Brigham Young University

2022 Collegiate Wind Competition

Project Development Wind Farm Report

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3. Site Description and Energy Estimation

3.1. Site Selection

Out of the total space available for development, we chose to place our wind farm in BOEM lease blocks 172,173,199, and 200. This lies at approximately (29.14^{o}N, -94.15^{o}E). The site was chosen due to its shallow waters and distance from major shipping lanes. The Galveston coast sits on a gulf shelf which provides a planer and homogenous ocean bed, while the open ocean assures a fairly homogenous wind profile across the lease blocks. This means that neither wind resources nor ocean bed conditions are limiting factors for site selection. Instead, our choice of lease blocks was influenced by ocean shipping lanes. Several major shipping lanes run through this section of the gulf, preventing major development. The chosen blocks consist of the shallowest available region that is not already consumed with commercial activity.

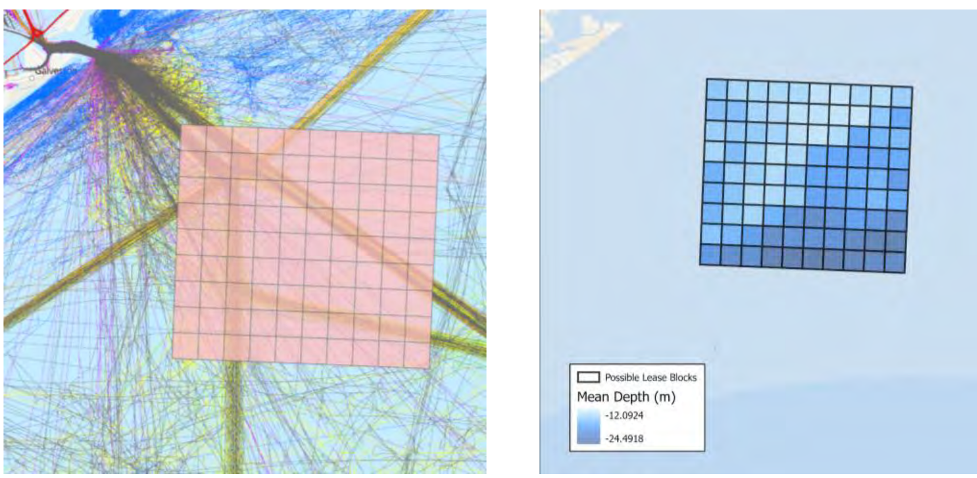

Figure 1 - Side-by-side maps of ocean depth and commercial shipping activities reveal the northeast corner of the leasing area as the most plausible site for a wind farm.

A more detailed description of this process is available in our preliminary design report. The rest of this analysis will address the area's local wind resource, proposed turbine design, and special environmental considerations.

Figure 2 - Development of selected lease blocks. Our site will occupy the red area.

3.2. Wind Resource

While reliable oceanic weather data is scarce and hard to come by, our team was able to find a wind rose of wind resources at 5 m. The magnitude of wind speed across the wind rose was then multiplied by 1.5 in order to estimate the wind resource at a height of 90 m.

