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MEASURING RENEWABLE ENERGY AS BASELOAD POWER

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Table of Contents

Table of Figures

Executive Summary

- The all-in costs of generating baseload energy from solar and wind must include the full costs of back-up power and associated extra modifications to Transmission/Distribution.

- On this basis, the all-in costs of baseload renewable energy are substantially higher than the LCOE reported in many studies today.

- The greatest challenge for providing baseload power with solely renewable energy is its inability to match the reliability and service factors of conventional fuel-fire plants, which operate, on average, at 85% capacity. This means configuring baseload solar and wind power generation with back up or energy storage facilities to bridge the gap between service factors of 25-50% for wind and solar with the 85% service factors currently in place for conventional baseload power generation.

- This service factor challenge can be seen more clearly by considering a calendar year of 365 days. The reference scenario, a 650 MW NGCC plant will meet its full power generation requirement for 85% of the year, mathematically equivalent to about 310 days, while a 650MW solar plant will fall short of meeting its baseload demand every day of the year due to its lower capacity factor of 21%. To overcome these shortfalls, the solar project must increase in capacity beyond 650MW to meet baseload demand for 85% of the year. However, due to the intermittency of solar resource, large scale solar developments require generation backup capacity- either a natural gas plant or large-scale storage facility -to meet the baseload demand on days when solar resource is unavailable.

- Achieving baseload configurations—at least within the constraints that currently define baseload energy—burdens renewable power with a major 'scale-up' problem, i.e. the need to overbuild generation capacity to store electricity in sufficient quantity to serve year-round load demand. The extent of this overbuilding is noteworthy, producing capital costs 6-10X those of the reference natural gas plant for serving the same demand.

- This scale-up problem and associated capital costs substantially raise the wholesale cost of power in various 'renewables + backup' configurations. The lowest cost 'renewables +' configuration is a solar plus natural gas combination, with a wholesale electricity price approximately double that of the 650 MW NGCC reference case plant. Alternative 'solar/wind +' cases produce substantially higher wholesale prices but facilitate full decarbonization of baseload electricity generation.

- In recognition of the carbon-free electricity generation of the 'solar/wind +' cases, break-even carbon taxes were computed. These carbon taxes, when applied to the NGCC reference scenario, increased the NGCC wholesale power price to levels which allow the 'solar/wind +' cases to earn an equivalent Return on Equity (ROE). Said differently, the carbon tax, applied to the NGCC scenario, would make an investor indifferent between the NGCC and solar/wind generation on an ROE basis. In our cases, these carbon taxes range from ~$75-390/ton—levels significantly above the tax levels generally referenced in public policy discussions on this topic.

- Electricity storage is crucial in reducing the scale-up problem of solar/wind. However, even when incorporating an optimal mix of storage and solar/wind resource, the scale-up problem is still a limiting factor. Project CAPEX remains excessively high due to the scale-up requirement of solar/wind generation. Current day prices of storage are very high, negatively impacting the economics of solar/wind.

- Storage and generation have a quadratic relationship. To sustain the baseload standard, an increase in storage capacity requires a decrease in resource generation. Conversely, an increase in generation requires a decrease in storage. This relationship dictates the optimal mix of storage and generation to minimize CAPEX while maintaining baseload.

- This study established the minimum CAPEX needed for each scenario. Beyond these minimums, increases in either generation or storage are inefficient from a capital point of view. The main influencers of CAPEX are installed storage and generation costs, as well as solar and wind availably, particularly low resource days.

- By combining storage with wind and solar from high resource locations with complementary generation profiles, projects can achieve lower capital costs and wholesale power prices. However, the extent of the improvement does not significantly alter the conclusions reported above.

- Considering plausible forward pricing scenarios, the wholesale rate for VREs can be significantly reduced. However, the price gap between generating a NGCC plant and VRE options remains considerable and potentially prohibitive without economic incentives such as a carbon tax or VRE subsidy.

- Considerable scope may exist for altering the electricity demand load curve in the future, flattening its slope and making it more responsive to the marginal costs of generating power. Considerable scope may also exist for accessing power backup over broader geographic market sectors. Such steps reduce the volatility of electricity demand and associated 'ramping' challenges, and they provide more reservoirs of already-built backup power that can compensate for solar/wind intermittency.

- These findings suggest that the path to electricity de-carbonization via solely replacing fossil fuels with wind/solar will be much more expensive than widely perceived and point to the need for alternative and/or hybrid solutions, which may include combining wind/solar with natural gas, nuclear, carbon capture/sequestration and some level of carbon taxes.

Abstract

On September 12, 2017, Hillsborough became the first town in North Carolina to commit to 100% renewable energy, joining 43 other U.S. localities in making the pledge. In addition, the RE 100 has fostered commitments from 116 corporations, while over 1,100 individual businesses have pledged to maintain commitments under the Paris Climate Accord. However, questions remain about how these entities can accomplish 100% renewable energy goals and the full economics of such goals.

This study, sponsored by the Frank Hawkins Kenan Institute of Private Enterprise and the Kenan-Flagler Energy Center, analyzes the economic cost of renewable energy's 'last frontier', providing reliable baseload power. The analysis utilizes five financial and energy models to examine the cost of replacing baseload power with various energy sources to achieve fully decarbonized utility scale electricity generation:

1. Natural Gas Combined Cycle Plant (NGCC) – Reference Case
2. NGCC and Universal Solar Power – Partial Decarbonization
3. Universal Solar Power and Battery Storage – Full Decarbonization
4. Universal Wind Power and Battery Storage – Full Decarbonization
5. Universal Solar and Wind Power and Battery Storage – Full Decarbonization

While similar studies on reaching 100% renewable energy have been authored, the purpose of our research is to form reasonable debates today around the cost of solar and wind profiles matching a reliable baseload profile, and the following themes implicated in the study:

- The capital intensity of resources with lower capacity factors, requiring large overbuilds
- Optimizing for resource generation vs. storage in today's economic conditions
- The role of a cost of carbon in moving towards a fully decarbonized generating portfolio
- How complimentary generating profiles and resource location mitigate CAPEX and cost of carbon
- Baseload power defined today vs. an outlook of baseload power

Introduction

In the United States, 64% of utility scale electricity generation was produced through combustion of fossil fuels in 2016; natural gas comprised 34% while coal comprised 30%.[1] Coal and natural gas have traditionally made for good power generation options due to the relative abundance of local resources¸ cheap market prices, excellent power density[2], and ability to meet demand through the ramping up and ramping down of energy production. However, as society begins to consider the future costs of climate change, there is significant market momentum towards decarbonization of power generation through renewable energy sources. Renewable energy sources utilize abundant and low-cost resources, such as wind and solar, and have made significant strides towards becoming cost competitive with natural gas on a PPA basis. To support the movement towards decarbonization, is it pertinent to consider the economics surrounding the transition to a power industry based on variable renewable energy (VREs), defined in this study as solar and wind.

The study focuses primarily on the economic impacts of decarbonizing the utility power industry, and specifically questions the business implications of replacing fossil-fuel baseload power generators with VREs. For electric utilities, the term 'baseload' refers to the minimum level of demand on the electric grid for a given period. While demand for electricity varies significantly over the course of a day, season, or year, the lowest amount demanded during that period is "the baseload." Baseload generation is a common, but technically undefined, term that refers to the power plants which run constantly to supply power to meet baseload demand. These assets typically run at consistent rates throughout the year, pausing only during pre-planned periods of maintenance. The constant usage allows the plants to operate at maximum efficiency, avoiding the mechanical strain as well as fuel consumption that results from ramping turbine engines up and down. We define baseload as 650MW per hour for 85% of the year.

All VRE models are compared to the NGCC baseload case. VREs require a minimum generation of 650MW per hour for all hours in a year, less the allotted 15% downtime (7446 of 8760 hours), mathematically equivalent to a 650MW NGCC plant operating at 85% capacity all year round. Excess generation above the required 650MW is discharged into storage or sold to the market at an avoided cost rate. Holding VRE assets to this baseload threshold requires considerable scaling up of generating assets and storage, as intermittency and the unpredictable nature of low-resource availability challenge VRE's ability to provide consistent and reliable baseload power equivalent to an NGCC plant.

To explore the economic impact of using VREs as baseload generators, this study presents a series of scenarios each containing an energy model and a financial model, which represents feasible transition steps from the current state of utility scale power production, towards carbon-neutral generation options. Financial models calculate the wholesale rate of electricity—on a dollar per megawatt-hour basis—needed to recoup a specified return on equity. Market rates across all scenarios are compared to derive economic implications of renewable energy generating assets. We limit our analysis of economic impacts to the generating assets only. We do not represent possible externalities associated with the replacement of a fossil fuel-based asset with a renewable based asset.

[1] EIA Electricity Explained report, 2016. Combustion of petroleum accounted for an additional <1% of power generation.

[2] Power density as defined by watts per square meter, advantaged for coal and natural gas over wind and solar.

We define the current state of utility scale power production as the retirement of a 650 MW coal-fired power plant, and the replacement of that plant with a combined cycle natural gas plant of equal nameplate generation capacity. We define carbon-neutral (also herein referred to as decarbonized) as power production with zero emissions from power generation. We are not considering the full lifecycle of emissions associated with manufacturing, transporting and installing power generating assets. We are only analyzing the carbon emitted via burning of natural gas to generate electricity and penalize such emissions through a dollar per ton cost on carbon.

We identify simplifications inherent in this study, while providing a solid foundation to compare various scenarios, that are outlined below to further set the stage for analysis and interpretations:

Alternative energy technology: Renewable energy assets being evaluated in this study are limited to solar and wind only. We do not consider other renewable options – as may variously be defined through state regulations – such as biofuels, geothermal, or hydro. Additionally, we consider the role of lithium-ion battery storage in conjunction with wind and solar assets.

Central plant design: Furthermore, we analyze the generating profiles of these assets as if located in a single geographic location. It is feasible, and perhaps probable, that given the large scale of the proposed generating assets, that the generators would be located across a geographic region, ultimately changing the generating profile. For the purposes of this study, we provide solar generation located in Charlotte, NC and wind generation located in Oklahoma.

Plant-level comparison: This study is based solely on the comparison of new forms of generation to replace a 650MW coal-fired power plant that is serving baseload power. Other studies may take a systems-level approach that optimizes for the lowest total system cost, allowing each generator to participate in additional markets (i.e. frequency control, congestion, etc.). However, this study solves for only the wholesale MWh rate that each new generator would have to earn to achieve a return on equity of 10.5%.

Static wholesale power rates: The modeling of this study assumes that every generator is paid the same wholesale price for every MWh generated to meet the designated baseload requirements. For the scenarios where an excess of electricity is produced, a constant – avoided cost – rate is applied to compensate for the excess generation. In markets today, generators may bid into regional markets and receive prices based on the balance between supply and demand. As technology and markets become more sophisticated, rates will become more fluid and dynamic. This model does not consider these market effects.

Current-day component pricing: All models utilize 2017 component pricing as a baseline and identify aggressive and conservative prices relative to the identified baseline. The study recognizes pricing for components in solar, wind and storage have been falling exponentially over the last several years and may cause forward prices to look quite different. Taking future pricing for the renewable energy generator components, energy storage and solar modules for example, would result in more favorable results for those models.

Engineering constraints: Lastly, this study uses a simple hourly dispatch model for each of the generators. It assumes that all generators and devices can ramp up and down as necessary to meet the required baseload profile. There is room to incorporate more engineering constraints in further studies to ensure the alignment between different technologies. In addition, the heat rate for scenarios 1 and 2 is held constant, no matter the production of the NGCC plant. And for energy storage, study does not consider the differential charge and discharge rates for lithium-ion batteries, nor does it consider any discharge rate limitation which may impact a batteries ability to meet relatively instantaneous and highly variable power demands on an hourly basis.

Project Overview

In this study, we define baseload as 650MW of constant demand over a one-year period. To meet this demand, we established a reference case using a 650MW Natural Gas Combined Cycle (NGCC) plant, Scenario 1, operating at 85% nameplate capacity annually and meeting a 10.5% ROE obligation; this standard requires a wholesale electricity price of $47.1/MWh. The study then uses published energy standards to model different combinations of generation technologies and compares the required wholesale electricity prices to the reference case, Scenario 1. Using this method to meet the required financial and baseload thresholds defined in the study, a transition portfolio of NGCC and solar requires a $88.4/MWh wholesale rate, while fully decarbonized generating portfolios (solar, wind, and storage assets) require between $99.0/MWh - $181.0/MWh to meet the same baseload power and financial conditions (Table 1).

The higher wholesale price for decarbonized assets reflects both the limited capacity factor and the intermittent nature of VREs. To meet 24-hour baseload power requirements, these VRE-based generation assets must be built far beyond the nameplate capacity created by the reference case. This remains true even when VRE assets are combined with energy storage technology. In our study, a generating portfolio of pure solar augmented by storage assets, Scenario 3, had to be scaled to 5x the capacity of a 650MW NGCC plant to provide the same baseload power requirement over 8,760 hours. The scaling issue for generation, supported by required energy storage to meet baseload power, increased capital expenditures for the project to 10x that of the NGCC model.

Similar issues occur in a wind plus storage model, Scenario 4, although partially mitigated by wind's higher capacity factor and more optimal resource location. In this model, Oklahoma wind resources were used to produce power, which was then transmitted to North Carolina through High Voltage Distribution Cables (HVDC). As in Scenario 3, technical and resource limitations required building a portfolio with a much higher nameplate capacity to meet baseload requirements. Both models show that while VRE-based generation assets are cheap, they require significant scaling to meet baseload. This scaling of generation assets also requires scaled up supporting infrastructure. Energy storage systems and transmission lines drive CAPEX costs far above the costs of the generation assets themselves. As VREs transition from an incremental power source sitting on top of existing baseload generators, becoming the baseload generators themselves, the cost per MWh increases due to those scaling requirements.

In addition to the expense of generation assets, a major driver of high costs for our VRE-based models were storage assets, despite recent and significant cost declines. In Scenario 3 – solar + storage accounts for 42% of total CAPEX (**Figure 1**). Costly raw materials and production technology make lithium-ion batteries, currently the most commonly used and cost-competitive storage technology, challenging for large-scale applications. The ability to shift power from peak generating times to peak load times makes storage technologies a critical resource in an economy based on VREs. Within our models, we found the relationship between generation and storage assets is non-linear under the most favorable scenario (see **Appendix C** for more information). Future reductions in storage technology costs could change this relationship.

Pending continued declines in storage and generation asset prices, some vehicle may be required to equate established carbon-based generators with partial and full decarbonized generators. For the purposes of this study, we assign a cost of carbon in $/ton to equate the wholesale electricity rate of carbon emitting assets to decarbonized assets. We consider the cost on carbon to be represented by the difference between each model's required wholesale electricity price and the reference case price. For ease of discussion, we refer to this cost on carbon as a carbon tax throughout the report; although we recognize that a tax is only one possible method of establishing a cost on carbon, it is a concept that many readers are familiar with and can be easily compared to existing policy considerations around the world. These contemporary carbon tax considerations fall far short of the levels implied by this study. Our research suggests a partially decarbonized portfolio requires a carbon tax up to $75.0/ton while a fully decarbonized portfolio requires a maximum carbon tax of $389.6/ton – a 5.2X multiple over the partially decarbonized one – to make investors indifferent between generating profiles based on economics alone.

Though a cost of carbon plays an integral role, there are avenues to mitigate significant capital expenditures and thus reduce the cost of carbon to transition to a fully decarbonized generating portfolio. Complementary generating profiles and geographic distribution of assets provide the most effective way to lower capital expenditures. Our Scenario 5, solar + wind + storage, combines North Carolina-based solar assets with Oklahoma-based wind and allows for transmission of wind power over HVDC lines (capacity on the line is rented to arrive at the lowest price). This combined solar and wind generation portfolio utilizes historical weather data available through PV Watts and NREL's SAM[3], detailing daytime solar peak production during the summer, and peak wind production overnight and during winter months. These complementary production profiles significantly reduce reliance on battery storage and scaled-up generation assets in producing the baseload 85% capacity for the year, resulting in more efficient deployment of capital. Even with complementary generating profiles and optimal resource location, such a scenario generated a wholesale price of $99.0/MWh to meet our 10.5% return on equity obligation, requiring the reference scenario to stack a $151.0/ton cost of carbon to economically equate the competing portfolios (**Table 1)**.

[3] https://sam.nrel.gov/

	NGCC	NGCC with Carbon Tax	Solar and NGCC	Solar and Storage	Wind and Storage	Solar, Wind and Storgae
Scenario	1	1	2	3	4	5
AC System Size NGCC (MW)	650	650	650	-	-	-
AC System Size Solar (MW)	-	-	650	2,958	-	845
AC System Size Wind (MW)	-	-	-	-	2,625	2,065
Total Annual MWh	4,839,900	4,839,900	4,839,900	6,738,381	12,392,152	11,671,720
Battery Capacity, MWh	-	-	-	10,250	6,550	2,410
Acreage	30	30	5,460	24,843	22,053	24,443
Wholesale Rate, $/MWh	**$47.1**	**$88.4**	**$88.4**	**$181.0**	**$135.9**	**$99.0**
Carbon Tax ($/MWh)	N/A	$41.3	$41.3	$133.9	$88.7	$51.9
Carbon Tax ($/ton)	N/A	$75.0	$75.0	$389.6	$258.2	$151.0
Capital Expenditure	$702,000,000	$702,000,000	$1,630,200,000	$7,720,641,000	$5,811,379,774	$5,075,501,108
Annual O&M + Fuel Cost	$110,627,806	$110,627,806	$116,087,806	$101,718,000	$363,743,664	$272,621,604
Debt	$280,800,000	$280,800,000	$652,080,000	$3,088,256,400	$2,324,551,909	$2,030,200,443
Equity	$421,200,000	$421,200,000	$978,120,000	$4,632,384,600	$3,486,827,864	$3,045,300,665
ROE	10.50%	13.24%	10.50%	10.50%	10.50%	10.51%

Table 1: Summary Table

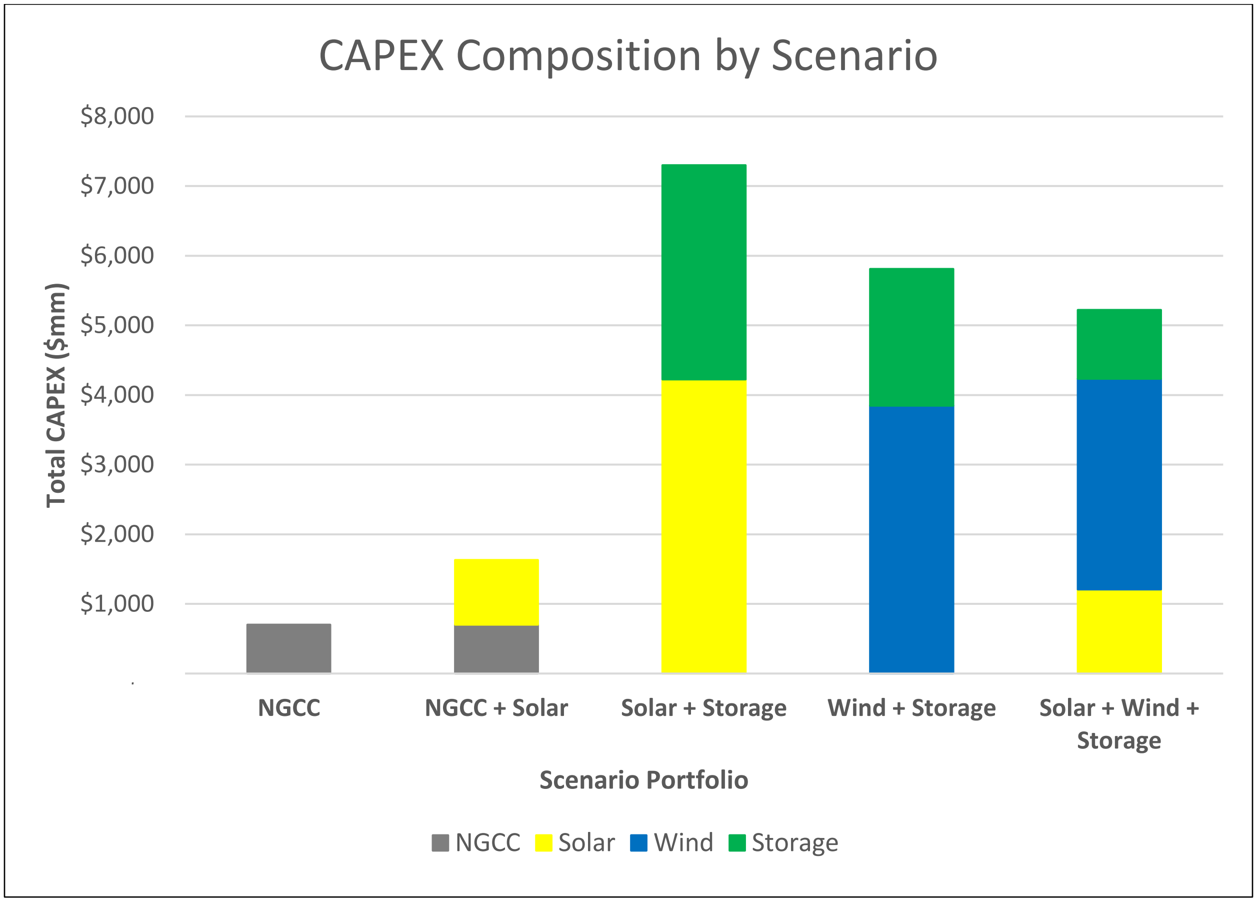

Figure 1: Composition of Total CAPEX by Scenario

Methodology

This study takes a project finance approach to determining the wholesale price that a power generator would require when using different forms of renewable energy to provide baseload power. Given the recent advances and cost declines in renewable energy technology, a portfolio of four different combinations of commercially-available technologies was selected for plant-to-plant comparison. Each scenario is comprised of two components: an energy model and a financial model. The energy model required each renewable energy-based scenario to meet the standard of baseload power, which we have defined as 650MW per hour for 85% of the 8,760 hours per year. This equated to an annual production of 4,839 GWh per year. Each scenario uses current industry standard technological and cost parameters and simulates the required electricity generation for the year. Given the variable nature of renewable electricity generation, Scenarios 2, 3, 4, and 5 consider both aggregate energy production as well as hourly generation where necessary.

The financial models are then built to identify the wholesale price required by each portfolio to generate a satisfactory ROE over the project's lifetime. The wholesale rate is an average price applied to every MWh generated. Each financial model takes the production data from the energy model, in addition to current industry-standard cost and market data to determine the wholesale price which enables 10.5% ROE. Revenue is generated solely for energy sold, and not for any additional grid services that such a plant could technically provide.

This exercise also considers the cost of carbon required to make an investor indifferent between producing energy using NGCC or renewable energy options. For each of the cases containing renewable energy generators, we estimated a cost of carbon, on a dollar per ton of carbon basis, that would equate the wholesale electricity cost of a carbon neutral generation portfolio with that of a NGCC plant (Scenario 1).

Key Planning and Simplifying Assumptions

The energy modeling required some simplifications to keep the analysis manageable, and lead to favorable assumptions for each scenario. The modeling attempted not to favor NGCC over VRE, or VRE over NGCC. These favorable assumptions form the basis for the sensitivity analysis performed in the section of the report titled **Secondary Value Drivers**.

- NGCC: The NGCC scenarios has a significantly favorable outlook on fuel prices, its major cost driver. The Natural Gas price sensitivity analysis was also favorable, as we tested a relatively narrow price band of natural gas, which are very low by historical standards.
- VRE: VRE scenarios require a minimum generation of 650MW per hour throughout the year – less 15% - as weather can create uncertainty in available generation. This is viewed as equivalent to NGCC despite that NGCC allows for specific reliability and known down time while VRE generations is unable to control or predict such downtime. In reality, this would be an additional hurdle for VRE to meet reliable baseload.
- Storage: Storage modeling contained no limitations on charging/discharging rates, no cycle losses or long-term storage losses and total capacity dictated only by the specific requirements for each scenario.

