February 27, 2024
VIA ELECTRONIC MAIL

Amanda Hiller
Acting Tax Commissioner and General Counsel
New York State Department of Taxation and Finance
William A. Harriman Campus, Building 9
Albany, NY 12227

Dear Ms. Hiller:

The Alliance for Clean Energy New York (ACE NY) and the New York Solar Energy Industries Association (NYSEIA) appreciate the ongoing efforts of the Department of Taxation and Finance (DTF or the Department) to develop an accurate and stable model for valuing wind and solar projects, and we are grateful for the opportunity to provide feedback on the draft 2024 model. Our comments below outline key concerns of the solar and wind developers our associations represent and provide concrete recommended modifications to increase the accuracy of the draft model.

Before providing specific recommendations, we seek to draw the Department's attention to the fact that the 2024 draft model differs substantially from the previous version. Our members supported the legislation enacted through the 2021-2022 State Budget that directed DTF to publish a standard methodology for real property tax assessment for solar and wind energy systems because we believe that a standard and fair appraisal methodology increases certainty and convenience for both taxing jurisdictions and renewable energy development companies. A consistent appraisal methodology promotes economic development through the creation of thousands of high-paying construction jobs and provides local governments with a significant, increased, and stable revenue stream. It also provides budgeting certainty for assessors, towns, and developers, and reduces risk to local governments of tax certiorari created by the inconsistent and often contradictory practices used to appraise renewable energy projects prior to the development of the DTF model.

If successive versions of the model contain radically different values for critical components of the valuation formula, and produce dramatically different valuations, this undermines legislative intent and erodes the value of the model for both developers and assessors alike. We appreciate the need to ensure that the values in the model are accurate and defensible, but we urge the Department to prioritize consistency wherever possible to mitigate unnecessary confusion and disruption in the market.

Recommended Modifications to 2024 Draft Appraisal Model

ACE NY and NYSEIA (The Parties) respectfully recommend that DTF consider several modifications to the draft 2024 wind and solar appraisal model to increase the model's accuracy. These recommendations relate to: capacity factors for wind and solar projects, which materially impact revenue forecasts; community solar operating expenses and utility-scale renewables host community agreement expenses; Taxable Status Year, which impact revenue forecasts by time-shifting the analysis period; Fraction of Off-taker Credits to Owner, which impacts revenue forecast for many projects; the Economic Life of wind assets; and capitalization rate issues, including the assumed debt/equity split and the weighted average cost of capital. Finally, ACE NY and NYSEIA include recommendations to adjust the user interface to reduce user error and confusion along with process improvements to make the annual model update process more transparent and predictable.

CAPACITY FACTOR

The Department's sources for capacity factors are not included with the model, however we do not believe the capacity factors included in the model are accurate. We have examined the historic and projected capacity factors for operating NY based plants from a variety of credible sources, and observe that the Department's draft model overstates capacity factor in comparison to actual NYISO renewable energy projects and in comparison to modeled capacity factor from the National Renewable Energy Laboratory. The following sections provide detailed analysis and recommendations for capacity factor by technology for the Department's consideration.

Wind

If an application is to be made to *all* wind assets regardless of age, we request that the model use the average historic capacity factor of wind assets in NY at **25%** to avoid overassessment *(see figure 1)* [1]. NYISO recently published "Overview of NY Renewables" with data regarding 2019-2022 Wind Capacity Factors further supporting the S&P data *(see figure 2)*.[2]