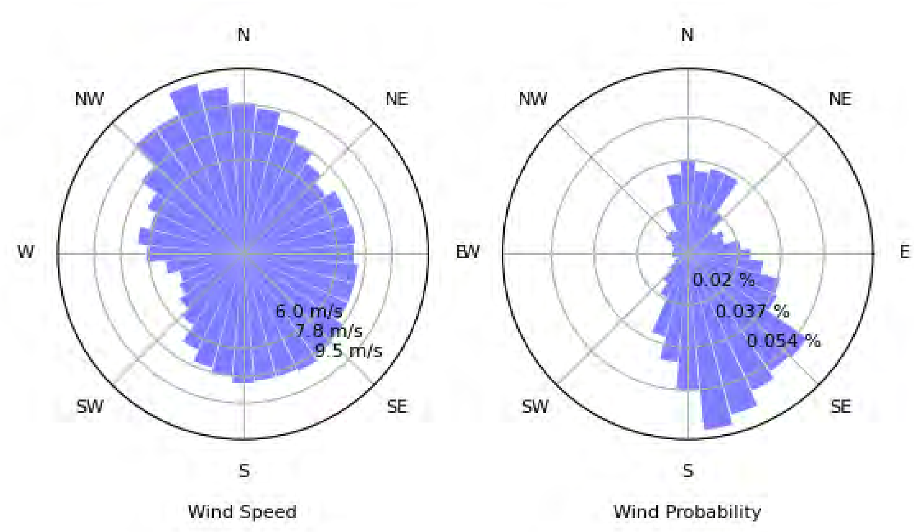

Figure 3 - Wind Rose of our lease block area.

It can be observed from Figure 3 that wind generally travels SSE at a speed of around 8m/s throughout the wind lease blocks.

3.3. Turbine Layout

After site selection, our team chose to determine an optimal layout for the 144 planned wind turbines using a linear optimizer. We arrived at the optimal layout seen in Figure 4.

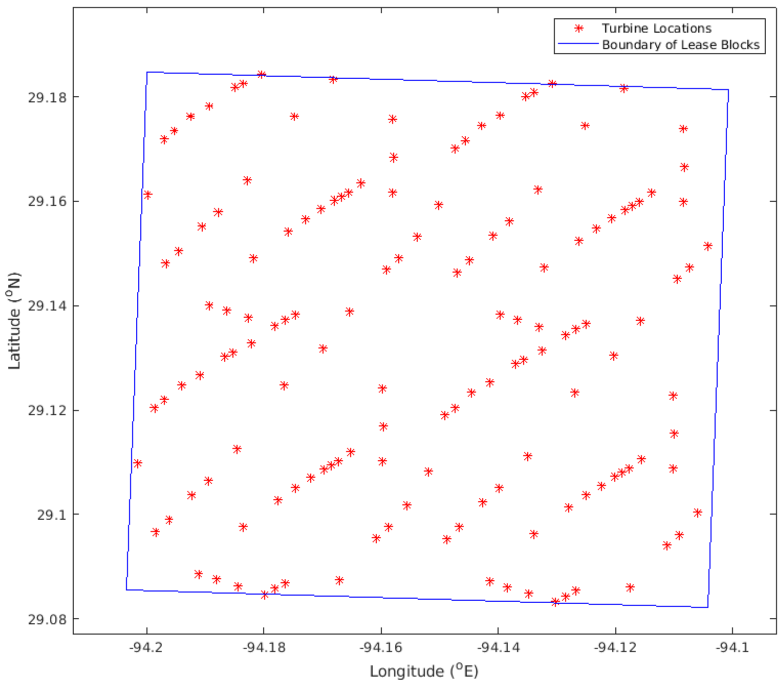

Figure 4 - The projected wind farm layout for lease blocks 172, 173, 199, and 200

This layout consists of several lines of turbines facing perpendicular to the SSE wind direction. Also seen in this layout are a few rows of turbines that face perpendicular to a north by north east vector, correlating to the second most likely wind direction. This is advantageous, as these rows prevent the wakes of the turbines from interfering with the turbines lying downstream. A further description of this layout can be read in the "Optimization" section of the report.

3.4. Turbine Selection

The selected turbine is a Gamesa G128 4.5 MW. The rotor diameter is 128 meters and the hub height is 100 meters. One downside to the chosen turbine is that the power curve peaks between 12 and 18 m/s, which are velocities that are rarely reached in Galveston. This means that the wind turbines will not fully be taken advantage of and will always produce less than the rated power. Instead, they are estimated to produce up to 3.7 MW each.

The foundation design will be a twisted jacket. This is ideal in order to stabilize the turbines during hurricane-type weather, common to the Gulf of Mexico, despite the need to install this foundation 12 meters down from the surface. The greater upfront costs will be worth not paying for damaged foundations or turbines that could not withstand the storm.

