs or levelized costs for wind projects;
4. Prices for projects recently built or under construction if reported in publicly available sources.

[26] LevelTen makes Executive Summaries for their quarterly reports available free of charge but require a substantial fee to purchase the quarterly report which provides details by region.
[27] The specific projects and exact references are confidential.

The type of data collected will also have to be scrutinized to ensure the characteristics of wind and solar projects in various regions of the US and Canada are appropriately applied. As an example, while relying on reported LCOE data for wind may seem straightforward, it is important to note that projects may vary significantly in terms of capacity factor, regional labor costs, regulations, and terrain for these projects compared to other regions of North America. For example, data has shown that the capacity factor for wind projects located in the northeast is generally lower than in more wind-friendly regions such as Texas, the southwest US, or the Pacific northwest.

Due to these factors Merrimack Energy has also prepared estimates of levelized costs of wind and other resources by assessing the capital costs or Engineering, Procurement and Construction ("EPC") costs by calculating the annualized costs based on a capital cost recovery factor or fixed charge rate and adding fixed operations and maintenance costs ("FOM"), and other administration and operations costs combined with an expected capacity factor to derive an estimate of the LCOE.

For this assessment, Merrimack Energy will undertake multiple approaches for calculating the LCOE of projects in the northeast and will test the results against data from recent RFPs or Call for Tenders. Merrimack Energy would prefer to rely on publicly available data and "test" the accuracy and reasonableness of the data based on actual bids submitted into recent solicitation processes which reflect summer 2022 pricing trends. However, there is generally a lack of publicly available data for project capital costs and LCOE's for summer 2022, particularly for the Northeast US, which has not seen a reasonable number of recent on-shore wind projects during the timeframe in question.[28]

4.1.3 Data on Wind Costs Reported in Recent Studies or Trade Articles for Recent Cost Trends for Wind-Generated Electricity

An article on wind project costs increases by IHS Markit, a part of S&P Global, issued on January 31, 2022[29] identified the major drivers of cost increases for wind projects based on discussions with Original Equipment Manufacturers ("OEM"). The article notes that the cost of onshore wind fell 40% in the latter half of the

[28] New York (NYISO) and New England (ISO-NE) have focused their attention on offshore wind procurement. New York State Energy Research and Development Authority ("NYSERDA") has held annual procurements for renewable resources, but maintains confidentiality of the data. The focus in ISO-NE and the New England states has generally been on offShore wind with limited recent solicitation activity. For example, as will be discussed Merrimack Energy has relied upon LevelTen data to observe trends in wind and solar pricing, However, while Level Ten reports pricing by ISO market in the US (i.e., PJM, MISO, ERCOT, SPP, and CAISO), there is little to no data directly available for ISO-NE and NYISO.

[29] HIS Markit, "North America Wind Capital Cost and LCOE Outlook", January 2022.

2010's; however, prices are now on the rise, and that trajectory is set to continue, as cost increases and COVID induced bottlenecks snarl supply chains. For example, Vestas indicated it expected costs to continue to rise through 2022 and beyond because the company expected an increased impact from cost inflation related to raw materials, wind turbine components and energy prices. GE Renewables, the second largest turbine equipment supplier also expected prices to continue to rise.

The article also noted that the cost increases behind the price hike span materials, freight, labor needs coming out of the pandemic, and geopolitical risk. Rising material costs for aluminum, copper, fiber glass resins, and more have played a prominent role. Higher raw material prices are resulting in higher costs for all critical components including towers, blades, power electronics, and foundations. The top of the material cost list is the increase in steel prices, which accounts for a significant portion of wind project costs. In addition, increasing transportation and logistics costs are expected to continue to affect the wind power industry throughout 2022.

Other articles by Reuters Events have confirmed the reasons for the increases in wind project costs citing inflationary pressures, supply chain constraints and grid connection delays along with increases in the price of steel and other commodity costs as reasons for the increase. The article provided a summary of the results of a survey of project developers in which 75% of developers said that procurement and supply chain challenges drove Power Purchase Agreement ("PPA") price volatility.

LevelTen Energy (Q1, 2021 through Q3, 2022) PPA Price Index Executive Summary North America

Each quarter, the LevelTen Energy PPA price Index[30] reports the prices that wind and solar project developers have offered for power purchase agreements (PPAs) available on the LevelTen Energy Marketplace, a large collection of PPA pricing offers. The offers underlying the index are from projects that are currently under development and posted by developers to the LevelTen Energy Marketplace, which provides a look at actual PPA price offers.[31] The Quarterly

[30] Merrimack Energy has seen the LevelTen Energy PPA Price Index referenced in several articles and reports dealing with price increases for wind and solar projects.

[31] LevelTen Energy noted that price data is aggregated and reported in percentile buckets (e.g., P25 refers to the most competitive 25th percentile offer price). Indices calculated and presented by LevelTen in their quarterly publicly available reports are calculated at the 25th percentile and are averages of the individual P25 ISO components. Data are based on PPA prices that assume financial settlement in the real time wholesale energy market by ISO (i.e., PJM, MISO, ERCOT, SPP, and CAISO with no or little data available or reported for ISO-NE and

Executive Summaries are available publicly but the full report has to be purchased separately at a hefty price. Merrimack Energy has accessed only the publicly available data beginning with the Q1, 2021 report through the Q3 2022 Executive Summary to inform our own knowledge of market price changes. Merrimack Energy views this period (Q1 2021 – Q3 2022) as the period where project developers first began to raise concerns regarding cost increases for solar, wind and storage projects in power procurement solicitations, up through Q3, 2022 which coincides with the receipt of tenders for Hydro-Quebec's December 2021 Call for Tenders.

Merrimack Energy began its review of the LevelTen Energy PPA price index for Q1 2021 and compiled the price trends through Q3 2022. For wind projects on a US national level, wind prices have experienced an upward trend every quarter since Q1 2021. Table 6 presents the quarterly index for wind on a US national level.

Table 6: Quarterly Changes in Wind PPA Prices – Q1 2021 – Q3 2022

Period of Analysis (Quarter)	Index Price for Wind ($/MWh US$)
Q1 2021	$30.74
Q2 2021	$33.34
Q3 2021	$36.14
Q4 2021	$38.36
Q1 2022	$43.51
Q2 2022	$44.59
Q3 2022	$49.66

As the data above illustrates, the quarterly index for wind projects has increased by $18.92/MWh (US$) or by 61.6% over the past 6 quarters, starting with Q1, 2021.

In its Q1 2022 report, LevelTen noted that for the first time since LevelTen Energy's PPA Price Index Report began in 2018, renewable PPA prices increased across all ISOs for both wind and solar quarter over quarter. The Q1 2022 report concluded that on a market averaged National Index for the US, the P25 Market-Averaged index for wind prices increased on a year over year basis by 41.5% or $12.77 per MWh. While the LevelTen report did not include any pricing for ISO-NE or NYISO, the report noted that the P25 wind prices in PJM continued their steep increases and rose 15.6% to $55.10/MWh (US$). Prices in the California ISO (CAISO), another high-cost market similar to the New England and New York markets, illustrated a cost for wind power approaching $60/MWh (US$).

NYISO). All prices are hub settled with bundled project RECs included. Prices were offered across a range of project contract start dates with contract tenors ranging from 10 – 15 years.

LevelTen Energy's Q2 2022 PPA Price Index provides interesting data on wind and solar prices by quarter. LevelTen compared their market average index price by quarter and on a year-over-year basis (Q2, 2021 to Q2 2022) and concluded that wind prices increased 33.7% or $11.25/MWh (US$) over that period, with an average US price for wind at $44.59/MWh (US$).

The report stated that wind prices as a whole continued to climb across markets, a trend fueled by inflation, permitting issues, and transmission constraints. The report also cited issues around the uncertainty over implementation of the IRA in the US, noting that developers won't be able to understand specific benefits around tax credit requirements until the US Government releases new guidance.

While again there were no prices reported for ISO-NE or NYISO, LevelTen noted that wind prices in PJM did drop by 14.2% for the Q2 2022 index, but noted this was likely due to a decrease in offer volume causing data fluctuations and should not be taken as indicative of market price levels as a whole.

The Q3 2022 PPA Price Index Executive Summary illustrated that during Q3 2022, P25 wind prices increased in every market. From Q2 to Q3, the wind P25 Market Average National Index increased by 11.4% or $5.07/MWh (US$) and now rests at $49.66/MWh (US$). On a year over year basis the wind P25 Market Average Index increased by $37.4% or $13.51/MWh (US$). The Q3 report also stated that the Q3 price in CAISO increased by 13.3%, approaching $70/MWh (US$). Figure 1, below, illustrates the PPA price trends since Q3 2018 through Q2 2022.

Figure 1. Nominal Wind PPA Prices in US$ (25th Percentile of Offers)

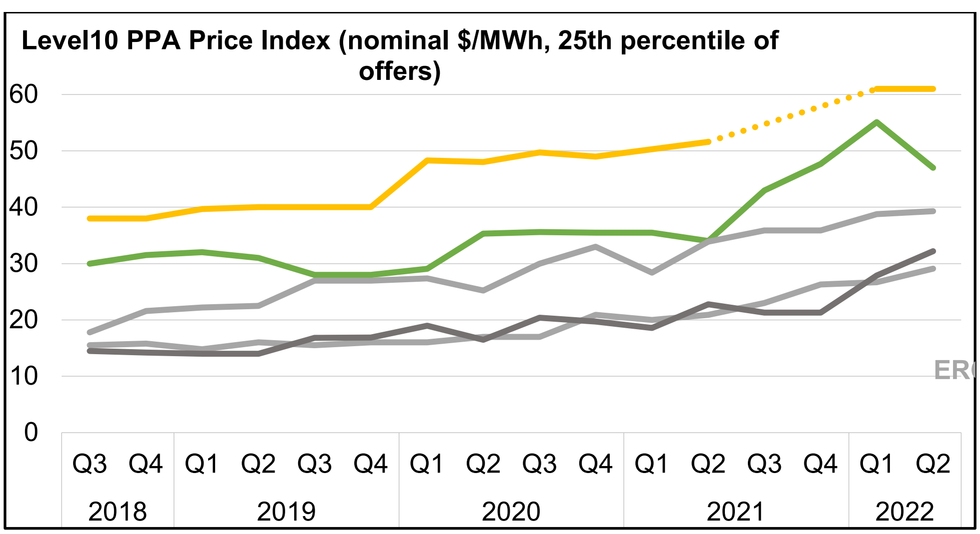
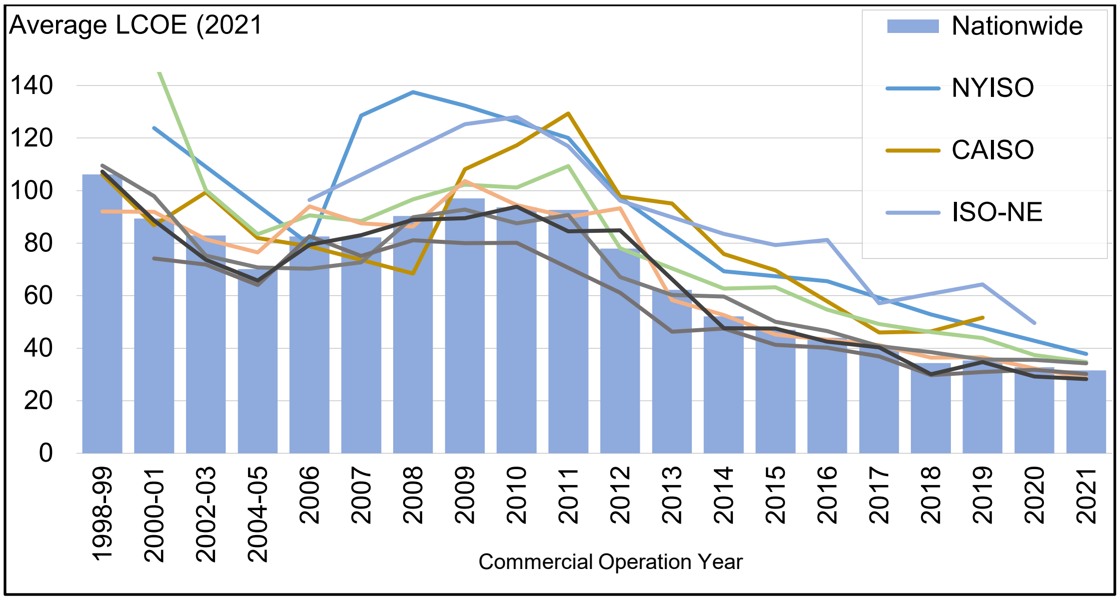


Figure 2 shows the trends in the average LCOE of wind PPAs nationwide and regionally, as collected by the Berkeley Lab. While the Berkley Labs report shows interesting trends in wind prices by region, the report does not contain data for 2022, which as illustrated, witnessed significant increases in wind project cost components.

Figure 2. Average LCOE of Wind Projects (2021 US$/MWh)



Based on the data included in the Figure above, the cost of wind power in New England was $57/MWh (US$) in 2017, $64/MWh (US$) in 2019 and $50/MWh (US$) in 2022. The NYISO prices were reported to be $66/MWh (US$) in 2016, $53/MWh (US$) in 2018, $52/MWh (US$) in 2019 and $38/MWh (US$) in 2021. There were several years during this timeframe for which no cost information was provided indicating a lack of data and few or no transactions.