[1] S&P Capital IQ Power Screener

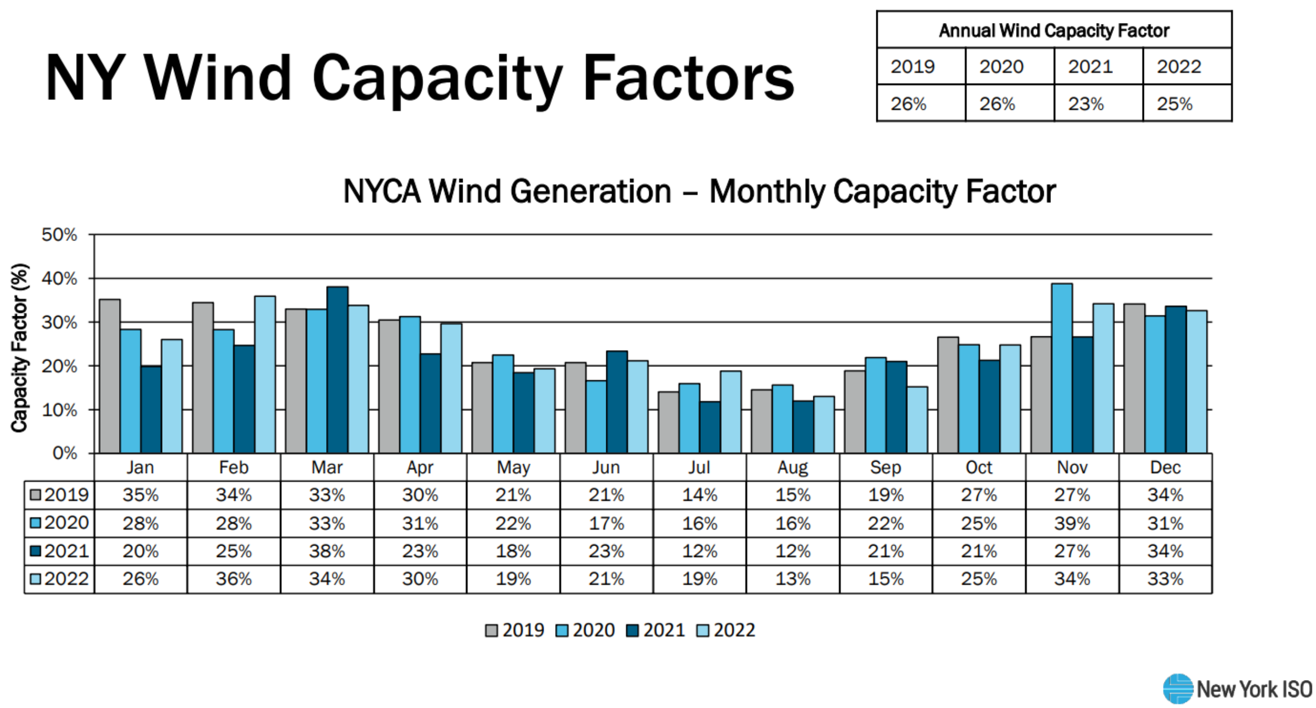
[2] New York Independent System Operator, Overview of NY Renewables in 2022 https://www.nyiso.com/documents/20142/36845856/2022%20NYCA%20Renewables%20Presentation%20FINAL.pdf/65f48ad8-cf06-4a7f-8d1a-2cd716380063

Figure 1: NY Onshore Wind Historic Capacity Factors

NY Wind Capacity Factors			
Tech Type	**Historic Mean**	**Last Five Years**	**Last 10 Years**
Wind Turbine	25.52	25.26	25.92

Figure 1 is a summary of an S&P data download for historic capacity factors of NY Onshore Wind summarized in the three categories noted above.

Figure 2: NY Wind Capacity Factors



While technology has improved and some aging projects may receive a capacity pickup from pending repowers, wind curtailments are also on the rise.[3] If capacity factors are applied universally, we request a concluded applicable capacity factor of 25% for Onshore Wind reduced ratably by applicable zone *(see figure 3).*

[3] Id

Figure 3: Onshore Wind Requested Revision

Onshore Wind Requested Revision					
5	Onshore Wind - Tier 1	A	5A	0.3043	0.22
5	Onshore Wind - Tier 1	B	5B	0.3200	0.23
5	Onshore Wind - Tier 1	C	5C	0.3200	0.23
5	Onshore Wind - Tier 1	D	5D	0.3437	0.25
5	Onshore Wind - Tier 1	E	5E	0.3437	0.25
5	Onshore Wind - Tier 1	F	5F	0.3437	0.25
5	Onshore Wind - Tier 1	G	5G	0.3437	0.25
5	Onshore Wind - Tier 1	H	5H	0.3437	0.25
5	Onshore Wind - Tier 1	I	5I	0.3437	0.25
5	Onshore Wind - Tier 1	J	5J	0.3437	0.25
5	Onshore Wind - Tier 1	K	5K	0.3437	0.25

Solar

The updated model includes inaccurate and erratic capacity factors for solar PV systems. In general, the updated model overstates solar capacity factors, which results in overstated gross revenue. However, there are nuanced issues as well. For example, solar irradiance is stronger in New York's southern latitudes vs northern latitudes whereas the draft model includes higher capacity factors for single-axis tracker systems in upstate Zones A and B than in downstate Zones G-K *(see figures 4-6)*[45]

Figure 4. 'ModelFactors' Tab of Proposed 2024 Model, With Outliers Highlighted for Emphasis

13	2	Solar Tracking - VDER	A	2A	0.2334
14	2	Solar Tracking - VDER	B	2B	0.2399
15	2	Solar Tracking - VDER	C	2C	0.2246
16	2	Solar Tracking - VDER	D	2D	0.2210
17	2	Solar Tracking - VDER	E	2E	0.2210
18	2	Solar Tracking - VDER	F	2F	0.2235
19	2	Solar Tracking - VDER	G	2G	0.2100
20	2	Solar Tracking - VDER	H	2H	0.2100
21	2	Solar Tracking - VDER	I	2I	0.2100
22	2	Solar Tracking - VDER	J	2J	0.2100
23	2	Solar Tracking - VDER	K	2K	0.2100

[4] Best Practice Energy. https://bestpracticeenergy.com/2020/04/02/new-york-electricity-supply-price-components/

[5] National Renewable Energy Laboratory. https://www.nrel.gov/gis/assets/images/nsrdb-v3-ghi-2018-01.jpg.

