Memphis Summary of Benefits

December 2019

Benefits of Memphis Contract with TVA

Annual Value (FY18)	Description
$10M - $15M	▪ Economic Development benefits, incl. investment credits, performance grants, etc.
$18.3M	▪ Payments in Lieu of Taxes (PILOT)
$2.2M	▪ Community benefits, including Home Uplift (weatherization) and other energy efficiency programs
$330k	▪ Community investments in schools, local organizations, and non-profits
$37M	▪ Revenue from 161kV transmission lease (varies slightly year to year)
$140k	▪ Comprehensive Services Program (CSP) matching funds (split 50/50 with MLGW)
$50M* - $120M*	▪ Capital investment by businesses in the Memphis area induced by TVA's economic development efforts

**Note that capital investment by other businesses does not represent direct spend by TVA but does represent increased MLGW revenue and increased City of Memphis tax base*

Memphis-Area Investment & Job Creation

Since 2012, TVA has helped attract 24 new location projects and 63 expansion projects in the Memphis area

Recent Announcements:			Since 2012:
Jobs :			
700	**610**	**500+**	**28,000** jobs
North American Operations Headquarters	**Headquarters Expansion**	**Advanced Research Center**	**24 New Projects** **63 Expansions**
Investment:			
$6.6 million	**$83.6** million	**$412** million	**$3.6** billion

PARTNERSHIP BENEFITS AND TVA PUBLIC POWER

Benefits of TVA Public Power

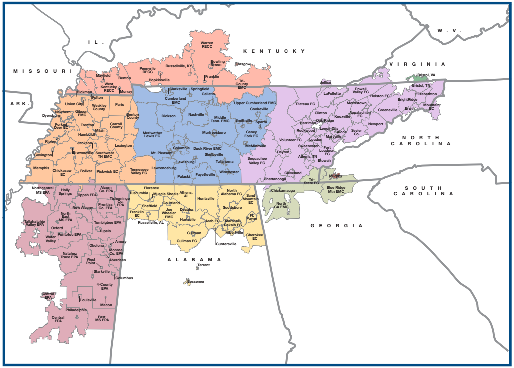
- As a part of the partnership agreement, TVA has offered a 3.1% credit on wholesale power rates to all Local Power Companies (LPCs); for MLGW, this credit is approximately $22.5 million per year, or $400 million over 20 years.
- LPCs that commit to the partnership agreement also gain additional access to the TVA planning process and an opportunity to self-generate some renewable energy (up to 5%) to meet local needs.
- All 154 LPCs are offered the same contract terms and benefits.
- Potential options for consideration may include but are not limited to $700M Transmission Prepay, $200M Gas Prepay and $100M Electric Prepay.*
- TVA is also commited to support future port development at the former Allen Fossil Plant site.*

Description	Annual Benefit 5-Year Contract	Annual Benefit 20-Year Partner Contract
Transmission Lease TVA lease of MLGW's 161kV system on an annual basis	$35M	$35M
PILOT Payments Payments in lieu of taxes distributed via the State of TN	$18.3M	$18.3M
Economic Development Benefits TVA's Investment Credit program rewards companies for new/expanded operations Numbers are specific to Memphis area	$13.8M	$13.8M
Programs to Reduce Energy Burden Includes weatherization programs like Share the Pennies and Home Uplift Provides incentives to homes, businesses, and local industries	$3.2M	$3.2M
Memphis Community Support Includes grants to Mid-South Food Bank, Memphis in May, Library, Museums, NAACP Awards, Urban League, School Programs / STEM, etc.	$0.3M	$0.3M
Partner Credit 3.1% wholesale bill credit	Not Included	$22.5M
Total Per Year	**$71M**	**$93M**
Items below and prepays are for further consideration.		
Transmission Lease Prepay TVA lease of MLGW's 161kV system on an annual basis	Not Included	Available prepay up to $700M
Gas JAA Prepay Bank and MLGW enter into a Joint Action Agency to prepay gas, TVA converts gas to electricity through tolling arrangement	Not Included	Available prepay up to $200M
Electric Prepay MLGW issues tax exempt bonds to prepay electric service, TVA repays with floating credit	Not Included	Available prepay up to $100M
		$1B Potential Benefits in Year One

** For discussion purposes only and does not constitute a binding offer and shall not form the basis for an agreement under any legal or equitable theory.*

TVA Public Power

TVA works with **154 local power companies** to keep safe, clean, reliable and affordable public power flowing to homes and businesses throughout the seven-state region. As of April 2020, 138 of the 154 local power companies have signed the TVA Partnership Agreement, including **Electric Power Board** (Chattanooga, TN), **Nashville Electric Service** (Nashville, TN) **Huntsville Utilities** (Huntsville, AL), and **Knoxville Utilities Board** (Knoxville, TN).



What happened to LPCs that left TVA?

Paducah and Princeton, Kentucky

History: Paducah and Princeton left in 2009 due to concern over TVA rates. They formed the Kentucky Municipal Power Agency (KMPA) to invest in a coal mine and build a large, new coal plant.

Challenge: Plant costs came in 75% higher than expected. In five years, their rates rose to the highest in KY, and KMPA carried $500M+ in debt while losing $300k per month.

Result: Paducah and Princeton wanted to return to TVA, but are unable due to outstanding debt.

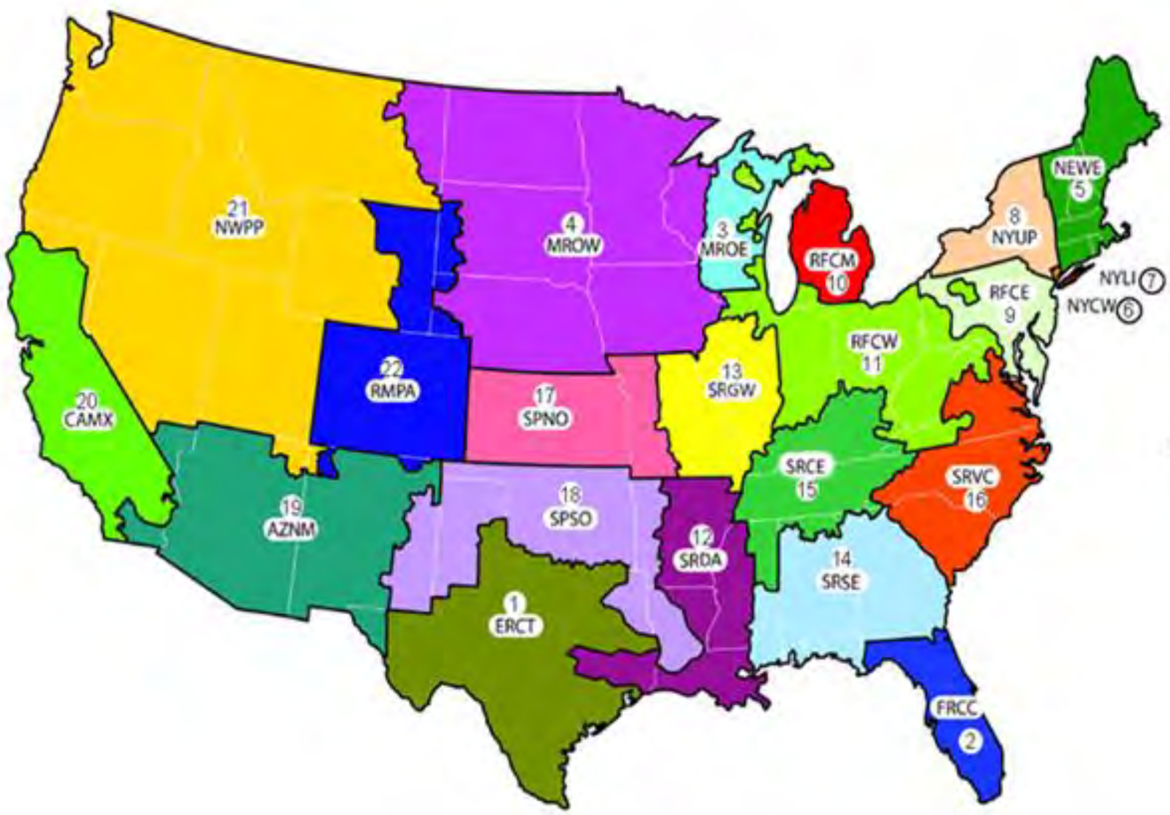
Bristol, Virginia

History: Bristol Virginia Utility (BVU) left TVA in 1997 looking for lower rates. They switched to AEP in 2005 and returned to TVA in 2008 seeking rate stability.

Challenge: Reliability and price stability were significantly worse at other power providers, despite lower advertised prices. After a 40% rate hike with AEP, BVU negotiated a deal to re-join TVA.

Result: Bristol returned to TVA 10 years later.

Appendix B: Regional Capital Cost Multiplier



Technology	Advanced 2x1 Combined Cycle	Advanced Simple Cycle Frame CT	Small Aero Simple Cycle CT	Onshore Wind	Offshore Wind	Utility Solar PV Tracking	Batteries Li-ion
Average	1	1	1	1	1	1	1
ERCT	0.88	0.91	0.88	0.78	1.00	0.88	1.00
FRCC	0.90	0.94	0.91	N/A	1.00	0.94	1.00
MROE	0.87	0.90	0.87	1.07	N/A	0.98	1.00
MROW	0.91	0.93	0.91	0.88	N/A	1.01	1.00
NEWE	1.02	0.98	0.98	1.19	1.00	1.06	1.00
NYCW	1.39	1.33	1.40	N/A	1.00	N/A	1.00
NYLI	1.39	1.33	1.40	1.08	1.00	1.43	1.00
NYUP	1.03	0.97	0.97	1.08	N/A	1.00	1.00
RFCE	1.07	1.04	1.05	1.08	1.00	1.06	1.00
RFCM	0.91	0.93	0.91	1.07	N/A	1.01	1.00
RFCW	0.95	0.96	0.93	1.07	N/A	1.01	1.00
SRDA	0.88	0.92	0.89	0.98	1.00	0.91	1.00
SRGW	0.96	0.97	0.95	1.07	N/A	1.03	1.00
SRSE	0.90	0.94	0.93	1.16	1.00	0.90	1.00
SRCE	0.96	1.00	0.97	0.97	N/A	0.94	1.00
SRVC	0.86	0.89	0.87	1.16	1.00	0.86	1.00
SPNO	0.93	0.95	0.93	0.73	N/A	0.98	1.00
SPSO	0.91	0.93	0.91	0.67	N/A	0.94	1.00
AZNM	1.08	1.09	1.07	0.96	N/A	0.99	1.00
CAMX	1.17	1.08	1.09	0.96	N/A	1.14	1.00
NWPP	1.00	0.99	0.97	0.96	1.00	1.01	1.00
RMPA	1.12	1.13	1.30	0.73	N/A	0.96	1.00

Appendix C: Model Description

In order to perform the stochastic analysis, a set of probability distributions are required for key market driver variables. These include probabilistic distributions for demand growth (load), fuel costs (natural gas and coal), environmental compliance costs (carbon), and capital costs.

Load Stochastics

To account for variations in electricity demand stemming from economic growth, weather, and energy efficiency and demand side management measures, Siemens developed stochastics around the load growth expectations for the MLGW control area and the neighboring ISO zones. While values in the 95th percentile are driven by strong economic growth, values in the 5th percentile are driven by economic stagnation or other load modifiers such as energy efficiency and demand-side management implementation.

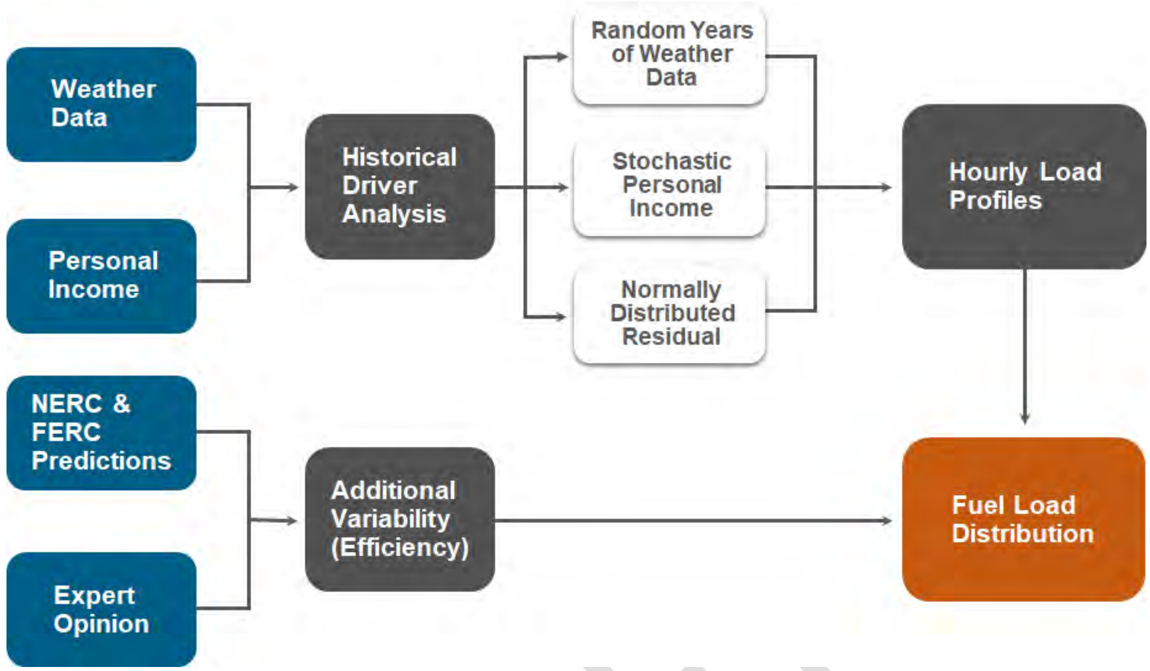
Siemens's long-term load forecasting process captures both the impact of historical load drivers such as economic growth and variability of weather and the possible disruptive impacts of energy efficiency penetration in constructing the average and peak demand outlook.

Finally, Siemens benchmarked the projections against MISO-sponsored load forecasting studies that are conducted by independent consultants and institutions and then released into the public domain. The process to benchmark the load to MISO's forecasts is undertaken during the quantum step, which is described below.

Load Forecast Process

The process for developing stochastic distributions for MLGW and surrounding MISO zone loads begins with a deterministic estimation of load uncertainties, followed by parametric forecasts for the MISO zones.

Exhibit 192: Flow Chart to Address Load Uncertainty



Source: Siemens

With respect to the historical driver analysis, we find that historical monthly weather data and personal income have explained changes in monthly average and peak load well. This relationship forms the basis for Siemens 's load uncertainty analysis. The basic premise of the model is that load can be expressed as a function of heating degree days, cooling degree days, humidity, and personal income.

$$Load_t=\alpha+ \beta_1*HDD_t+ \beta_2*CDD_t+ \beta_3*HUM_t+ \beta_4*PI_t+ \xi_t$$

Where the independent variables are:

- HDD (Heating Degree Days): 65 - Average daily temperature in degrees Fahrenheit or zero (HDD is never negative)
- CDD (Cooling Degree Days): Average daily temperature -65 in degrees Fahrenheit or zero. (CDD is never negative)
- HUM (Humidity): Average daily percent humidity
- PI: Personal Income
- ξ: A normally distributed variable with mean 0 and constant variance
- α: A constant derived from the regression analysis
- β_n: Coefficients derived from the regression analysis
- t: Month of the year

A stepwise regression then calibrates this model for the historic net peak and average MLGW load data. The stochastic distributions of the load were then computed by running 200 iterations on the independent variables as the randomly generated input parameters and applied to the equation and the calibrated model coefficients above.

MISO Forecast Load Uncertainty

The subsequent load stochastics propagation for the surrounding MISO zones is a parametric estimation process that separately employs the same econometric specification for each MISO Local Resource Zone (LRZ) based on the historical relationships between average and peak load, and key driver variables, including temperature data (HDD, CDD, and humidity) and an economic factor variable (personal income for the geographical area). Siemens uses the historical personal income drift rates and volatility and a sampling from 17 years of historical data for each region to assess the distribution of overall load growth conditions for each year of the forecast. The base average and peak demand forecasts are based on the average of the peak and average demand forecasts.

To produce load stochastics, Siemens propagates three independent random paths: weather data, personal income, and a residual. Weather data includes heating and cooling degree days and humidity. To produce reasonable weather data projections, Siemens samples actual yearly paths from history. On average, we use about 17 years of historical data to perform the weather projections for the forward study period. Personal income is assumed to follow Geometric Brownian Motion. This means that there exists a normal distribution with constant mean and variance that describes how the return on personal income will behave at any time. Historical personal income data produces a best estimate for the relevant monthly mean and variance of this process going forward. Finally, to account for unexplained variation in the observed data, Siemens adds a normally distributed residual with mean zero and standard deviation equal to the root mean squared error of the previously mentioned stepwise regression.

Finally, to benchmark and formulate a reference, Siemens used the most recent historical average and peak load for each of the MISO LRZs and the forecasted compounded annual growth rate (CAGR) of peak and average demand from MISO-sponsored 10-year independent load forecasts.

Gas Stochastics

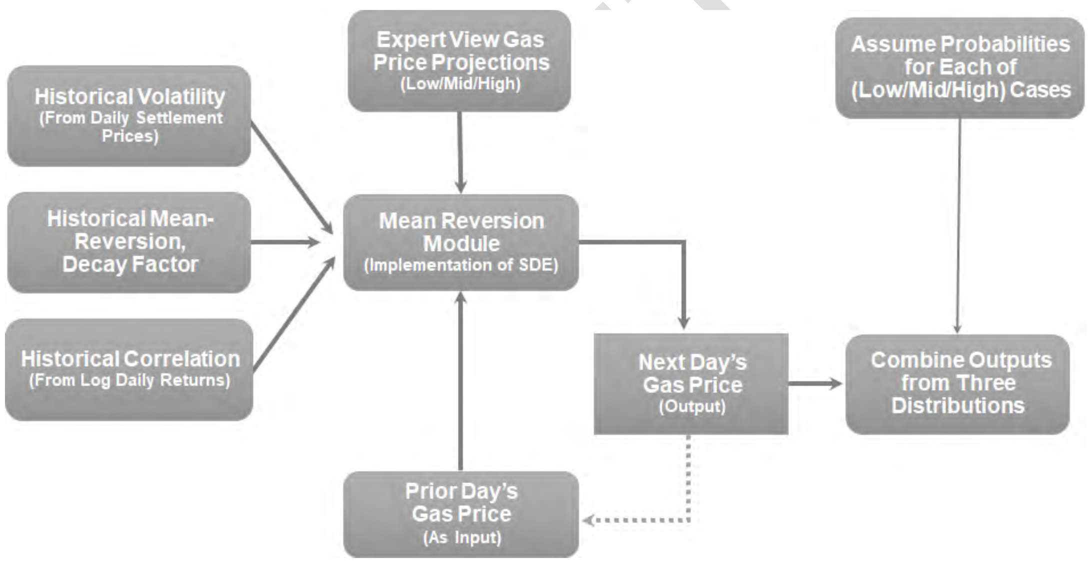
Siemens develops natural gas stochastic distributions for Henry Hub and other basis points. These stochastic distributions are based on a reference case view of natural gas prices with probability bands developed based on a combination of historical volatility and mean reversion parameters as well as a forward view of expected volatility.

Siemens has developed stochastics around the price at the Henry Hub (and other gas basis point as needed) based on historical volatility, current market forwards, and a long-term term fundamental view that considers the expected supply-demand balance. The 95th percentile probability bands are driven by increased gas demand (most likely due to coal retirements) and fracking regulations that raise the cost of producing gas. Prices in the 5th percentile are driven by significant renewable development that keeps gas plant utilization down as well as little to no environmental legislation around power plant emissions.

The steps involved in the development of gas stochastics are as follows:

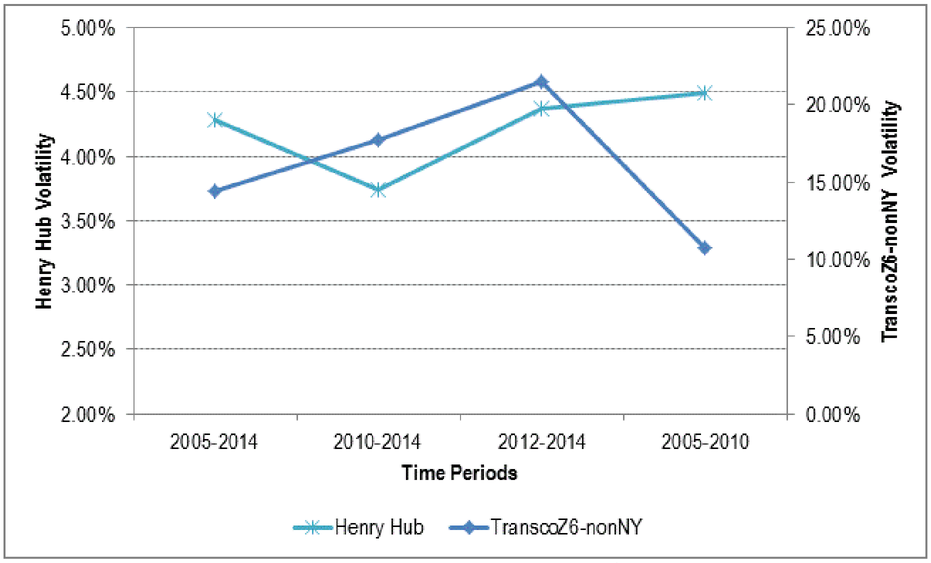
- As the first step, Siemens develops the long-term fundamental forecast of Henry hub and several other gas basis points prices (using the GPCM model). The probability distributions are developed around this fundamental forecast.
- From historical data sets, the volatility parameter is calculated using the daily settled prices. Volatilities for different historical time periods are calculated (such as past 10-years, past 5 years, recent 2.5 years etc.)
- The daily gas prices are modeled as a single-factor continuous mean-reverting process. The mean reversion parameter is also calculated from the historical daily settled prices.
- For more than one gas basis point prices, the appropriate correlations are also calculated from the historical data.
- The entire process to develop the gas stochastics is described in the exhibit below.

Exhibit 193: Gas Stochastics Development Process



Source: Siemens

- The volatilities tend to vary for different time periods. In order to capture this for the forecast time period, different volatility values from different historical time periods are considered. For example, for the first 3 forecast years, volatility calculated from the past 30 months price data will be used. For years 4-8, volatility calculated from the past 5 years will be used. Beyond that time period, the past 10-year historical volatility will be used.
- For example, the exhibit below shows the volatilities for Henry hub and a gas point in the Northeast (for illustration), for different historical time periods:



Source: Siemens

- The long-term fundamental forecast for each month in the forecast time period will be treated as the mean-reverting level in this process.

Coal Stochastics

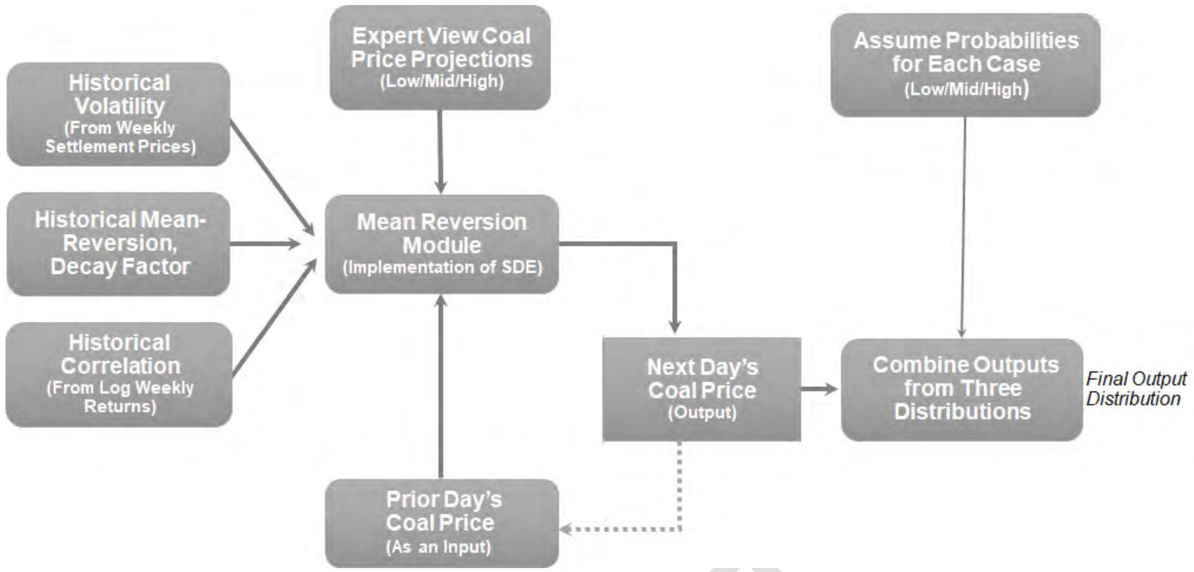
Siemens develops coal price stochastic distributions for CAPP, NAPP, ILB and PRB basins.

These stochastic distributions are based on a reference case view of coal prices with probability bands developed based on a combination of historical volatility and mean reversion parameters.

It is to be noted that majority of coal contracts in the U.S. are bilateral and only about 20% are traded in NYMEX. The historical data set which is used to calculate the parameters comprise of the traded data reported in NYMEX, which is weekly.

The methodology involved in the distribution of stochastic coal prices is exactly similar to natural gas stochastics.

Exhibit 194: Process for Coal Price Stochastic



Source: Siemens

The steps involved in the development of coal basin price stochastics are as follows:

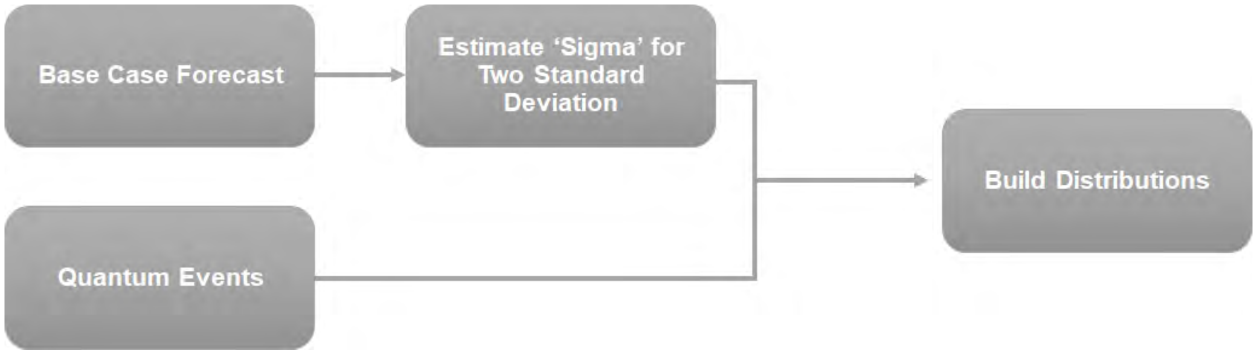
- As the first step, Siemens develops the long-term fundamental forecast of each of the coal basins. The probability distributions are developed around these fundamental forecasts.
- From historical data sets, the volatility parameter is calculated using the weekly prices. Volatilities for different historical time periods are calculated (such as past 10-years, past 5 years, recent 2.5 years etc.)
- The coal prices are modeled as a single-factor continuous mean-reverting process. The mean reversion parameter is also calculated from the historical prices.
- For the four coal basin prices, the appropriate correlations are calculated from the historical data.

CO_2 Stochastics

Siemens develops uncertainty distributions around carbon compliance costs, which will be used in the power dispatch modeling to capture the inherent risk associated with regulatory compliance requirements.

The technique to develop carbon costs distributions, unlike the previous variables, is based on the "expert-opinion" based projections. There are no historical data sets to estimate the parameters for developing carbon costs distributions. The views of the internal subject matter experts (Siemens's) are taken into consideration. The exhibit below shows the high-level methodology for developing stochastic distributions, when the historical data is not available.

Exhibit 195: Technique to Develop Carbon Costs Distributions



Source: Siemens

Given below are the steps involved in this process:

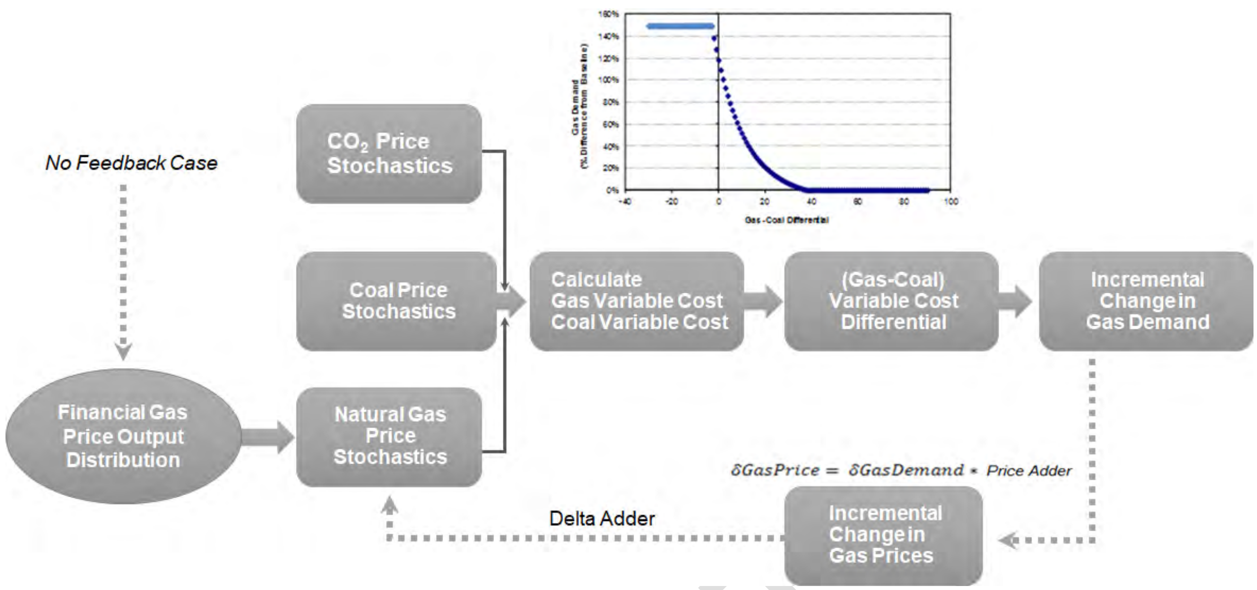
- Siemens PTI's environmental team develops a reference case (base case) forecast, and an associated high and low case. In addition to the high and low cases, the probability values for the high and low cases are also developed.
- These three cases are treated as 16th, 50th and 84th percentiles. Using these percentiles and statistical techniques (tools), the standard deviation values are calculated.
- The reference case is treated as the mid-case (median).
- Using the standard deviation values and a sampling from an underlying standard normal distribution (which has a mean zero and variance one), the probability bands are constructed around the reference projections. This underlying distribution captures the "quantum" events that can happen in the market.
- The distributions are then adjusted to incorporate probabilities such as "the probability of a CO_2 program not taking effect", "greater chance of a nation-wide CO2 regime starting in, say 2022" etc.
- Separate distributions are developed for national carbon costs, California carbon costs and RGGI prices, which are then applied to the respective states.

Gas-Coal-CO_2 prices feedback (Cross-Commodity Correlations)

Siemens has implemented a distinct process to capture the cross-commodity correlations into the stochastic processes. This is a separate process which is implemented after modeling the gas, coal and CO_2 processes discussed above.

The exhibit below describes the coal and CO_2 feedback to gas prices. At a high level, the feedback effects are based on statistical relationships between coal and gas switching and the variable cost of coal and gas generators.

Exhibit 196: Cross Commodity Correlations



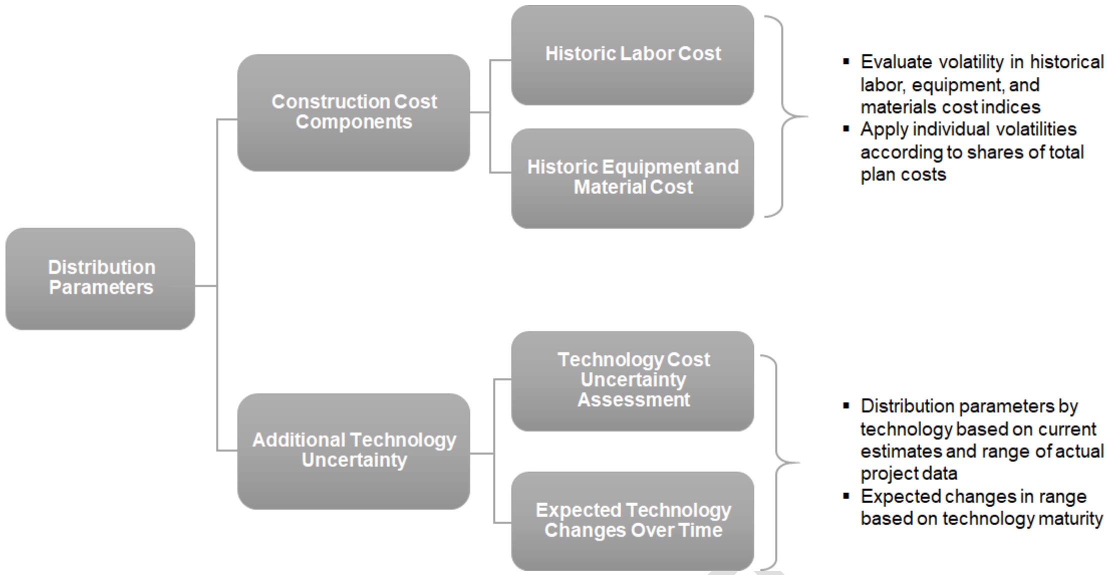
Source: Siemens

- Siemens PTI has performed some fundamental analyses to define the relationship between gas-coal dispatch cost and demand; incremental gas demand curve as a function of the gas-coal differential was calibrated.
- For each iteration, the dispatch cost of gas and coal is calculated from the fuel stochastics and CO_2 stochastics, along with generic assumptions for VOM.
- If the gas-coal dispatch differential changes significantly enough to affect demand, gas demand from previous year is adjusted to reflect the corresponding change in demand.
  - Adjustment can happen in both directions
- A gas price delta is then calculated based on the defined gas demand – price relationship developed.
- This gas price delta is added to the gas stochastic path developed from historic volatility to calculate an integrated CO_2 and natural gas stochastic price.

Capital Cost Stochastics

Siemens develops the uncertainty distributions for the cost of new entry units by technology types, which will be used in the AURORA dispatch model for determining the economic new builds based on market signals. The exhibit below describes the methodology at a high level:

Exhibit 197: Capital Costs Stochastics Methodology



Source: Siemens

The methodology of develop the capital cost distributions is a two-step process:

Step 1: Parametric Distribution:

Siemens 's subject matter experts provide a reference case forecast of $/KW all-in capital costs for different technology types. Along with it, high and low case forecasts are also developed.

The plant costs are broken down by Equipment, Materials, Labor & Others. Historical data (from Handy-Whitman Index) is used to estimate mean price changes and volatilities in these cost categories.

Suitable weights are allocated to each of these 4 categories. The weighted average of the historical mean and volatilities are then estimated.

Using the mean and volatility values, and sampling from an underlying standard normal distribution (which has a mean zero and variance one), the probability bands are constructed around the reference forecast.

Step 2: Quantum Distribution:

This step captures the additional uncertainty associated with each technology. It also factors-in the learning curve effects, improvements in technology over time and other "uncertain" events. The expert-opinion based high and low cases are treated as 1 standard deviation from the mean. With this assumption, the variance values are calculated.

To come with probability distributions, a log-normal distribution is assumed. This distribution is combined with the parametric distribution obtained in the previous step, to come up with the final set of distributions.

Appendix D: Portfolio Details

This section covers the detailed generation buildout by year for the planning horizon 2025-2039, and by technology type for each of the ten selected final portfolios as well as the key performance metrics and costs[40].

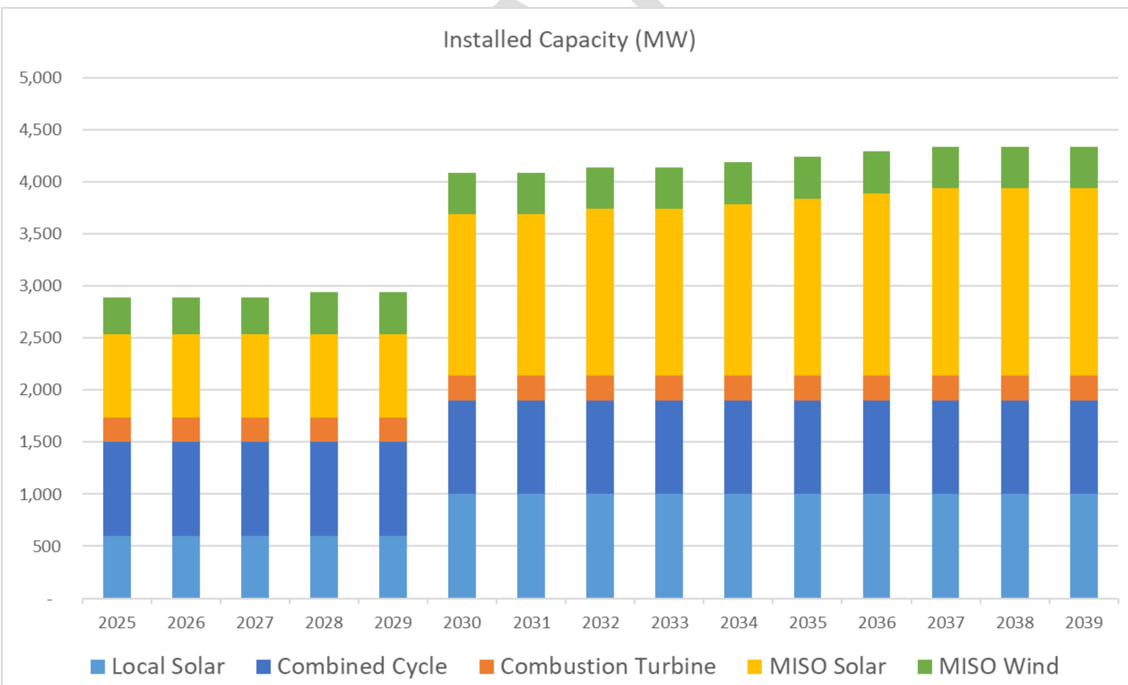
Portfolio 1 (S3S1_P)

This is the base portfolio derived from the capacity expansion plan, with the CT advanced to 2025.

Capacity Expansion (Build Out)

The exhibits below show the capacity expansion by year. 600 MW local Solar is installed in first year, and another 400 MW installed in 2030. Thermal generation (3CCGTs+1 CT) are all installed in first year 2025.

Exhibit 198: Portfolio 1 Installed Capacity by Year



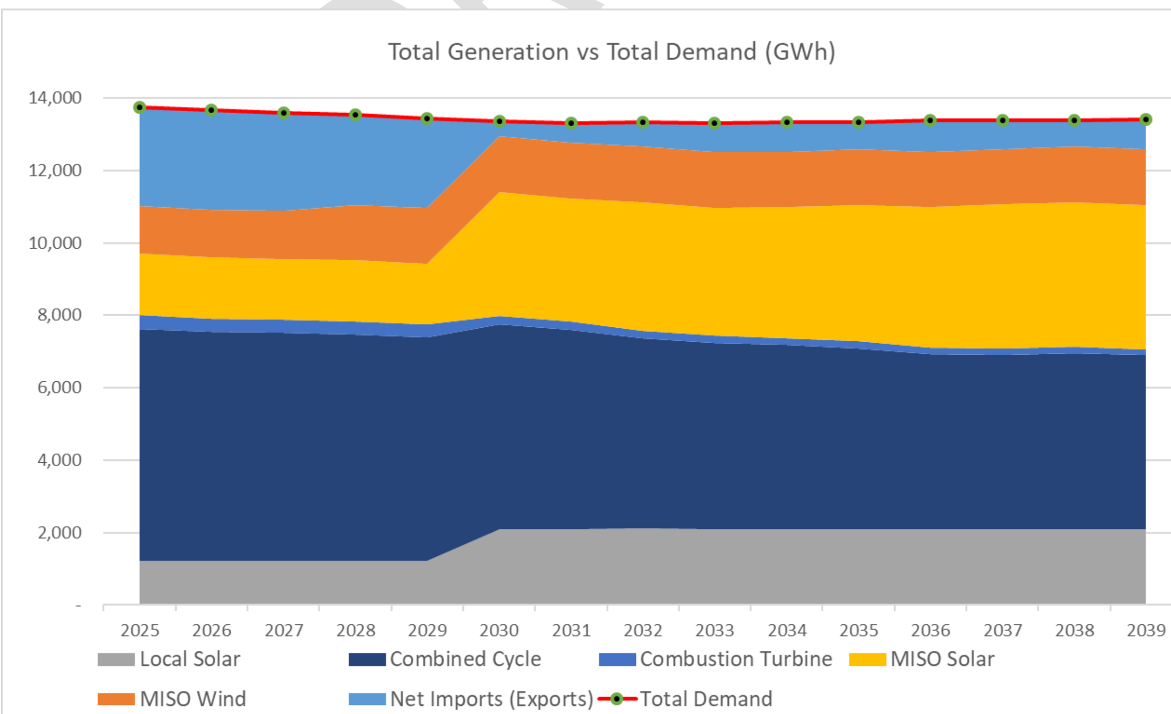
[40] All graphs in this section were the result of analysis performed by Siemens.

Exhibit 199: Portfolio 1 Installed Capacity by Year (Table)

	Advanced Frame CT	Convl. Frame 7FA CT	1x1 Combined Cycle	Utility Solar	Battery	Arkansas Solar	Arkansas Wind	MISO_Cap	Demand
2025	0	237	900	600	0	800	350	1989	3197
2026	0	0	0	0	0	0	0	1983	3182
2027	0	0	0	0	0	0	0	1977	3168
2028	0	0	0	0	0	0	50	1963	3153
2029	0	0	0	0	0	0	0	1958	3139
2030	0	0	0	400	0	750	0	1648	3124
2031	0	0	0	0	0	0	0	1654	3113
2032	0	0	0	0	0	50	0	1654	3108
2033	0	0	0	0	0	0	0	1675	3110
2034	0	0	0	0	0	50	0	1684	3112
2035	0	0	0	0	0	50	0	1694	3114
2036	0	0	0	0	0	50	0	1704	3116
2037	0	0	0	0	0	50	0	1715	3118
2038	0	0	0	0	0	0	0	1738	3121
2039	0	0	0	0	0	0	0	1761	3123

Energy generated from thermal decreases over the years while energy coming from renewables increases, especially starting in 2030 when the cost of renewables is projected to be much more competitive. Imported energy goes down after 2030 as well.

Exhibit 200: Portfolio 1 Energy by Resource Type by Year



Portfolio Costs

Exhibit below shows the supply side NPV cost by year as can be seen the cost is about $670 million per year (2018 $) or $50/MWh, where fixed cost is the largest component due to the investments in generation, followed by cost of fuels and market purchases.

Exhibit 201: Portfolio 1 Cost Components 2018 $

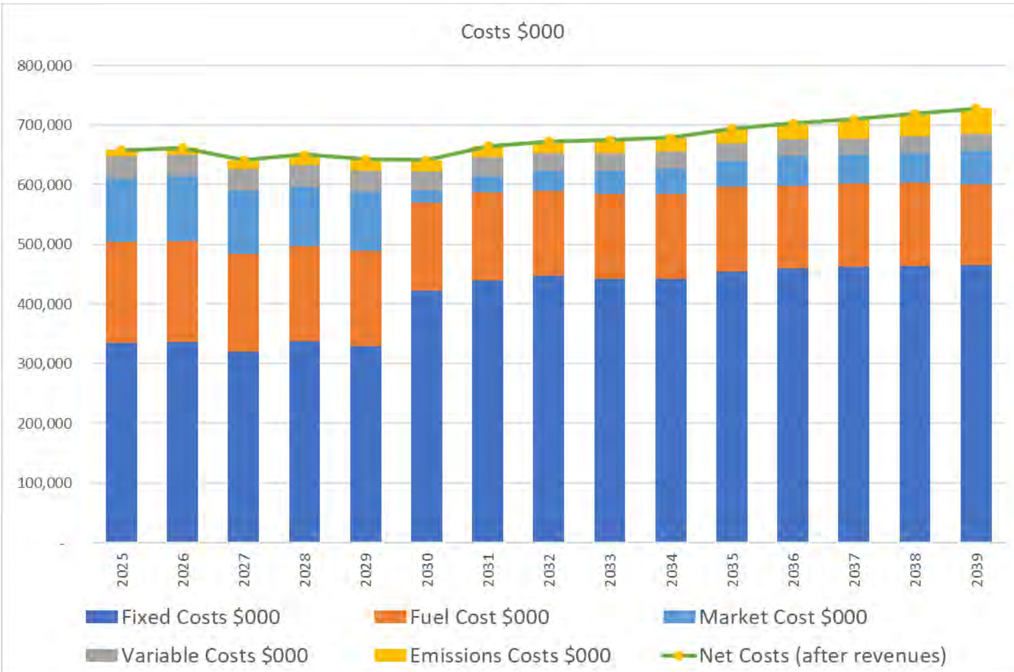
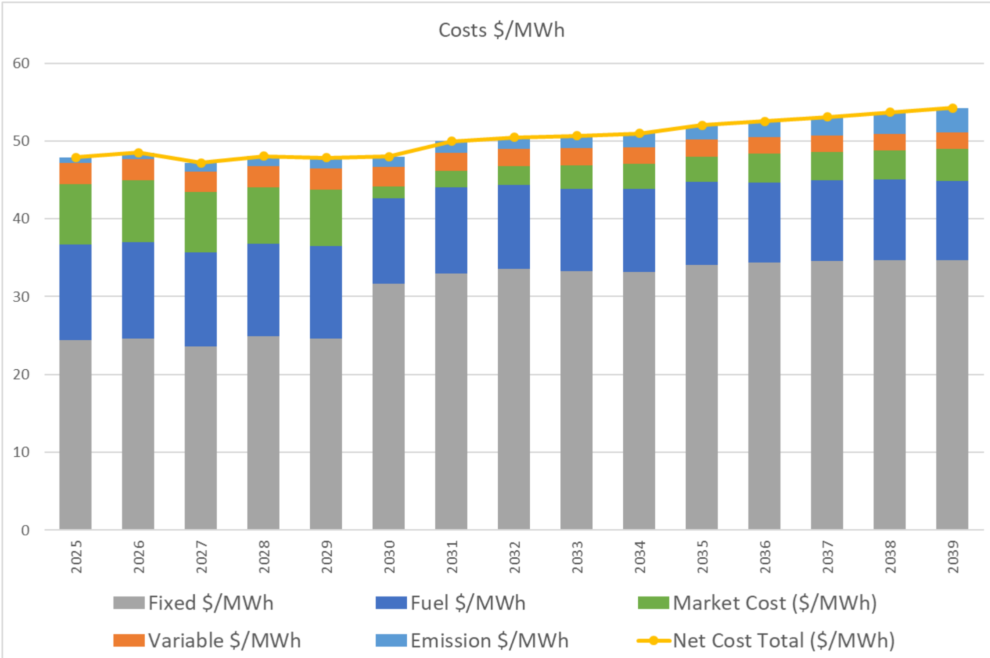
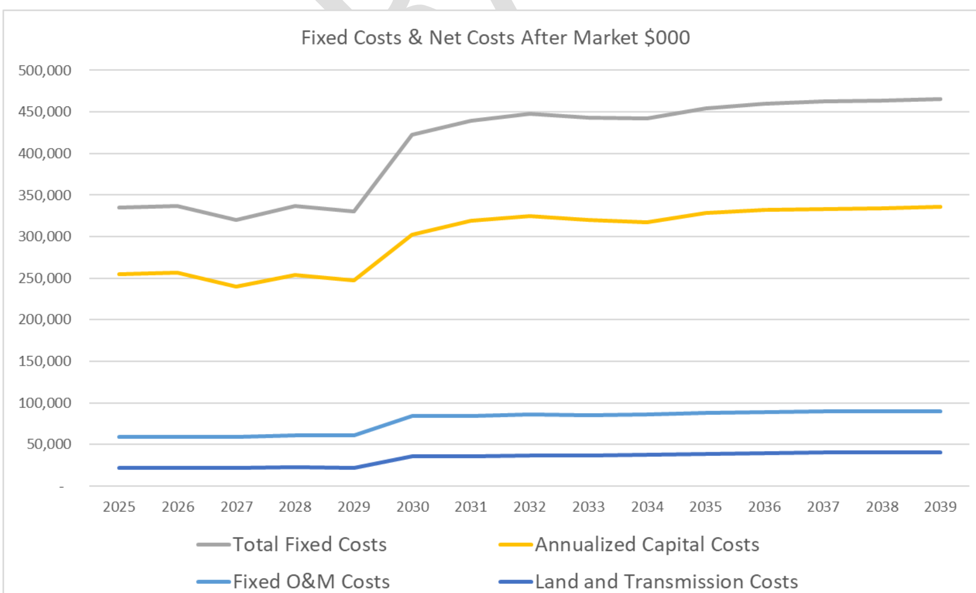


Exhibit 202: Portfolio 1 Cost Components 2018 $/MWh



Graph below shows the breakdown of total fixed costs by components, where the majority comes from the base capital costs on generation.

Exhibit 203: Portfolio 1 Fixed Cost Components 2018 $



Market purchases and sales as also important components. The market purchases by MLGW system are projected to be decreasing while the sales are increasing although the sales are maintained at a low level. As mentioned above, the cost of renewables is projected to be much more competitive after 2030, which resulted in reduced market purchases.

Exhibit 204: Portfolio 1 Market Purchases and Sales 2018 $

These graphs show the purchases and sales amount in energy and as % of demand. It shows the high market risk in the beginning of the planning years of this portfolio.