US Department of Energy (DOE) Land-Based Wind Market Report: 2022 Edition

The *"US DOE Land-Based Wind Market Report: 2022 Edition"* only provides data in 2021 but does include pricing and other information by region in the United States. This report contains significant details on project costs and other information regarding wind projects, including data by region and ISO. While the report does provide some information for ISO-NE and NYISO, the data is limited based on limited development activity.

Provided below is a summary of the conclusions from the report pertaining primarily to cost and pricing trends for wind resources.

- Wind turbine prices increased by an average of 5% to 10% in 2021 given supply chain pressures, after declining by 50% between 2008 and 2020;
- Installed project costs in 2021 held steady at an average of $1,500/kW (US$) even as turbine prices rose. Given the time-lag between turbine orders and project commissioning, installed project costs may rise in 2022;
- Installed costs differed by region from $1,350/kW (US$) to $1,600/kW (US$), with the lowest costs in the non-California western states and the highest costs in the MISO area at $1,600/kW (US$). The summary information did not include any data on installed costs in New England and New York;
- Operation and Maintenance costs varied by project age and commercial operation date;
- Wind power purchase agreement prices have been drifting higher since about 2018 with a recent range from below $20/MWh (US$) to more than $30/MWh (US$) in part due to supply chain pressures and to the on-going phase-down of the Production Tax Credits ("PTC"). The study notes that LevelTen Energy's price indices confirm rising PPA prices, and regional variations;
- Hybrid wind plants that pair wind with storage and other resources saw limited growth in 2021 with just two new projects completed. There were 41 hybrid wind power plants in operation at the end of 2021 representing 2.4 GW of wind and .9 GW of co-located assets (storage, solar PV or fossil-fuel generation);
- Most of the wind projects included in the interconnection queues in ISO-NE and NYISO are offshore wind projects;
- Although the data for ISO-NE is limited, the data illustrates that New England's installed cost for wind are the highest of any region at over $2,400/kW (US$) for the period prior to 2022;
- The study stated that the O&M costs for the 76 wind projects installed since 2010 had an average cost of $21/kW-year (US$). With regard to total operating costs, the study noted that a US wind industry survey conducted by the National Renewable Energy Laboratory ("NREL") of total operating costs shows that these expenses for recently installed projects are anticipated to average between $33/kW-year (US$) and $59/kW-year (US$) with a mid-point of $44/kW-year US$). The disparity between these estimates of total operating costs and fixed O&M costs only reflects in large part differences in the scope of expenses reported with the survey noting that turbine O&M is expected to constitute less than half the total operating costs;
- With regard to LCOE values, the study noted that the national average LCOE of newly built wind projects has largely held steady since 2018 and

stood at $32/MWh (US$) in 2021. With rising turbine prices and stagnating capacity factor improvements, LCOE's may increase in 2022;

- The study noted that in New England, Renewable Energy Certificate (REC) prices in 2021 (outside of Maine) stabilized around $40/MWh (US$), following a steep rise over the preceding years. These prices remain well below the relevant alternative compliance payment (ACP) rates in these states, suggesting a balanced RPS supply and demand.

<u>CohnReznick Capital Solar & Wind Market Cost of Energy Analysis – July 2022</u>

CohnReznick Capital report provided data for wind and solar costs based on its Market Cost of Energy ("MCOE") analysis as opposed to LCOE values.[32] The analysis analyzes six US market regions: CAISO, the Southwest, ERCOT, PJM, combined MISO/SPP and the Southeast (solar only). New England and New York are not included. The study noted that across regions, solar CAPEX increased 33% or more from Q2 2021 to Q1 2022 while wind average MCOE increased by 9%. This is largely due to increased commodity costs, labor costs, and related supply chain delays inflating prices. For Q1 2022, the MCOE of wind costs ranged from $37/MWh (US$) to $60/MWh (US$) for PJM with an average of $47/MWh (US$) while for CAISO, the MCOE for wind was the same as PJM. For solar, the MCOE for PJM ranged from $52/MWh (US$) to $76/MWh (US$) with an average of $62/MWh (US$) compared to CAISO, where the MCOE range was $37/MWh (US$) to $56/MWh (US$) with an average of $45/MWh (US$). For PJM, the results of the CohnReznick analysis illustrates that the levelized cost of wind is lower than the levelized cost of solar.

The CohnReznick study also includes forecasts of MCOE values from 2022 to 2028 for the above regions. The report also identifies the underlying assumptions for the forecast.[33]

4.1.4 Assessment of Recent Bid Prices

Merrimack Energy has served as Independent Evaluator for several recent power procurement solicitations in which bidders submitted initial prices for wind power in 2021 and best and final prices in 2022. In some cases, final contracts were actually executed in 2022. Review of this data matches closely with the cost

[32] The CohnResnick report states that the MCOE represents a year 1 $/MWh contracted offtake rate with a creditworthy off taker on a 15-year bundled (energy + capacity + RECs) utility scale PPA with 2% escalation. The report notes that LCOE measures the average net present cost of energy generation for a power plant over its lifetime. MCOE utilizes a market-based approach to determine the PPA price required to reach specific investor returns.

[33] It appears that the assumptions underlying the forecast of the MCOE needed to determine the PPA price required to reach specific returns may be based on previous US tax incentives.

trends reported by LevelTen Energy regarding the recent cost increases. As a result of observing the increase in bid prices, Merrimack Energy proposes to include an increase in costs for wind projects (either on the basis of total installed costs or LCOE values) similar to the LevelTen increases of approximately 18.92/MWh (US$) or 61.6% increase since Q1 2021.

While the LevelTen information is particularly pertinent since it corresponds to the timeframe for which Hydro-Quebec received proposals in response to its Call for Tenders, Merrimack Energy has seen recent project proposals submitted by an experienced wind project developer in a typically lower cost power market that contains capital costs that are at the high end of the range of costs identified for Northeast US projects.

4.1.5 Methodology and Assumptions for Estimating Wind Generation Costs

Merrimack is proposing to undertake an assessment of wind generation costs in the Northeast US based on estimating the expected installed cost for wind projects in 2022 and calculating the nominal levelized and real levelized cost of wind energy based on a capital cost recovery methodology. The general assumptions for the analysis of wind generation project costs in the Northeast US were derived from other studies and reports as well as information gathered by Merrimack Energy through regular involvement in the renewable energy market throughout the US. To calculate the levelized cost of wind power, Merrimack Energy has relied upon the following formula for calculating the levelized cost of wind power[34]: Levelized cost of energy = ((Installed Capital Cost x Capital Cost Recovery Factor by resource) + Operating Costs)/Annual Energy Generation, with the Capital Cost Recovery Factor ("CRF" or alternatively Fixed Charge Rate) based on the NREL reported value of 7.5%, which represents the annualized revenue requirements recovered for the return on and of investment. NREL reported a Weighted Average Cost of Capital ("WACC") of 6.3% and a 30-year life for evaluating wind project costs[35]. The WACC incorporates in the inputs the interest rate, rate of return on equity, debt percent and equity percent. Both the WACC and CRF inputs are derived from the NREL *Annual Technology Baseline ("ATB"): The 2022 Electricity Update.*

The Northeast US is generally marked as a high-cost region for developing, constructing and operating renewable energy projects, including wind. The region generally faces higher labor costs, higher costs of developing and

[34] Merrimack Energy has used this same methodology for calculating the levelized cost of solar, storage, biomass, and hydro resources as well.
[35] Merrimack Energy confirmed NREL's calculation of a Capital Recovery Factor of 7.5% for a wind projects based on a discount rate of 6.3% and an asset life of 30 years using a revenue requirements model for wind projects.

constructing projects in challenging locations, higher taxes and operating costs overall. As the data from the various reports have noted, New England and New York have limited data on recent projects but the available data does indicate the installed costs of wind projects in these regions is certainly higher than the national average.

Based on recent data we have witnessed across the country, the installed costs of wind projects in areas of the country that have typically enjoyed lower capital costs than the Northeast have increased substantially, to the point we are seeing costs for projects submitted and/or contracted to be in excess of $2,000 per kW installed (US$)[36]. This is up from $1,300/kW (US$) a few years ago for the same project. Since the most recent installed costs reported for a wind project in New England was approximately $2,500/kW (US$), Merrimack Energy would expect a reasonable range for costs for wind projects in the Northeast US to be between $2,000/kW (US$) to $2,500/kw (US$).[37] Based on recent increases in wind project capital costs, Merrimack Energy views the low end of the range of capital costs to be very optimistic while the high end of the range is more representative of project costs for wind in the Northeast US based on continuation of recent market cost trends.

The US Department of Energy (DOE) (Land Based Wind Market Report 2022) estimated O&M costs to average about $21/kW-year (US$) for projects that have entered service since 2010. According to DOE, O&M costs represent about 50% of all total operating costs, which according to DOE is estimated to be about $44/kW-year (US$). There are a number of other costs that should also be included in operating costs such as insurance, property taxes, capital expenditures, etc. We have seen estimates of total operating costs to range from about $35/kW-year (US$) to over $50/kW-year (US$). The NREL ATB calculates a Fixed O&M rate of $42.19/kW-year (US$) for wind projects. The cost components aggregated in the fixed O&M cost includes:

- Administrative Fees
- Administrative Labor
- Insurance
- Land Lease Payments
- Legal Fees
- Operating Labor
- Other

---

[36] Merrimack Energy recently reviewed proposals for wind projects in a region in the US where wind is a predominant resource where capital costs for such projects exceeded the mid-point cost of $2,250/kW.

[37] Note that all data assumptions included in the tables for each technology are presented initially in US$ for the purposes of calculating the levelized cost of each technology. Merrimack Energy will also present the results in levelized costs in Cn$ as well as presenting real levelized costs in both US$ and Cn$.

* Property Taxes
* Site Security
* Taxes
* Project Management
* Blades
* Gearboxes
* Generators
* General Maintenance
* Scheduled Maintenance over Technical Life
* Unscheduled Maintenance over Technical Life
* Transformers
* Turbines
* Annualized present value of large component replacement over technical life

Merrimack Energy is therefore using an operating cost consistent with the NREL value of $42.19/kW-year (US$) starting in 2026 and escalating annually by inflation, utilizing Hydro-Quebec's internal forecasted annual inflation rates.

Another major factor is the capacity factor for wind in each of the markets. For projects in the Northeast, Merrimack Energy has observed capacity factors from below 30% up to around 40%. Based on projects observed the average has been around 35%. The assumptions utilized in the assessment of levelized costs based on recovery of capital costs plus operating costs are presented in Table 7.

Table 7: Input Assumptions and Cost Parameters for Wind Projects

Parameter	Assumption
Capital Cost ($/kW) (US$)	$2,000 to $2,500[38]
Fixed O&M plus Operating Costs ($/kW-year) (US$)	$42.19
Capacity Factor (%)	35%
Project Size (MW)	100 MW
Discount Rate (%)	6.3%
Capital Cost Recovery Factor (%)	7.5%
Inflation Rate (%)	2.2%
Contract Term	30 years

Based on these assumptions, Merrimack Energy has calculated the LCOE of wind projects in the Northeast US to range from $66.36/MWh (US$) based on a low-end

[38] Merrimack Energy also calculated the LCOE values for wind based on a capital cost of $2,250/kW (US$) to represent a mid-point in the cost range given the variability of capital costs for wind projects and timing of the Hydro-Quebec Call for Tenders.

capital cost of $2,000/kW (US$) installed to $78.59/MWh (US$). Based on the capital cost assumptions noted above, the real levelized cost of energy ranges from $47.77/MWh (US$) (assuming a capital cost of $2,000/kW in US$) to $56.57/MWh (US$) (assuming a capital cost of $2,500/kW in US$). If these values are converted to Canadian dollars the real levelized cost in (Cn$ 2022$) would be $62.11/MWh (Cn$) assuming a capital cost of $2,000/kW (US$) and $73.56/MWh (Cn$) assuming a capital cost of $2,500/kW (US$). This is generally consistent with the cost increases reported by LevelTen and applied to costs for comparable markets and recent prices for projects in New England and New York. For example, the LevelTen cost for Q2 prices for CAISO, which is a high-cost market similar to New England and New York could be estimated to be $66.07/MWh (US$) ($61/MWh (US$) in Q2 2022 plus $5.07/MWh (US$) increase between Q2 and Q3 2022). In addition, Merrimack Energy observed proposed prices for wind projects in New England in the 2017 timeframe and for New York in the 2020 timeframe. The average prices Merrimack Energy observed at that time was approximately $55/MWh (US$) to $63/MWh (US$). If these prices remained flat into 2021 and experienced the same level of increase as experienced nationally based on LevelTen data as well as our own experience observing price increases for projects in recent solicitations, Q3 2022 prices would be approximately $68.92/MWh[39] (US$) to $73.92/MWh (US$) or more (i.e., $55/MWh (US$) + $18.92/MWh (US$) or $73.92/MWh US$)).

Merrimack Energy observed wind project prices in New York in the 2020 timeframe that are similar or slightly higher than the New England wind costs. While the LevelTen data for NYISO is showing costs of $53/MWh (US$) in 2018 and $52/MWh (US$) in 2019, the 2020 ISO-NE cost is $50/MWh (US$) in 2020. As a conservative estimate Merrimack Energy estimates the wind generated electricity costs in New England and New York should be very similar on average in 2022 for projects that enter service in 2026.

