STANDARDIZED INPUTS FOR COST-BENEFIT ANALYSIS

This document describes the background and creation of standardized inputs for applicants to use in applying to sell Offshore Wind RECs (ORECs) to the State. These inputs and methods apply specifically to the cost-benefit analysis that all bidders must submit under N.J.A.C 14:8-6.5.(a).(11).

The goal of these inputs is to provide a common set of methods and assumptions for applicants so that evaluators may review projects on a comparable basis. While the cost-benefit analysis must use these inputs, **bidders may still provide alternative valuations using inputs they feel are reasonable.** Any such analyses should be supported by a detailed description of what was done and work papers that would allow evaluators to reproduce any such analyses.

The price projections are included at the end of this document and will also be available as a separate file on the procurement website.

Energy Revenues

Energy revenues represent a significant but uncertain source of revenue for the project. The process used to create these price estimates is explained below.

- To create an energy price estimate we start with the cost of peak monthly energy futures at PJM's Western Hub from the NYMEX/Clearport exchange.[1] These quotes go out through the end of 2021. The prices for that year (as of August 24, 2018) are shown in Table One below.

- To create monthly off-peak prices we multiply the monthly prices times a historic ratio of on-peak to off-peak prices. The ratio is taken from the New Jersey Electric Distribution Company (EDC) retail rate impact models, posted on the New Jersey Basic Generation Service (BGS) Auction website.[2] These are public and calculated by each EDC based on three years of historical data. These are also shown in the table below, specifically for PSE&G.

[1] https://www.cmegroup.com/trading/energy/electricity/pjm-western-hub-peak-calendar-month-real-time-lmp_quotes_settlements_futures.html#tradeDate=08%2F24%2F2018

[2] http://www.bgs-auction.com/bgs.dataroom.occ.asp. See the "BGS RSCP Pricing Factors" models.

- This gives us a set of peak and off-peak prices at PJM's Western Hub (in western Pennsylvania). To create estimates for New Jersey we multiply these prices times the historic differential between the Western Hub and a specific EDC's zone. Again, these are provided in the EDC rate models, based off of three years of data, and shown below, specifically for PSE&G.

TABLE ONE
ENERGY PRICE BUILDUP

Month	Peak Western Hub Price ($/MWh)[1]	On/Off-Peak Ratio[2]	Off-Peak Western Hub Price ($/MWh)	Hub to Zone Ratio (On Peak)[2]	Hub to Zone Ratio (Off Peak)[2]	Final PSE&G On-Peak Price	Final PSE&G Off-Peak Price
21-Jan	$ 46.73	0.7756	$ 36.24	95%	95%	$ 44.38	$ 34.37
21-Feb	$ 43.95	0.7756	$ 34.09	95%	95%	$ 41.74	$ 32.33
21-Mar	$ 35.32	0.7756	$ 27.39	95%	95%	$ 33.54	$ 25.98
21-Apr	$ 31.05	0.7756	$ 24.08	95%	95%	$ 29.49	$ 22.84
21-May	$ 30.95	0.7756	$ 24.01	95%	95%	$ 29.39	$ 22.76
21-Jun	$ 30.95	0.6401	$ 19.81	93%	86%	$ 28.83	$ 17.10
21-Jul	$ 37.11	0.6401	$ 23.76	93%	86%	$ 34.56	$ 20.51
21-Aug	$ 33.83	0.6401	$ 21.66	93%	86%	$ 31.51	$ 18.69
21-Sep	$ 30.76	0.6401	$ 19.69	93%	86%	$ 28.65	$ 17.00
21-Oct	$ 28.47	0.7756	$ 22.08	95%	95%	$ 27.04	$ 20.94
21-Nov	$ 28.47	0.7756	$ 22.08	95%	95%	$ 27.04	$ 20.94
21-Dec	$ 31.60	0.7756	$ 24.51	95%	95%	$ 30.01	$ 23.24

1 https://www.cmegroup.com/trading/energy/electricity/pjm-western-hub-peak-calendar-month-real-time-lmp_quotes_settlements_futures.html#tradeDate=08%2F24%2F2018

2 http://www.bgs-auction.com/bgs.dataroom.occ.asp "2019_PSE&G_BGS_RSCP_Rate_Spreadsheet_29_June_2018.xls"")

To project prices farther out we utilize a forecast of price growth. For this, we turn to the latest Annual Energy Outlook (AEO) produced by the US Energy Information Administration (EIA). The 2018 AEO produces a number of projections regarding energy use, prices, capacity, emissions, and other items. For this analysis we can take the projected growth of the nominal cost of generation in the RFC East (Eastern PJM) zone. The current base or "reference" case for the AEO predicts a rate of growth per year for this area from 2017 through 2050.[3] Using this, our forecast escalates each year by the forecast annual growth rate for that specific year.