Exhibit 205: Portfolio 1 Market Purchases and Sales in Energy

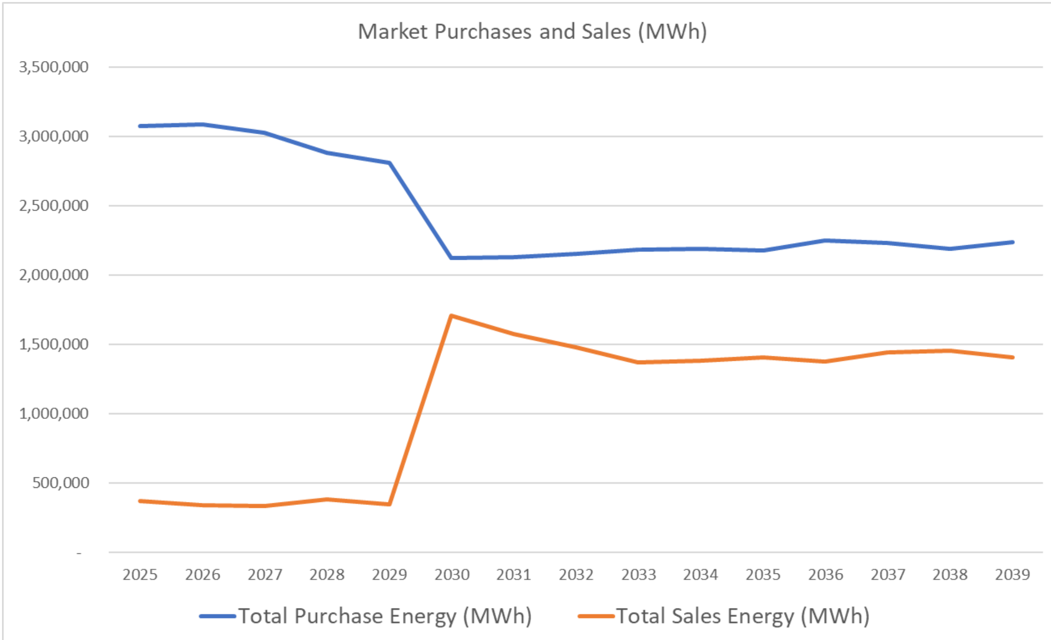
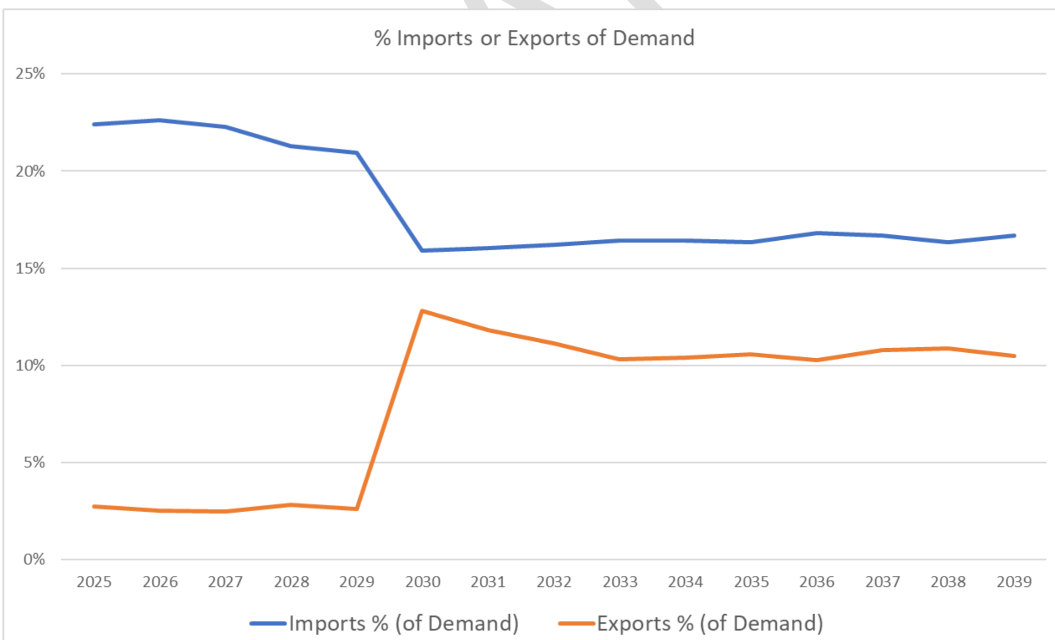


Exhibit 206: Portfolio 1 Market Purchases and Sales as % of Demand



The risk can also be appreciated looking at the difference between purchase price (high) and sale price (low). The more purchase this portfolio needs, the higher risk it has.

Exhibit 207: Portfolio 1 Market Purchases and Sales Prices $/MWh

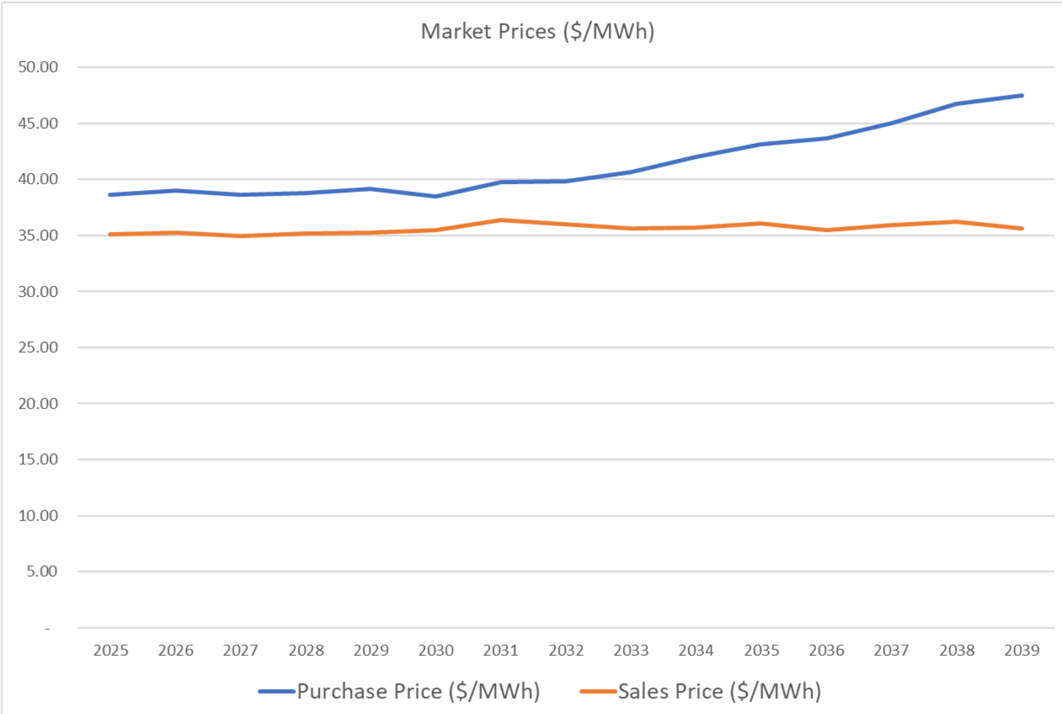
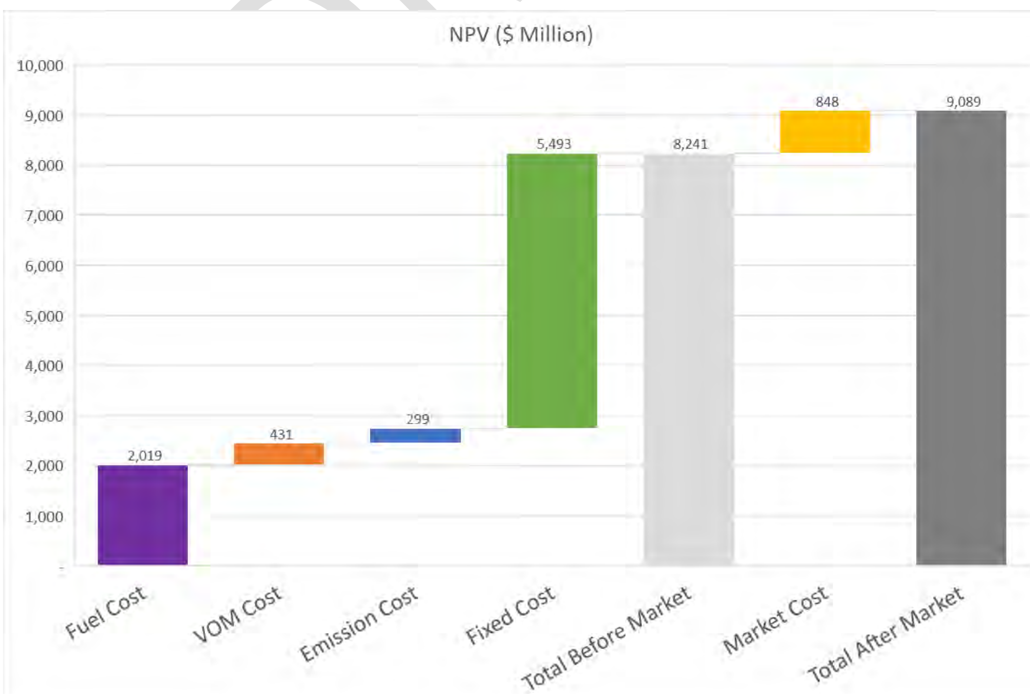


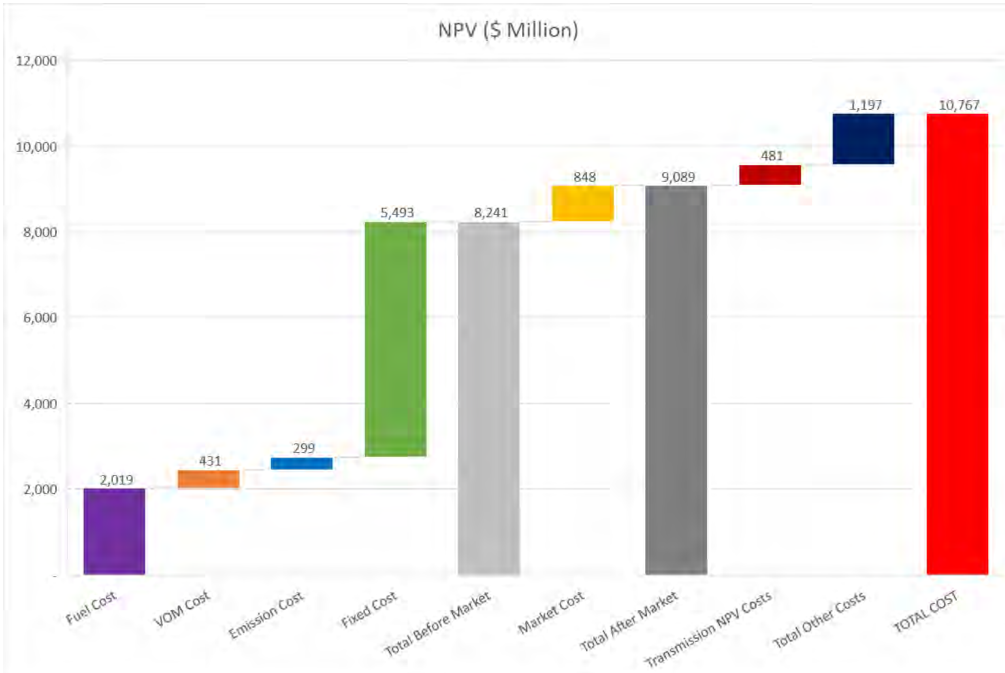
Exhibit below shows the supply side total NPV for 2025-2039, which is about $9.09 billion in 2018 $. Fixed cost is the largest component, followed by fuel and market costs.

Exhibit 208: Portfolio 1 Generation Resource NPV 2018 $



The total NPVRR is shown below which includes the other cost components, i.e. transmission and other costs, including PILOT, TVA Benefits, energy efficiency, gap costs, MISO Admin fees. The total NPVRR of this portfolio is approximately $10.77 billion for 2025-2039 in 2018 $.

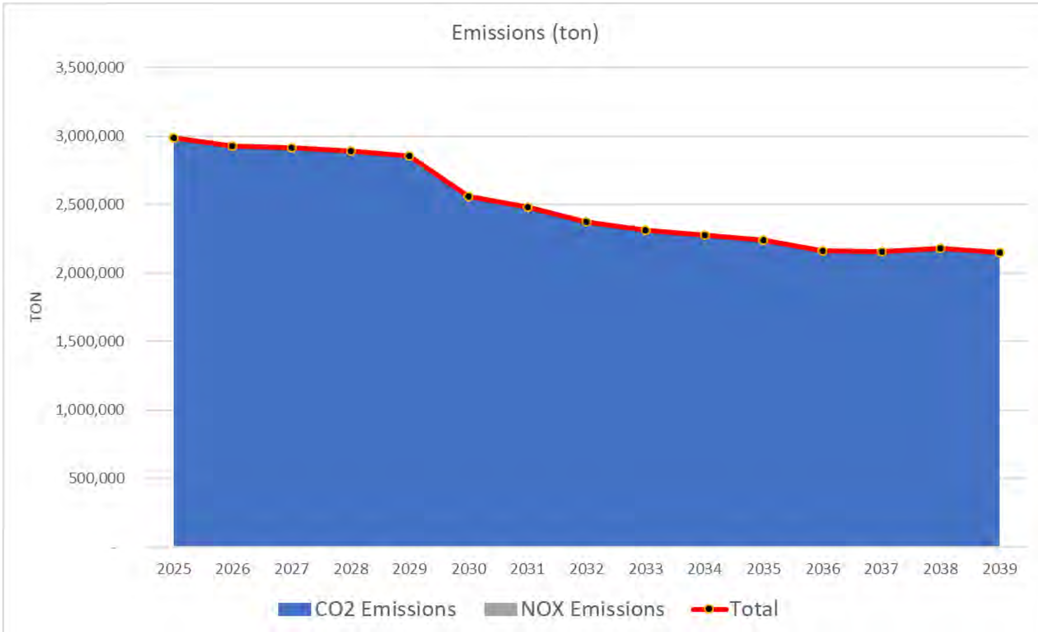
Exhibit 209: Portfolio 1 All NPVRR with Other Components 2018 $



Environmental

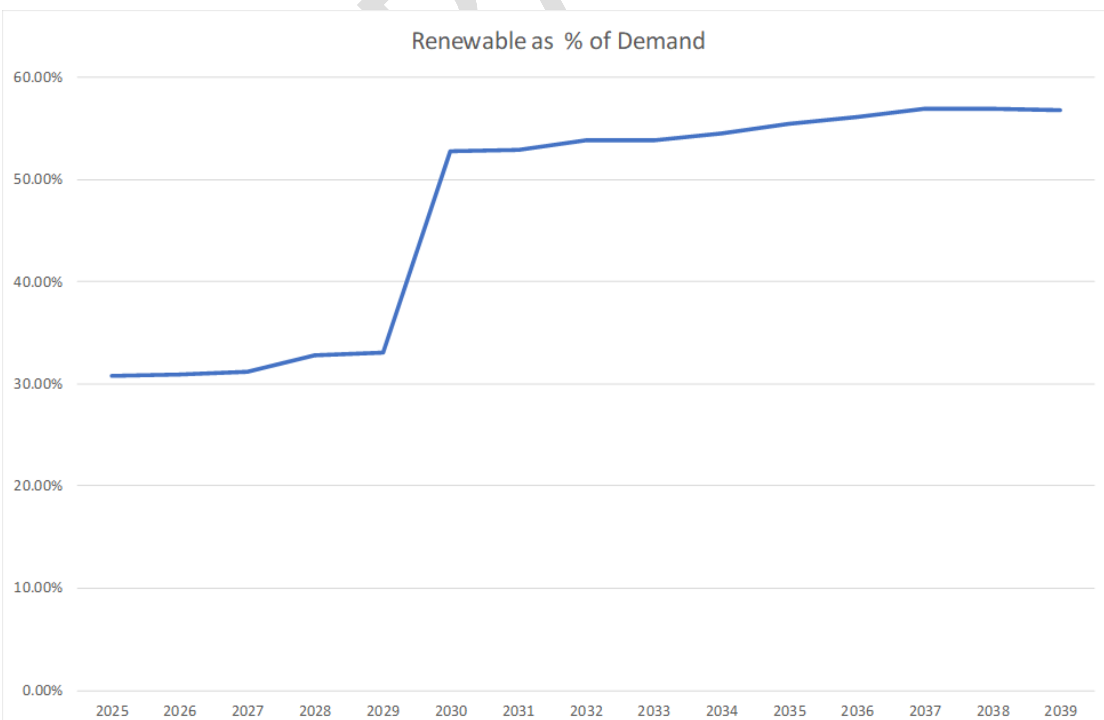
The emission from this portfolio is shown in the graph below. As energy from thermal generation is coming down, the capacity factor of the units decreases which resulted in decreased CO_2 emission over the years.

Exhibit 210: Portfolio 1 Total Emission by Year



And the RPS as of demand in energy of this portfolio starts at about 30% and reaches more than 55% in 2039 as there is new renewables built in 2030 and onwards.

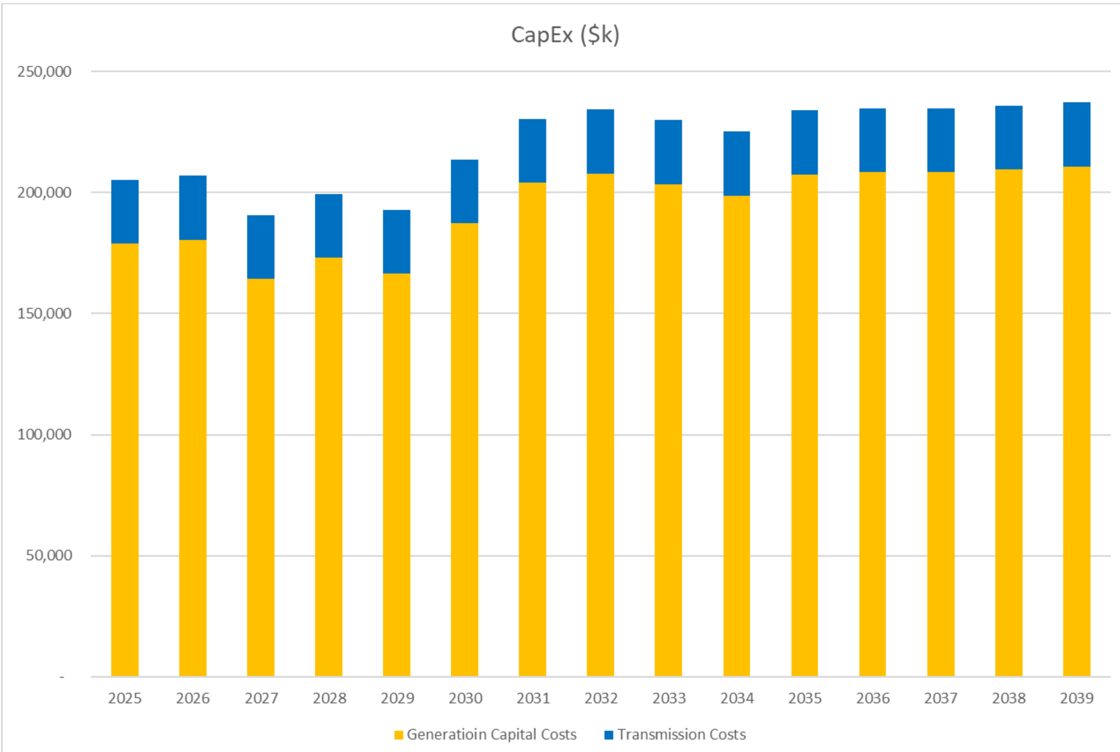
Exhibit 211: Portfolio 1 RPS by Year



Capital Expenditure

Total capital expenditures on generation and transmission are shown in the graph below. We annualized these capital costs from 2025 to 2039 by year and it's about $180 to $230 million per year on average for this portfolio. Most of the capital costs are on the generation side.

Exhibit 212: Portfolio 1 Annualized Capital Expenditure by Year



Portfolio 2 (S3S1_F)

This is the modified portfolio derived from the capacity expansion plan, with one more CCGT added to the case, also with accelerated local renewables.

Capacity Expansion (Build Out)

The exhibits below show the capacity expansion by year. 3 CCGTs and 1 CT are installed in the first year 2025. Local solar is installed as much and quickly as it can in this portfolio.

Exhibit 213: Portfolio 2 Installed Capacity by Year

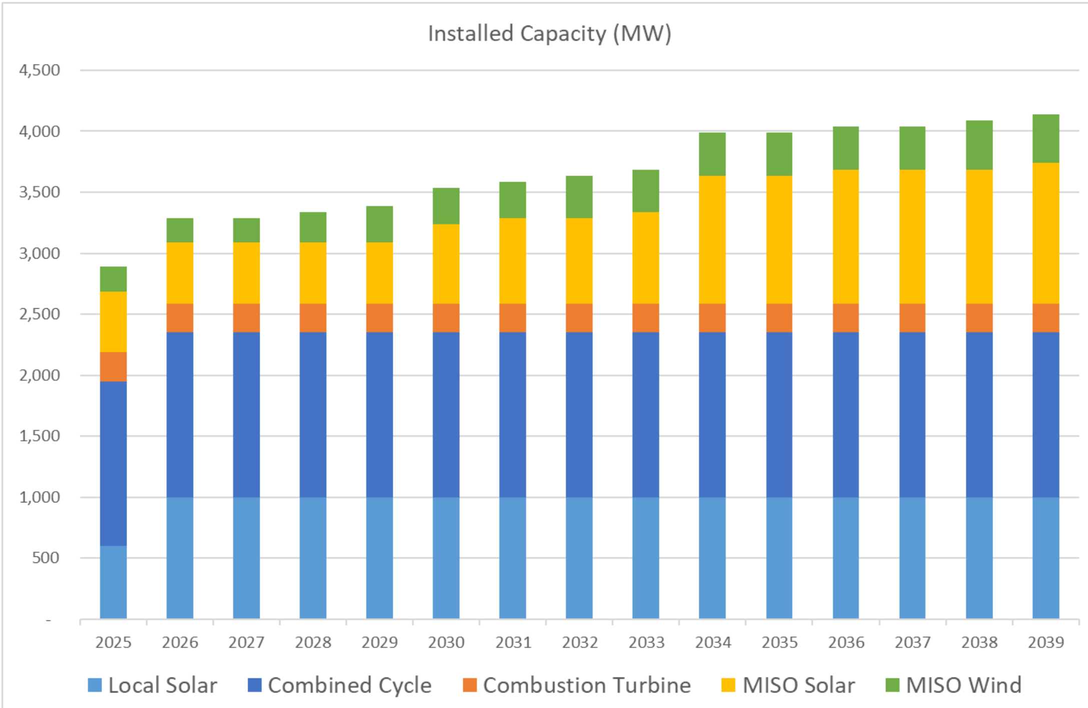
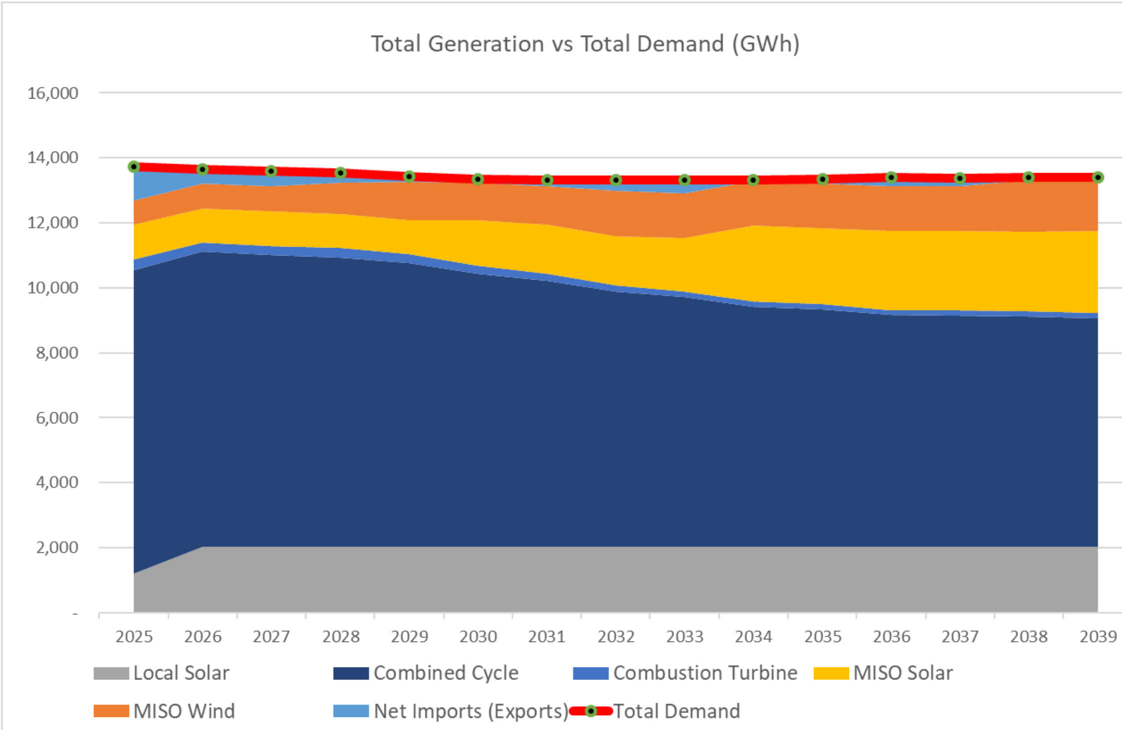


Exhibit 214: Portfolio 2 Installed Capacity by Year (Table)

	Advanced Frame CT	Convl. Frame 7FA CT	1x1 Combined Cycle	Utility Solar	Battery	Miss Solar	Arkansas Solar	Arkansas Wind	MISO_Cap	Demand
2025	0	237	1350	600	0	0	500	200	1699	3197
2026	0	0	0	400	0	0	0	0	1573	3182
2027	0	0	0	0	0	0	0	0	1569	3168
2028	0	0	0	0	0	0	0	50	1555	3153
2029	0	0	0	0	0	0	0	50	1543	3139
2030	0	0	0	0	0	0	150	0	1498	3124
2031	0	0	0	0	0	0	50	0	1485	3113
2032	0	0	0	0	0	0	0	50	1483	3108
2033	0	0	0	0	0	0	50	0	1486	3110
2034	0	0	0	0	0	0	300	0	1430	3112
2035	0	0	0	0	0	0	0	0	1446	3114
2036	0	0	0	0	0	0	50	0	1452	3116
2037	0	0	0	0	0	0	0	0	1469	3118
2038	0	0	0	0	0	0	0	50	1480	3121
2039	0	0	0	0	0	0	50	0	1487	3123

Energy generated from thermal generation decreases slightly over the years while energy coming from renewables increases.

Exhibit 215: Portfolio 2 Energy by Resource Type by Year



Portfolio Costs

Exhibit below shows the supply side NPV cost by year as can be seen the cost is about $700 million per year (2018 $) or $52/MWh, where fixed cost is the largest component due to the investments in generation, followed by cost of fuels. The net market cost is very low in this portfolio due to more local thermal generation.

Exhibit 216: Portfolio 2 Cost Components 2018 $

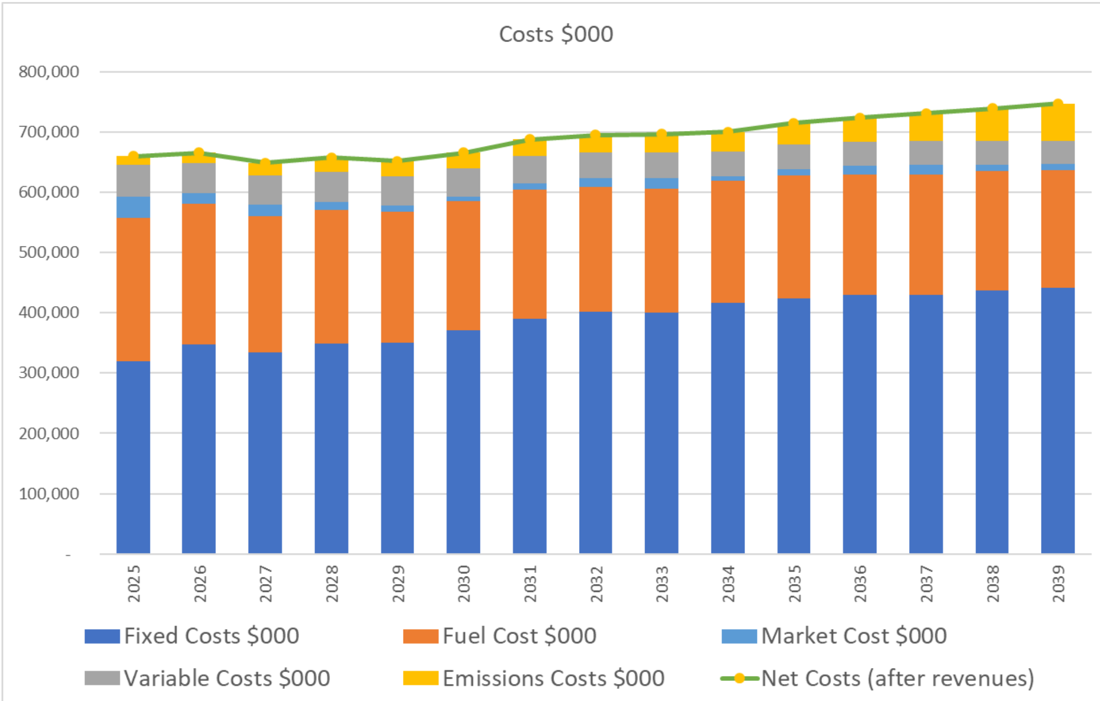
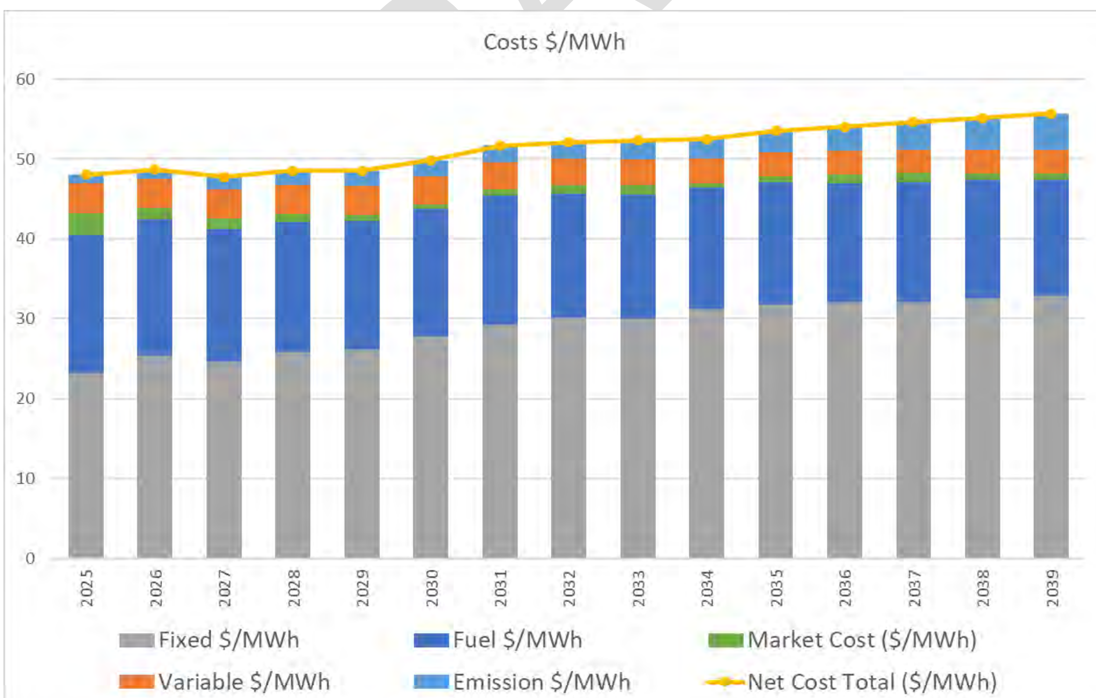
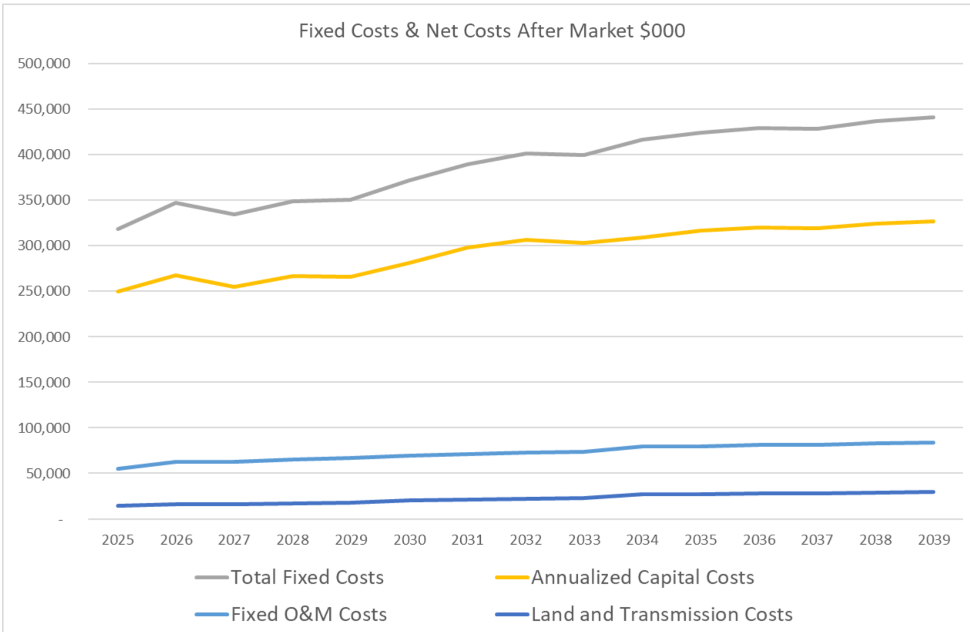


Exhibit 217: Portfolio 2 Cost Components 2018 $/MWh



Graph below shows the breakdown of total fixed costs by components, where the majority comes from the base capital costs on generation.

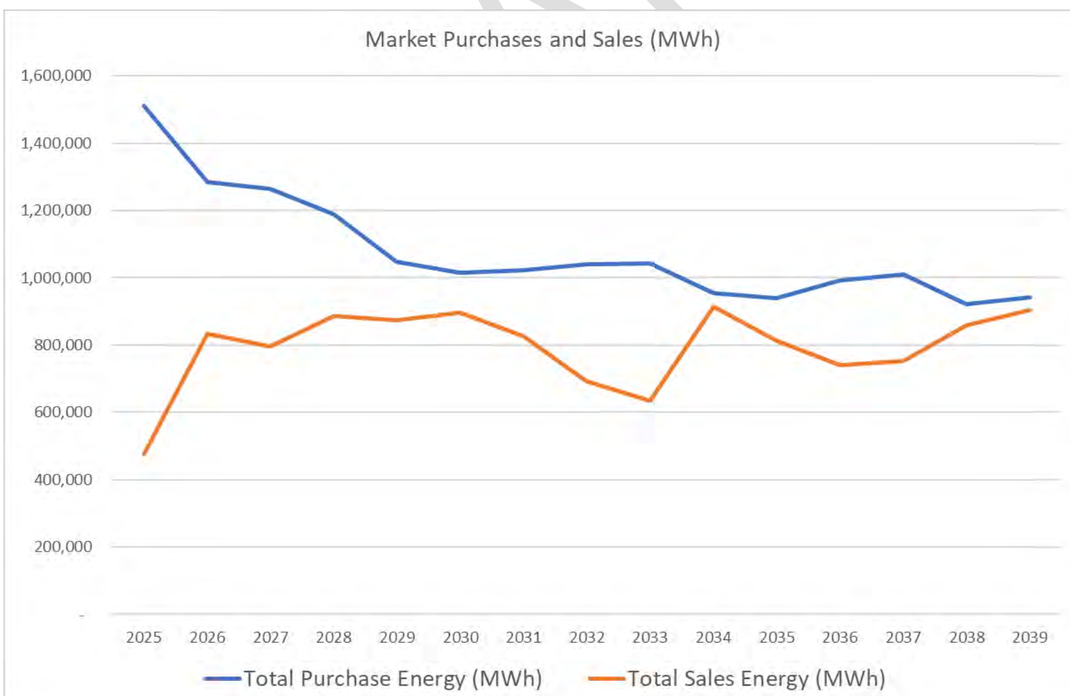
Exhibit 218: Portfolio 2 Fixed Cost Components 2018 $



Market purchases and sales as also important components. The market purchases by MLGW system are projected to be decreasing while the sales are increasing although the sales are maintained at the same level throughout. The net market cost stays flat except the first couple years due to ramping up of generation development.

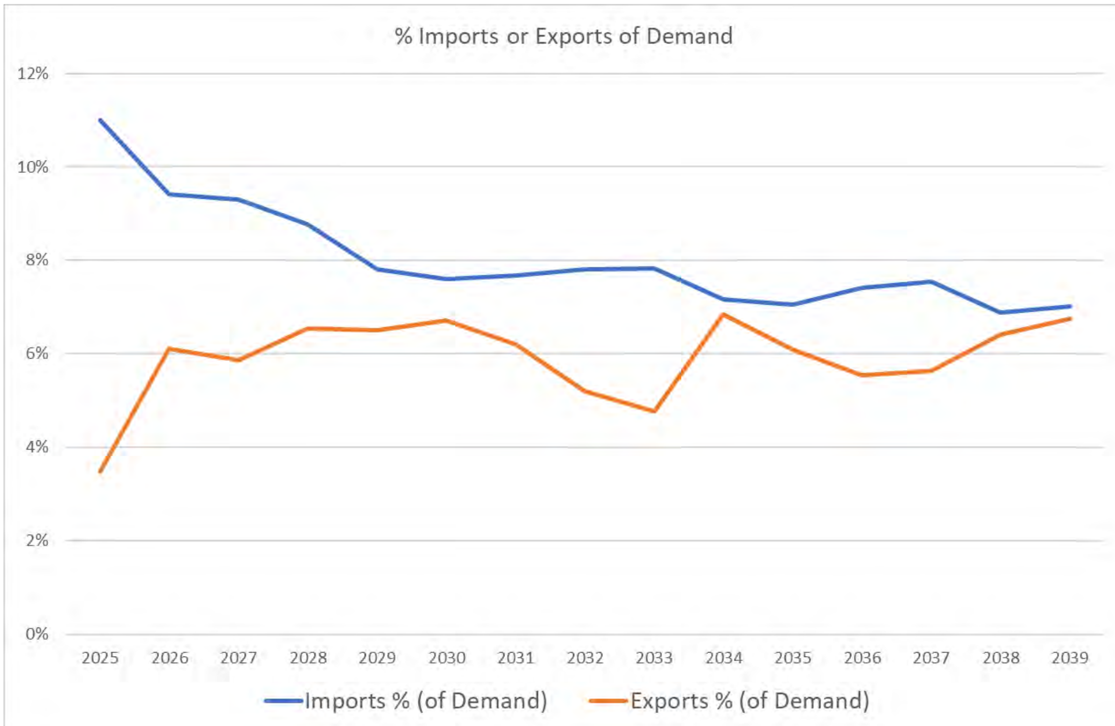
Exhibit 219: Portfolio 2 Market Purchases and Sales 2018 $

Exhibit 220: Portfolio 2 Market Purchases and Sales in Energy



These graphs show the purchases sales amount in energy and as % of demand.

Exhibit 221: Portfolio 2 Market Purchases and Sales as % of Demand



The market risk of this portfolio is estimated to be low as a result of more local generation.

Exhibit 222: Portfolio 2 Market Purchases and Sales Prices $/MWh

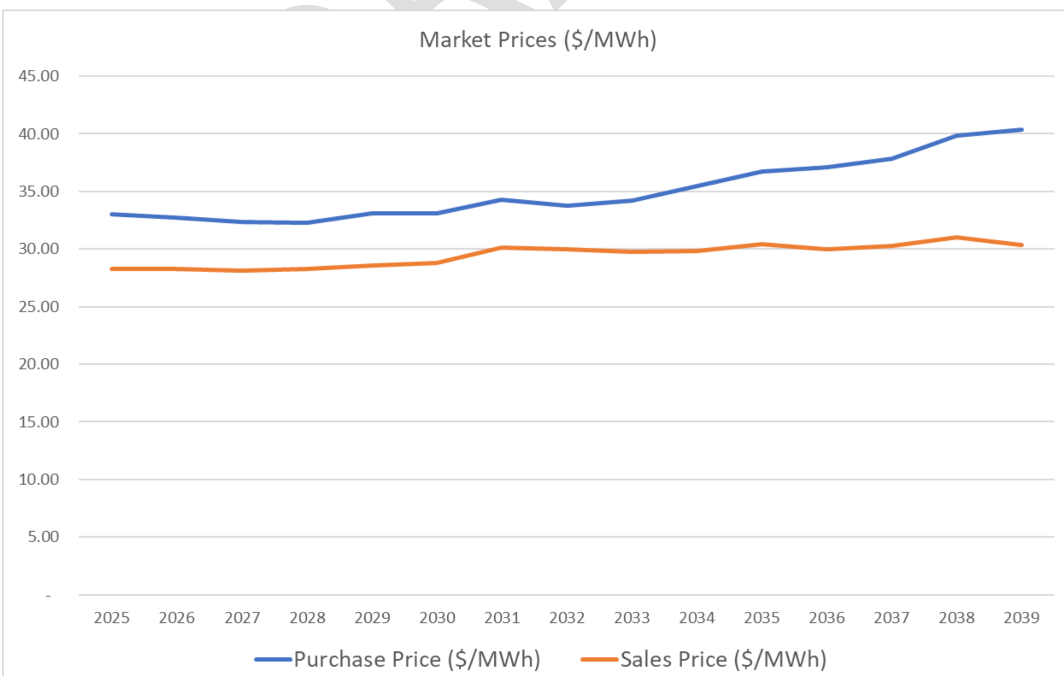
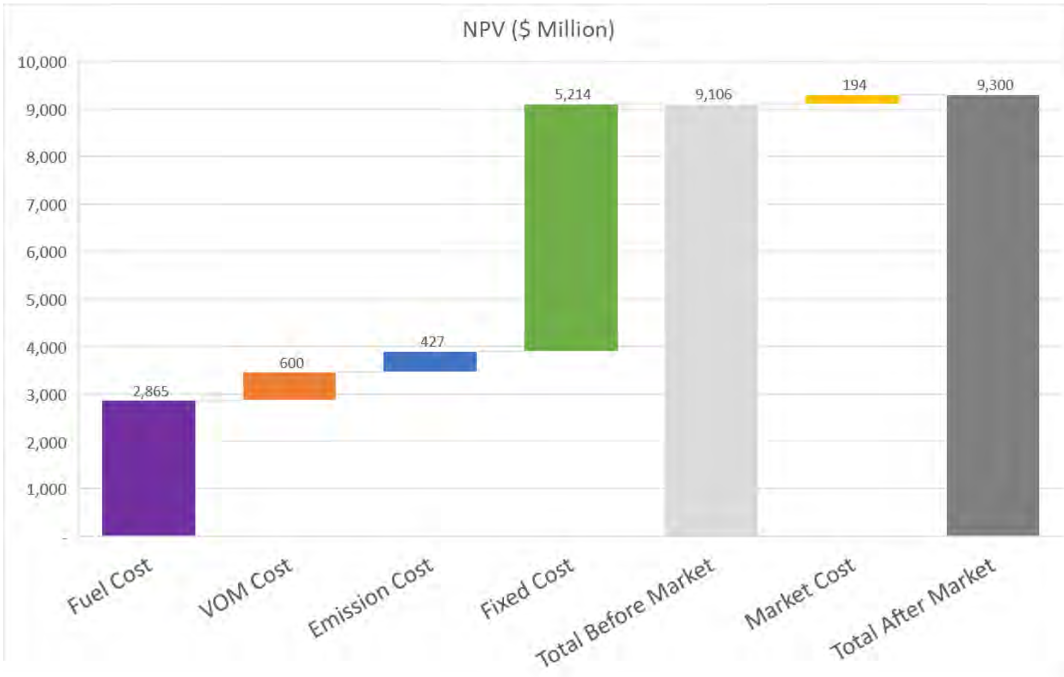


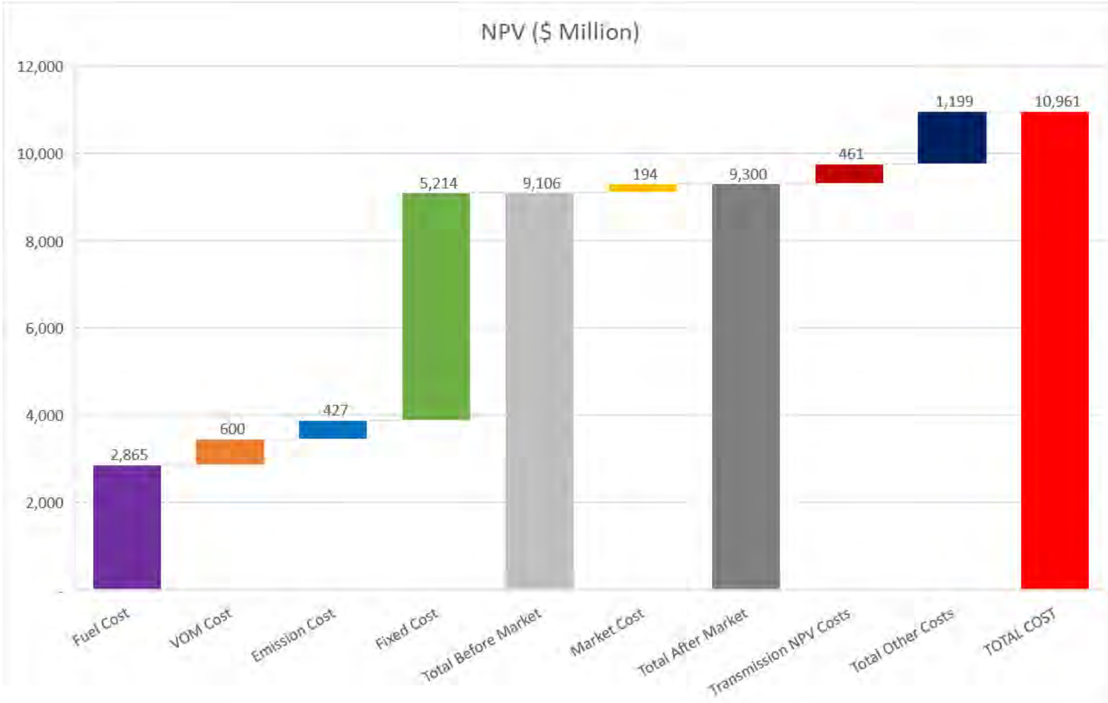
Exhibit below shows the supply side total NPV for 2025-2039, which is about $9.3 billion in 2018 $. Fixed cost is the largest component, followed by fuel.

Exhibit 223: Portfolio 2 Generation Resource NPV 2018 $



The total NPVRR of this portfolio is approximately $10.96 billion for 2025-2039 in 2018 $.

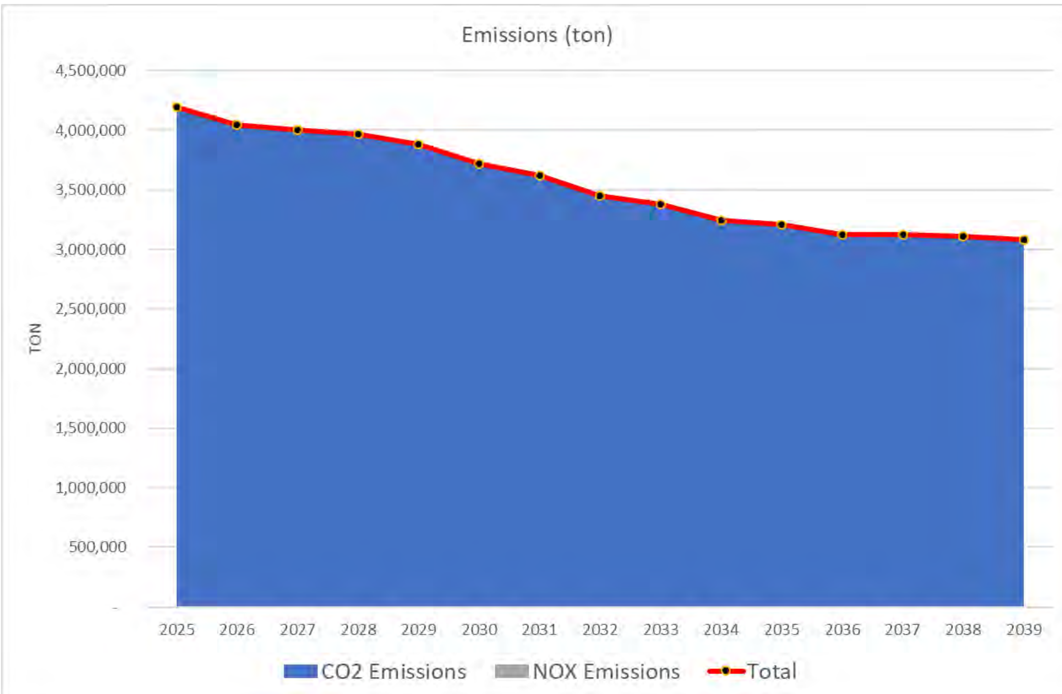
Exhibit 224: Portfolio 2 All NPVRR with Other Components 2018 $



Environmental

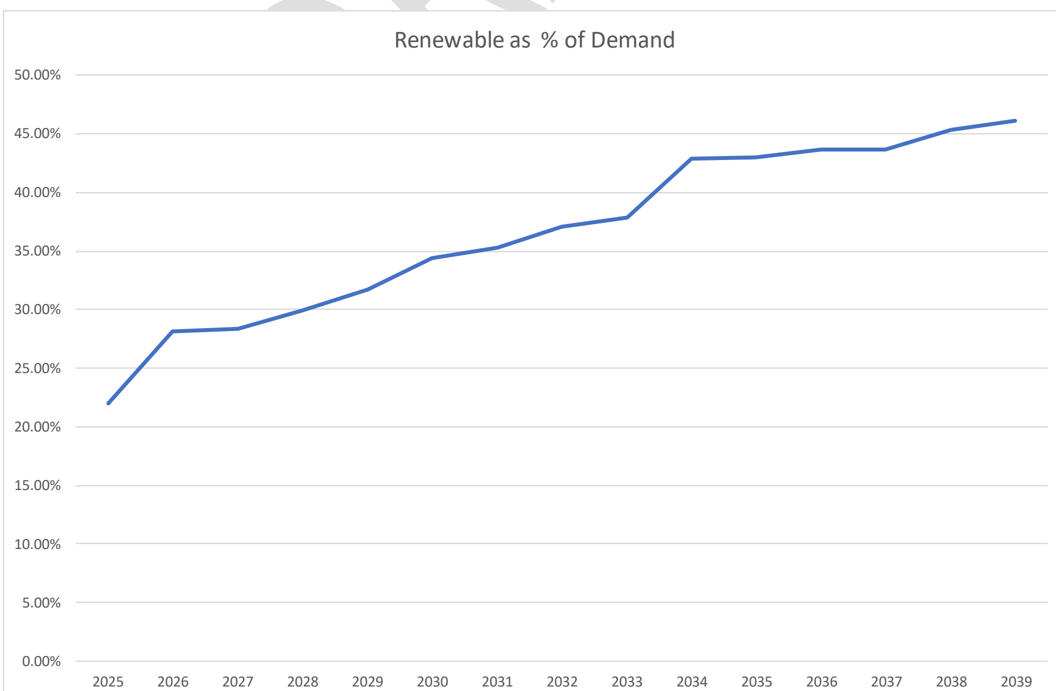
The emission from this portfolio is shown in the graph below. As energy from thermal generation is coming down, the capacity factor of the units decreases which resulted in decreased CO_2 emission over the years.

Exhibit 225: Portfolio 2 Total Emission by Year



And the RPS as of demand in energy of this portfolio starts at about 22% and reaches just over 45% in 2039 as more renewable generation are built.