As an additional data point, Massachusetts included a cost cap for Offshore Wind projects based on the cost of the initial solicitation for offshore wind in Massachusetts of $77.76/MWh (US$). The cost cap was recently eliminated by the Governor and approved by the legislature in Massachusetts.[40] As a result, while

[39] The lower level of $68.92/MWh (US$) reflects the $50/MWh (US$) as illustrated in Figure 2 plus the total increase in wind prices from Q1 2021 to Q3 2022 based on the LevelTen index. The high end of the range based on review of other prices we have observed for New England would fall within the range of the levelized costs calculated based on the range of capital costs of $2,000 (US$) to $2500/kW (US$) for wind projects.

[40] The prices for the most recent offshore wind solicitation in Massachusetts were lower than the cost cap. One of the winning bidders has requested a price increase due to current market conditions during the hearings for contract approval. The utilities in Massachusetts have refused to renegotiate the contract price and the Massachusetts Department of Public Utilities agreed with the utilities. As noted, the contract price of $72/MWh (US$) was viewed by the project sponsor to be too low to cover costs in the current market resulting in termination of the contract.

Merrimack Energy has presented a range of costs for wind generated electricity in the Northeast US, in our view, based on recent market information, an LCOE for wind project costs based on $2,500/kW (US$) is a reasonable benchmark for planning purposes.

4.2 Calculation of Solar Benchmark Costs

Similar to wind generated electricity cost, Merrimack Energy is relying on publicly available data as well as generic data from recent solicitations in other regions of the country and the US Northeast for purposes of calculating solar photo-voltaic ("PV") costs for utility-scale (> 20 MW) solar PV projects.

As noted previously in the report, the solar market has been disrupted more than most markets due to government regulations and policy in addition to trends in inflation, supply chain issues, cost and availability of inputs, and availability of generation equipment. Similar to the analysis of wind generated costs, Merrimack Energy will rely on LevelTen data for solar project costs as well. LevelTen's Q1 2022 Executive Summary report provides an excellent summary of the issues facing the solar industry, which obviously affect both solar only projects as well as solar combined with energy storage projects.

The LevelTen Q1 2022 report notes that "regulatory uncertainty has reached new heights with the United States Department of Commerce announcement of its investigation, at the behest of a single US PV component producer, into allegations of circumvention of antidumping/countervailing orders on the part of PV component manufacturers in Southeast Asia. With the threat of tariffs of 50% - 250% on products from this region, which provides around 80% of modules imported into the US, the investigation casts a shadow of profound uncertainty over development costs for US solar developers and added further volatility to the solar supply chain. With the PV supply chain still adapting to immense disturbances driven by a human rights crisis and a larger polysilicon shortage, the presence of this significant supply chain instability has made it harder than ever to commit with certainty to a long-term PPA price. Amid these headwinds, the P25 Market-Average index for solar prices rose by 6% in Q1 or $1.31/MWh (US$) and is now at $36.31/MWh (US$), and 15.8% year over year or by $4.95/MWh (US$)".[41]

[41] While the LevelTen index does not include any solar pricing for ISO-NE or NYISO, the PJM index stood at around $42/MWh (US$) in Q1 2022.

Similar to Merrimack Energy's assessment of wind project costs, the assessment of increases in solar PV costs includes a review of LevelTen's index going back to Q1 2021 through Q3 2022 to assess the magnitude of the increase in costs over the past 7 quarters. Table 8 provides the LevelTen index for solar projects from Q1 2021 through Q3 2022.

Table 8: Quarterly Changes in Solar PV PPA Prices – Q1 2021 – Q3 2022

Period of Analysis (by Quarter)	Index Cost for Solar Projects ($/MWh US$)
Q1 2021	$31.26
Q2 2021	$31.45
Q3 2021	$32.39
Q4 2021	$34.25
Q1 2022	$36.31
Q2 2022	$39.26
Q3 2022	$42.21

According to the LevelTen index for solar costs, cost have increased consistently each quarter with the level of increase picking up each quarter. Since Q1 2021, the index has increased by $10.85/MWh (US$) or by 34.6% over that period.

In the LevelTen Q2 2022 Summary, the report provides an update on the status of the US Department of Commerce investigation. The report notes the investigation, and the threat of higher tariffs brought the whole solar industry into a state of near paralysis. "In June, the Biden administration introduced a 24-month suspension of any new tariffs that might emerge from the Department of Commerce investigation,[42] but many developers and financiers still feel the move does not provide adequate assurance that tariffs will not be retroactively applied. In our Q2 developer survey, around one-third of respondents indicated they would need further certainty around the potential outcome of the investigation. Amid this environment of extreme regulatory uncertainty, P25 solar prices rose by 8.1% in Q2". The report also identified the factors causing uncertainty in the solar industry. LevelTen noted that key factors included ongoing permitting difficulties, congested interconnection queues, a fractured supply chain and powerful inflationary pressures, and a high degree of regulatory uncertainty.

The LevelTen Q2 report concluded that the P25 Market-Averaged National Index for solar prices rose by 8.1% from Q1 to Q2 or $2.94/MWh (US$) and stands at $39.26/MWh (US$). On a year over year basis the P25 Market-Averaged Index for solar prices rose 25.4% or $7.99/MWh (US$), illustrating that prices rose from $31.27

[42] As noted in footnote 13, the US Department of Commerce reached a preliminary decision to impose anti-circumvention duties on solar panels and cells produced in Vietnam, Malaysia, Thailand, and Cambodia using Chinese parts. Since the preliminary decision was reached on December 2, 2022, Merrimack Energy has seen project developers submit even higher prices for solar PV projects.

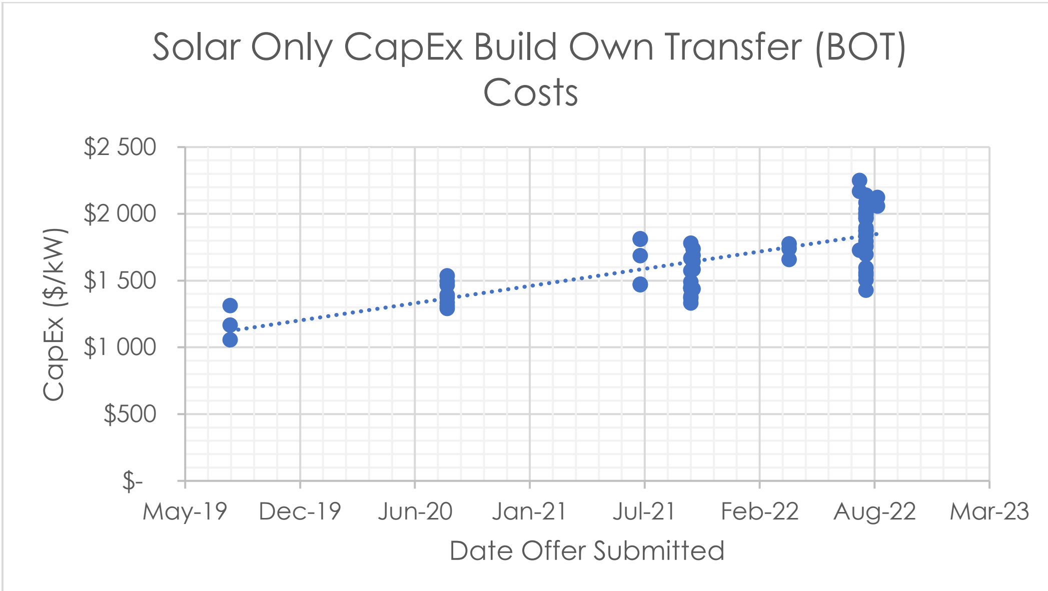
to $39,26/MWh (US$) from Q2 2021 to Q2 2022. While the LevelTen assessment for Q2 did not provide any data for ISO-NE or NYISO, the report did note that year over year, PJM prices have risen by 31.1%.

The LevelTen Q3 2022 report concluded that the solar P25 Market-Averaged National index rose by 7.5% or $2.95/MWh (US$) from Q2 to Q3 in 2022 and is now at $42.21/MWh (US$) or an increase of $10.94/MWh (US$) from Q2 2021 to Q3 2022. The report also states that on a year over year basis the Solar Index rose by 30.3% of by $9.82/MWh (US$).

Based on recent cost information Merrimack Energy has witnessed across the country, the installed costs of solar projects have increased significantly, to the point we are seeing costs for projects contracted to be approximately $1,800 (US$) to now over $2,000 per kWac (US$) installed. This is up from approximately $1,4000/kW (US$) in 2020 for the same market including projects competing in subsequent annual solicitations.[43] Merrimack Energy would expect that solar project costs would be higher for the Northeast US given the difference in size of utility-scale projects in other areas of the US relative to New England and New York. Since there is limited public data on capital costs for utility-scale solar projects in the Northeast US, Merrimack Energy is using the capital cost noted above of $2,000/kWac (US$) installed as a base case (i.e., more competitive case) for a July 2022 project as a conservative estimate, but has also generated LCOE costs based on capital costs of $1,800/kWac (US$) as a low-end estimate and $2,200/kWac (US$) as a high-end estimate. Figure 3 illustrates the costs submitted by date for several solicitations for which Merrimack Energy has served as IE. Similar to wind project cost, based on recent trends in solar costs, the high-end estimate of $2,200/kW (US$) may be applicable to Northeast markets by Q4 2022.

[43] Merrimack Energy served as Independent Evaluator for Renewable RFPs in three successive years (2000 – 2022) in the same market. The average Build Own Transfer cost for solar PV projects increased from $1,400/kWac (US$) in 2020 to $1,650/kWac (US$) in 2021 and to slightly over $2,000/kWac (US$) in 2022.

Figure 3: Capital Cost for Solar Only Projects (US$)



4.2.1 Methodology and Assumptions for Estimating Solar PV Generation Costs

The Lawrence Berkley Labs study entitled Utility Scale Solar – 2022 Edition estimated O&M costs for solar PV projects to be approximately $13/ kW-year (US$). According to NREL *("US Solar Photovoltaic System and Energy Storage Cost Benchmarks With Minimum Sustainable Price Analysis Q1 2022, September 2022")*, the estimated O&M costs were reported to range from $16.11/KW-year (US$) to $16.42/kW-year (US$). The NREL ATB estimated Fixed O&M costs plus other operating costs for 2022 solar projects to be $19.95/kW-year (US$). These costs are reported to include:

- Administrative Fees
- Administrative Labor
- Insurance
- Land Lease Payments
- Legal Fees
- Operating Labor
- Other
- Property Taxes
- Site Security
- Taxes
- Project Management
- Inverters at 15 Years

- General Maintenance
- Scheduled Maintenance over Technical Life
- Unscheduled Maintenance over Technical Life
- Transformers
- Cleaning
- Solar PV Plants
- Vegetation Removal
- Annualized present value of large component replacement over technical life

In the US, the O&M costs presented by Lawrence Berkley Labs and NREL are similar to the O&M costs and other admin costs we have seen in utility specific solicitations.

The Capital Cost Recovery Factor will also be based on several factors including the utility's discount rate, tax structure, and depreciation levels. For this analysis, Merrimack Energy is using a Capital Cost Recovery Factor for Solar of 6.7% based on NREL data.

Another major factor is the capacity factor for solar projects in each of the markets. The Lawrence Berkley Labs report identified that solar capacity factors are highest in California and non-ISO western states and lowest in the Northeast (ISO-NE and NYISO) with capacity factors in the 17-18% range in the Northeast. For projects in the Northeast, Merrimack Energy has observed capacity factors from proposals above 20%, with an average between the New England and New York markets at approximately 22%. Since the capacity factor will likely have the most significant impact on the LCOE for Northeast markets, Merrimack Energy will consider a range of 17% to 22% as a bandwidth for evaluation. The assumptions utilized in the assessment of levelized costs based on recovery of capital costs plus operating costs are presented in Table 9.

Table 9 Input Assumptions and Cost Parameters for Solar Projects

Parameter	Assumption
Capital Cost ($/kW) (US$)	$1,800 - $2,000 - $2,200
Fixed O&M plus Operating Costs ($/kW-year) (US$)	$19.95
Capacity Factor (%)	17% - 22%
Project Size (MW)	100 MW
Discount Rate	5.3%
Capital Cost Recovery Factor (%)	6.7%
Inflation Rate (%)	2.2%
Contract Term	20 years
Annual Degradation Rate	.5%

Based on these assumptions, including a capacity factor of 22% and a .5% annual degradation rate in the output of the project, Merrimack Energy has calculated the LCOE of solar PV projects to range from $112.85/MWh (US$) to $133.79/MWh (US$) at a 17% capacity factor and from $87.20/MWh (US$) to $103.38/MWh (US$) at a 22% capacity factor. Based on these same cost assumptions, Merrimack Energy estimates the real levelized cost of energy for solar PV projects in the Northeast US for July 2022 with a 2026 COD date to be between $67.62/MWh (US$) (at a capital cost of $1,800/kW) to $80.15/MWh (US$) (at a capital cost of $2,200/kW US$). If these values are converted to Canadian dollars, the real levelized cost in (Cn$ 2022$) would be $87.91/MWh assuming a capital cost of $1,800/kW (US$) and $104.19/MWh (Cn$) assuming a capital cost of $2,200/kW (US$).