Figure 5: Best Practice Energy New York Capacity Zones

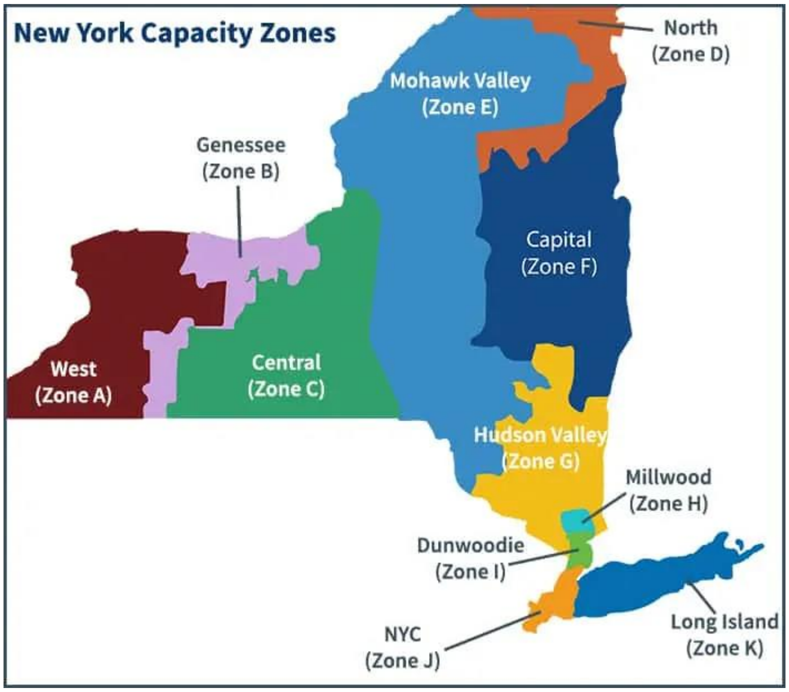
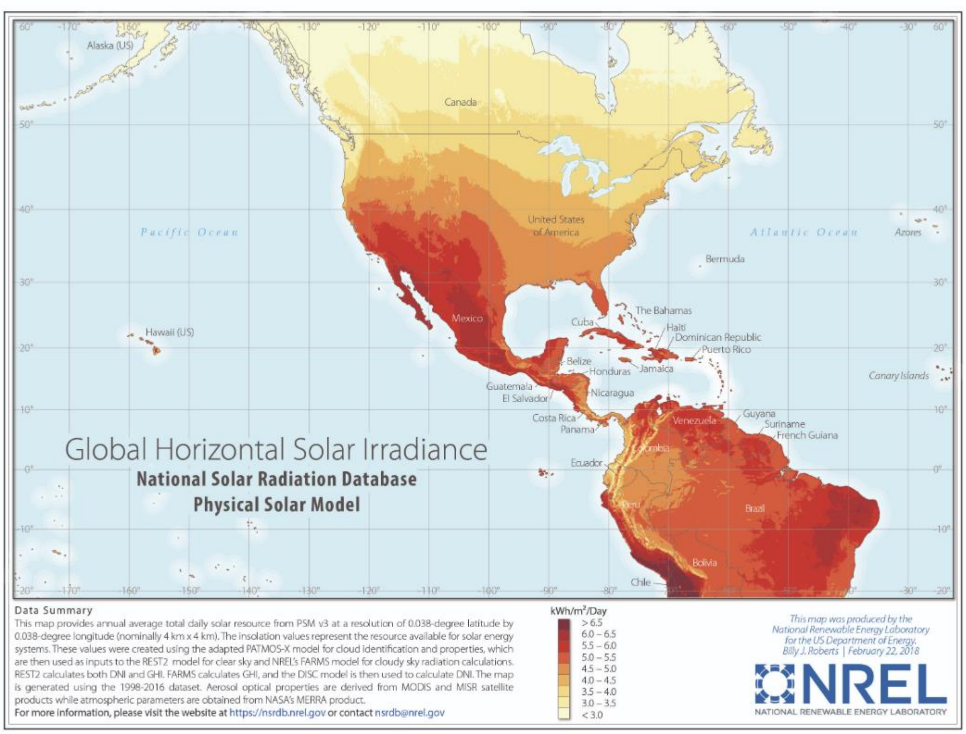


Figure 6: NREL Global Horizontal Solar Irradiance



The three most significant factors that influence a solar PV facility's capacity factor are: local solar resource (which varies by region); DC/AC ratio, defined as the aggregate direct current nameplate capacity of the solar PV modules divided by the AC nameplate rating of the inverter; and mounting method. Here are a few key facts to ground this feedback:

- Projects located in Zones A-F have lower capacity factors relative to Zones G-K due to the lesser solar resource/irradiance in northern latitudes vs southern latitudes.
- Projects with trackers have a higher capacity factor than fixed-tilt projects.
- Projects with higher DC/AC ratios tend to have a higher capacity factor due to the increased DC nameplate capacity, which allows the systems to generate more power during "shoulder hours", i.e. times that the inverters are not saturated/clipping.