There are no sensitive species near the chosen lease blocks and no identifiable bird migration patterns over the Gulf so this wind farm is not expected to endanger any wildlife or plant life. To minimize the noise pollution that might affect any other species in the area, the foundations will be installed after having fluidized the sand with water jets so that the jackets sink faster and quieter. This process is beneficial not only for marine life but will also lower installation times and costs.

4. Optimization Process

4.1. Methods

Due to the basic, convex boundary offered by the offshore lease block, a simple optimization process could be employed. Given the wind area and boundary of our lease block, we chose to use a non-linear, gradient accent based optimizer to determine the optimal layout of wind turbines within the lease block. The optimizer chosen was FLOWFarm, a Julia-based code library pushed through Brigham Young University. The program worked by taking an initial random turbine layout. It would then move or "step" each turbine slightly in the direction that most increased estimated annual energy production (AEP). This process of "stepping" was repeated for either 50 iterations or until the program had reached a local optimum.

It was found while using this stochastic optimizer, that our initial projected size of offshore wind farm was too big for the program to handle. The optimization of 144 separate wind turbines was too large and expended too much computer memory to be properly performed. To solve this problem, the lease block was divided into 4 equally sized circular boundaries, which were sized slightly smaller than the block itself such that no circular area was touching another. Then, we ran an optimization for 36 turbines within one of the circular boundaries and obtained a result. This result was then applied to all 4 circular subsections, assuming that all received approximately the same wind resource. This divide-and-conquer method allowed us to find a locally optimal method of spacing our wind turbines.

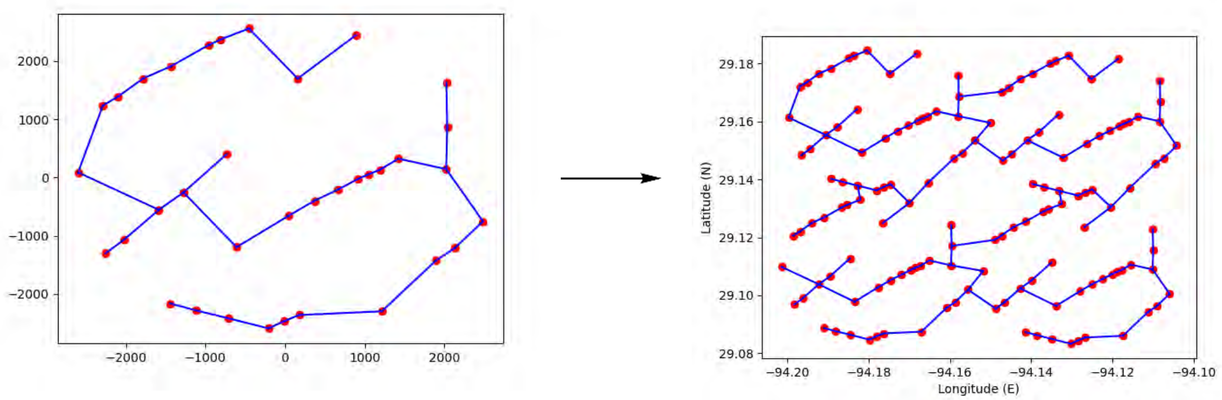

Figure 5 - The lease plot was divided into 4 smaller quadrants of 36 turbines that were optimized, and then combined into the full wind farm.

To optimize infrastructure costs, prim's algorithm was used to find the minimum spanning tree of straight cabling between all of the wind turbines. This algorithm assumed that cable cost could be expressed as a linear relationship, cabling between the turbines would be roughly straight. A cost of $2485.50 per meter was then used to find the minimum cost of cable infrastructure for our optimized layout.

4.2. Results

The final optimal layout reflected a series of approximately straight rows running perpendicular to the direction of greatest wind. This layout fits within 4 lease blocks. The optimizer was able to produce an estimated annual AEP of $1.566\text{x}10^4$ MWh with an estimated cable cost of $209.49 million. However, for purposes of the financial model, only the layout and its cable cost were used in the project's financial analysis. AEP was later estimated using NREL's System Advisor Model (SAM) software.