When the capacity factor is adjusted to 17%, the levelized costs increase. In this scenario, the real levelized cost would be between $87.52/MWh ($US) (at a capital cost of $1,800/kW US$) to $103.72/MWh (US$) (at a capital cost of $2,200/kW US$). If these values are converted to Canadian dollars, the real levelized cost in (Cn$ 2022$) would be $113.77/MWh assuming a capital cost of $1,800/kW (US$) and $134.84/MWh (Cn$) assuming a capital cost of $2,200/kW (US$). This 5% adjustment to the capacity factor led to a roughly 30% increase in the levelized costs of solar PV resources. As this data illustrates, the capacity factor of the solar PV project will have a major impact on the relative economics of these projects.

Based on current market conditions, Merrimack Energy believes the most reasonable combination of capital costs and capacity factor that would be applicable in the Northeast would be a capital cost of $2,000/kW (US$) combined with a capacity factor of 22%. This combination would result in an LCOE of $95.29/MWh (US$) and $123.88/MWh (Cn$).

In addition, Merrimack Energy observed proposed prices for solar projects in New England in the 2017 timeframe and for New York in the 2020 timeframe. The average prices Merrimack Energy observed at that time was approximately $60/MWh (US$) for New York. New England prices were considerably higher but were an earlier vintage. In addition, many of the projects were around 20 MW, which contributed to the higher overall average cost. There were a few larger projects that ranged in cost between $57/MWh (US$) and $76/MWh (US$). If the sample prices in New York remained flat into 2021 and experienced the same level of increase as experienced nationally based on LevelTen data as well as our own experience observing price increases for projects in recent solicitations, Q3 2022 prices would be least approximately $70.85/MWh (US$) or more (i.e.,

$60/MWh + $10.85/MWh or $70.85/MWh US$). As a conservative estimate Merrimack Energy estimates the solar generated electricity costs in New England to be higher than New York at $77.90/MWh (US$) and New York to be at least $70.85/MWh (US$) in 2022 for projects that enter service in 2026. These results generally conform to a solar PV project at a cost of $1800/kW (US$) but with a higher capacity factor, or alternatively a lower capital cost at the same capacity factor. At a capacity factor of 22%, the capital cost for this solar PV project in New England would be $1,570/kW (US$), which is much lower than we are seeing in the current market even in low-cost power market areas.[44] If instead, the percentage increase in the cost of solar projects (both $/MWh based on LevelTen data and Capital cost in $/kW based on proposals submitted) is considered, solar costs have increased by 35% to 40% over the past two years. If this percent increase is applied to the New York cost estimate from 2020 of $60/MWh (US), the cost of solar would be $81 to $84/MWh (US$) and New England prices would be at least $10/MWh (US$) higher.

The above estimates would appear to be optimistic given the recent trends in capital cost and the expected capacity factor for Northeast US projects. As a result, Merrimack Energy is using the estimated LCOE of $95.29/MWh (US$) as the base case for solar PV projects in the Northeast US based on a capital cost of $2,000/kW at a 22% capacity factor. Merrimack Energy will also use the above solar PV cost as the basis for calculating the cost of solar combined with storage projects.

As a point of interest, the *"2021 State of the Market Report for the New York ISO Markets, May 2022"* submitted by Potomac Economics, concluded:

> "At recent market prices and costs (including state and federal incentives), we estimate that revenues justify investment in land-based wind. This is consistent with current trends that nearly all recent investment has been in land-based wind, although other considerations (such as permitting and siting) may limit the extent of development. Other technologies, including solar and offshore wind, do not appear to be economic under prevailing conditions. This may explain why most such projects under contract with the State are significantly delayed. However, the cost of these technologies are expected to fall over the long term. State and federal incentives account

[44] For New York, assuming the capacity factor is 22% for solar, the equivalent capital cost of solar would be $1,395/kW (US$), which is similar to the costs experienced in the market in 2020 before the increase in costs over the past two years. As a result, our conclusion is that the costs generated for New York, in particular, as well as New England, are very optimistic and are low by current standards. As a result, while we are showing such costs, Merrimack Energy does not believe these costs represent reasonable benchmarks.

for the majority of revenues for all types of renewable generation, although wholesale energy and capacity revenues make up a significant share."

For solar, unlike wind, the levelized cost varies more broadly based on LCOE's calculated as a result of recent capital costs and O&M costs annualized over a 20-year period compared to adding the increase in costs for solar calculated by LevelTen over the Q1 2021 to Q3 2022 timeframe. This could result from conservatively low levelized costs derived from recent identified costs in the Northeast US markets adjusted for cost increases since Q1 2021 or from underestimating the capacity factor of solar.

Merrimack Energy was also able to compile data on the components of solar projects. Our observations indicate that the solar PV system costs represent generally less than 35% of total solar PV project costs with Balance of Plant representing the largest component, generally over 50%. Owners cost and contingency comprise a small portion of the costs.

4.3 Calculation of Stand-Alone Battery Energy Storage Benchmark Costs

The cost of Battery Energy Storage Systems ("BESS") is driven by a number of factors including the discharge duration[45], number of cycles per year, round trip efficiency, battery size, and battery technology.

BESS projects, like solar and wind resources, have experienced significant increases in cost over the past year as well due to inflationary pressures, higher costs of rare metals used in battery modules, shipping delays, increased shipping costs and increases in input costs. Suppliers have been asking for indexing of pricing for BESS projects to mirror the cost changes for metals and commodities such as lithium. For example, the lithium price index increased from 16.6 in Q2 2019 to 57.5 in Q1 2022.

Merrimack Energy has witnessed increases in BESS pricing based on increases in capital costs for those projects bid as Build Own Transfer arrangements as well as PPA pricing for the same projects or other PPA options.

Unlike solar and wind, there are no specific indices similar to the LevelTen analysis. One of the issues is that standalone storage projects can vary significantly with limited standard design features.

[45] The capital cost of a 2-hour battery is lower than a 4-hour battery. Capital costs increase with longer duration associated with battery operations. While there is much discussion in the industry about the need for long-duration storage (i.e., 6-8 hours), the capital costs of these options negatively affect the overall project economics.

One of the primary sources of cost information for BESS projects is NREL data. The NREL ATB published Utility-Scale stand-alone BESS costs per year based on the discharge duration. Table 10 provides NREL's estimate for capital costs in 2020 and 2021 for different discharge duration batteries:

Table 10: BESS costs by Discharge Duration

Discharge Duration (Hours)	2020 ($/kW) (US$)	2021 ($/kW) (US$)
2	$988	$857
4	$1,727	$1,475
6	$2,466	$2,094
8	$3,205	$2,713
10	$3,944	$3,331

Merrimack Energy's experience with the costs of standalone storage projects is based on serving as Independent Evaluator for a number of RFPs for battery storage PPAs and Build Own Transfer resources in which the utility either purchases the project after completion or through Engineering Procurement Construction ("EPC") contracts where the utility puts up a site for the project and solicits EPC bids to contract the project which the utility will eventually own.

In other RFPs, for Stand-Alone BESS projects, Merrimack has reviewed bids submitted in Q3 of 2021 for four-hour discharge lithium batteries (either Lithium Iron Phosphate, LFP, or Nickel Manganese Cobalt, NMC) ranging from 50 MW to 200 MW to be located in the Southwest United States that had a median capital cost of just over $1,600/kW (US$). These projects all had a very quick installation requirement, so installation timelines would result in slightly higher capital costs than industry average. In addition, Merrimack reviewed bids from a separate solicitation submitted in the July and August timeframe that averaged about $1,800/kW (US$) to $1,900/kW (US$) for four-hour discharge duration batteries, or nearly a 20% increase over this period and recently witnessed proposals for large scale BESS projects in the range of $1,800/kW (US$) to $2,000/kW (US$).

As another example of recent cost increases associated with standalone storage projects, Merrimack Energy is familiar with several contracts that were executed in Q4 2021 and renegotiated in Q3 2022. Over that time the average cost of the PPAs renegotiated increased by 34% or by over $3.50/kW-month (US$). The reasons for the increases included equipment costs, cost of commodities, EPC costs, labor and insurance costs.

Another factor of importance when evaluating the cost of a BESS is the contract structure for the project. The contract structure can vary based on the market structure and intended application of the BESS. For example, the BESS can operate similar to a gas project in that the buyer of the contract can elect to discharge the battery under the parameters of the contract (duration, round trip efficiency, allowable cycles per day and year, variable O&M charges). In this case, the cost in the contract can be presented on the basis of $/kW-month fixed charge or capacity charge as opposed to a levelized cost. In this case, the use of the BESS is essentially a toll, where the buyer can propose charging and discharging within the contract parameters based on payment of a fixed capacity charge and Variable O&M costs ("VOM").

In ISO markets, the pricing structure can vary. For example, Pacific Gas & Electric's Energy Storage contract allows the seller to bid to a Long-Term Agreement for Resource Adequacy with an Energy Settlement provision. Under this type of Agreement, the capacity charge in the contract would compensate the seller for its capacity costs plus energy revenue which would be provided to the utility as an offset to the capacity charge. The energy settlement amount is based on the premise that the battery will be charged during the lowest cost hours and discharged during the highest cost hours during the day. If the battery is a 4-hour duration battery, the energy value would essentially be based on the highest minus lowest four-hour period from a pricing perspective.[46]

Alternatively, the seller could sell the capacity from the battery to the buyer (i.e., utility) and schedule or dispatch the project into the ISO itself or based on use of a scheduling coordinator.

In terms of the value streams for the battery, shorter duration batteries, such as two-hour batteries are lowest cost but generally don't qualify for full capacity value but will generally participate more in the ancillary service market than in the energy market. Longer duration storage is more costly but is expected to provide more value as more renewable resources enter the market and the potential duration of the utility system peak is longer and later in the day. As a result, basing BESS projects on an LCOE basis can serve to skew the results in favor of lowest cost options but with limited value. BESS projects are unique in that regard and the only reasonable way to assess these projects on an equal basis is to calculate both the cost and benefits (or value). However, Merrimack Energy has proposed a methodology for calculating the LCOE of battery energy storage projects to meet the requirements of the benchmark cost assessments and as a result our focus is on cost only for this assignment.

[46] This is the simplest example of how the contract structure works but actual contract provisions have some nuances that are more complicated.

4.3.1 Methodology and Assumptions for Estimating Stand-Alone BESS Generation Costs

Merrimack Energy assumes the battery size will be utility scale with a 4-hour duration which is most common in the industry. Merrimack Energy has also observed that the vast majority of BESS projects are lithium-ion batteries.

Given that the capacity factor of Battery Energy Storage Systems ("BESS") does not vary regionally with a fixed discharge duration, there are fewer factors that would impact regional differences in BESS costs, notably capital costs, project size and O&M costs.

The NREL ATB estimated Fixed O&M costs for 2022 solar projects to be $34.27/kW-year. These costs are reported to include:

- Battery Replacement Costs - 20% Augmentations after year 10 and year 20 to maintain the guaranteed capacity
- Administrative Fees
- Administrative Labor
- Insurance
- Land Lease Payments
- Legal Fees
- Operating Labor
- Other
- Property Taxes
- Site Security
- Taxes
- Project Management
- General Maintenance
- Scheduled Maintenance over Technical Life
- Unscheduled Maintenance over Technical Life
- Transformers
- Annualized present value of large component replacement over technical life

For this analysis, Merrimack Energy is assuming a four-hour battery designed to provide capacity and energy value to the utility system. Table 11 provides the assumptions Merrimack Energy is applying for purposes of calculating the LCOE of standalone BESS systems. Merrimack Energy assumes that the size of the BESS project in the northeast will be relatively small and will not have the same economies of scale of larger BESS projects in other parts of the US. Therefore, Merrimack Energy is assuming that the capital cost of the BESS will be on the high side relative to costs for larger scale projects we have seen in recent solicitations.

Table 11: Input Assumptions and Cost Parameters for Standalone Storage Projects

Parameter	Assumption
Capital Cost ($/kW) (US$)	$1,900
Fixed O&M plus Operating Costs ($/kW-year) (US$)	$34.27
Project Size (MW)	100 MW/400 MWh
Number of Cycles	365 per Year
Roundtrip Efficiency	85%
Discount Rate	5.3%
Capital Cost Recovery Factor (%)	6.7%
Inflation Rate (%)	2.5%
Contract Term	20 years

From the perspective of the levelized cost analysis, the cost of standalone storage can be considered from the perspective of $/kW-year based on the recovery of the capital cost only. A number of studies present the economic analysis for standalone storage based on a $/MWh metric to reflect the storage of energy in the battery. For example, a 100 MW battery with a four-hour duration can storage 400 MWh. Alternatively, a battery of this same size with daily cycling or 365 days of cycling per year at an 85% round-trip efficiency can deliver 124,100 MWh per year.