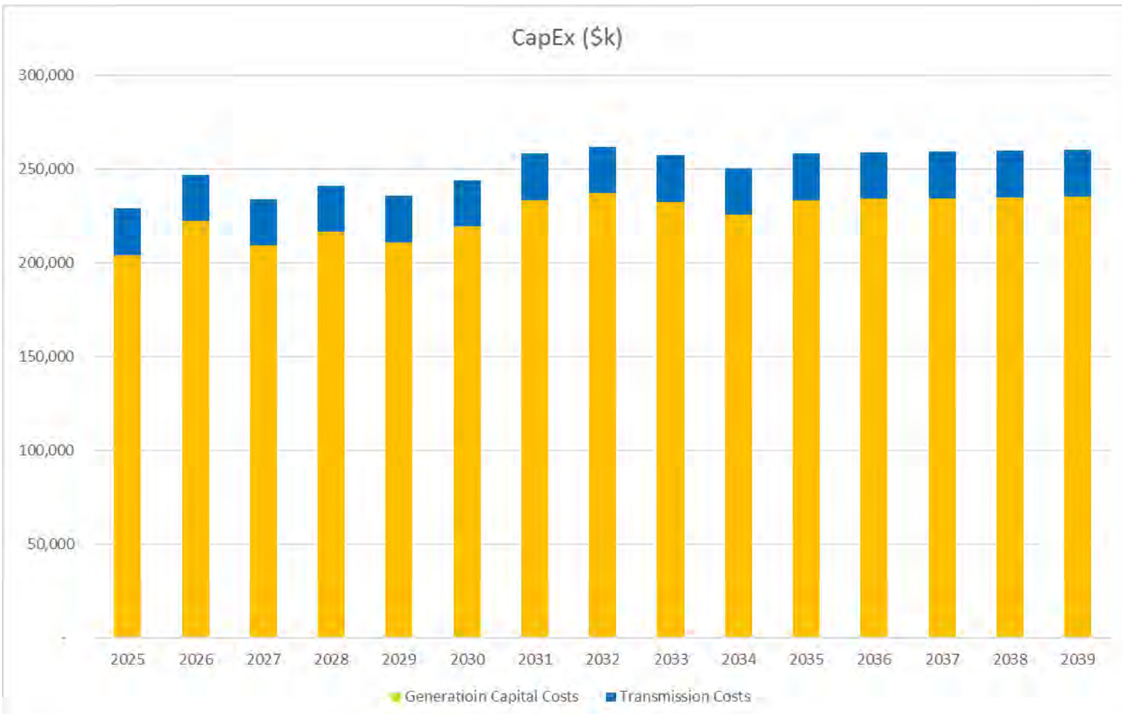
Exhibit 226: Portfolio 2 RPS Year



Capital Expenditure

Total capital expenditures on generation and transmission are shown in the graph below. We annualized these capital costs from 2025 to 2039 by year and it's about $250 million per year on average for this portfolio. Most of the capital costs are on the generation side.

Exhibit 227: Portfolio 2 Annualized Capital Expenditure by Year



Portfolio 3 (S3S2_BB)

This is the portfolio derived from the high load base gas price scenario.

Capacity Expansion (Build Out)

The exhibits below show the capacity expansion by year. 600 MW local Solar is installed in first year, and additional installed after 2029. Thermal generation (3 CCGTs + 1 CT) are all installed in first year 2025.

Exhibit 228: Portfolio 3 Installed Capacity by Year

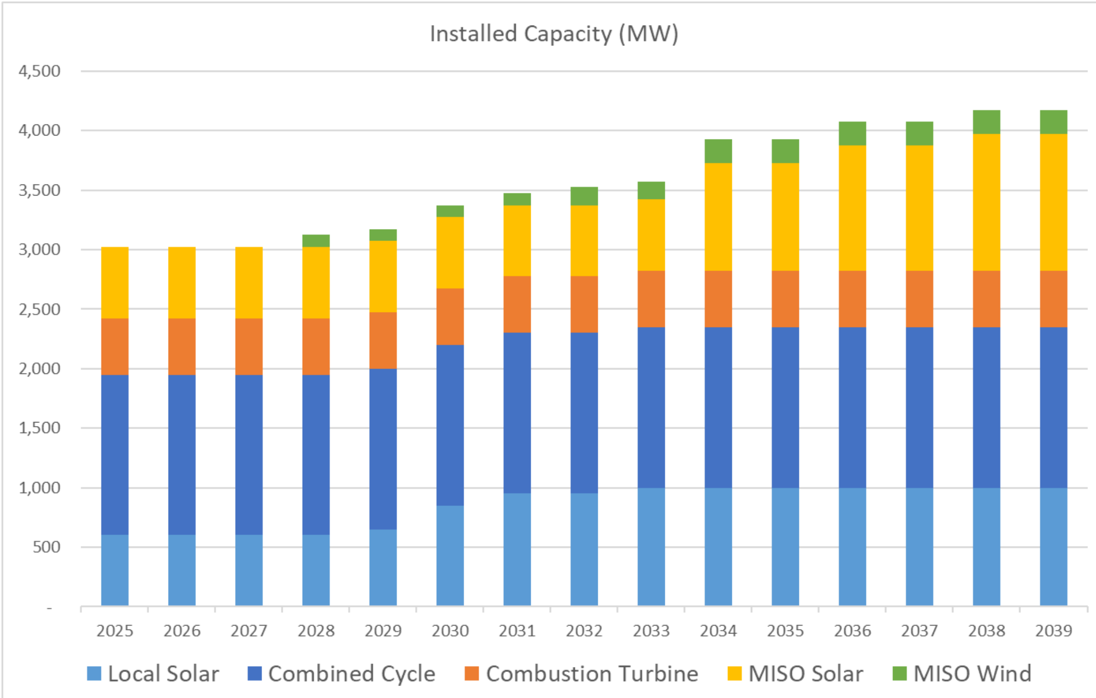
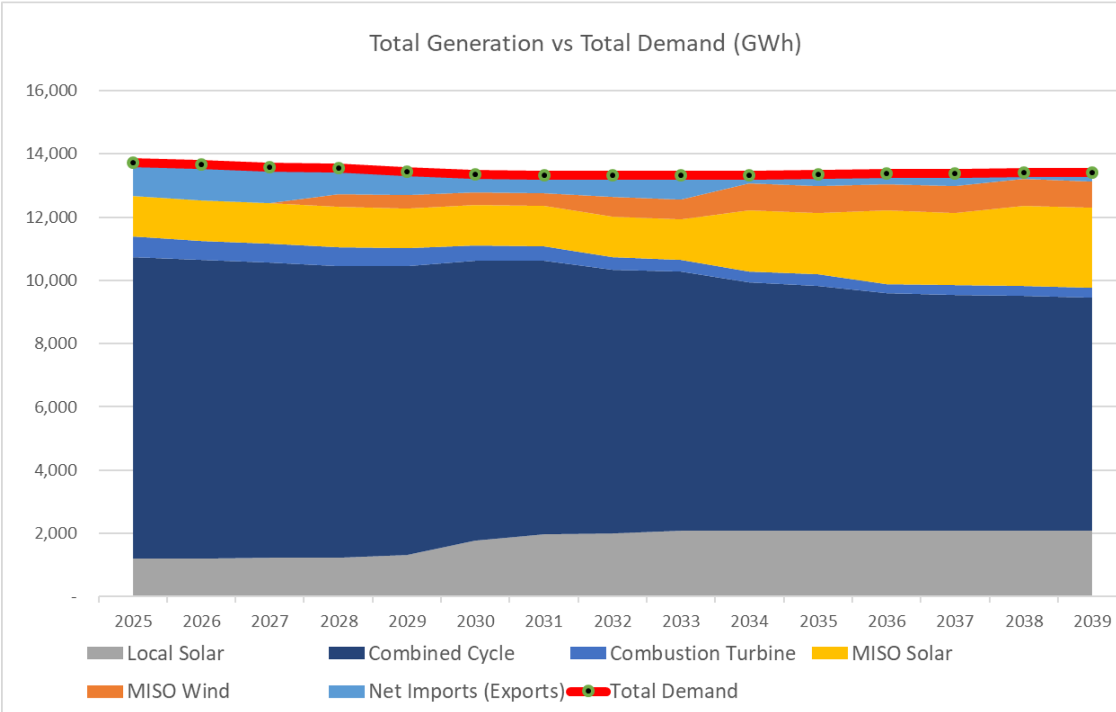


Exhibit 229: Portfolio 3 Installed Capacity by Year (Table)

	Advanced Frame CT	Convl. Frame 7FA CT	1x1 Combined Cycle	Utility Solar	Battery	Miss Solar	Arkansas Solar	Arkansas Wind	MISO_Cap	Demand
2025	0	474	1350	600	0	0	600	0	1490	3197
2026	0	0	0	0	0	0	0	0	1482	3182
2027	0	0	0	0	0	0	0	0	1476	3168
2028	0	0	0	0	0	0	0	100	1452	3153
2029	0	0	0	50	0	0	0	0	1432	3139
2030	0	0	0	200	0	0	0	0	1372	3124
2031	0	0	0	100	0	0	0	0	1344	3113
2032	0	0	0	0	0	0	0	50	1342	3108
2033	0	0	0	50	0	0	0	0	1343	3110
2034	0	0	0	0	0	0	300	50	1278	3112
2035	0	0	0	0	0	0	0	0	1294	3114
2036	0	0	0	0	0	0	150	0	1276	3116
2037	0	0	0	0	0	0	0	0	1293	3118
2038	0	0	0	0	0	0	100	0	1291	3121
2039	0	0	0	0	0	0	0	0	1308	3123

Energy generated from thermal decreases slightly over the years while energy coming from renewables increases. Imported energy goes down over the years as well.

Exhibit 230: Portfolio 3 Energy by Resource Type by Year



Portfolio Costs

Exhibit below shows the supply side NPV cost by year as can be seen the cost is about $700 million per year (2018 $) or $52/MWh, where fixed cost is the largest component due to the investments in generation, followed by fuel costs.

Exhibit 231: Portfolio 3 Cost Components 2018 $

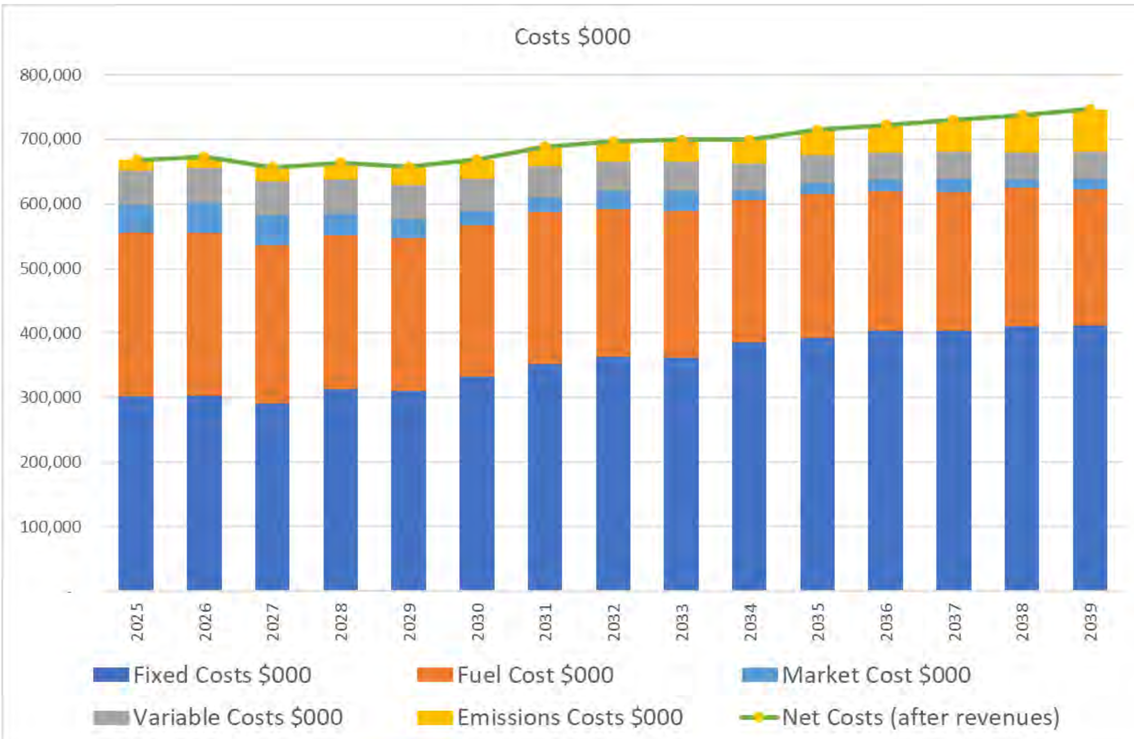
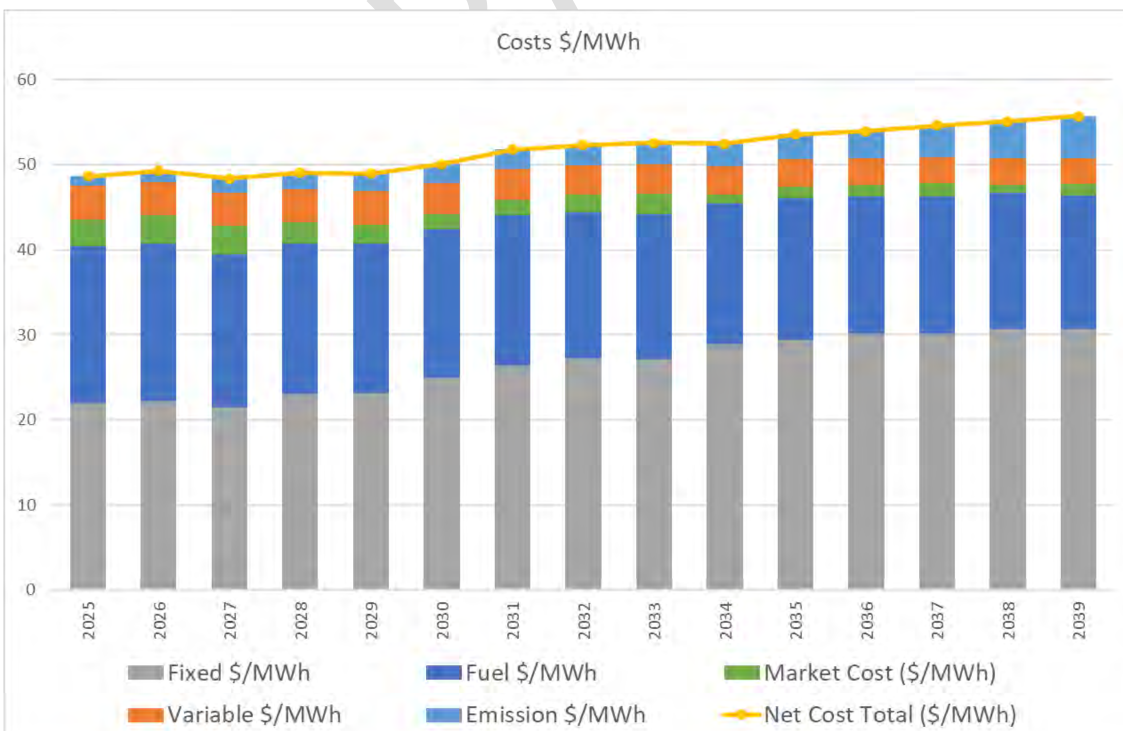
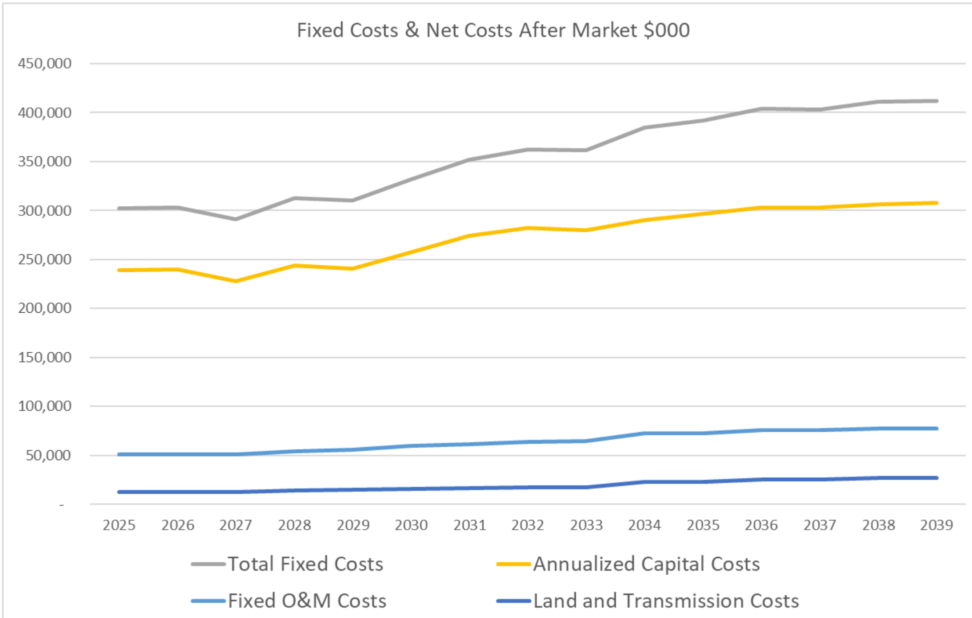


Exhibit 232: Portfolio 3 Cost Components 2018 $/MWh



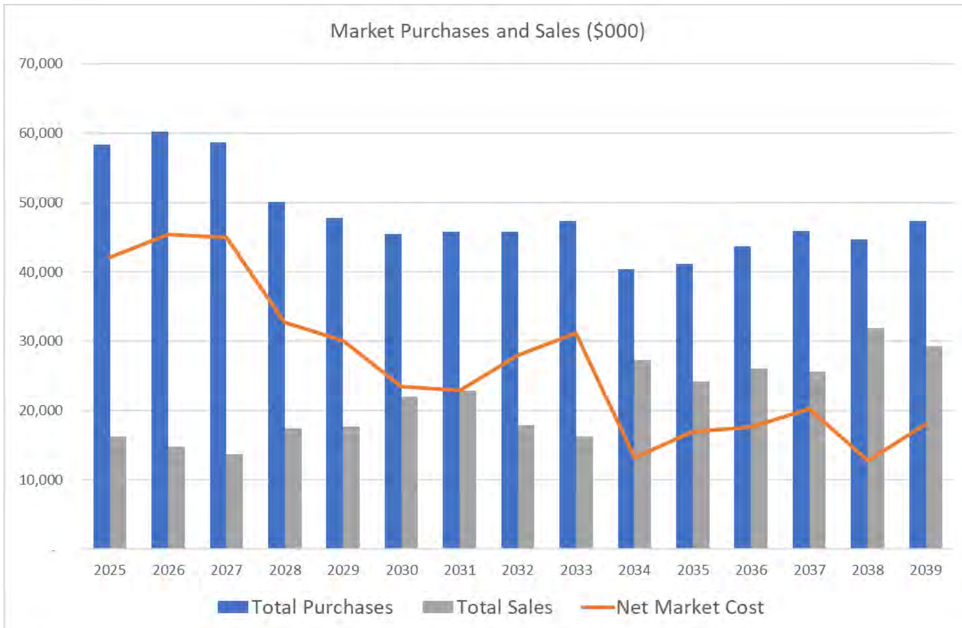
Graph below shows the breakdown of total fixed costs by component, where the majority comes from the base capital costs on generation.

Exhibit 233: Portfolio 3 Fixed Cost Components 2018 $



Market purchases and sales as also important components. The market purchases by MLGW system are projected to be decreasing while the sales are increasing although the sales are maintained at a low level. As mentioned above, the cost of renewables is projected to be much more competitive after 2030, which resulted in reduced market purchases.

Exhibit 234: Portfolio 3 Market Purchases and Sales 2018 $



These graphs show the purchases sales amount in energy and as % of demand. The purchase cost stays low throughout the planning years of this portfolio.

Exhibit 235: Portfolio 3 Market Purchases and Sales in Energy

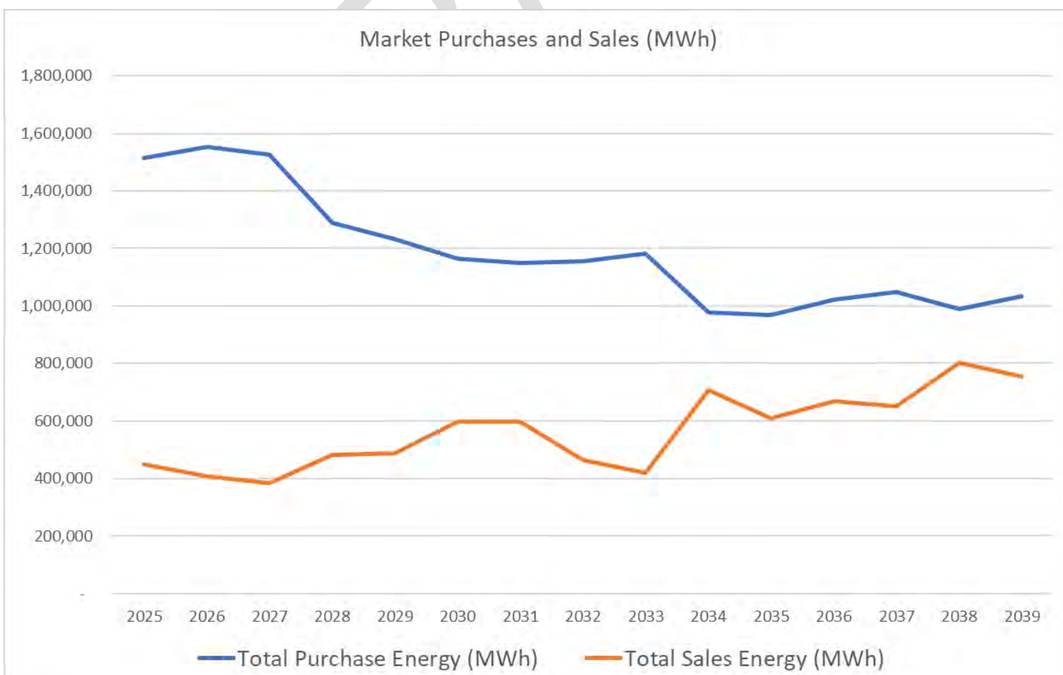
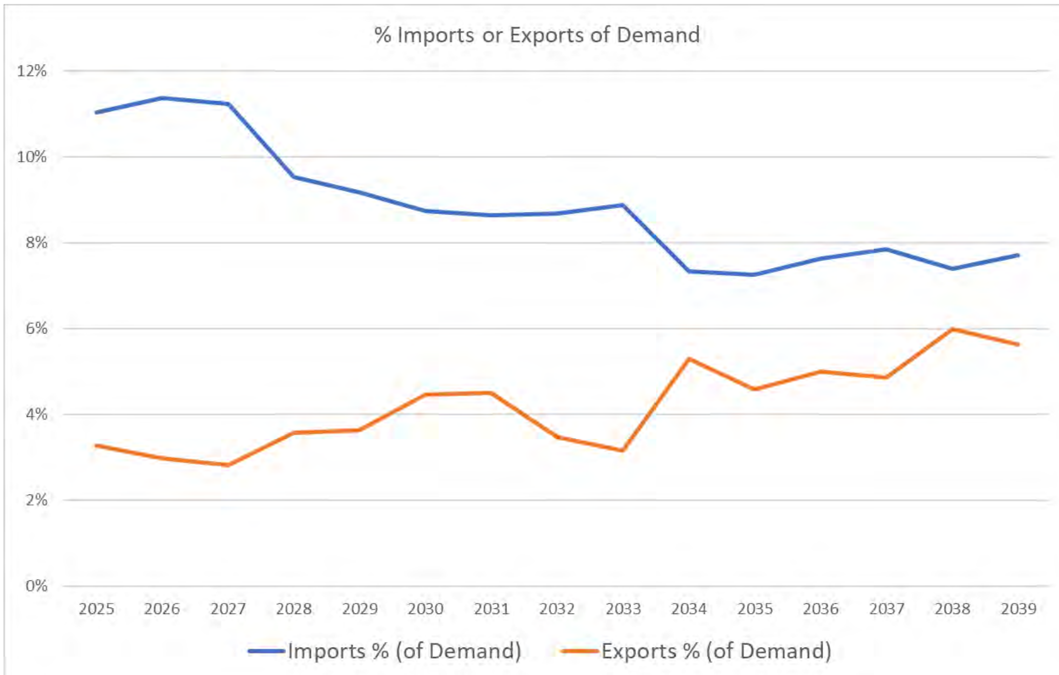


Exhibit 236: Portfolio 3 Market Purchases and Sales as % of Demand



The risk can also be appreciated looking at the difference between purchase price (high) and sale price (low). The more purchase this portfolio needs, the higher risk it has.

Exhibit 237: Portfolio 3 Market Purchases and Sales Prices $/MWh

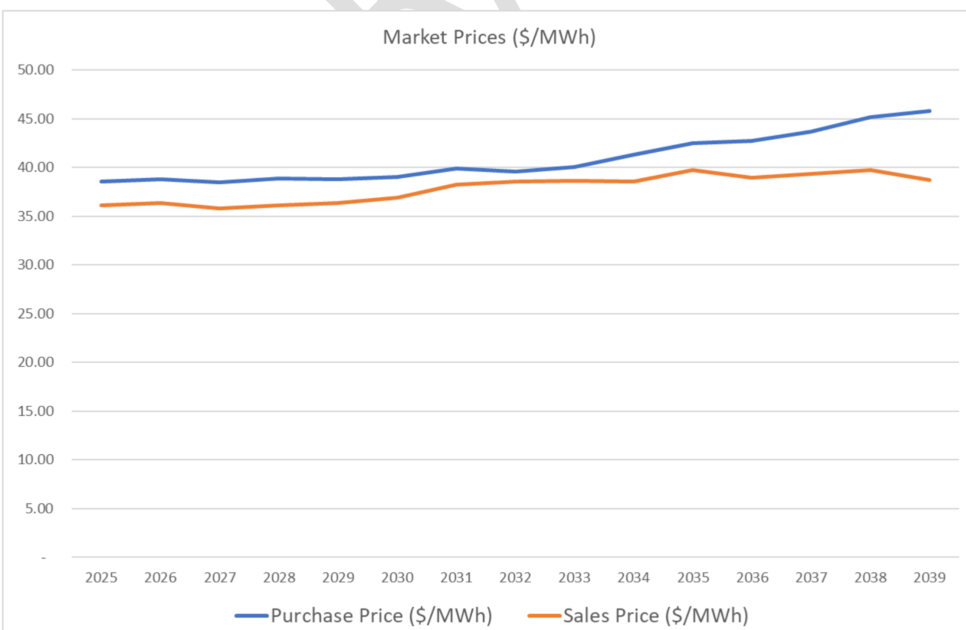
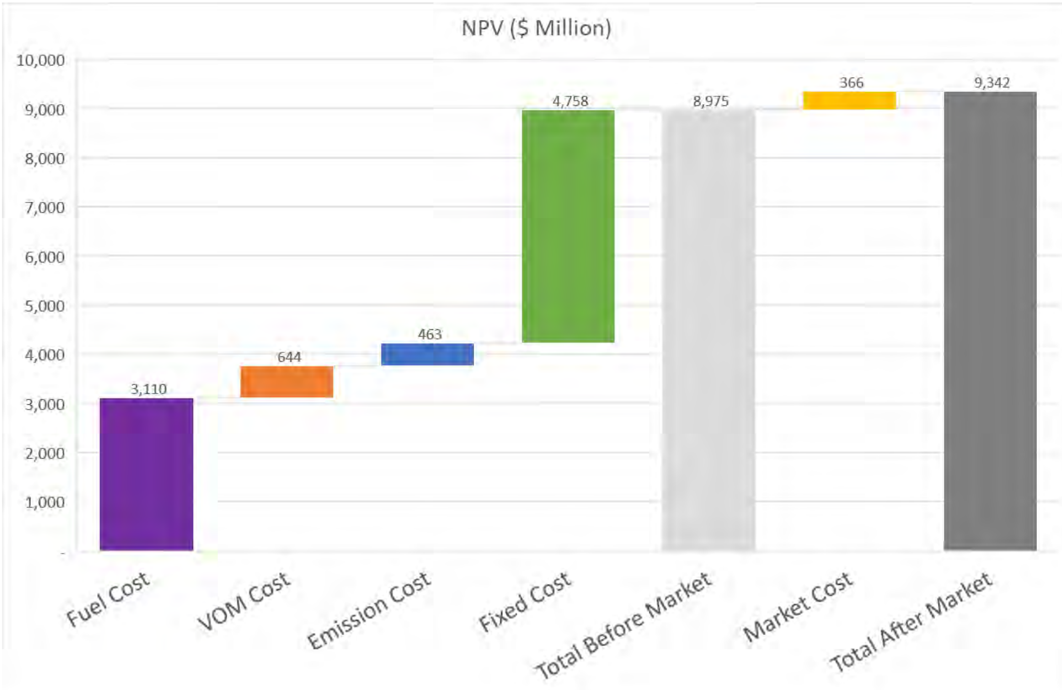


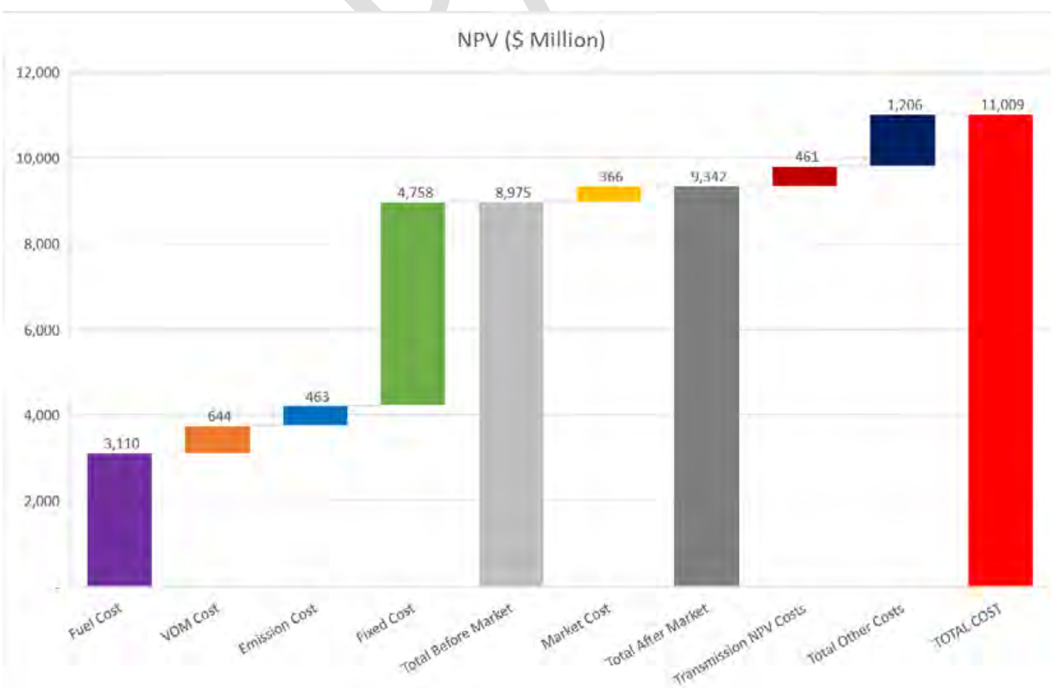
Exhibit below shows the supply side total NPV for 2025-2039, which is about $9.34 billion in 2018 $. Fixed cost is the largest component, followed by fuel.

Exhibit 238: Portfolio 3 Generation Resource NPV 2018 $



The total NPVRR of this portfolio is approximately $11 billion for 2025-2039 in 2018 $.

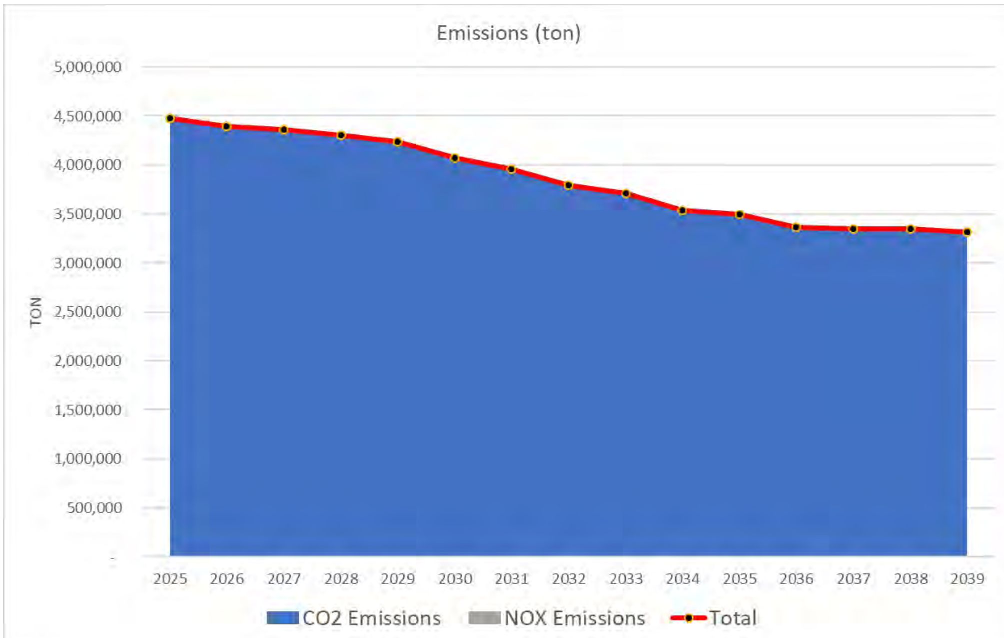
Exhibit 239: Portfolio 3 All NPVRR with Other Components 2018 $



Environmental

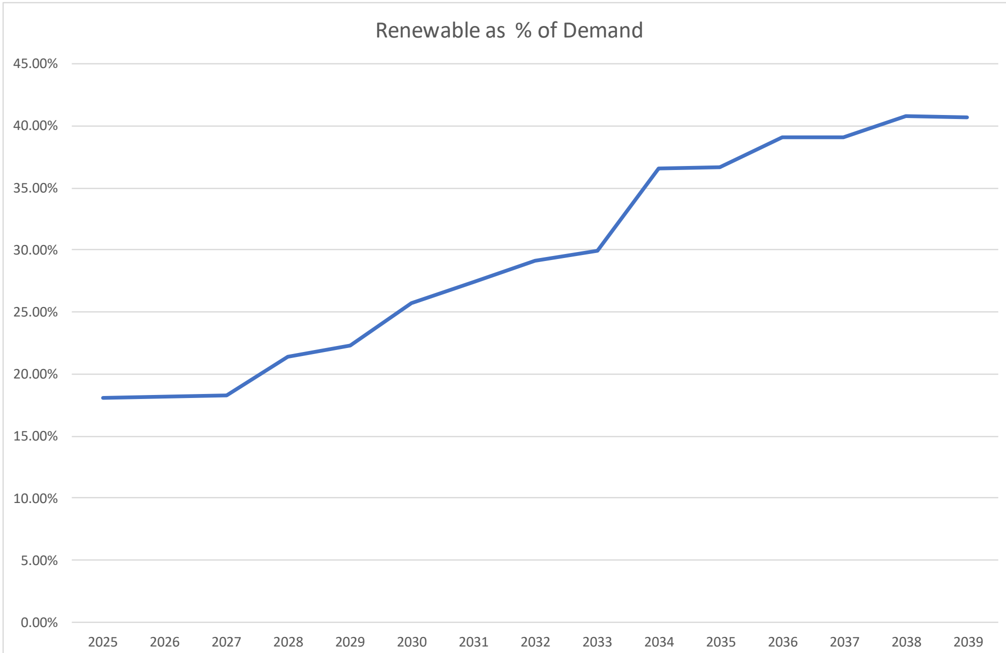
The emission from this portfolio is shown in the graph below. As energy from thermal generation is coming down, the capacity factor of the units decreases which resulted in decreased CO_2 emission over the years.

Exhibit 240: Portfolio 3 Total Emission by Year



And the RPS as of the demand in energy of this portfolio starts at about 17% and reaches just over 40% in 2039 as more renewable generation are built.

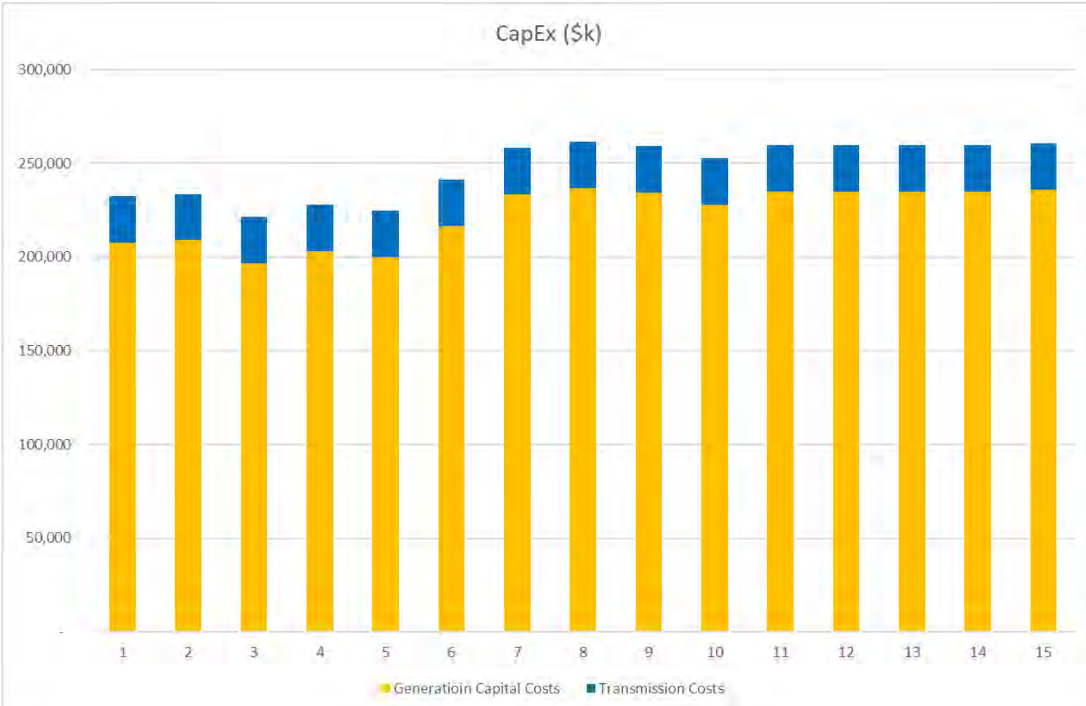
Exhibit 241: Portfolio 3 RPS by Year



Capital Expenditure

Total capital expenditures on generation and transmission are shown in the graph below. We annualized these capital costs from 2025 to 2039 by year and it's about $250 million per year on average for this portfolio. Most of the capital costs are on the generation side.

Exhibit 242: Portfolio 3 Annualized Capital Expenditure by Year



Portfolio 4 (S3S3_BB)

This is the portfolio derived from low load base gas price scenario.

Capacity Expansion (Build Out)

The exhibits below show the capacity expansion by year. Thermal generation are installed all in first year 2025, with a total of three CCGTs.

Exhibit 243: Portfolio 4 Installed Capacity by Year

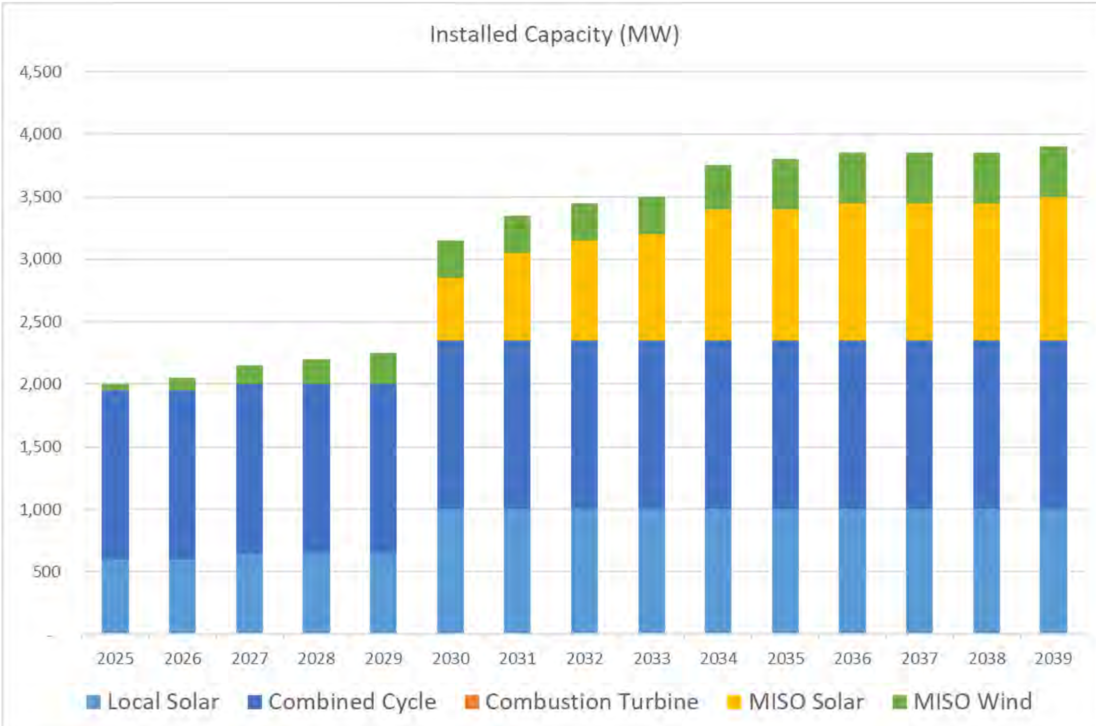
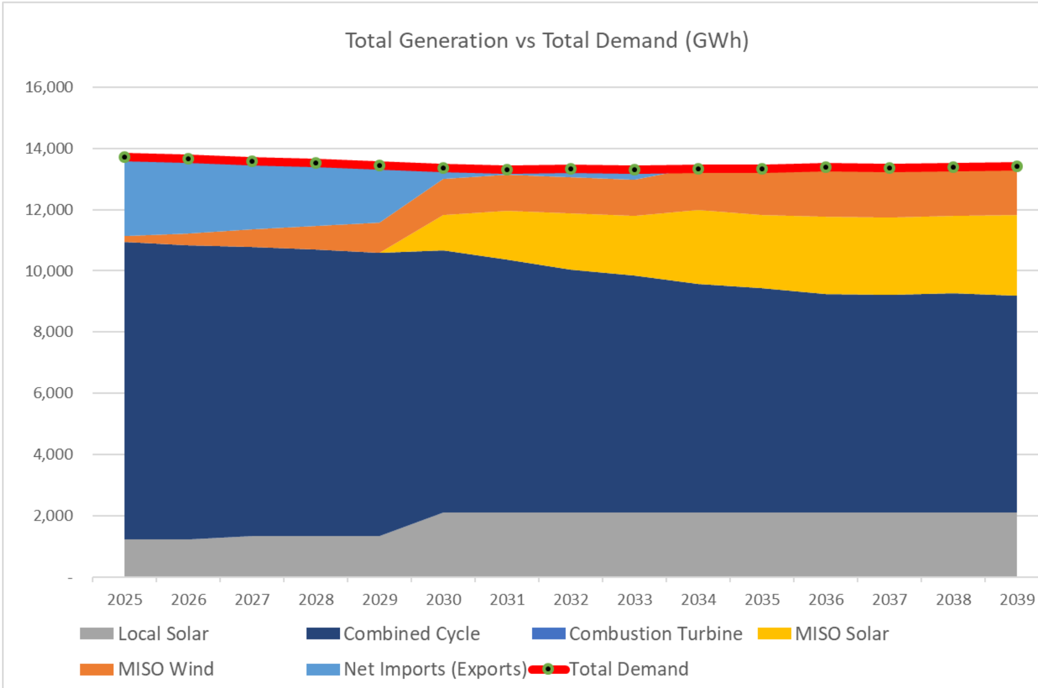


Exhibit 244: Portfolio 4 Installed Capacity by Year (Table)

	Advanced Frame CT	Convl. Frame 7FA CT	1x1 Combined Cycle	Utility Solar	Battery	Miss Solar	Arkansas Solar	Arkansas Wind	MISO_Cap	Demand
2025	0	0	1350	600	0	0	0	50	2083	3197
2026	0	0	0	0	0	0	0	50	2063	3182
2027	0	0	0	50	0	0	0	50	2030	3168
2028	0	0	0	0	0	0	0	50	2010	3153
2029	0	0	0	0	0	0	0	50	1992	3139
2030	0	0	0	350	0	0	500	50	1748	3124
2031	0	0	0	0	0	0	200	0	1695	3113
2032	0	0	0	0	0	0	100	0	1677	3108
2033	0	0	0	0	0	0	50	0	1679	3110
2034	0	0	0	0	0	0	200	50	1640	3112
2035	0	0	0	0	0	0	0	50	1649	3114
2036	0	0	0	0	0	0	50	0	1655	3116
2037	0	0	0	0	0	0	0	0	1672	3118
2038	0	0	0	0	0	0	0	0	1690	3121
2039	0	0	0	0	0	0	50	0	1697	3123

Energy generated from thermal generation decreases over the years while energy coming from renewables increases, especially starting 2030 when the cost of renewables is projected to be much more competitive. Imported energy goes down after 2030.

Exhibit 245: Portfolio 4 Energy by Resource Type by Year



Portfolio Costs

Exhibit below shows the supply side NPV cost by year, as can be seen the cost is about $680 million per year (2018 $) or $50/MWh, where fixed cost is the largest component due to the investments in generation, followed by cost of fuels.

Exhibit 246: Portfolio 4 Cost Components 2018 $

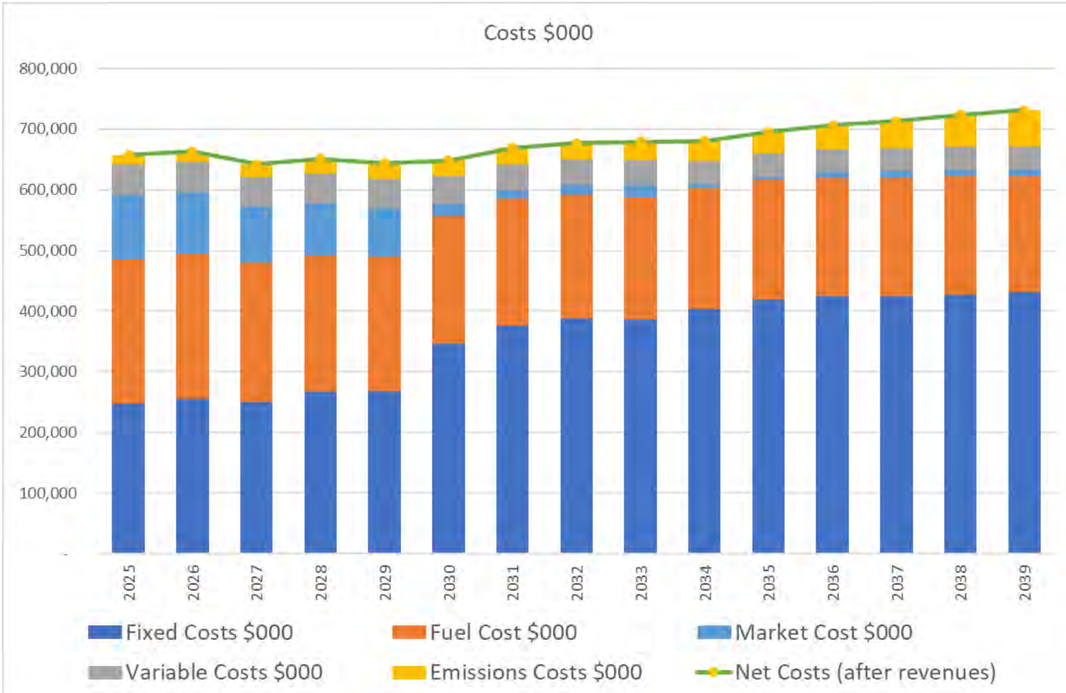
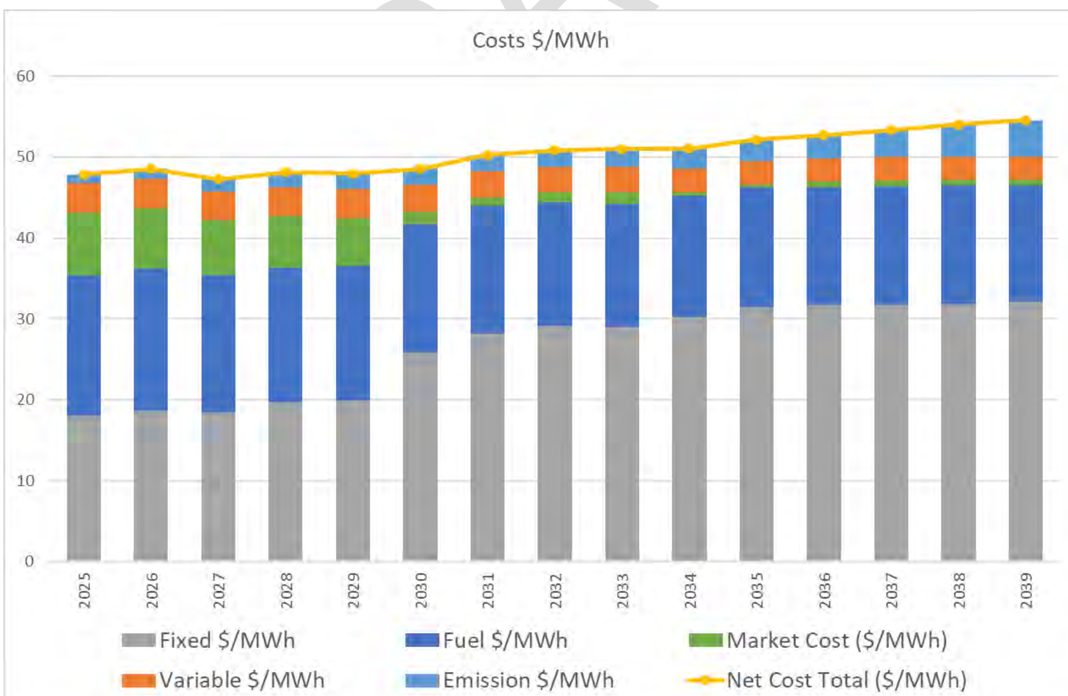
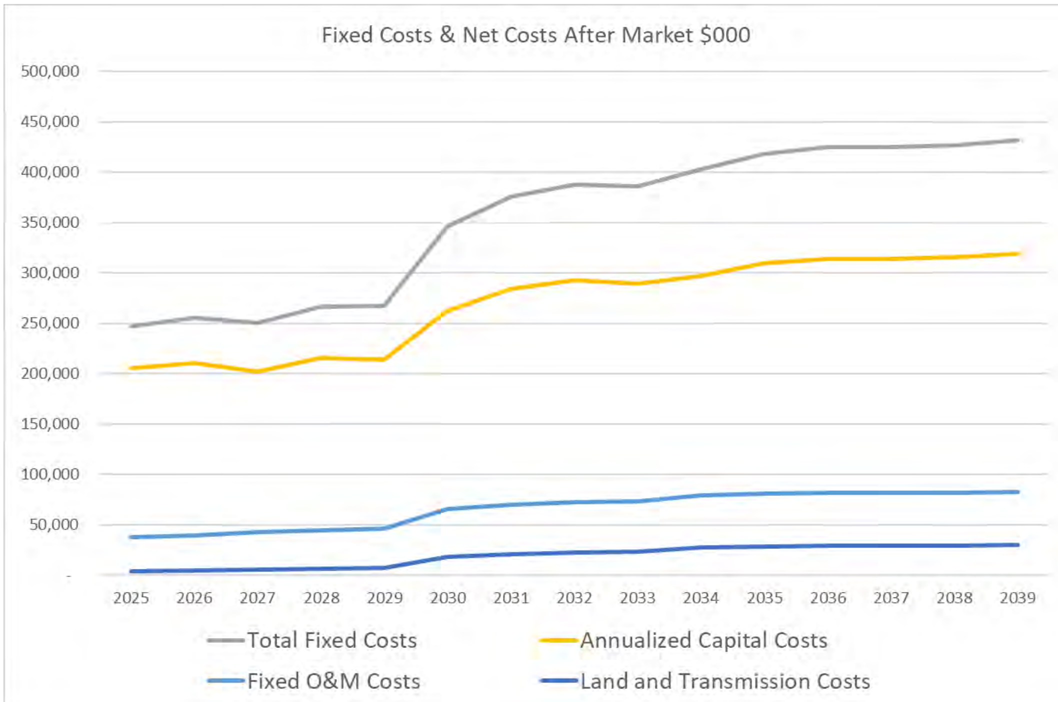


Exhibit 247: Portfolio 4 Cost Components 2018 $/MWh



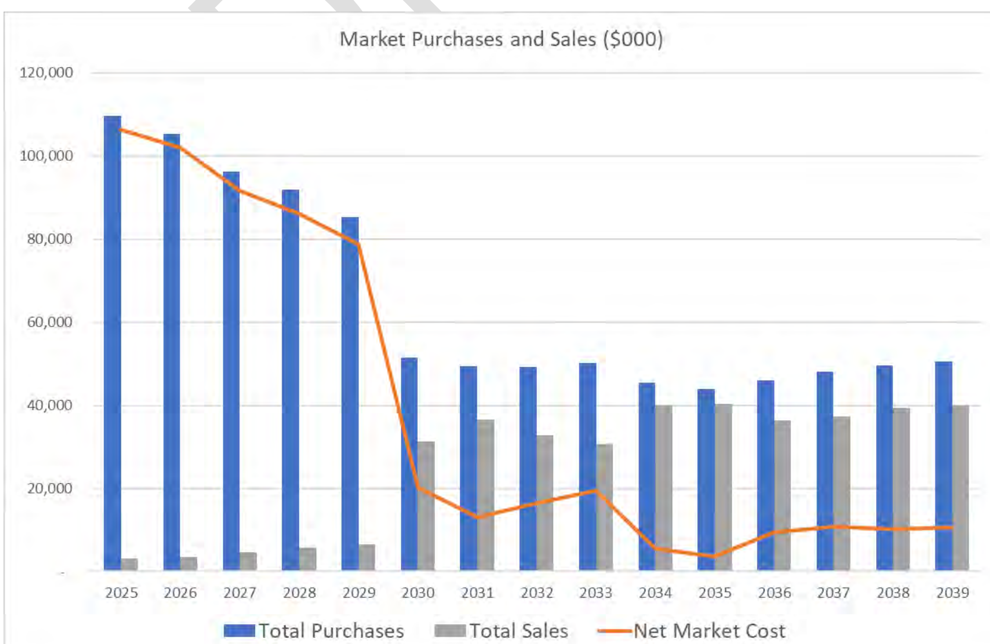
Graph below shows the breakdown of total fixed costs by components, where the majority comes from the base capital costs on generation.