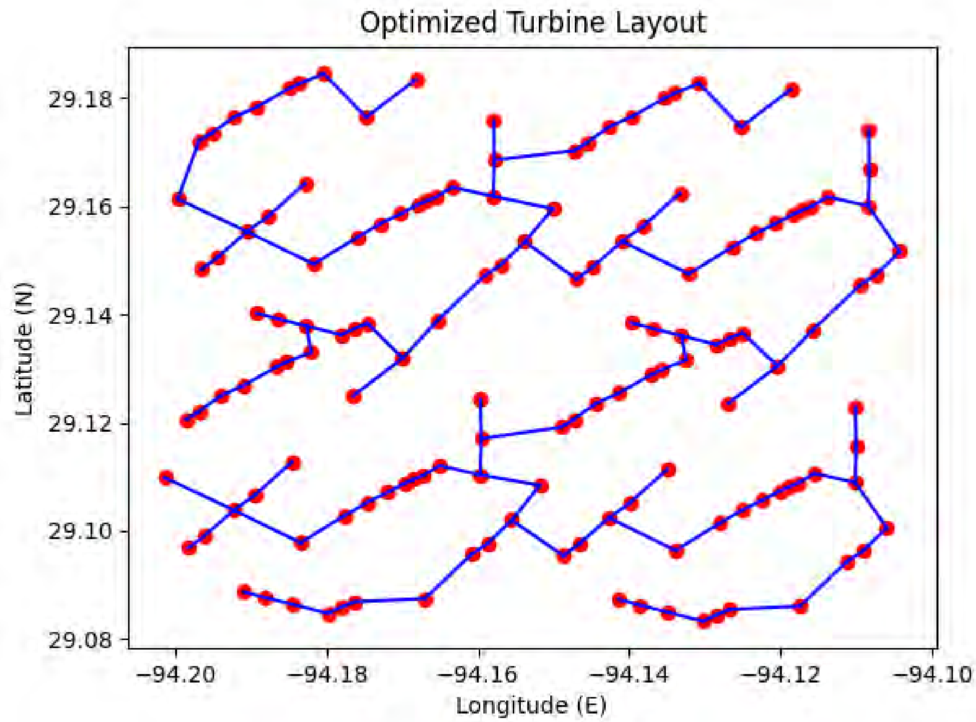

Figure 6 - The final optimized layout of the wind turbines. The red nodes represent an individual wind turbine while the blue lines represent theoretical array cabling.

4.3. Discussion

Upon examination of the optimization, it is clear that there are some shortcomings with the methods we employed. In particular, the divide and conquer method used to find the final layout of the wind farm did not account for how turbine wakes along the edges of each subsection would affect its adjacent subsections. Thus, there may be unwanted interactions between some turbines in the layout. Additionally, gradient accent optimizers can get caught in local optimums, preventing us from obtaining a most perfect wind farm layout. If the wind farm bid were to be accepted, future work might include running a full-scale, 144 turbine optimization on a supercomputer capable of doing the needed computation. Moreover, the optimization could be run several times in order to identify an ideal layout among several local optimums.

Overall, our team is satisfied with the layout. The appearance of rows facing perpendicular to the SSE direction indicates that this layout will allow turbines to turn and generate energy while not creating wakes that could reduce the production capabilities of their neighboring turbines. Additionally, the appearance of rows perpendicular to the NNE directions demonstrates that the farm is capable of efficiently generating energy even when wind is not blowing in the principal direction. This shows that the locally optimal layout we have found is sufficient for our planned offshore wind farm.