Financial Modeling

To facilitate the economic comparison of renewable generating technologies to that of a NGCC plant, financial assumptions were held constant across all financial models. A consistent capital structure allowed for an economic analysis unbiased by varying degrees of leverage. The financial models are built to meet an ROE of 10.5%, representative of the average hurdle rate of a regulated utility. For each scenario, a discounted cash flow model is used to solve for the wholesale electricity price required to generate the required ROE. All financial models reflect the recent US tax reform, including a 21% corporate tax rate. For a complete overview of all financial and operating assumptions, refer to the **Detailed Planning Bases** located within **Appendix A**.

The capital structure is an important distinction in our modeling. Leverage was calculated based on the ability to meet interest and principle payments from operating income. Maximum scenario leverage was restricted by a Debt Service Coverage Ratio (DSCR)[4] of 1.2x, conservatively appropriate for a large-scale utility investment. The scenario with the most restrictive cash flows was used to calculate the maximum leverage possible while meeting our target DSCR. This leverage was then held consistent across all scenarios. We employed a leverage ratio of 40% debt.

The treatment of debt is also a key driver in each financial model. The cost of debt is 5%. The debt tenure for each scenario consists of the duration of construction (2 or 3 years) and a 10-year repayment period. Interest is capitalized during construction and added back to the principle until the scenario begins to generate revenue. We do not include any completion tests or completion guarantees in our debt assumptions.

Residual value also drives project economics. The financial models use the Gordon Growth annuity method to project out cash flows for the 15 years following the 20-year operational period that is modeled, equating to a total useful life of 35 years for all scenarios. The WACC used for this calculation is 7.5%. It is also worth noting that net operating losses are carried forward, allowing deferment of income taxes in the early years of operation. Tax depreciation schedules for each scenario follow acceptable modified accelerated cost recovery system (MARCS)[5] schedules as per industry standards.

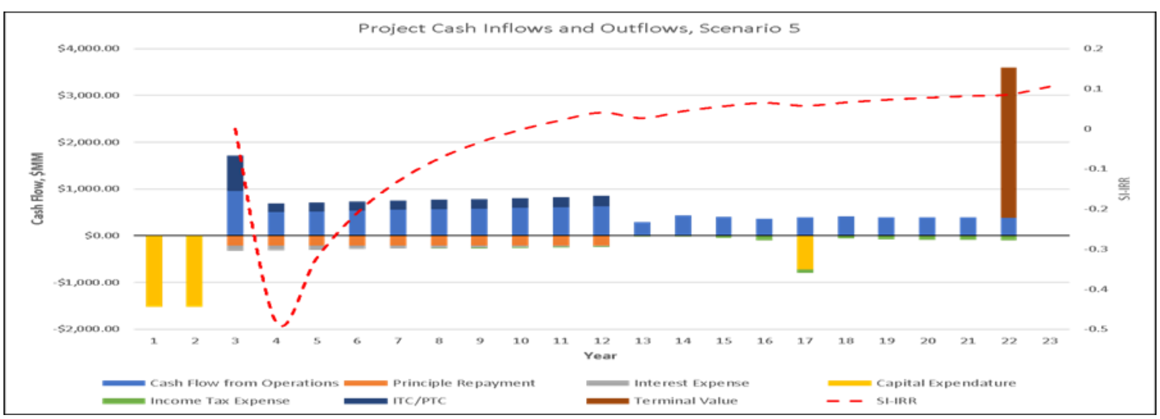

Figure 2 Project Cash Inflows and Outflows, Scenario 5.

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[4] DSCR = (Operating Income + Interest) / (Principle + Interest + Lease Expenses)

[5] MACRS schedule for NGCC and renewable energy generating assets can be found in Appendix A

Input Price Ranges

To understand the sensitivity of the wholesale rate with respect to increases or decreases in the install price of VREs, we developed three pricing scenarios as illustrated in **Table 2** below. The mid-prices are reflective of today's average market prices for a utility scale development. Mid-range prices were estimated through discussions with leading utility and solar developers.

	VRE Installation Cost		
Scenario	**Low**	**Mid**	**High**
Solar ($/W)	0.85	1.00	1.24
Wind ($/W)	0.75	0.95	1.15
Storage ($/MWh)	250	300	345

Table 2. Installation Price Ranges for Solar, Wind and Storage assets.

These forward-price scenarios represent possible future prices for VREs and reflect a ~15% price reduction relative to today's average market price for a large, utility scale development in a regulated market. Installing VRE developments at these prices may soon be possible given sufficient economies of scale or through firms targeting lower ROE hurdle rate requirements than designated in this study. These prices are also possible for utility scale developments given rapid price declines in solar, wind, and storage technologies due to innovation or other unforeseen factors.

Conversely, the conservative price scenarios may be reflective of ~15% price increase for VREs. Possible causes of a price increase include resource limitations (e.g. lithium, silicon, cobalt, steel and other base materials), tariffs on imported steel and solar panels, and changing supply and demand dynamics as VREs are deployed at increasing scale.

Energy Modeling

Each scenario contains an energy model, which simulated the hourly energy production for each generating technology, according to the specifications of each scenario. Consider Scenario 1, an NGCC plant: the energy model estimated that at 650MW nameplate capacity, the plant would produce 650MW per hour for 85% of the 8,760 operational hours per year. At this 85% capacity factor, plant production amounted to 4,839 GWh per year. This energy production, both on an hourly and an annual basis, defined the baseload characteristics upon which all other energy models are compared.

For scenarios 3, 4, and 5, a detailed energy model was constructed to estimate the hourly energy production for each renewable energy scenario. Utilizing PVWatts modeling software for solar, and SAM modeling software for wind, we estimated the hourly energy production for 650MW_{ac} of solar capacity located in Charlotte, NC and 2000 MW of wind capacity located in Oklahoma. We then scaled each development independently using a linear scaler to meet the hourly energy requirements of baseload production. Using a linear scaler may introduce error into the models, especially in the case of the wind developments (e.g. wake effects) but is a necessity due to the capacity limitations inherent in the modeling software. For a thorough description of the inputs into the PVWatts and SAM models, refer to **Appendix B**.

Lastly, the energy models were optimized to achieve efficient employment of capital with respect to CAPEX. Given the non-linear interplay between increase/decrease in generating resource and battery storage capacity, a detailed analysis was performed on the hourly energy production by increasing or decreasing the capacity scalar. The optimization was built around two main constraints: (1) the total hourly energy sold to the market—through a combination of resource production and energy discharge from battery storage—must equal or exceed the hourly baseload demand of 650MW on 85% of the hours in a year, and (2) the combination of generating resource capacity and battery storage capacity must be balanced to achieve a minimum CAPEX. This optimization approach facilitated efficient capital employment, as an increase/decrease in either generating resource and/or battery storage to meet the 85% capacity factor would result in a larger CAPEX, and hence require a higher wholesale price of electricity. See **Appendix C** for illustrations of the optimization of Scenarios 3, 4 and 5.

Reference Scenario: 650MW NGCC Plant

For the reference case, we simulated the generation and financial returns for a utility-owned 650 MW NGCC plant operating at an annual generation capacity of 85%. This generation profile defines the thresholds required for additional scenarios in our study to meet baseload.

Our scenario utilizes a 7-year recovery period for depreciation of the plant, and a three-year construction window. The scenario assumes a base overnight cost of $1,000/kW, a project contingency factor of 8% and an average heat rate of 6,800 Btu/kWh. Natural gas prices are forecasted for 30 years, with an initial price of $2.88/MMBtu for electricity generation beginning in year 3 of the scenario (**Figure 3).**

Natural gas is charged a fixed transportation fee over the life of the project as we use long term agreements to secure both a source of natural gas as well as reliable transportation. More detailed planning bases for this scenario and all other scenarios can be found in **Appendix A.**

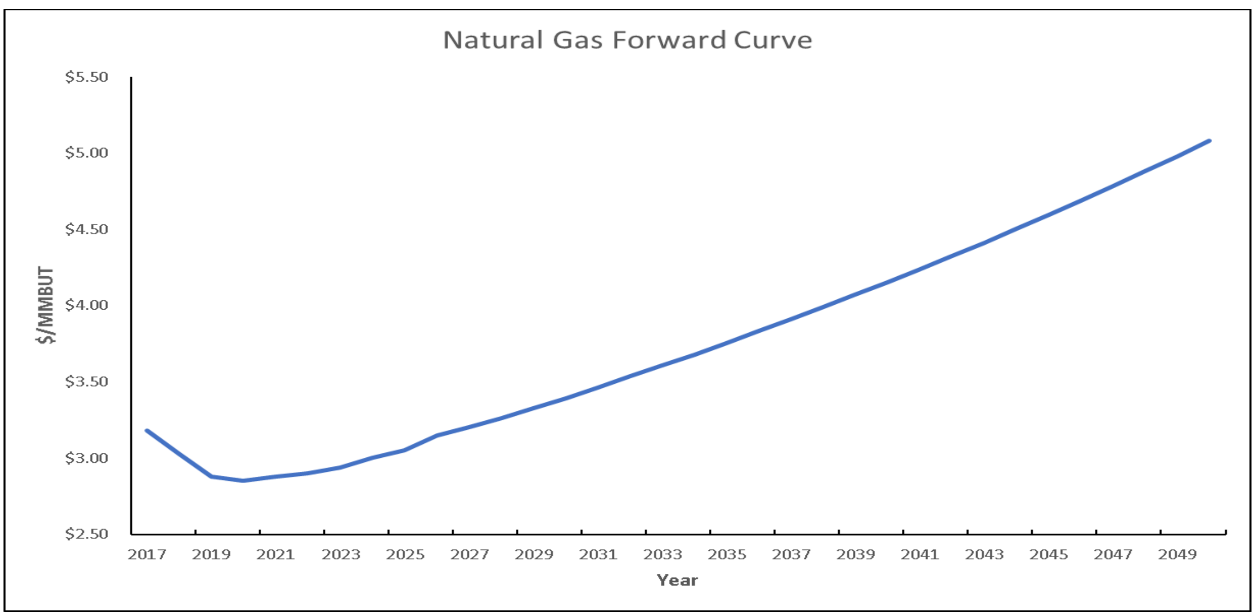

Figure 3: Natural gas price forecast

Scenario 2: 650MW NGCC Plant + 650MW Solar Plant

Scenario 2 is our bridging scenario from fossil fuels to renewable energy. It is comprised of both an NGCC plant and a solar photovoltaic plant. Since there is no energy storage here, the solar scenario is built to avoid excessive curtailment. The solar plant is built to $650MW_{ac}$, equivalent to the NGCC plant nameplate capacity. Fossil fuel generation is used to back up the solar production. Here, the same NGCC plant included in the reference case is utilized as its efficiency proved more economic relative to a traditional combustion turbine peaker plant when implementing a cost of carbon on both peaker and NGCC plants.

Financial metrics differ given the treatment that renewable energy plants face compared to natural gas plants. The solar plant uses a 5-year depreciation recovery period, land for the solar project is leased over the project's lifetime, and the project can leverage the 30% federal Investment Tax Credit (ITC). We assume that the project can capitalize the ITC on a dollar-for-dollar basis in the first year of its economic life.

The solar plant modeled here has an installed cost of \$1/W(dc). We utilized the PVWatts modeling software to estimate annual generation portfolios for a solar plant operating in Charlotte, NC. Specifically, this software uses p50 historical average solar irradiation data to calculate system output for all hours of the year. We modeled a crystalline silicon module mounted on a dual-axis fixed tracking system with annual module degradation of 0.5%. Total aggregate annual output was 1,481 GWh.

Scenario 3: 2956MW Solar Plant + 10250MWh Storage

Scenario 3 is the first fully decarbonized scenario that we built, leveraging only solar photovoltaic and battery energy storage technology. Instead of natural gas-fired generation as the backup resource, this scenario was scaled to support baseload needs with only solar energy. The solar PV and energy storage plants were scaled to meet day-time generation while also generating enough electricity to be stored for use when the solar plant was not producing. Given the variability of solar, we could not replicate Scenario 1's generation profile on an hourly basis from solar generation alone. Instead, our criteria to satisfy baseload was to supply 650 MW of power per hour for 85% of hours throughout the year through a combination of solar power produced and discharged directly onto the grid, and surplus[6] solar power stored in a battery and later discharged onto the grid when hourly solar electricity generation was less than the baseload requirement of 650MW. See **Appendix B** for illustrations of the average hourly production profile of scenarios 3, 4, and 5.

The variable nature of solar resulted in a production profile that was very different from Scenario 1 and which required significant augmentation to meet baseload power requirements. Solar's lower average capacity factor required that the asset be scaled up to meet consistent energy needs, but during peak production periods—in many hours throughout the year—excess solar[7] electricity was produced. For this scenario, as with scenarios 4-5, we assume that excess solar production is sold into the market at a fixed avoided cost rate of \$35/MWh.

[6] Surplus power is defined as electricity generated beyond the 650MW per hour that is required to satisfy baseload demand.

[7] Excess solar is defined as the aggregate electricity remaining after baseload demand has been satisfied through both solar electricity generated and discharged onto the grid, and electricity consumed in charging the batteries.

The solar PV plant in this model is a scaled-up version of that in Scenario 2, assuming the same generation profile and single geographic location, but scaled to meet the requirements for baseload. The solar and battery capacity was determined through an iterative approach to minimize the CAPEX of the development to yield the lowest possible wholesale rate of electricity while meeting the baseload requirement. For the energy storage component, we utilize lithium ion battery technology with a life of 15 years and current pricing of $300/kWh.

Scenario 4: 2625MW Wind Plant + 6550MWH Storage

Scenario 4 is also fully decarbonized, this time utilizing wind as the sole generation resource rather than solar photovoltaic. The wind energy is coupled with lithium ion battery energy storage to provide electricity to the same baseload standard as with Scenario 3, with technological characteristics identical to those in Scenario 3.

Given the relatively unattractive wind resources of North Carolina, the scenario takes an innovative approach to utilizing wind energy. This model calculates wind generation using the high-quality resources within the Oklahoma wind corridor. That electricity is then transmitted to North Carolina by renting capacity on an existing high voltage transmission line. To wheel the electricity to North Carolina, we assume a fixed rental rate for transmission capacity. The installed price for wind is $950/kW, and the rental rate for transmission capacity is $25/MWh[8].

The wind generation profile was created using NREL's System Advisor Model (SAM), which used historical p50 wind speed data to estimate electricity production. Modeled wind turbines consisted of 12kW rotors with 7.5m diameters, 125m hub heights, and 20m/s wind speed cutoffs. Turbine wake was modeled using the Eddy-Viscosity Wake Model. For more details on the SAM modeling, see **Appendix B**. The relative sizes of the wind and battery capacity were determined through an iterative approach to minimize the CAPEX of the development to yield the lowest possible wholesale rate of electricity while meeting the baseload requirement.

Scenario 5: 845MW Solar Plant + 2065MW Wind Plant + 3300MWh Storage

Scenario 5 was the final iteration of a fully decarbonized scenario. It leverages a blend of two high-quality, complementary resources—the solar photovoltaic energy produced in North Carolina and wind energy produced in Oklahoma and wheeled into North Carolina. The technological specifications of the solar PV, wind, and energy storage facilities are consistent with those utilized in Scenarios 3 and 4. Solar and wind generation profiles were combined to calculate total variable renewable energy generation for each hour of the year, and generation gaps below baseload requirements were backfilled with battery storage. The generation plants are then scaled up to meet the baseload requirements. Given the often-complementary nature of variable solar and wind generation, as shown in **Figure 4**, we combined these two resources in the hopes of reducing the required battery storage capacity.

The relative size of the wind, solar and battery capacity was determined through an iterative approach to minimize the CAPEX of the development to yield the lowest possible wholesale rate of electricity while meeting the baseload requirement.

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[8] Transmission capacity does accommodate for line losses in generation delivered.

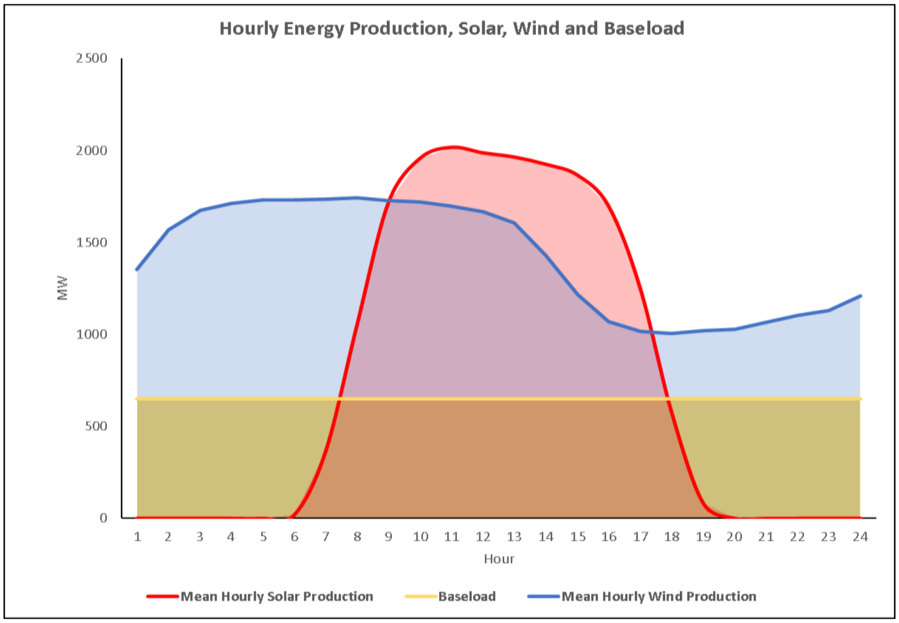

Figure 4: Average 24-hour generation profiles for wind, solar, and baseload NGCC

Battery Storage Modeling

For each scenario, a fit-for-purpose battery storage was designed to mitigate baseload production gaps produced by VRE models. Battery storage is a very significant component of VRE system designs, allowing for smaller scale developments to meet the baseload supply than would be possible without utilizing storage. Each scenario has a uniquely sized storage capacity, as listed in **Table 1: Summary Table.** Sizing of the battery and associated generating assets was carried out with an objective to reduce the total installation Capex for each scenario. For a detailed discussion on this optimization methodology and resulting non-liner relationship of storage and generating assets, see the section **Generation/Storage Relationship**.

The battery assumptions including in this report are favorable for storage and overlook many of the current technological issues associated with large scale lithium ion storage ability to provide large scale supply. Storage modeling assumes that all batteries have no cycle losses and have identical and relatively instantaneous charging and discharging rates, which stand in stark contrast to average cycle losses of 20% and a slower charging rate than discharging. Additionally, our storage modeling assumes that lithium ion batteries can be sufficiently sourced and scaled to satisfy very large-scale requirements; the scale of battery storage proposed in this study far exceed the largest lithium-ion battery ever built. Tesla presently holds the record with a 129MWh lithium ion battery storage facility installed in South Australia. In comparison, the largest battery proposed in this study has a capacity of 10,250 MWh. It is assumed that there will be no technological limitation associated with developing a lithium-ion battery 80X the largest development to date. These assumptions were necessary to simplify the hourly power analysis for each generation and storage model and represent a very favorable outlook for innovation in storage technology[9] which may be required to implement such large-scale developments.

[9] For a complete list of battery assumptions, refer to Appendix A.

Financial Modeling Results

The wholesale rate of electricity required to meet the baseload threshold for VREs is significantly greater than the wholesale rate of a NGCC plant providing equivalent baseload power. The wholesale rate is driven primarily by the CAPEX required for installing VREs, and by the cost of natural gas for a NGCC plant. Additionally, there are many secondary valuation drivers influencing the wholesale rate, which are discussed at length in the section **Secondary Value Drivers**. For VREs, changes in installation prices introduce significant variability into the estimated wholesale rate.

Figure 5 illustrates the range of wholesale prices charged to the market to meet the specified 10.5% ROE hurdle rate, given the three pricing scenarios in **Table 2**. The wholesale price range for a NGCC plant is a product of high and low-price sensitivities to natural gas, discussed further below. **Figure 6** illustrates the Carbon Tax range that would coincide with the wholesale rates proposed in **Figure 5**.

Scenario 5: Solar, Wind and Storage

Scenario 5, a combined development of solar, wind, and storage, produced the lowest wholesale rate of all fully decarbonized VRE only scenarios. Utilizing the complimentary resource profiles of solar and wind, scenario 5 is subjected less to intermittency issues, reducing the required overbuild of nameplate capacity and hence has the lowest CAPEX of all decarbonized scenarios, while still meeting the baseload standard (see **Figure 4**). Using today's average market prices for each VRE ($1.0/W solar, $0.95/W wind and $300/MWh storage) our financial models produced a wholesale price of $99.00/MWh to return a 10.5% ROE. However, in comparison to a NGCC plant, the portfolio approach to solar, wind and storage is significantly more expensive, as a NGCC plant meets the same baseload standard at a wholesale rate of $47.10/MWh.

Figure 5 Wholesale Price Ranges for each Scenario.

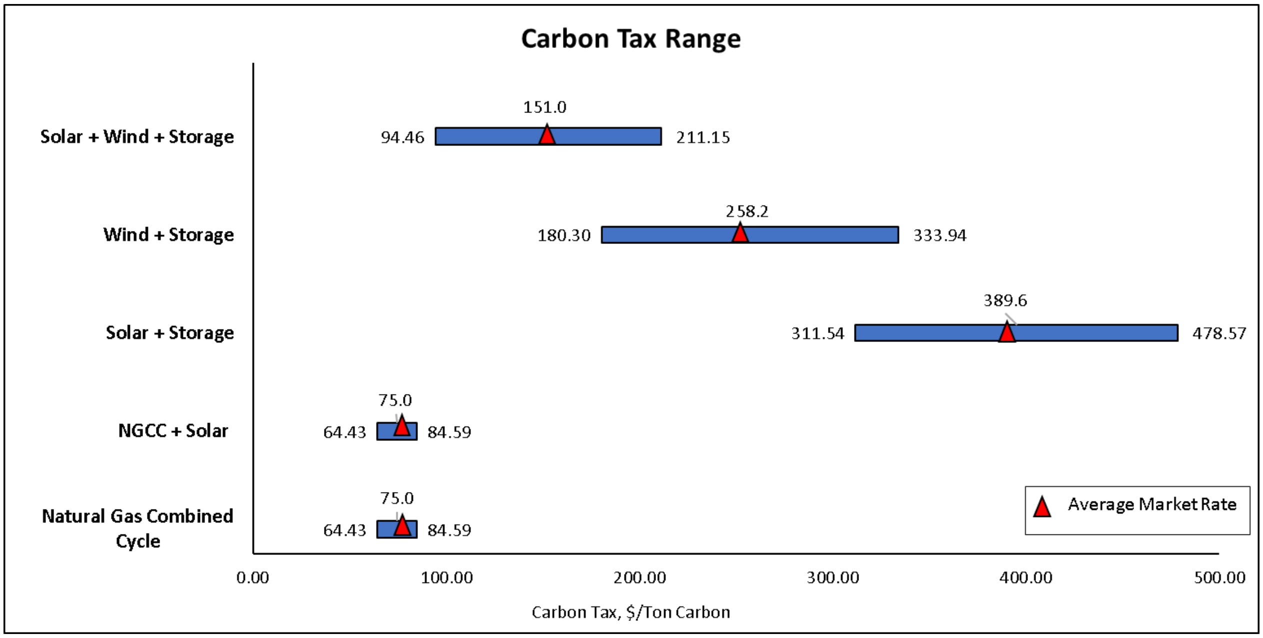

Figure 6 Caron Tax ranges for each scenario.

Considering the forward-price range for scenario 5, the price gap with respect to the NGCC asset remains significant. At a reduced installation cost of $0.85/W solar, $0.75/W wind, and $250/MWh storage, the lowest wholesale rate for the portfolio of VREs is $76.20/MWh, still over $20.0/MWh greater than the highest price estimated for NGCC plant of $51.49/MWh. **Figure 7** illustrates the relationship between the wholesale rate required to deliver a 10.5% ROE and the installation cost of solar, wind, and storage. To achieve a wholesale rate of $50.0/MWh, the average price of solar and wind would have to approach $0.58/W, with storage at $165/MWh, assuming all else is held constant and assuming that storage, solar and wind prices reduce in tandem. An alternative approach to bridging the gap between the wholesale rate of the VRE portfolio and NGCC plant may be through a carbon tax, as discussed in the section **Carbon Tax**.