Exhibit 248: Portfolio 4 Fixed Cost Components 2018 $



Market purchases and sales as also important components. The market purchases by MLGW system are projected to be decreasing while the sales are increasing although the sales are maintained at a low level.

Exhibit 249: Portfolio 4 Market Purchases and Sales 2018 $



These graphs show the purchases sales amount in energy and as % of demand. It shows the high market risk in the beginning of the planning years of this portfolio.

Exhibit 250: Portfolio 4 Market Purchases and Sales in Energy

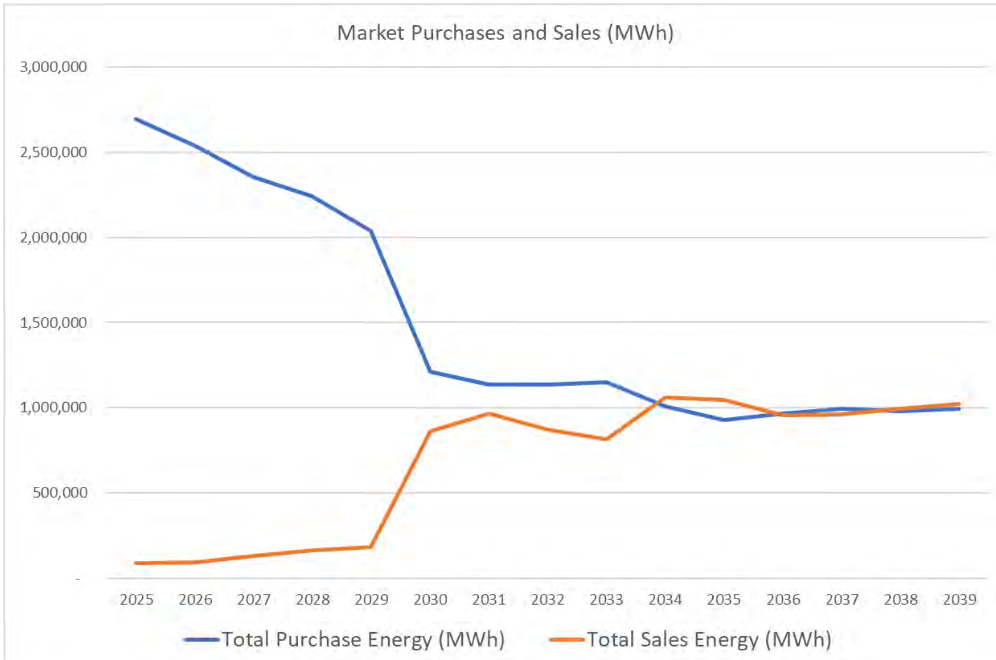
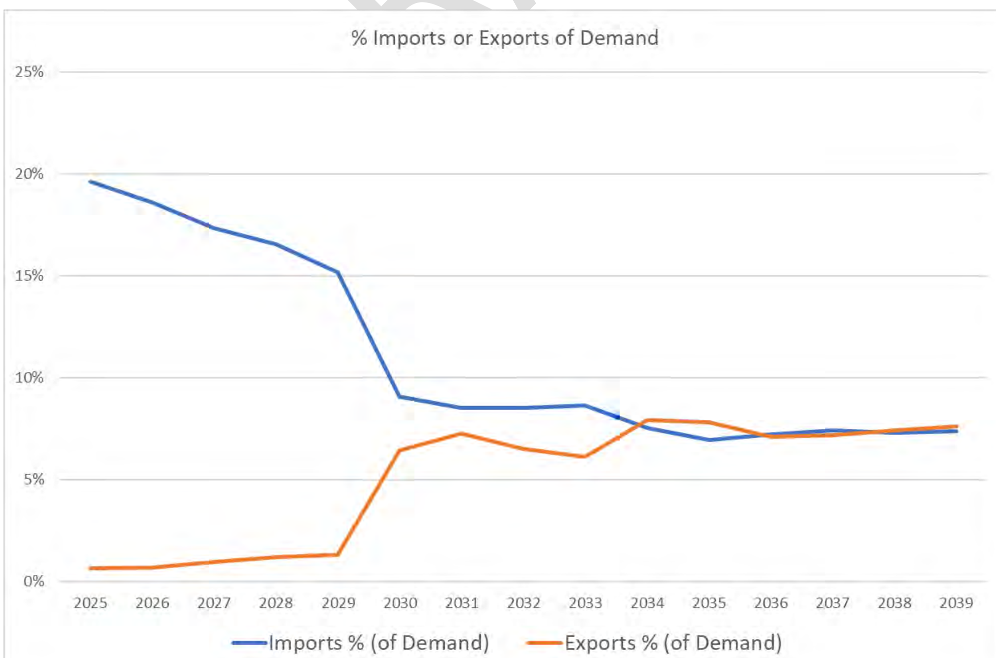


Exhibit 251: Portfolio 4 Market Purchases and Sales as % of Demand



The risk can also be appreciated looking at the difference between purchase price (high) and sale price (low). The more purchase this portfolio needs, the higher risk it has.

Exhibit 252: Portfolio 4 Market Purchases and Sales Prices $/MWh

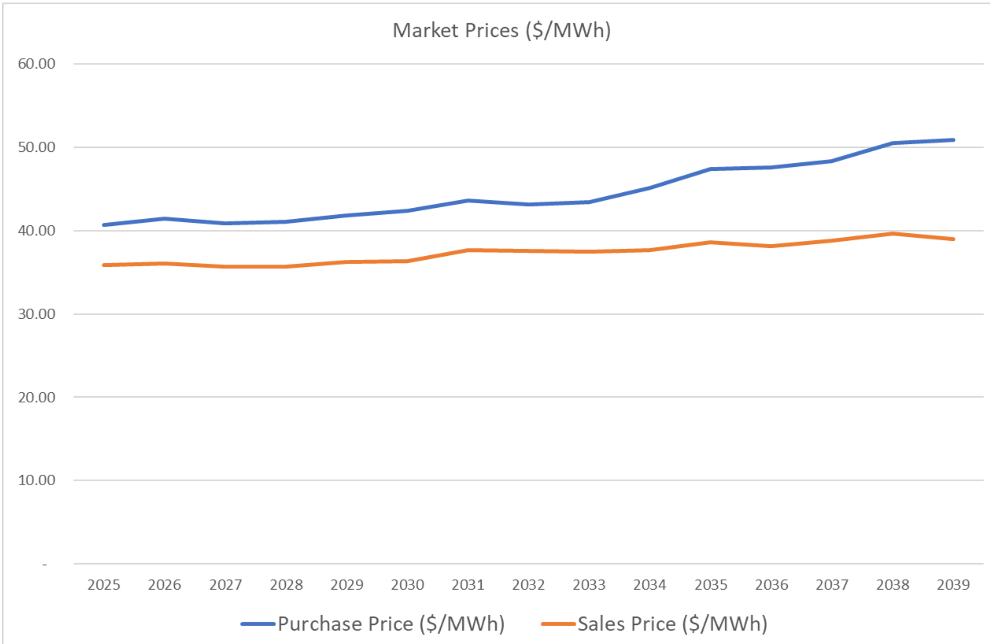
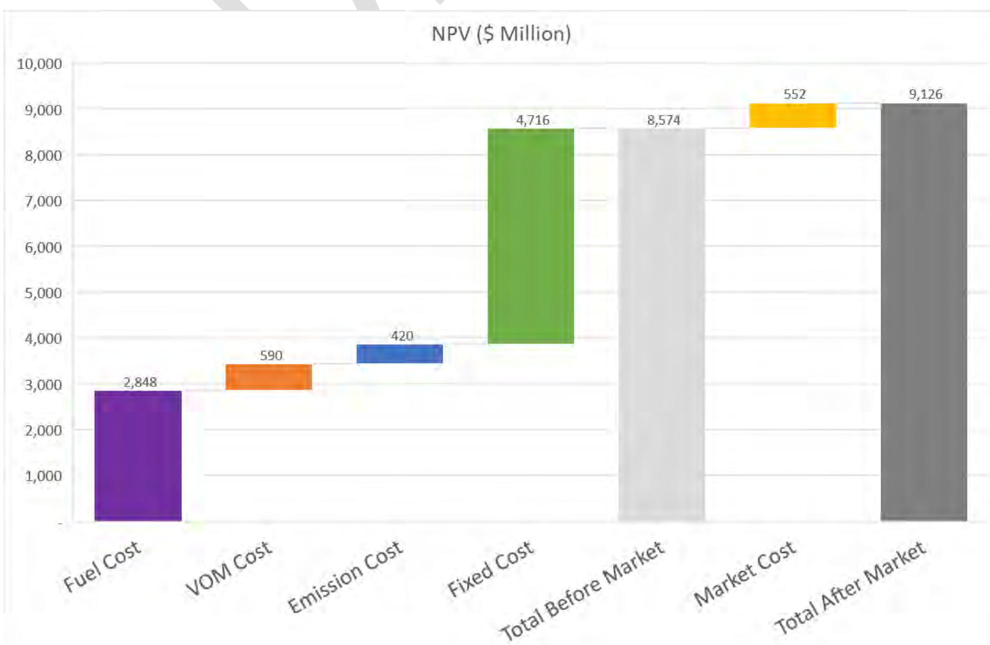


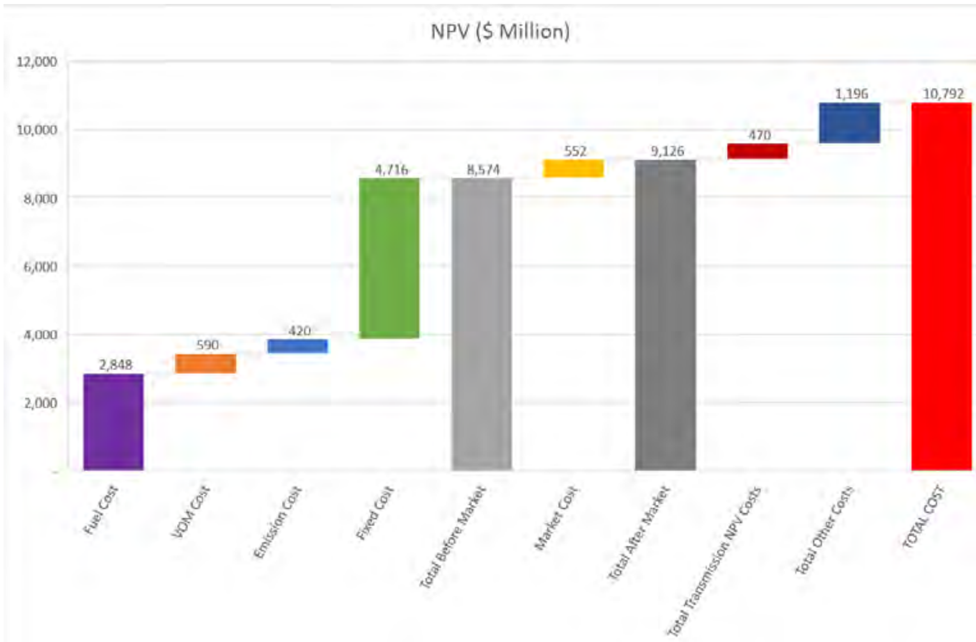
Exhibit below shows the supply side total NPV for 2025-2039, which is about $9.13 billion in 2018 $. Fixed cost is the largest component, followed by fuel cost.

Exhibit 253: Portfolio 4 Generation Resource NPV 2018 $



The total NPVRR is shown below which includes the other cost components, i.e. transmission and other costs, including PILOT, TVA Benefits, energy efficiency, gap costs, MISO Admin fees. The total NPVRR of this portfolio is approximately $10.79 billion for 2025-2039 in 2018 $.

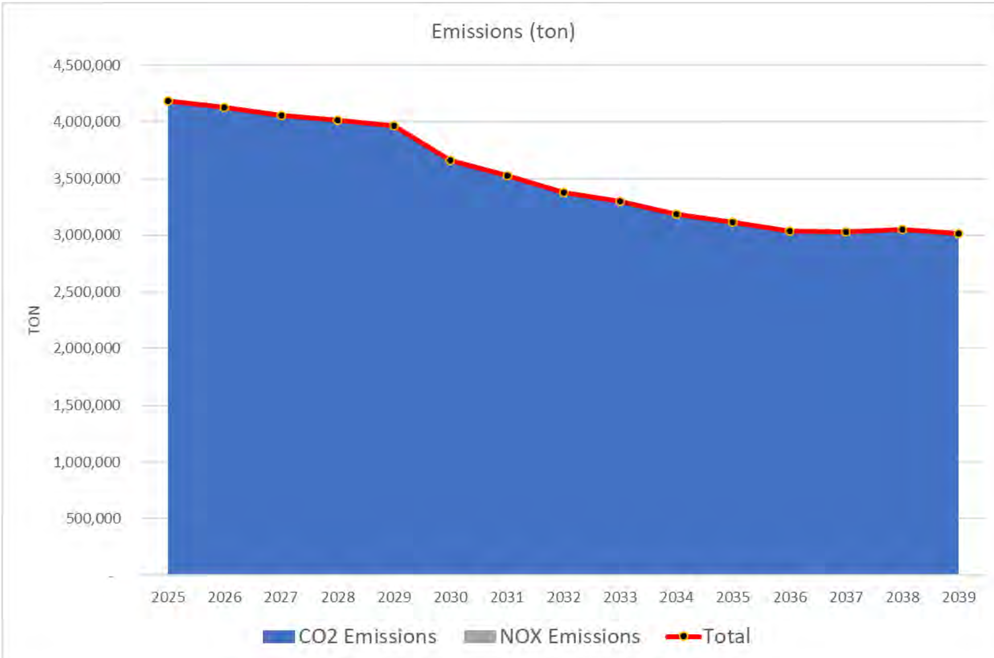
Exhibit 254: Portfolio 4 All NPVRR with Other Components 2018 $



Environmental

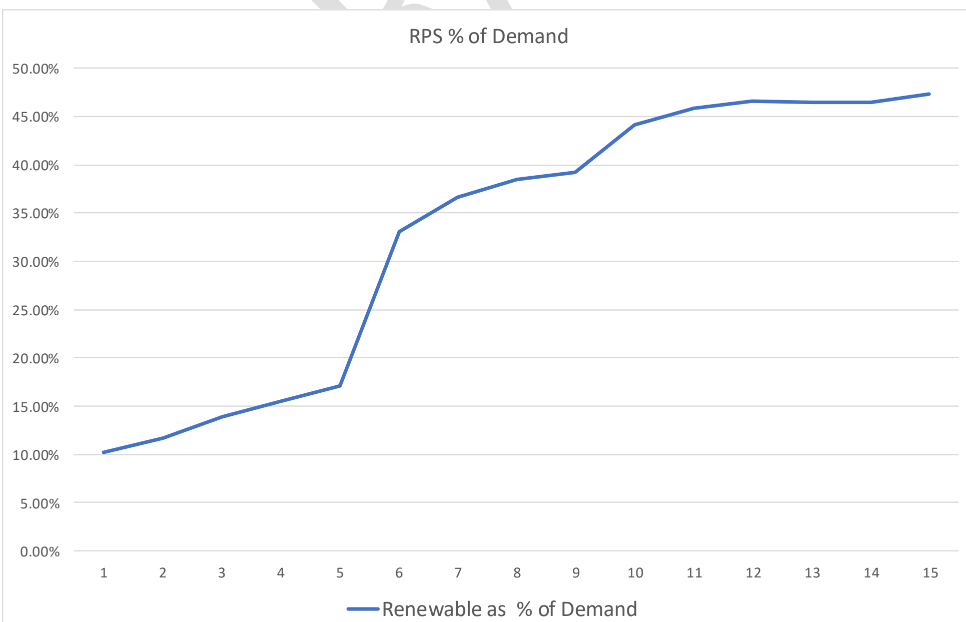
The emission from this portfolio is shown in the graph below. As energy from thermal generation is coming down, the capacity factor of the units decreases which resulted in decreased CO_2 emission over the years.

Exhibit 255: Portfolio 4 Total Emission by Year



And the RPS as of the demand in energy of this portfolio starts at about 10% and reaches more than 45% in 2039 as more renewable generation are built.

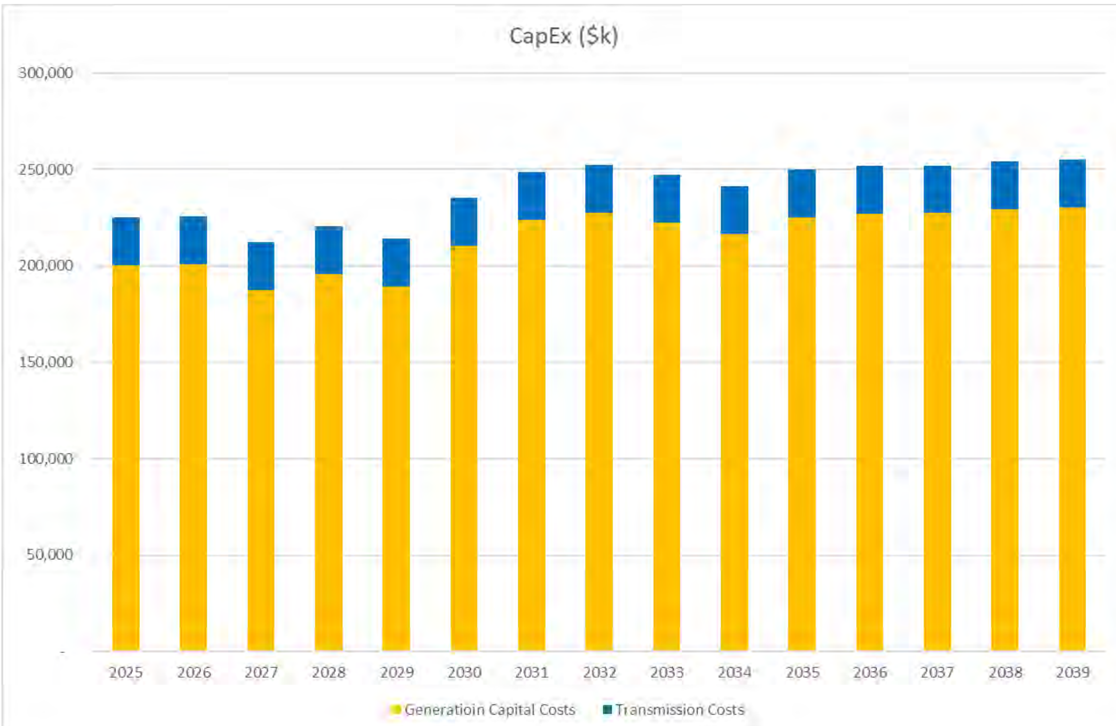
Exhibit 256: Portfolio 4 RPS by Year



Capital Expenditure

Total capital expenditures on generation and transmission are shown in the graph below. We annualized these capital costs from 2025 to 2039 by year and it's about $240 million per year on average for this portfolio. Most of the capital costs are on the generation side.

Exhibit 257: Portfolio 4 Annualized Capital Expenditure by Year



Portfolio 5 (S3S5)

This is the base portfolio derived from high transmission scenario, with the CTs built in the last few years from the expansion plan.

Capacity Expansion (Build Out)

The exhibits below show the capacity expansion by year, where local solar is installed as much and quickly as it can. Only the CCGT of all thermal generation is installed in first year 2025, and the rest of CTs are installed in the last few years of the planning horizon. This portfolio also has installed 100MW of BESS.

Exhibit 258: Portfolio 5 Installed Capacity by Year

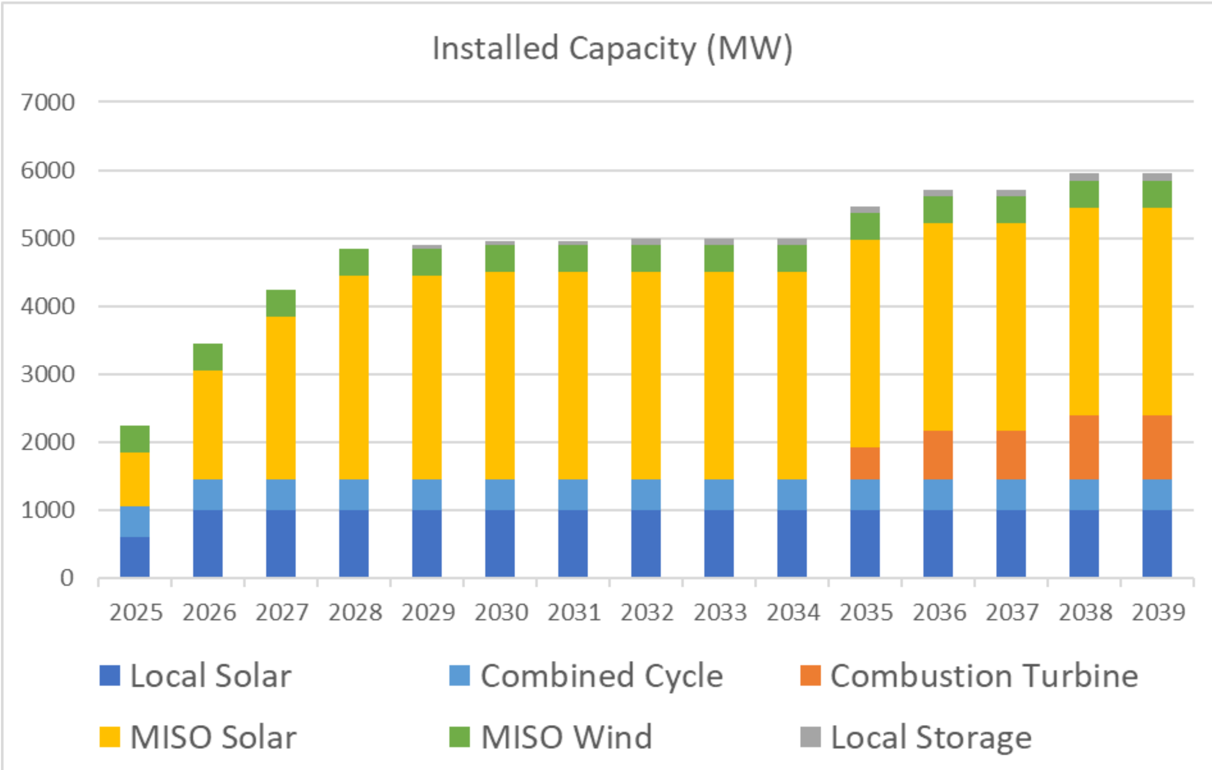
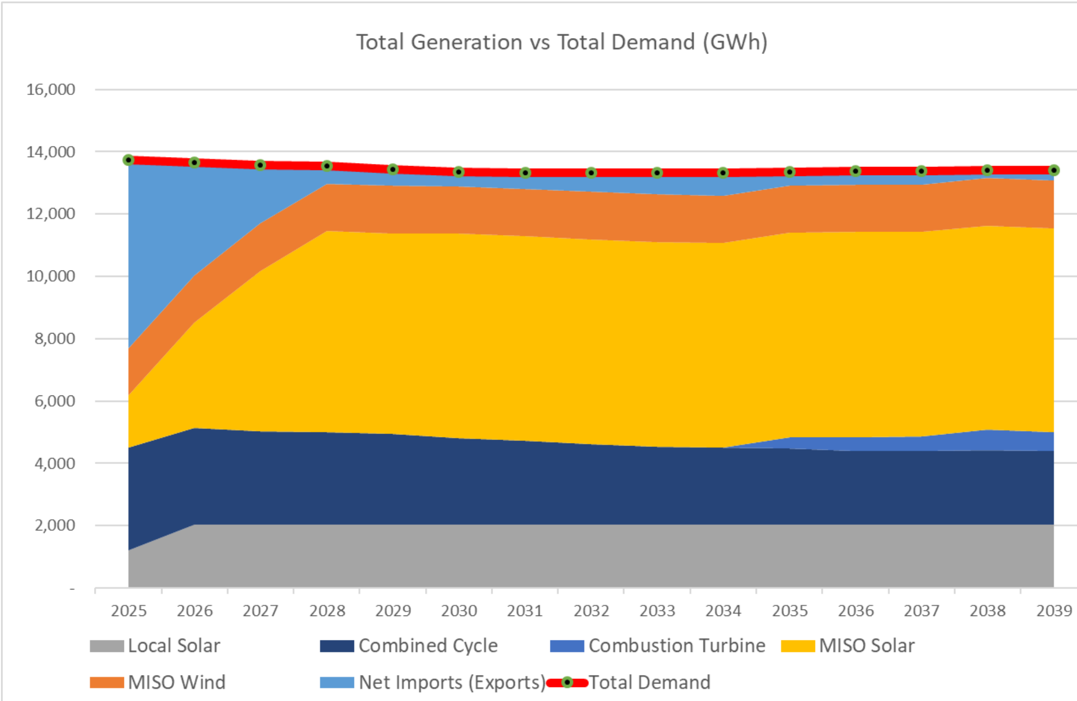


Exhibit 259: Portfolio 5 Installed Capacity by Year (Table)

	Advanced Frame CT	Convl. Frame 7FA CT	1x1 Combined Cycle	Utility Solar	Battery	Miss Solar	Arkansas Solar	Arkansas Wind	MISO_Cap	Demand
2025	0	0	450	600	0	0	800	400	2595	3197
2026	0	0	0	400	0	0	800	0	2237	3182
2027	0	0	0	0	0	0	800	0	2012	3168
2028	0	0	0	0	0	0	600	0	1853	3153
2029	0	0	0	0	50	0	0	0	1816	3139
2030	0	0	0	0	0	0	50	0	1815	3124
2031	0	0	0	0	0	0	0	0	1832	3113
2032	0	0	0	0	50	0	0	0	1806	3108
2033	0	0	0	0	0	0	0	0	1837	3110
2034	0	0	0	0	0	0	0	0	1868	3112
2035	0	474	0	0	0	0	0	0	1478	3114
2036	0	237	0	0	0	0	0	0	1299	3116
2037	0	0	0	0	0	0	0	0	1330	3118
2038	0	237	0	0	0	0	0	0	1152	3121
2039	0	0	0	0	0	0	0	0	1183	3123

Energy generated from thermal generation decreases over the years while energy coming from renewables increases, especially starting 2030 when the cost of renewables is projected to be much more competitive. Imported energy goes down after 2030 as well.

Exhibit 260: Portfolio 5 Energy by Resource Type by Year



Portfolio Costs

Exhibit below shows the supply side NPV cost by year, as can be seen the cost is about $670 million per year (2018 $) or $50/MWh, where fixed cost is the largest components due to the investments in generation, followed by cost of fuels and market purchases.

Exhibit 261: Portfolio 5 Cost Components 2018 $

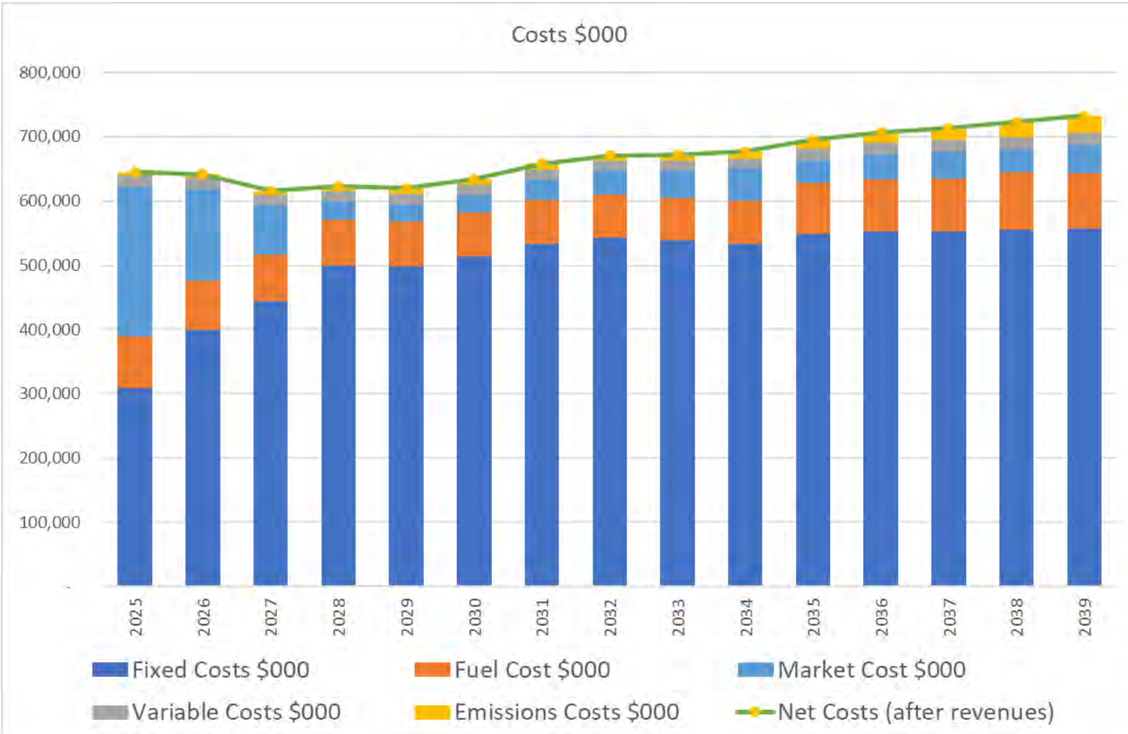
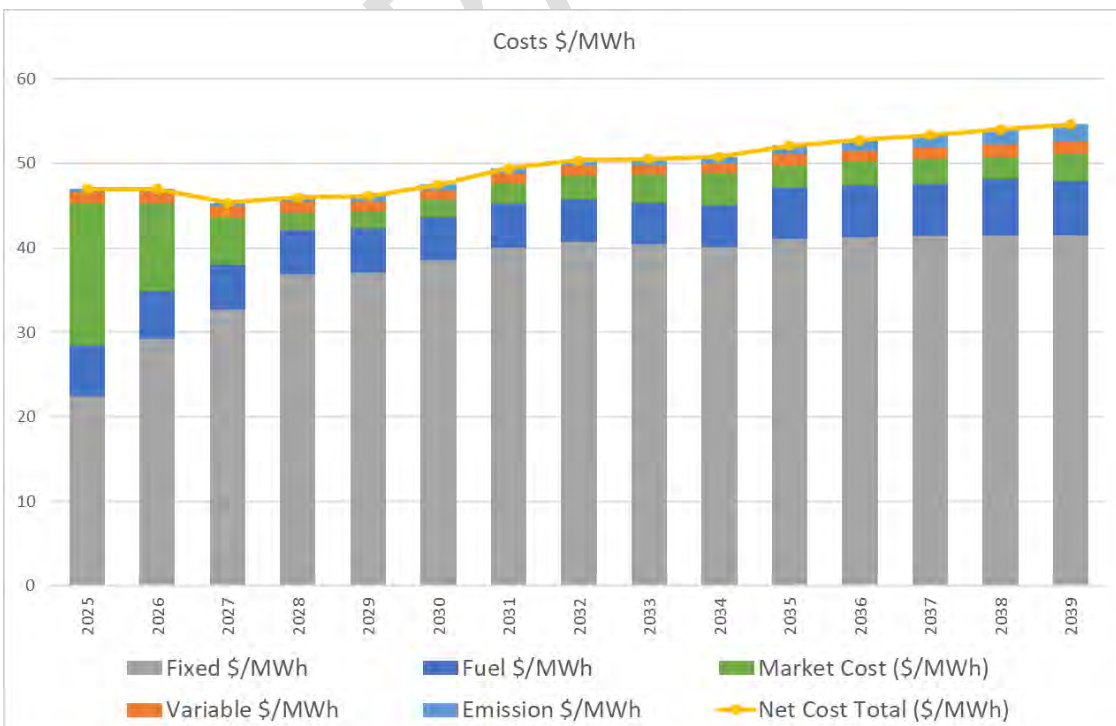
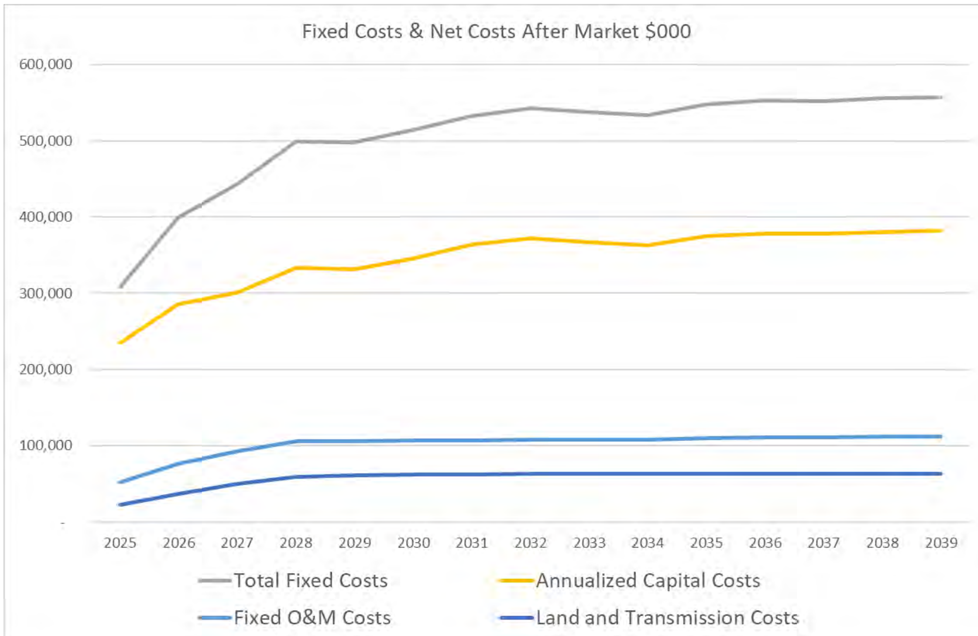


Exhibit 262: Portfolio 5 Cost Components 2018 $/MWh



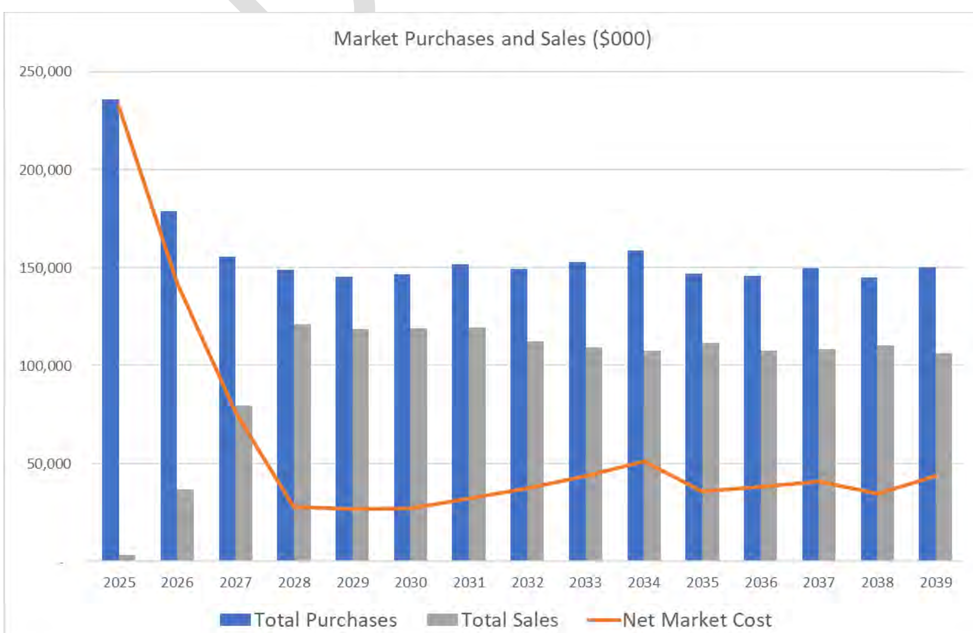
Graph below shows the breakdown of total fixed costs by component, where the majority comes from the base capital costs on generation.

Exhibit 263: Portfolio 5 Fixed Cost Components 2018 $



Market purchases and sales are also important components. The market purchases by MLGW system are projected to be decreasing while the sales are increasing although the sales are maintained at a low level.

Exhibit 264: Portfolio 5 Market Purchases and Sales 2018 $



These graphs show the purchases sales amount in energy and as % of demand. It shows the high market risk in the beginning of the planning years of this portfolio.

Exhibit 265: Portfolio 5 Market Purchases and Sales in Energy

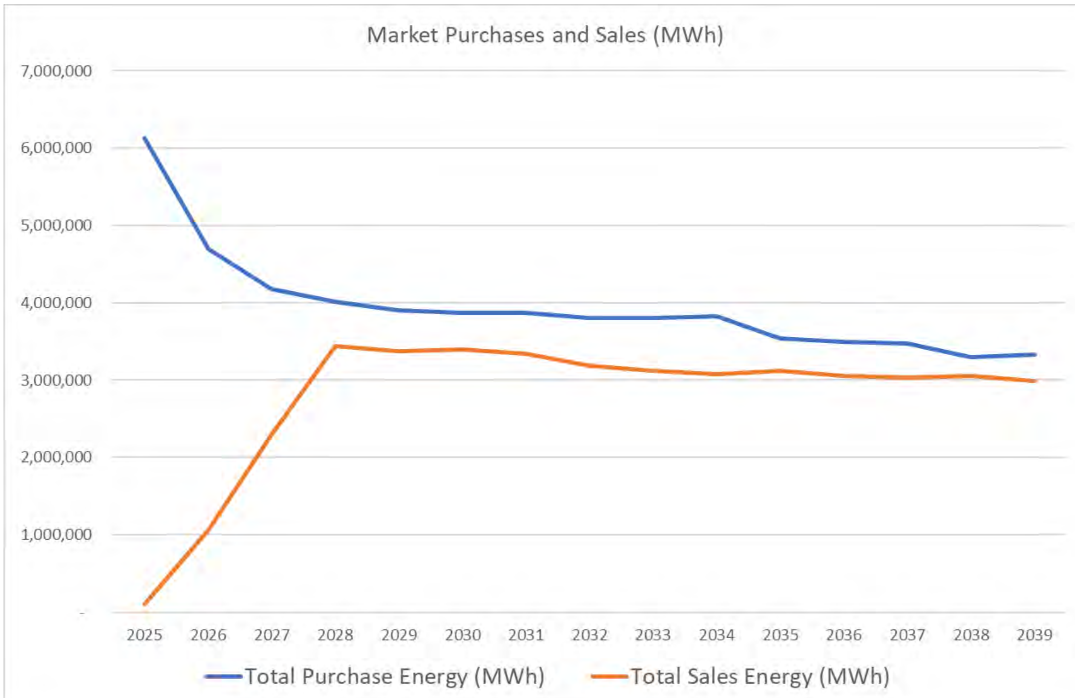
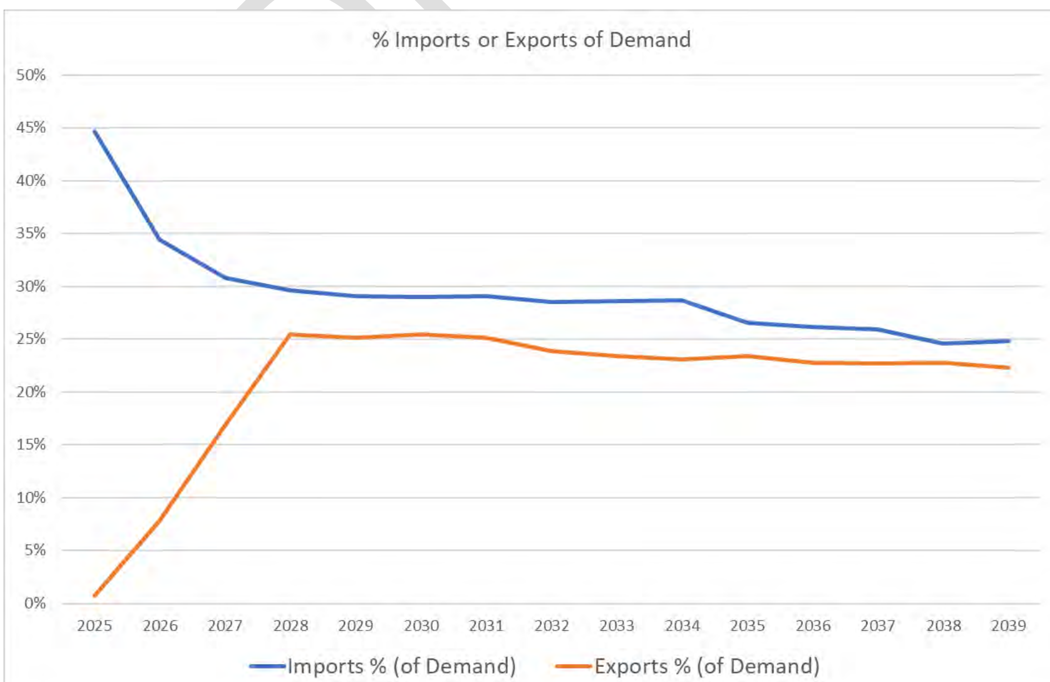


Exhibit 266: Portfolio 5 Market Purchases and Sales as % of Demand



The market risk associated with this portfolio is more on the availability of resources in the market than the market price itself, because this is a portfolio that requires relatively higher percentage of purchase from the market due to less local generation. The more purchase this portfolio needs, the higher risk it has.

Exhibit 267: Portfolio 5 Market Purchases and Sales Prices $/MWh

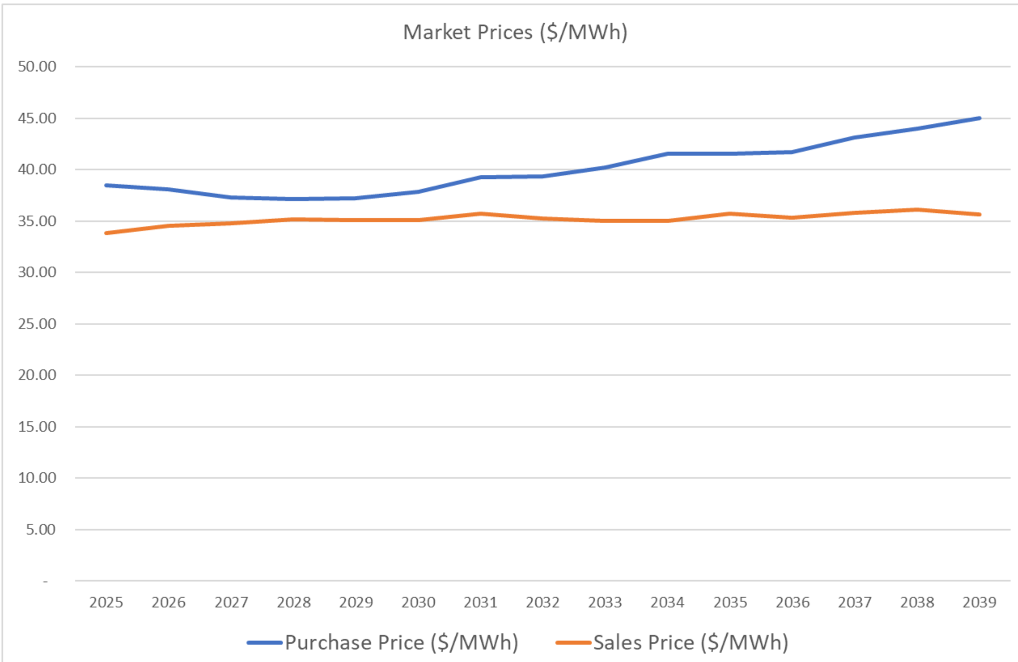
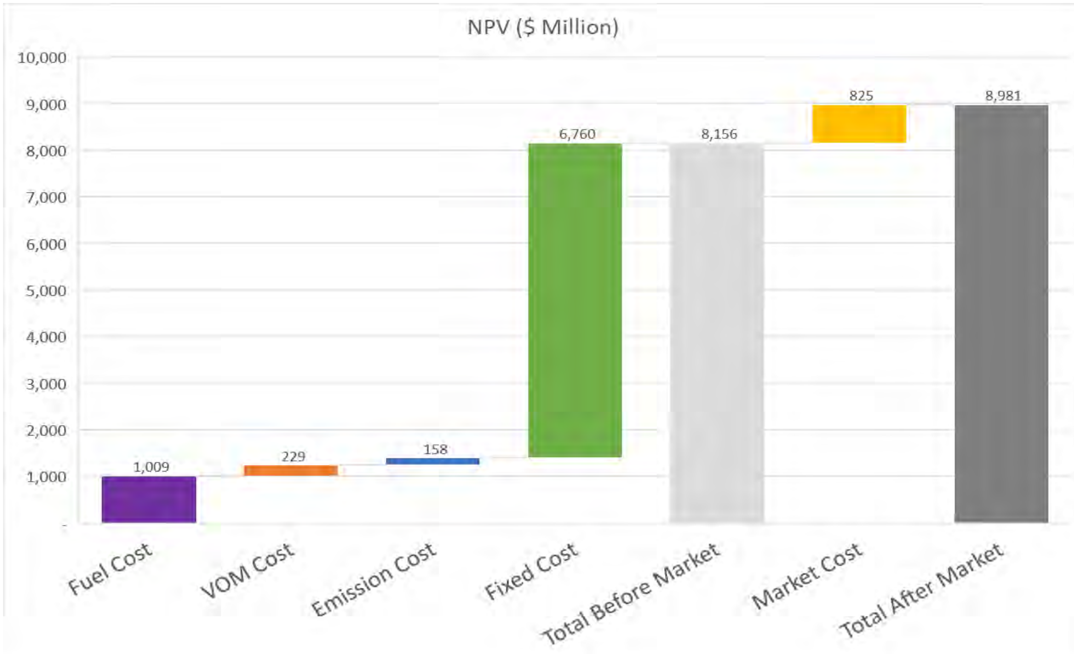


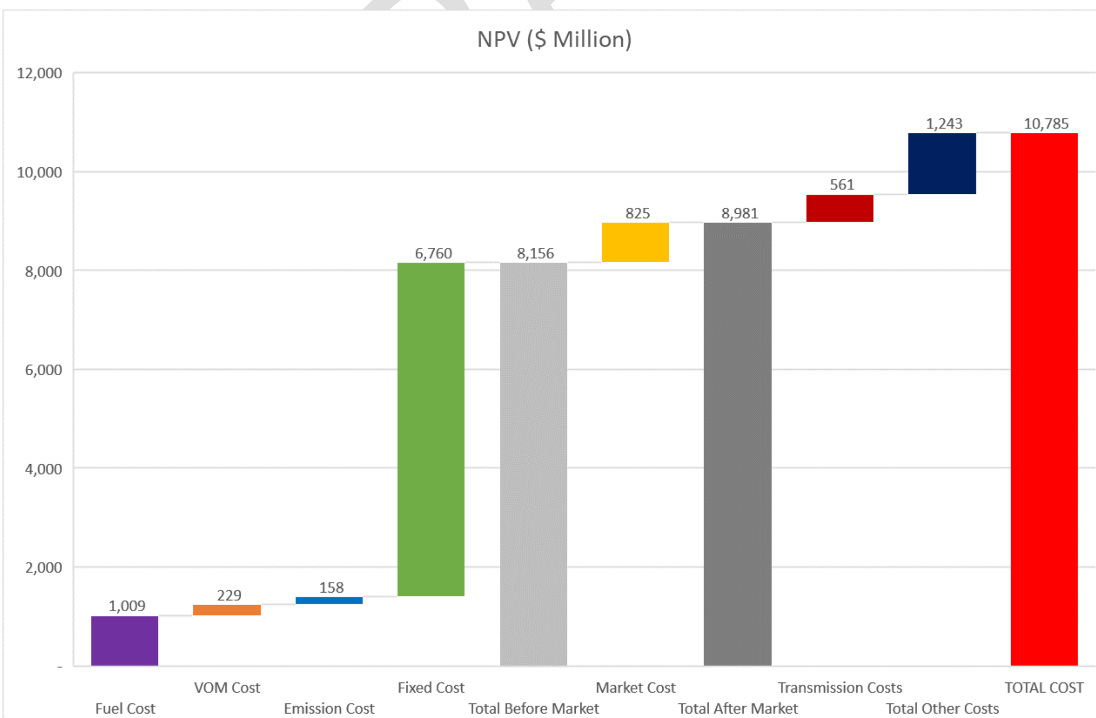
Exhibit below shows the supply side total NPV for 2025-2039, which is about $8.98 billion in 2018 $. Fixed cost is the largest component, followed by fuel and market costs.