The appraisal model is highly sensitive to capacity factor, as this value determines estimated energy yield and gross revenue. As such, it is critical for the model to include realistic capacity factors. This can be accomplished by incorporating accurate baseline capacity factor estimates by NYISO Zone and Plant Type. Another accuracy improvement we recommend is adjusting project-specific capacity factor based on the DC/AC Ratio. This could be accomplished by prompting users to enter both DC and AC nameplate capacity, which could then be used to calculate the project-specific DC/AC Ratio to adjust a default capacity factor for a given Plant Type in a given NYISO Zone.

Example:

NYISO Zone	***Plant Type***	***Default DC/AC Ratio***	***Default Capacity Factor***
Q	*Fixed-Tilt*	*1.5*	*18%*

Project-specific DC/AC ratio: 1.4

*Dynamically calculated project-specific capacity factor: 18% * (1.4/1.5) = 16.8%*

Calculating Accurate Default Capacity Factors by NYISO Zone and Project Type

The Parties estimated default capacity factors for fixed-tilt and single-axis tracking systems in each load zone using the National Renewable Energy Laboratory's (NREL) PVWatts PV simulation software. PVWatts is a reputable, opensource PV simulation tool that relies upon data from the National Solar Radiation Database and models PV energy yield based on a Typical Meteorological Year; an hourly data that best represents median weather conditions over a multiyear period. We completed this exercise for a 5 MW-AC project with a 1.5 DC/AC ratio. In the case of fixed-tilt systems, the tilt was set to 15 degrees. With this exception, default values were used for all other inputs *(see figure 7)*.

Figure 7: Step 1 Requested DCF Model Capacity Factors by Valuation Group and Zone

Valuation Group	Valuation Group	NYISO Zone	Group-Zone	CapFactor	**PVWatts**	**Delta**
1	Solar Fixed - VDER	A	1A	0.1911	**0.1735**	-9.2%
1	Solar Fixed - VDER	B	1B	0.1911	**0.1740**	-8.9%
1	Solar Fixed - VDER	C	1C	0.1860	**0.1763**	-5.2%
1	Solar Fixed - VDER	D	1D	0.1952	**0.1761**	-9.8%
1	Solar Fixed - VDER	E	1E	0.1952	**0.1728**	-11.5%
1	Solar Fixed - VDER	F	1F	0.1952	**0.1818**	-6.8%
1	Solar Fixed - VDER	G	1G	0.1952	**0.1791**	-8.2%
1	Solar Fixed - VDER	H	1H	0.1952	**0.1913**	-2.0%
1	Solar Fixed - VDER	I	1I	0.1952	**0.1913**	-2.0%
1	Solar Fixed - VDER	J	1J	0.1952	**0.1936**	-0.8%
1	Solar Fixed - VDER	K	1K	0.1952	**0.1939**	-0.6%
2	Solar Tracking - VDER	A	2A	0.2334	**0.2102**	-9.9%
2	Solar Tracking - VDER	B	2B	0.2399	**0.2107**	-12.2%
2	Solar Tracking - VDER	C	2C	0.2246	**0.2132**	-5.1%
2	Solar Tracking - VDER	D	2D	0.2210	**0.2167**	-1.9%
2	Solar Tracking - VDER	E	2E	0.2210	**0.2116**	-4.2%
2	Solar Tracking - VDER	F	2F	0.2235	**0.2227**	-0.3%
2	Solar Tracking - VDER	G	2G	0.2100	**0.2188**	4.2%
2	Solar Tracking - VDER	H	2H	0.2100	**0.2334**	11.1%
2	Solar Tracking - VDER	I	2I	0.2100	**0.2334**	11.1%
2	Solar Tracking - VDER	J	2J	0.2100	**0.2361**	12.4%
2	Solar Tracking - VDER	K	2K	0.2100	**0.2350**	11.9%

The results deviated from the draft 2024 model by -12.2% to +12.4%. In general, we believe that the DTF model significantly overestimates Upstate capacity factors and underestimates Downstate capacity factors. The PVWatts values calculated by The Parties, included in the table above, are more accurate than those included in the draft model, although may be an overestimation of production in many cases. The PVWatts capacity factor estimates represent the P50 values, or the median capacity factor estimate. Recent research and analysis of empirical PV system performance conducted by DNV GL found that that large solar projects tended to underperform by **6.3%** vs the P50 estimate, even after adjusting for weather[6], leading the authors to conclude that P90 estimates are likely more appropriate for valuing PV assets. Therefore, we recommend using the below values to estimate Year One Capacity Factor in the model. As discussed above, we also recommend that these values be dynamically adjusted based on DC/AC ratio (calculated from user-defined DC and AC nameplate capacity), whereby DC/AC ratios higher than the default value increase capacity factor and DC/AC ratios below decrease capacity factor *(see figure 8)*.

[6] https://www.projectfinance.law/publications/2020/october/overestimation-of-solar-output/.