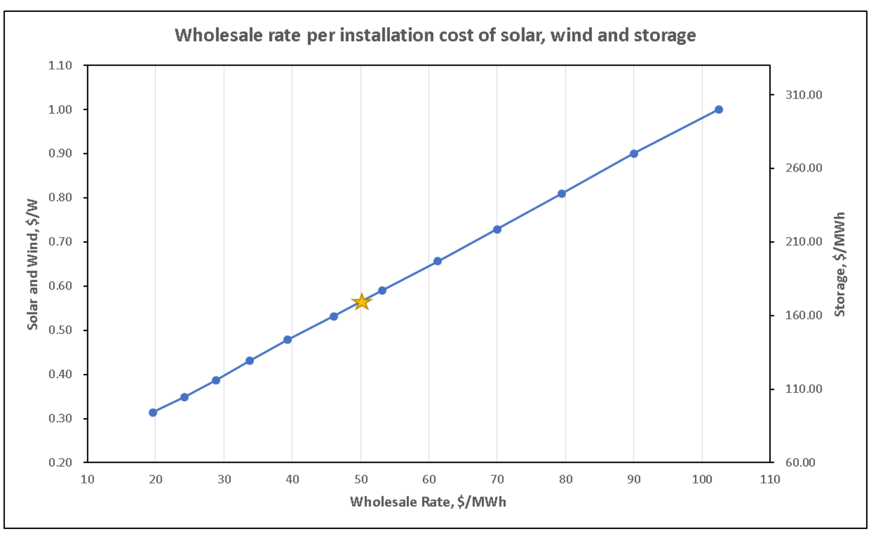

Figure 7. Average forward price of a portfolio of solar, wind assets, and storage versus the wholesale rate required to generate a 10.5% ROE for scenario 5, holding all else constant.

Scenario 3 and 4: Solar and Storage and Wind and Storage

Scenarios 3 and 4 illustrate the wholesale prices charged to the market for single-resource VRE generators: solar + storage and wind + storage assets, evaluated independently. These models are significantly impacted by wind and solar resource intermittency and require a large overbuild to meet the baseload standard. Upfront CAPEX requirements are higher relative to the reference case and thus require a higher wholesale rate to recoup the investment and meet the 10.5% ROE hurdle. For a solar and storage asset installed at the baseline market rate, the wholesale price of electricity is estimated to be $181.00/MWh, with a high to low range of $208.20- $150.80/MWh. For a wind and storage asset installed at the baseline market rate, the wholesale price of electricity is estimated to be $135.90/MWh, with a high to low range of $158.50- $105.70/MWh. Compared to solar, the wholesale rate for the wind scenario is lower primarily due to wind's higher capacity factor; the higher capacity factor permits a smaller wind development while meeting the same baseload standard, and hence a lower upfront CAPEX.

With respect to Scenario 1, the NGCC plant meets the same baseload standard at a significantly lower average wholesale rate of $47.10/MWh. Even with aggressive price reductions in solar and wind assets, the economic gap between single asset VREs and NGCC projects remains considerable. For the solar assets to meet the 10.5% ROE hurdle rate at a wholesale rate of $50.0/MWh, the average installation price for solar would have to decline by 72% to $0.28/w. Likewise for wind, installation prices would have to drop by 58% to $0.42/w to reach $50.0/MWh. Storage costs would need to approach $84.76/MWh and $128/MWh, respectively (**Figure 8)**.

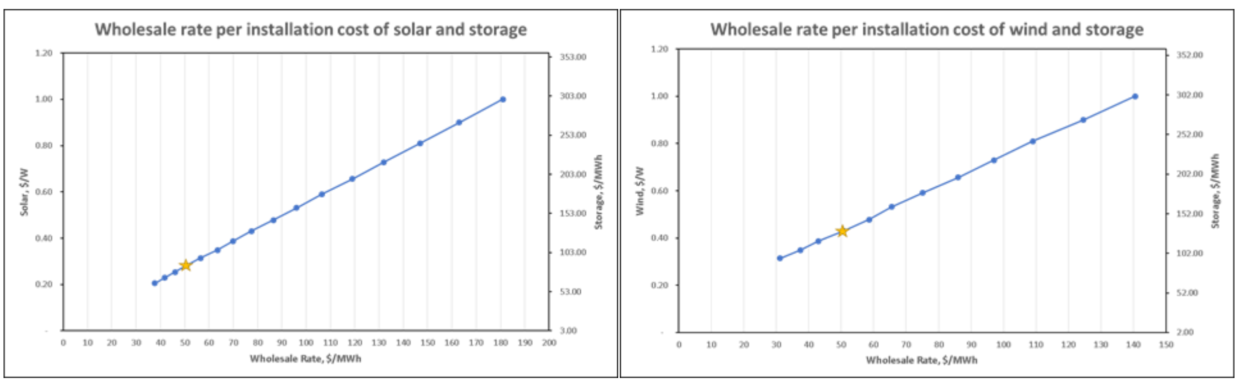

Figure 8 Wholesale rate per installation cost of solar (left) and wind (right).

Scenario 1 and 2: Natural Gas Combined Cycle

The wholesale rate of power for a 650MW natural gas combined cycle plant is primarily driven by the cost of natural gas, as the NGCC plant consumes approximately 32,900,000 MMBtu/year. This high operating expenditure contrasts starkly with the VRE assets, which have no fuel expenses. Additionally, the NGCC plants have notable annual O&M fees, which are also significantly higher than the annual O&M required for the VRE assets. As such, fuel cost and O&M fees are the primary value drivers for the NGCC plants.

We estimated that a 650MW NGCC plant, installed at the average market rate of $1.00/W and buying natural gas at $2.88/MMBtu (plus forward price forecasts; **Figure 3**), can meet the baseload power standard at a wholesale rate of $47.10/MWh. Variability in the price of natural gas influences the NGCC model, as volatility significantly impacts the wholesale rate. Table 3 is a sensitivity analysis from Scenario 1 with respect to the price of natural gas, the wholesale rate charged to the market, and the ROE. As we move from $2.88/MMBtu towards a lower price of $2.40/MMBtu, the wholesale rate required to generate a 10.5% ROE drops to \$44.12/MWh from \$47.12/MWh. Conversely, as the price of natural gas increases to \$3.50/MMBtu[10], a wholesale rate of \$50.12/MWh would be required to meet the 10.5% ROE hurdle. These boundaries constitute the valuation ranges illustrated in Figure 5 for the NGCC plant wholesale rate.

		Wholesale Electricity Price, \$/mWh						
		44.12	45.12	46.12	47.12	48.12	49.12	50.12
Natural Gas, \$/MMBtu	2.40	10.79%	11.68%	12.39%	13.22%	13.90%	14.67%	15.44%
	2.50	10.28%	11.01%	11.88%	12.61%	13.42%	14.11%	14.86%
	2.65	9.33%	10.24%	10.97%	11.84%	12.57%	13.38%	14.08%
	2.88	7.94%	8.85%	9.62%	10.50%	11.40%	12.13%	12.97%
	3.10	6.37%	7.35%	8.28%	9.18%	10.10%	10.84%	11.73%
	3.30	4.88%	5.99%	6.99%	7.95%	8.87%	9.78%	10.53%
	3.50	3.25%	4.38%	5.49%	6.51%	7.59%	8.53%	9.32%

Table 3: Sensitivity analysis of the price of natural gas and wholesale price of electricity. Yellow shaded areas meet or exceed the 10.5% ROE for the corresponding wholesale rate and price of natural gas.

For scenario 2, a 650MW solar development with backup power from a 650MW NGCC plant, the wholesale price reflects the combined economics of scenario 1 and a small solar asset, representing a possible transition step between pure VRE generating assets and NGCC plants. The wholesale price is driven by the installation price of solar and storage, \$1.0/W and \$300/MWh, as well as natural gas fuel cost, and sensitized over the price scenarios discussed above. Using the average market prices of solar, scenario 2 requires a wholesale rate of \$62.10/MWh to meet the baseload standard and return a 10.5% ROE.

Carbon Tax

To bridge the significant gap in the wholesale rate between VREs and NGCC generating assets, we assigned a tax to penalize the carbon emissions of a NGCC plant. Assuming an average NGCC plant emits 0.435tons of $C0_2$ per MWh of generation, scenario 1 produces ~2.1million tons of CO_2 annually. By taxing the annual carbon emissions, we can elevate the cost of generating electricity with a NGCC plant such that the wholesale rate of the NGCC plant is levelized with a VRE generating asset. Ideally, this would make an investor indifferent between VRE vs. NGCC projects, as the ROE would be identical between assets. In lieu of decreasing installation prices of VREs, a carbon tax may encourage investment in utility scale VRE assets at the scale suggested in this study to meet the baseload requirements. Table 4 is a comparison of the carbon tax rates applied to the NGCC plant to equate its wholesale rate with the wholesale rate for scenarios 2, 3, 4, and 5, as outlined in Figure 5. For a discussion of the implications of a Carbon Tax, refer to the section **Negative Externality: Carbon Tax**.

	Scenario			
	2	3	4	5
Wholesale Rate, NGCC, \$/MWh	47.1	47.1	47.1	47.1
Wholesale Rate, VRE, \$/MWh	88.4	181.0	135.9	99.0
Carbon Tax, \$/MWh	41.3	133.9	88.8	51.9
Carbon Tax, \$/Ton Carbon	75.0	389.6	258.2	151.0

Table 4 Carbon tax rates for scenarios 2-5.

[10] While this could be considered a low price for an upper boundary, we believe it reflects expected prices for the near future.

Secondary Value Drivers

In addition to the primary valuation drivers, many secondary valuation drivers have notable implications on the financial modeling outcomes. The sensitivity analysis of secondary valuation drivers analyzes the impact of changing an individual baseline assumption, holding all else constant. Results are reported relative to changes in the wholesale rate required to meet the 10.5% ROE hurdle rate. The following discussion will be limited to scenario 5. For an overview of the impact of each secondary valuation driver on scenarios 3 and 4, see **Appendix A, Secondary Value Drivers.**

Leverage

Leverage is defined as the percent of long-term debt in the capital structure. The leverage calculation does not include capital leases or short-term debt. Changing the capital structure has a significant impact on the ROE and the wholesale rate. As we increase the leverage, we reduce the amount of equity required to fund each scenario's CAPEX, and hence we can charge a lower wholesale rate to meet the 10.5% ROE hurdle rate. Increasing the leverage of scenario 5 from 40% (used in the financial model) to 55% would allow for a decrease in the wholesale rate from $99.0 to $94.0/MWh. Decreasing the leverage from 40% to 25% would increase the wholesale rate to $103.50/MWh (Figure 9). This analysis of leverage does not consider possible DSCR violations or ability to meet repayments (see **Error! Reference source not found.** f or a discussion of DSCR).

		Wholesale Electricity Price. $/MWh						
		$ 94.00	$ 96.00	$ 97.50	$ 99.00	$ 100.50	$ 102.00	$ 103.50
Leverage, % Debt	55%	10.56%	10.81%	11.17%	11.46%	11.72%	11.96%	12.22%
	50%	10.21%	10.46%	10.83%	11.09%	11.33%	11.58%	11.84%
	45%	9.95%	10.20%	10.55%	10.80%	11.02%	11.26%	11.52%
	40%	9.72%	9.98%	10.29%	10.51%	10.74%	10.97%	11.22%
	35%	9.51%	9.76%	10.04%	10.27%	10.49%	10.73%	10.95%
	30%	9.35%	9.56%	9.83%	10.05%	10.28%	10.50%	10.70%
	25%	9.19%	9.39%	9.67%	9.90%	10.11%	10.30%	10.51%

Figure 9 The sensitivity of leverage to the wholesale rate of scenario 5. Yellow shaded area represents a ROE greater than or equal to the 10.5% hurdle rate.

Avoided Cost

VRE assets generate a significant amount of excess power, defined as the amount of power generated beyond what is required to satisfy baseload demand and/or required to charge the battery storage for subsequent discharge to meet baseload requirements. Excess power is sold to the market at the avoided cost, defined by the Independent Energy Producers Association[11] as "the marginal cost for a public utility to produce one more unit of power." We assume that our energy models will receive an avoided cost of $35/MWh on all excess power generated. A decrease in the avoided cost from $35 to $20/MWh increases the wholesale rate of scenario 5 from $99.0 to $119.50/MWh. An increase in the avoided cost to $50/MWh decreases the wholesale rate to $79.00/MWh (**Figure 10**).

[11] http://www.iepa.com/avoid.asp

		Avoided Cost, $MWh						
		$ 20.00	$ 25.00	$ 30.00	$ 35.00	$ 40.00	$ 45.00	$ 50.00
Wholesale Price. $/MWh	$ 119.50	10.54%	11.57%	12.58%	13.56%	14.55%	15.48%	16.47%
	$ 112.50	9.47%	10.50%	11.54%	12.55%	13.54%	14.53%	15.46%
	$ 105.50	8.32%	9.43%	10.47%	11.50%	12.52%	13.52%	14.51%
	$ 99.00	7.21%	8.36%	9.44%	10.51%	11.54%	12.57%	13.57%
	$ 92.50	6.56%	7.24%	8.39%	9.48%	10.55%	11.59%	12.59%
	$ 85.50	5.06%	6.49%	7.18%	8.34%	9.44%	10.51%	11.55%
	$ 79.00	3.66%	5.07%	6.51%	7.21%	8.38%	9.47%	10.55%

Figure 10 The sensitivity of the Avoided Cost to the wholesale rate of scenario 5. Yellow shaded area represents a ROE greater than or equal to the 10.5% hurdle rate.

ITC

Investment tax credits are an important component of the financial modeling involving both solar assets and battery storage. The financial models capitalize the ITC in the first year of revenue generation on a dollar-for-dollar basis; we assume that the ITC is "sold" at the face value of the tax credit to a third-party tax equity investor with a significant tax liability. The ITC is calculated as 30% of the CAPEX of solar and storage assets, minus miscellaneous costs. Receiving less than the face value of the ITC would increase the wholesale rate of electricity required to meet the ROE hurdle rate. Figure 11 is a sensitivity analysis of the dollar-for-dollar impact of the ITC on the wholesale rate for scenario 5. If the ITC is sold for 70 cents on the dollar instead of par value, the wholesale rate of electricity would increase to $103.0/MWh to meet the 10.5% ROE hurdle rate. Selling the ITC for 40 cents on the dollar further increases the wholesale rate to $107.0/MWh (**Figure 11**).

		ITC Face Value						
		$ 1.00	$ 0.90	$ 0.80	$ 0.70	$ 0.60	$ 0.50	$ 0.40
Wholesale Price. $/MWh	$ 99.00	10.51%	10.30%	10.11%	9.91%	9.72%	9.54%	9.35%
	$ 100.50	10.74%	10.53%	10.33%	10.14%	9.95%	9.76%	9.58%
	$ 101.50	10.89%	10.69%	10.48%	10.29%	10.09%	9.91%	9.72%
	$ 103.00	11.07%	10.86%	10.66%	10.46%	10.26%	10.08%	9.89%
	$ 104.50	11.29%	11.09%	10.88%	10.68%	10.49%	10.29%	10.11%
	$ 105.50	11.50%	11.29%	11.09%	10.88%	10.69%	10.49%	10.30%
	$ 107.00	11.73%	11.51%	11.31%	11.10%	10.90%	10.71%	10.52%

Figure 11 Sensitivity of selling the ITC to an equity investor at a discount to the face value. A $0.90 face value represents selling the ITC for 90 cents on the dollar of value.

Cost of Debt

The cost of debt for the project was assumed to be 5%, representing the average market values reported by regulated utility scale firms. Changing market conditions, such as interest rates, can impact the cost of debt and hence alter the interest expenses in the financial models. Altering the interest expense impacts cash flows, as well as the interest tax shield. As illustrated in Figure 12 an increase in the cost of debt by 200 basis points will increase the wholesale rate of electricity for scenario 5 from $99.0 to $101.75/MWh. Alternatively, a decrease of 200 basis points would decrease the cost of debt to $96.0/MWh (**Figure 12**).

		Cost of Debt						
		3%	4%	4.50%	5%	5.50%	6%	7%
Wholesale Price. $/MWh	$ 96.00	10.52%	10.28%	10.17%	10.06%	9.95%	9.82%	9.65%
	$ 97.50	10.76%	10.49%	10.38%	10.29%	10.19%	10.08%	9.88%
	$ 98.50	10.94%	10.65%	10.54%	10.43%	10.34%	10.23%	10.05%
	$ 99.00	11.03%	10.73%	10.62%	10.51%	10.40%	10.31%	10.13%
	$ 99.50	11.11%	10.80%	10.69%	10.58%	10.48%	10.39%	10.20%
	$ 100.50	11.27%	10.98%	10.85%	10.74%	10.63%	10.52%	10.35%
	$ 101.75	11.45%	11.17%	11.06%	10.93%	10.82%	10.71%	10.51%

Figure 12 Sensitivity analysis of the cost of debt on the wholesale rate required to meet the 10.5% ROE hurdle.

Electricity Growth Rate

All energy models include an electricity growth rate assumption to allow for improvements in the amount of total power produced per year. Improvements in annual MWh may result from improvements in technology integrated during annual O&M, for example. All energy models assume a 1% annual growth rate in electricity, which directly impacts the revenue line in all financial models. Reducing the electricity growth rate to 0 increases the wholesale rate of scenario 5 from $99.0 to $107.50/MWh. Alternatively, increasing the annual growth rate to 2% decreases the wholesale rate to $91.25/MWh **(Figure 13**).

		Electricity Growth Rate						
		0.00%	0.50%	0.75%	1.00%	1.25%	1.50%	2.00%
Wholesale Price. $/MWh	$ 107.50	10.50%	11.18%	11.48%	11.80%	12.12%	12.45%	13.07%
	$ 103.50	9.91%	10.55%	10.89%	11.22%	11.54%	11.84%	12.47%
	$ 101.00	9.51%	10.16%	10.49%	10.81%	11.16%	11.48%	12.10%
	$ 99.00	9.18%	9.87%	10.20%	10.51%	10.83%	11.15%	11.82%
	$ 96.75	8.83%	9.49%	9.85%	10.18%	10.48%	10.81%	11.47%
	$ 94.50	8.47%	9.15%	9.47%	9.80%	10.15%	10.48%	11.10%
	$ 91.00	7.87%	8.58%	8.92%	9.26%	9.57%	9.90%	10.58%

Figure 13 Sensitivity analysis of the impact of the electricity growth rate on the wholesale rate required to meet the 10.5% ROE hurdle.

Implications

Capacity Overbuilds

As shown, pure solar or wind scenarios require significant scaling-up of installed capacity to provide baseload power, even when supported by battery storage systems. The lower capacity factors of these renewable energy sources require scaling up generation assets to match average production of the NGCC plant. The scale required is even greater for these VREs to store sufficient electricity to meet year-round demand. The result is that, from a purely financial perspective, the NGCC is far more capital efficient than a generating portfolio based on a single renewables source plus storage. In our reference case, Scenario 1, the NGCC's total costs were about $702M dollars (in NPV), while our renewables plus backup models incurred capital costs 6-10X higher to serve the same power demands (**Table 1**).

The high capital expenditure of renewables as baseload stems primarily from two factors: capacity factor and variability in generating profile. To make up for the lower capacity factor of solar and wind generation assets, the model required that these assets were scaled up in size to produce the requisite power to meet baseload requirements. For example, wind assets with a 50% capacity factor must be built to twice the nameplate capacity as the NGCC to produce the same amount of aggregate power per annum. It is important to note that this is true *during periods of production* and that VREs will experience periods in which they do not produce or underperform relative to baseload demand. Wind assets do not produce power constantly, and there are periods during which the assets produce no power at all. Battery storage technology is required for renewables to cover generating gaps and changes the size of renewable assets nameplate capacity. VREs backed by storage must produce enough power not only to meet baseload requirements, but also to charge batteries sufficiently such that baseload requirements are met when the VRE is under-producing or not producing at all (i.e. on concurrent clouded days for solar or calm days for wind).

The need to generate sufficient stored power to cover extended non-generating periods makes the scaling factor even greater for VRE assets. In our scenarios, the costs of taking solar assets from an incremental power source as in Scenario 2 (i.e. generating electricity during sunny periods with an NGCC providing unfulfilled requirements) to a baseline power source as in Scenario 3 (i.e. solar plus storage providing a minimum of 650MW for 85% of the hours in a year) required a 4.7x increase in CAPEX for non-fossil-fuel assets. The change in CAPEX is attributable in part to the high cost of storage, which accounts for 40% of project capital, but also due to the massive amounts of solar needed to sufficiently charge storage assets to get through extended non-generating periods. The total solar capacity required to store and provide baseload through non-generating periods was 2,958 MWs, a 4.55X increase over the baseload power requirement. **Figure 14** shows the specific asset increase of Scenario 3 over Scenario 1.

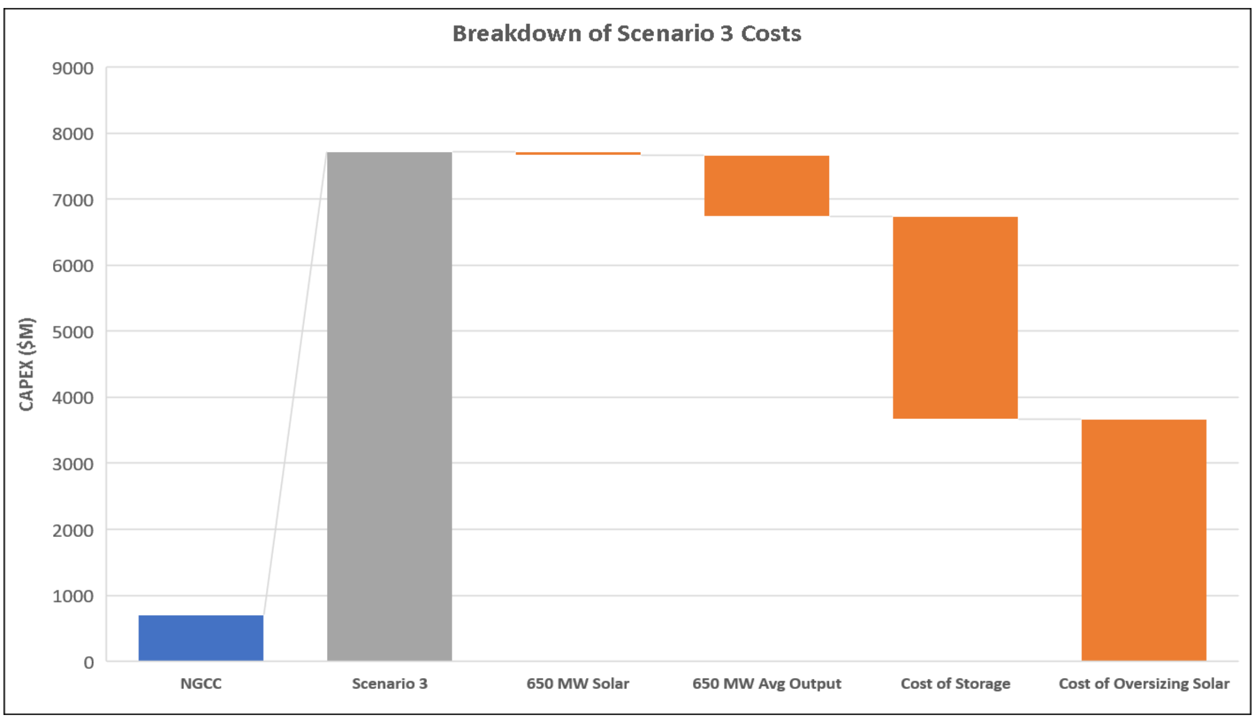

Figure 14: Price comparison of NGCC CAPEX vs Solar/Storage CAPEX by function

True Cost of Baseload Renewables

A secondary result of the need to scale generation and storage assets is the inversion of a popular contemporary theory regarding renewables: that they will only become cheaper. The increasing adoption of solar and wind generation globally has allowed manufacturers and service providers to continuously lower prices for their goods, and storage manufacturers have recently experienced a similar trend. For example, over the last 10 years, prices for photovoltaic cells have dropped by over 75% with little evidence suggesting these prices have hit the bottom of the cost curve. However, this study shows that the price of VRE assets per MW of nameplate capacity doesn't tell the full story. In a world of baseload renewables, the full price of each MWh added to the grid must include the cost of storage assets, the additional generation assets required to fill that storage, and any supporting infrastructure that wouldn't otherwise be required. The implication is that as VREs penetrate further into the grid and provide a larger proportion of national 'baseload' energy, the price per VRE-generated MWh will begin to increase rather than decrease.