5. Financial Analysis

Project financing is a necessity as the path to solvency is important when considering a project of this magnitude. The LCOE of offshore wind farms is substantially higher than that of onshore wind as well as many other competitors with the LCOE averaging somewhere around $95/MWh (1). As the offshore wind is still in its relative nascency, every project developed helps to contribute to lower future potential costs as technology, best practices, and the regulatory landscape improve. With this in mind, it is virtually impossible to quantify the value of these improvements in a meaningful way in any sort of Discounted Cash Flow model. NPV should not be seen as an absolute standard but rather one piece of information to be included in a comprehensive analysis.

As offshore wind has the possibility to play a massive role in the future of renewable energy, many countries have deemed the construction of offshore wind projects today as a necessary cost to achieve their goals of carbon-free/carbon-neutral energy. This can be seen by the Biden Administrations' recent goal of creating 30 Gigawatts of Offshore Wind Energy by 2030 (2). The Utility industry in the United States functions differently than in many other countries but there also have been few offshore wind projects in the United States making it difficult to find accurate comparables both for the capital structure of the project as well as initial outlay projections.

The project that is the furthest along today is the Vineyard wind project and will be used as one example of capital structure and incentive scheme. As the project wind farm is in Texas, it will not have many of the substantial incentives that Vineyard did, but it is still useful to see what would happen with a similar structure in development.

While difficult to calculate with certainty, after adjusting for contract type, transmission, policy, and access to external revenue (tax credits), the Vineyard Wind project has an all-in price of $98/MWh (3). This represents a significantly higher cost of energy than other sources so it is important to keep the above information in mind when considering this.

5.1. Capital Structure

Capital Structure also plays a significant role as the profitability depends largely on the ability of the firm to capture the benefits of the accelerated depreciation and the investment tax credit. If the project is taken strictly by a firm designed for the express purpose of the project, then they will not be able to take full advantage of the tax benefits as they will not be profitable enough to fully utilize them. For this reason, it makes more sense for the project to be taken on by an already profitable firm, likely an energy company as was the case with Vineyard Wind, that can fully capitalize on the benefits, or for the firm taking on the project to look for a tax equity partner who can use the benefits. While the structure of these two outcomes is drastically different, the results for a DCF model are virtually the same.

The amount of debt that should be taken on depends on the existing capital structure of the firm. The firm must weigh the benefits of the tax shield with the increased risk of financial distress that comes with the debt.

5.2. Power Purchase Agreement

One of the most important considerations for the economic feasibility of the project is the Power Purchase Agreement (PPA). The PPA is an agreement between the seller of the energy - the wind farm - and a potential buyer - often a utility. This is a necessity, as the viability of the project can not be evaluated without knowing the future selling price of the energy that will be produced. Our PPA pricing is $72 per MWh, falling within a competitive range for renewable energy while providing sufficient returns to attract investors. The Vineyard Windfarm PPA was struck between Vineyard and the Massachusetts EDC for $74/Mwh for the year 2022 (4). It is likely that the Economic Development Council of Texas or a smaller region of Texas would be willing to institute a similar agreement with our wind farm. We are choosing to do this largely because it is difficult for offshore wind to compete without significant government help and the PPA that was struck with Vineyard would be necessary to facilitate a project of this magnitude.

5.3. Interconnection Site

When considering an interconnection site, two of the most important factors are the distance from the site-as cabling cost represents a significant fixed cost- as well as the capacity of the interconnection site. The maximum capacity of the site must be sufficient to handle the energy production of the wind farm or there will be wasted production. The Electric Reliability Council of Texas (ERCOT) will need to play a critical role in helping to develop the necessary infrastructure to help support offshore wind farms but seems open to this possibility. They recently have been placing a greater emphasis on integrating both solar and wind into the grid and this seems like a natural extension of this. A number of interconnection substations have been proposed by ERCOT with the most promising of these being the South Texas site as it is close and could be modified to have sufficient capacity.