Figure 8: Final Requested PV Capacity Factors by Valuation Group and Zone

Valuation Group	Valuation Group	NYISO Zone	Group-Zone	CapFactor	**PVWatts (adjusted)**	**Delta**
1	Solar Fixed - VDER	A	1A	0.1911	**0.1626**	-14.9%
1	Solar Fixed - VDER	B	1B	0.1911	**0.1630**	-14.7%
1	Solar Fixed - VDER	C	1C	0.1860	**0.1652**	-11.2%
1	Solar Fixed - VDER	D	1D	0.1952	**0.1650**	-15.4%
1	Solar Fixed - VDER	E	1E	0.1952	**0.1619**	-17.0%
1	Solar Fixed - VDER	F	1F	0.1952	**0.1703**	-12.7%
1	Solar Fixed - VDER	G	1G	0.1952	**0.1678**	-14.0%
1	Solar Fixed - VDER	H	1H	0.1952	**0.1792**	-8.1%
1	Solar Fixed - VDER	I	1I	0.1952	**0.1792**	-8.1%
1	Solar Fixed - VDER	J	1J	0.1952	**0.1814**	-7.0%
1	Solar Fixed - VDER	K	1K	0.1952	**0.1817**	-6.9%
2	Solar Tracking - VDER	A	2A	0.2334	**0.1970**	-15.6%
2	Solar Tracking - VDER	B	2B	0.2399	**0.1974**	-17.7%
2	Solar Tracking - VDER	C	2C	0.2246	**0.1998**	-11.0%
2	Solar Tracking - VDER	D	2D	0.2210	**0.2030**	-8.1%
2	Solar Tracking - VDER	E	2E	0.2210	**0.1983**	-10.3%
2	Solar Tracking - VDER	F	2F	0.2235	**0.2087**	-6.6%
2	Solar Tracking - VDER	G	2G	0.2100	**0.2050**	-2.4%
2	Solar Tracking - VDER	H	2H	0.2100	**0.2187**	4.1%
2	Solar Tracking - VDER	I	2I	0.2100	**0.2187**	4.1%
2	Solar Tracking - VDER	J	2J	0.2100	**0.2212**	5.4%
2	Solar Tracking - VDER	K	2K	0.2100	**0.2202**	4.9%

OPERATING EXPENSES

The updated model includes operating expense estimates that are dramatically lower than the 2022 model. Significant reductions to expenses are not directionally correct considering the impact of inflation and rising labor costs since the prior model was published. The updated model also includes smaller inconsistencies. For example, the O&M costs for systems with trackers appear to be lower than O&M costs for fixed tilt systems. However, systems with trackers have more moving parts and complexity; if anything, the tracker systems should have a higher O&M cost estimate.

Subscriber Management Fees for Community Solar Projects

A major area of concern regarding expenses is that the projected O&M expenses for solar projects may be significantly understated due to the omission of subscriber management cost. ACE NY and NYSEIA recommend the Department consider using the National Renewable Energy Laboratory's recently published U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks, With Minimum Sustainable Price Analysis: Q1 2023.[7] This publication includes estimated O&M costs for community solar projects. NREL's modeled O&M costs are $39.83/kW-DC/yr. While these cost estimates are inclusive of inverter replacement and property taxes, items that are disaggregated in the draft 2024 model, one

[7] National Renewable Energy Laboratory, [U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks, With Minimum Sustainable Price Analysis: Q1 2023 (nrel.gov)]

important observation in NREL's report is that the community solar O&M cost is higher because of the community solar subscriber management cost, which accounts for approximately 40% of the total community solar O&M cost. Subscriber management costs are omitted from the DTF 2024 model, and we recommend that this cost be added for VDER projects at a rate of $15.93/kW-DC/year.

Host Community Agreements

The Parties have previously commented on the issue of omitting costs specific to projects in the state of New York, namely Host Community Agreement payments. These payments are commonly made by solar projects and are a significant cost item omitted from the Department's model. We recommend either: (1) Adding a fixed cost of $3/KW of installed capacity subject to annual inflationary increases or (2) allowing each project to submit their modeled HCA payments. Omitting these costs has the potential to significantly overestimate the value of projects in New York.

TAXABLE STATUS YEAR

The model should be modified to allow users to accurately model projects that are under development and have an expected "Start Date of Plant Operation" date in the future.

It is common for a solar developer and a municipality to negotiate a PILOT agreement 1-2 years before a solar energy system or wind farm is expected to be operational. The model allows users to specify a future Start Date of Plant Operation, however, when a user makes this selection, the model provides an error stating that "Tax Status year cannot be before Date of Operation" and the model does not function. The user is not able to modify the Taxable Status Year to align with the Start Date of Plant Operation.

Addressing this issue is important because the model includes assumptions regarding the price of energy that change over time. If the model assumes that a plant will be operational during a different time window than the parties truly expect the plant to operate, this could result in a material underestimation or overestimation of the value of the energy generated, depending upon the energy price assumptions included in the model.