VRE-based assets currently provide only a small portion of total energy in America, while dispatchable assets provide the bulk. Despite their mismatch to power markets, VREs backed by storage are able to meet incremental electricity demands while nuclear or fossil-fuel based assets are solely responsible for baseload demands. As dispatchable power generators age out or become uncompetitive, VREs plus storage will have to meet baseload and the scaling issues revealed by this study will begin to appear in market prices. As VREs become responsible for meeting increasing baseload demand, there will be an inflection point at which the cost of each additional MWh of electricity produced by variable assets and their supporting infrastructure will increase rather than decrease despite economies of scale. While determining the exact inflection point was beyond the scope of this study, this outcome is clearly implied by our results.

Generation/Storage Relationship

In this study, all scenarios were optimized for hourly energy production and capital expenditure. In Scenarios 3, 4, and 5, this process required finding the optimal balance between generation capacity and storage capacity. Energy storage is often discussed as a key element of a successful renewables-based economy due to its ability to transfer power from periods of peak generation to periods of peak demand. In models 3, 4, and 5, storage was critical as VRE assets could not provide electricity at the consistent level required by our baseload definition, despite up-scaling. This critical ability to shift power from periods of generation, or when wholesale prices may be low, to periods of non-generation, when prices may be higher, makes storage assets quite valuable. However, the high cost of raw materials and associated services also make storage assets extremely expensive compared to the renewables generation assets. The high value and high cost of storage required finding the most efficient way to leverage these assets in each scenario.

We found the relationship between VRE generation assets and energy storage technology is non-linear (**Figure 15**). At current prices, there is a non-linear relationship in which storage assets are most cost-effective at 1:3.6 (MWs/MWhs) ratio for solar and 1:3.2 for wind assets.

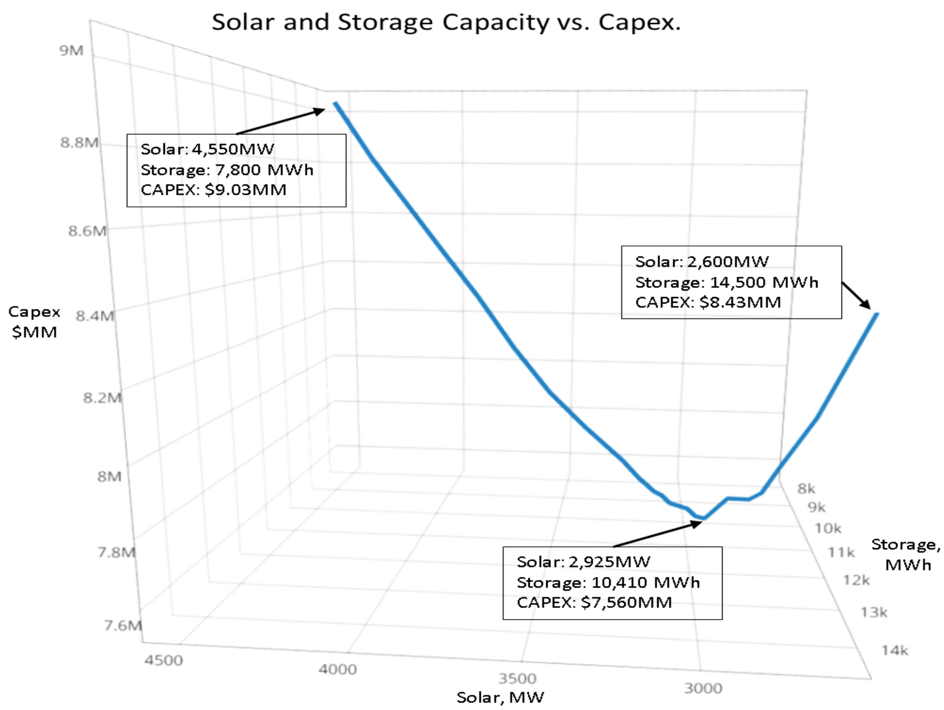

Figure 15: Relationship between battery storage capacity and solar capacity with respect to project CAPEX.

Dispatchability

Due to their intermittent generation profile, VREs face major challenges as baseload energy providers. Without scaling up, a 650MW solar plant will fall short of meeting baseload demand every day of the year. A large scale solar development requires generation backup capacity, either a natural gas plant or large-scale storage capacity. Even with battery storage, solar generation must be further scaled so that it can meet the daytime baseload demand and store surplus energy for nighttime demand and future periods of low-production. In our model, additional watts produced above baseload have a constant assigned value of $35. However, in a real-world market system, each additional watt produced above load has diminishing value. While the exact value per watt changes as the available storage capacity changes, Figure 8 shows that additional generating and storage capacity continually become more expensive beyond the 85% capacity factor required.

However, this 85% definition for baseload is somewhat misleading. For dispatchable resources like the NGCC plant in scenarios 1 and 2, any unfilled capacity is planned to allow for operations and maintenance and can be altered if required by unforeseen circumstances. In the case of VREs, this is not true. Periods of unserved load in scenarios 3,4, and 5 represent unplanned and unpredictable outages that result when solar or wind resources fail to generate, and storage assets are fully discharged. These outages may be forecasted in the short-term but cannot be controlled and especially in the case of solar, may occur at times when power is most crucial to maintaining quality of life, such as during dark winter months. While at these critical moments, the intermittent generators may still generate MWh, they do not generate enough energy to meet the designated baseload thresholds. A comparison of periods of unserved demand is shown in the section **Periods of Unserved Demand** within **Appendix A**.

The impact of these unplanned outages can be mitigated to some extent by combining renewable assets with different resource profiles. This can apply to solar in different geographic areas which experience production peaks at different times or can apply to complementary generation profiles, as shown in Figure 5. In certain locations, combining wind and solar with storage can achieve lower capital costs and wholesale power prices due to the complimentary production profiles. These complementary profiles not only more effectively meet baseload demand but also allow for more efficient use of storage assets by mitigating the feast-famine nature of solar production. However, the extent of the improvement does not materially alter the conclusions reported above: complementary VRE portfolios would still experience unplanned outages and a wholesale electricity rate significantly higher than the price in the reference case.

Negative Externality: Carbon Tax

As this study has shown, decarbonized energy generation requires much higher total costs than conventional fossil-fuels and many of these costs occur at the beginning of the project's life. Therefore, pending major shifts in storage and renewable asset prices, some cost on carbon is required make an investor indifferent between established carbon-based generators like the NGCC in Scenario 1 and decarbonized generators like those in Scenarios 3, 4, and 5 on an ROE basis (**Table 4** and **Figure 17**).

In this study, we consider the cost on carbon to be represented by the difference between each scenario's required wholesale electricity price and the reference case price. Although this study does not intend to make policy recommendations, we recognize that one of the most discussed forms of a cost on carbon is carbon taxes. While a tax is only one possible method of establishing a cost on carbon, it is a concept that many readers are familiar with and allows comparison between our findings and existing or suggested policies around the world. These contemporary carbon tax considerations unfortunately fall far short of the levels implied by this study.

Our research suggests a partially decarbonized portfolio like scenario 2 requires a carbon tax up to $75.0/ton and a fully decarbonized scenario requires a maximum carbon tax of $389.9/ton – a 5.2x multiple over the partially decarbonized scenario – to make investors indifferent to generating profile based on economics alone. Compare this to the most well-known carbon tax proposals and you'll see a significant discrepancy in most countries (**Figure 16**). Ultimately, full decarbonization requires higher energy costs due to the capital intensity of replacing baseload generation with contemporary renewables technology and battery storage. As a result, a cost on carbon must play an integral role in this process, though societies must decide for themselves whether and how the process should be accomplished.

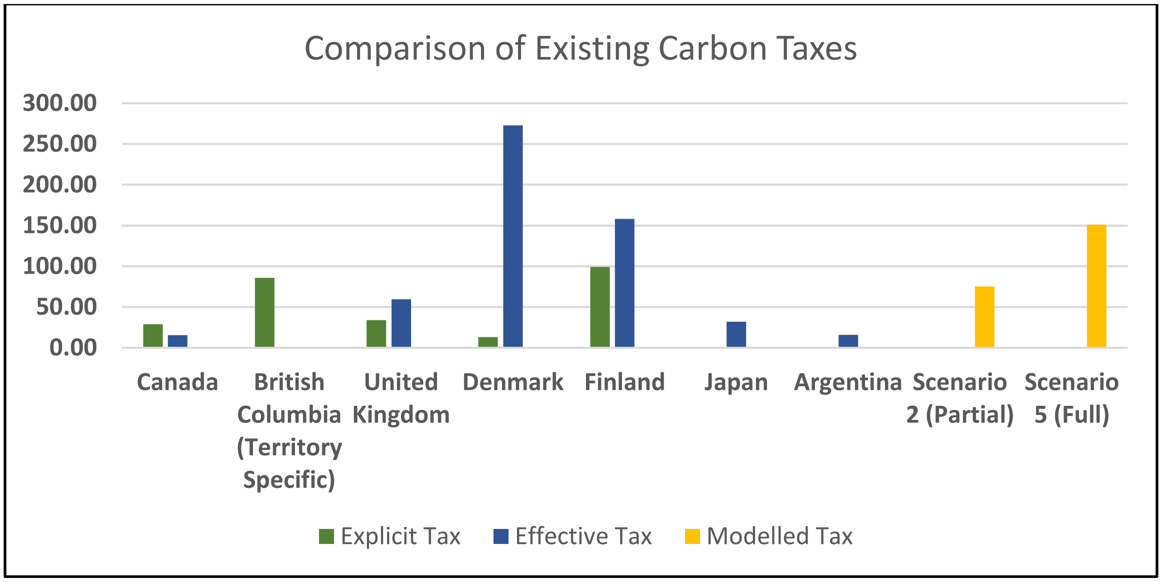

Figure 16. Comparison of existing effective carbon taxes world-wide and implied scenario carbon taxes

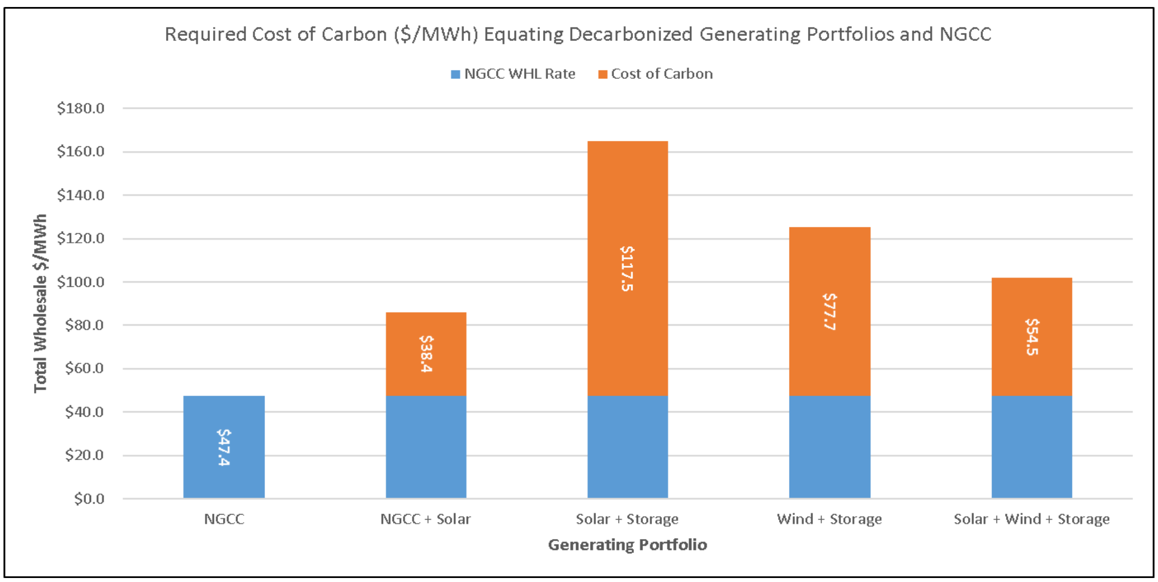

Figure 17 Cost of Carbon per Scenario required to equate a NGCC to a VRE asset.

Outlook

Changing Nature of Baseload Demand

Throughout this study we define baseload as a given amount of power produced nearly continuously over the course of time. In the real economy, baseload generators are typically large nuclear or fossil-fuel power plants that are technically dispatchable, but which typically run at 100% capacity (less planned downtime for maintenance) to maximize their efficiency. Baseload demand is the amount of electricity demand that is constant regardless of time of day or season. While our scenarios are written to meet this conventional view of baseload demand, many authors have suggested that the nature of this demand is changing. VRE generators are reducing the periods in which there is consistent demand. Utility programs like Demand-Management and Demand-Response are already in place to mitigate periods of peak demand, when transmission and distribution systems are strained and electricity prices spike. Residential consumers are also finding ways to shift their usage by adopting smart appliances that can be programmed to use electricity when prices should be lowest while also using less total energy than previous models. Storage assets may be the best example of a technology that destroys the concept of baseload demand. As mentioned above, batteries can shift periods of demand by storing additional energy when use is lower than generation. As a result, periods that have traditionally seen lower demand (the base of baseload) may see more, while peak periods are shaved or removed entirely. In this case, batteries serve two purposes, they protect customers from asset generation shortfalls and they protect grids from overproduction and wasted power, maximizing system efficiency. Of course, ongoing developments in energy efficiency have also impacted the definition of baseload as total load demand has stagnated despite increasing users and appliances in the US.

Conclusions

The last ten years have been a time of drastic change for renewable energy technologies. Improvements in photovoltaics, turbine manufacturing, and battery storage, amongst many other factors, have resulted in falling prices and widespread adoption. Much of this change can be attributed to government policies supporting renewable-energy based generation due to increasing public concerns about climate change and the impacts of greenhouse gases on the environment. These concerns have led to both indirect policy support through research and development funding and direct support in the form of tax credits. As a result, sticker prices for renewable assets like solar and wind have decreased almost to par with traditional fossil-fuel based assets like coal-fired power plants. However, current technical limits of these assets mean they are mismatched to the demands of providing baseload power. Forcing variable assets to meet such consistent demand has serious implications for the economics of such an application.

This study set out to examine the all-in economic impacts of decarbonizing power generators. As VRE assets become more prevalent in the electric system, they must be paired with supporting technologies like battery storage and transmission upgrades to overcome their variable resource profile and the non-dispatchable nature of their generation. Expensive storage, infrastructure upgrades, and up-scaling all increase project capital immensely. By capturing the capital requirements of the supporting technologies as well as the installation costs of primary technologies, the study has found that the cost of decarbonizing power generation is far greater than the cost of contracted renewables on top of existing networks of dispatchable generators. When these all-in costs are accounted for, it becomes clear that project capital requirements of baseload renewables must result in wholesale electricity prices far above current rates. Our model is neutral on how these rates are paid; however, it’s important to understand what these expenses represent. These increases represent the price of decarbonization.

Our study referred to the difference between wholesale prices from fossil-fuel assets and prices from fully decarbonized portfolios as a cost on carbon. While there are many possible mechanisms to decarbonize the power systems, including aggregating VRE resources across massive geographies using extensive HVDC, next level demand response enabled by IoT, more generation diversity like Quebec hydropower, creating virtual power plants with EVs, dynamic rates, all have major capital requirements. We are neutral as to how these capital requirements could be paid, whether directly (at purchase) or indirectly (in the form of carbon taxes), but it’s clear this cost is required to move to a power-generation system in which carbon-dioxide-producing fossil-fuels are fully removed. Many countries have attempted to address the negative externalities of carbon pollution with carbon taxes or other policy initiatives that discourage large amounts of fossil-fuel consumption, however, in all but a few cases, these initiatives fall short of the associated cost-increases highlighted here. Instead, this study has found that if populations wish to remove carbon from their power generation systems, they must recognize and accept the cost increases such a transformation requires. Whether governments, businesses, and consumers would be willing to pay such high rates to achieve this goal remains unclear.

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Appendix A

Detailed Planning Bases

Financial Basis	
Corporate Tax Rate	21%
Avoided Cost, $/MWh	$35
Target Return on Equity	10.5%
Electricity Growth Rate	1.0%
Terminal Period, years (Annuity)	15
NOL, loss carryforward max, %	80.0%

Capital Structure	
% Debt	40.0%
E/V	60.0%
Debt Tenure, years	10.00
Cost of Debt	5.0%
Cost of Equity	9.51%
WACC	7.8%
Debt, EAR	0.41%
DSCR Target	1.20 X
Debt/EBITDA	8.00 X

Renewable Energy Credits	
ITC Basis, % CAPEX	30%
ITC Development Fee	15%
PTC Basis, years	10
PTC Percentage	80.0%

MARCS Depreciation Schedules	
NGCC	7 year
Solar	5 year
Wind	5 year
Battery Storage	5 year

Natural Gas Capital Items	
Base Overnight Cost, $/kW	$1,000.00
Project Contingency	8%
Natural Gas Consumption, MMBtu/year	32,911,320.00
Natural Gas, $/mmBTU	2.88
Variable O&M, $/MWh	$1.96
Fixed O&M, $/MWh/year	$9.78
Nautral Gas Transportation Fee, $/MMBtu	$1.00
Carbon Tax, $/Ton	$75.00
Carbon Tax, $/MWh	$41.30

Solar Capital Items	
Install Price, $/W	$1.00
Developer Fee, $/W	$0.02
Land Lease, $/acre	$700
Acres/MW	6.00
Annual Lease Escalator	2.00%
Insurance, $/kW	$3.15
Insurance Escalator	1.00%
Fixed O&M, $/kW/year	$6.00
Annual Fixed O&M Escalator	2.50%

Wind Capital Items	
Install Price, $/W	$0.95
Developer Fee, $/W	$0.03
Land Lease, $/acre	$700
Acres/MW	6.00
Annual Lease Escalator	2.00%
Insurance, $/kW	$3.00
Insurance Escalator	1.00%
Fixed O&M, $/kW/year	$1.31
Annual Fixed O&M Escalator	2.50%
Transmission Line Rental, $/mWh	$25.00

Storage Capital Items	
Install Price, $/kWh	$300.00
Warranty % Capex	20.00%
Lease, Acres/mWh	0.01
Land Lease, $/Acre	$700
O&M, % of Capex	2.50%
O&M Escalator	2.25%

Natural Gas Planning Bases	
Capacity Factor	85.0%
Plant Capacity, AC, MW	650
Electricity Output, MWh/year	4,839,900.00
Heat Rate, Btu/kWh	6800
Lb Carbon per kWh	0.87
Ton Carbon per mWh	0.435

Solar Planning Bases	
Capacity Factor	19.9%
DC:AC Overbuild	1.40
Solar Module Degredation, %/year	0.5%
AC System Size, mW, Scenario 2	650.00
AC System Size, mW, Scenario 3	2957.50
AC System Size, mW, Scenario 5	845.00

Wind Planning Bases	
Capacity Factor	45.3%
DC:AC Overbuild	1.40
Transmission Line Capacity, MWh	
Scenario 4	12,392,151.92
Scenario 5	9,746,468.58
AC System Size, mW, Scenario 4	2,625.34
AC System Size, mW, Scenario 5	2,890.76

Storage Planning Bases	
Capacity, MWh Scenario 3	10,250.00
Capacity, MWh Scenario 4	6,550.00
Capacity, MWh Scenario 5	2,410.00

MARCS Accelerate Depreciation Schedule

Natural Gas Combined Cycle plants used a 7-year depreciation schedule.

Wind, Solar and Storage assets used a 5-year depreciation schedule.

MACRS Accelerated Depreciation		
Year	**5 Year**	**7 Year**
0	20.00%	14.29%
1	32.00%	24.49%
2	19.20%	17.49%
3	11.52%	12.49%
4	11.52%	8.93%
5	5.76%	8.92%
6	0.00%	8.93%
7	0.00%	4.46%
Total	**100.00%**	**100.00%**

Debt Metrics by Scenario

Scenario	**Debt Metrics**													
	Year	0	1	2	3	4	5	6	7	8	9	10	11	12
1) Utility	DSCR				1.75x	1.88x	1.98x	2.09x	2.12x	2.21x	2.31x	2.19x	2.09x	2.48x
	Debt/EBITDA				3.63x	3.12x	2.71x	2.30x	1.92x	1.57x	1.21x	0.87x	0.52x	0.17x
1) Utility Carbon Tax	DSCR				1.92x	2.42x	2.31x	2.28x	2.29x	2.42x	2.58x	2.52x	2.49x	2.67x
	Debt/EBITDA				1.02x	0.90x	0.78x	0.67x	0.56x	0.46x	0.35x	0.25x	0.15x	0.05x
2) Solar_NCGG Carbon Tax	DSCR			106.26x	1.47x	1.55x	1.49x	1.51x	1.45x	1.63x	1.39x	1.37x	1.43x	1.50x
	Debt/EBITDA			4.60x	2.34x	2.05x	1.78x	1.51x	1.25x	1.00x	0.74x	0.50x	0.25x	0.25x
3) Solar_Storage	DSCR			5.29x	1.65x	1.71x	1.79x	1.86x	1.76x	1.64x	1.71x	1.79x	1.87x	
	Debt/EBITDA			16.98x	3.43x	3.01x	2.59x	2.17x	1.77x	1.36x	0.97x	0.58x	0.19x	
4) Wind_Storage	DSCR			2.73x	2.07x	2.15x	2.27x	2.37x	2.36x	2.27x	2.40x	2.50x	2.65x	
	Debt/EBITDA			18.91x	4.40x	3.90x	3.41x	2.93x	2.45x	1.99x	1.53x	1.09x	0.65x	
5) Wind_Solar_Storage	DSCR			3.15x	1.84x	1.91x	2.02x	2.10x	2.19x	2.25x	2.38x	2.49x	2.64x	
	Debt/EBITDA			7.62x	4.37x	3.83x	3.29x	2.76x	2.24x	1.72x	1.22x	0.73x	0.24x	

Debt/EBITDA	
Max	7.6x
Min	0.0x
Threshold (max)	**8.0x**

Debt Service Coverage Ratio	
Max	2.7x
Min	1.4x
Threshold (min)	**1.2x**

Financial Models

Scenario 1 – NGCC

Income Statement	Projected Year Ending December 31											
	0	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**21**	**22**	**23**
Wholesale $/MWh				$ 47.12	47.59	48.07	48.55	49.03	49.52	56.36	56.93	
Revenue				$ 228,056,088.00	230,336,648.9	232,640,015.4	234,966,415.5	237,316,079.7	239,689,240.5	272,788,714.0	275,516,601.1	
COGS				(149,347,005.6)	(148,376,473.0)	(149,380,637.4)	(150,055,706.4)	(151,389,019.7)	(153,380,577.3)	(183,568,639.7)	(186,211,594.7)	
Fixed O+M				(6,357,000.0)	(6,363,743.7)	(6,370,494.6)	(6,377,252.6)	(6,384,017.8)	(6,390,790.2)	(6,479,487.5)	(6,486,361.1)	
Variable O+M				(9,486,204.0)	(9,496,267.3)	(9,506,341.2)	(9,516,425.8)	(9,526,521.2)	(9,536,627.2)	(9,668,985.4)	(9,679,242.6)	
Fuel Cost				(94,784,601.6)	(93,797,262.0)	(94,784,601.6)	(95,442,828.0)	(96,759,280.8)	(98,733,960.0)	(128,700,966.8)	(131,326,790.9)	
Transportation Fee				(38,719,200.0)	(38,719,200.0)	(38,719,200.0)	(38,719,200.0)	(38,719,200.0)	(38,719,200.0)	(38,719,200.0)	(38,719,200.0)	
Gross Profit (EBITDA)				78,709,082.4	81,960,175.9	83,259,378.0	84,910,709.1	85,927,059.9	86,308,663.1	89,220,074.3	89,305,006.5	
Depreciation and Ammortization				(100,315,800.0)	(171,919,800.0)	(122,779,800.0)	(87,679,800.0)	(62,688,600.0)	(62,618,400.0)	0.0	0.0	
EBIT				**$ (21,606,717.60)**	**(89,959,624.09)**	**(39,520,422.01)**	**$ (2,769,090.9)**	**23,238,459.9**	**23,690,263.1**	**89,220,074.3**	**89,305,006.5**	
Interest Expenses				(15,025,238.5)	(13,522,714.6)	(12,020,190.8)	(10,517,666.9)	(9,015,143.1)	(7,512,619.2)			
Net Interest Expense				(15,025,238.5)	(13,522,714.6)	(12,020,190.8)	(10,517,666.9)	(9,015,143.1)	(7,512,619.2)			
% of EBITDA				19.1%	16.5%	14.4%	12.4%	10.5%	8.7%	0.0%	0.0%	
Alternative Tax Shield				*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	
EBT				**$ (36,631,956.07)**	**(103,482,338.72)**	**(51,540,612.78)**	**(13,286,757.83)**	**14,223,316.85**	**16,177,643.89**	**89,220,074.31**	**89,305,006.45**	
Loss Carryforward (prior period)				0.0	(36,631,956.1)	(140,114,294.8)	(191,654,907.6)	(204,941,665.4)	(190,718,348.5)	0.0	0.0	
Net Operating Gain (Loss)				(36,631,956.1)	(140,114,294.8)	(191,654,907.6)	(204,941,665.4)	(193,563,011.9)	(180,620,896.8)	647,733,214.7	719,177,219.8	
Taxable Income				0.0	0.0	0.0	0.0	0.0	0.0	89,220,074.3	89,305,006.5	
NOL 20% Adjustment				0.0	0.0	0.0	0.0	14,223,316.9	16,177,643.9	0.0	0.0	
Income Tax Expenses				0.0	0.0	0.0	0.0	(2,986,896.5)	(3,397,305.2)	(18,736,215.6)	(18,754,051.4)	
Net Income				**$ (36,631,956.07)**	**(103,482,338.72)**	**(51,540,612.78)**	**(13,286,757.83)**	**11,236,420.31**	**12,780,338.67**	**70,483,858.70**	**70,550,955.10**	