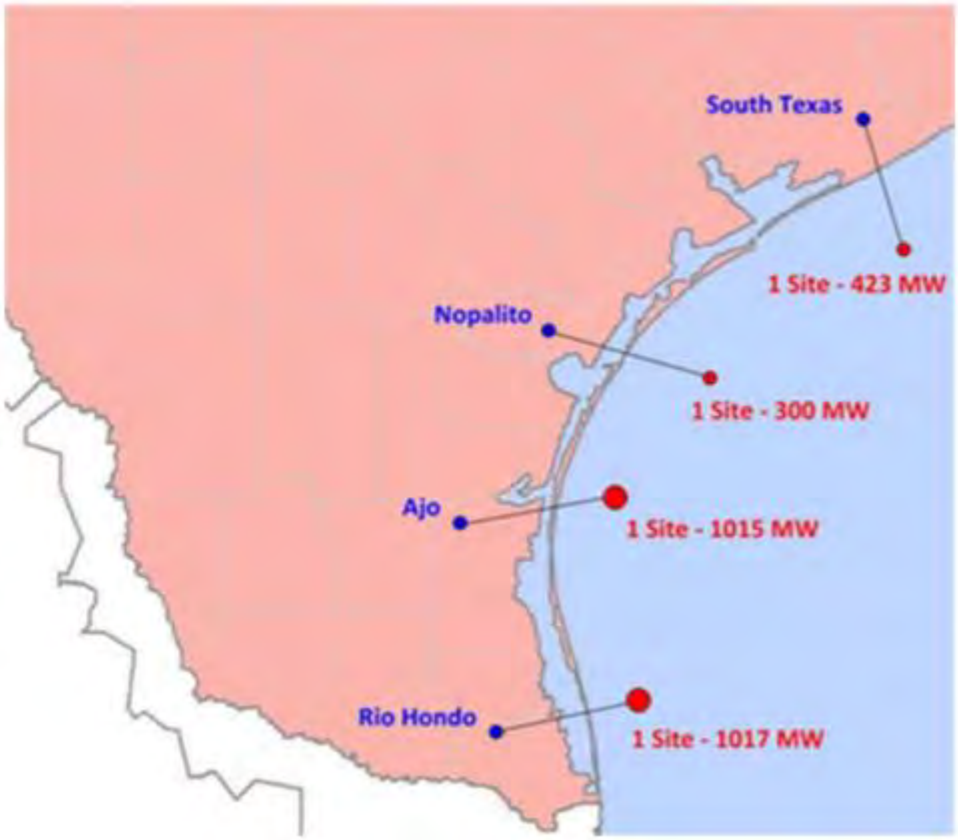

Figure 7 - Grid interconnect site comparison for the Galveston area.

Onshore Substation	Wind Site	Capacity (MW)	Distance (mi)	Delivery System
Nopalito 345 kV	1012	301	45.7	HVAC
Rio Hondo 345 kV	1031	1,017	32.7	HVAC
Tap on 6 lines out of South Texas 345 kV	1010	423	26.2	HVAC
Ajo 345 kV	1008	1,015	42.6	HVAC
Total		**2,755**		**HVAC - 4 HVDC - 0**

Overloaded Element Type	Voltage Level	Wind Output 30% 827 MW	50% 1,378 MW	100% 2,755 MW
Transmission line	345 kV			1
	138 kV	2	3	12
Transformer	345 kV/138 kV			2

Figure 8 - Table of grid interconnect site capabilities comparison.

5.4. Path to Solvency

The overall project will render the tax equity investor a net present value (NPV) of $35.1 million dollars and an IRR of 12.08% at the end of the project. We see a NPV return of $89.7 million at the end of the project. During years 16 and 17 of the project lifespan, our after-tax cash flow results in -$12,349 and -$532,170 respectively. This negative return is attributed to our final debt servicing and federal tax liabilities combining against and surpassing the EBIT amount. After our debt is serviced, our after-tax cash flows pick up to the 20 million range. The small losses we suffered during those years is insufficient relative to our overall project NPV.