FRACTION OF OFF-TAKER CREDITS TO OWNER

The 95% assumption for VDER projects is not realistic in most cases. The majority of VDER projects participate in New York's community distributed generation (community solar) programs. Under New York's community solar Net Crediting program, solar providers are required to offer a customer saving rate of *at least* 5%, although it is common for projects to offer higher customer saving rates, especially projects that participate in New York's growing low-income community solar programs. Additionally, New York's utility companies are entitled to a 1% administrative fee, which directly reduces VDER revenue to the owner. For most projects, 94% of the value of credits allocated to mass market customers is the absolute maximum fraction of off-taker credits to the owner. However, in practice the true fraction is typically lower.

In June 2023, NYSERDA and the Department of Public Service (DPS) filed their proposal for Statewide Solar for All (SSFA), a proposed low-income solar program that would be available to VDER projects across the state. In January 2024, NYSERDA and DPS filed an even more detailed proposal requesting the Public Service Commission to authorize SSFA with a customer savings rate between 10-20%.

In addition to incorporating a more realistic customer savings rate, the model should account for cases of customer nonpayment. The model assumes that customers will issue payment on-time 100% of the time for NEM, Remote Crediting and Community Solar projects. ACE NY and NYSEIA recommend a modest default/nonpayment assumption (e.g. 2%) to account for customers who move, default or otherwise don't pay the totality of their bill. Revenue projections are commonly discounted by financiers who are conducting valuation analysis of projects, and we recommend that the DTF model do the same.

We recommend that the model set 90% as a default Fraction of Off-taker Credits to Owner value, which is in better alignment with New York's current and proposed VDER programs.

ECONOMIC LIFE

The definition of economic life is, "*the period of time, usually stated in number of years, that a new property can be used before it would benefit the owner to replace it with the most economical replacement property that could perform an equivalent service. . . an asset's economic life will often be less than its normal useful life.*"[8]

The Department uses a 25-year period as "economic life", for both wind and solar projects. While the Organization recognizes this may be typical warrantied period and potential physical life of a renewable energy asset, there are several essential considerations when determining the *economic* life of a renewable energy project:

- Typical Power Purchase Agreement ("PPA") length
- Typical re-powering time frame
- Trends in installation costs
- Trends in federal incentives

Examining the available data from S&P Capital IQ, PPA's in NY ranged from 15-25 years with a typical PPA of approximately 20 years. For PPA's signed for wind energy projects a PPA is exclusively 20 years *(see figure 9).* 15-25 years is the typical range of PPA terms across the U.S.[9], although more recently terms may be as low as 10 years as renewable energy producers and capital markets are bullish on the

[8] ASA Valuing Machinery and equipment 4th Edition, P. 53
[9] Windustry, https://www.windustry.org/community_wind_toolbox_13_power_purchase_agreement

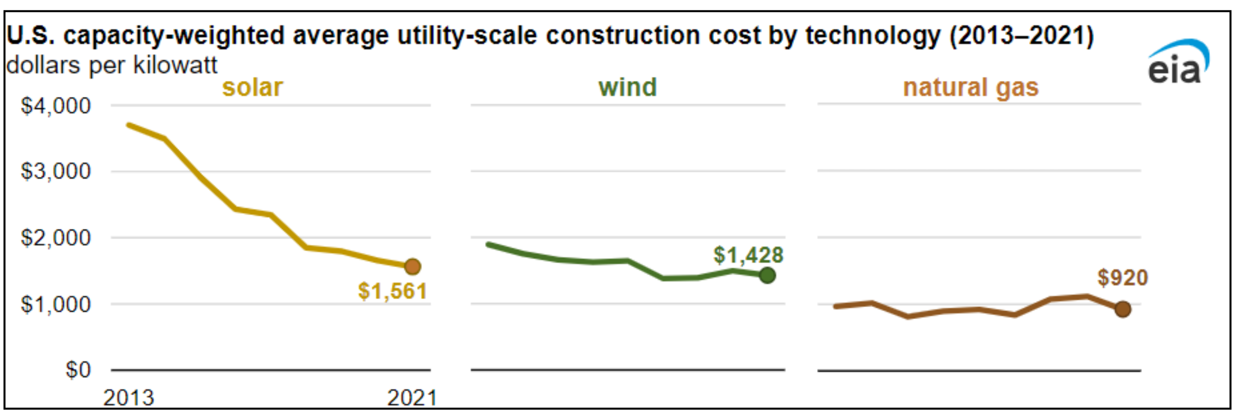
price of electricity and government incentives increasing with time.[10] The inflation reduction act was signed into law in 2022, re-incentivizing renewable energy projects. The IRA reducing levelized cost of energy ("LCOE") and incentivizing repowers from older projects will further reduce economic life as increased power supply may reduce the long-term economics of projects.[11]

Figure 9: PPA Length for Wind Projects in NY

Tech Type	Year in Service	PPA Length
Wind Turbine	2018	20
Wind Turbine	2021	20
Wind Turbine	2023	20
Wind Turbine Total		**20**

In 2021, turbines involved in partial repowers ranged in age from 9 to 16 years old and had a median age of 10 years.[12] The average age of the US wind farms subject to partial repowering in 2020 was just 12 years.[13] The IRA and advances in technology have resulted in significant decreases in installed costs for wind and solar energy, especially for solar assets *(see figure 10).* Advances reducing installed costs and improving technology, like capacity factors, can dramatically reduce the economic life of a project.