Exhibit 268: Portfolio 5 Generation Resource NPV 2018 $



The total NPVRR of this portfolio is approximately $10.79 billion for 2025-2039 in 2018 $.

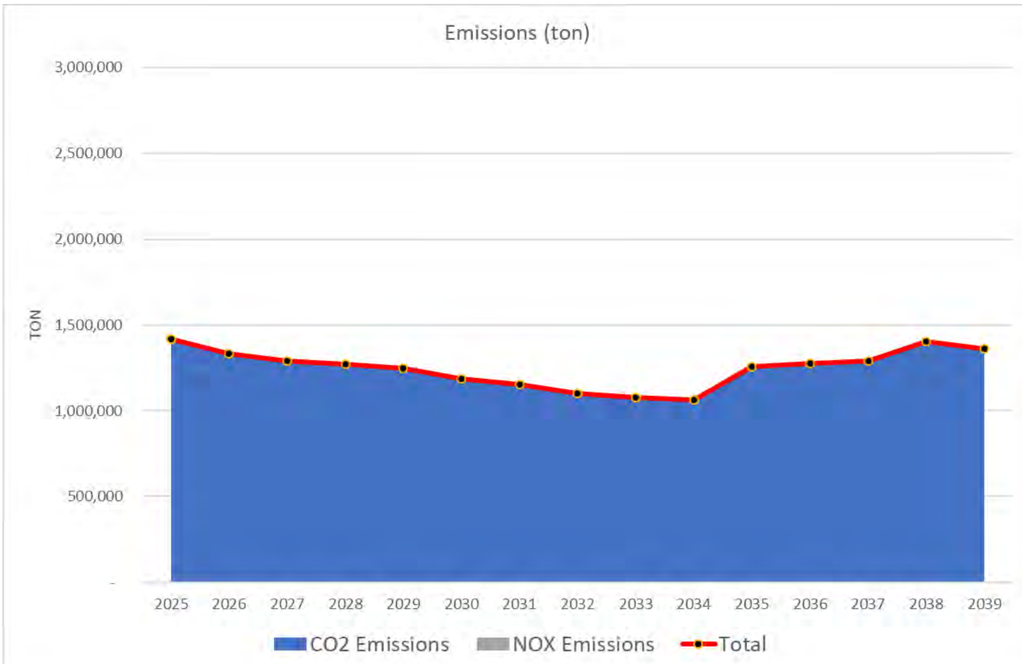
Exhibit 269: Portfolio 5 All NPVRR with Other Components 2018 $



Environmental

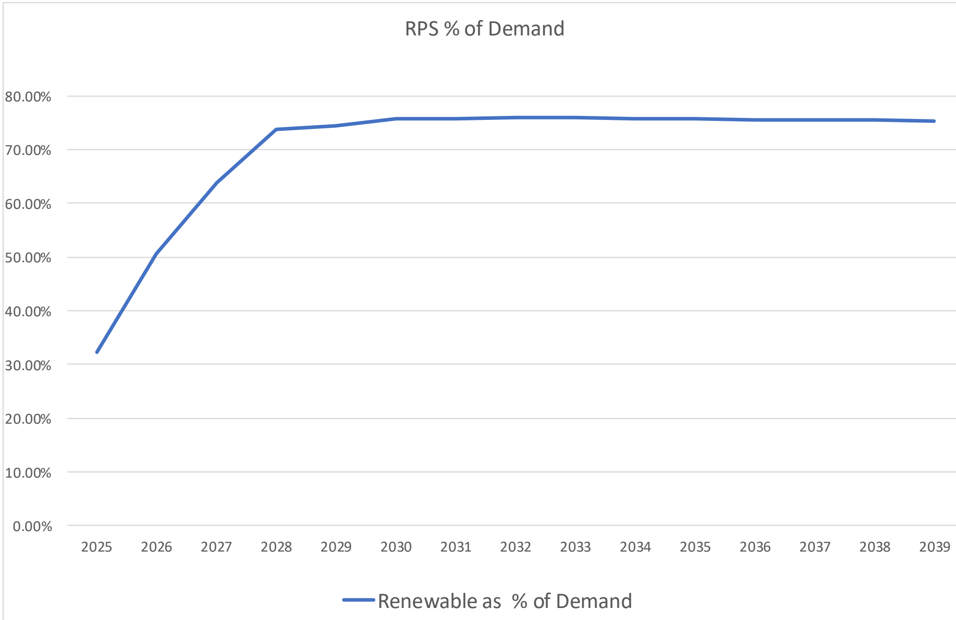
The emission from this portfolio is shown in the graph below. The emission is low compared with other portfolios due to high renewable and low thermal nature in this portfolio.

Exhibit 270: Portfolio 5 Total Emission by Year



This is the high renewable case and the RPS as of demand in energy of this portfolio starts at about 32% and reaches very quickly to 75% in 2039 as lots of renewable generation are built in this portfolio.

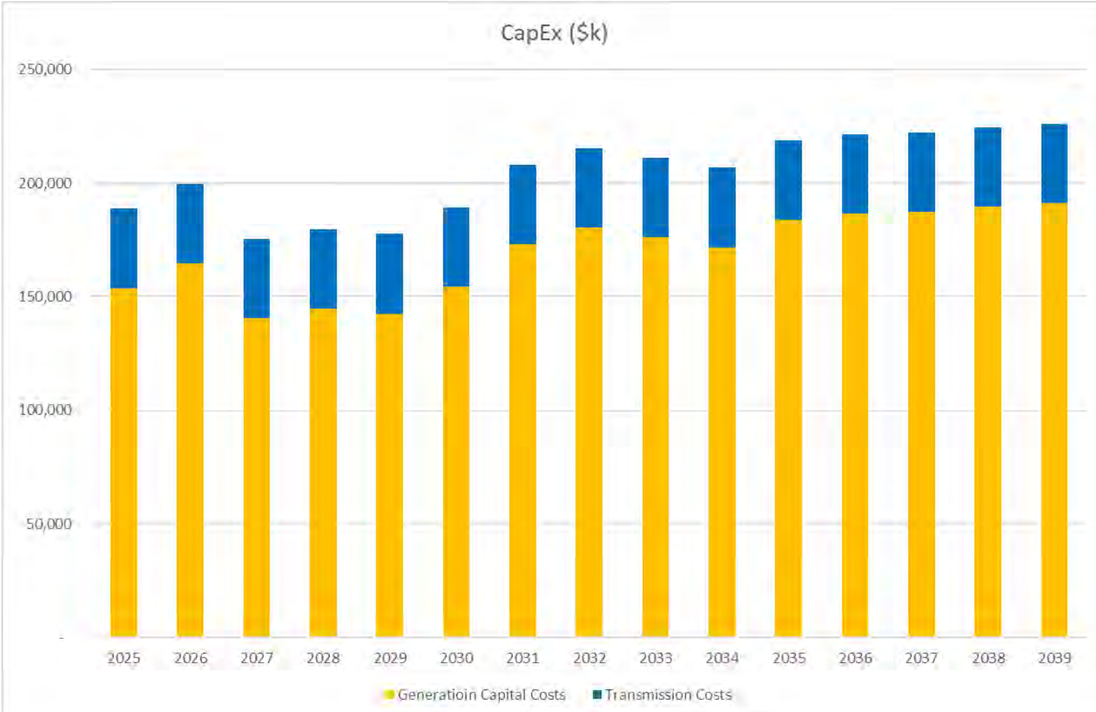
Exhibit 271: Portfolio 5 RPS by Year



Capital Expenditure

Total capital expenditures on generation and transmission are shown in the graph below. We annualized these capital costs from 2025 to 2039 by year and it's about $200 million per year on average for this portfolio. Most of the capital costs are on the generation side although relatively less local thermal generation were built, it does require more transmission compared with other portfolios.

Exhibit 272: Portfolio 5 Annualized Capital Expenditure by Year



Portfolio 6 (S3S7_BB)

This is the S3S7 low load high gas price portfolio derived from the capacity expansion plan, with the CCGT, CT and solar all accelerated, ran on the base load base gas price conditions.

Capacity Expansion (Build Out)

The exhibits below show the capacity expansion by year. Both local solar and MISO renewables are installed as much and fast as they can. Thermal generations are 2 CCGTs and 1 CT, which were all installed in 2025.

Exhibit 273: Portfolio 6 Installed Capacity by Year

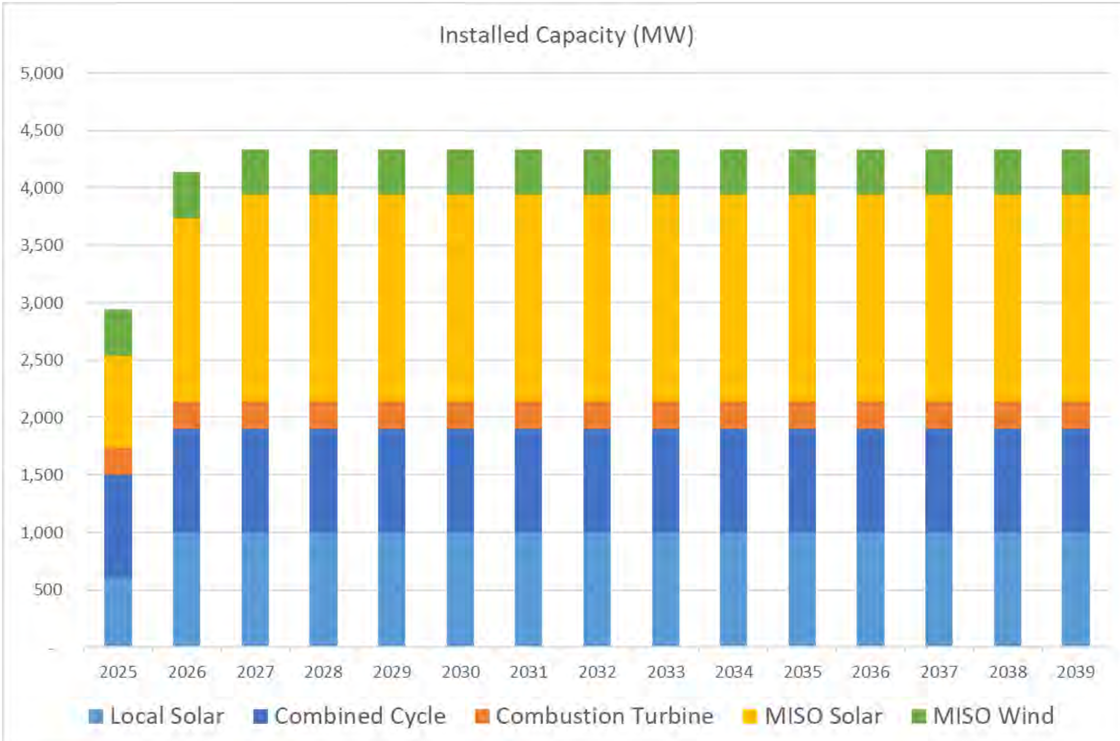
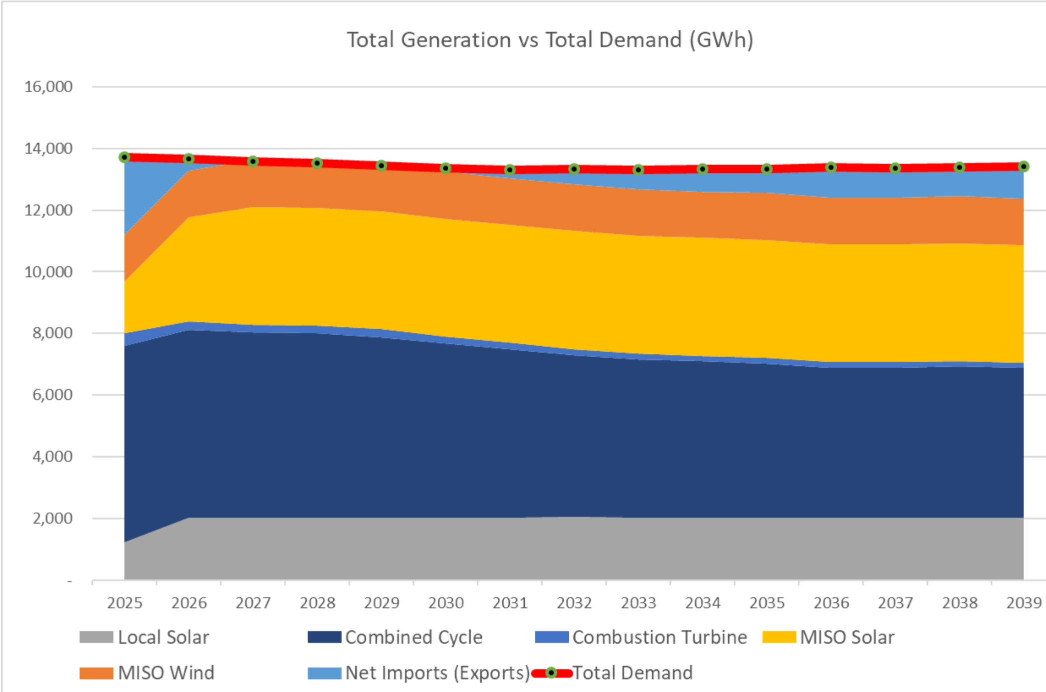


Exhibit 274: Portfolio 6 Installed Capacity by Year (Table)

	Advanced Frame CT	Convl. Frame 7FA CT	1x1 Combined Cycle	Utility Solar	Battery	Miss Solar	Arkansas Solar	Arkansas Wind	MISO_Cap	Demand
2025	0	237	900	600	0	0	800	400	1981	3197
2026	0	0	0	400	0	0	800	0	1623	3182
2027	0	0	0	0	0	0	200	0	1570	3168
2028	0	0	0	0	0	0	0	0	1573	3153
2029	0	0	0	0	0	0	0	0	1578	3139
2030	0	0	0	0	0	0	0	0	1582	3124
2031	0	0	0	0	0	0	0	0	1590	3113
2032	0	0	0	0	0	0	0	0	1604	3108
2033	0	0	0	0	0	0	0	0	1626	3110
2034	0	0	0	0	0	0	0	0	1649	3112
2035	0	0	0	0	0	0	0	0	1671	3114
2036	0	0	0	0	0	0	0	0	1693	3116
2037	0	0	0	0	0	0	0	0	1715	3118
2038	0	0	0	0	0	0	0	0	1738	3121
2039	0	0	0	0	0	0	0	0	1761	3123

Energy generated from all resources stay relatively flat over the years.

Exhibit 275: Portfolio 6 Energy by Resource Type by Year



Portfolio Costs

Exhibit below shows the supply side NPV cost by year, as can be seen the cost is about $690 million per year (2018 $) or $51/MWh, where fixed cost is the largest components due to the investments in generation, followed by cost of fuels.

Exhibit 276: Portfolio 6 Cost Components 2018 $

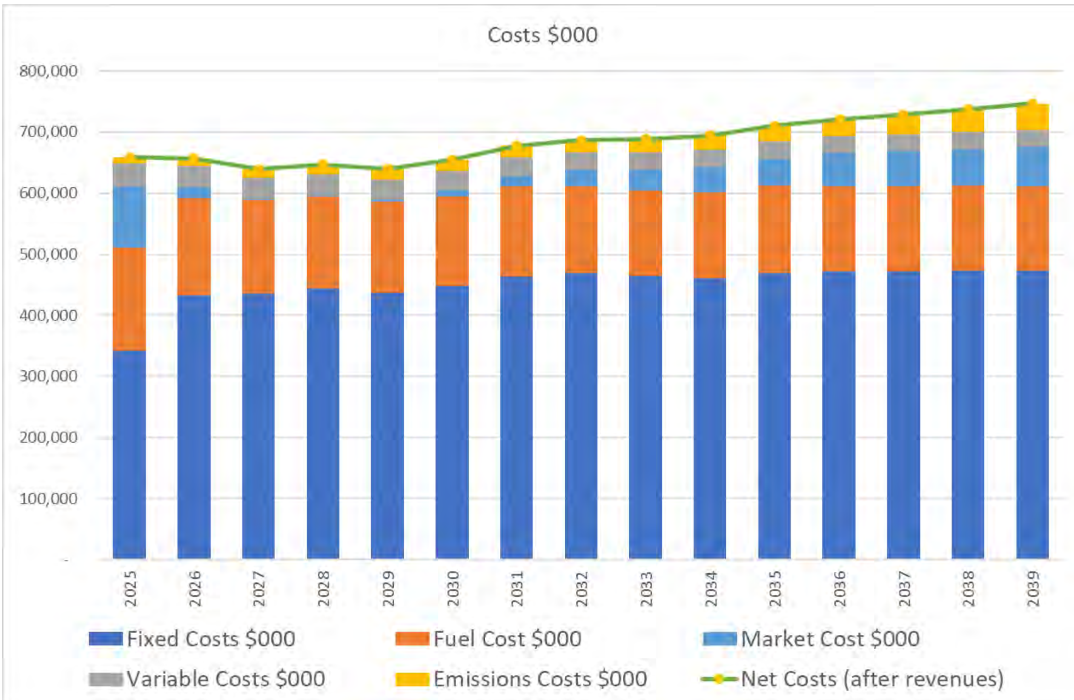
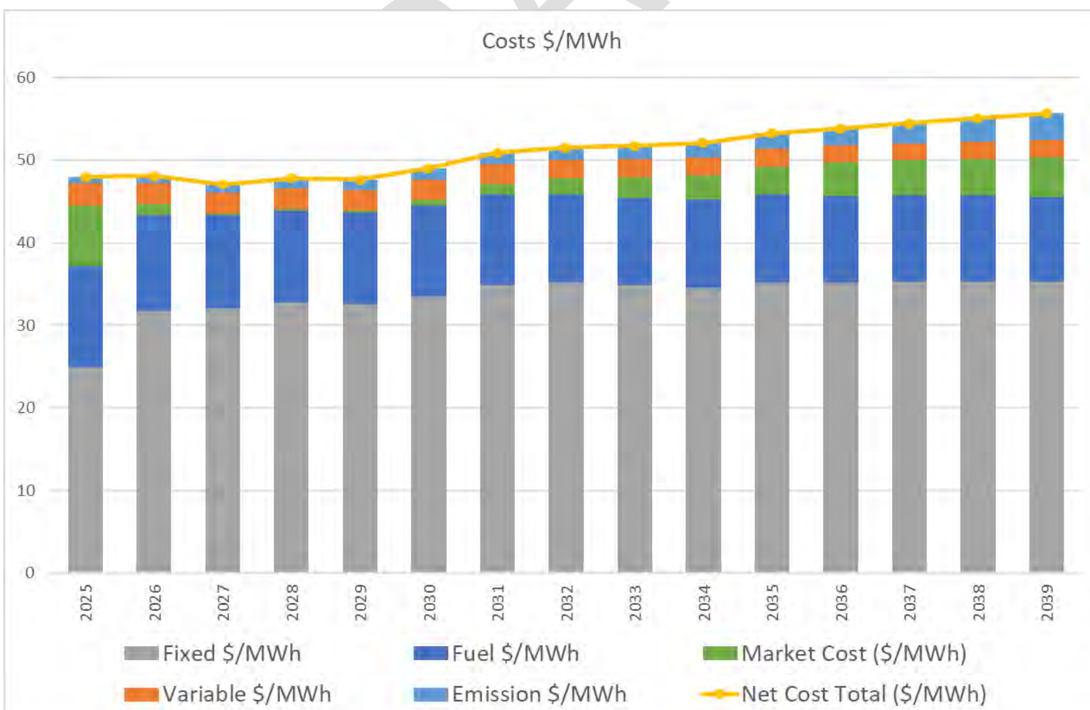
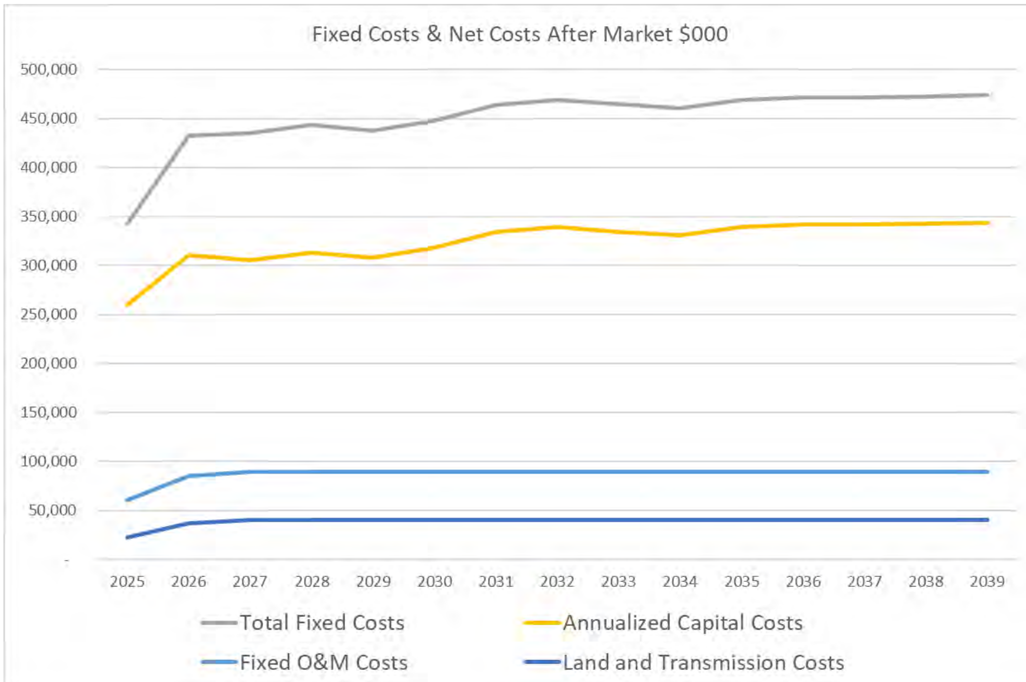


Exhibit 277: Portfolio 6 Cost Components 2018 $/MWh



Graph below shows the breakdown of total fixed costs by component, where the majority comes from the base capital costs on generation.

Exhibit 278: Portfolio 6 Fixed Cost Components 2018 $



Market purchases and sales as also important components. The market purchases by MLGW system are projected to be increasing slightly while the sales are decreasing.

Exhibit 279: Portfolio 6 Market Purchases and Sales 2018 $

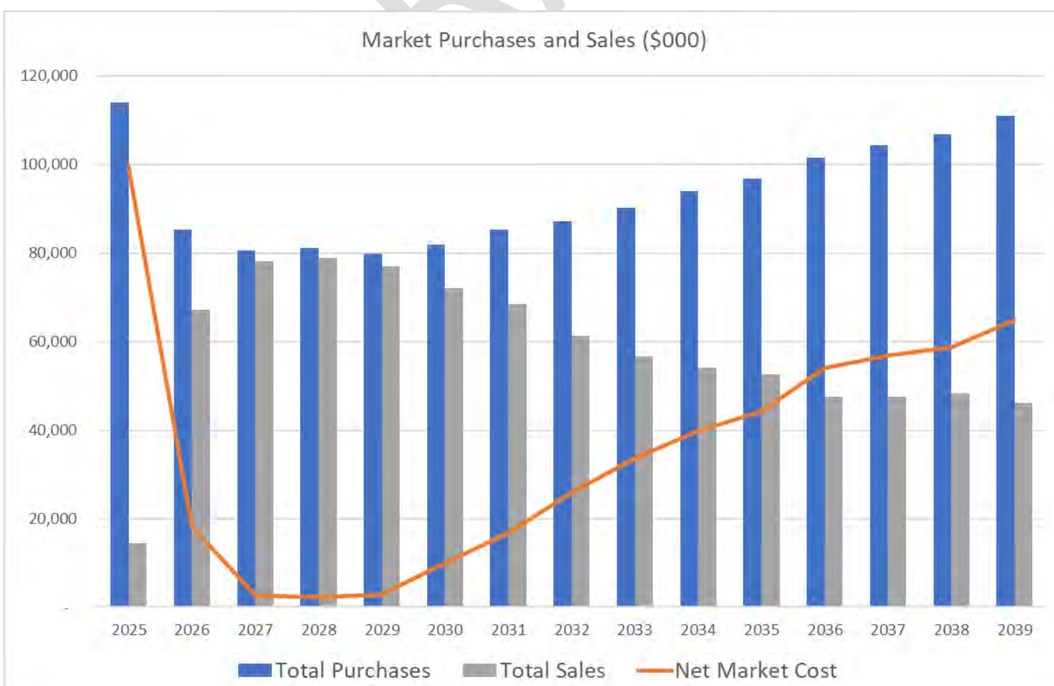
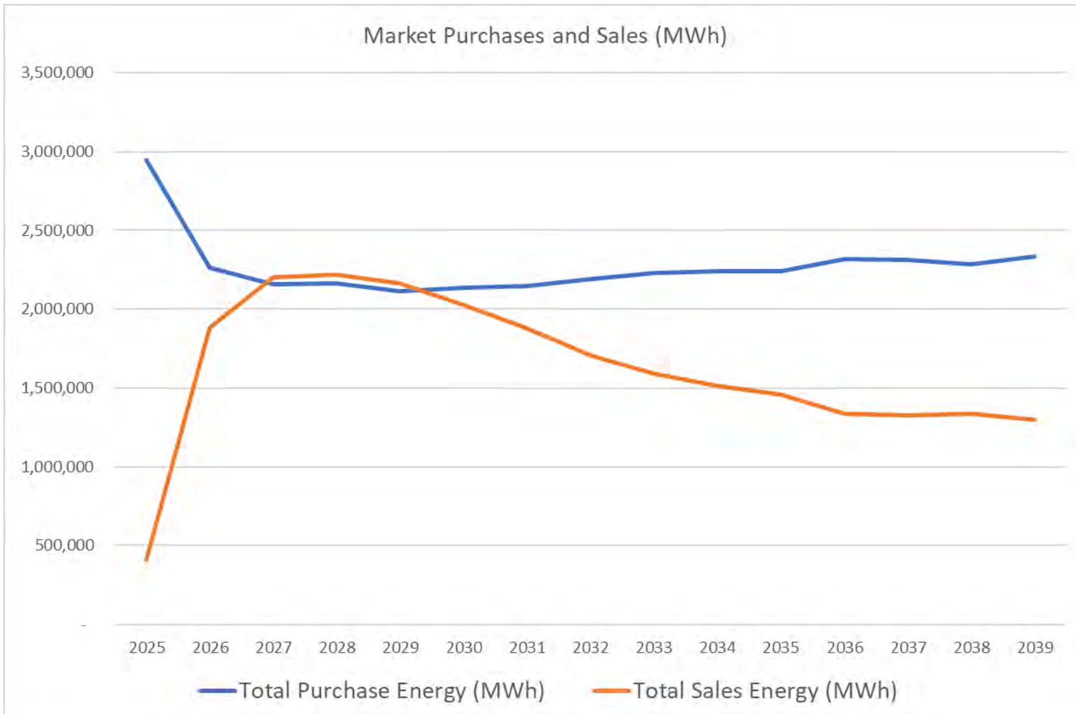
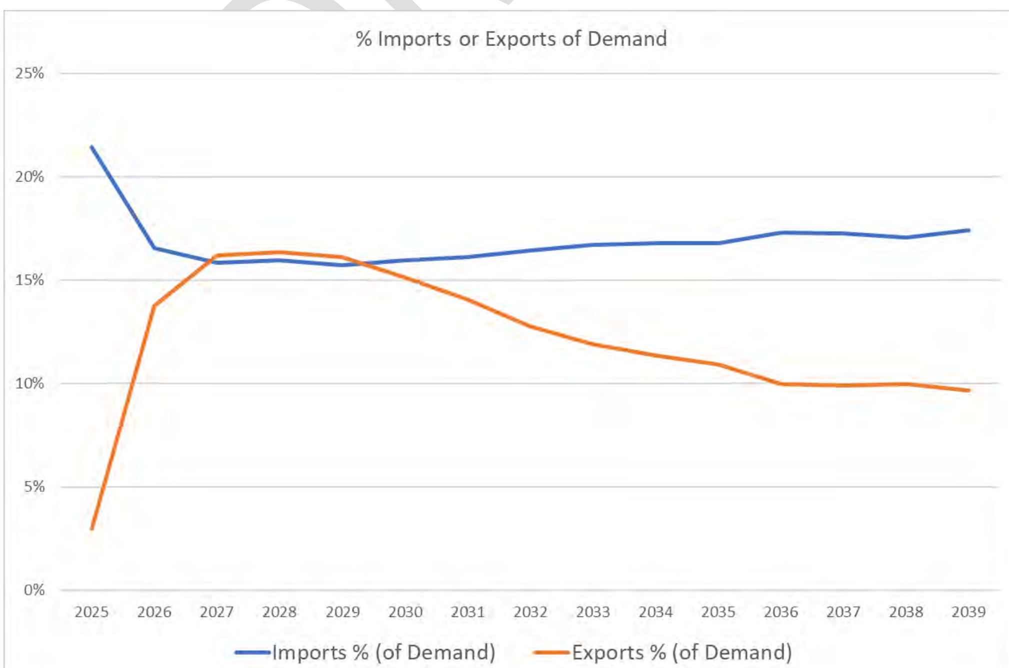


Exhibit 280: Portfolio 6 Market Purchases and Sales in Energy



These graphs show the purchases sales amount in energy and as % of demand. It shows the high market risk towards the end of the planning years of this portfolio.

Exhibit 281: Portfolio 6 Market Purchases and Sales as % of Demand



The risk can also be appreciated looking at the difference between purchase price (high) and sale price (low). The more purchase this portfolio needs, the higher risk it has, especially the price is estimated to be high in the far future.

Exhibit 282: Portfolio 6 Market Purchases and Sales Prices $/MWh

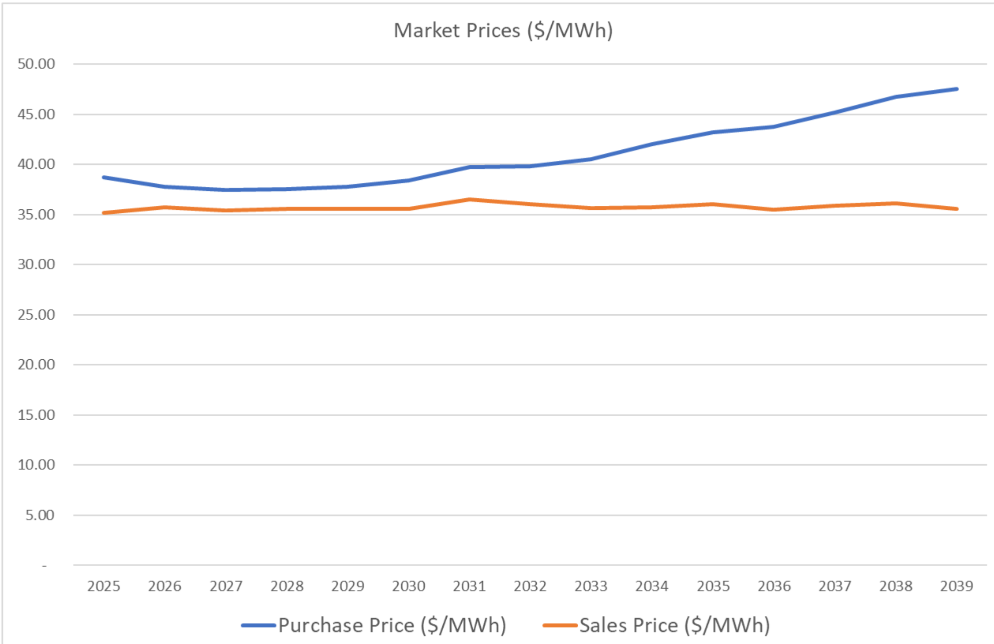
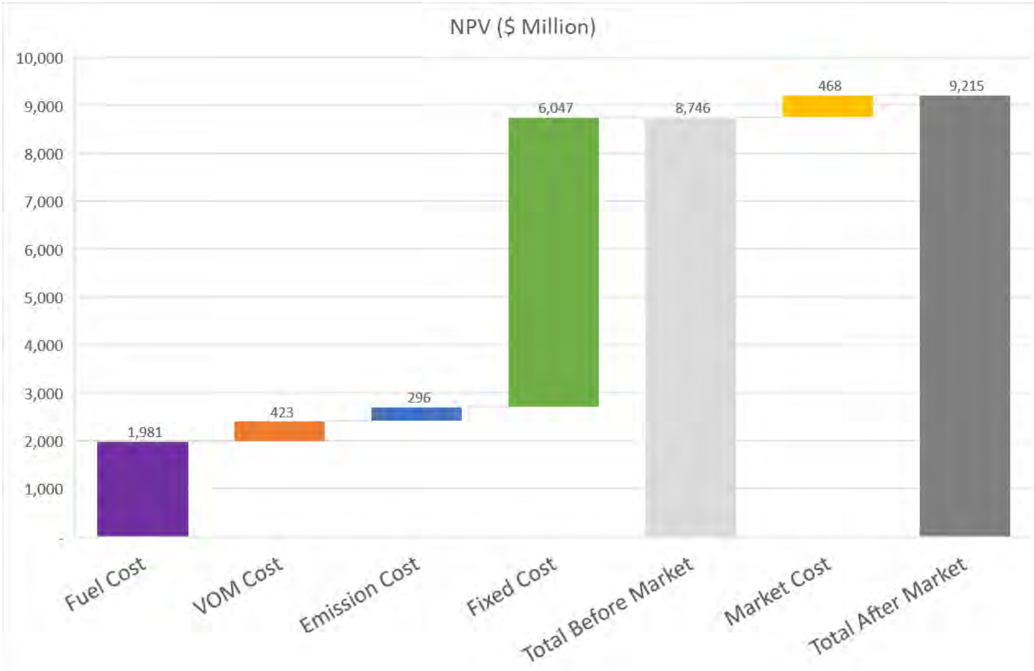


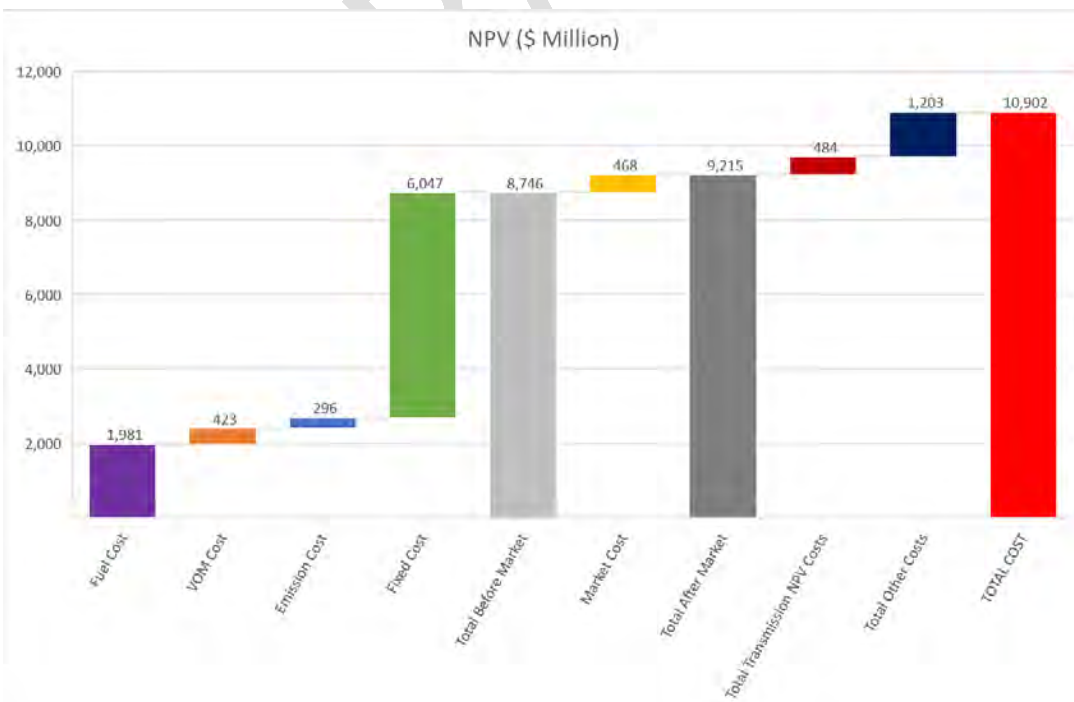
Exhibit below shows the supply side total NPV for 2025-2039, which is about $9.22 billion in 2018 $. Fixed cost is the largest component, followed by fuel and market costs.

Exhibit 283: Portfolio 6 Generation Resource NPV 2018 $



The total NPVRR of this portfolio is approximately $10.9 billion for 2025-2039 in 2018 $.

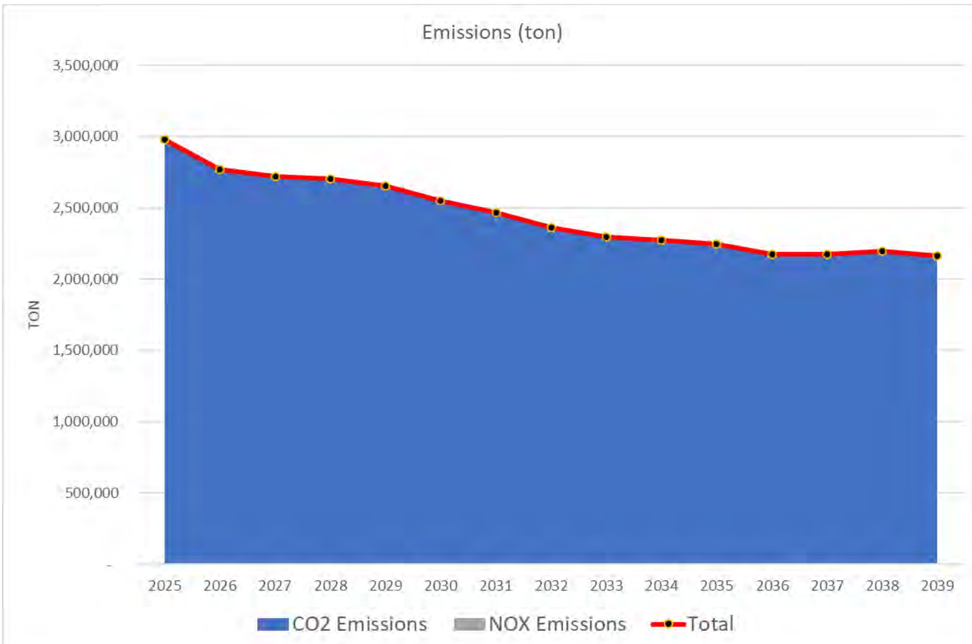
Exhibit 284: Portfolio 6 All NPVRR with Other Components 2018 $



Environmental

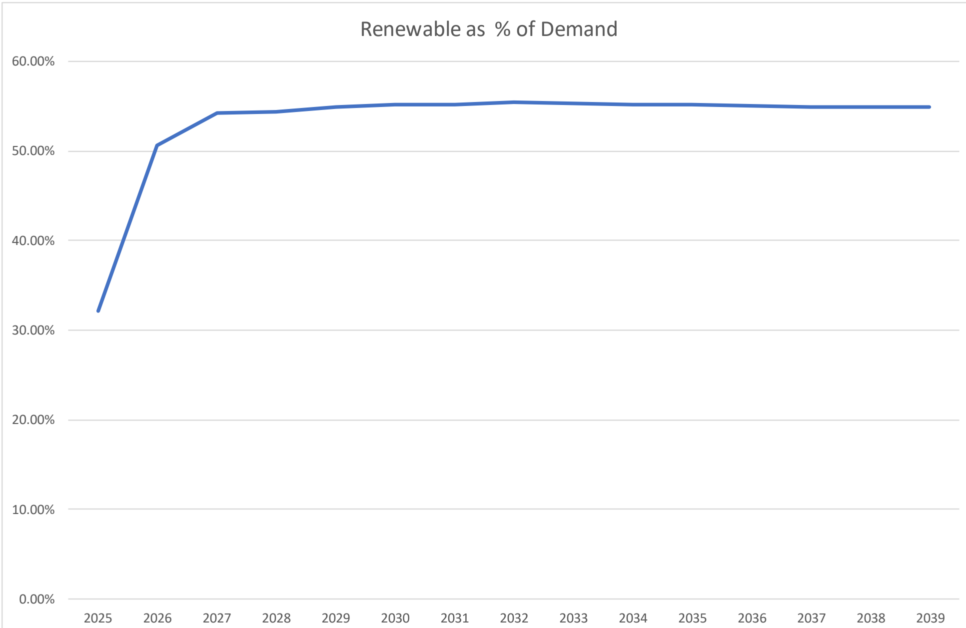
The emission from this portfolio is shown in the graph below. As energy from thermal generation is coming down, the capacity factor of the units decreases which resulted in decreased CO_2 emission over the years.

Exhibit 285: Portfolio 6 Total Emission by Year



And the RPS as of the demand in energy of this portfolio starts at about 32% and reaches quickly to about 55% and stay flat until 2039.

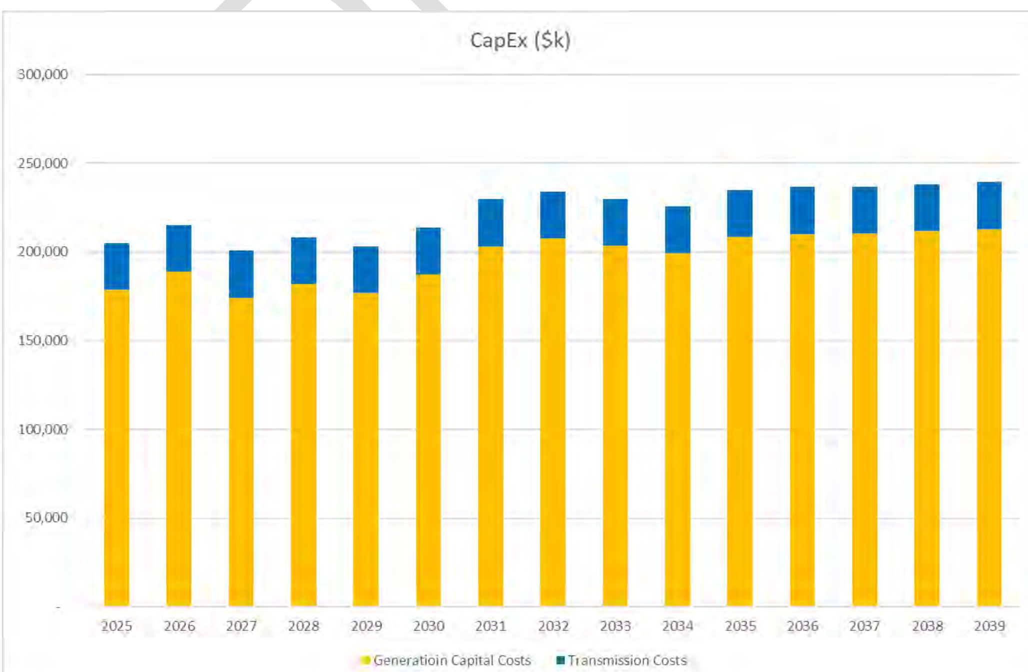
Exhibit 286: Portfolio 6 RPS by Year



Capital Expenditure

Total capital expenditures on generation and transmission are shown in the graph below. We annualized these capital costs from 2025 to 2039 by year and it's about $200 to $230 million per year on average for this portfolio. Most of the capital costs are on the generation side.

Exhibit 287: Portfolio 6 Annualized Capital Expenditure by Year



Portfolio 7 (S3S1_2CT)

This is the modified portfolio derived from the S3S1, with one additional CT built in 2025 due to resource adequacy concern.

Capacity Expansion (Build Out)

The exhibits below show the capacity expansion by year. It is the same build out except the additional CT in 2025 as compared to the S3S1 case.

Exhibit 288: Portfolio 7 Installed Capacity by Year

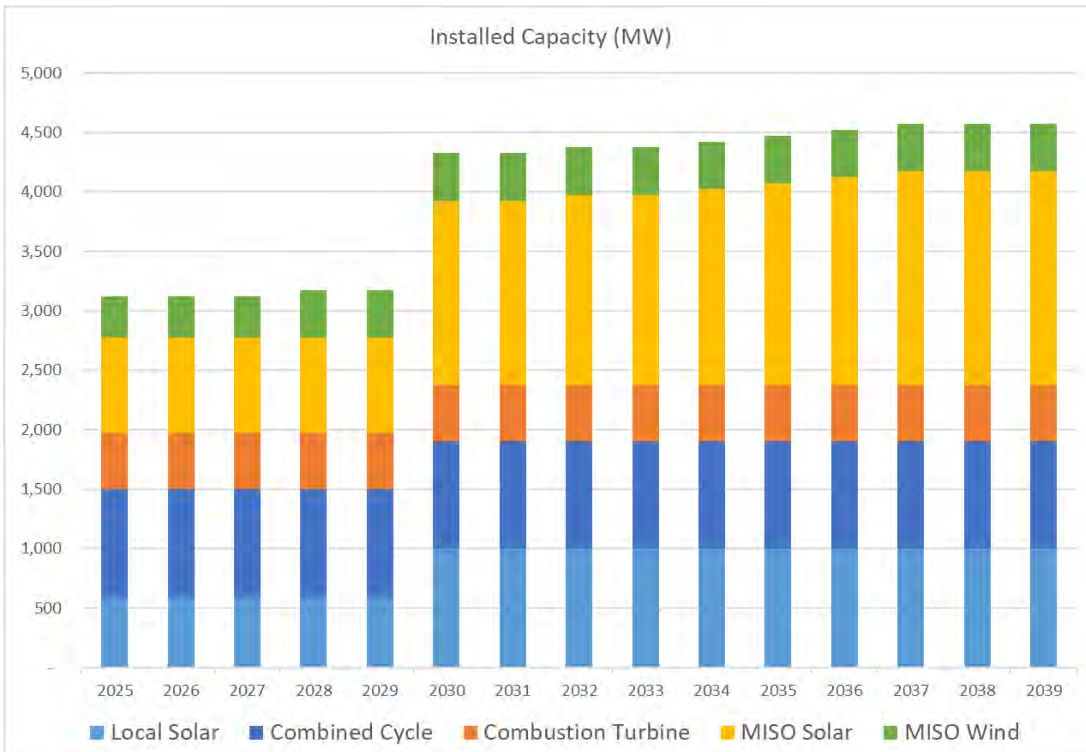
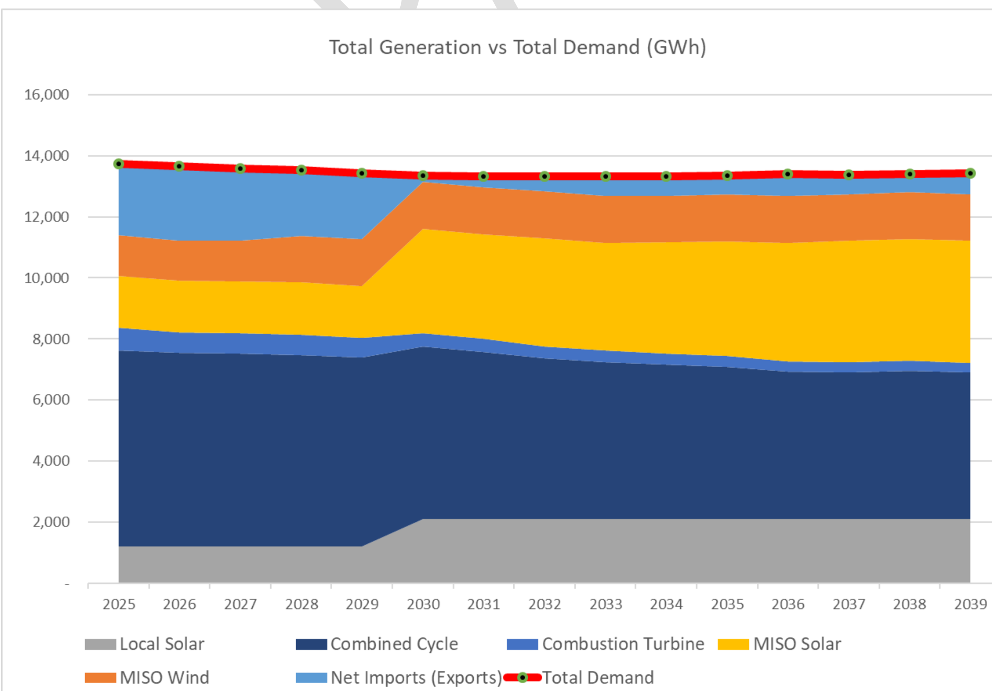


Exhibit 289: Portfolio 7 Installed Capacity by Year (Table)

	Advanced Frame CT	Convl. Frame 7FA CT	1x1 Combined Cycle	Utility Solar	Battery	Miss Solar	Arkansas Solar	Arkansas Wind	MISO_Cap	Demand
2025	0	474	900	600	0	0	800	350	1779	3197
2026	0	0	0	0	0	0	0	0	1772	3182
2027	0	0	0	0	0	0	0	0	1767	3168
2028	0	0	0	0	0	0	0	50	1753	3153
2029	0	0	0	0	0	0	0	0	1748	3139
2030	0	0	0	400	0	0	750	0	1437	3124
2031	0	0	0	0	0	0	0	0	1444	3113
2032	0	0	0	0	0	0	50	0	1444	3108
2033	0	0	0	0	0	0	0	0	1465	3110
2034	0	0	0	0	0	0	50	0	1474	3112
2035	0	0	0	0	0	0	50	0	1483	3114
2036	0	0	0	0	0	0	50	0	1494	3116
2037	0	0	0	0	0	0	50	0	1505	3118
2038	0	0	0	0	0	0	0	0	1528	3121
2039	0	0	0	0	0	0	0	0	1550	3123

Energy generated from thermal generation decreases over the years while energy coming from renewables increases, especially starting 2030 when the cost of renewables is projected to be much more competitive. Imported energy goes down after 2030 as well.

Exhibit 290: Portfolio 7 Energy by Resource Type by Year



Portfolio Costs

Exhibit below shows the supply side NPV cost by year, as can be seen the cost is about $680 million per year (2018 $) or $50/MWh, where fixed cost is the largest components due to the investments in generation, followed by cost of fuels and market purchases.