Based on these assumptions, Merrimack Energy has calculated the LCOE of standalone BESS projects in the Northeast US to range from $119.36/MWh (US$) at a capital cost of $1,600/kW (US$) to $135.56/MWh (US$) at a capital cost of $1,900/kW (US$). Based on the capital cost assumptions noted above, the real levelized cost of energy ranges from $99.94/MWh (US$) (assuming a capital cost of $1,600/kW US$) to $113.51/MWh (US$) (assuming a capital cost of $1,900/kW US$). If these values are converted to Canadian dollars, the real levelized cost in (Cn$ 2022$) would be $129.76/MWh (Cn$) assuming a capital cost of $1,600/kW (US$) and $147.55/MWh (Cn$) assuming a capital cost of $1,900/kW (US$). The LCOE for the BESS is calculated over a 20-year term and it is assumed that the BESS would maintain the same capacity and energy throughout the term of the contract by augmenting the BESS as required to maintain the same capacity and energy.

Since some buyers of BESS projects are generally acquiring BESS projects to meet capacity requirements (e.g., utilities in California are an example), Merrimack Energy has also calculated the levelized cost in $/kW-month to provide an estimated levelized cost of capacity for comparison purposes. These estimates as provided in Table 23.

Merrimack Energy was also able to compile data on the components of BESS projects. Our observations indicate that the BESS system costs represent generally between 70-80% of the total project costs with Balance of Plant representing between 15% to 20%. Owner's cost and contingency comprise a small portion of the costs.

4.4 Calculation of Hybrid Renewable & Battery Energy Storage Benchmark Costs

Hybrid solar plus storage and wind plus storage projects are the most challenging projects for which to create benchmark costs due to a number of factors highlighted below. Yet, in most of the all-source solicitations for which we are serving as IE, the majority of the bids submitted are hybrid solar plus storage projects. These projects offer the benefit of providing relatively higher levels of capacity credit based largely upon the battery size with the battery generally being charged by the solar PV facility in the off-peak hours.[47] However, under the IRA, the storage facility can now be charged from the grid with no difference in financial incentives. The change in tax credits is allowing more flexibility for BESS projects to charge either from the renewable project or from the grid.

In addition, hybrid systems offer tremendous flexibility and enhanced value streams. For the summer capacity systems in the southwestern and western US where there are already high levels of solar penetration, the excess solar produced during the morning and early afternoon hours is used to charge the battery, which is then discharged to meet evening peak. With that said, Hybrid project costs can vary widely. There are several key factors impacting the costs of hybrid or co-located renewable plus BESS resources:

- The sizing of the BESS relative to the Solar PV capacity (i.e., ratio of BESS to solar).
- The BESS technology used (Lithium-Ion, LFP, Flow Battery, etc.)
- The discharge duration of the battery
- Whether the project is DC-coupled or AC-coupled.
- Whether the project is co-located or fully hybrid.
- Operational characteristics of the battery including:
  - Storage discharge duration
  - Degradation that may require more frequent or earlier augmentation

[47] Utilities looking for both capacity and energy for summer periods are essentially using the storage component to provide capacity to meet peak requirements and energy to meet RPS or emission reduction purposes.

- Roundtrip Efficiency

Merrimack Energy has also seen utilities prefer different battery storage levels relative to the size of the solar component given the nature of their system and the amount of renewable energy already on the system. For example, some utilities may require battery size at 25% or 50% of the size of the solar or wind project. As an example, a 100 MW solar system could be paired with a 50 MW battery with a four-hour discharge. This battery can store 200 MWh which could be discharged over four-hours during the peak at 50 MWh/per hour. The different solar/wind and storage system requirements or options have different cost and value structures as will be discussed below. Certainly, a battery which is 25% of the size of the solar will have lower overall costs but potentially less value than a system for which the solar capacity and the storage capacity are generally the same. The less expensive option identified above would have a lower LCOE but may also provide less value. The hybrid case provides the most obvious example of the shortfalls associated with using LCOE values as a basis for selection of similar resources. Instead, it is necessary to calculate the costs and benefits of the different BESS system options to ensure the proper relationship of BESS relative to solar is more economical for the specific utility system. While a utility system that has a large surplus of renewable energy output during off-peak period would likely prefer a BESS to solar ratio that is approaching 1 to 1, utility systems with limited renewable generation would probably prefer a low BESS to solar ratio (i.e., .25 to .10 to 1).[48]

As described in the previous section, another factor affecting cost and value is the duration of the BESS system. Two-hour duration batteries are less costly than traditional four-hour duration batteries as noted in Table 10 but provide different value streams. While 4-hour duration batteries would likely receive capacity value at close to 100% of the nameplate rating, 2-hour duration batteries would receive lower capacity credit. Two-hour duration batteries may be more applicable in cases where a utility is looking to provide ancillary services. At the other extreme is long-duration BESS systems (i.e., six or more hours of duration) which would receive the maximum capacity credit but are much more costly. The cost of the BESS system increases significantly the longer the duration of the battery.

A third factor affecting cost and value of combined solar/wind and BESS is the technology. However, at this point in time lithium-based (nickel manganese cobalt or lithium iron phosphate) batteries are the most prevalent options. Flow batteries have also been contracted by utilities but in much fewer cases than lithium ion.

---

[48] It is interesting to note that some of the early All Source solicitations requested a BESS to solar ratio of .25 to 1 while we are now starting to see requests for BESS to solar ratios of 1 to 1.

Other factors that affect the cost of the systems include requirements for augmentation of the battery (i.e., the seller is responsible for maintaining the capacity of the battery system over its life or contract term), AC vs DC coupling, and the availability of tax credits for one or both systems. With regard to tax credits, until passage of the Inflation Reduction Act, there were restrictions regarding the availability of tax credits and depreciation benefits for a battery system combined with a renewable energy project.[49] The Inflation Reduction Act expands the tax credit benefits for storage components such that storage projects can be eligible for tax credits even if grid-charging.

There are also differences in costs for AC-coupled systems compared to DC-coupled systems, which are the two standard configurations for BESS projects. In DC-coupled systems, the BESS is exclusively charged from the solar PV array and the inverters are situated after the BESS before the grid interconnection. In AC-coupled systems there are separate inverters for the solar PV array and the BESS. In this configuration, the BESS can be charged by the solar PV system or from the grid, and both the solar PV and BESS portions can be dispatched together or independently. Generally, DC-coupled systems use much less equipment and therefore these options experience less electrical losses in the system; however, there is much less flexibility in these systems as the BESS is solely charged from the solar PV array. Table 12 lists several of the Pros and Cons to each configuration:

Table 12: Pros and Cons of Hybrid System Configuration

Configuration	Pros	Cons
DC-Coupled	• Cheaper as there are fewer equipment needs such as number of inverters, voltage transformers, and switchgear. • Solar panels can generate more electricity than the inverter rating, which can be stored. • Higher efficiency as the current is converted only once, reducing losses.	• Less resiliency in the case of inverter failure. • Limited flexibility as inverter needs to be located close to the BESS. • Augmentation can be more difficult • Not ideal for adding to existing PV system.
AC-Coupled	• Batteries can be added more easily on AC-coupled solar PV system.	• More expensive due to the need for more equipment including dedicated inverters and balance of plant equipment.

[49] According to NREL Federal Tax Incentives Storage Systems report, under previous tax rules, if the battery was charged by the renewable energy system more than 75% of the time on an annual basis, the battery should qualify for the 5-year MACRS depreciation schedule, equal to about a 21% reduction in capital costs. Battery systems that are charged by a renewable energy system more than 75% of the time are eligible for the ITC, currently 30% for systems charged by PV and declining to 10% from 2022 onward. Battery systems that are charged by a renewable energy system 75% to 99.9% of the time are eligible for that portion of the value of the ITC.

	• Increased charging and discharging flexibility as BESS can charge from the grid. • Decreased risk of outages if some inverters fail. • Incrementally scalable • Can provide ancillary services if designed as a centralized system	• There are supply limitations as BESS is not designed to be used off-grid. • Lower efficiency due to the stored energy being converted multiple times. • Does not capture excess PV energy (DC clipped energy).

Before passage of the IRA, in order to receive tax credits in the US for hybrid systems, the BESS needed to be charged exclusively from the solar project. Therefore, most hybrid systems developed to this point were DC-coupled. However, the IRA allows for BESS systems to receive tax credits even while grid-charging, so it's expected that developers will configure hybrid systems as AC-coupled more often due to improved system flexibility. For the purpose of this report, the costs reported should be assumed to be DC-coupled systems.

Merrimack Energy has seen a range of hybrid renewable and storage options proposed. We are also aware of methodologies and models being developed to allow utilities to identify and quantity the value to the system of integrating renewable plus storage as well as standalone storage resources that may be charged by power from the grid. This combination of resources is becoming a focus for utilities to more appropriately value storage.

As for general market trends for hybrid projects in the United States, there are far more solar PV plus BESS hybrid projects being bid into RFPs compared to hybrid projects with wind or fossil fuel resources as the primary generators; however, the fossil fuel plus storage projects lead in terms of overall capacity. Co-location of energy storage and renewable generation has to date mostly focused on pairing with solar PV rather than wind. This is because wind projects have a large minimum size, meaning a bigger battery is required. Wind power is also much more intermittent than solar, meaning potentially much more cycling of the battery and faster degradation, whereas solar generation is more predictably tied to a daily generation profile. On average, generator ratios and discharge durations are higher for Solar PV plus storage than other generator plus storage combinations. Table 13 below provides a summary of the solar combined with storage and wind combined with storage projects operating in the US at the end of 2020. However, similar to our discussion regarding the availability and timing of pricing data, this data does not provide a reasonable perspective of contracts executed over the past three years which will start to come online in the near term. Merrimack Energy has monitored contract negotiations and prepared reports for solicitation processes that alone have contracted for more hybrid capacity that is reported in Table 13.

Table 13: Characteristics of Hybrid Projects Deployed in U.S. at end of 2020

	Count	Generator Capacity (MW)	BESS Capacity (MW)	BESS Energy (MWh)	Average BESS: Generator Ratio	Average BESS Duration (hrs)
Solar Hybrid	73	992	250	658	25%	2.6
Wind Hybrid	14	1425	198	122	14%	0.6

Aggregate capacity of solar hybrids in the interconnection queues listed in Table 14 for the seven organized wholesale markets is more realistic in describing the current market for hybrid projects with large numbers of projects and significant MWs of generation included in existing interconnection queues. This data is consistent with Merrimack Energy's note above that hybrid projects dominate many large-scale procurement processes in terms of the number of bids and MWs offered.

Table 14: Characteristics of Hybrid Projects in Interconnection Queues

		NYISO	ISO-NE	CAISO	ERCOT	SPP	MISO	PJM
Solar Hybrid	Count	4	35	150	53	38	62	177
	Generator Capacity	590	474	41,400	13,050	7,906	9,593	17,228
	Battery Capacity	134	-	33,838	6,209	3,435	1,238	737
	Average Capacity Ratio	23%	-	82%	48%	43%	13%	4%
Wind Hybrid	Count	1	0	9	4	3	0	2
	Generator Capacity	101	-	4,327	1,015	620	-	390
	Battery Capacity	5	-	1,779	344	144	-	49
	Average Capacity Ratio	5%	-	41%	34%	23%	-	13%

In a recent study by Lawrence Berkley Labs from August 2021 entitled *"Hybrid Power Plant Status of Installed and Proposed Projects"* the authors identified cost adders or storage premium values based on the size of the storage project relative to the renewable resource. Figure 4 below from the Lawrence Berkley Labs report provides the relationship between the size of the BESS relative to the solar PV component based on the cost per Watt(ac). A majority of BESS systems are sized at 50% to 100% of the capacity of the solar PV capacity. As illustrated, the pricing can vary significantly at a fixed ratio, which be attributed to a number of factors including, but not limited to, battery chemistry and coupling configuration.

Figure 4: Solar PV plus BESS Costs Relative to Capacity Ratio (US$)

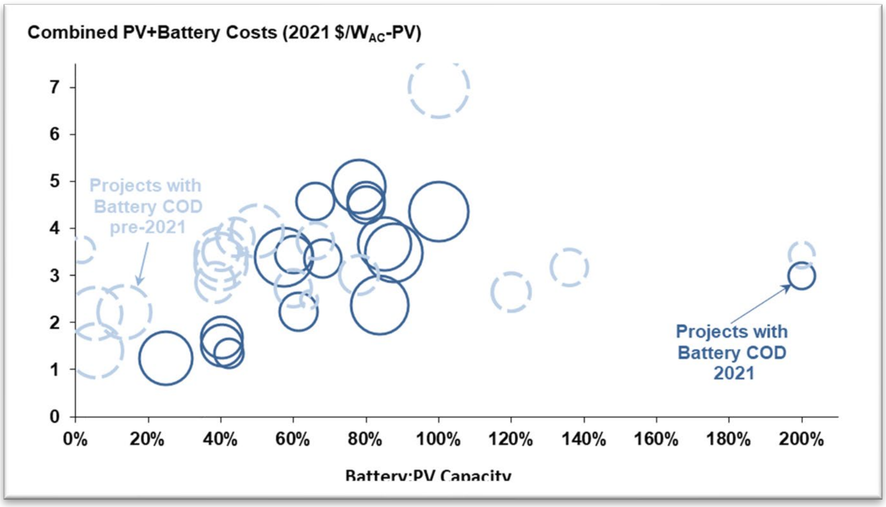
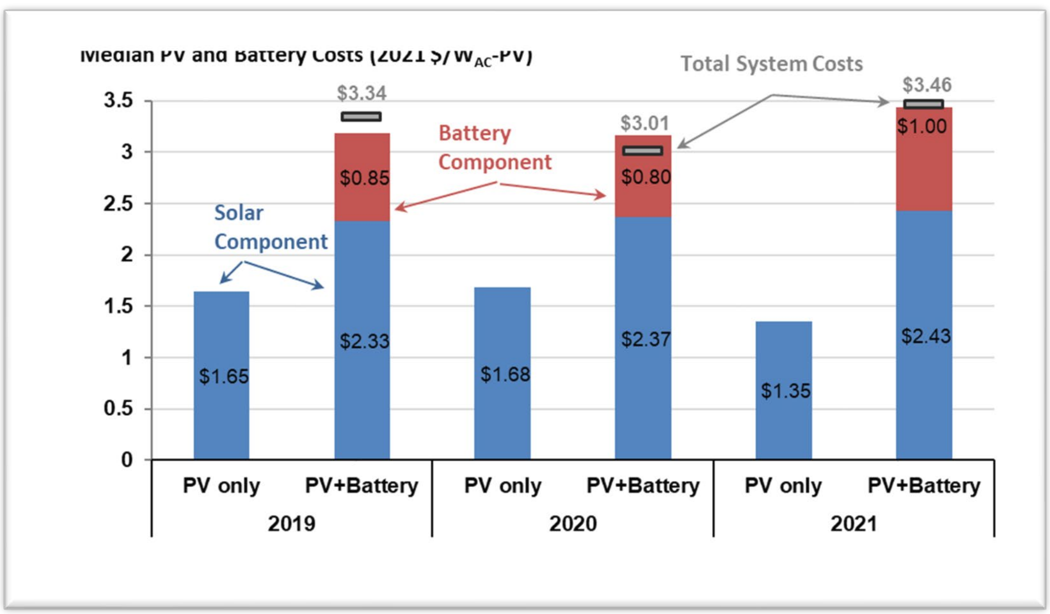


Figure 5 provides median costs of solar PV-only compared to solar PV plus BESS.