Statement of Cash Flows												
	0	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**21**	**22**	**23**
Operating Activities												
Net Income				(36,631,956.07)	(103,482,338.72)	(51,540,612.78)	(13,286,757.83)	11,236,420.31	12,780,338.67	70,483,858.70	70,550,955.10	
Depreciation				100,315,800.0	171,919,800.0	122,779,800.0	87,679,800.0	62,688,600.0	62,618,400.0			
Cash Flow from Operations				63,683,843.9	68,437,461.3	71,239,187.2	74,393,042.2	73,925,020.3	75,398,738.7	70,483,859	70,550,955	
Investing Activities												
Capital Expenditure	(140,400,000.0)	(140,400,000.0)	(140,400,000.0)									
Cash Flow from Investing Activities	(140,400,000.0)	(140,400,000.0)	(140,400,000.0)									
Financing Activities												
(Payment) Withdrawl Debt Service Reserve Account	0.0	0.0	0.0	(15,025,238.5)	0.0	0.0	0.0	0.0	0.0	-	-	
Beginning Balance of Debt	95,363,401.9	195,442,447.3	300,504,769.4	300,504,769.4	270,454,292.4	240,403,815.5	210,353,338.6	180,302,861.6	150,252,384.7			
Borrowing / (Payment) of Long Term Debt				(30,050,476.9)	(30,050,476.9)	(30,050,476.9)	(30,050,476.9)	(30,050,476.9)	(30,050,476.9)			
Ending Balance of Debt	95,363,401.9	195,442,447.3	300,504,769.4	270,454,292.4	240,403,815.5	210,353,338.6	180,302,861.6	150,252,384.7	120,201,907.8			
												Terminal Value
Net Change in Cash	$ (140,400,000.00)	(140,400,000.0)	(140,400,000.0)	18,608,128.5	38,386,984.3	41,188,710.3	44,342,565.2	43,874,543.4	45,348,261.7	70,483,858.7	70,550,955.1	595,701,457.9
PV of Net CF	$ (140,400,000.00)	(130,253,270.2)	(120,839,846.2)	14,858,237.0	28,436,104.9	28,306,477.8	28,271,573.6	25,951,550.2	24,884,726.3	14,586,186	13,544,922	114,367,409
Equity Value	$ 35,617,452.23											
Terminal Value (Gordon Growth)	$ 595,701,457.86											
PV of Terminal Value	$ 114,367,408.57											
NPV of CF (Enterprise Value)	**$ 149,984,860.80**											
IRR	**10.50%**											

Scenario 1 – NGCC + Carbon Tax

Income Statement	Projected Year Ending December 31											
	0	1	2	3	4	5	6	7	8	21	22	23
Wholesale $/MWh				$ 88.42	89.30	90.20	91.10	92.01	92.93	105.76	106.82	
Revenue				$ 427,943,958.00	432,223,397.6	436,545,631.6	440,911,087.9	445,320,198.8	449,773,400.7	511,884,085.1	517,002,925.9	
COGS				(149,347,005.6)	(148,376,473.0)	(149,380,637.4)	(150,055,706.4)	(151,389,019.7)	(153,380,577.3)	(183,568,639.7)	(186,211,594.7)	
Fixed O+M				(6,357,000.0)	(6,363,743.7)	(6,370,494.6)	(6,377,252.6)	(6,384,017.8)	(6,390,790.2)	(6,479,487.5)	(6,486,361.1)	
Variable O+M				(9,486,204.0)	(9,496,267.3)	(9,506,341.2)	(9,516,425.8)	(9,526,521.2)	(9,536,627.2)	(9,668,985.4)	(9,679,242.6)	
Fuel Cost				(94,784,601.6)	(93,797,262.0)	(94,784,601.6)	(95,442,828.0)	(96,759,280.8)	(98,733,960.0)	(128,700,966.8)	(131,326,790.9)	
Transportation Fee				(38,719,200.0)	(38,719,200.0)	(38,719,200.0)	(38,719,200.0)	(38,719,200.0)	(38,719,200.0)	(38,719,200.0)	(38,719,200.0)	
Gross Profit (EBITDA)				278,596,952.4	283,846,924.6	287,164,994.2	290,855,381.4	293,931,179.0	296,392,823.4	328,315,445.4	330,791,331.3	
Depreciation and Ammortization				(100,315,800.0)	(171,919,800.0)	(122,779,800.0)	(87,679,800.0)	(62,688,600.0)	(62,618,400.0)	0.0	0.0	
EBIT				**$ 178,281,152.40**	**111,927,124.61**	**164,385,194.18**	**203,175,581.4**	**231,242,579.0**	**233,774,423.4**	**328,315,445.4**	**330,791,331.3**	
Interest Expenses				(15,025,238.5)	(13,522,714.6)	(12,020,190.8)	(10,517,666.9)	(9,015,143.1)	(7,512,619.2)			
Net Interest Expense				(15,025,238.5)	(13,522,714.6)	(12,020,190.8)	(10,517,666.9)	(9,015,143.1)	(7,512,619.2)			
% of EBITDA				5.4%	4.8%	4.2%	3.6%	3.1%	2.5%	0.0%	0.0%	
Alternative Tax Shield				*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	
EBT				**$ 163,255,913.93**	**98,404,409.98**	**152,365,003.40**	**192,657,914.52**	**222,227,435.92**	**226,261,804.15**	**328,315,445.43**	**330,791,331.28**	
Loss Carryforward (prior period)				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Net Operating Gain (Loss)				163,255,913.9	261,660,323.9	414,025,327.3	606,683,241.8	828,910,677.8	1,009,920,121.1	4,182,380,069.9	4,447,013,134.9	4,447,013,134.9
Taxable Income				163,255,913.9	98,404,410.0	152,365,003.4	192,657,914.5	222,227,435.9	226,261,804.2	328,315,445.4	330,791,331.3	
NOL 20% Adjustment				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Income Tax Expenses				(34,283,741.9)	(20,664,926.1)	(31,996,650.7)	(40,458,162.0)	(46,667,761.5)	(47,514,978.9)	(68,946,243.5)	(69,466,179.6)	
Cost of Carbon				(157,911,417.3)	(157,911,417.3)	(157,911,417.3)	(157,911,417.3)	(157,911,417.3)	(157,911,417.3)	(157,911,417.3)	(157,911,417.3)	
Net Income				**$ (28,939,245.29)**	**($80,171,933.4)**	**($37,543,064.6)**	**($5,711,664.8)**	**$17,648,257.1**	**$20,835,408.0**	**$101,457,784.6**	**$103,413,734.4**	
Statement of Cash Flows												
Operating Activities												
Net Income				(28,939,245.29)	(80,171,933.41)	(37,543,064.61)	(5,711,664.83)	17,648,257.08	20,835,407.98	101,457,784.59	103,413,734.41	
Depreciation				100,315,800.0	171,919,800.0	122,779,800.0	87,679,800.0	62,688,600.0	62,618,400.0			
Cash Flow from Operations				71,376,554.7	91,747,866.6	85,236,735.4	81,968,135.2	80,336,857.1	83,453,808.0	101,457,785	103,413,734	
Investing Activities												
Capital Expenditure	(140,400,000.0)	(140,400,000.0)	(140,400,000.0)									
Cash Flow from Investing Activities	(140,400,000.0)	(140,400,000.0)	(140,400,000.0)									
Financing Activities												
(Payment) Withdrawl Debt Service Reserve Account				(15,025,238.5)	0.0	0.0	0.0	0.0	0.0	-	-	
Beginning Balance of Debt	95,363,401.9	195,442,447.3	300,504,769.4	300,504,769.4	270,454,292.4	240,403,815.5	210,353,338.6	180,302,861.6	150,252,384.7			
Borrowing / (Payment) of Long Term Debt				(30,050,476.9)	(30,050,476.9)	(30,050,476.9)	(30,050,476.9)	(30,050,476.9)	(30,050,476.9)			
Ending Balance of Debt	95,363,401.9	195,442,447.3	300,504,769.4	270,454,292.4	240,403,815.5	210,353,338.6	180,302,861.6	150,252,384.7	120,201,907.8			
												Terminal Value
Net Change in Cash	$ (140,400,000.00)	(140,400,000.0)	(140,400,000.0)	26,300,839.3	61,697,389.6	55,186,258.5	51,917,658.2	50,286,380.1	53,403,331.0	101,457,784.6	103,413,734.4	873,180,416.5
PV of Net CF	$ (140,400,000.00)	(130,253,270.2)	(120,839,846.2)	21,000,720.4	45,703,862.3	37,926,135.4	33,101,240.0	29,744,116.3	29,304,922.1	20,996,044	19,854,175	167,639,982
Equity Value	$ 164,823,356.85											
Terminal Value (Gordon Growth)	$ 873,180,416.47											
PV of Terminal Value	$ 167,639,981.61											
NPV of CF (Enterprise Value)	**$ 332,463,338.47**											
IRR	**13.2%**											

Scenario 2 – NGCC + Solar

Income Statement	Projected Year Ending December 31											
	0	1	2	3	4	5	6	7	8	21	22	23
Solar Production			**1,480,963**	**1,473,558**	**1,466,190**	**1,458,859**	**1,451,565**	**1,444,307**	**1,437,086**	**1,346,427**	**1,339,695**	
NGCC Production			**0**	**3,358,937**	**3,358,937**	**3,358,937**	**3,358,937**	**3,358,937**	**3,358,937**	**3,358,937**	**3,358,937**	
Wholesale $/MWh			$62.1	$62.7	$63.3	$64.0	$64.6	$65.3	$65.9	$75.0	$75.8	
Revenue			$91,967,795.7	$303,098,930.53	$305,663,183.50	$308,250,768.66	$310,861,907.89	$313,496,825.23	$316,155,746.93	$353,013,170.33	$356,033,182.70	
COGS			(13,045,500.0)	(162,656,535.6)	(162,244,293.5)	(163,759,296.8)	(164,960,284.1)	(166,835,046.6)	(169,384,049.8)	(208,514,287.3)	(211,996,344.9)	
Fixed O+M			(6,357,000.0)	(12,872,925.0)	(13,279,009.2)	(13,697,903.5)	(14,130,012.1)	(14,575,751.8)	(15,035,552.6)	(22,514,847.0)	(23,225,091.4)	
Variable O+M				(9,486,204.0)	(9,548,296.9)	(9,548,296.9)	(9,548,296.9)	(9,548,296.9)	(9,548,296.9)	(9,548,296.9)	(9,548,296.9)	
Fuel				(94,784,601.6)	(93,797,262.0)	(94,784,601.6)	(95,442,828.0)	(96,759,280.8)	(98,733,960.0)	(128,700,966.8)	(131,326,790.9)	
Transportation				(38,719,200.0)	(38,719,200.0)	(38,719,200.0)	(38,719,200.0)	(38,719,200.0)	(38,719,200.0)	(38,719,200.0)	(38,719,200.0)	
Land Lease			(3,822,000.0)	(3,898,440.0)	(3,976,408.8)	(4,055,937.0)	(4,137,055.7)	(4,219,796.8)	(4,304,192.8)	(5,567,932.3)	(5,679,290.9)	
Insurance			(2,866,500.0)	(2,895,165.0)	(2,924,116.7)	(2,953,357.8)	(2,982,891.4)	(3,012,720.3)	(3,042,847.5)	(3,463,044.3)	(3,497,674.7)	
Gross Profit (EBITDA)			78,922,295.7	140,442,394.9	143,418,890.0	144,491,471.9	145,901,623.8	146,661,778.6	146,771,697.1	144,498,883.1	144,036,837.8	
Depreciation and Ammortization			(119,340,000.0)	(291,259,800.0)	(286,486,200.0)	(191,519,640.0)	(156,419,640.0)	(97,058,520.0)	(62,618,400.0)	0.0	0.0	
EBIT			**($40,417,704.3)**	**($150,817,405.1)**	**($143,067,310.0)**	**($47,028,168.1)**	**($10,518,016.2)**	**$49,603,258.6**	**$84,153,297.1**	**$144,498,883.1**	**$144,036,837.8**	
Interest Expenses				(34,891,942.7)	(31,402,748.4)	(27,913,554.1)	(24,424,359.9)	(20,935,165.6)	(17,445,971.3)			
Net Interest Expense				(34,891,942.7)	(31,402,748.4)	(27,913,554.1)	(24,424,359.9)	(20,935,165.6)	(17,445,971.3)			
% of EBITDA			0.0%	24.8%	21.9%	19.3%	16.7%	14.3%	11.9%	0.0%	0.0%	
Alternative Tax Shield			*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*		
EBT			**$ (40,417,704.26)**	**(185,709,347.74)**	**(174,470,058.40)**	**(74,941,722.24)**	**(34,942,376.05)**	**28,668,093.01**	**66,707,325.79**	**144,498,883.05**	**144,036,837.77**	
Loss Carryforward (prior period)			0.0	(40,417,704.3)	(226,127,052.0)	(400,597,110.4)	(475,538,832.6)	(510,481,208.7)	(481,813,115.7)	0.0	0.0	
Net Operating Gain (Loss)			(40,417,704.3)	(226,127,052.0)	(400,597,110.4)	(475,538,832.6)	(510,481,208.7)	(487,546,734.3)	(434,180,873.6)	980,916,271.8	1,124,953,109.6	
Taxable Income			0.0	0.0	0.0	0.0	0.0	0.0	0.0	144,498,883.1	144,036,837.8	
NOL 20% Adjustment			0.0	0.0	0.0	0.0	0.0	28,668,093.0	66,707,325.8	0.0	0.0	
Income Tax Expenses			0.0	0.0	0.0	0.0	0.0	(6,020,299.5)	(14,008,538.4)	(30,344,765.4)	(30,247,735.9)	
Cost of Carbon			0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
ITC			288,206,100.0		0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Net Tax Savings (Expenses)			288,206,100.0	0.0	0.0	0.0	0.0	(6,020,299.5)	(14,008,538.4)	(30,344,765.4)	(30,247,735.9)	
Net Income			**$247,788,395.7**	**($185,709,347.7)**	**($174,470,058.4)**	**($74,941,722.2)**	**($34,942,376.1)**	**$22,647,793.5**	**$52,698,787.4**	**$114,154,117.6**	**$113,789,101.8**	

Statement of Cash Flows												
Operating Activities												
Net Income			$247,788,395.7	($185,709,347.7)	($174,470,058.4)	($74,941,722.2)	($34,942,376.1)	$22,647,793.5	$52,698,787.4	$114,154,117.6	$113,789,101.8	
Depreciation			119,340,000.0	291,259,800.0	286,486,200.0	191,519,640.0	156,419,640.0	97,058,520.0	62,618,400.0			
Cash Flow from Operations			367,128,395.7	105,550,452.3	112,016,141.6	116,577,917.8	121,477,263.9	119,706,313.5	115,317,187.4	114,154,117.6	113,789,101.8	
Investing Activities												
Capital Expenditure	(326,040,000.0)	(326,040,000.0)	(326,040,000.0)									
Cash Flow from Investing Activities	(326,040,000.0)	(326,040,000.0)	(326,040,000.0)									
Financing Activities												
Beginning Balance of Debt	221,455,011.0	453,860,794.4	697,838,853.4	697,838,853.4	628,054,968.0	558,271,082.7	488,487,197.3	418,703,312.0	348,919,426.7			
Borrowing / (Payment) of Long Term Debt				(69,783,885.3)	(69,783,885.3)	(69,783,885.3)	(69,783,885.3)	(69,783,885.3)	(69,783,885.3)			
Ending Balance of Debt	221,455,011.0	453,860,794.4	697,838,853.4	628,054,968.0	558,271,082.7	488,487,197.3	418,703,312.0	348,919,426.7	279,135,541.3			
												Terminal Value
Net Change in Cash	(326,040,000.00)	(326,040,000)	41,088,395.7	35,766,566.9	42,232,256.3	46,794,032.4	51,693,378.6	49,922,428.1	45,533,302.0	114,154,117.6	113,789,101.8	1,557,184,587
PV of Net CF	(326,040,000.00)	(302,477,039)	35,364,070.0	28,558,924.0	31,284,584.9	32,158,672.4	32,958,245.7	29,528,840.7	24,986,266.7	23,623,468.9	21,846,118.6	298,960,433
Equity Value	($12,757,733.6)											
Terminal Value (Gordon Growth)	$1,557,184,586.6											
PV of Terminal Value	$298,960,433.1											
NPV of CF (Enterprise Value)	**$286,202,699.5**											
IRR	**10.50%**											

Scenario 2 – NGCC + Solar + Carbon Tax

Income Statement	Projected Year Ending December 31											
	0	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**21**	**22**	**23**
Solar Production			**1,480,962.9**	**1,473,558**	**1,466,190**	**1,458,859**	**1,451,565**	**1,444,307**	**1,437,086**	**1,346,427**	**1,339,695**	
NGCC Production			**0**	**3,366,341.9**	**3,366,304.9**	**3,366,268.1**	**3,366,231.4**	**3,366,194.9**	**3,366,158.6**	**3,365,703.1**	**3,365,669.2**	
Portfolio $/MWh			$ 88.42	89.30	90.20	91.10	92.01	92.93	93.86	106.82	107.89	
Revenue			$ 130,946,739.12	432,223,397.58	435,877,737.71	439,565,315.17	443,286,445.97	447,041,449.18	450,830,647.02	503,354,381.72	507,657,951.15	
COGS			(13,045,500.0)	(162,656,535.6)	(162,244,293.5)	(163,759,296.8)	(164,960,284.1)	(166,835,046.6)	(169,384,049.8)	(208,514,287.3)	(211,996,344.9)	
Fixed O+M			(6,357,000.0)	(12,872,925.0)	(13,279,009.2)	(13,697,903.5)	(14,130,012.1)	(14,575,751.8)	(15,035,552.6)	(22,514,847.0)	(23,225,091.4)	
Variable O+M				(9,486,204.0)	(9,548,296.9)	(9,548,296.9)	(9,548,296.9)	(9,548,296.9)	(9,548,296.9)	(9,548,296.9)	(9,548,296.9)	
Fuel				(94,784,601.6)	(93,797,262.0)	(94,784,601.6)	(95,442,828.0)	(96,759,280.8)	(98,733,960.0)	(128,700,966.8)	(131,326,790.9)	
Transportation				(38,719,200.0)	(38,719,200.0)	(38,719,200.0)	(38,719,200.0)	(38,719,200.0)	(38,719,200.0)	(38,719,200.0)	(38,719,200.0)	
Land Lease			(3,822,000.0)	(3,898,440.0)	(3,976,408.8)	(4,055,937.0)	(4,137,055.7)	(4,219,796.8)	(4,304,192.8)	(5,567,932.3)	(5,679,290.9)	
Insurance			(2,866,500.0)	(2,895,165.0)	(2,924,116.7)	(2,953,357.8)	(2,982,891.4)	(3,012,720.3)	(3,042,847.5)	(3,463,044.3)	(3,497,674.7)	
Gross Profit (EBITDA)			117,901,239.1	269,566,862.0	273,633,444.2	275,806,018.4	278,326,161.9	280,206,402.6	281,446,597.2	294,840,094.4	295,661,606.2	
Depreciation and Ammortization			(267,268,430.0)	(437,331,830.0)	(279,082,830.0)	(179,359,830.0)	(158,117,310.0)	(105,641,640.0)	(53,285,310.0)	0.0	0.0	
NGCC Depreciation			(85,268,430.0)	(146,131,830.0)	(104,362,830.0)	(74,527,830.0)	(53,285,310.0)	(53,225,640.0)	(53,285,310.0)	0.0	0.0	
Solar Depreciation			(182,000,000.0)	(291,200,000.0)	(174,720,000.0)	(104,832,000.0)	(104,832,000.0)	(52,416,000.0)	0.0	0.0	0.0	
EBIT			**$ (149,367,190.88)**	**(167,764,968.02)**	**(5,449,385.79)**	**96,446,188.41**	**120,208,851.89**	**174,564,762.57**	**228,161,287.22**	**294,840,094.43**	**295,661,606.22**	
Interest Expenses				(35,029,862.2)	(31,526,876.0)	(28,023,889.8)	(24,520,903.6)	(21,017,917.3)	(17,514,931.1)			
Net Interest Expense				(35,029,862.2)	(31,526,876.0)	(28,023,889.8)	(24,520,903.6)	(21,017,917.3)	(17,514,931.1)			
% of EBITDA			*0.0%*	*13.0%*	*11.5%*	*10.2%*	*8.8%*	*7.5%*	*6.2%*	*0.0%*	*0.0%*	
Alternative Tax Shield			*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	
EBT			**$ (149,367,190.88)**	**(202,794,830.26)**	**(36,976,261.81)**	**68,422,298.61**	**95,687,948.32**	**153,546,845.22**	**210,646,356.10**	**294,840,094.43**	**295,661,606.22**	
Loss Carryforward (prior period)			0.0	(149,367,190.9)	(352,162,021.1)	(389,138,283.0)	(320,715,984.3)	(238,712,495.7)	(104,303,240.2)	0.0	0.0	
Net Operating Gain (Loss)			(149,367,190.9)	(352,162,021.1)	(389,138,283.0)	(334,400,444.1)	(257,850,085.4)	(135,012,609.2)	33,504,475.6	2,989,156,038.3	3,284,817,644.5	
Taxable Income			0.0	0.0	0.0	0.0	0.0	0.0	106,343,115.9	294,840,094.4	295,661,606.2	
NOL 20% Adjustment			0.0	0.0	0.0	68,422,298.6	95,687,948.3	153,546,845.2	0.0	0.0	0.0	
Income Tax Expenses			0.0	0.0	0.0	(14,368,682.7)	(20,094,469.1)	(32,244,837.5)	(22,332,054.3)	(61,916,419.8)	(62,088,937.3)	
Cost of Carbon			0	(109,592,040.9)	(109,592,040.9)	(109,592,040.9)	(109,592,040.9)	(109,592,040.9)	(109,592,040.9)	(109,592,040.9)	(109,592,040.9)	
ITC			288,206,100.0		0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Net Tax Savings (Expenses)			288,206,100.0	(109,592,040.9)	(109,592,040.9)	(123,960,723.7)	(129,686,510.1)	(141,836,878.4)	(131,924,095.3)	(171,508,460.8)	(171,680,978.3)	
Net Income			**$ 138,838,909.12**	**(312,386,871.21)**	**(146,568,302.76)**	**(55,538,425.04)**	**(33,998,561.77)**	**11,709,966.78**	**78,722,260.81**	**123,331,633.65**	**123,980,627.97**	