Exhibit 291: Portfolio 7 Cost Components 2018 $

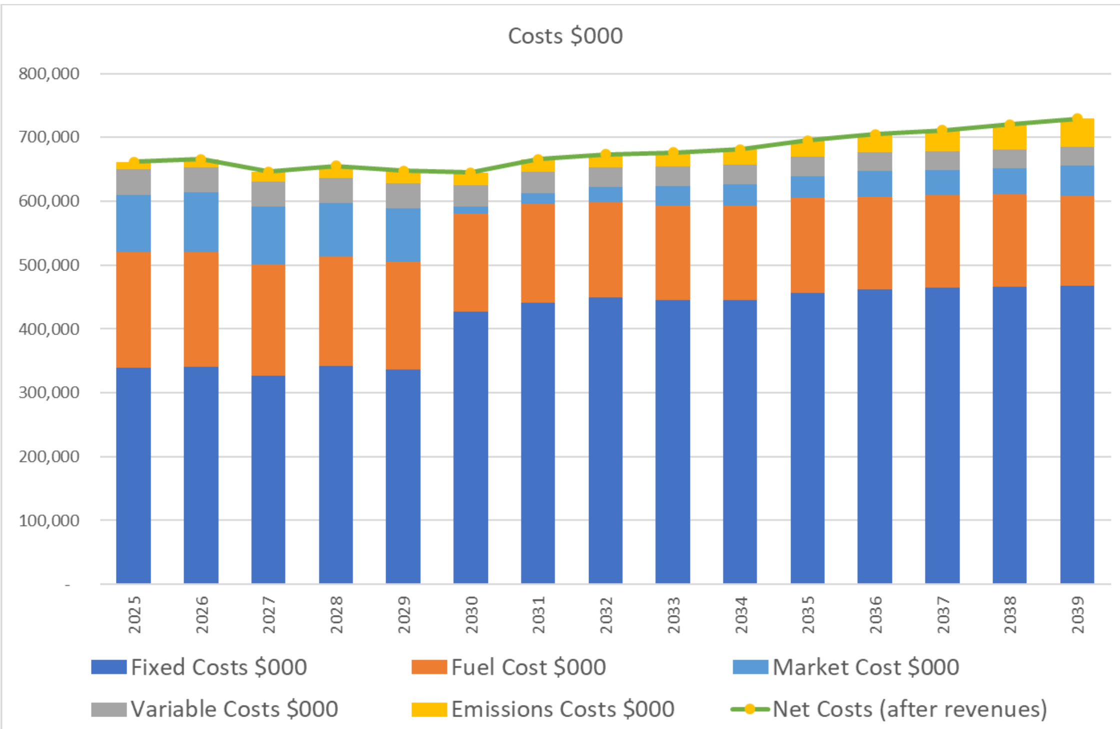
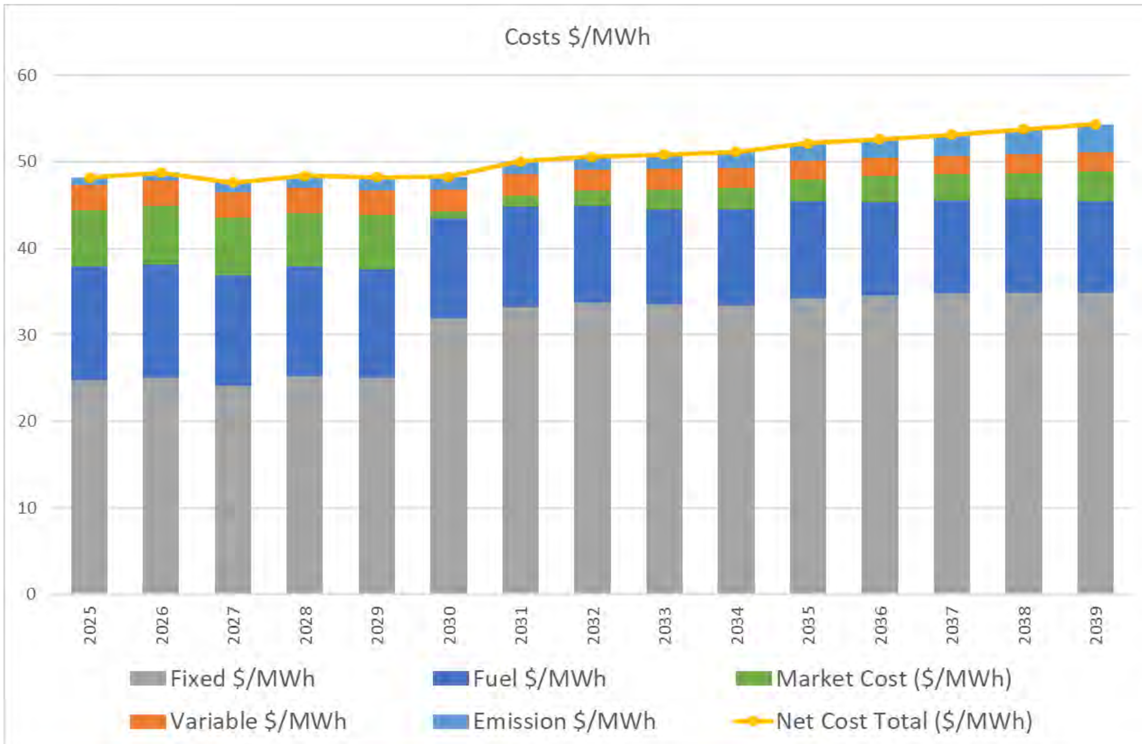
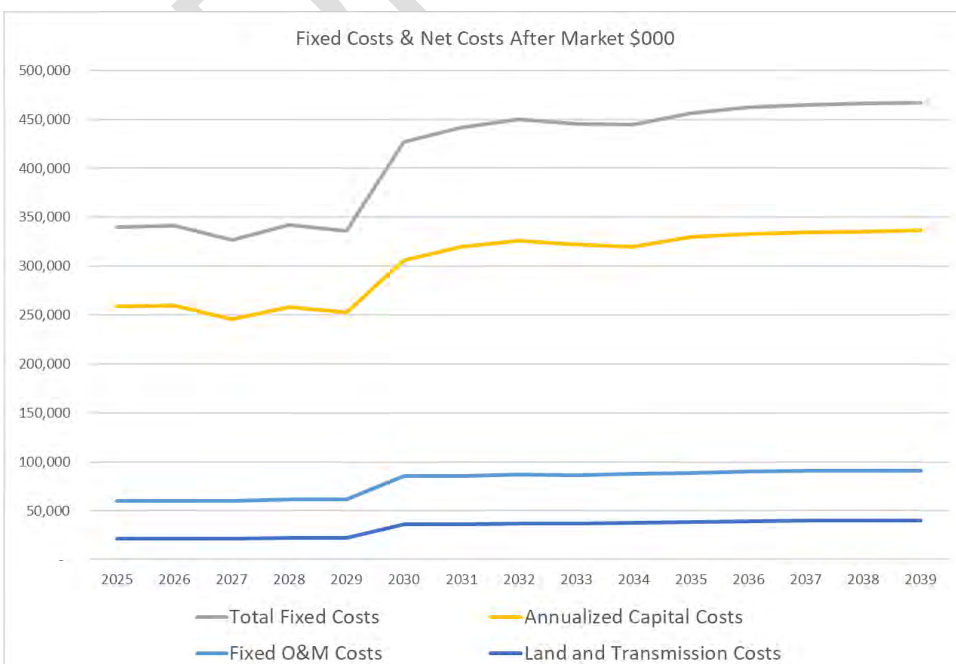


Exhibit 292: Portfolio 7 Cost Components 2018 $/MWh



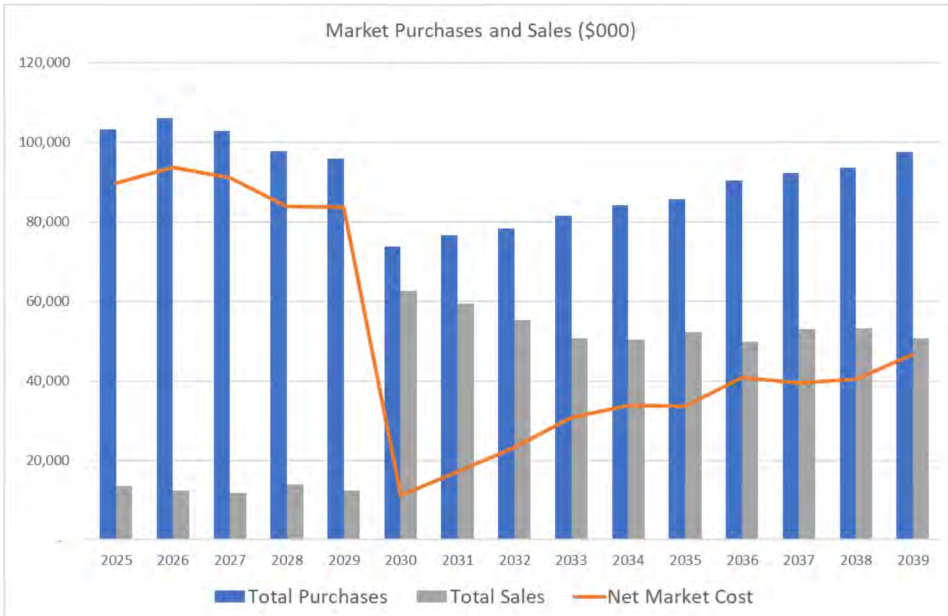
Graph below shows the breakdown of total fixed costs by component, where the majority comes from the base capital costs on generation.

Exhibit 293: Portfolio 7 Fixed Cost Components 2018 $



Market purchases and sales are also important components. The market purchases by MLGW decreased and then increased over the years while the sales showing increased trend, especially starting 2030.

Exhibit 294: Portfolio 7 Market Purchases and Sales 2018 $



These graphs show the purchases and sales amount in energy and as % of demand. It shows the high market risk in the beginning of the planning years of this portfolio.

Exhibit 295: Portfolio 7 Market Purchases and Sales in Energy

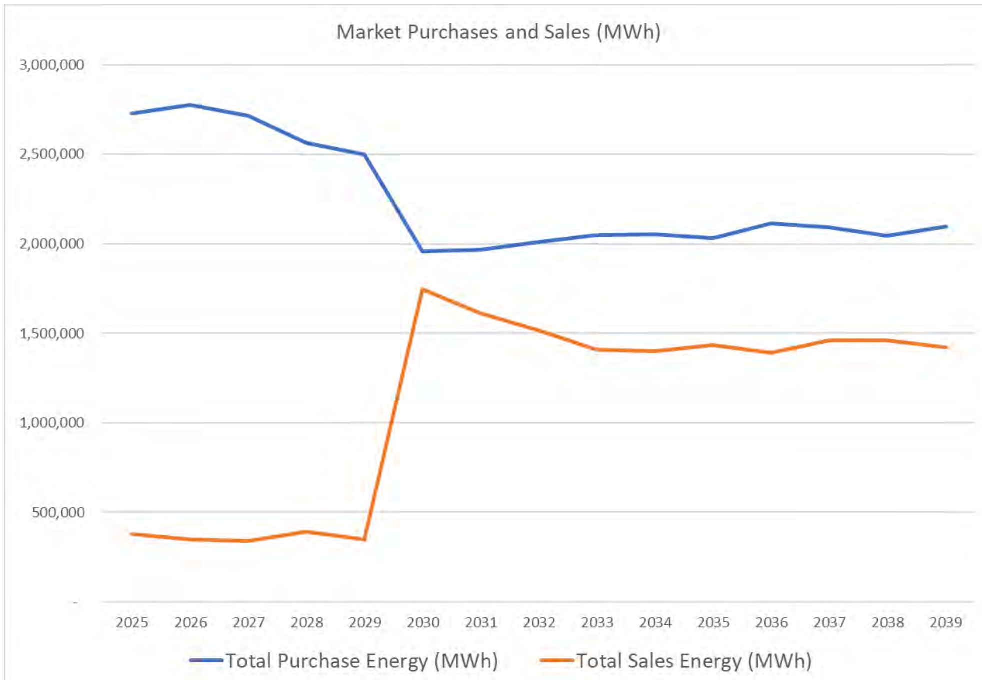
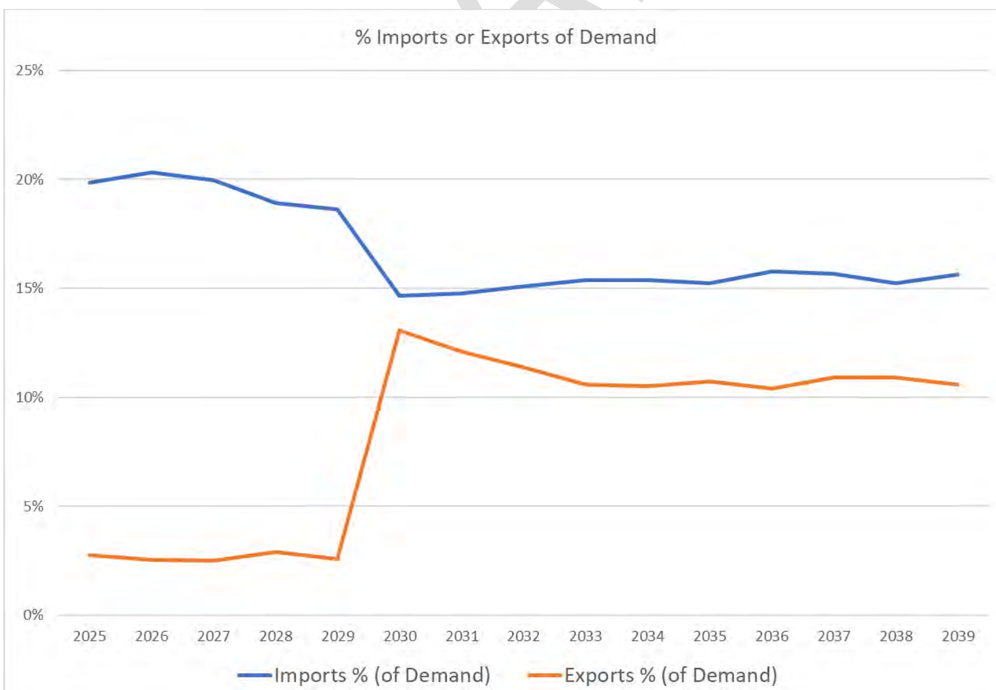


Exhibit 296: Portfolio 7 Market Purchases and Sales as % of Demand



The risk can also be appreciated by looking at the difference between purchase price (high) and sale price (low). The more purchase this portfolio needs, the higher risk it has.

Exhibit 297: Portfolio 7 Market Purchases and Sales Prices $/MWh

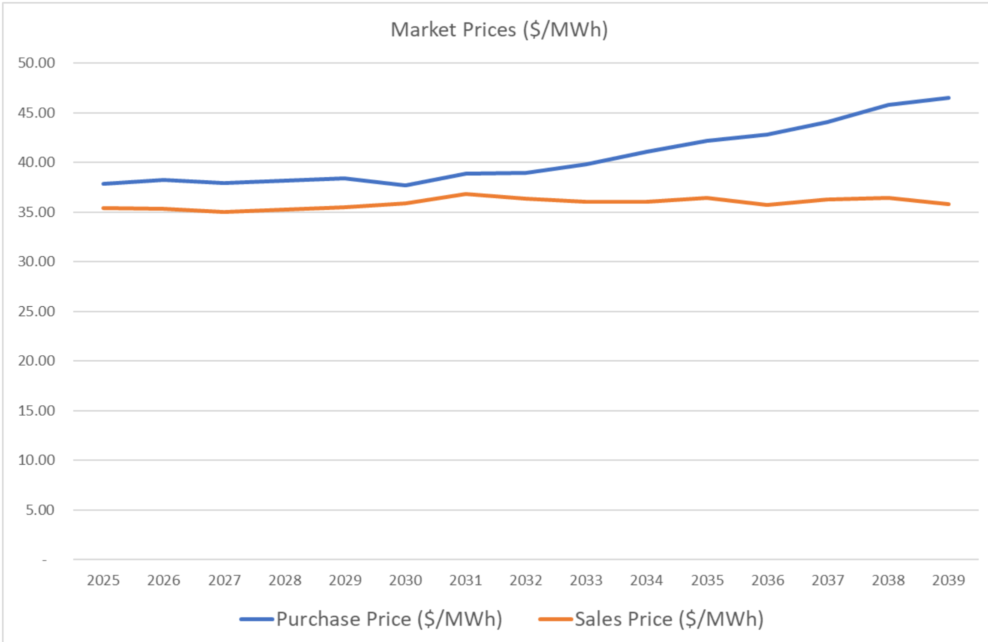
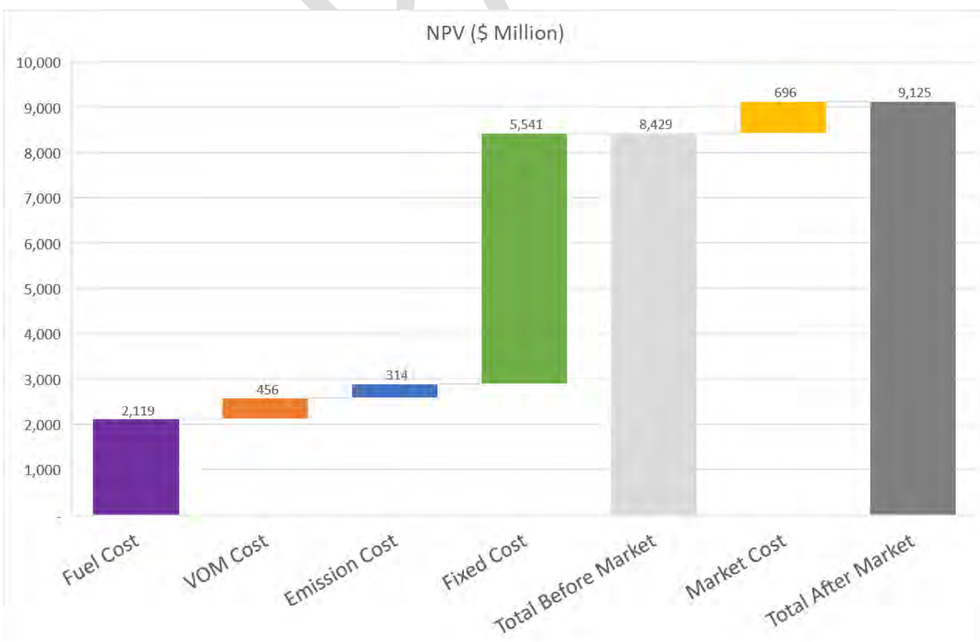


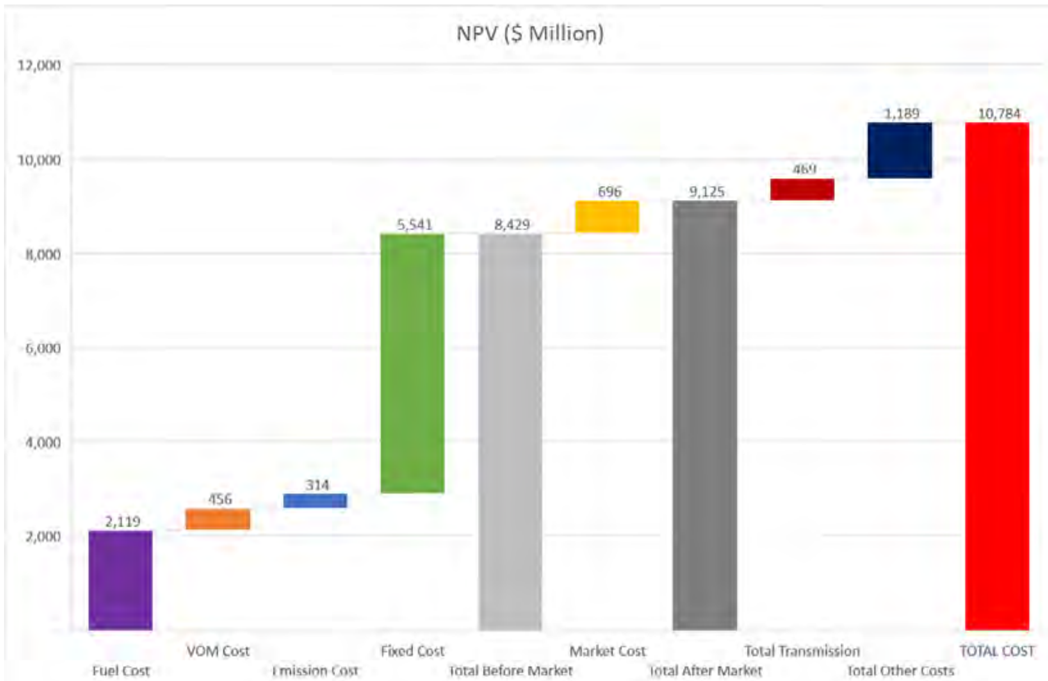
Exhibit below shows the supply side total NPV for 2025-2039, which is about $9.13 billion in 2018 $. Fixed cost is the largest component, followed by fuel and market costs.

Exhibit 298: Portfolio 7 Generation Resource NPV 2018 $



The total NPVRR of this portfolio is approximately $10.78 billion for 2025-2039 in 2018 $.

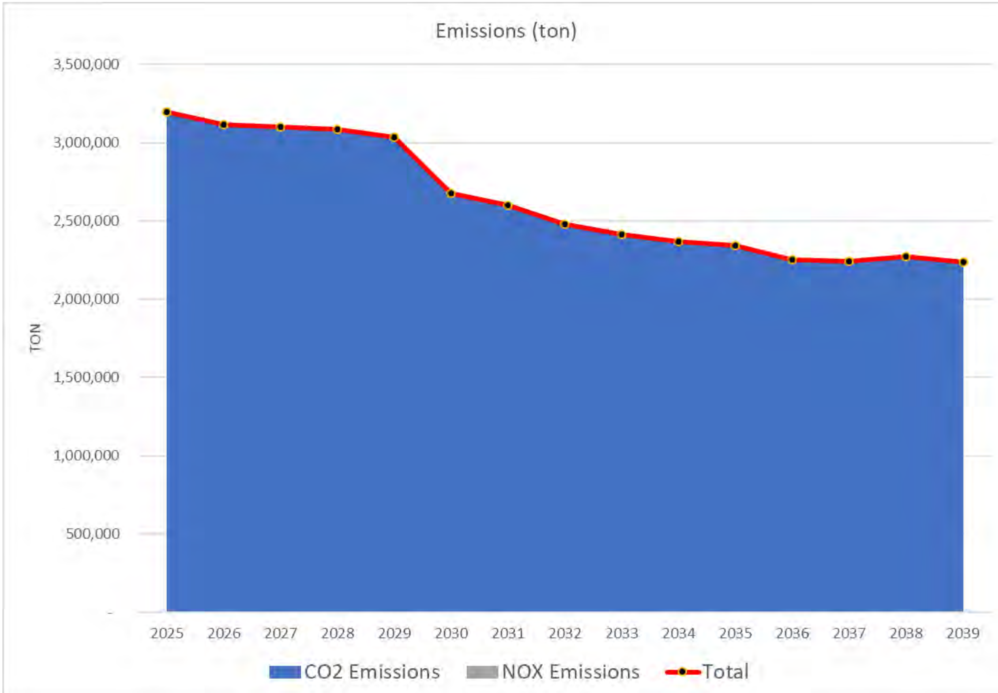
Exhibit 299: Portfolio 7 All NPVRR with Other Components 2018 $



Environmental

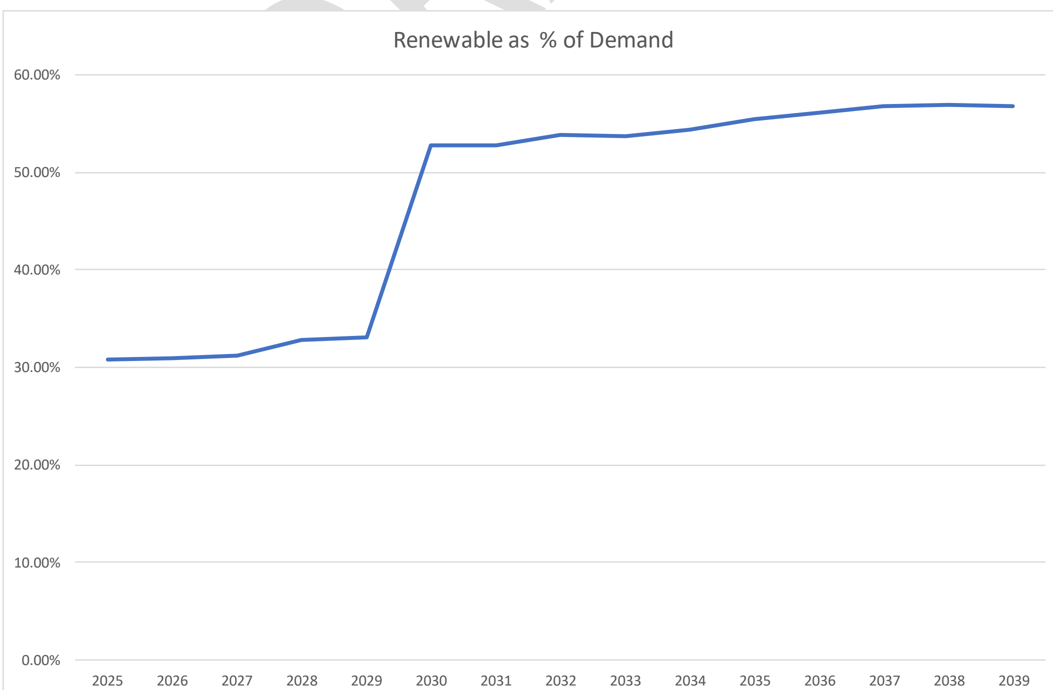
The emission from this portfolio is shown in the graph below. As energy from thermal generation is coming down, the capacity factor of the units decreases which resulted in decreased CO_2 emission over the years.

Exhibit 300: Portfolio 7 Total Emission by Year



And the RPS as of demand in energy of this portfolio starts at about 30% and reaches just over 55% in 2039 as more renewable generations are built.

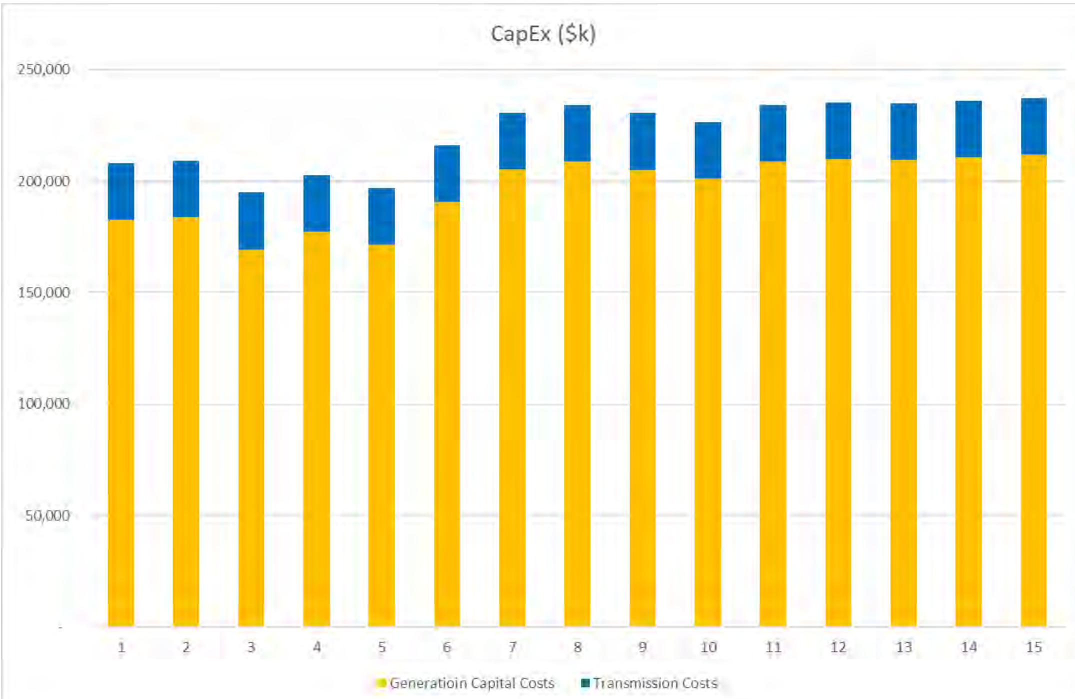
Exhibit 301: Portfolio 7 RPS by Year



Capital Expenditure

Total capital expenditures on generation and transmission are shown in the graph below. We annualized these capital costs from 2025 to 2039 by year and it's about $200 to $240 million per year on average for this portfolio. Most of the capital costs are on the generation side.

Exhibit 302: Portfolio 7 Capital Expenditure



Portfolio 8 (S3S7_2CT)

This is the modified portfolio derived from the S3S7 plan, with an additional CT installed in 2025 due to resource adequacy concern.

Capacity Expansion (Build Out)

The exhibits below show the capacity expansion by year. Local solar and MISO solar were installed as much and quickly as they can. Thermal generation are installed all in first year 2025, 2 CCGTs and 2CTs.

Exhibit 303: Portfolio 8 Installed Capacity by Year

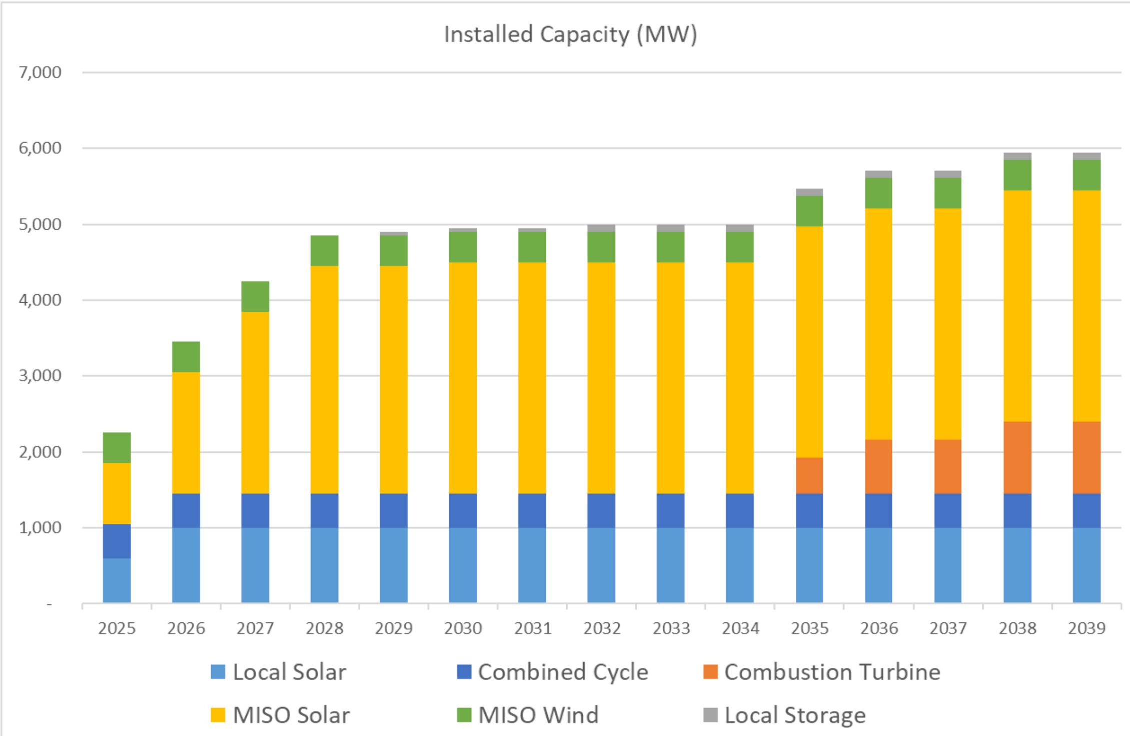
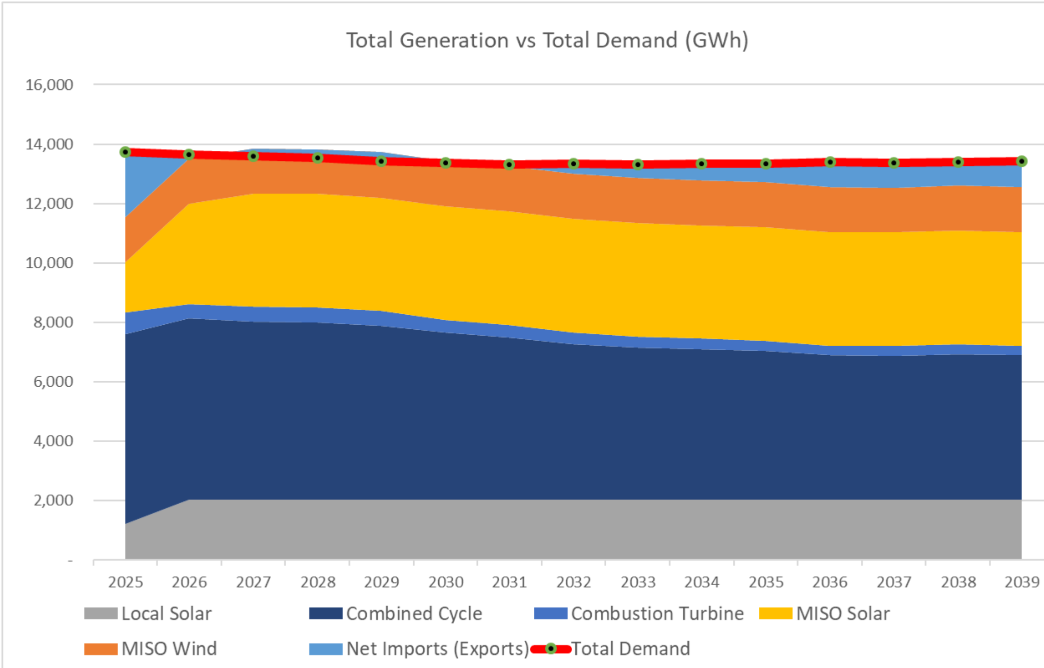


Exhibit 304: Portfolio 8 Installed Capacity by Year (Table)

	Advanced Frame CT	Convl. Frame 7FA CT	1x1 Combined Cycle	Utility Solar	Battery	Miss Solar	Arkansas Solar	Arkansas Wind	MISO_Cap	Demand
2025	0	474	900	600	0	0	800	400	1771	3197
2026	0	0	0	400	0	0	800	0	1413	3182
2027	0	0	0	0	0	0	200	0	1359	3168
2028	0	0	0	0	0	0	0	0	1363	3153
2029	0	0	0	0	0	0	0	0	1368	3139
2030	0	0	0	0	0	0	0	0	1371	3124
2031	0	0	0	0	0	0	0	0	1379	3113
2032	0	0	0	0	0	0	0	0	1394	3108
2033	0	0	0	0	0	0	0	0	1416	3110
2034	0	0	0	0	0	0	0	0	1438	3112
2035	0	0	0	0	0	0	0	0	1460	3114
2036	0	0	0	0	0	0	0	0	1483	3116
2037	0	0	0	0	0	0	0	0	1505	3118
2038	0	0	0	0	0	0	0	0	1528	3121
2039	0	0	0	0	0	0	0	0	1550	3123

Energy generated from various resources stay very flat over the planning years.

Exhibit 305: Portfolio 8 Energy by Resource Type by Year



Portfolio Costs

Exhibit below shows the supply side NPV cost by year as can be seen the cost is about $690 million per year (2018 $) or $51/MWh, where fixed cost is the largest component due to the investments in generations, followed by cost of fuels.

Exhibit 306: Portfolio 8 Cost Components 2018 $

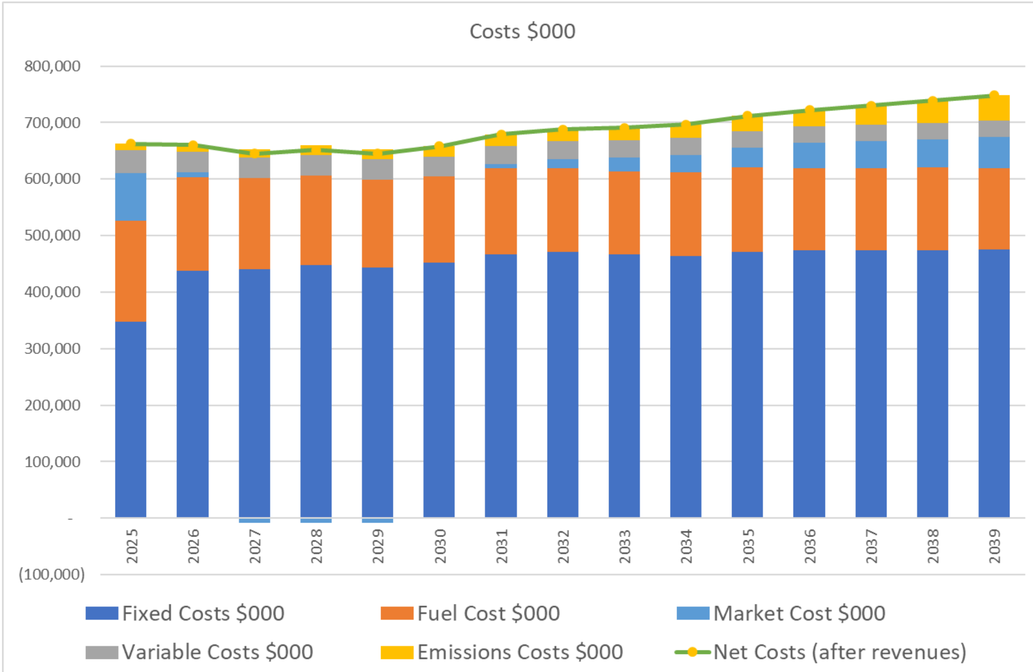
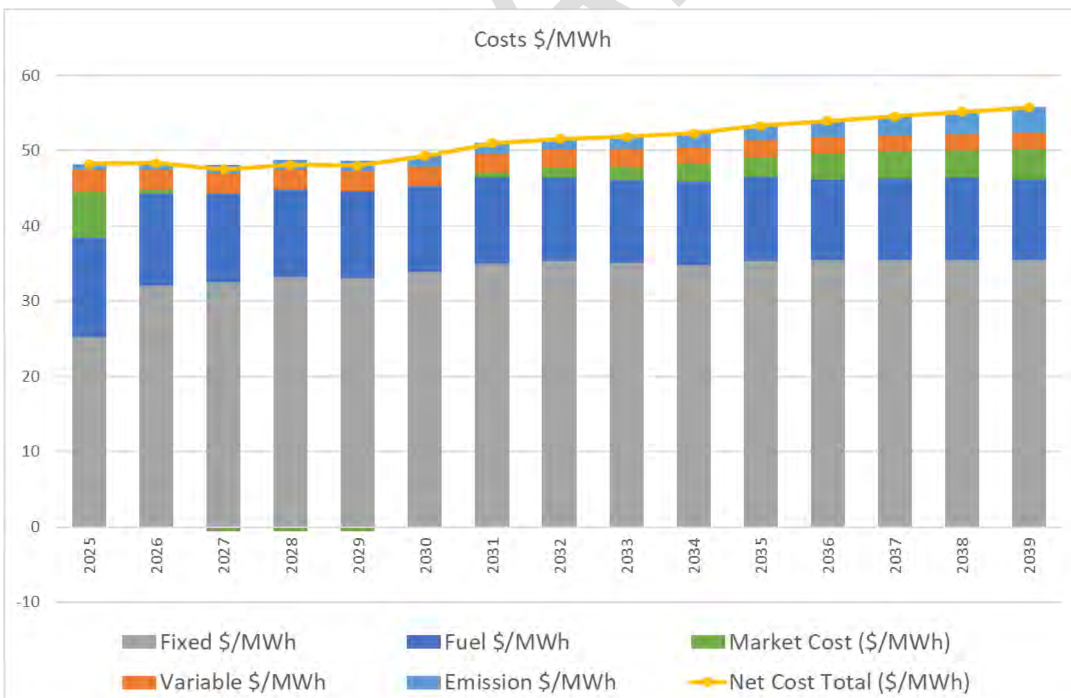
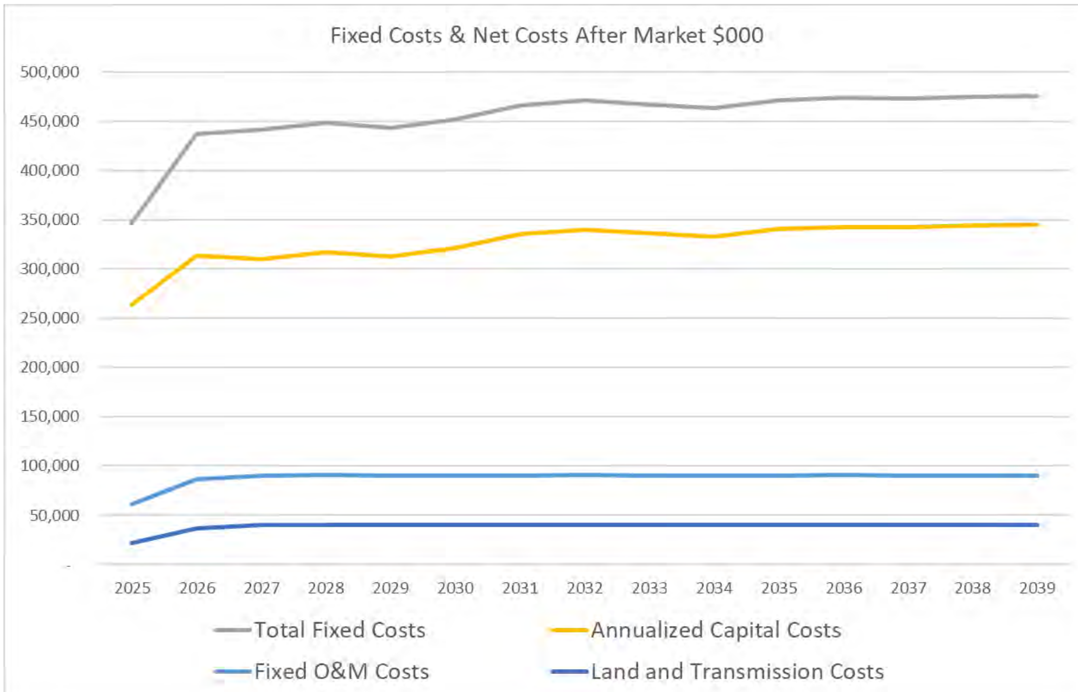


Exhibit 307: Portfolio 8 Cost Components 2018 $/MWh



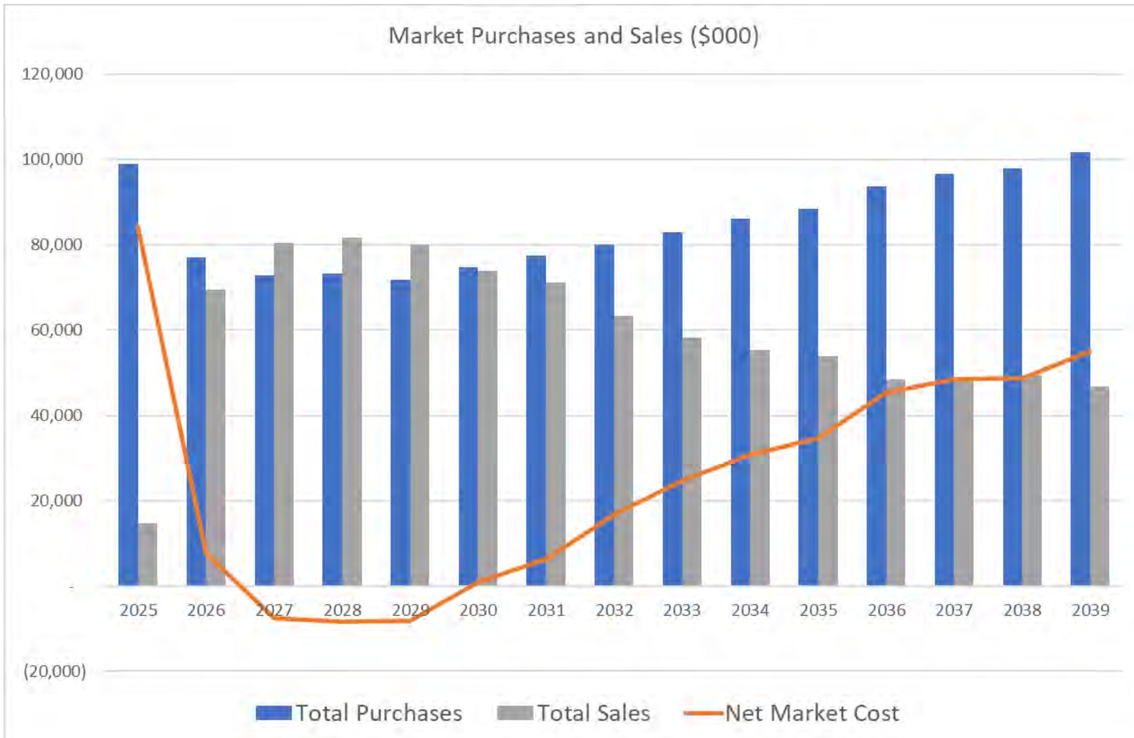
Graph below shows the breakdown of total fixed costs by component, where the majority comes from the base capital costs on generation.

Exhibit 308: Portfolio 8 Fixed Cost Components 2018 $



Market purchases and sales as also important components. The market purchases by MLGW decreased first and then increased over the planning years. The market sales by MLGW increased from the early years due the accelerations on all the renewables, and then as the purchases increase, the sales are decreasing. The combination effect results in a net sales status for MLGW during three years of the 15-year planning horizon, although the net sales are small and MLGW is still a net purchaser for the entire planning horizon.

Exhibit 309: Portfolio 8 Market Purchases and Sales 2018 $



These graphs show the purchases sales amount in energy and as % of demand. They show that the high market risk in the beginning and towards the end of the planning years of this portfolio.

Exhibit 310: Portfolio 8 Market Purchases and Sales in Energy

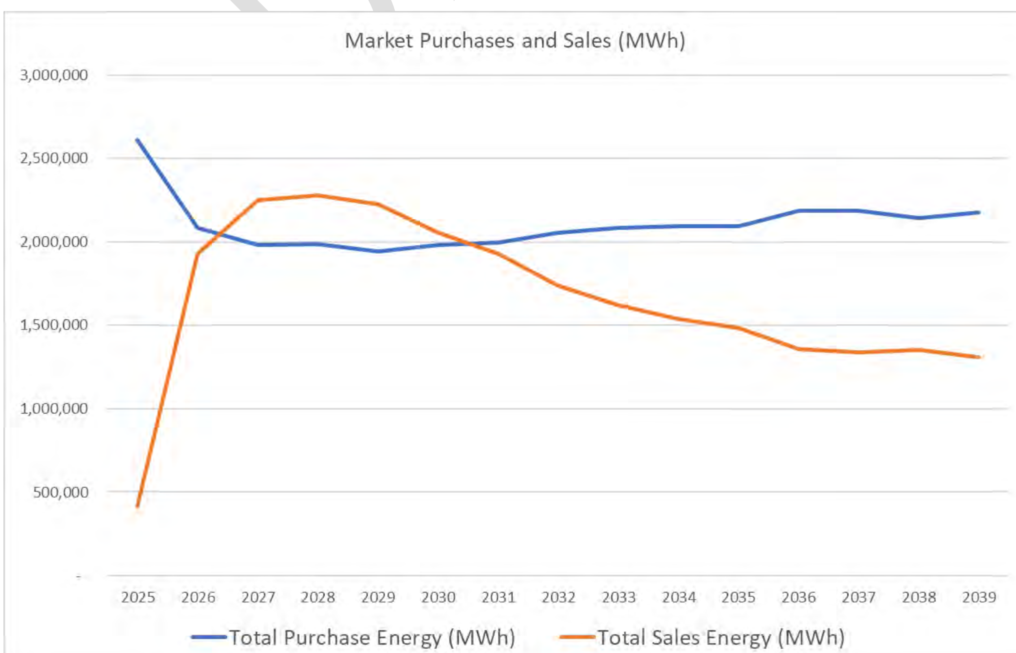
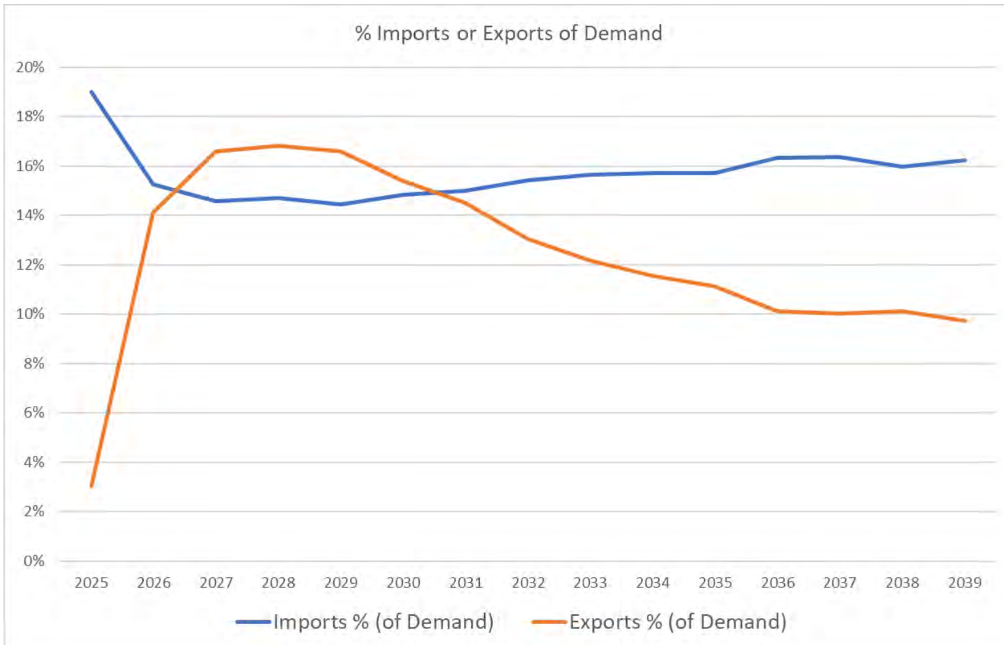


Exhibit 311: Portfolio 8 Market Purchases and Sales as % of Demand



The risk can also be appreciated by looking at the difference between purchase price (high) and sale price (low). The more purchase this portfolio needs, the higher risk it has.