Figure 10: Wind and Solar installed cost trends



As potential curtailment looms, a solution available to many wind and solar operators is battery storage. Battery storage represents an additional capital cost that may extend the economics of solar and wind

[10] Types of Power Purchase Agreements for Renewable Energy, February 27, 2023 https://www.landgate.com/news/types-of-power-purchase-agreements-ppas-for-renewable-energy
[11] Energy Information Administration, https://www.eia.gov/outlooks/aeo/electricity_generation/pdf/AEO2023_LCOE_report.pdf
[12] Wiser, R., Bolinger, M., Hoen, B., Millstein, D., Rand, J., Barbose, G., Darghouth, N., Gorman, W., Jeong, S., and Paulos, B. *Land-Based Wind Market Report: 2022 Edition*. Oak Ridge, Tennessee: U.S. Department of Energy. https://www.energy.gov/sites/default/files/2022-08/land_based_wind_market_report_2202.pdf
[13] Wind Power Monthly, https://www.windpowermonthly.com/article/1735687/why-repowering-key-wind-power-industrys-

assets, but at a substantial <u>cost to cure.</u> This cost to cure must be accounted for when quantifying the economic life of an asset.

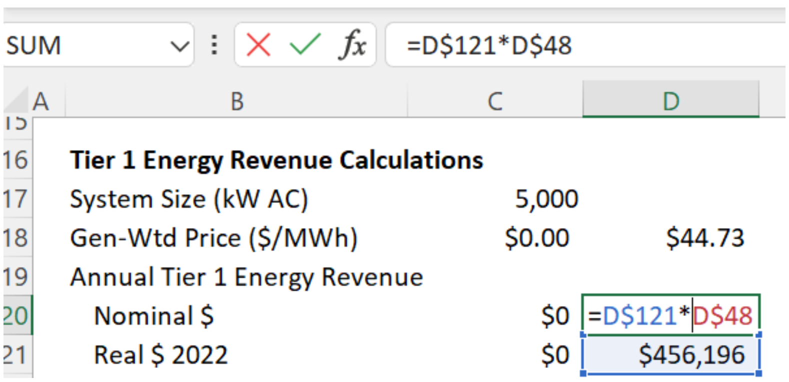
Examining PPA length, history of repowers, trends in federal incentives, projected curtailments, and changes in technology, the Parties request a maximum of **20-year life** updated in the inputs section for wind projects.

CAPITALIZATION RATE

Real vs. Nominal Discount Rates

Reviewing the model, the Department is trending forecasted revenue in a nominal scenario up at a rate of *inflation (see figure 11)*.

Figure 11: Excel Formula for Tier 1 Energy Revenue Calculation from Unlocked Draft Model



Price forecasts are not deflated on the price forecasts tab or in the revenue projections tab. It is typical for price forecasts to be completed in nominal dollars. By increasing the Nominal dollar revenue projection at the rate of inflation, the department is double counting growth. Further, if applying a Real dollar rate to the energy projections there should be a subject *deflation*.

In general, application of a nominal rate is the preferred method of investors. It is simpler to calculate and avoids numerous potential errors, such as the one mentioned above. We recommend removing the Real rate and method from the model and setting the default method to nominal, corrected to show accurate revenue forecasts in the nominal scenario as "*power price X growth*", rather than, "*power price X growth X inflation*".

Capitalization Rate Source

In addition to the challenges of application, the Department's cost of capital is too low considering recent changes to the risk-free rate as the U.S. Department of Treasury attempts to curb inflation.

The Department's source for cost of capital appears to be the NREL. In 2021 NREL did a comprehensive study to determine the cost of capital for renewable energy projects; however, the 2023 update includes a 1% bump to the cost of equity, without significant support or review. This oversimplifies the changes in capital markets that have occurred from 2021 to the present. As of January 2021, the 20-year treasury bond yield was 1.46%, while the 20-year Treasury bond had increased to 4.25% as of January 2024.[14] These changes have significant impacts on the cost of capital that are not accounted for by the NREL update.

Proposed Modifications to Capitalization Rate

The Parties have examined the Department's proposed Pre-Tax WACC for Wind and Solar as compared to California Modern Electric Generation Rate and the Colorado Independent Power Producer rate published in their 2023 Capitalization Rate studies. We recognize these are not renewable energy specific capitalization rates; however, examining the guideline companies within these studies, several companies hold regulated entities that reduce their overall risk. The Parties believe the guideline companies holdings may result in an understatement of the applicable discount rate for renewable energy projects *(see figure 12).*

Figure 12: WACC Review and Proposed Adjustment

	CA	CO	DTF Wind	DTF Solar
Equity %	65%	60%	52%	49%
Debt %	35%	40%	48%	51%
Cost of Equity*	11.33%	11.50%	10.00%	8.80%
Pre-Tax Cost of Equity*	15.10%	15.33%	13.65%	12.01%
Debt Return	7.87%	6.50%	6.80%	6.80%
WACC	12.57%	11.80%	10.38%	9.35%
**CO Cost of Equity is post tax and CA pre-tax, converted at an assumed rate of 26.75%*				