Statement of Cash Flows	0	1	2	3	4	5	6	7	8	21	22	23
Operating Activities												
Net Income			138,838,909.12	(312,386,871.21)	(146,568,302.76)	(55,538,425.04)	(33,998,561.77)	11,709,966.78	78,722,260.81	123,331,633.65	123,980,627.97	
Depreciation			267,268,430.0	437,331,830.0	279,082,830.0	179,359,830.0	158,117,310.0	105,641,640.0	53,285,310.0			
Cash Flow from Operations			406,107,339.1	124,944,958.8	132,514,527.2	123,821,405.0	124,118,748.2	117,351,606.8	132,007,570.8	123,331,633.7	123,980,628.0	
Investing Activities												
Capital Expenditure	$ (326,040,000)	$ (326,040,000)	$ (326,040,000)									
Cash Flow from Investing Activities	(326,040,000.0)	(326,040,000.0)	(326,040,000.0)									
Financing Activities												
(Payment) Withdrawl Debt Service Reserve Account			(35,029,862.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Beginning Balance of Debt	221,455,011.0	453,860,794.4	700,597,244.9	700,597,244.9	630,537,520.4	560,477,795.9	490,418,071.4	420,358,346.9	350,298,622.4			
Borrowing / (Payment) of Long Term Debt				(70,059,724.5)	(70,059,724.5)	(70,059,724.5)	(70,059,724.5)	(70,059,724.5)	(70,059,724.5)			
Ending Balance of Debt	221,455,011.0	453,860,794.4	700,597,244.9	630,537,520.4	560,477,795.9	490,418,071.4	420,358,346.9	350,298,622.4	280,238,898.0			
												Terminal Value
Net Change in Cash	$ (326,040,000.00)	(326,040,000)	45,037,476.9	54,885,234.3	62,454,802.8	53,761,680.5	54,059,023.7	47,291,882.3	61,947,846.3	123,331,633.7	123,980,628.0	1,046,838,284.8
PV of Net CF	$ (326,040,000.00)	(302,477,039)	38,762,975.6	43,824,816.5	46,264,934.7	36,947,110.2	34,466,514.5	27,972,887.4	33,993,700.0	25,522,697.5	23,802,767.2	200,980,173
Equity Value	$ 49,488,205.38											
Terminal Value (Gordon Growth)	$ 1,046,838,284.83											
PV of Terminal Value	$ 200,980,172.61											
NPV of CF (Enterprise Value)	**$ 250,468,377.99**											
IRR	**10.50%**											

Scenario 3 – Solar + Storage

Income Statement	Projected Year Ending December 31											
	0	1	2	3	4	5	6	7	8	21	22	23
Wholesale $/MWh			$ 181.00	182.81	184.64	186.48	188.35	190.23	192.14	218.67		
Revenue			$ 928,336,232.92	$936,921,247.5	$945,592,112.3	$954,349,685.7	$963,194,834.9	$972,128,435.5	$981,151,372.2	$1,106,998,071.1		
COGS			(747,222,425.0)	(135,052,850.3)	(137,946,009.3)	(140,903,318.8)	(143,926,227.6)	(147,016,217.7)	(150,174,804.8)	(198,235,083.3)		
Fixed O+M			(24,843,000.0)	(25,464,075.0)	(26,100,676.9)	(26,753,193.8)	(27,422,023.6)	(28,107,574.2)	(28,810,263.6)	(39,715,266.6)		
Land Lease			(17,461,850.0)	(17,811,087.0)	(18,167,308.7)	(18,530,654.9)	(18,901,268.0)	(19,279,293.4)	(19,664,879.2)	(25,438,618.2)		
Insurance			(13,042,575.0)	(13,173,000.8)	(13,304,730.8)	(13,437,778.1)	(13,572,155.8)	(13,707,877.4)	(13,844,956.2)	(15,756,851.6)		
Battery Warranty			(615,000,000.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
Charging O&M			(76,875,000.0)	(78,604,687.5)	(80,373,293.0)	(82,181,692.1)	(84,030,780.1)	(85,921,472.7)	(87,854,705.8)	(117,324,347.0)		
Gross Profit (EBITDA)			181,113,807.9	801,868,397.3	807,646,103.0	813,446,366.9	819,268,607.2	825,112,217.8	830,976,567.3	908,762,987.8		
Depreciation and Ammortization			(1,298,431,270.0)	(2,077,490,032.0)	(1,246,494,019.2)	(747,896,411.5)	(747,896,411.5)	(373,948,205.8)	0.0	(150,552,000.0)		
Solar Depreciatioin			(775,681,270.0)	(1,241,090,032.0)	(744,654,019.2)	(446,792,411.5)	(446,792,411.5)	(223,396,205.8)	0.0	0.0		
Battery Depreciation			(522,750,000.0)	(836,400,000.0)	(501,840,000.0)	(301,104,000.0)	(301,104,000.0)	(150,552,000.0)	0.0	(150,552,000.0)		
EBIT			**$ (1,117,317,462.08)**	**(1,275,621,634.71)**	**(438,847,916.24)**	**65,549,955.36**	**71,372,195.71**	**451,164,012.05**	**830,976,567.32**	**758,210,987.81**		
Interest Expenses			(161,839,783.3)	(145,655,804.9)	(129,471,826.6)	(113,287,848.3)	(97,103,870.0)	(80,919,891.6)	(64,735,913.3)	0.0	-	-
Net Interest Expense			(161,839,783.3)	(145,655,804.9)	(129,471,826.6)	(113,287,848.3)	(97,103,870.0)	(80,919,891.6)	(64,735,913.3)	0.0	-	-
% of EBITDA			*89.4%*	*18.2%*	*16.0%*	*13.9%*	*11.9%*	*9.8%*	*7.8%*	*0.0%*		
Alternative Tax Shield			*(54,334,142.4)*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*		
EBT			**$ (1,171,651,604.46)**	**(1,421,277,439.66)**	**(568,319,742.85)**	**(47,737,892.93)**	**(25,731,674.25)**	**370,244,120.42**	**766,240,654.02**	**758,210,987.81**		-
Loss Carryforward (prior period)			0.0	(1,171,651,604.5)	(2,592,929,044.1)	(3,161,248,787.0)	(3,208,986,679.9)	(3,234,718,354.1)	(2,864,474,233.7)	0.0	-	
Net Operating Gain (Loss)			(1,171,651,604.5)	(2,592,929,044.1)	(3,161,248,787.0)	(3,208,986,679.9)	(3,234,718,354.1)	(2,938,523,057.8)	(2,325,530,534.6)	4,089,362,291.9		
Taxable Income			0.0	0.0	0.0	0.0	0.0	0.0	0.0	758,210,987.8	-	
NOL 20% Adjustment			0.0	0.0	0.0	0.0	0.0	370,244,120.4	766,240,654.0	0.0		
Income Tax Expenses			0.0	0.0	0.0	0.0	0.0	(77,751,265.3)	(160,910,537.3)	(159,224,307.4)		
ITC			2,372,212,755.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	
Net Tax Savings (Expenses)			**2,372,212,755.0**	0.0	0.0	0.0	0.0	(77,751,265.3)	(160,910,537.3)	(159,224,307.4)	-	
Net Income			**$ 1,200,561,150.54**	**(1,421,277,439.66)**	**(568,319,742.85)**	**(47,737,892.93)**	**(25,731,674.25)**	**292,492,855.13**	**605,330,116.67**	**598,986,680.37**	**-**	
Statement of Cash Flows												
Operating Activities												
Net Income			1,200,561,150.54	(1,421,277,439.66)	(568,319,742.85)	(47,737,892.93)	(25,731,674.25)	292,492,855.13	605,330,116.67	598,986,680.37		
Depreciation			1,298,431,270.0	2,077,490,032.0	1,246,494,019.2	747,896,411.5	747,896,411.5	373,948,205.8	0.0	150,552,000.0	0.0	0.0
Cash Flow from Operations			2,498,992,420.5	656,212,592.3	678,174,276.3	700,158,518.6	722,164,737.3	666,441,060.9	605,330,116.7	749,538,680.4	0	0
Investing Activities												
Capital Expenditure	(2,316,192,300.0)	(2,316,192,300.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
Cash Flow from Investing Activities	(2,316,192,300.0)	(2,316,192,300.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Financing Activities												
(Payment) Withdrawl Debt Service Reserve Account			(161,839,783.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
Beginning Balance of Debt	1,573,219,210.1	3,236,795,665.4	3,236,795,665.4	2,913,116,098.9	2,589,436,532.4	2,265,756,965.8	1,942,077,399.3	1,618,397,832.7	1,294,718,266.2			
Borrowing / (Payment) of Long Term Debt			(323,679,566.5)	(323,679,566.5)	(323,679,566.5)	(323,679,566.5)	(323,679,566.5)	(323,679,566.5)	(323,679,566.5)			
Ending Balance of Debt	1,573,219,210.1	3,236,795,665.4	2,913,116,098.9	2,589,436,532.4	2,265,756,965.8	1,942,077,399.3	1,618,397,832.7	1,294,718,266.2	971,038,699.6			
											Terminal Value	
Net Change in Cash	$ (2,316,192,300.00)	(2,316,192,300.0)	2,013,473,070.7	332,533,025.8	354,494,709.8	376,478,952.0	398,485,170.7	342,761,494.3	281,650,550.1	749,538,680.4	6,328,777,321.4	
PV of Net CF	$ (2,316,192,300.00)	(2,148,800,723.6)	1,732,961,369.3	265,521,301.6	262,600,694.8	258,730,925.1	254,062,947.7	202,741,532.1	154,554,917.8	155,112,264.9	1,215,047,994	-
Equity Value	$ (31,884,739.27)											
Terminal Value (Gordon Growth)	$ 6,328,777,321.38											
PV of Terminal Value	$ 1,215,047,994.43											
NPV of CF (Enterprise Value)	**$1,183,163,255**											
IRR	**10.50%**											

Scenario 4: Wind + Storage

Income Statement	Projected Year Ending December 31										
	0	1	2	3	4	5	6	7	8	21	22
Wholesale $/MWh			$ 135.85	137.21	138.58	139.97	141.37	142.78	144.21	164.12	
Revenue			$ 912,067,153.74	918,510,657.80	925,018,596.91	931,591,615.41	938,230,364.09	944,935,500.26	951,707,687.80	1,046,162,240.59	
COGS			(783,252,901.0)	(391,898,505.8)	(393,579,285.1)	(395,296,008.8)	(397,049,463.5)	(398,840,453.4)	(400,669,800.5)	(428,350,863.5)	
Fixed O+M			(4,814,866.2)	(4,935,237.9)	(5,058,618.8)	(5,185,084.3)	(5,314,711.4)	(5,447,579.2)	(5,583,768.7)	(7,697,286.8)	
Land Lease			(15,482,825.7)	(15,792,482.2)	(16,108,331.8)	(16,430,498.5)	(16,759,108.4)	(17,094,290.6)	(17,436,176.4)	(22,555,553.4)	
Insurance			(11,026,411.2)	(11,136,675.3)	(11,248,042.1)	(11,360,522.5)	(11,474,127.7)	(11,588,869.0)	(11,704,757.7)	(13,321,106.1)	
Battery Warranty			(393,000,000.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Charging O&M			(49,125,000.0)	(50,230,312.5)	(51,360,494.5)	(52,516,105.7)	(53,697,718.0)	(54,905,916.7)	(56,141,299.8)	(74,973,119.3)	
Transmission Line Rental			(309,803,797.9)	(309,803,797.9)	(309,803,797.9)	(309,803,797.9)	(309,803,797.9)	(309,803,797.9)	(309,803,797.9)	(309,803,797.9)	
Gross Profit (EBITDA)			128,814,252.7	526,612,152.0	531,439,311.8	536,295,606.6	541,180,900.6	546,095,046.9	551,037,887.3	617,811,377.1	
Depreciation and Ammortization			(969,189,662.5)	(1,550,703,460.0)	(930,422,076.0)	(558,253,245.6)	(558,253,245.6)	(279,126,622.8)	0.0	(96,206,400.0)	
Wind Depreciation			(635,139,662.5)	(1,016,223,460.0)	(609,734,076.0)	(365,840,445.6)	(365,840,445.6)	(182,920,222.8)	0.0	0.0	
Battery Depreciation			(334,050,000.0)	(534,480,000.0)	(320,688,000.0)	(192,412,800.0)	(192,412,800.0)	(96,206,400.0)	0.0	(96,206,400.0)	
EBIT			**$ (840,375,409.72)**	**(1,024,091,307.92)**	**(398,982,764.21)**	**(21,957,638.97)**	**(17,072,344.97)**	**266,968,424.11**	**551,037,887.32**	**521,604,977.13**	
Interest Expenses			(121,817,922.0)	(109,636,129.8)	(97,454,337.6)	(85,272,545.4)	(73,090,753.2)	(60,908,961.0)	(48,727,168.8)	0.0	
Net Interest Expense			(121,817,922.0)	(109,636,129.8)	(97,454,337.6)	(85,272,545.4)	(73,090,753.2)	(60,908,961.0)	(48,727,168.8)	0.0	
% of EBITDA			*94.6%*	*20.8%*	*18.3%*	*15.9%*	*13.5%*	*11.2%*	*8.8%*	*0.0%*	
Alternative Tax Shield			*(38,644,275.8)*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	
EBT			**$ (879,019,685.55)**	**(1,133,727,437.71)**	**(496,437,101.80)**	**(107,230,184.37)**	**(90,163,098.16)**	**206,059,463.11**	**502,310,718.53**	**521,604,977.13**	
Loss Carryforward (prior period)			0.0	(879,019,685.5)	(2,012,747,123.3)	(2,509,184,225.1)	(2,616,414,409.4)	(2,706,577,507.6)	(2,500,518,044.5)	0.0	
Net Operating Gain (Loss)			(879,019,685.5)	(2,012,747,123.3)	(2,509,184,225.1)	(2,616,414,409.4)	(2,706,577,507.6)	(2,541,729,937.1)	(2,139,881,362.3)	2,251,832,387.4	
Taxable Income			0.0	0.0	0.0	0.0	0.0	0.0	0.0	521,604,977.1	
NOL 20% Adjustment			0.0	0.0	0.0	0.0	0.0	206,059,463.1	502,310,718.5	0.0	
Income Tax Expenses			0.0	0.0	0.0	0.0	0.0	(43,272,487.3)	(105,485,250.9)	(109,537,045.2)	
ITC			589,500,000.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
PTC			237,929,316.8	237,929,316.8	237,929,316.8	247,843,038.3	247,843,038.3	257,756,759.8	257,756,759.8	0.0	
Net Tax Savings (Expenses)			**827,429,316.8**	**237,929,316.8**	**237,929,316.8**	**247,843,038.3**	**247,843,038.3**	**214,484,272.6**	**152,271,508.9**	**(109,537,045.2)**	
Net Income			**$ (51,590,368.77)**	**(895,798,120.94)**	**(258,507,785.03)**	**140,612,853.94**	**157,679,940.14**	**420,543,735.70**	**654,582,227.48**	**412,067,931.93**	
Statement of Cash Flows											
Operating Activities											
Net Income			(51,590,368.77)	(895,798,120.94)	(258,507,785.03)	140,612,853.94	157,679,940.14	420,543,735.70	654,582,227.48	412,067,931.93	
Depreciation			969,189,662.5	1,550,703,460.0	930,422,076.0	558,253,245.6	558,253,245.6	279,126,622.8	0.0	96,206,400.0	
Changes in Working Capital				0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Cash Flow from Operations			917,599,293.7	654,905,339.0	671,914,290.9	698,866,099.5	715,933,185.7	699,670,358.5	654,582,227.5	508,274,331.9	
Investing Activities											
Capital Expenditure	(1,743,413,932.1)	(1,743,413,932.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Cash Flow from Investing Activities	(1,743,413,932.1)	(1,743,413,932.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Financing Activities											
(Payment) Withdrawl Debt Service Reserve Account			(121,817,922.0)	0.0	0.0	0.0	0.0	0.0	0.0		
Beginning Balance of Debt	1,184,172,958.9	2,436,358,439.9	2,436,358,439.9	2,192,722,595.9	1,949,086,751.9	1,705,450,907.9	1,461,815,063.9	1,218,179,219.9	974,543,375.9		
Borrowing / (Payment) of Long Term Debt			(243,635,844.0)	(243,635,844.0)	(243,635,844.0)	(243,635,844.0)	(243,635,844.0)	(243,635,844.0)	(243,635,844.0)		
Ending Balance of Debt	1,184,172,958.9	2,436,358,439.9	2,192,722,595.9	1,949,086,751.9	1,705,450,907.9	1,461,815,063.9	1,218,179,219.9	974,543,375.9	730,907,532.0		**Terminal Value**
Net Change in Cash	$ (1,743,413,932.08)	(1,743,413,932.1)	552,145,527.7	411,269,495.0	428,278,447.0	455,230,255.5	472,297,341.7	456,034,514.5	410,946,383.5	508,274,331.9	4,291,646,514.4
PV of Net CF	$ (1,743,413,932.08)	(1,617,417,137.1)	475,222,084.5	328,390,876.0	317,257,816.9	312,851,872.6	301,123,513.9	269,741,898.3	225,505,629.2	105,184,141.8	823,943,745
Equity Value	$ 121,840,699.60										
Terminal Value (Gordon Growth)	$ 4,291,646,514.37										
PV of Terminal Value	$ 888,128,963.18										
NPV of CF (Enterprise Value)	**$ 1,009,969,662.79**										
IRR	**10.50%**										

Scenario 5: Solar + Wind + Storage

Income Statement	Projected Year Ending December 31										
	0	1	2	3	4	5	6	7	8	21	22
Wholesale, $/mWh			$ 99.00	99.99	100.99	102.00	103.02	104.05	105.09	119.60	
Revenue			$ 712,068,740.00	716,764,410.98	721,507,038.67	726,297,092.64	731,135,047.14	736,021,381.20	740,956,578.59	809,789,855.93	
COGS			(446,746,959.6)	(303,292,289.3)	(304,424,025.9)	(305,579,955.5)	(306,760,611.6)	(307,966,539.4)	(309,198,296.6)	(327,839,411.2)	
Wind Fixed O+M			(3,786,889.1)	(3,881,561.3)	(3,978,600.3)	(4,078,065.3)	(4,180,016.9)	(4,284,517.4)	(4,391,630.3)	(6,053,910.9)	
Solar Fixed O&M			(7,098,000.0)	(7,275,450.0)	(7,457,336.3)	(7,643,769.7)	(7,834,863.9)	(8,030,735.5)	(8,231,503.9)	(11,347,219.0)	
Wind Land Lease			(12,141,171.0)	(12,383,994.4)	(12,631,674.3)	(12,884,307.8)	(13,141,994.0)	(13,404,833.8)	(13,672,930.5)	(17,687,393.6)	
Solar Land Lease			(4,985,470.0)	(5,085,179.4)	(5,186,883.0)	(5,290,620.6)	(5,396,433.1)	(5,504,361.7)	(5,614,449.0)	(7,262,888.4)	
Wind Insurance			(8,672,265.0)	(8,758,987.7)	(8,846,577.5)	(8,935,043.3)	(9,024,393.7)	(9,114,637.7)	(9,205,784.0)	(10,477,041.0)	
Solar Insurance			(3,726,450.0)	(3,763,714.5)	(3,763,714.5)	(3,763,714.5)	(3,763,714.5)	(3,763,714.5)	(3,763,714.5)	(3,763,714.5)	
Battery Warranty			(144,600,000.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Charging O&M			(18,075,000.0)	(18,481,687.5)	(18,897,525.5)	(19,322,719.8)	(19,757,481.0)	(20,202,024.3)	(20,656,569.9)	(27,585,529.4)	
Transmission Line Rental			(243,661,714.5)	(243,661,714.5)	(243,661,714.5)	(243,661,714.5)	(243,661,714.5)	(243,661,714.5)	(243,661,714.5)	(243,661,714.5)	
Gross Profit (EBITDA)			265,321,780.4	413,472,121.7	417,083,012.8	420,717,137.1	424,374,435.6	428,054,841.8	431,758,282.0	481,950,444.7	
Depreciation and Ammortization			(823,556,917.8)	(1,317,691,068.4)	(790,614,641.1)	(474,368,784.6)	(474,368,784.6)	(237,184,392.3)	0.0	0.0	
Wind Depreciation			(499,536,917.8)	(799,259,068.4)	(479,555,441.1)	(287,733,264.6)	(287,733,264.6)	(143,866,632.3)	0.0	0.0	
Solar Depreciation			(201,110,000.0)	(321,776,000.0)	(193,065,600.0)	(115,839,360.0)	(115,839,360.0)	(57,919,680.0)	0.0	0.0	
Battery Depreciation			(122,910,000.0)	(196,656,000.0)	(117,993,600.0)	(70,796,160.0)	(70,796,160.0)	(35,398,080.0)	0.0	0.0	
EBIT			**$ (558,235,137.33)**	**(904,218,946.71)**	**(373,531,628.25)**	**(53,651,647.52)**	**(49,994,349.08)**	**190,870,449.47**	**431,758,282.02**	**481,950,444.71**	
Interest Expenses			(106,392,461.4)	(95,753,215.2)	(85,113,969.1)	(74,474,722.9)	(63,835,476.8)	(53,196,230.7)	(42,556,984.5)	0.0	
Net Interest Expense			(106,392,461.4)	(95,753,215.2)	(85,113,969.1)	(74,474,722.9)	(63,835,476.8)	(53,196,230.7)	(42,556,984.5)	0.0	
% of EBITDA			*40.1%*	*23.2%*	*20.4%*	*17.7%*	*15.0%*	*12.4%*	*9.9%*	*0.0%*	
Alternative Tax Shield			*(79,596,534.1)*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	
EBT			**$ (637,831,671.46)**	**(999,972,161.93)**	**(458,645,597.33)**	**(128,126,370.46)**	**(113,829,825.89)**	**137,674,218.79**	**389,201,297.48**	**481,950,444.71**	
Loss Carryforward (prior period)			0.0	(637,831,671.5)	(1,637,803,833.4)	(2,096,449,430.7)	(2,224,575,801.2)	(2,338,405,627.1)	(2,200,731,408.3)	0.0	
Net Operating Gain (Loss)			(637,831,671.5)	(1,637,803,833.4)	(2,096,449,430.7)	(2,224,575,801.2)	(2,338,405,627.1)	(2,228,266,252.1)	(1,916,905,214.1)	2,221,157,879.4	
Taxable Income			0.0	0.0	0.0	0.0	0.0	0.0	0.0	481,950,444.7	
NOL 20% Adjustment			0.0	0.0	0.0	0.0	0.0	27,534,843.8	77,840,259.5	0.0	
Income Tax Expenses			0.0	0.0	0.0	0.0	0.0	(5,782,317.2)	(16,346,454.5)	(101,209,593.4)	
ITC (solar battery)			578,898,000.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
PTC (wind)			187,132,196.7	187,132,196.7	187,132,196.7	194,929,371.6	194,929,371.6	202,726,546.5	202,726,546.5	0.0	
Net Tax Savings (Expenses)			**766,030,196.7**	**187,132,196.7**	**187,132,196.7**	**194,929,371.6**	**194,929,371.6**	**196,944,229.3**	**186,380,092.0**	**(101,209,593.4)**	
Net Income			**$ 128,198,525.28**	**($812,839,965.2)**	**($271,513,400.6)**	**$66,803,001.1**	**$81,099,545.7**	**$334,618,448.1**	**$575,581,389.5**	**$380,740,851.3**	

Statement of Cash Flows	0	1	2	3	4	5	6	7	8	21	22
Operating Activities											
Net Income			128,198,525.3	(812,839,965.2)	(271,513,400.6)	66,803,001.1	81,099,545.7	334,618,448.1	575,581,389.5	380,740,851.3	
Depreciation			823,556,917.8	1,317,691,068.4	790,614,641.1	474,368,784.6	474,368,784.6	237,184,392.3	0.0	0.0	
Changes in Working Capital			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Cash Flow from Operations			951,755,443.1	504,851,103.2	519,101,240.5	541,171,785.8	555,468,330.3	571,802,840.4	575,581,389.5	380,740,851.3	
Investing Activities											
Capital Expenditure	(1,522,650,332.3)	(1,522,650,332.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Cash Flow from Investing Activities	(1,522,650,332.3)	(1,522,650,332.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Financing Activities											
(Payment) Withdrawl Debt Service Reserve Account			(106,392,461.4)	0.0	0.0	0.0	0.0	0.0	0.0		
Beginning Balance of Debt	1,122,670,828.1	2,127,849,227.1	2,127,849,227.1	1,915,064,304.4	1,702,279,381.7	1,489,494,459.0	1,276,709,536.3	1,063,924,613.6	851,139,690.8		
Borrowing / (Payment) of Long Term Debt			(212,784,922.7)	(212,784,922.7)	(212,784,922.7)	(212,784,922.7)	(212,784,922.7)	(212,784,922.7)	(212,784,922.7)		
Ending Balance of Debt	1,122,670,828.1	2,127,849,227.1	1,915,064,304.4	1,702,279,381.7	1,489,494,459.0	1,276,709,536.3	1,063,924,613.6	851,139,690.8	638,354,768.1		
											Terminal Value
Net Change in Cash	$ (1,522,650,332.25)	(1,522,650,332.3)	632,578,059.0	292,066,180.5	306,316,317.8	328,386,863.1	342,683,407.6	359,017,917.7	362,796,466.7	380,740,851.3	3,214,809,493.2
PV of Net CF	$ (1,522,650,332.25)	(1,412,608,156.8)	544,448,969.9	233,209,294.7	226,911,363.3	225,680,177.9	218,485,311.6	212,357,116.8	199,083,502.8	78,791,898.7	617,204,182
Equity Value	$ 158,799,070.83										
Terminal Value (Gordon Growth)	$ 3,214,809,493.17										
PV of Terminal Value	$ 665,284,387.34										
NPV of CF (Enterprise Value)	**$ 824,083,458.17**										
IRR	**10.51%**										

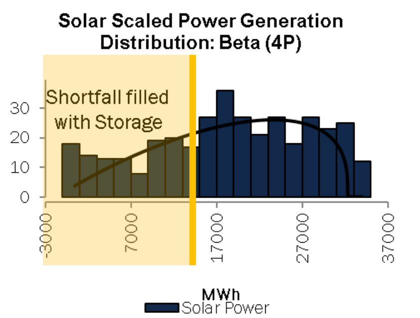
Periods of Unserved Demand

The following tables illustrates the projected periods of unserved baseload demand for scenarios 3, 4, and 5. Battery storage is significantly leveraged in the energy modeling to provide baseload power during non-productive periods, reducing the number of unserved hours significantly. Nevertheless, approximately 15% of annual hours do not meet the 650MW baseload demand hurdle with the application of large scale battery storage. These periods of shortfall are relatively unpredictable over the long term but are seasonally influenced.