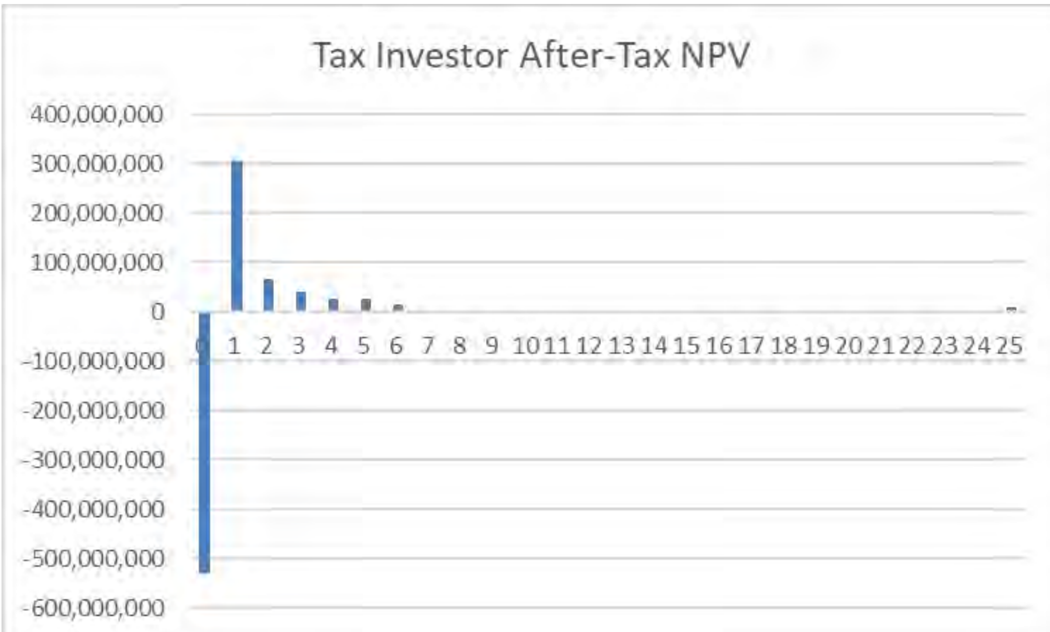

Figure 9 - Tax Investor After-Tax NPV. Y-axis: dollar amount, X-axis: years.

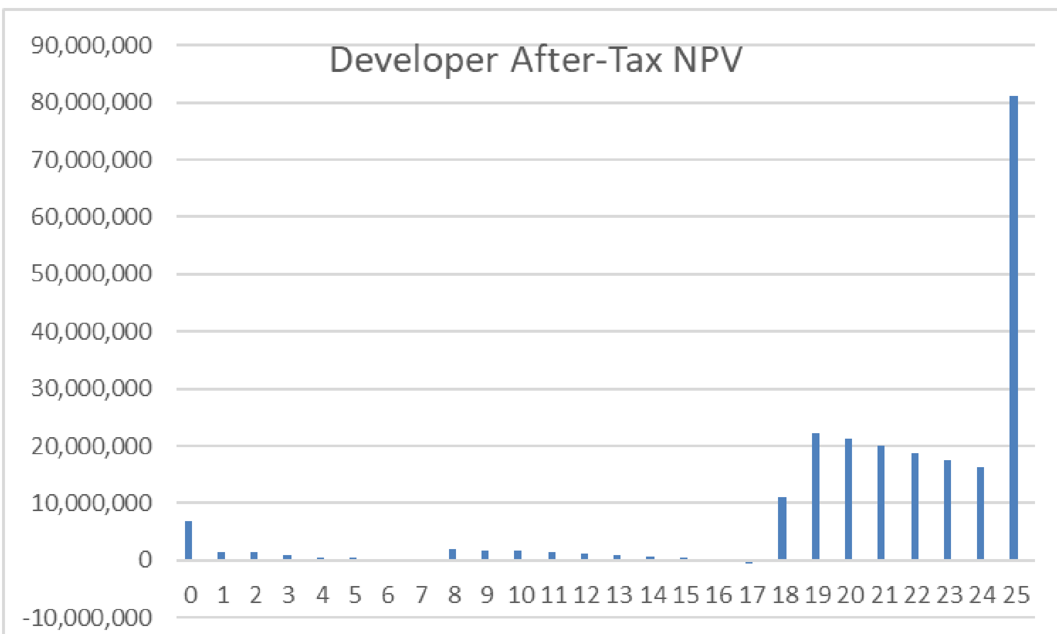

Figure 10 - Developer After-Tax NPV. Y-axis: dollar amount, X-axis: years.