Figure 5: Solar PV-only vs. Solar PV plus BESS Median Costs (US$)



As discussed above, this chart illustrates that PV costs for a PV system only are much lower than a project that includes solar PV plus storage. This is attributed to the balance of plant which, as noted in our previous discussion, comprises the most significant cost component associated with a solar combined with storage project. As described below, Merrimack Energy expects that Figure 5 includes the majority of Balance of Plant costs in the solar component based on review and assessment of some recent projects which provided a breakdown of solar, storage, and balance of plant costs.

In recent RFPs (summer 2022 and fall 2022) that have included Build Transfer Agreement ("BTA") Options for Solar PV plus BESS hybrid projects, Merrimack Energy has reviewed bids for which the size of the battery and the solar system are the same or can vary. Based on the situation with the same size renewable and battery project, it is likely that the cost of the combined system will be at the high end of the range of such combined projects. For one recent solicitation, there were six proposals that included combined solar and storage BTAs. Merrimack Energy felt that one of the proposals was an outlier given its extremely high cost. The average total capital cost for three projects which provided separate costs for the solar and storage components was approximately $3,300/kW (US$). The average solar cost associated with the three proposals represented 47.7% of the total project (solar plus storage) costs while the storage cost component comprised 52.3%. All projects included storage capacity equal to the Solar PV nameplate capacity and had four-hour duration batteries. In this case, there was no breakdown of Balance of Plant costs.

Merrimack Energy has also compiled information for solar and storage projects that breaks down the cost components in more detail. For one solar plus storage project in which the storage component was 50% of the size of the solar project, the solar PV system comprised approximately 20% of the total costs for the project, the BESS system comprised approximately 30% of the total cost, Balance of Plant comprised the largest component at nearly 40%. Other cost categories included contingency at 7% and Owners costs comprising the remaining costs for the project. Merrimack Energy also compiled information for a similar solar plus storage project in which the storage component represented two-thirds of the capacity of the solar project. In this case, the solar component represented approximately 16% of total project costs, BESS approximately 30%, and Balance of Plant representing 41%. In all cases evaluated above, for solar combined with storage projects, the portion of the costs associated with the BESS system exceeds the portion of the cost associated with the solar system. It is important to note that Balance of Plant represents the largest portion of total project capital costs.

The size of the combined projects proposed in recent solicitations are, in our view, much larger than such projects in New England and New York as well. These projects are located in utility systems with a significant amount of existing renewable generation which can support larger storage projects. We would expect that New England and New York at this point would probably select a solar combined with storage project structure that is on the order 100 MW of solar with a 10 MW/40 MWh battery or slightly higher to perhaps 20 MW/ 80 MWhs given the limited amount of intermittent renewable energy currently in the portfolio of both systems.

Merrimack Energy is aware of hybrid solar and storage and wind and storage projects in the Northeast which were proposed to utility buyers. The majority of projects proposed have included a small amount of storage capacity relative to the capacity of the renewable resource. In addition, Merrimack Energy is aware of bidders that have offered solar or wind only projects as well as solar and wind combined with storage for the same project. In most cases, the amount of storage relative to the solar or wind capacity was 10% or less. The premiums[50] were in the order of $2-3/MWh (US$) for such options prior to the run-up in resource costs in 2022. Merrimack Energy would expect that the current premium would likely be closer to$4-$5/MWh (US$) in the current market. In the Lawrence Berkley Labs Report on hybrid power plants, the study concluded that for 4-hour discharge batteries, the levelized storage adders are approximately $5/MWh at 25% (battery storage capacity relative to solar PV capacity); $10/MWh (US$) at 50% battery storage to solar PV; and $20/MWh (US$) at 100% battery to solar PV. In addition, trends have shown that bidders are now sizing hybrid projects in the 75-100% battery storage capacity to solar PV capacity.

Based on the conclusions of the Berkley Labs report which generally coincide with actual proposals we have seen prior to recent cost increases, Merrimack Energy estimates that for the hybrid project most applicable to New England and New York markets with storage at 10% or less relative to the renewable capacity, that the adders should be applied to the solar and wind costs to derive a cost for a renewable plus storage. Given the increase in storage cost from 2021 to 2022 that would not be reflected in Lawrence Berkley Labs 2021 report, we would assume that the storage premium would be at least $2.00/MWh (US$) higher than the Berkley Lab estimates.[51] Merrimack Energy estimates that the cost of solar plus storage in New York and New England assuming 100 MW solar PV and a 10 MW

[50] The so-called "premium" is based on the cost of a solar only option relative to the cost of solar with a battery storage component. For the Northeast market many of the projects reviewed included battery storage sized at 10% of the size of the solar PV only project.
[51] For this assessment, Merrimack Energy is assuming a premium of $5/MWh for a 10 MW battery relative to just the solar component of the LCOE.

BESS would be $99.29/MWh (US$) (solar at $95.29/MWh (US$) plus storage at $4.00/MWh US$).[52] Based on the cost increase results identified in the standalone storage section (i.e., 18.75% to 34% increase) between 2021 and Q3 2022, Merrimack Energy estimates that the increase in standalone battery storage costs were approximately 25% on average. As a result, for projects for which the size of the solar and storage are the same (i.e., 100 MW solar and 100 MW BESS) the storage component would add $25/MWh (US$) (i.e., the $20/MWh (US$) adder identified by Lawrence Berkley Labs plus 25% increase in storage costs). Thus, the solar plus storage costs for this combination would be $120.29/MWh (US$) (solar priced at $95.29/MWh (US$) plus storage at $25.00/MWh US$) or $120.29/MWh (US$).

Merrimack Energy has recently reviewed BTA costs for combined solar plus storage projects in the range of approximately $3,000/kW (US$) to $3,500/kW (US$) depending on the size of the overall project and the size of the BESS relative to the solar component. We would expect the capital cost of a solar plus storage project in the Northeast would probably start at the $3,500/kW level and maybe higher.

Another way to use this data or the data above would be to combine the cost of solar as a separate project with storage as a separate project. For example, on Table 23, Merrimack Energy calculated the levelized cost of solar (at a capital cost of $2,000/kW (US$)) to be $95.29/MWh (US$) which could be combined with a separate battery with a levelized cost of $14,02/kW-month (US$), at a capital cost of $1,900/kW (US$).

NREL has noted in a few of its studies that hybrid solar plus storage projects located in the same area enjoy a 6-7% cost advantage over separate solar and storage projects in different locations. As a result, the above costs should be reduced to reflect the benefits of siting the two components in the same area behind the same interconnection.

---

[52] Merrimack Energy used the calculated LCOE value for solar based on the scenario of a capital cost of $2,000/kW (US$) and a 22% capacity factor plus the storage premiums of $4.00/MWh (US$) for storage at 10% of the capacity of the solar and $25.00 MWh (US$) in the case where the size of the storage and solar are the same. In addition, the round-trip efficiency of the systems is likely around 85% meaning that one unit of charging the battery results in .85 units of output. This may increase the premium slightly. However, since Merrimack Energy has assumed that the premium will be higher due to the increase in BESS system costs, we are not including another adjustment for round-trip efficiency, instead assuming that the round-trip efficiency is included in the premium value. Likewise, Merrimack Energy has not differentiated between the potential cost difference in New England and New York since we are assuming the same size solar and storage projects.

4.5 Calculation of Hydropower Benchmark Costs

For Hydropower resources, due to the very limited amount of new construction projects, Merrimack Energy is relying on publicly available data. NREL's 2022 Annual Technology Baseline study provides cost data for several different categories of Hydropower resources within the two broader categories of non-powered dams ("NPD") and new stream development ("NSD"). NPDs are existing dams that do not currently have hydropower, which are further broken into lock and lake design categories, each with four cost groups (low cost, medium cost, high cost, and very high cost). NSDs are then split into four categories based on the two resource characteristics of 10 MW or fewer, greater than 10 mw, 3-30ft head, and head greater than 30 ft.

The NREL ATB has published CapEx costs by resource category are provided in Table 15 below.

Table 15: Hydropower Project Costs by Resource Category

Resource Category	Resource Detail 1	Resource Detail 2	CapEx ($/kW US$ 2021)	Capacity Factor	Fixed O&M ($/kW-yr US$)
NPD 1	Lake	Low Cost	$2,574.06	34%	$64
NPD 2	Lake	Medium Cost	$5,514.42	41%	$77
NPD 3	Lake	High Cost	$5,470.63	33%	$91
NPD 4	Lake	Very High Cost	$12,372.29	38%	$154
NPD 5	Lock	Low Cost	$4,215.72	44%	$30
NPD 6	Lock	Medium Cost	$6,873.83	44%	$34
NPD 7	Lock	High Cost	$11,888.44	61%	$54
NPD 8	Lock	Very High Cost	$16,282.95	31%	$119
NSD 1	3-30ft head	1-10 MW	$7,965.47	66%	$137
NSD 2	3-30ft head	10+ MW	$7,110.97	66%	$45
NSD 3	30+ ft head	1-10 MW	$6,964.79	62%	$129
NSD 4	30+ ft head	10+ MW	$6,269.89	66%	$32

4.5.1 Methodology and Assumptions for Estimating Hydropower Generation Costs

The NREL ATB estimated Fixed O&M costs for 2022 Hydropower projects are based on the resource category as provided in Table 12 above. These costs are reported to include:

- Administrative Fees
- Administrative Labor
- Insurance
- Land Lease Payments

- Legal Fees
- Operating Labor
- Other
- Property Taxes
- Site Security
- Taxes
- Project Management
- Bearing Replacement
- Cavitation Damage Patching
- Rewind Stator
- General Maintenance
- Scheduled Maintenance over Technical Life
- Unscheduled Maintenance over Technical Life
- Transformers
- Annualized present value of large component replacement over technical life

The *"EIA Annual Energy Outlook 2022"* published costs for Hydropower projects of $2,025/kW (US$) in New England and $4,144/kW (US$) in Upstate NY. The large variance in CapEx costs for these two regions are likely due to the limited number of projects and specific resource characteristics in each sample set. The EIA estimated the fixed O&M for conventional Hydropower costs to be $43.78/kW-year (US$) in 2021 dollars.

The Capital Cost Recovery Factor will also be based on several factors including the utility's discount rate, tax structure, and depreciation levels. For this analysis, Merrimack Energy is using a Capital Cost Recovery Factor for Hydro of 6.8%. Table 16 includes the assumptions and cost information used in the evaluation.

Table 16: Input Assumptions and Cost Parameters for Hydropower Projects

Parameter	Assumption
Capital Cost ($/kW) (US$)	$2,025 - $4,244
Fixed O&M plus Operating Costs ($/kW-year) (US$)	$43.78
Capacity Factor	60%[53]
Discount Rate	5.4%
Capital Cost Recovery Factor (%)	6.8%
Inflation Rate (%)	2.2%
Contract Term	30 years

[53] A capacity factor of 60% was used for the NY and NE average project costs. For the NPD and NSD classifications, the respective capacity factors and O&M costs provided by NREL as listed in Table 15 were utilized in the evaluation.

Based on these assumptions, Merrimack Energy has calculated that the real levelized cost of energy ranges from $26.23/MWh (US$) (assuming a capital cost of $2,025/kW US$) to $46.62/MWh (US$) (assuming a capital cost of $4,244/kW US$). If these values are converted to Canadian dollars, the real levelized cost in (Cn$ 2022$) would be $34.08/MWh (Cn$) assuming a capital cost of $2,025/kW (US$) and $60.62/MWh (Cn$) assuming a capital cost of $4,244/kW (US$).