Scenario 3

Sum of Days Month	1	2	3	4	5	6	7	8	9	10	11	12
1	5,213.21	17,700.61	19,009.22	16,811.75	30,440.60	29,460.49	28,344.91	16,364.36	27,421.10	18,300.52	18,165.95	14,843.94
2	17,363.92	14,381.52	13,600.82	27,203.94	30,438.45	10,458.38	15,554.45	23,576.52	3,803.11	11,270.88	18,328.80	4,799.18
3	8,215.80	20,328.66	23,685.96	29,549.01	30,764.47	17,975.03	18,328.40	21,426.01	8,671.58	13,292.50	19,767.12	12,308.30
4	12,034.57	10,273.92	26,654.77	29,199.75	26,836.87	30,397.87	21,844.58	16,154.32	28,319.02	15,420.30	15,350.17	4,010.30
5	18,022.66	2,199.68	12,905.75	13,240.52	29,990.83	29,635.19	31,159.78	26,238.15	26,544.33	4,840.91	20,797.24	7,101.77
6	11,302.96	9,261.36	7,822.74	30,127.93	20,693.04	32,211.28	30,973.26	22,545.57	27,979.85	12,031.03	2,634.62	16,339.57
7	4,207.06	19,421.81	24,310.81	28,852.28	28,112.99	26,324.43	29,395.49	17,624.66	22,950.54	21,386.27	8,377.37	5,041.34
8	2,130.19	12,509.49	27,252.62	22,847.07	27,414.10	24,136.34	25,139.47	18,309.23	27,292.77	22,022.07	19,822.95	14,608.93
9	5,034.43	21,665.89	27,187.14	7,430.32	19,542.69	28,385.27	30,490.21	9,531.74	26,812.01	23,016.36	19,898.05	15,160.72
10	12,425.35	7,568.52	25,799.48	18,756.00	29,628.75	29,720.90	25,881.13	12,815.21	23,311.39	15,953.11	19,533.60	14,917.83
11	17,607.71	5,604.74	17,129.13	19,258.85	29,682.86	16,618.46	17,337.62	18,050.80	22,037.90	23,949.43	18,954.23	15,147.65
12	18,146.48	23,925.73	7,057.57	12,932.56	26,672.79	23,881.92	25,356.92	15,723.20	13,989.33	23,872.59	12,708.70	15,152.73
13	18,561.30	23,766.66	25,367.49	30,325.57	29,620.74	27,049.60	26,925.56	18,917.60	25,823.00	23,398.19	2,828.15	10,750.49
14	18,370.23	11,607.73	28,061.85	29,657.90	30,847.59	12,869.71	29,406.78	21,986.84	24,206.80	22,678.24	7,083.57	12,053.50
15	2,961.84	23,676.93	27,682.24	28,944.99	11,726.85	21,787.67	25,589.21	26,678.00	22,324.58	22,578.32	3,065.57	2,201.32
16	15,506.90	2,791.75	19,062.52	8,544.83	12,927.19	22,646.59	27,293.40	18,480.99	14,868.20	18,449.97	12,490.72	7,875.20
17	2,646.06	19,311.02	17,341.15	30,903.65	4,555.22	29,991.84	22,070.46	21,883.17	19,620.48	19,275.23	12,025.44	15,677.34
18	19,040.97	22,270.32	11,783.10	29,786.12	24,890.97	28,866.22	11,324.00	14,836.95	16,392.69	10,539.64	3,442.22	16,351.86
19	19,709.77	3,011.59	20,554.21	28,772.27	30,988.44	30,111.31	22,794.62	18,983.94	11,094.79	13,049.97	2,653.06	7,236.61
20	8,548.41	25,087.47	17,740.84	23,114.32	26,594.93	9,400.25	26,295.59	20,163.72	4,251.31	21,102.40	7,640.70	16,450.04
21	19,109.86	13,350.39	27,180.95	16,218.19	14,777.38	32,283.01	28,796.34	26,443.73	12,865.18	16,604.20	18,027.14	2,215.40
22	2,182.82	21,850.13	28,926.77	9,375.64	22,233.24	28,320.86	23,526.02	21,550.81	11,240.38	11,908.08	18,152.64	12,831.87
23	6,727.53	16,619.25	10,270.27	24,892.93	21,699.60	20,730.29	10,755.63	23,554.73	12,602.77	16,896.13	17,754.36	6,728.86
24	20,182.10	8,341.29	4,201.76	25,416.63	30,737.83	26,716.83	19,030.31	18,869.93	23,185.17	11,307.60	18,057.59	15,816.00
25	16,533.60	24,268.55	6,864.21	26,847.60	27,351.57	19,351.44	16,239.07	27,599.25	6,339.53	6,759.58	18,223.42	11,716.56
26	15,244.66	24,881.62	17,083.47	14,672.98	22,331.81	27,360.11	24,821.26	26,928.10	18,337.12	2,300.33	17,649.48	2,190.22
27	4,695.58	4,169.57	28,848.90	21,302.23	27,444.12	29,944.78	25,847.05	26,517.12	16,929.46	6,486.71	4,068.61	15,744.44
28	4,426.79	25,224.25	29,093.33	6,573.29	9,307.92	30,456.83	15,307.16	23,242.38	21,148.23	13,209.44	17,517.38	11,476.16
29	20,248.39		29,354.08	31,582.15	16,996.63	23,219.65	15,739.42	25,744.89	7,877.96	20,503.94	17,420.31	5,831.89
30	20,581.67		17,790.18	31,707.20	30,714.63	18,410.80	24,068.66	26,669.29	6,683.86	19,937.99	16,003.00	3,180.86
31	18,721.89		12,288.34		24,844.25		18,803.87	23,454.17		17,794.90		16,742.81

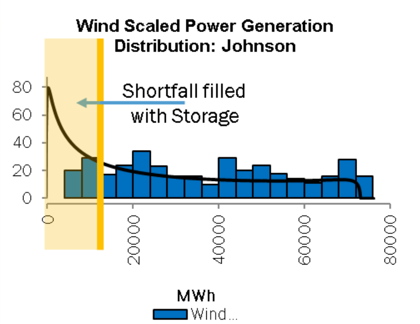
Daily Baseload Demand = 15600
Yellow: Slightly Below Baseload - 21 days
Red: Significantly Below Baseload -102 days



Scenario 4

Sum o Column Labels Rov	1	2	3	4	5	6	7	8	9	10	11	12
1	54796.84643	13516.86073	43108.19256	63946.13822	47088.63866	15968.32843	37808.89309	36309.05321	2130.540258	16322.58869	5579.864006	66806.9877
2	36747.82312	15708.99966	50682.70739	65572.90059	67596.47624	14858.5359	45975.06322	42530.38694	4575.073618	24716.05751	41098.06905	17213.28097
3	42305.50274	60653.74602	22224.85904	25609.84081	65861.17082	23846.39945	53539.51885	51394.80686	37589.60377	12263.10823	37144.67058	66054.32887
4	41055.00478	58402.35371	43486.08217	21887.52416	61518.10248	25987.21802	49481.51616	49237.5891	31107.15379	41488.56969	7404.193866	46396.42548
5	30081.59453	47706.0931	37040.75561	25108.55973	62829.52865	5994.339719	36589.47452	22670.96998	18940.22529	23437.04122	35427.94302	6433.018946
6	52481.35775	3535.247954	70844.40859	8940.408392	56789.33894	13716.05814	31614.5799	8376.395625	3592.708558	34532.38791	7818.827932	54067.42433
7	48054.37517	4094.915749	70076.9062	37093.64738	33117.38848	16081.80737	13131.81482	15700.00676	33146.45345	4135.392471	6406.044827	5499.515681
8	16554.70665	20461.76915	67937.40738	19119.61246	21267.09017	1607.677881	7124.394973	12112.6182	37272.27649	10708.41213	68891.30863	4046.697078
9	23306.17864	4614.385982	38027.74193	6346.272386	2357.836306	22056.19075	10326.53734	21316.07603	715.0850942	51043.94529	69625.35257	40525.89207
10	13322.65258	25267.12611	16764.35931	6908.813798	15391.22941	64889.19642	7783.658222	23180.41296	6839.369286	37921.47874	69557.41054	48816.22293
11	23428.86522	50864.74319	15801.95572	28368.60947	36477.63312	35223.43877	3213.516652	11882.43701	54975.54014	24516.52521	47038.67101	13962.08275
12	72103.7281	12132.92948	49249.80358	58811.30188	13613.01683	19452.66421	6276.447699	27977.19512	58189.74733	38207.54036	17818.83544	49103.22608
13	18510.96952	62146.76627	46242.8725	55578.94278	8337.669585	18221.3062	9237.017337	21567.97118	38608.51001	63220.81623	17645.71961	70018.56956
14	46764.83155	6393.647628	63401.11847	65761.10509	2173.475615	47439.23811	11006.33479	15263.16677	21910.24582	52043.28652	38579.36503	66418.81719
15	55943.76484	38477.41865	62493.55648	66914.13475	982.8399541	35956.09637	16147.12698	18329.39253	951.202505	13985.36015	47586.80491	56773.72027
16	70168.13454	20712.08543	62680.47207	33920.30999	17556.63754	43614.85699	23193.46838	42610.6718	19.090985	65607.5842	6263.845299	49347.09229
17	61706.10987	2569.194065	68276.97167	3631.441057	29069.38499	26516.53118	45223.00864	16737.57455	8062.656888	64586.37433	29103.56936	18908.44747
18	14834.03268	14835.73965	68790.74992	57127.78642	64144.87616	65692.27003	42993.62748	16070.34549	17023.90211	60327.13338	68413.62249	40006.45909
19	42382.92515	12166.463	52440.15315	66627.56474	67741.5198	67593.40502	32534.94394	10715.06914	48067.56603	51784.15944	45051.72672	29670.04424
20	18352.26546	68847.39884	9361.494826	45285.76246	30910.97322	66906.62128	27455.33475	4133.780348	41358.55418	36769.47047	812.9265413	69997.7419
21	33267.53707	41501.46242	7755.682475	15120.43929	6268.943947	24852.17718	8294.054499	4384.787431	38245.85288	65855.95765	20032.42582	28602.51649
22	69345.75845	6133.460482	2549.150583	20301.90623	18042.07034	1798.800425	28510.99977	18960.86918	16542.11337	64680.61556	65775.57236	67881.65857
23	38845.67319	68572.92621	22843.41858	10791.51447	65691.86998	29098.60915	37213.34186	51594.79912	29706.91533	67230.94196	60522.01249	37330.83649
24	50592.61253	48126.06101	448.8830747	46093.06837	53631.01056	38594.66949	46093.75341	56858.0769	47770.9889	65892.86654	24161.35797	31402.24731
25	21132.6138	20046.13629	5301.683529	48514.6795	55753.47178	8168.86819	58536.17917	59070.41421	65480.92632	67867.5651	44835.94472	54662.27088
26	25552.90827	56950.92712	45942.93828	21760.86228	54127.02987	6057.121504	38531.78385	21436.64604	45231.83477	64151.9729	36150.83463	45062.86272
27	39613.3234	25691.40479	63856.74762	60254.61994	66040.81881	42524.10906	16382.45231	11040.83555	11852.33274	17905.07026	27532.81875	26126.51052
28	39110.30339	51550.39761	56596.87264	19381.18639	42184.08512	46554.29152	19324.24319	19355.58261	1286.90737	160.3105171	32466.57811	20926.76537
29	47563.56236		52891.72344	18785.53757	5796.029297	50607.00603	30993.99589	12883.93972	1980.95453	16821.96169	70789.17235	19496.49749
30	67478.77784		23438.53433	31444.62023	27788.20393	42371.42702	43664.63294	12352.4122	4715.889932	40379.56167	41328.70981	46287.78658
31	56046.27175		14696.69956		38133.4885		36974.148	11807.00194		19273.75502		30749.79547

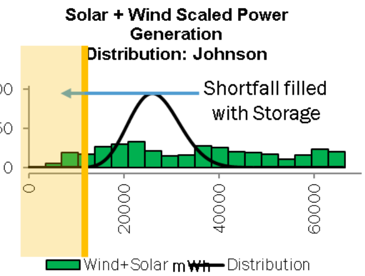
Daily Baseload Demand = 15600
Yellow: Slightly Below Baseload – 13 days
Red: Significantly Below Baseload -73 days



Scenario 5

Sum of | Column Labels												
Row	1	2	3	4	5	6	7	8	9	10	11	12
1	45350.82379	15536.79352	41094.10594	56724.32982	47375.33706	20407.16131	37543.64773	32600.53849	9150.954842	19710.05719	9578.830978	57407.85263
2	32570.63526	18262.59727	42628.4408	59302.36907	61459.22776	14560.53681	41231.13165	40691.71369	5208.045986	20859.55871	39803.57451	14835.26578
3	38004.84513	53467.9669	24654.10995	27495.29577	60819.70339	24418.72559	47177.2242	47147.27937	32181.76193	15489.41285	33229.68328	54680.78918
4	33550.82525	49167.29541	41111.85951	24542.76286	56079.81607	28298.03324	45242.67107	42599.91671	32749.45792	35373.83345	9675.195581	37229.61568
5	30971.14238	36247.25961	34676.18783	23883.85803	57906.05646	12875.08779	37144.81728	24378.69336	21886.46904	20288.99997	34778.40019	7088.824868
6	43512.44613	5083.225409	58051.32711	16073.85636	49785.34675	20593.69039	33232.22453	13271.6028	10845.13128	30086.10592	6460.997322	47113.28426
7	38446.08478	9927.379896	62032.68542	37475.04608	33681.02371	19658.43014	18484.84349	17563.99555	34535.85567	9092.812187	8078.971702	4979.305402
8	13573.14419	18509.66619	60380.50735	20692.14643	24097.49978	8259.127123	12795.60562	14802.93664	35079.66483	16302.66981	60870.37307	7301.708531
9	19832.43039	9857.258635	36709.25383	7291.074393	7102.40371	26985.73657	16887.97998	19869.96056	8028.963688	45450.58739	60431.50825	38542.98149
10	14152.64591	23847.47365	20514.31106	10930.55263	21286.99333	59915.94928	13506.5746	21388.49298	12605.5495	34288.08636	60288.64476	40240.67562
11	24918.58535	40380.2582	18627.64448	28616.51321	37060.5454	31161.62263	8085.660723	14661.75766	51159.94594	27684.75828	41935.17949	15948.74592
12	60617.51798	17110.503	40474.01098	50994.4234	18210.81797	21709.06453	11867.62544	26318.02421	49201.22119	36195.35416	16374.10595	44736.86267
13	20940.68825	55727.19668	44142.77229	50495.61468	14686.91267	22543.85251	14878.20396	22089.40283	37851.21678	57463.28299	15066.44442	58090.32942
14	39808.64716	7522.402295	57788.50048	62124.8346	10477.00578	41184.59314	16853.61877	18697.54374	22698.24931	45201.07106	32980.14244	55672.45132
15	47209.07047	37081.71354	56674.63277	60890.08307	4013.355227	34698.47295	20938.27727	22530.53379	6814.477019	19508.0234	37426.35367	44459.9735
16	59563.04965	16484.91996	55448.47176	26893.69127	17709.1287	41069.09091	25825.73564	39571.32347	4457.944227	57003.09208	8072.708258	40240.5469
17	47952.86977	7645.60055	58704.29745	12121.81535	25350.23525	29729.41979	42013.22254	17808.6604	12134.47739	56105.80981	28254.11334	19981.21674
18	17844.88826	18806.14643	57431.82113	55093.87927	58228.17123	60214.2412	36502.63559	17332.11201	17731.90826	50561.75693	54941.78649	34793.04096
19	37943.27022	10387.54748	45983.45417	60126.105	62297.05998	61784.13866	31952.46562	13756.18961	42782.08975	42405.55626	33899.35406	27694.34048
20	17729.82647	62787.78497	11825.5607	42307.30434	29774.02593	55020.4251	28942.65855	8620.234867	32724.53034	35872.44255	2822.424473	58451.81446
21	31289.49569	34862.77744	13414.10752	14848.40196	9287.108951	26914.40382	15160.67425	11233.43534	33523.40714	57764.09468	23190.74039	24318.78951
22	56280.59146	11836.5747	10657.29667	20026.44676	21702.72256	9680.032349	29089.4885	21698.31264	17170.55442	54292.43193	56137.47551	57143.31377
23	30700.10384	59453.74148	20562.56012	14239.49216	58667.63182	30038.90544	32872.20082	48111.72214	26326.29589	57537.42761	52297.73848	30201.7782
24	46788.94661	38030.99076	1490.072604	45645.5889	48880.9329	36915.33782	41807.95788	49953.56632	45495.12944	55220.56871	25425.04819	28781.28223
25	20293.86564	24966.25548	6804.592541	43982.46582	53695.88281	11640.25055	51201.53808	54724.20584	53331.22979	55215.66681	38079.54261	48099.91331
26	24717.80979	49686.66735	42516.49125	22186.77598	48962.97316	12912.09403	36727.72097	22852.79535	39127.58523	50139.19553	35721.30502	33544.94964
27	33884.24396	21726.32633	57279.36655	54307.57306	59775.73726	42680.06501	20798.31872	16750.26293	13620.41394	14783.26151	21051.13609	25984.15141
28	30079.0196	47268.47729	53819.29554	15373.84532	33698.95427	45747.87827	18440.90295	21966.89726	7387.999108	4102.304344	32422.03217	20847.73582
29	44876.45525		50106.00761	24765.05564	10040.37739	46435.85017	29196.77567	17212.68108	3543.449124	19939.8606	60633.06851	15064.16244
30	59171.09978		21827.21756	33120.24783	31363.18967	38141.3727	41114.66538	17417.65614	5706.859068	37265.29702	36378.56517	39562.33068
31	47436.9747		15230.60952		37020.35013		35098.662	15713.80835		19365.2566		26658.45125

Daily Baseload Demand = 15600
Yellow: Slightly Below Baseload – 22 days
Red: Significantly Below Baseload -52 days



Secondary Valuation Drivers

Leverage

Scenario 3

Wholesale Electricity Price. $/MWh

Leverage, % Debt		$ 174.00	$ 176.00	$ 178.00	$ 181.00	$ 182.00	$ 184.00	$ 188.00
	55%	10.60%	10.83%	11.06%	11.41%	11.52%	11.76%	12.50%
	50%	10.29%	10.50%	10.72%	11.05%	11.16%	11.43%	12.06%
	45%	10.01%	10.22%	10.42%	10.73%	10.84%	11.09%	11.65%
	40%	9.77%	9.96%	10.16%	10.50%	10.60%	10.96%	11.32%
	35%	9.55%	9.74%	9.92%	10.41%	10.50%	10.66%	10.99%
	30%	9.35%	9.53%	9.75%	10.17%	10.23%	10.41%	10.71%
	25%	9.17%	9.38%	9.70%	9.93%	10.01%	10.17%	10.47%

Scenario 4

Wholesale Electricity Price. $/MWh

Leverage, % Debt		$ 129.75	$ 131.25	$ 133.00	$ 134.50	$ 136.25	$ 138.00	$ 139.75
	55%	10.40%	10.61%	10.98%	11.20%	11.42%	11.66%	11.91%
	50%	10.13%	10.45%	10.68%	10.86%	11.09%	11.32%	11.55%
	45%	10.00%	10.19%	10.42%	10.58%	10.80%	11.02%	11.36%
	40%	9.78%	9.96%	10.15%	10.33%	10.54%	10.87%	11.08%
	35%	9.58%	9.73%	9.93%	10.11%	10.31%	10.62%	10.81%
	30%	9.37%	9.54%	9.73%	9.90%	10.20%	10.39%	10.57%
	25%	9.20%	9.36%	9.55%	9.81%	10.00%	10.18%	10.36%

Scenario 5

Wholesale Electricity Price. $/MWh

Leverage, % Debt		$ 94.00	$ 96.00	$ 97.50	$ 99.00	$ 100.50	$ 102.00	$ 103.50
	55%	10.56%	10.81%	11.17%	11.46%	11.72%	11.96%	12.22%
	50%	10.21%	10.46%	10.83%	11.09%	11.33%	11.58%	11.84%
	45%	9.95%	10.20%	10.55%	10.80%	11.02%	11.26%	11.52%
	40%	9.72%	9.98%	10.29%	10.51%	10.74%	10.97%	11.22%
	35%	9.51%	9.76%	10.04%	10.27%	10.49%	10.73%	10.95%
	30%	9.35%	9.56%	9.83%	10.05%	10.28%	10.50%	10.70%
	25%	9.19%	9.39%	9.67%	9.90%	10.11%	10.30%	10.51%

Avoided Cost

Scenario 3

Avoided Cost, $/mWh

Wholesale Price. $/MWh		$ 20.00	$ 25.00	$ 30.00	$ 35.00	$ 40.00	$ 45.00	$ 50.00
	$ 187.00	10.51%	10.88%	11.04%	11.22%	11.41%	11.56%	11.74%
	$ 185.00	10.28%	10.51%	10.87%	11.03%	11.22%	11.41%	11.55%
	$ 183.00	10.08%	10.27%	10.50%	10.87%	11.03%	11.21%	11.40%
	$ 181.00	9.88%	10.07%	10.26%	10.50%	10.86%	11.02%	11.21%
	$ 179.00	9.69%	9.88%	10.07%	10.26%	10.49%	10.85%	11.02%
	$ 177.00	9.50%	9.68%	9.87%	10.06%	10.25%	10.49%	10.85%
	$ 175.00	9.30%	9.49%	9.68%	9.87%	10.06%	10.25%	10.48%