On our path to solvency, we explored incentives and used both a Federal Production Tax Credit of $0.015 per KWh for the first 10 years of the project and a 30% Federal Investment

Tax Credit. These incentives provided the means to capture positive NPV and obtain returns making the development worthwhile. For example, year 10 rendered a Federal PTC amount of $34.8 million dollars, allowing a cumulative, project after-tax IRR of 14.6%. A project of this cost and scale would not be undertaken without compensation through decent returns. The government incentives allow the industry to progress and renewable energy to exist when in other circumstances these projects would fail economically.

5.5. Balance of Station Element Costs

There are a number of different ways to evaluate the Balance of Station Element Cost, we used SAM software to do all of our calculations and came to the following results.

Year	1	10	20
OPERATING EXPENSES			
O&M capacity-based expense ($)	$ 66,744,000.00	$ 83,354,112.00	$ 106,700,304.00
Insurance expense ($)	$ 12,419,568.00	$ 15,510,339.00	$ 19,854,544.00
Total operating expenses ($)	$ 79,163,568.00	$ 98,864,448.00	$ 126,554,856.00

Figure 11 - Balance of Station Element Costs

SAM used a capacity-based costing system to estimate Operating Expenses which scaled up over time. The numbers fall slightly above industry averages according to the offshore wind market report which provides us with some margin of safety.

5.6. Return Metrics

There are a number of return metrics that can be utilized in order to demonstrate the financial viability of the project. These primary two are Net Present Value (NPV) which presents the value of all future cash flows discounted back to present dollar terms and Internal Rate of Return (IRR) which shows the discount rate that would result in the project breaking even. A project that is NPV positive should be accepted and a project that has an IRR above the hurdle rate should also be undertaken. The following data shows many industry-specific metrics but both the NPV and IRR metrics suppress the industry-accepted guidelines. In addition, the LCOE metrics are in line with industry averages but could be lowered as technology and best practices improve.

Metric	Value
Net electricity to grid (year 1)	1,833,679,488 kWh
Capacity	648,000 kW
Capacity factor (year 1)	32.3%
PPA price (year 1)	7.20 ¢/kWh
PPA price escalation	1.00 %/year
Levelized PPA price (nominal)	7.80 ¢/kWh
Levelized PPA price (real)	6.19 ¢/kWh
Levelized COE (nominal)	7.18 ¢/kWh
Levelized COE (real)	5.70 ¢/kWh
Investor IRR in flip year	11.51 %
Flip year	7
Investor IRR at end of project	12.08 %
Investor NPV over project life	$35,052,784
Developer IRR at end of project	NaN
Developer NPV over project life	$89,705,872
Net capital cost	$994,587,776
Equity	$542,328,704
Debt	$452,259,040
Debt Percent	45.47%

Figure 12 - Return Metrics

5.7. Auction Bid

As opposed to many types of auctions where companies bid on the land, many energy contracts operate differently where a PPA is struck for a certain price and quantity of energy, and the land is given as part of this contract. With this and the current incentive structure in mind, we would require a PPA price of at least $.072 KWh in order to generate a significant return that also compensates investors for the systematic risk of the project. This is in line with other previous wind farms and does not seem out of the question in any way. The other method would be to find a reasonable IRR and then work into the maximum bid price that the company would be willing to pay. Considerations should also be taken depending on the auction structure as different types of auctions necessitate different methods.

6. References

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