Using similar methodologies as CA and CO, the Organization has quantified a pre-tax cost of equity and capital structure. Guideline companies and capital structure are listed below *(see figure 13 & 14).* Inserting the pre-tax cost of equity and capital structure and conservatively retaining the debt rate from the Department's cost of debt, we have concluded a 1/1/2024 WACC of **13.19%** *(see figure 15).*

[14] Treasury Yield Rates https://home.treasury.gov/resource-center/data-chart-center/interest-rates/TextView?type=daily_treasury_yield_curve&field_tdr_date_value=2024

Figure 13: Guideline Companies and Capital Structure

Company Name	Stock Price as of 12/29/23 per ValueLine	Current % Equity	Current % Debt	Value Line Adjusted Beta
AES Corp.	$19.25	39%	61%	1.15
Exelon Corp.	$35.90	50%	50%	NA
NextEra Energy	$60.74	69%	31%	1
NRG Energy	$51.70	60%	40%	1.1
Southern Co.	$70.12	60%	40%	0.95
Vistra Corp.	$38.52	56%	44%	1.05
	Weighted Average	**60%**	**40%**	
	Median	**58%**	**42%**	**1.05**
		60%	**40%**	**1.05**

Figure 14: Pre-Tax Cost of Equity

Beta	1.05	*ValueLine Guideline Companies*
Risk-Free Rate	4.25%	*1/3/2024 Daily Treasury Par Yield Curves*
Equity Risk Premium	7.17%	*Kroll Cost of Capital Navigator Long-Term Supply Side*
Cost of Equity	11.78%	
Renewable Specific Risk	1.00%	*Adder to reflect impact of regulated entities on beta*
Total Cost of Equity	12.78%	
Pre-Tax Cost of Equity	**17.45%**	*Quantified using tax rate of 26.75%*

Figure 15: Proposed Pre-Tax Nominal Cost of Capital

Source of Capital	Capital Structure	Cost of Capital	Weighted Cost
EQUITY	**60.00%**	**17.45%**	**10.47%**
DEBT	**40.00%**	**6.80%**	**2.72%**
TOTAL	**100.00%**		**13.19%**

The Parties recognize the requested capitalization rate is a significant increase from the previously proposed rates and a moderate increase above CA and CO 2023 rates. Reviewing the risk to renewable projects as compared to the guideline companies, and the need to update the NREL study to better reflect changes in capital markets, we believe the request above is fully supported.

USER INTERFACE ADJUSTMENTS AND REVIEW PROCESS IMPROVEMENTS

We strongly recommend that the new model revert to the industry-standard “nominal” view. The draft model resulted in significant user confusion, as the new model shows discounted cash flows in inflation adjusted “real” dollars, whereas the prior model defaulted to “nominal” view. The nominal view is more common, more intuitive and is strongly recommended.

We also recommend defaulting the MTC and CC values to zero for VDER projects; the Community Credit and Market Transition Credit expired years ago, and projects with MTC or CC allocations are increasingly rare.

Finally, we respectfully recommend that, in future years, a change log and sources documentation be provided along with the revised model when it is made available for public comment. Providing transparency into the datasets and assumption utilized will eliminate confusion and result in clearer and more concise feedback in future iterations of the model.

CONCLUSION

Providing a stable, accurate appraisal model for wind and solar projects supports clean energy deployment and provides a critical shared understanding for New York’s clean energy industry, host communities and appraisers. The draft 2024 model deviates dramatically from the prior model, and contains several material inaccuracies noted in this memorandum. If the draft 2024 model is adopted without modification, it will impede clean energy project deployment, undermine legislative intent and have a detrimental impact on all stakeholders. ACE NY and NYSEIA encourage DTF to incorporate the recommendations detailed in this memorandum and summarized below before the model is finalized and adopted:

- Revise capacity factors as illustrated in figures 3 & 8.
- Gather DC nameplate capacity as a user-input to account for DC/AC ratio and more accurately model PV capacity factor.
- Add HCA expenses at $3/kw/year of installed capacity subject to annual inflationary increases as detailed in section 2.
- Add $15.93/kW-DC/year of variable expense for community solar as detailed in section 2.
- Revise economic life projection to 20 years for wind.
- Use exclusively nominal model.
- Revise forecast revenue to remove the inflation growth in the nominal model.
- Revise nominal capitalization rate to 13.19%.
- Default the MTC and CC values to zero for VDER projects.

- Publish documentation for all assumptions in the model.

ACE NY and NYSEIA appreciate the opportunity to provide input on this critical topic. Please advise if any additional details are needed, and we thank you for your consideration.

Thank you for your consideration of our request.

Sincerely,

/s/ Deb Peck Kelleher
Deb Peck Kelleher
Interim Executive Director
Alliance for Clean Energy New York

/s/ Noah Ginsburg
Noah Ginsburg
Executive Director
New York Solar Energy Industries Association