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Scenario 4

Avoided Cost, $/mWh

Wholesale Price. $/MWh		$ 20.00	$ 25.00	$ 30.00	$ 35.00	$ 40.00	$ 45.00	$ 50.00
	$ 158.00	10.47%	11.45%	12.52%	13.31%	14.29%	15.05%	16.04%
	$ 151.00	9.65%	10.52%	11.51%	12.55%	13.36%	14.35%	15.11%
	$ 143.50	8.57%	9.64%	10.52%	11.51%	12.55%	13.37%	14.35%
	$ 135.90	7.49%	8.54%	9.62%	10.50%	11.50%	12.54%	13.36%
	$ 128.50	6.09%	7.48%	8.54%	9.63%	10.51%	11.51%	12.55%
	$ 121.00	4.96%	6.07%	7.42%	8.53%	9.62%	10.50%	11.50%
	$ 113.50	3.77%	4.93%	6.05%	7.42%	8.52%	9.61%	10.50%

Scenario 5

Avoided Cost, $/mWh

Wholesale Price. $/MWh		$ 20.00	$ 25.00	$ 30.00	$ 35.00	$ 40.00	$ 45.00	$ 50.00
	$ 119.50	10.54%	11.57%	12.58%	13.56%	14.55%	15.48%	16.47%
	$ 112.50	9.47%	10.50%	11.54%	12.55%	13.54%	14.53%	15.46%
	$ 105.50	8.32%	9.43%	10.47%	11.50%	12.52%	13.52%	14.51%
	$ 99.00	7.21%	8.36%	9.44%	10.51%	11.54%	12.57%	13.57%
	$ 92.50	6.56%	7.24%	8.39%	9.48%	10.55%	11.59%	12.59%
	$ 85.50	5.06%	6.49%	7.18%	8.34%	9.44%	10.51%	11.55%
	$ 79.00	3.66%	5.07%	6.51%	7.21%	8.38%	9.47%	10.55%

Investment Tax Credit

Scenario 3

ITC Face Value

Wholesale Price. $/MWh		$ 1.00	$ 0.90	$ 0.80	$ 0.70	$ 0.60	$ 0.50	$ 0.40
	$ 181.00	10.50%	9.95%	9.45%	8.97%	8.52%	8.11%	7.71%
	$ 185.00	11.03%	10.47%	9.95%	9.46%	9.00%	8.57%	8.16%
	$ 192.00	11.66%	11.08%	10.54%	10.03%	9.56%	9.11%	8.69%
	$ 198.00	12.22%	11.62%	11.06%	10.54%	10.05%	9.59%	9.16%
	$ 201.00	12.69%	12.08%	11.51%	10.97%	10.47%	10.00%	9.56%
	$ 207.00	13.24%	12.61%	12.02%	11.48%	10.96%	10.48%	10.02%
	$ 214.00	13.83%	13.18%	12.58%	12.01%	11.49%	10.99%	10.52%

Scenario 4

ITC Face Value

Wholesale Price. $/MWh		$ 1.00	$ 0.90	$ 0.80	$ 0.70	$ 0.60	$ 0.50	$ 0.40
	$ 135.90	10.50%	10.33%	10.16%	10.00%	9.84%	9.68%	9.53%
	$ 137.00	10.63%	10.46%	10.29%	10.13%	9.97%	9.81%	9.65%
	$ 138.00	10.87%	10.70%	10.53%	10.36%	10.20%	10.04%	9.88%
	$ 139.00	10.99%	10.82%	10.65%	10.48%	10.31%	10.15%	10.00%
	$ 141.00	11.22%	11.04%	10.87%	10.70%	10.53%	10.37%	10.21%
	$ 142.00	11.33%	11.16%	10.98%	10.81%	10.65%	10.48%	10.32%
	$ 144.00	11.57%	11.39%	11.21%	11.04%	10.87%	10.71%	10.55%

Scenario 5

ITC Face Value

Wholesale Price. $/MWh		$ 1.00	$ 0.90	$ 0.80	$ 0.70	$ 0.60	$ 0.50	$ 0.40
	$ 99.00	10.51%	10.30%	10.11%	9.91%	9.72%	9.54%	9.35%
	$ 100.50	10.74%	10.53%	10.33%	10.14%	9.95%	9.76%	9.58%
	$ 101.50	10.89%	10.69%	10.48%	10.29%	10.09%	9.91%	9.72%
	$ 103.00	11.07%	10.86%	10.66%	10.46%	10.26%	10.08%	9.89%
	$ 104.50	11.29%	11.09%	10.88%	10.68%	10.49%	10.29%	10.11%
	$ 105.50	11.50%	11.29%	11.09%	10.88%	10.69%	10.49%	10.30%
	$ 107.00	11.73%	11.51%	11.31%	11.10%	10.90%	10.71%	10.52%

Cost of Debt

Scenario 3

Cost of Debt

Wholesale Price. $/MWh		3%	4%	4.50%	5%	5.50%	6%	7%
	$ 175.50	10.46%	10.16%	10.02%	9.89%	9.76%	9.63%	9.38%
	$ 178.25	10.94%	10.50%	10.32%	10.19%	10.05%	9.92%	9.66%
	$ 180.00	11.08%	10.84%	10.53%	10.36%	10.22%	10.09%	9.82%
	$ 181.00	11.18%	10.94%	10.80%	10.50%	10.32%	10.19%	9.92%
	$ 182.50	11.32%	11.06%	10.95%	10.82%	10.51%	10.33%	10.06%
	$ 184.00	11.43%	11.20%	11.07%	10.96%	10.83%	10.52%	10.21%
	$ 187.00	11.71%	11.45%	11.36%	11.22%	11.09%	10.98%	10.54%

Scenario 4

Cost of Debt

Wholesale Price. $/MWh		3%	4%	4.50%	5%	5.50%	6%	7%
	$ 132.50	10.49%	10.29%	10.19%	10.09%	10.02%	9.92%	9.73%
	$ 134.50	10.85%	10.53%	10.43%	10.33%	10.24%	10.14%	9.97%
	$ 135.00	10.91%	10.59%	10.49%	10.39%	10.30%	10.20%	10.03%
	$ 135.90	11.02%	10.82%	10.60%	10.50%	10.40%	10.31%	10.11%
	$ 137.00	11.14%	10.95%	10.85%	10.63%	10.53%	10.44%	10.24%
	$ 137.50	11.20%	11.01%	10.91%	10.69%	10.59%	10.50%	10.30%
	$ 139.00	11.38%	11.18%	11.09%	10.99%	10.89%	10.67%	10.48%

Scenario 5

Cost of Debt

Wholesale Price. $/MWh		3%	4%	4.50%	5%	5.50%	6%	7%
	$ 96.00	10.52%	10.28%	10.17%	10.06%	9.95%	9.82%	9.65%
	$ 97.50	10.76%	10.49%	10.38%	10.29%	10.19%	10.08%	9.88%
	$ 98.50	10.94%	10.65%	10.54%	10.43%	10.34%	10.23%	10.05%
	$ 99.00	11.03%	10.73%	10.62%	10.51%	10.40%	10.31%	10.13%
	$ 99.50	11.11%	10.80%	10.69%	10.58%	10.48%	10.39%	10.20%
	$ 100.50	11.27%	10.98%	10.85%	10.74%	10.63%	10.52%	10.35%
	$ 101.75	11.45%	11.17%	11.06%	10.93%	10.82%	10.71%	10.51%

Electricity Growth Rate

Scenario 3

Wholesale Price. $/MWh		Electricity Growth Rate 0.00%	0.50%	0.75%	1.00%	1.25%	1.50%	2.00%
	$ 166.00	7.24%	8.04%	8.44%	8.84%	9.37%	9.76%	10.51%
	$ 173.50	7.98%	8.94%	9.34%	9.72%	10.10%	10.49%	11.29%
	$ 177.50	8.53%	9.33%	9.72%	10.11%	10.50%	10.92%	11.81%
	$ 181.00	8.87%	9.68%	10.07%	10.50%	11.05%	11.40%	12.14%
	$ 184.25	9.20%	10.00%	10.60%	10.99%	11.34%	11.71%	12.41%
	$ 187.00	9.47%	10.48%	10.87%	11.22%	11.60%	11.94%	12.67%
	$ 195.50	10.50%	11.23%	11.61%	11.98%	12.35%	12.91%	13.63%

Scenario 4

Wholesale Price. $/MWh		Electricity Growth Rate 0.00%	0.50%	0.75%	1.00%	1.25%	1.50%	2.00%
	$ 124.00	7.32%	8.12%	8.64%	8.98%	9.32%	9.67%	10.48%
	$ 130.00	8.30%	8.98%	9.35%	9.81%	10.16%	10.49%	11.18%
	$ 133.00	8.62%	9.46%	9.82%	10.15%	10.50%	10.85%	11.65%
	$ 135.90	8.98%	9.80%	10.15%	10.50%	10.97%	11.31%	11.98%
	$ 139.00	9.48%	10.17%	10.52%	10.99%	11.32%	11.66%	12.34%
	$ 141.50	9.76%	10.47%	10.94%	11.28%	11.62%	11.95%	12.68%
	$ 147.00	10.54%	11.23%	11.58%	11.92%	12.31%	12.79%	13.42%

Scenario 5

Wholesale Price. $/MWh		Electricity Growth Rate 0.00%	0.50%	0.75%	1.00%	1.25%	1.50%	2.00%
	$ 107.50	10.50%	11.18%	11.48%	11.80%	12.12%	12.45%	13.07%
	$ 103.50	9.91%	10.55%	10.89%	11.22%	11.54%	11.84%	12.47%
	$ 101.00	9.51%	10.16%	10.49%	10.81%	11.16%	11.48%	12.10%
	$ 99.00	9.18%	9.87%	10.20%	10.51%	10.83%	11.15%	11.82%
	$ 96.75	8.83%	9.49%	9.85%	10.18%	10.48%	10.81%	11.47%
	$ 94.50	8.47%	9.15%	9.47%	9.80%	10.15%	10.48%	11.10%
	$ 91.00	7.87%	8.58%	8.92%	9.26%	9.57%	9.90%	10.58%

Appendix B

PVWatts detailed modeling inputs

Solar Resource			Solar Farm	
Location:	Charlotte		Array Type	2 Axis Tracking
Lat	35.22N		Tilt	35.2 deg
Long	-80.93 E		Azimuth	180 deg
Elevation	234 meters		Ground Coverage Ratio	0.4
Solar Pannel			AC System Size	650 MW
Module Type	Premium		DC System Size	882 MW
DC:AC	1.4		Annual Energy	1,481 MWh
Inverter Efficiency	96%		Total System Losses	14%
Capacity Factor	21.10%			

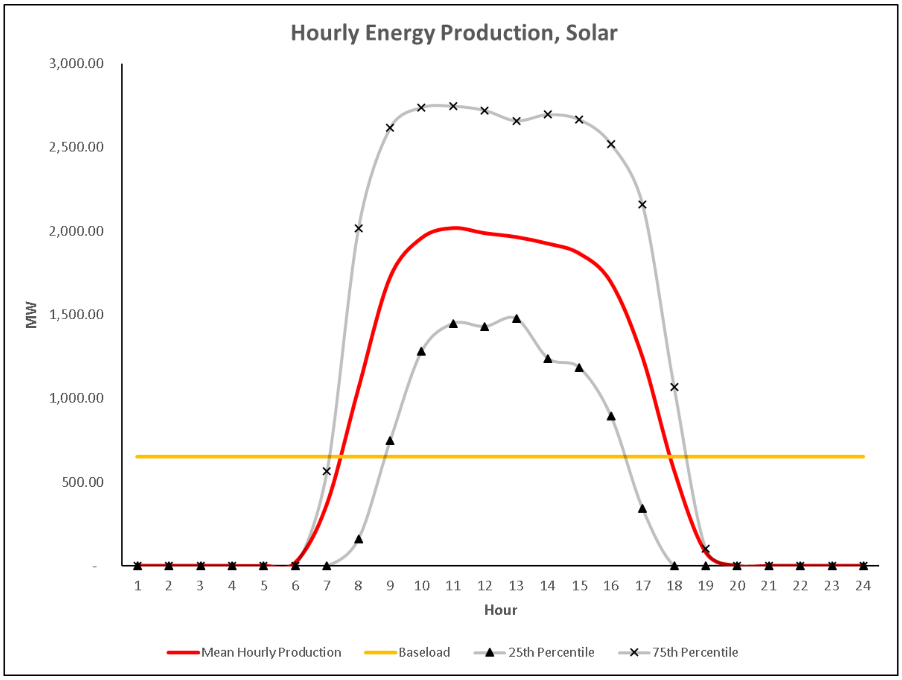
SAM detailed modeling inputs

Wind Resource			Wind Farm	
Location:	Oklahoma City		Number of Turbines	300
Lat	35.47 N		Turbines Per Row	30
Long	-97.6 E		Number of Rows	10
Elevation	397 meters		Trubine Spacing, # rotor diameters	8
Wind Turbine			Row Spacing, # rotor diameters	8
Name:	RePower MM 92		Row Orientation, degrees	0
Hub Height	135m		Wind Farm Losses	0.01%
Rotoe Diameter	100m		Turbulence Coefficient	0.1
Shear Coefficient	0.14		Wake Model	Eddy-Viscosity
Cut-in Wind Speed	4 m/s		AC System Size	630 MW
Cut-out Wind Speed	25 m/s		DC System Size	882 MW
Capacity Factor	45.30%		Annual Energy	2,973 MWh

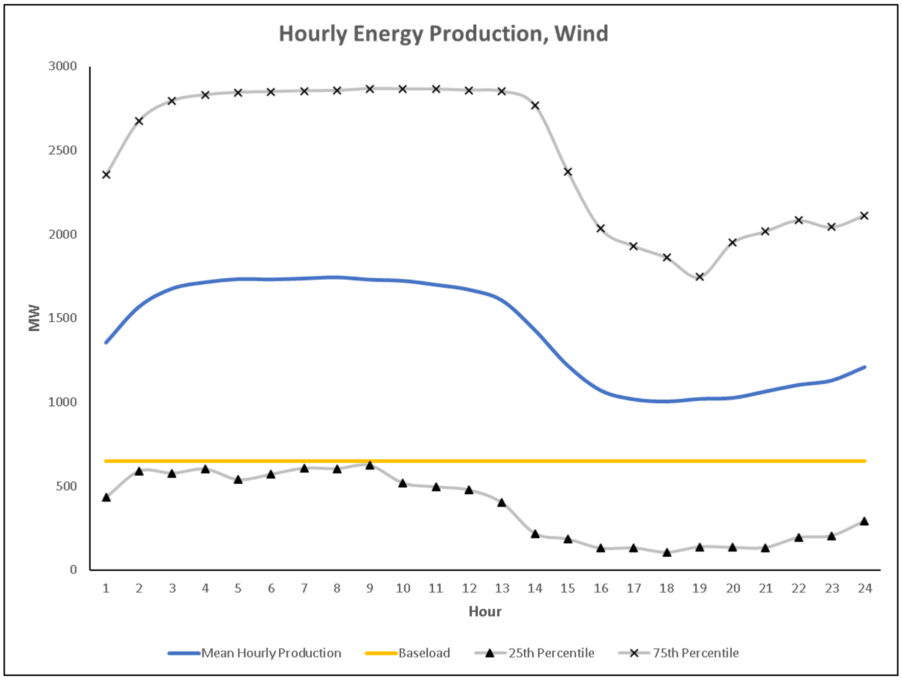
Energy Production Curves

The following illustrations depict the hourly mean energy production for each scenario. Also displayed are the 25th percentile and 75th percentile production profiles.

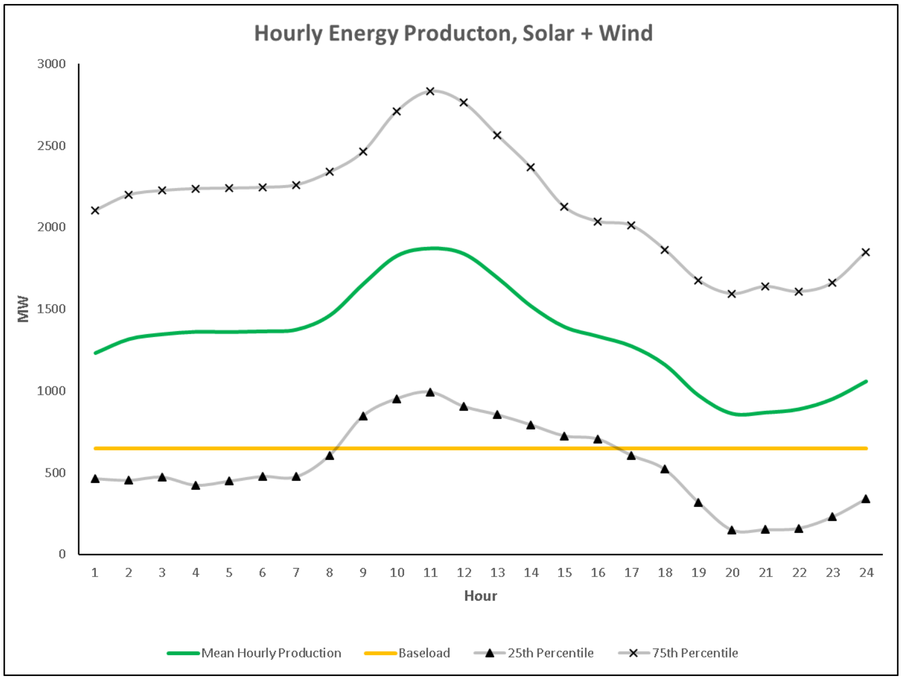
Scenario 3



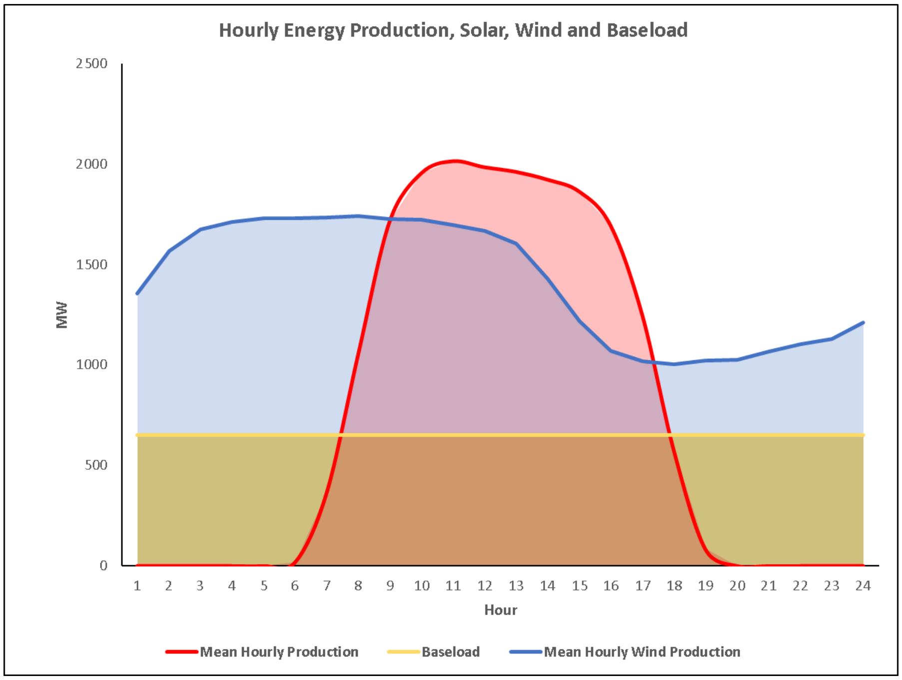
Scenario 4



Scenario 5



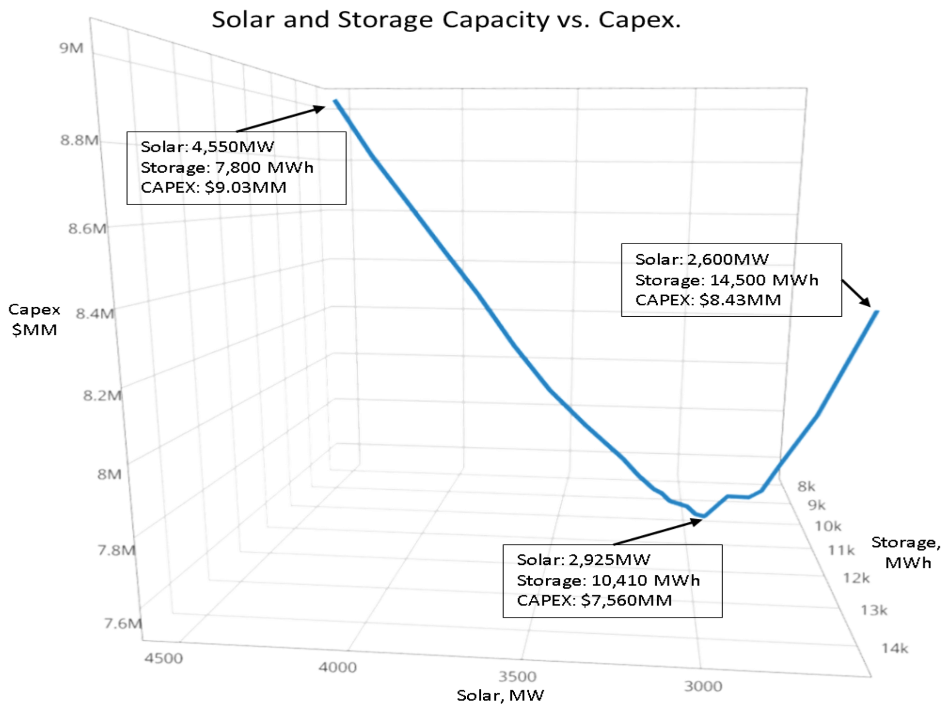
Overlay of Scenario 3 and Scenario 4.



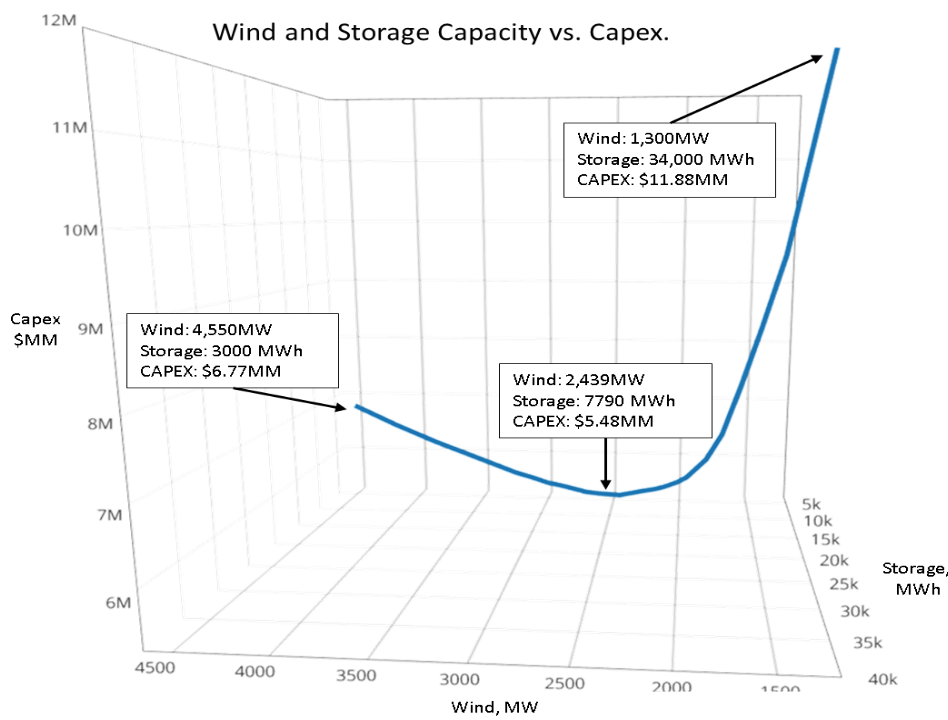
Appendix C

CAPEX as a Function of Wind, Solar and Storage Capacity

Scenario 3: Solar + Storage



Scenario 4: Wind + Storage



Scenario 5: Solar + Wind + Storage