Merrimack Energy has also modeled the hydropower costs included in Table 15 based on the medium cost cases. The results are presented in Table 20.

4.6 Calculation of Biomass Benchmark Costs

For Biomass resources, since there are very few utility-scale procurement efforts specifically for Biomass resources, Merrimack Energy is relying on publicly available data along with a few recent proposals we have seen bid into RFP processes. While Biomass resources are eligible to compete in most "all-source" solicitations, they are generally not cost competitive relative to other renewable resources like wind, solar, or energy storage projects, so it's rare that Biomass resources are offered into competitive utility solicitations. The lack of new resource development means there is very little new cost data available, so many of the inputs and assumptions used in public studies referenced below are from 2020 and prior. However, given the nature of the generation equipment for biomass, Merrimack Energy would not expect that capital costs would be very volatile as has been the case with renewables over the past two years, although the type of project (combined heat and power system or boiler) could determine cost.

The NREL ATB estimated CapEx costs for a dedicated Biomass facility to be $4,416/kW (US$) in 2020, decreasing to $4,360/kW (US$) in 2022, with fuel costs being $5/MMBtu (US$). The NREL ATB estimated Fixed O&M costs for 2022 Biomass projects to be $150.85/kW-year (US$).

The *EIA Annual Energy Outlook 2022* published costs for Biomass projects of $5,372/kW (US$) in New England and $5,389/kW (US$) in Upstate NY. The EIA estimated the fixed O&M costs for Biomass projects to be $131.62/kW-year (US$) in 2021 dollars.

Fitch Solutions published an article in June 2022 entitled *"Cost of Biomass Power Generation Stagnates, With Downward Pressure for the Future"*. The article discussed the worldwide trend in biomass production costs but did present limited cost information. The article stated that "from 2010 to 2020, installation costs and the levelized cost of electricity (LCOE) of the biomass sector have experienced a mix of year-over-year increases and decreases. Regardless, the overall trendline is relatively stagnant for costs, which according to the International Renewable Energy Agency (IRENA) data is at an annual average total installed cost of $2,289/kW(US$) and an LCOE of $69/MWh (US$) over that decade." The article also stated that the average installed cost tends to drop in years when Asia dominates biomass capacity additions, as opposed to when North America and Western Europe dominate. Equipment costs for biomass power plants are relatively higher in North America and Western Europe than in Asia, due to the introduction of combined heat and power systems. For 2020, total installed costs were approximately $2,500/kW (US$) and LCOE about $80/MWh (US$) worldwide.

In a recent solicitation for which Merrimack has served as Independent Evaluator, a Biomass resource slightly greater than 10 MW was submitted at a price between $130/MWh (US$) and $140/MWh (US$) fixed depending on the delivery term, with pricing for a 10-year delivery term at the low end of the range and pricing for a 15-year term at the high end of the range.

Merrimack Energy also served as Independent Monitor for a Bioenergy solicitation designed to review and evaluate proposals to construct a facility to utilize forest waste wood for the purposes of clearing high risk forest service lands. The generating equipment to be used would be based on dismantling and reconstructing the equipment from an existing facility mothballed in 2015. The pricing offered was $125/MWh (US$) escalating at 2% per year.

The bottom line with regard to biomass is the variation in cost based on the technology selected, the availability of biomass fuel, the cost to transport the fuel and operation and maintenance and admin costs. Merrimack Energy prepared a report on the Competitive Cost of Biomass Generated Electricity based on Hydro-Quebec's April 2009 Call for Tenders (A/O 2009-01) for Firm Capacity for a Total of 125 MW and Associated Energy Produced by Biomass Cogeneration. Merrimack Energy identified six studies on biomass costs. The capital costs of biomass varied widely depending on the technology and generation process, with capital costs ranging from $2,500/kW (US$) to $5,000/kW (US$) depending on the project size and technology with Fixed O&M costs ranging from $54/kW-year (US$) to $180/kW-year (US$). Merrimack Energy calculated the average levelized cost to be $130.08/MWh (Cn$) and real levelized costs to be $110.70/MWh (Cn$) in 2009$.

4.6.1 Methodology and Assumptions for Estimating Biomass Generation Costs

The Capital Cost Recovery Factor will also be based on several factors including the utility's discount rate, tax structure, and depreciation levels. For this analysis, Merrimack Energy is using a Capital Cost Recovery Factor for biomass of 7.1%. Table 17 includes the assumptions and cost information included in the evaluation. Merrimack Energy has also evaluated the levelized cost of biomass based on the capital and operating costs for New York and New England biomass projects as identified in the EIA Annual Energy Outlook 2022 identified above.

Table 17: Input Assumptions and Cost Parameters for Biomass Projects

Parameter	Assumption
Capital Cost ($/kW) (US$)	$2,500 - $5,000
Fixed O&M plus Operating Costs ($/kW-year) (US$)	$150.85
Capacity Factor	64%
Project Size (MW)	100 MW
Discount Rate	5.8%
Capital Cost Recovery Factor (%)	7.1%
Inflation Rate (%)	2.2%
Contract Term	30 years

Based on the assumptions above, Merrimack Energy has calculated the real levelized cost of energy ranging from $47.18/MWh (US$) (assuming a capital cost of $2,500/kW US$) to $69.81/MWh (US$) (assuming a capital cost of $5,000/kW US$). If these values are converted to Canadian dollars, the real levelized cost in (Cn$ 2022$) would be $61.35/MWh (Cn$) assuming a capital cost of $2,500/kW (US$) and $90.76/MWh (Cn$) assuming a capital cost of $5,000/kW (US$).

In addition, Merrimack modeled three if the NREL classifications using the NREL-estimated capital costs, capacity factors, and O&M costs: NSD4, NPD2, and NPD6. The results were a rea levelized cost in Canadian dollars of $74.71/MWh, $121.92/MWh, and $122.54/MWh respectively.

Merrimack Energy has also estimated the levelized cost of biomass based on the project cost for biomass projects provided by US DOE Energy Information Administration in the EIA Annual Energy Outlook 2022. The capital cost estimates provided by EIA for New England and New York were over $5,000/kW (US$) as well as the NREL capital cost estimates for biomass projects.

4.7 Calculation of Renewable Natural Gas Benchmark Costs

Renewable Natural Gas ("RNG") is upgraded biogas derived from organic waste products with two common ways of being produced: anaerobic digestion ("AD") and thermal gasification ("TG"). RNG can be sourced from landfills, livestock manure or industrial farms, and sewage treatment plants through the anaerobic digestion process. The other source is synthetically manufactured from TG of biomass like crop residue or debris from logging operations.

There are several challenges related to utilizing renewable natural gas as an energy source. One is that the availability is currently limited. However, a study by ICF stated that roughly 16% of current gas usage could be replaced with renewable natural gas. In addition, while RNG has roughly 60% of the emissions compared to natural gas, RNG is significantly more expensive compared to natural gas. RNG can be produced from a wide array of sources used in several different applications, therefore cost data can vary drastically. Project costs can include feedstock gathering or anaerobic digestion, gas upgrading and conditioning, gas compression and injection, interconnection, and pipeline expansion.

RNG can be used as a replacement to conventional natural gas with the intention of reducing emissions in the combustion of the fuel. In addition, it is sourced from renewable sources. The cost of RNG comes as a premium to natural gas. With that, to understand the full costs of a potential project, it should be noted the costs of developing a new natural ga plant. As reported by Statista, the average construction cost of a natural gas generators installed in the United States in 2020 are presented in Table 18.

Table 18: Cost Estimates for Construction of Natural Gas Plant

Generator Type	Cost ($/kW) (US$)
Combined Cycle	$1,155
Combustion Turbine	$636
Internal Combustion Engine	$1,103

With regard to the cost of RNG itself compared to conventional natural gas, from July 2020 to July 2022, the Henry Hub natural gas price increased from an average of $1.77 per million British thermal units to $7.28 per million British thermal units. A 2020 study titled *"Evaluating Market Conditions for Renewable Natural Gas and Clean Hydrogen"* concluded that RNG holds a price premium of over $15/MMBtu (US$) compared to natural gas. Merrimack Energy is aware of a few proposals for supplying biomethane submitted to utilities that offered a price premium of slightly over $20/MMBtu (US$) over the natural gas index. Table 19 provides cost estimates as provided by two different studies for the RNG costs from three different sources: landfill, animal waste, and wastewater.

Table 19: Cost Estimates for RNG

Source	Operational Projects as of 12/31/2021	Operational Output (MMBtu/year)	American Gas Foundation Cost 2020 ($/MMBtu US$)	Bluesource Estimated Cost 2020 ($/MMBtu US$)
Landfill	76	53,394,825	$7-19	$28
Animal Waste	128	18,330299	$18.4-33.6	$84
Wastewater	26	2,125,823	$7.4-26.1	$31

In a November 21, 2022 article in the Wall Street Journal entitled *"One Man's Trash is Another's Clean Fuel"*, the authors discussed the potential for renewable natural gas and potential technological breakthroughs that could make use of excess gas from landfills and other untapped fuels to convert into RNG. The article was written by Nick Stork, CEO of Archaea, which was recently acquired by British Petroleum. The author notes that Archaea designs, builds and operates RNG plants in the US and produces 6,000 oil-equivalent barrels per day through 13 RNG facilities. The company has plans to construct 88 more to serve rising demand. Obviously, as noted by the article, RNG sells at a significant premium to natural gas but expects breakthroughs in technology to drive down the differential.

4.8 Market Costs and Structure in Eastern Canada Power Markets

Merrimack Energy has been able to collect only limited data regarding project costs on eastern Canadian markets and the data we have been able to collect is generally several years old and certainly does not reflect current market conditions. However, Merrimack Energy is providing the data we have collected and the reports we have reviewed to assess cost and recent procurement activity, where available.

A report by Canadian Energy Regulator ("CER") entitled *"Canada's Energy Future 2021"* provided data on estimated capital cost for wind and solar in $2020 (Cn$). The cost information is included in Table 20.

Table 20: Electricity Cost Assumptions for Onshore Wind and Utility Scale Solar in Canada

Resource	Capital Cost (2020 $/kW Cn$)	Fixed O&M Costs (2020 $/kW Cn$)	Variable O&M Costs (2020 $/MWh Cn$)	Capacity Factor (%)
Wind	$1,389	$25 - $60	$0	30-45
Solar	$1,516	$20 - $27	$0	10-20

The above data illustrates that solar project costs will likely be higher than wind cost in Canada for several reasons. First, the capital costs are expected to be higher for solar PV than wind. While higher Fixed O&M costs for wind may offset some of the projected difference in capital costs, the much lower capacity factors for solar will likely result in much higher LCOE's for solar relative to wind.

A March 2021 report by the Canadian Energy Regulator (CER) entitled *"Canada's Renewable Power: Recent and Near-Term Developments"* provides a review of recent developments for renewable energy by Province and identifies specific projects that reflect the change in resource capacity added. Merrimack Energy was able to collect capital costs for several of the projects identified in the CER report as well as a few others. Table 21 provides a high-level summary of the specific individual projects in Ontario identified in the report for which we have been able to collect data. Merrimack Energy was able to collect cost data for most of the projects identified in the CER report above.

Table 21: Ontario Utility Scale Solar and Wind Project Costs

Project Name	Size (MW)	Estimated COD	Capital Cost ($/kW Cn$)
Wind Projects			
Belle River Wind	100	2017	$2,079.16
North Kent Wind	100	2017	N/A
Amherst Island Wind	75	2018	$2,510.46
Harvey Inlet Wind	300	2019	$2,648.90
Nations Rise Wind	100	2021	$1,769.00
Romney Wind Energy Center	60	2020	$1,666.67
Solar Projects			
Windsor	50	2016	$2,315.04
Southgate	50	2016	$2,162.16
Loyalist Solar	54	2019	$1,547.00
Nanticoke Solar	44	2019	$1,547.00

Although the number of projects is limited, it does appear that the costs of wind and solar projects has declined in Ontario over the period 2016 to 2020. In addition, it appears the capacity factor for the solar projects averaged around 20%.

There was also a hydro project called the Peter Sutherland Hydro Project that was also identified in the CER report. The project is a 28 MW project completed in 2017 which based on our follow-up assessment was reported to cost $300,000,000 or over $10,000/kW (Cn$).[54]

[54] Merrimack Energy reviewed several articles on the project and most report the investment in the project to be $300 million which seemed extremely costly.

There also appears to be a number of small-scale energy storage projects in Ontario, largely in the 2-10 MW range. Merrimack Energy calculated a total of nearly 90 MW of storage projects identified in Ontario, but no pricing information was provided.

While the CER report did not identify any specific projects build or under construction in New Brunswick over the past four years, Merrimack Energy has identified four wind projects either in commercial operation or about to be in commercial operations. These projects are listed in Table 22, with similar information presented as provided for projects in Ontario.