This forecast is done on an EDC-specific basis and bidders should use the zone of the EDC that they will deliver power to. In other words, if the project is going to connect into Atlantic Electric's territory it should use the on/off peak ratios and hub/zone differentials from Atlantic's models. If the project is connecting into PSE&G's territory it should use PSE&G's inputs. This helps account for the locational difference in market prices.

Net Output

With prices for each month and on and off peak period the bidder should then multiply their projected net output **at the P(50) value** for each on and off-peak period in each month to determine an estimate of energy market revenues. We use P(50) since this is the average output the project could expect over its lifetime.

Capacity Revenues

Ideally, any qualified offshore wind project will sell capacity into PJM's Reliability Pricing Model (RPM) Auction. Prices in that auction vary by year and by location with prices in PSE&G's territory being typically higher than elsewhere. Prices are set for one year three years ahead of time, so it's possible that a project could at least know its first year capacity value and use that value in their analysis. However, prices after that are generally harder to predict as they depend on new entry, plant retirements, PJM estimates of transmission constraints and load growth. Given this complexity we use a simple method using the historical record to set a price for capacity by zone and simply escalating the result by inflation. For example, the average resulting capacity price from the RPM Auction for the past five years in the PSE&G zone is \$188.61/MW-day.[4] For the Atlantic Electric Zone the number is \$165.30/MW-day. For ease of use we round these numbers to \$190/MW-day and \$165/MW-day. Prices for subsequent years are simply escalated out at 2% to reflect inflation.

Another factor with renewable projects in PJM is the quantity of capacity they are allowed to sell. PJM currently measures the capacity contribution of a wind facility by taking their average summer capacity factor over the most recent three years of operation. If no data is available for a given year then the project must use the PJM class average wind capacity factor, which is

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[3] https://www.eia.gov/outlooks/aeo/data/browser/#/?id=62-AEO2018&region=3-9&cases=ref2018&start=2016&end=2050&f=A&linechart=ref2018-d121317a.5-62-AEO2018.3-9&map=&sourcekey=0

[4] This reflects small adjustments for incremental auctions, which take place each year between the initial RPM auction and the delivery year.

currently 17.6%.[5] The bidder should use this method, using the unit's net maximum capacity and assuming the project hits it's P(50) summer capacity factor in each operating year. So a 100 MW project would provide 17.6 MW of capacity the first year. Starting in year four the project's capacity contribution would be 100 MW times the P(50) summer net capacity factor.[6] Just to give a sense of how much this would contribute to project value, at $160/MW-day a 100 MW wind facility with a 30% summer P(50) capacity factor would earn about $6.67/MWh.[7]

Class 1 RECs

Under New Jersey law each OREC is counted as a Class 1 REC, meaning that every OREC purchased is one less Class 1 REC that must be procured. Therefore the avoided cost of Class 1 RECs is a benefit created by the project. To estimate the value of this benefit we start with a value of $13/REC in energy year 2017 (June 2016—May 2017). This is roughly the weighted average price of Class 1 RECs for that time as reported in the EY2018 Compliance presentation.[8] This value is simply escalated by 2% each year as a rough proxy for inflation). So, for example, the Energy year 2022 price would be 13*(1+.02)^5 or $14.35/REC. Bidders should assume their net P(50) output for the purpose of calculating avoided Class 1 REC benefits.

Ancillary Services

No ancillary services revenues be should attributed to the project.

Discount Rate

In assessing the impacts of each project we wish to see the costs and benefits or each project on a net present value basis. For this exercise bidders should calculate costs and benefits be calculated on a nominal basis and discounted using a rate of 7%.

[5] Available at http://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en. This is the factor for wind in "open/flat terrain".

[6] Years 2-3 would be a blended rate. For example, with a 30% P(50) capacity factor, year 2's capacity contribution would be (17.8+17.8+30)/3 or 21.87 MW.

[7] The math here is ($160MW/day*365 days*30 MW)/(8760*.3*100)=$6.67/MWh. If the project were a standard combined cycle it would get credit for a full 100 MW of capacity and earn $22.22/MWh.

[8] Available at http://www.njcleanenergy.com/renewable-energy/program-updates/rps-compliance-reports. The actual value is on slide 7 and is $13.14/REC.