Exhibit 312: Portfolio 8 Market Purchases and Sales Prices $/MWh

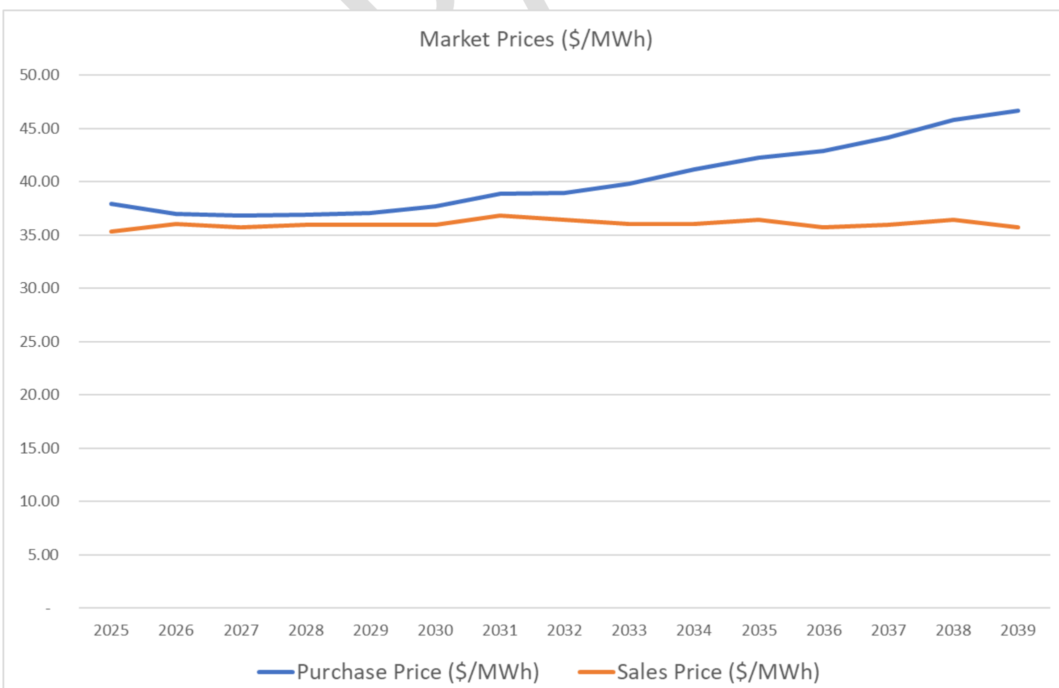
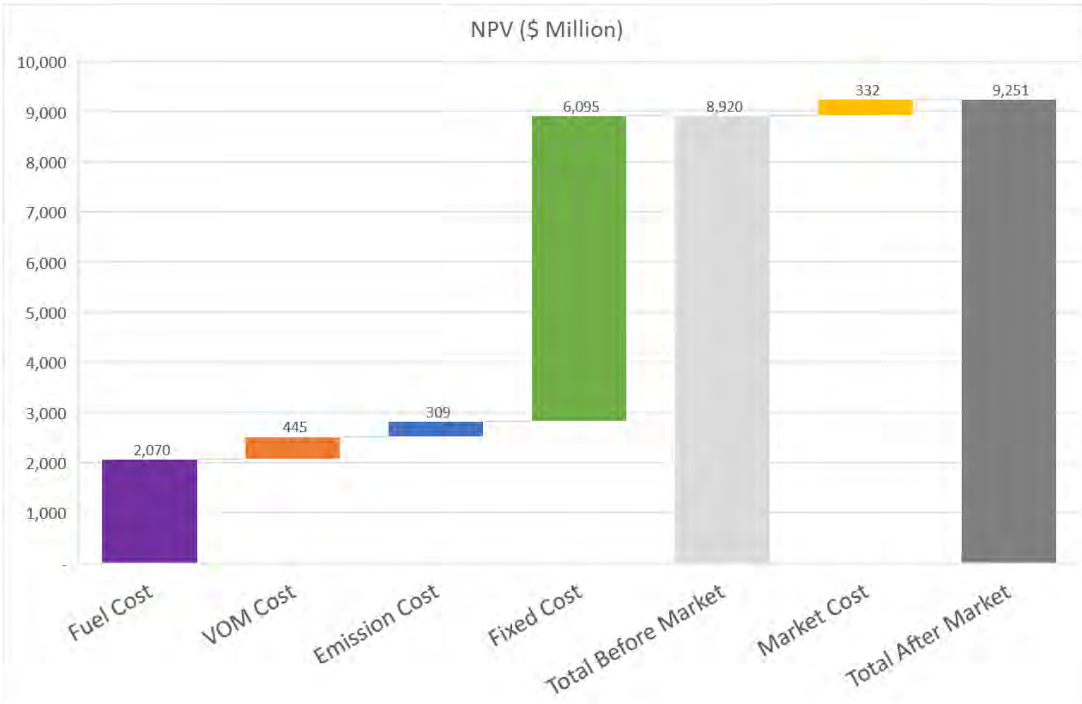


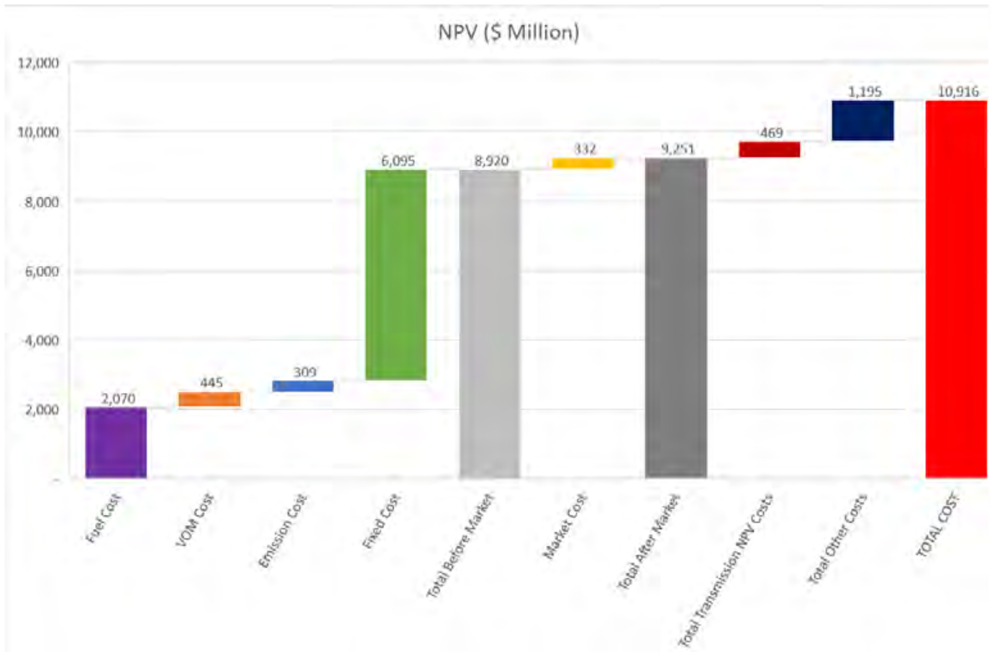
Exhibit below shows the supply side total NPV for 2025-2039, which is about $9.25 billion in 2018 $. Fixed cost is the largest component, followed by fuel costs.

Exhibit 313: Portfolio 8 Generation Resource NPV 2018 $



The total NPVRR of this portfolio is approximately $10.92 billion for 2025-2039 in 2018 $.

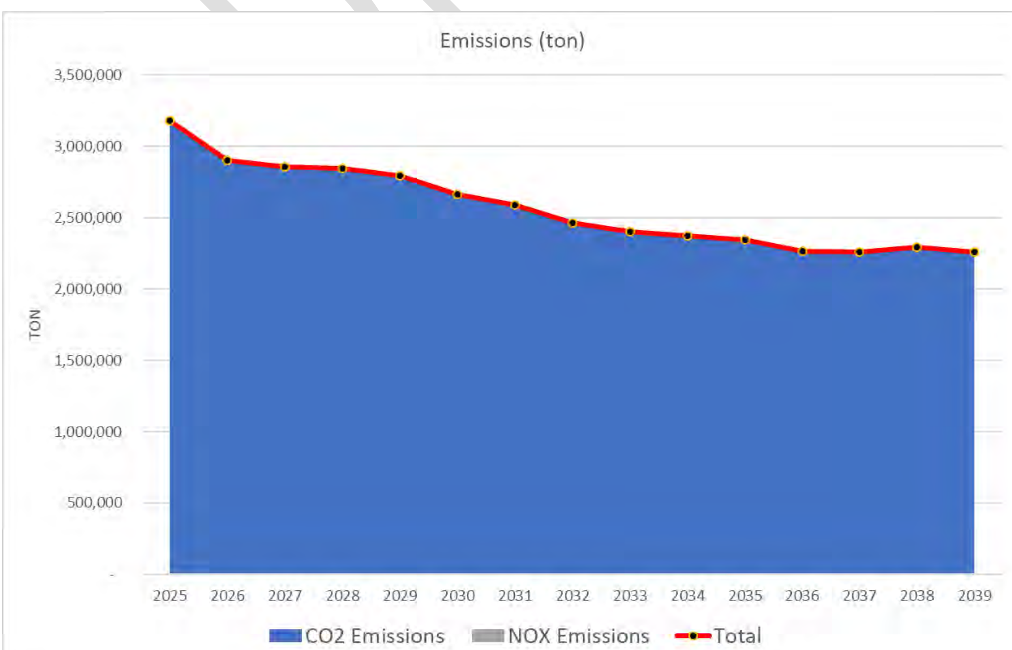
Exhibit 314: Portfolio 8 All NPVRR with Other Components 2018 $



Environmental

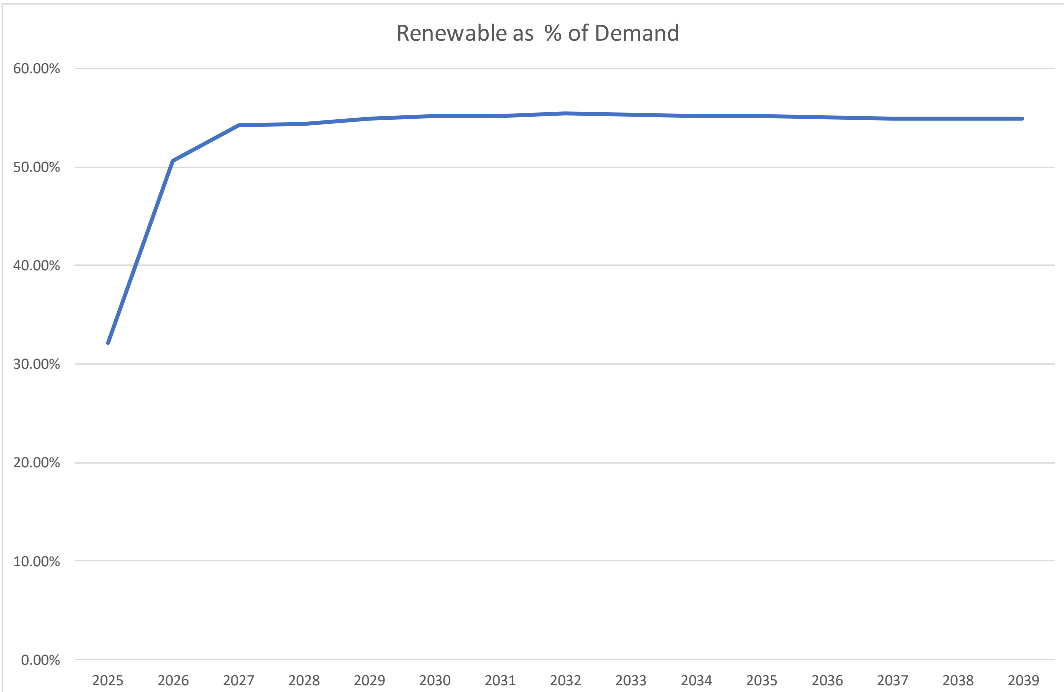
The emission from this portfolio is shown in the graph below. As energy from thermal generation is coming down, the capacity factor of the units decreases which resulted in decreased CO_2 emission over the years.

Exhibit 315: Portfolio 8 Total Emission by Year



And the RPS as of the demand in energy of this portfolio starts at about 32% and reaches quickly to about 55% and stays flat throughout the years to 2039.

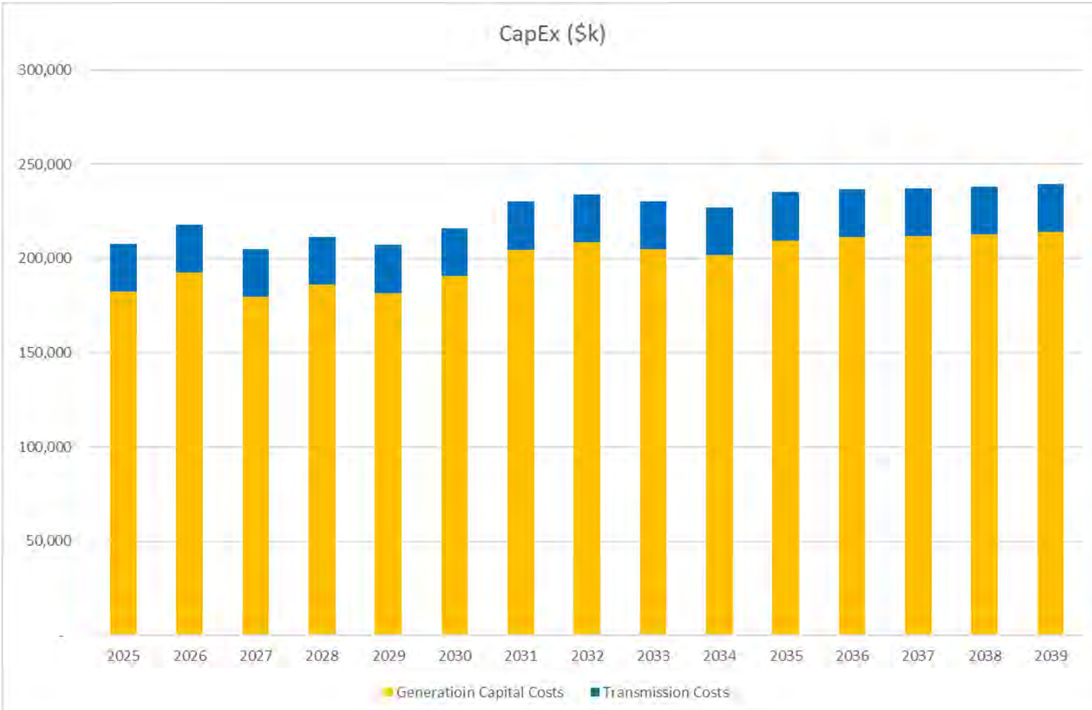
Exhibit 316: Portfolio 8 RPS by Year



Capital Expenditure

Total capital expenditures on generation and transmission are shown in the graph below. We annualized these capital costs from 2025 to 2039 by year and it's about \$200 to \$240 million per year on average for this portfolio. Most of the capital costs are on the generation side.

Exhibit 317: Portfolio 8 Annualized Capital Expenditure by Year



Portfolio 9 (S3S5_YD)

This is the portfolio derived from Portfolio 5 from the expansion plan, with all the CTs which were built in the last few years advanced to first year 2025 to avoid high transmission costs and resource adequacy concern.

Capacity Expansion (Build Out)

The exhibits below show the capacity expansion by year, where the only difference as compared to Portfolio 5 is all CTs were installed in first year 2025.

Exhibit 318: Portfolio 9 Installed Capacity by Year

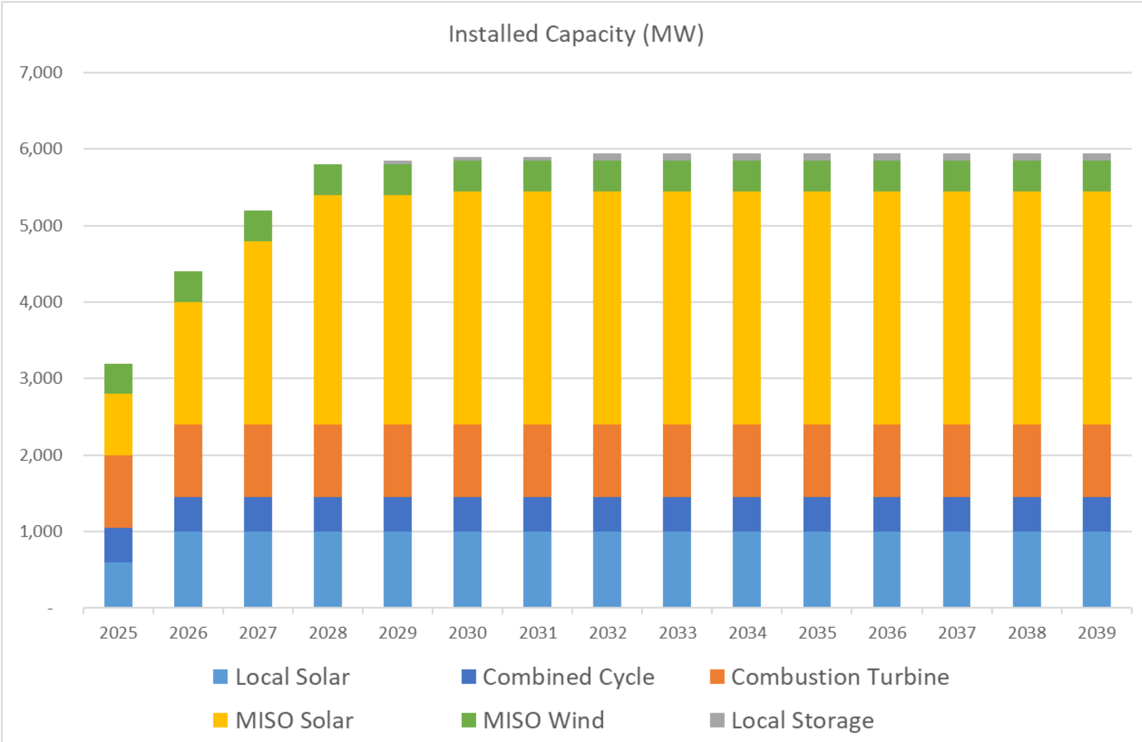
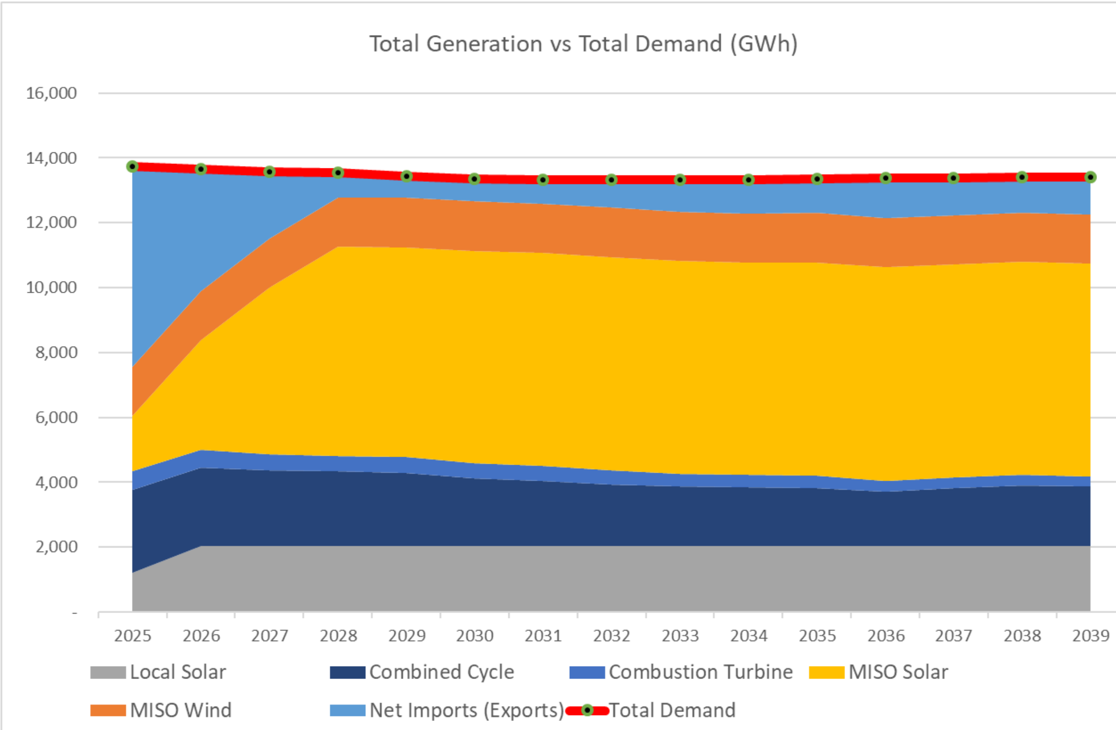


Exhibit 319: Portfolio 9 Installed Capacity by Year (Table)

	Advanced Frame CT	Convl. Frame 7FA CT	1x1 Combined Cycle	Utility Solar	Battery	Miss Solar	Arkansas Solar	Arkansas Wind	MISO_Cap	Demand
2025	0	948	450	600	0	0	800	400	1754	3197
2026	0	0	0	400	0	0	800	0	1396	3182
2027	0	0	0	0	0	0	800	0	1171	3168
2028	0	0	0	0	0	0	600	0	1012	3153
2029	0	0	0	0	50	0	0	0	977	3139
2030	0	0	0	0	0	0	50	0	976	3124
2031	0	0	0	0	0	0	0	0	993	3113
2032	0	0	0	0	50	0	0	0	968	3108
2033	0	0	0	0	0	0	0	0	999	3110
2034	0	0	0	0	0	0	0	0	1030	3112
2035	0	0	0	0	0	0	0	0	1061	3114
2036	0	0	0	0	0	0	0	0	1092	3116
2037	0	0	0	0	0	0	0	0	1123	3118
2038	0	0	0	0	0	0	0	0	1155	3121
2039	0	0	0	0	0	0	0	0	1186	3123

Energy generated from thermal generation decreases over the years while energy coming from renewables increases.

Exhibit 320: Portfolio 9 Energy by Resource Type by Year



Portfolio Costs

Exhibit below shows the supply side NPV cost by year, as can be seen the cost is about $670 million per year (2018 $) or $50/MWh, where fixed cost is the largest components due to the investments in generation, followed by cost of fuels and market purchases.

Exhibit 321: Portfolio 9 Cost Components 2018 $

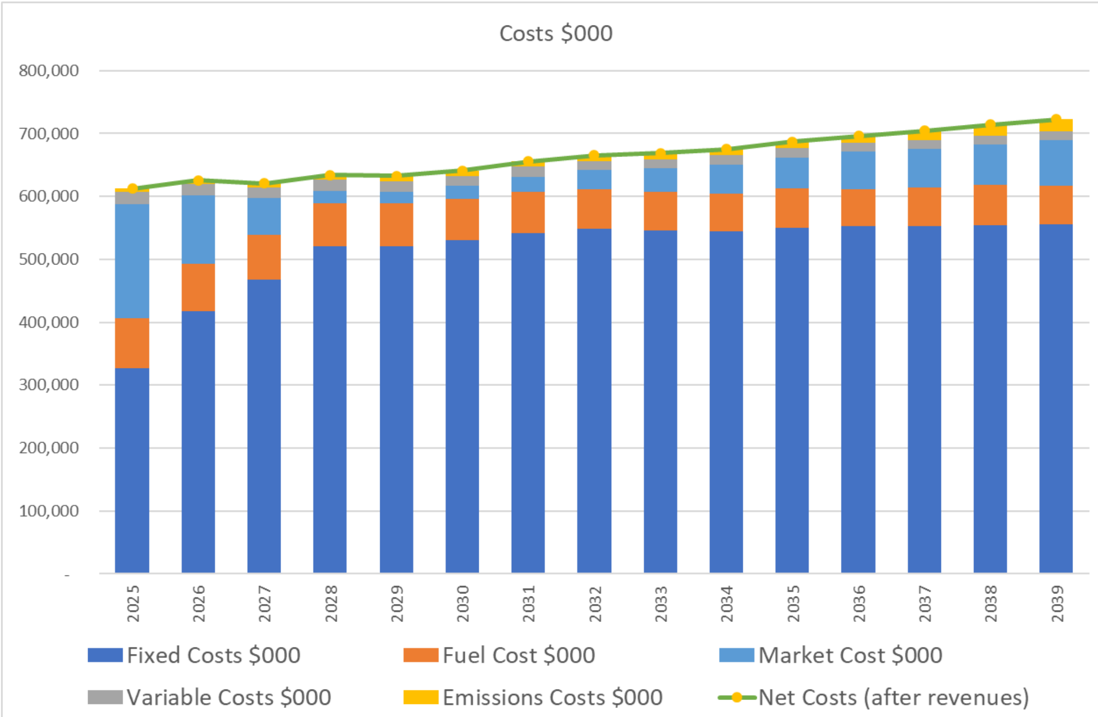
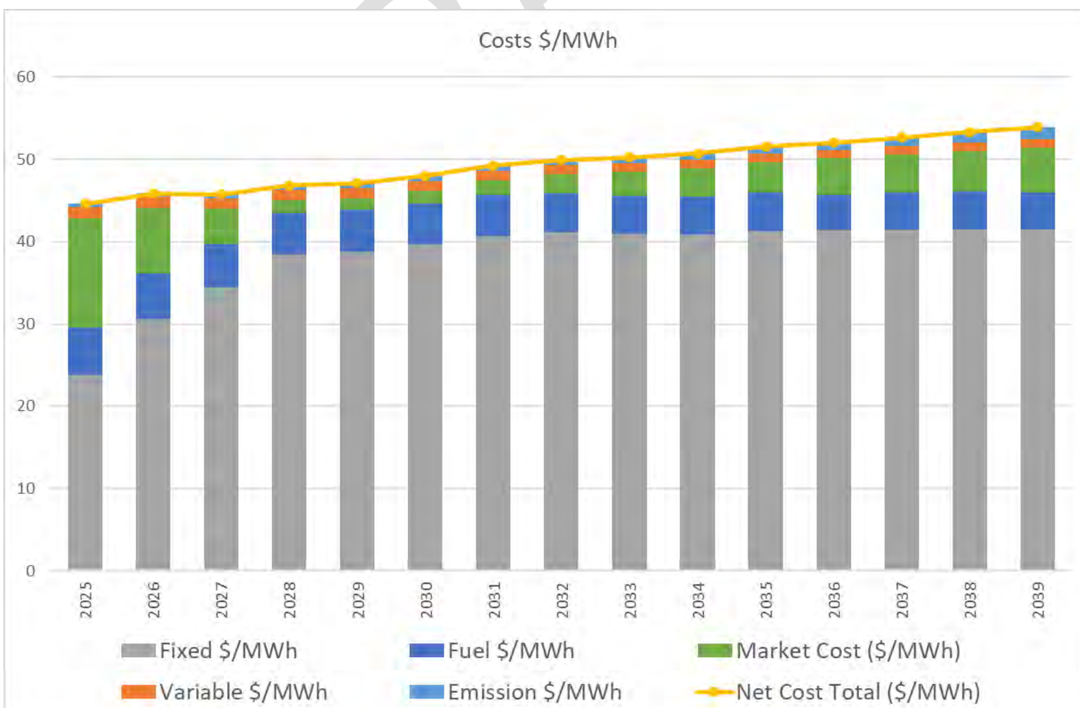
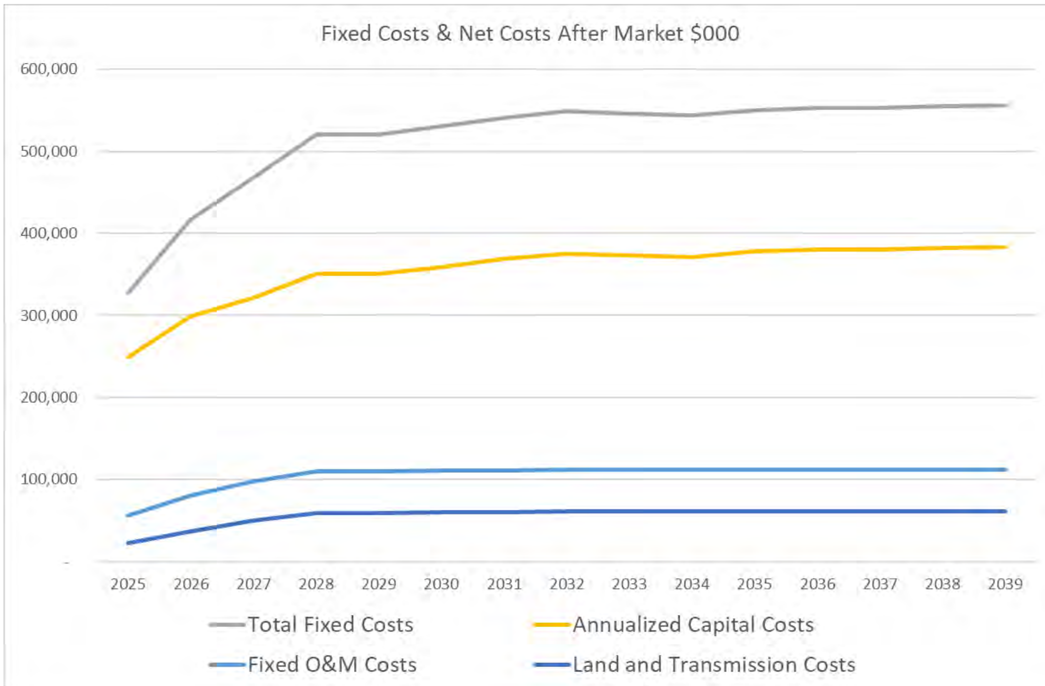


Exhibit 322: Portfolio 9 Cost Components 2018 $/MWh



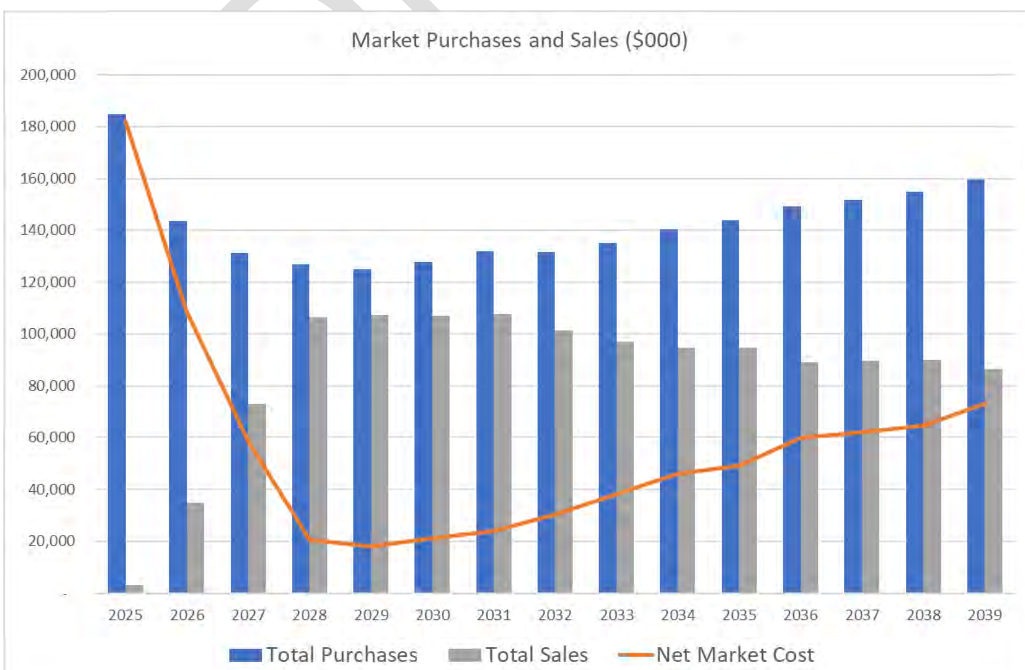
Graph below shows the breakdown of total fixed costs by component, where the majority comes from the base capital costs on generation.

Exhibit 323: Portfolio 9 Fixed Cost Components 2018 $



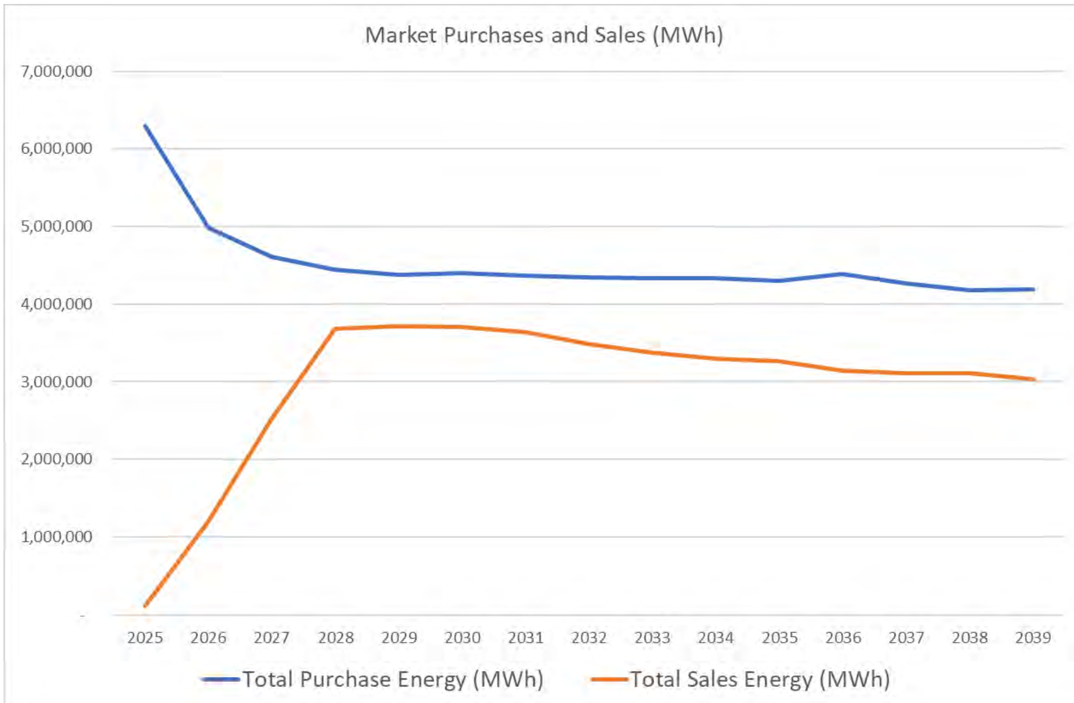
Market purchases and sales are also important components. The market purchases by MLGW system are projected to be decreasing while the sales are increasing although the sales are maintained at a low level.

Exhibit 324: Portfolio 9 Market Purchases and Sales 2018 $



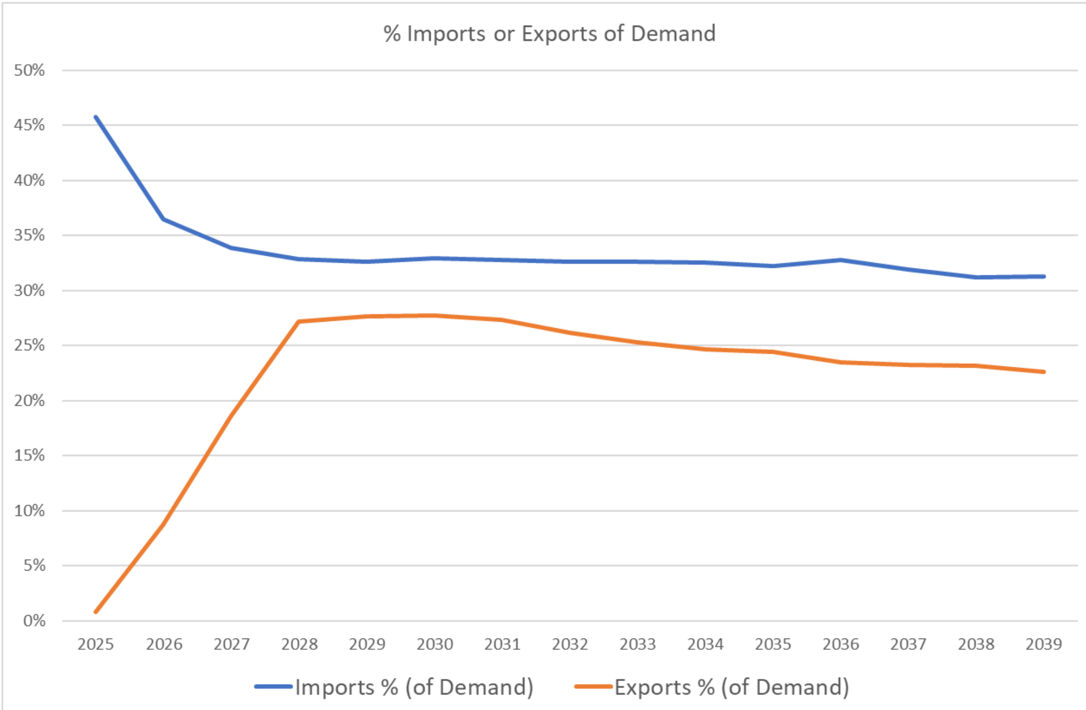
These graphs show the purchases sales amount in energy and as % of demand. It shows the high market risk in the beginning of the planning years of this portfolio due to the amount of purchases required.

Exhibit 325: Portfolio 9 Market Purchases and Sales in Energy



Restricted

Exhibit 326: Portfolio 9 Market Purchases and Sales as % of Demand



The market risk associated with this portfolio is more on the availability of resources in the market than the market price itself, because this is a portfolio that requires relatively higher percentage of purchase from the market due to less local generation. The more purchase this portfolio needs, the higher risk it has.

Exhibit 327: Portfolio 9 Market Purchases and Sales Prices $/MWh

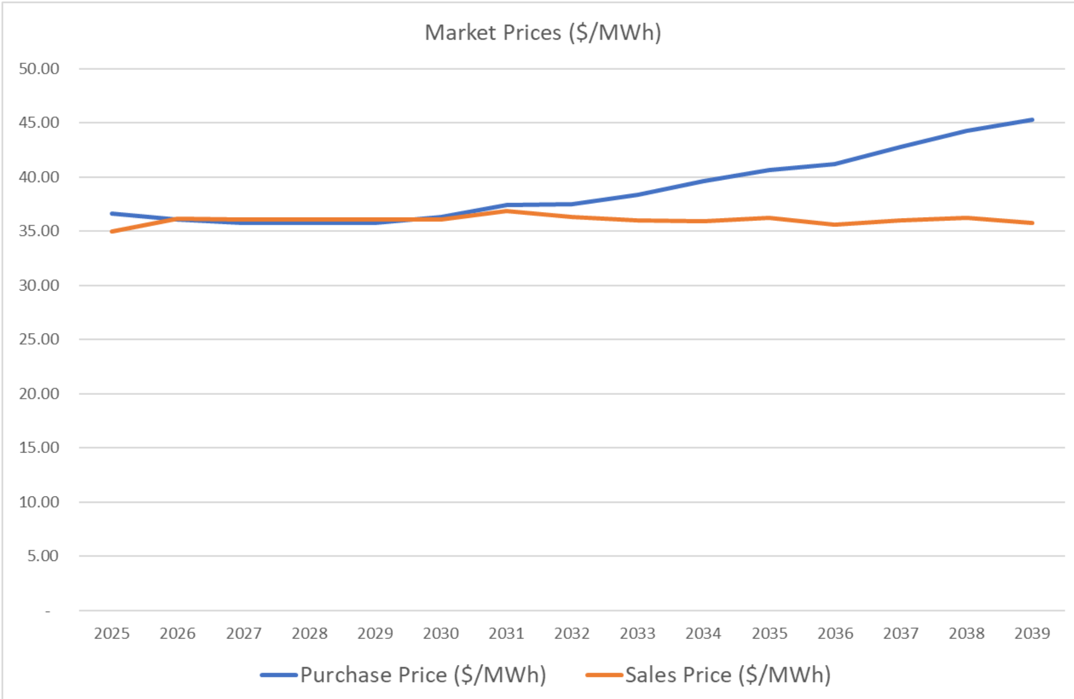
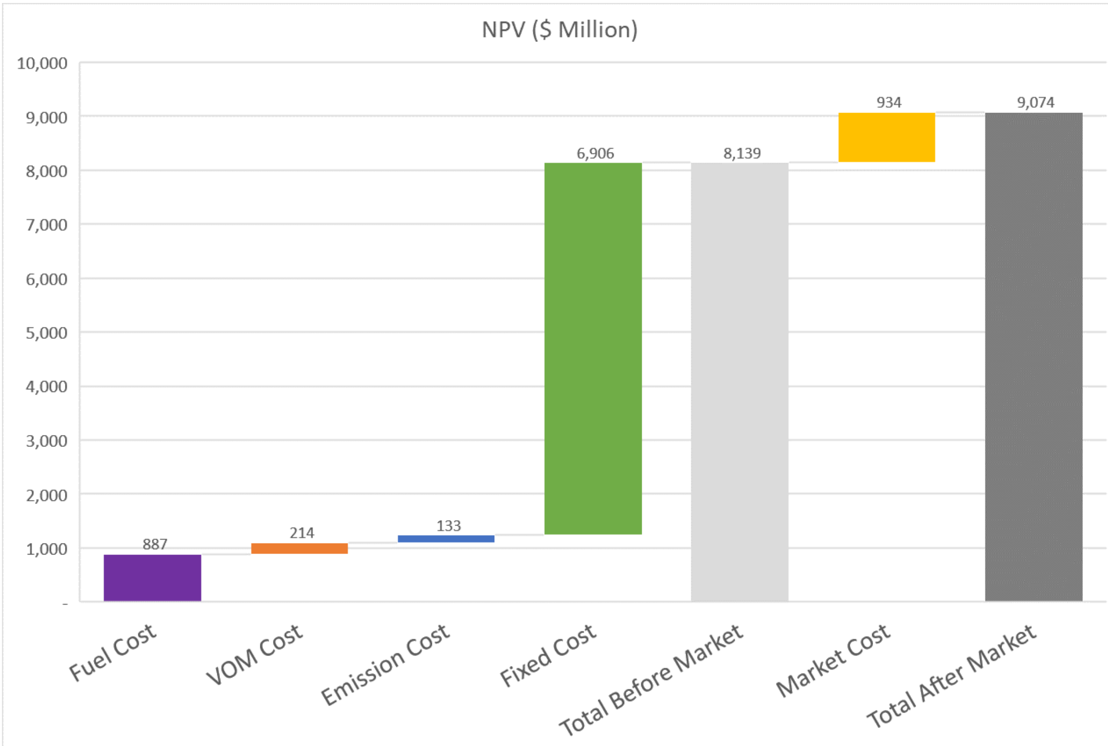


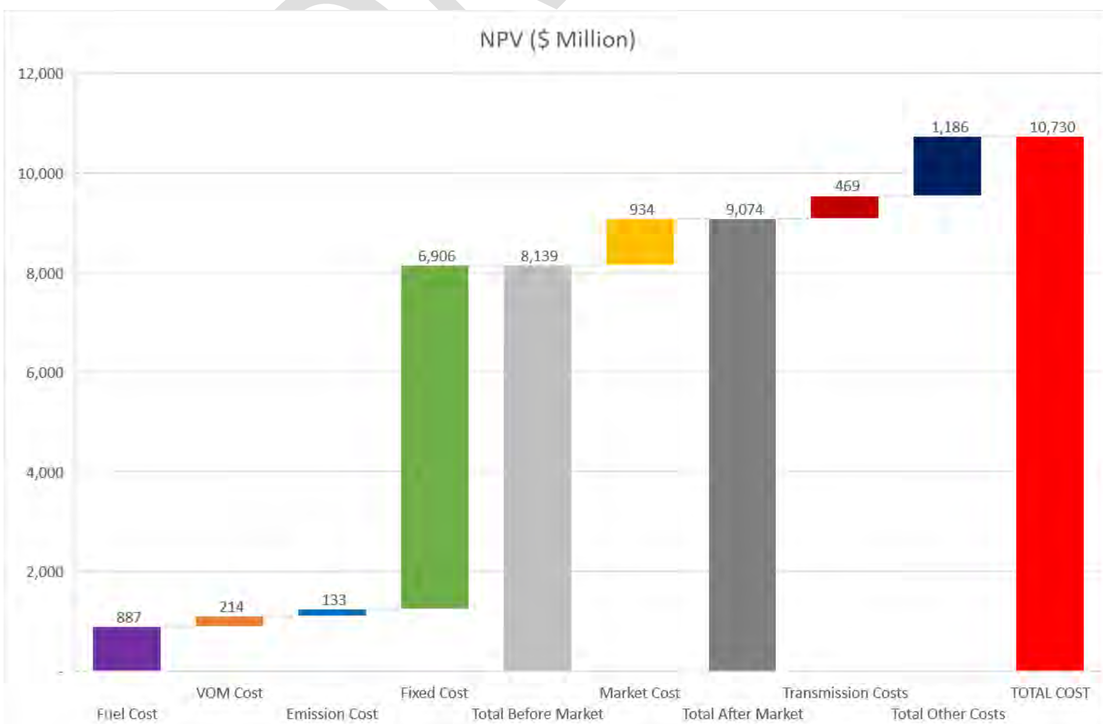
Exhibit below shows the supply side total NPV for 2025-2039, which is about $9.07 billion in 2018 $. Fixed cost is the largest component, followed by fuel and market costs.

Exhibit 328: Portfolio 9 Generation Resource NPV 2018 $



The total NPVRR of this portfolio is approximately $10.73 billion for 2025-2039 in 2018 $.

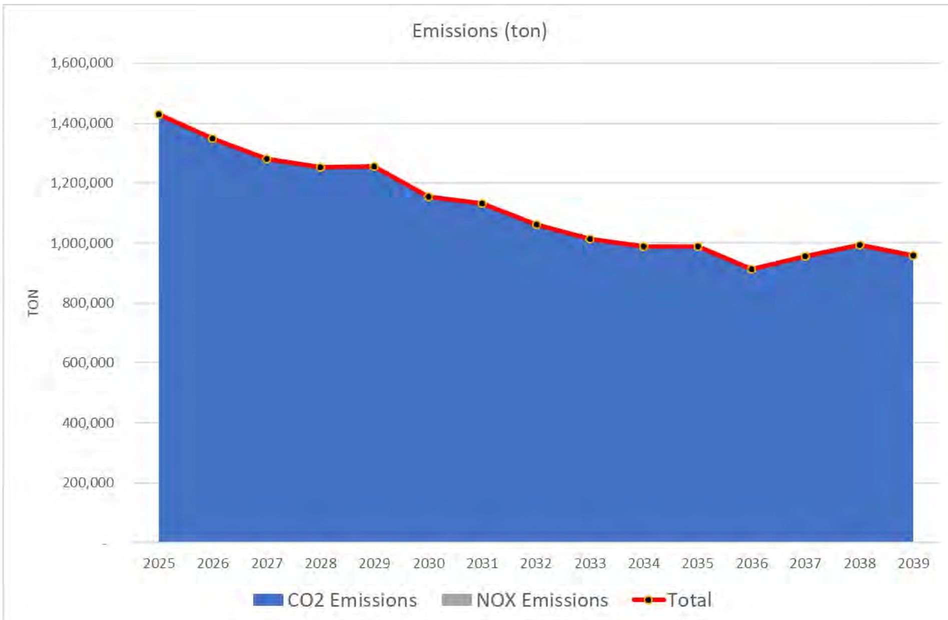
Exhibit 329: Portfolio 9 All NPVRR with Other Components 2018 $



Environmental

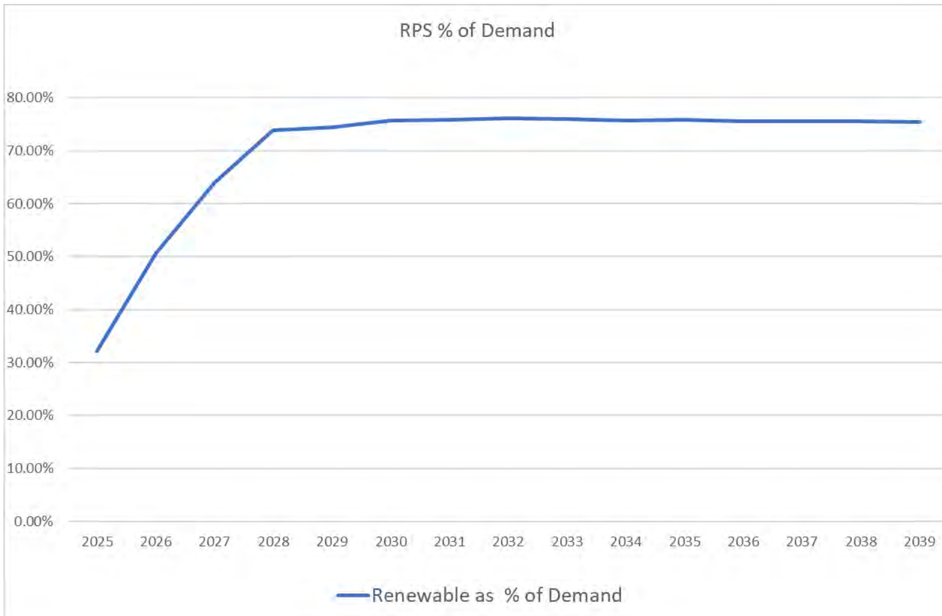
The emission from this portfolio is shown in the graph below. The emission is low compared with other portfolios due to high renewable and low thermal nature in this portfolio.

Exhibit 330: Portfolio 9 Total Emission by Year



This is the high renewable case and the RPS as of demand in energy of this portfolio starts at about 32% and reaches very quickly to 75% in 2039 as lots of renewable generation are built in this portfolio.

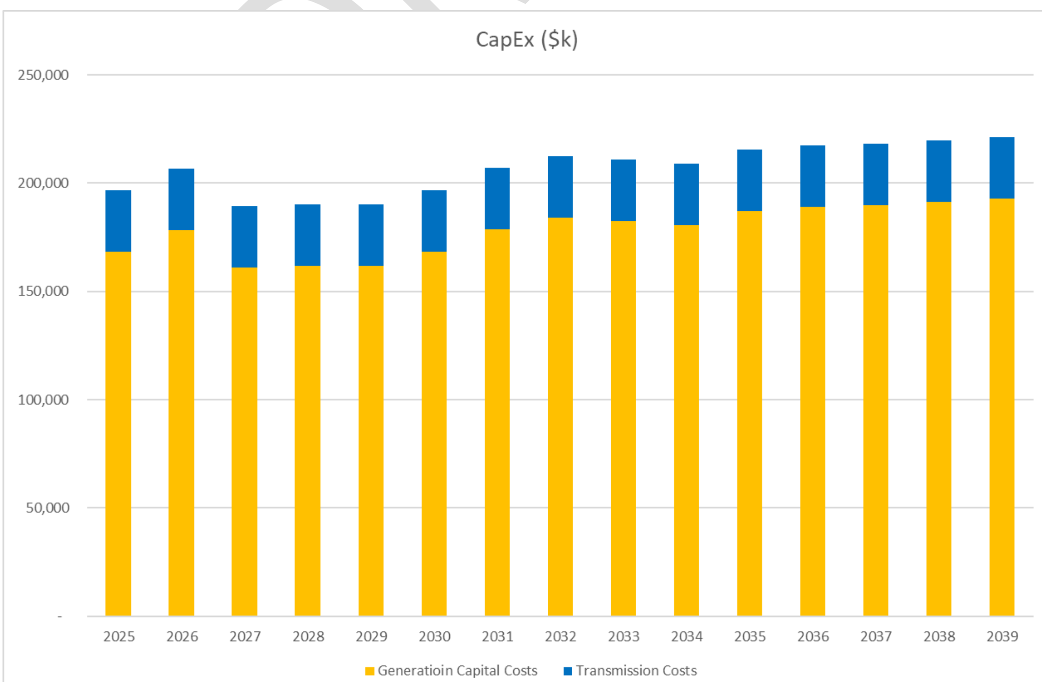
Exhibit 331: Portfolio 9 RPS by Year



Capital Expenditure

Total capital expenditures on generation and transmission are shown in the graph below. We annualized these capital costs from 2025 to 2039 by year and it's about $210 million per year on average for this portfolio. Most of the capital costs are on the generation side.

Exhibit 332: Portfolio 9 Annualized Capital Expenditure by Year



Portfolio 10 (S3S10)

This is the portfolio derived from Portfolio All MISO under Strategy 4. Based on that portfolio, we moved the CCGT and 1000 MW solar to MLGW footprint with the CCGT built in first year 2025 and local solar installed 600 MW in 2025 and 400 MW in 2028, respectively. The balance of the solar stays in MISO due to land constraint. We consider this portfolio under Strategy 3 due to the relocation of resources into MLGW as compared the Portfolio All MISO. This Portfolio is expected to produce lower NPV because as we know local resources are cheaper than remote resources.

Capacity Expansion (Build Out)

The exhibits below show the capacity expansion by year, where there is no difference in terms of total amount of each resource type, the only difference as compared to Portfolio All MISO is we moved the CCGT and 1000 MW solar to MLGW footprint, and MISO solar was adjusted accordingly.