Table 22: New Brunswick Utility Scale Wind Project Costs

Project Name	Size (MW)	Estimated COD	Capital Cost ($/kW Cn$)
Wind Projects			
Burchill Wind Energy Project	41 MW[55]	2023	$2,317.07
Wocawson Energy Project	20	2020	$2,500.00
Wisokolamson Wind Energy Project	18	2019	$2,270.56
Kent Hills 3	17.3	2018	N/A

In terms of project cost data for Nova Scotia, Merrimack Energy's research identified that the Province of Nova Scotia issued a Request for Proposals for new large-scale wind and solar projects capable of supplying 10% of the province's electricity from renewable sources in January 2022. The Request for Proposals promised to deliver electricity at least 57% cheaper than the discontinued Community Feed-in Tariff program known as COMFIT. The Province of Nova Scotia set a maximum price of $56/MWh compared to $131/MWh under COMFIT.

An article from CBC News posted August 17, 2022 noted that Nova Scotia had selected five wind projects, each majority-owned by one or more Mi'kmaw communities. The five projects are expected to generate 372 MW or 1,373 gigawatt hours per year of electricity. The average cost of energy produced by the wind projects is expected to be $53.17/MWh.

A recent Enerdata article stated that each project will receive a 25-year power purchase agreement with Nova Scotia Power for the sale of their renewable electricity at a rate of $53/MWh (Canadian dollars) or $41/MWh US$). The projects selected include:

---

[55] This project is also reported to include 10 MW of 2-hour duration storage

1. The 150 MW Benjamins Mill Wind Farm near Falmouth developed by Natural Forces;
2. The 23.5 MW Ellershouse 3 Wind Farm in Hants County, a joint venture between Annapolis Valley First Nation and Potentia Renewables;
3. The Higgins Mountain and Wedgeport wind farms, led by Sipekne'katik First Nation and Elemental Energy;
4. The 40 – 100 MW Weavers Mountain Wind project near Marshy Hope to be built by the Glooscap First Nation and Halifax-based SWEB Development.

All projects are majority-owned by one or more Nova Scotia's native Mi'kmaq communities.

In conclusion, based on the data available for renewable energy projects in the US and Canada, Merrimack Energy believes that use of US data for the Northeast US markets may provide the most accurate information on which to compare costs relative to the Hydro-Quebec distribution Call for Tenders results. As a result, Merrimack Energy will apply the costs developed for each of the resource options for US data equally to eastern Canadian markets as well for purposes of comparing the projects selected by Hydro Quebec against the benchmark resources calculated.

5. Summary and Conclusions for the Northeast US Market

This section of the report provides a summary of the LCOE values and real levelized costs (in both US$ and Canadian dollars) for the benchmark resource options identified in Section 4 of this report.[56] Table 23 presents the high-level assumptions for Capital and O&M costs for each resource type and also presents levelized cost estimates for New England and New York for each resource option where applicable. For several resources, Merrimack Energy is not able to adequately differentiate the costs by region and instead provides a single price for the US Northeast.

Table 23: Summary of Northeast US LCOE Calculations

Resource Cost Assessment	Levelized Cost of Energy ($/MWh US$)	Levelized Cost of Energy ($/MWh Cn$)	Real Levelized Cost of Energy (2022 $/MWh US$)	Real Levelized Cost of Energy (2022 $/MWh Cn$)
Wind				
Capital Cost - $2,000/kW	$66.36	$86.27	$47.77	$62.11
Capital Cost - $2,250/kW	$72.48	$94.22	$52.18	$67.82
Capital Cost - $2,500/kW	$78.59	102.17	$56.57	$73.56
New England LCOE	$73.92	$96.10	$52.23	$69.17
New York LCOE	$73.92	$96.10	$52.23	$69.17
Solar 17% CF				
Capital Cost - $1,800/kW	$112.85	$146.70	$87.52	$113.77
Capital Cost - $2,000/kW	$123.32	$160.31	$95.62	$124.29
Capital Cost - $2,200/kW	$133.79	$173.92	$103.72	$134.84
Solar 22% CF				
Capital Cost - $1,800/kW	$87.20	$113.36	$67.62	$87.91
Capital Cost - $2,000/kW	$95.29	$123.88	$73.88	$96.05
Capital Cost - $2,200/kW	$103.38	$134.39	$80.15	$104.19
New England LCOE	$77.90	$101.27	$60.43	$78.54

[56] The levelized cost of energy is calculated based on the contract term assumed with each contract beginning in 2026. The real levelized cost of energy is calculated back to a 2022 base period.

New York LCOE	$70.85	$92.11	$54.96	$71.43
Standalone Storage				
Capital Cost - $1,600/kW	$119.36	$155.17	$99.94	$129.76
Capital Cost - $1,900/kW	$135.56	$176.23	$113.51	$147.55
Capital Cost - $1,600/kW – LCOE ($/kW-month)	$12.34	$16.05	$10.33	$13.43
Capital Cost - $1,900/kW – LCOE ($/kW-month)	$14.02	$18.22	$11.74	$15.27
Solar + Storage				
4-hr duration BESS at 10% ($4/MWh Adder)	$99.29	$129.08	$75.83	$98.59
4-hr duration BESS at 100% ($25/MWh Adder)	$120.29	$156.38	$91.87	$119.44
Biomass				
Capital Cost - $2,500/kW	$65.99	$85.79	$47.18	$61.35
Capital Cost - $5,000/kW	$97.65	$126.95	$69.81	$90.76
Capital Cost – NREL - $4,360/kW	$89.55	$116.41	$64.02	$83.23
Capital Cost -NE - $5,372/kW	$102.58	$133.35	$73.34	$95.33
Capital Cost -NY - $5,389/kW	$102.36	$133.07	$73.19	$95.15
Hydropower				
Capital Cost - $2,025/kW	$36.89	$47.95	$26.23	$34.08
Capital Cost - $4,244/kW	$65.60	$85.27	$46.62	$60.62
Capital Cost – NSD4 10+ MW - $6,269/kW	$80.85	$105.10	$57.47	$74.71
Capital Cost – NPD2 – Medium - $5,514/kW	$131.91	$171.49	$93.78	$121.92
Capital Cost – NPD6 – Medium - $6,873/kW	$132.59	$172.37	$94.26	$122.54

6. Forecast of Renewable Energy Prices

Merrimack Energy was also asked to provide a forecast of renewable resource costs going forward. While most studies and forecasts of renewable resource costs project continued declines in cost, particularly for wind, solar, and energy storage resources due to expected continued improvements in resource technologies, Merrimack Energy is not as optimistic regarding the timing or magnitude of cost declines. In our view, we believe the recent trends and market conditions associated with increases in solar, wind and storage costs could remain for several more years due to regulatory policy and shortages of raw material inputs combined with a growing demand for these resources to meet aggressive clean energy targets in many developed countries as many areas of the world focus on reducing overall emissions by adding more renewable resources. For solar, we would expect that supply chains will be constrained for several more years until at least 2024 based on input from project developers due to the uncertainty associated with the US Department of Commerce investigation. Beyond 2024, the result of the US Department of Commerce investigation could lead to reimposition of tariffs which could negatively affect supply availability to US markets. However, this may have beneficial impacts on Canadian solar markets which may see higher equipment availability.

Likewise, for energy storage one of the constraining issues is the cost and availability of lithium given that the vast majority of BESS systems are based on lithium-ion batteries. Unless new technologies materialize commercially within the next few years, we question whether the magnitude of the cost declines envisioned by both US and Canadian agencies involved in projecting costs of renewable projects will materialize. The huge demand expected for energy storage projects combined with electric vehicle incentives and expected increased market penetration will lead to significant increases in battery demand. The ability of countries and companies to increase the supply of lithium will influence the ability of the industry to meet demand in an economic manner.

Merrimack Energy is more optimistic about the potential for wind project costs to decrease assuming input costs decline such as steel and the like. Unlike the solar and storage markets, wind turbine manufacturers are largely based in the US, Canada and Europe which should reduce the risk of supply disruption.

Another factor influencing costs for all resources is the costs required to upgrade transmission systems to allow more generation to be delivered to load centers. Our experience is that transmission interconnection queues in most power markets have a very large number of projects looking to secure interconnection agreements to allow the projects to move forward in the development process.

However, recent experience with regard to network upgrade costs to construct transmission facilities illustrates that such costs are also increasing and the timing for completing such facilities on the part of utilities and ISOs is increasing as well.

In conclusion, Merrimack Energy feels that there are a number of factors In the power market that will likely keep renewable energy prices higher than projected, including a significant increase in demand for such facilities to meet projected load growth, to replace retiring coal and gas units, and meet emission reduction targets.

7. References

NREL (National Renewable Energy Laboratory). 2022. *2022 Annual Technology Baseline*. Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/.

EIA (Energy Information Administration). *Annual Energy Outlook 2022*. Washington, D.C.: U.S. Energy Information Administration, March 2022. https://www.eia.gov/outlooks/aeo/.

LevelTen Energy. 2021. *2021 PPA Price Index*. Seattle, Washington: LevelTen Energy. http://www.leveltenenergy.com/resources.

LevelTen Energy. 2022. *2022 PPA Price Index*. Seattle, Washington: LevelTen Energy. http://www.leveltenenergy.com/resources.

Penrod, E. (2022, October 18). *PPA prices jump 9.6% in Q3 as growing demand hits supply chain, transmission roadblocks: LevelTen*. Utility Dive. https://www.utilitydive.com/news/ppa-prices-supply-chain-interconnection-levelten/634320/?utm_source=Sailthru&utm_medium=email&utm_campaign=Issue:%202022-10-20%20Utility%20Dive%20Renewable%20Energy%20%5Bissue:45418%5D&utm_term=Utility%20Dive:%20Renewable%20Energy

Weaver, J. F. (2022, August 25). *To PTC or ITC, that is the financial question*. Pv Magazine USA. https://pv-magazine-usa.com/2022/08/25/to-ptc-or-itc-that-is-the-financial-question/

American Clean Power Association (ACP). 2022. *Clean Power Annual Market Report 2021*. Washington, D.C.: American Clean Power Association. https://cleanpower.org/market-report-2021/

CohnReznick Capital (2022, July). *Capital Solar & Wind Market Cost of Energy Analysis*.

Bolinger, M., & Wiser, R. (2022, August). *Land-Based Wind Market Report*. Electricity Markets and Policy Group; Lawrence Berkeley National Laboratory for Department of Energy. https://emp.lbl.gov/wind-technologies-market-report

The International Renewable Energy Agency (2016). *The Power to Change: Solar and Wind Cost Reduction Potential to 2025*.

International Energy Agency (2021). *Renewables 2021 Analysis and Forecast to 2026*.

Kessler, R. (2022, May 4). *"Destroying clean energy."* Recharge | Latest Renewable Energy News. https://www.rechargenews.com/solar/destroying-clean-energy-industry-decries-potential-new-us-solar-tariffs-as-impacting-jobs-and-climate/2-1-1212019

Potomac Economics. (2022, May). *2021 State of the Market Report for the New York ISO Markets*. NYISO Market Monitoring Unit.

HIS Markit (2022, January). *North America Wind Capital Cost and LCOE Outlook*. The International Renewable Energy Agency (2016). *The Power to Change: Solar and Wind Cost Reduction Potential to 2025*.

Johnson, E. (2022). *New England Power System Outlook*. CBIA 2022 Energy & Environment Conference.

Canadian Energy Regulator (2022, March). *Canada's Renewable Power: Recent and Near-Term Developments*.

Canadian Energy Regulator (2022, May 24). *Canada's Energy Future*.

Independent Electricity System Operator (2022, October 7). *Resource Eligibility Interim Report*.

National Renewable Energy Laboratory (2022 September). *US Solar Photovoltaic System and Energy Storage Cost Benchmarks wit Minimum Sustainable Price Analysis Q1 2022.*

Montanes, C. C., Gorman, W., Mills, A., & Kim, J. H. (2022, June). *Keep it short: Exploring the impacts of configuration choices on the recent economics of solar-plus-battery and wind-plus-battery hybrid energy plants*. Journal of Energy Storage, 50.

Marsh, J. (2019, August 29). *AC vs. DC solar battery coupling: What you need to know*. EnergySage. https://news.energysage.com/ac-vs-dc-solar-battery-coupling-what-you-need-to-know/

Fitch Solutions (2022, June). *Cost of Biomass Poewr Generation Stagnates, with Downward Pressure for the Future*.

Natural gas generator construction cost U.S. (n.d.). Statista. Retrieved November, 2022, from https://www.statista.com/statistics/557322/installed-natural-gas-generator-construction-cost-in-the-us-by-type/

Rosa, J. D. (2022, August 25). *Natural gas power plants generate record electricity levels in July*. Talk Business & Politics. https://talkbusiness.net/2022/08/natural-gas-power-plants-generate-record-electricity-levels-in-july/

Ding, D., Pollan, S., & Yang, Z. (2021). *Evaluating Market Conditions for Renewable Natural Gas and Clean Hydrogen*.

Investor, I. (2022, October 4). *Renewable natural gas: Attracting significant capital*. Seeking Alpha. https://seekingalpha.com/article/4544525-renewable-natural-gas-attracting-significant-capital

ICF. (2019). *Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment*. American Gas Foundation.

Smith, S. (2022, August 17). *N.S. selects five wind projects to produce electricity from renewable sources*. CBC. https://www.cbc.ca/news/canada/nova-scotia/n-s-selects-five-projects-largest-ever-wind-procurement-1.6553677

Canada's Nova Scotia province approves 372 MW of onshore wind projects. (2022, August 22). Enerdata. https://www.enerdata.net/publications/daily-energy-news/canadas-nova-scotia-province-approves-372-mw-onshore-wind-projects.html