Exhibit 333: Portfolio 10 Installed Capacity by Year

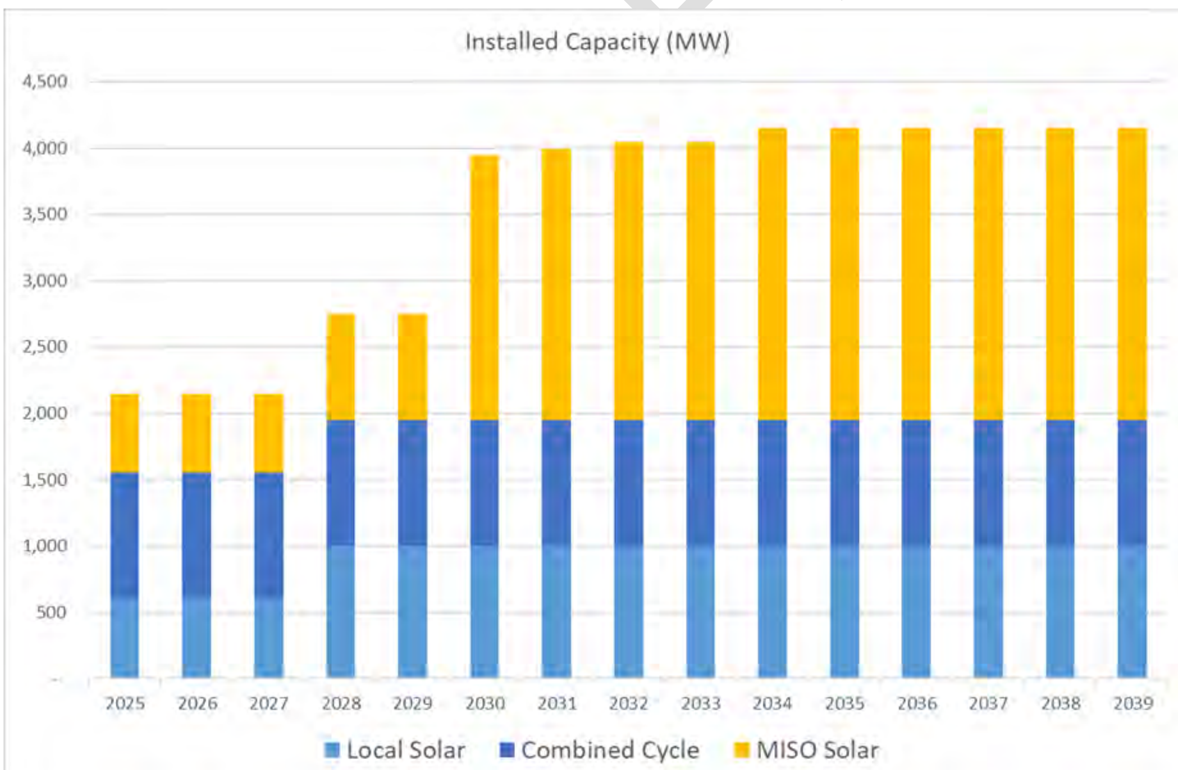
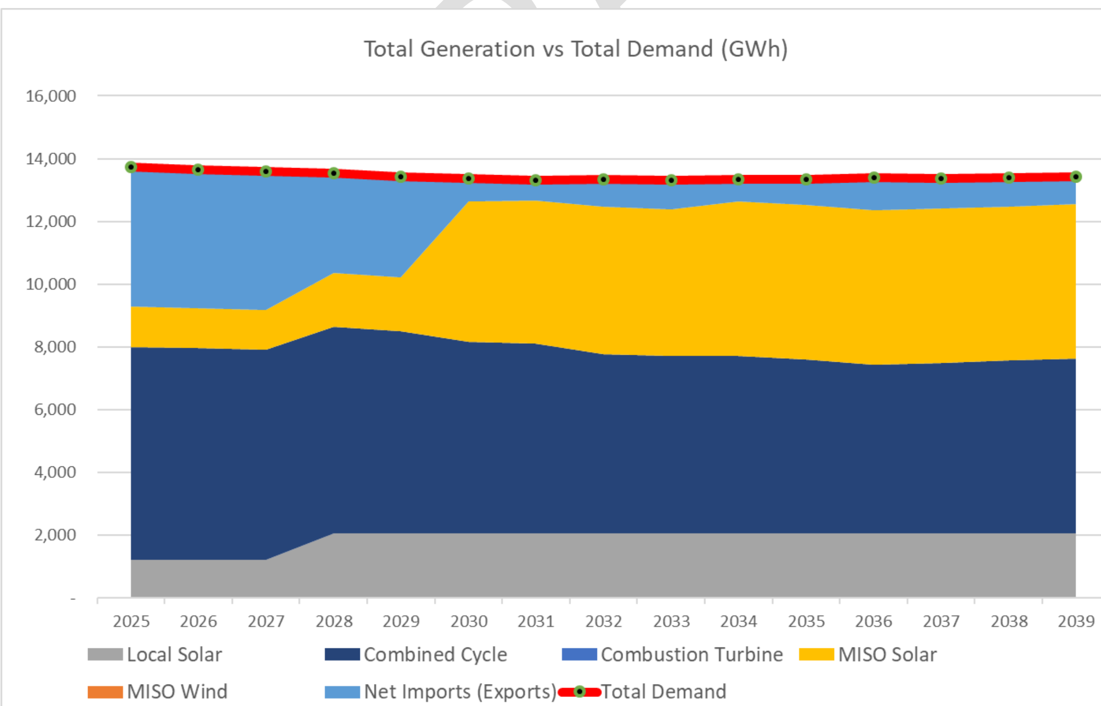


Exhibit 334: Portfolio 10 Installed Capacity by Year (Table)

	Advanced Frame CT	Convl. Frame 7FA CT	2x1 Combined Cycle	Utility Solar	Battery	Miss Solar	Arkansas Solar	Arkansas Wind	MISO_Cap	Demand
2025	0	0	950	600	0	0	600	0	2269	3197
2026	0	0	0	0	0	0	0	0	2262	3182
2027	0	0	0	0	0	0	0	0	2255	3168
2028	0	0	0	400	0	0	200	0	2080	3153
2029	0	0	0	0	0	0	0	0	2078	3139
2030	0	0	0	0	0	0	1200	0	1757	3124
2031	0	0	0	0	0	0	50	0	1754	3113
2032	0	0	0	0	0	0	50	0	1757	3108
2033	0	0	0	0	0	0	0	0	1782	3110
2034	0	0	0	0	0	0	100	0	1783	3112
2035	0	0	0	0	0	0	0	0	1808	3114
2036	0	0	0	0	0	0	0	0	1833	3116
2037	0	0	0	0	0	0	0	0	1858	3118
2038	0	0	0	0	0	0	0	0	1883	3121
2039	0	0	0	0	0	0	0	0	1909	3123

Energy generated from thermal generation decreases slightly over the years while energy coming from renewables increases.

Exhibit 335: Portfolio 10 Energy by Resource Type by Year



Portfolio Costs

Exhibit below shows the supply side NPV cost by year, as can be seen the cost is about $620 million per year (2018 $) or $47/MWh, where fixed cost is the largest components due to the investments in generation, followed by cost of fuels and market purchases.

Exhibit 336: Portfolio 10 Cost Components 2018 $

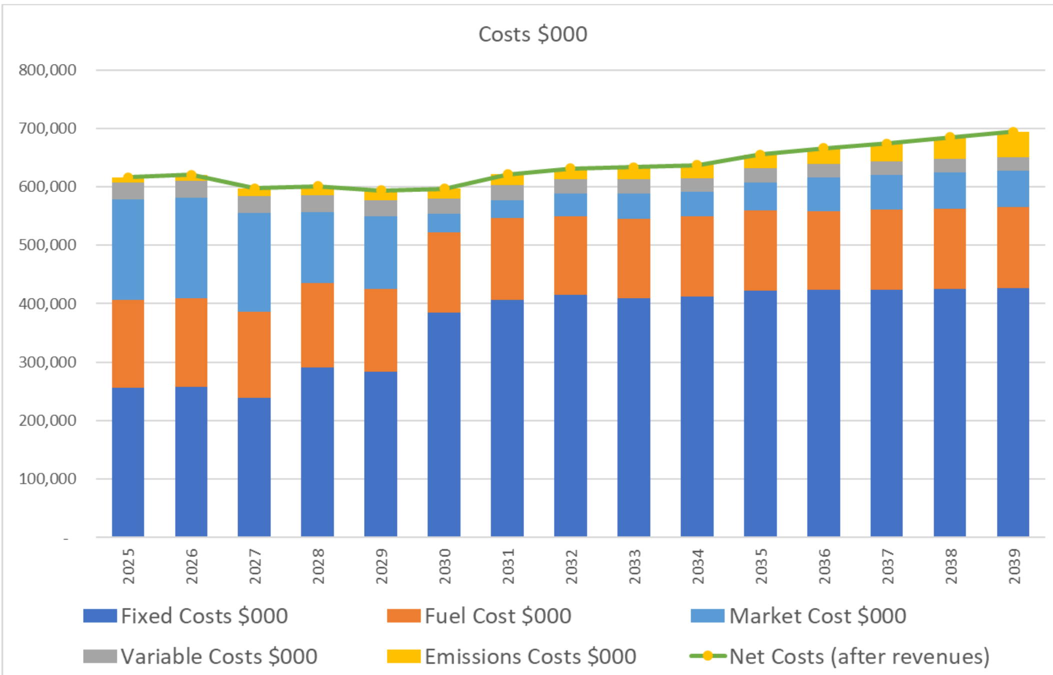
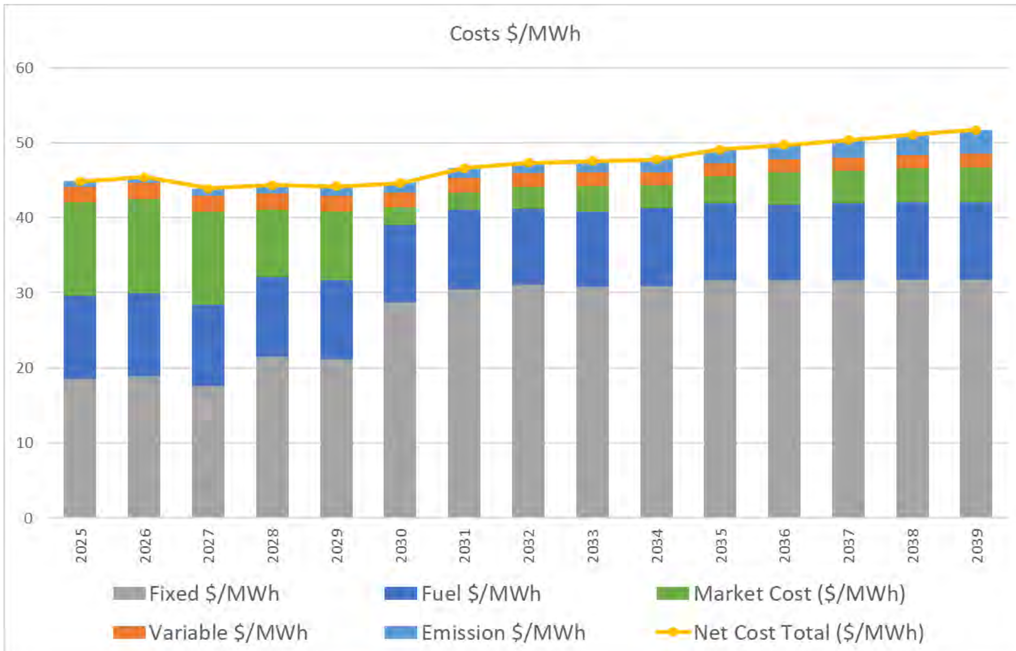
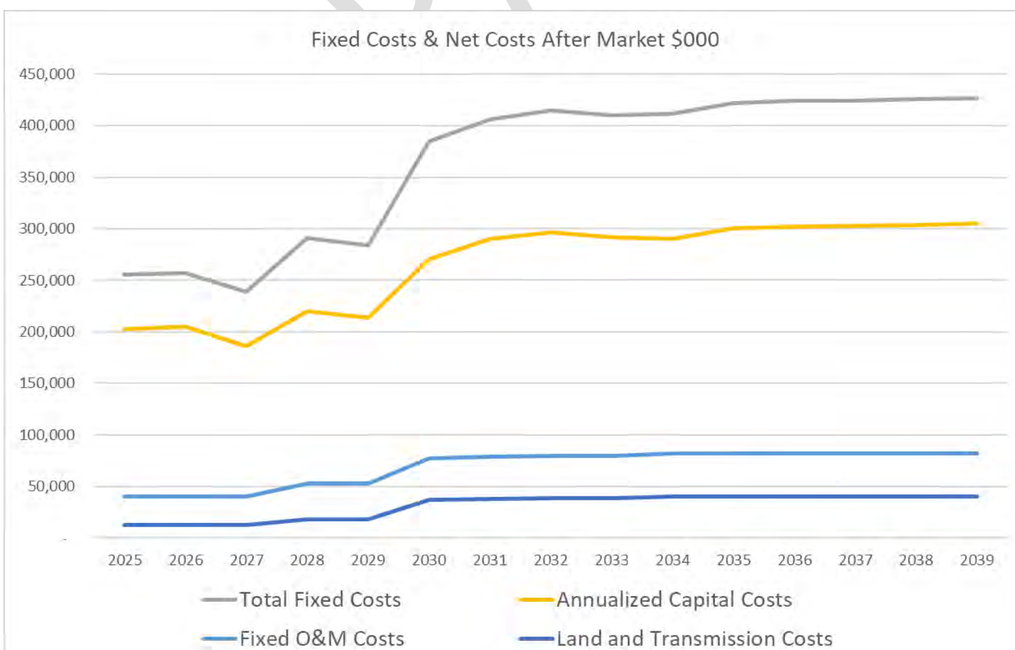


Exhibit 337: Portfolio 10 Cost Components 2018 $/MWh



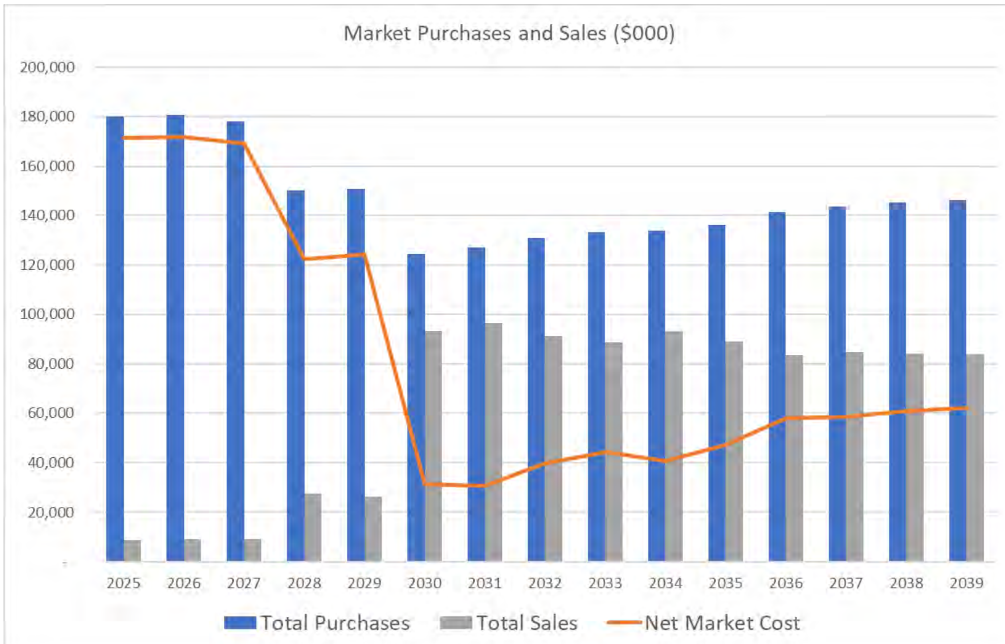
Graph below shows the breakdown of total fixed costs by component, where the majority comes from the base capital costs on generation.

Exhibit 338: Portfolio 10 Fixed Cost Components 2018 $



Market purchases and sales are also important components. The market purchases by MLGW system are projected to be decreasing then flat while the sales are increasing especially after 2030 although the sales are maintained at a low level.

Exhibit 339: Portfolio 10 Market Purchases and Sales 2018 $



These graphs show the purchases sales amount in energy and as % of demand. It shows the high market risk in the beginning of the planning years of this portfolio.

Exhibit 340: Portfolio 10 Market Purchases and Sales in Energy

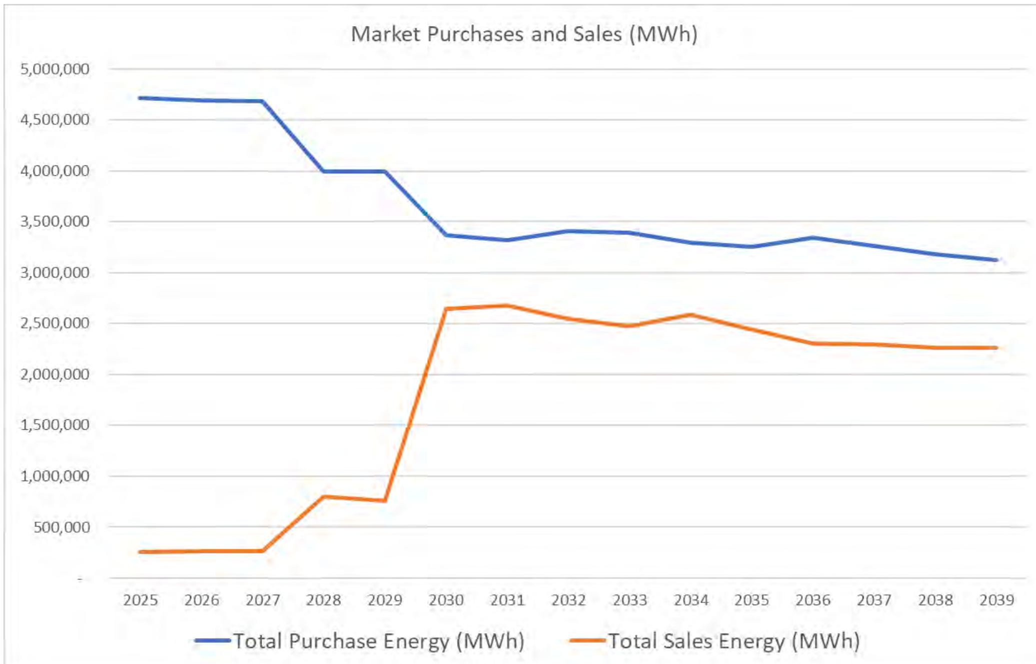
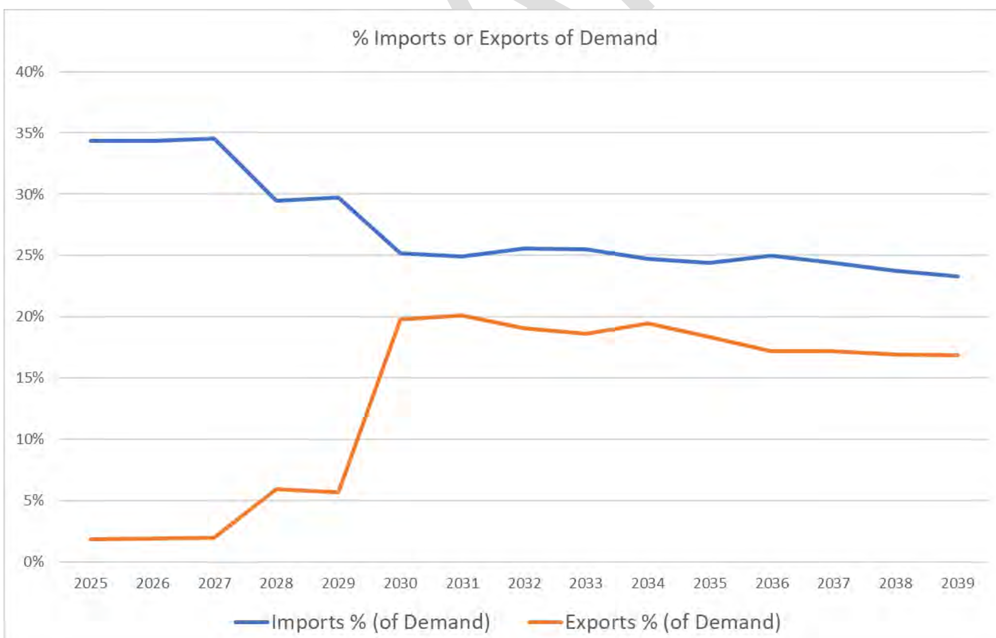


Exhibit 341: Portfolio 10 Market Purchases and Sales as % of Demand



The risk can also be appreciated looking at the difference between purchase price (high) and sale price (low). The more purchase this portfolio needs, the higher risk it has.

Exhibit 342: Portfolio 10 Market Purchases and Sales Prices $/MWh

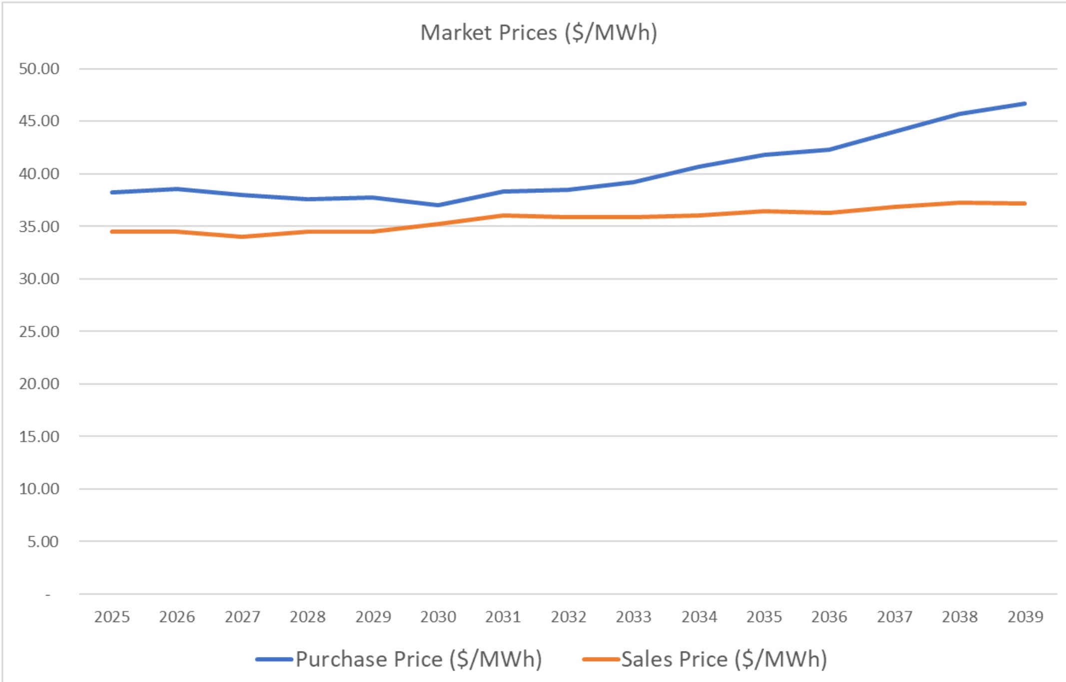
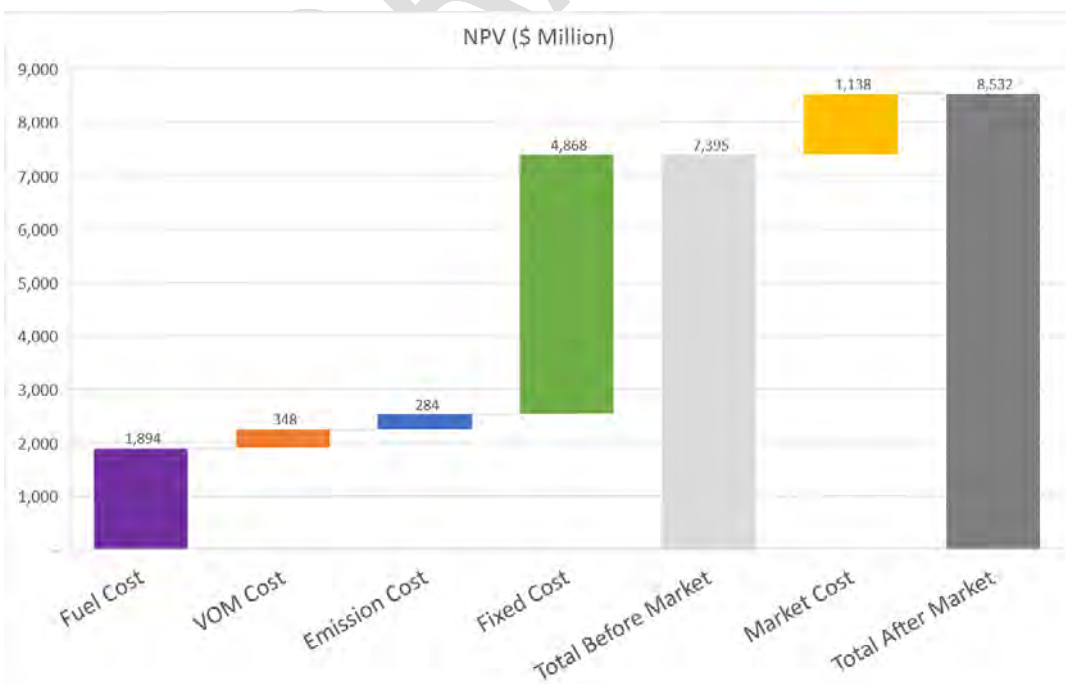


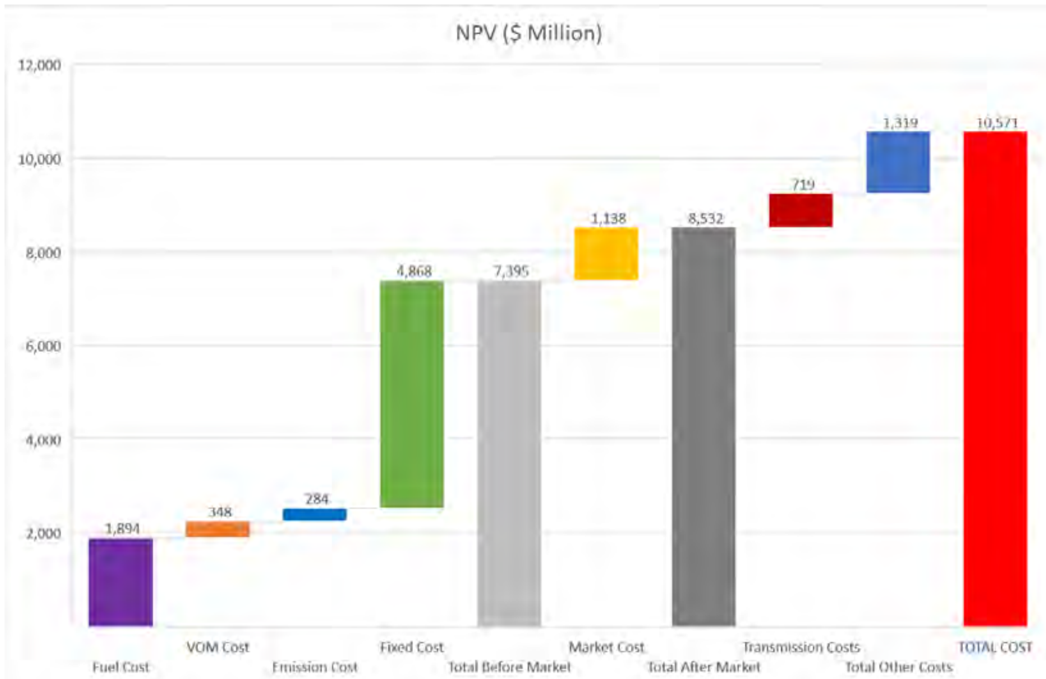
Exhibit below shows the supply side total NPV for 2025-2039, which is about $8.53 billion in 2018 $. Fixed cost is the largest component, followed by fuel and market costs.

Exhibit 343: Portfolio 10 Generation Resource NPV 2018 $



The total NPVRR of this portfolio is approximately $10.57 billion for 2025-2039 in 2018 $.

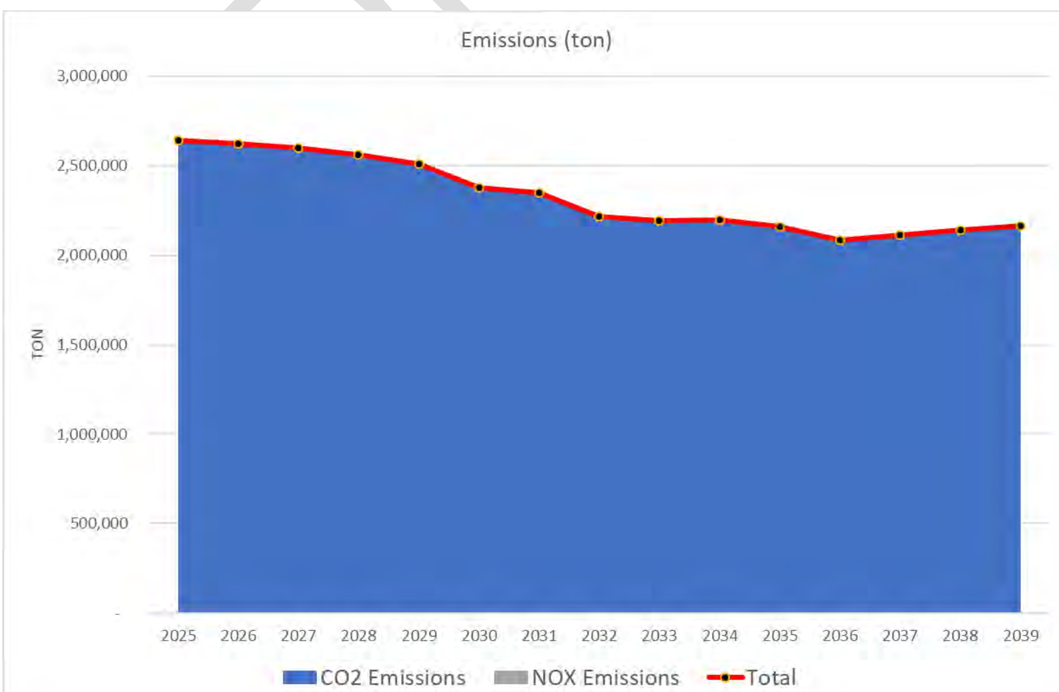
Exhibit 344: Portfolio 10 All NPVRR with Other Components 2018 $



Environmental

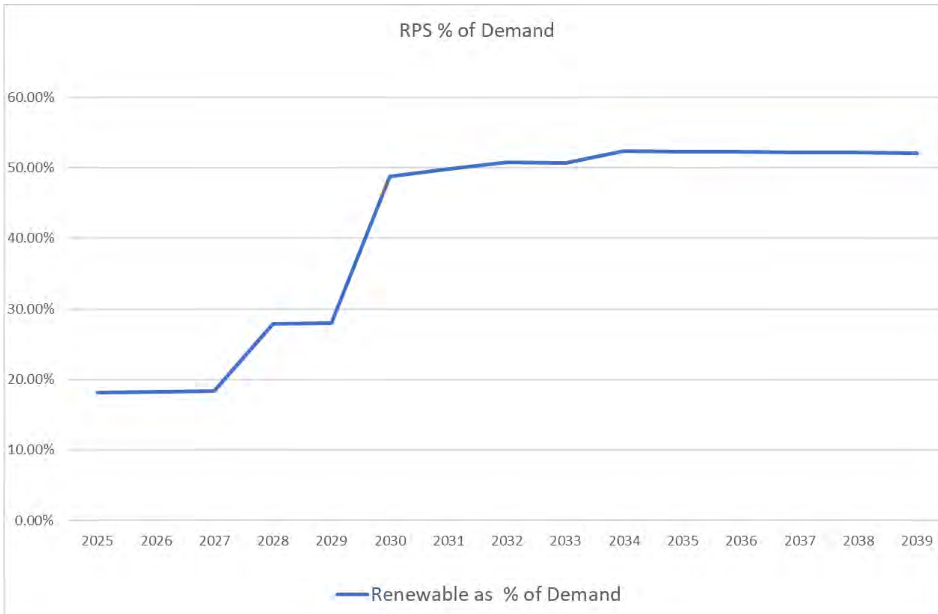
The emission from this portfolio is shown in the graph below. The emission is low compared with other portfolios due to high renewable and low thermal nature in this portfolio.

Exhibit 345: Portfolio 10 Total Emission by Year



This RPS as of demand in energy of this portfolio starts at about 20% and reaches very quickly to 53% in 2039 as lots of renewable generation are built in this portfolio.

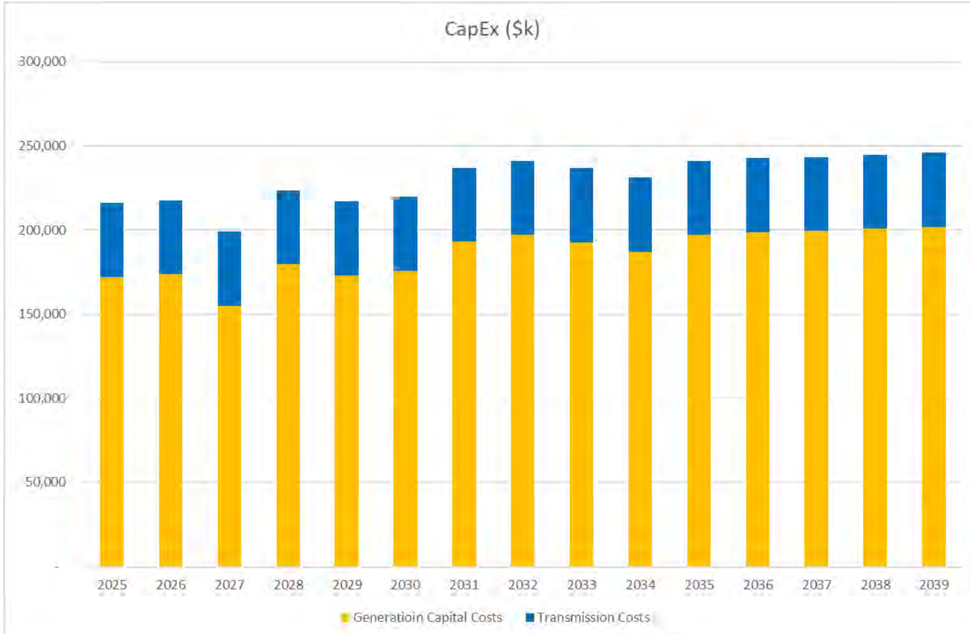
Exhibit 346: Portfolio 10 RPS by Year



Capital Expenditure

Total capital expenditures on generation and transmission are shown in the graph below. We annualized these capital costs from 2025 to 2039 by year and it's about $230 million per year on average for this portfolio. Most of the capital costs are on the generation side.

Exhibit 347: Portfolio 10 Annualized Capital Expenditure by Year



Portfolio All MISO (S4S1)

This is the Portfolio All MISO under Strategy 4.

Capacity Expansion (Build Out)

The exhibits below show the capacity expansion by year, the only resources selected in Portfolio All MISO are the large CCGT and solar.

Exhibit 348: Portfolio All MISO Installed Capacity by Year

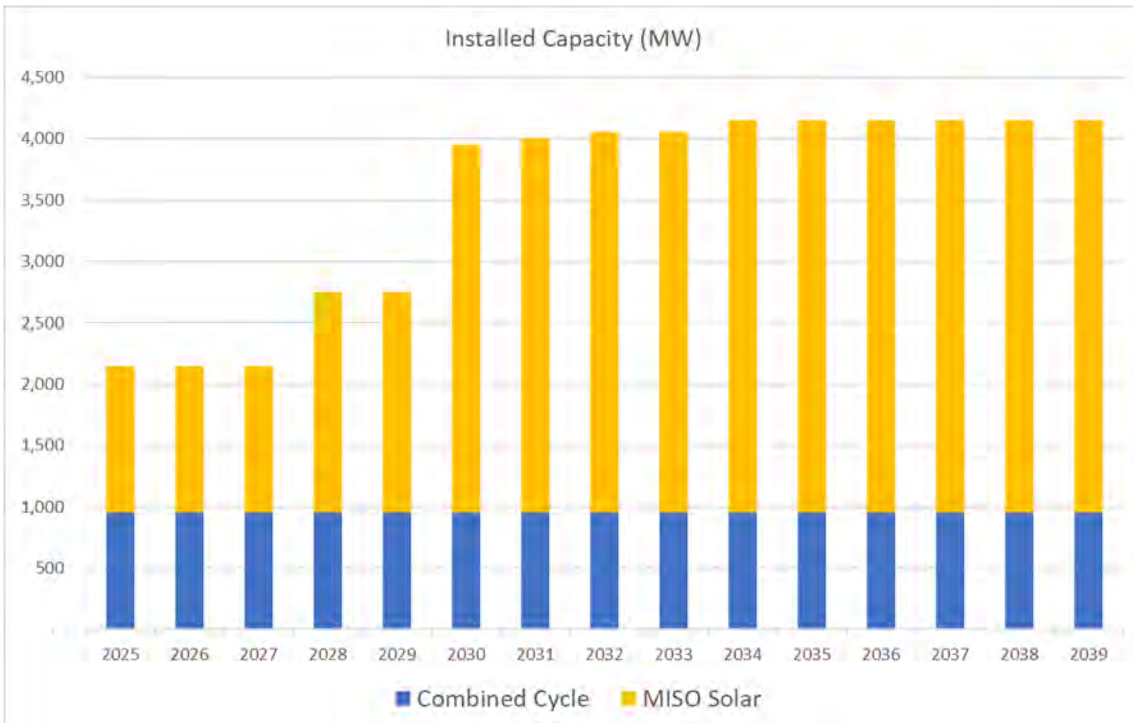
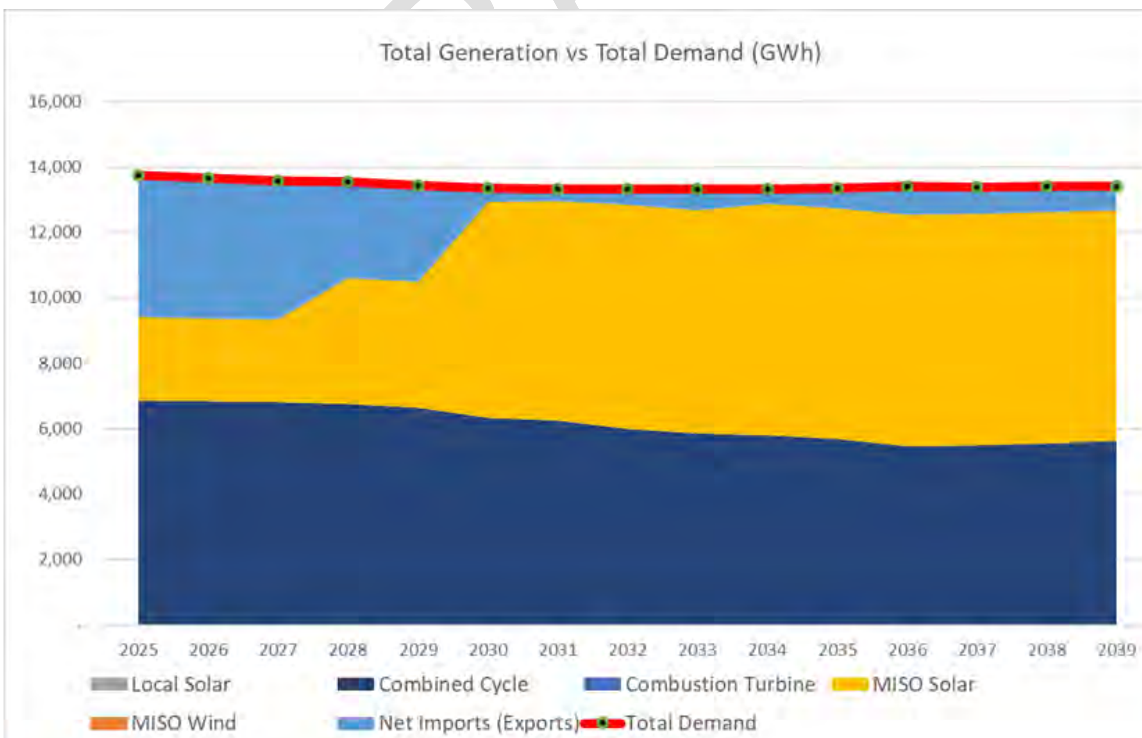


Exhibit 349: Portfolio All MISO Installed Capacity by Year (Table)

	Advanced Frame CT	Convl. Frame 7FA CT	2x1 Combined Cycle	Utility Solar	Battery	Miss Solar	Arkansas Solar	Arkansas Wind	MISO_Cap	Demand
2025	0	0	950	0	0	0	1200	0	2269	3197
2026	0	0	0	0	0	0	0	0	2262	3182
2027	0	0	0	0	0	0	0	0	2255	3168
2028	0	0	0	0	0	0	600	0	2080	3153
2029	0	0	0	0	0	0	0	0	2078	3139
2030	0	0	0	0	0	0	1200	0	1757	3124
2031	0	0	0	0	0	0	50	0	1754	3113
2032	0	0	0	0	0	0	50	0	1757	3108
2033	0	0	0	0	0	0	0	0	1782	3110
2034	0	0	0	0	0	0	100	0	1783	3112
2035	0	0	0	0	0	0	0	0	1808	3114
2036	0	0	0	0	0	0	0	0	1833	3116
2037	0	0	0	0	0	0	0	0	1858	3118
2038	0	0	0	0	0	0	0	0	1884	3121
2039	0	0	0	0	0	0	0	0	1909	3123

Energy generated from thermal generation decreases slightly over the years while energy coming from renewables increases as more installed.

Exhibit 350: Portfolio All MISO Energy by Resource Type by Year



Portfolio Costs

Exhibit below shows the supply side NPV cost by year, as can be seen the cost is about $640 million per year (2018 $) or $48.5/MWh, where fixed cost is the largest components due to the investments in generation, followed by cost of fuels and market purchases.

Exhibit 351: Portfolio All MISO Cost Components 2018 $

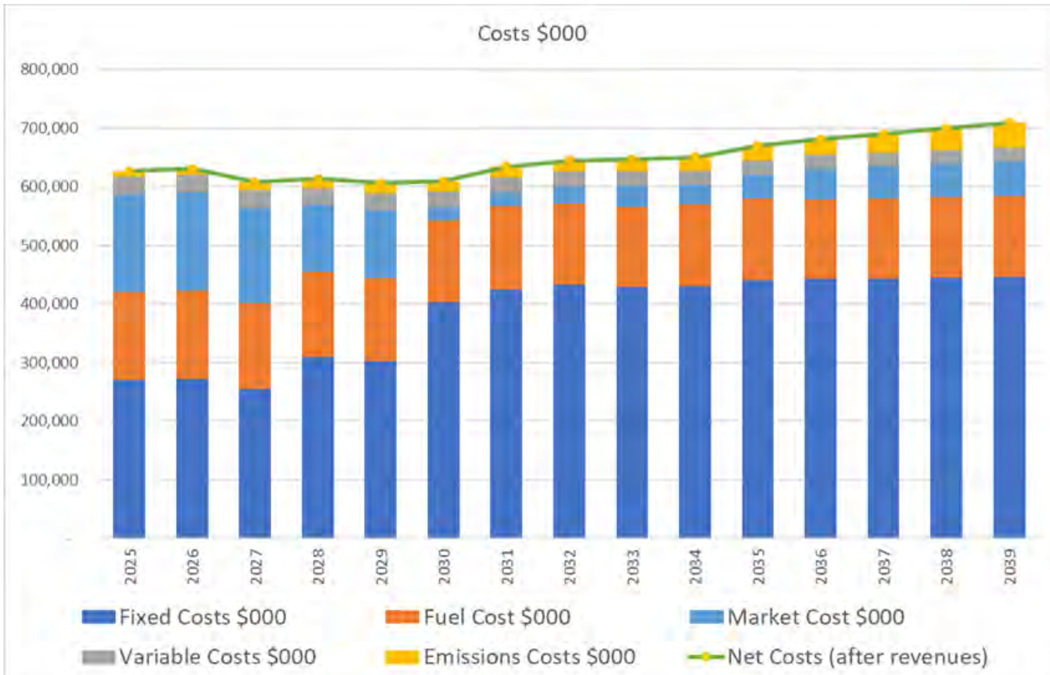
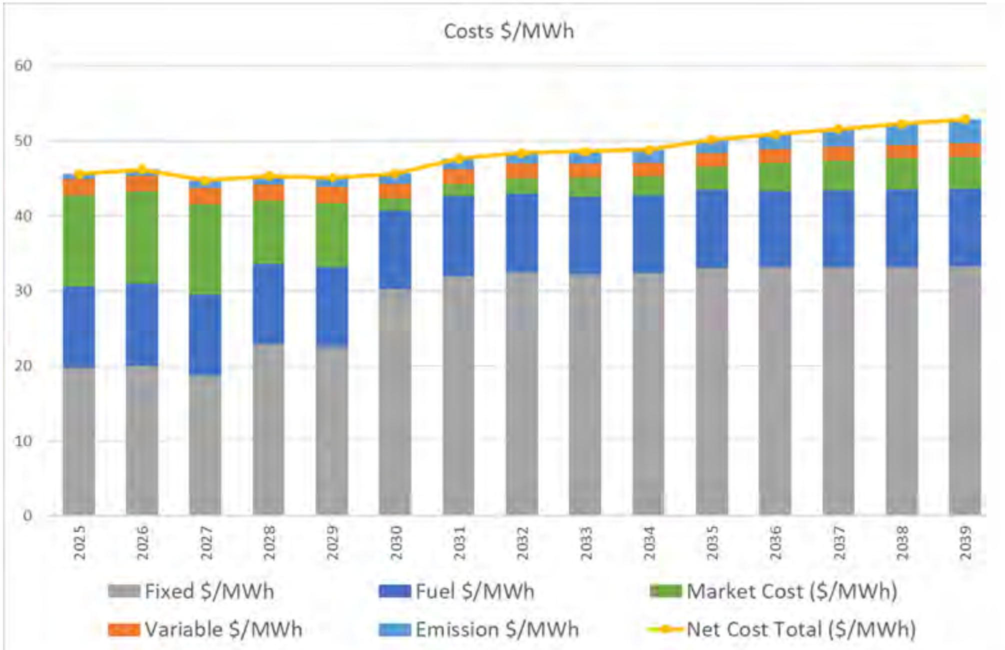
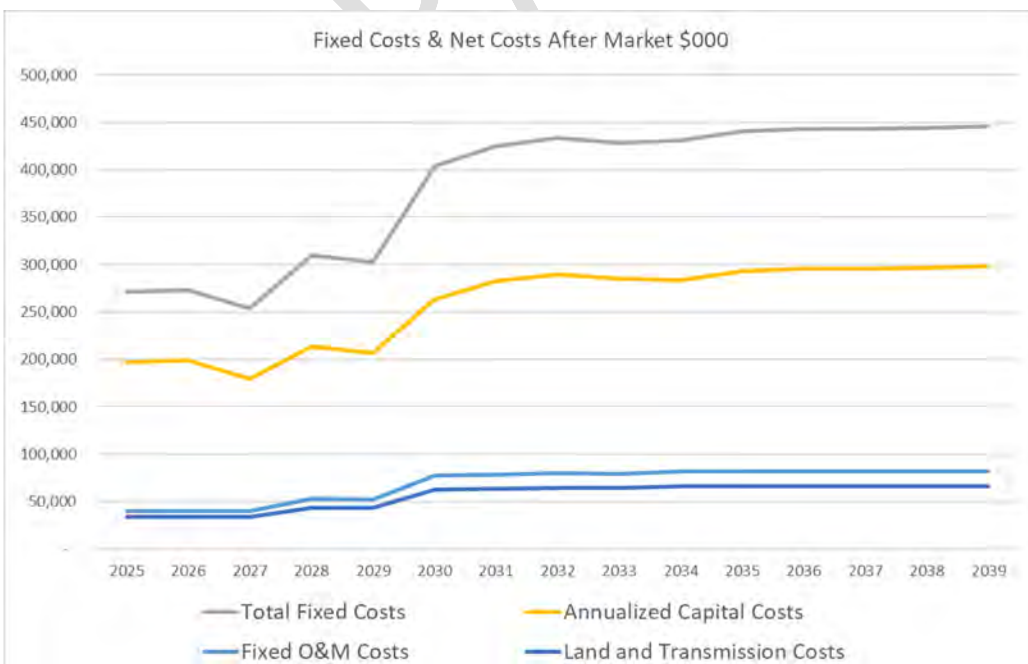


Exhibit 352: Portfolio All MISO Cost Components 2018 $/MWh



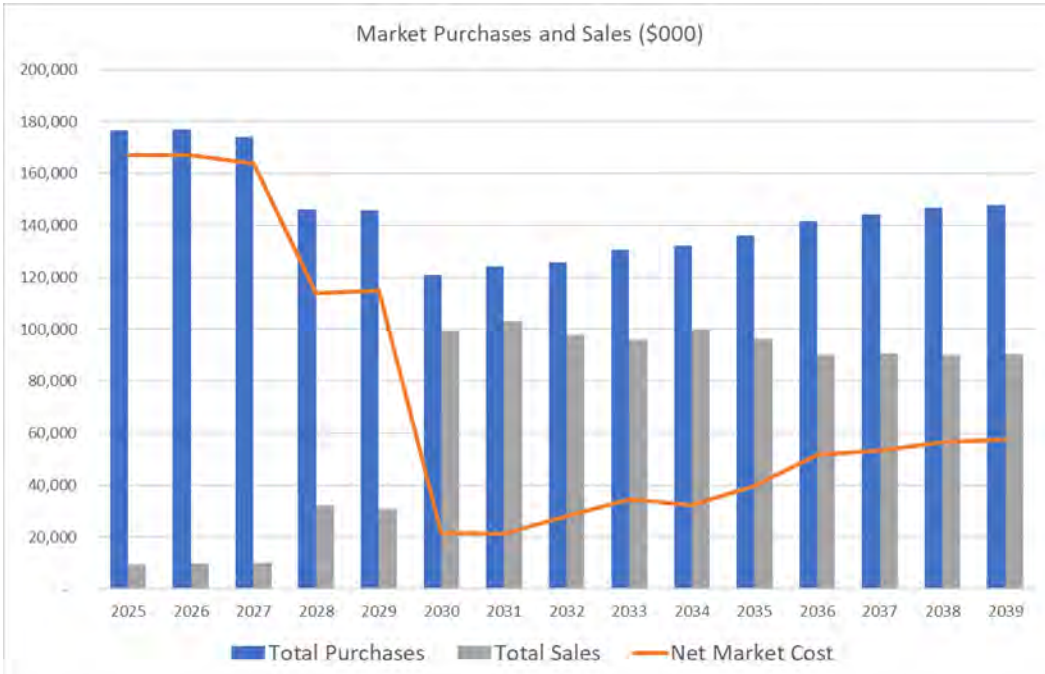
Graph below shows the breakdown of total fixed costs by component, where the majority comes from the base capital costs on generation.

Exhibit 353: Portfolio All MISO Fixed Cost Components 2018 $



Market purchases and sales are also important components. The market purchases by MLGW system are projected to be decreasing then flat while the sales are increasing especially after 2030 although the sales are maintained at a low level.

Exhibit 354: Portfolio All MISO Market Purchases and Sales 2018 $



These graphs show the purchases sales amount in energy and as % of demand. It shows the high market risk in the beginning of the planning years of this portfolio.

Exhibit 355: Portfolio All MISO Market Purchases and Sales in Energy

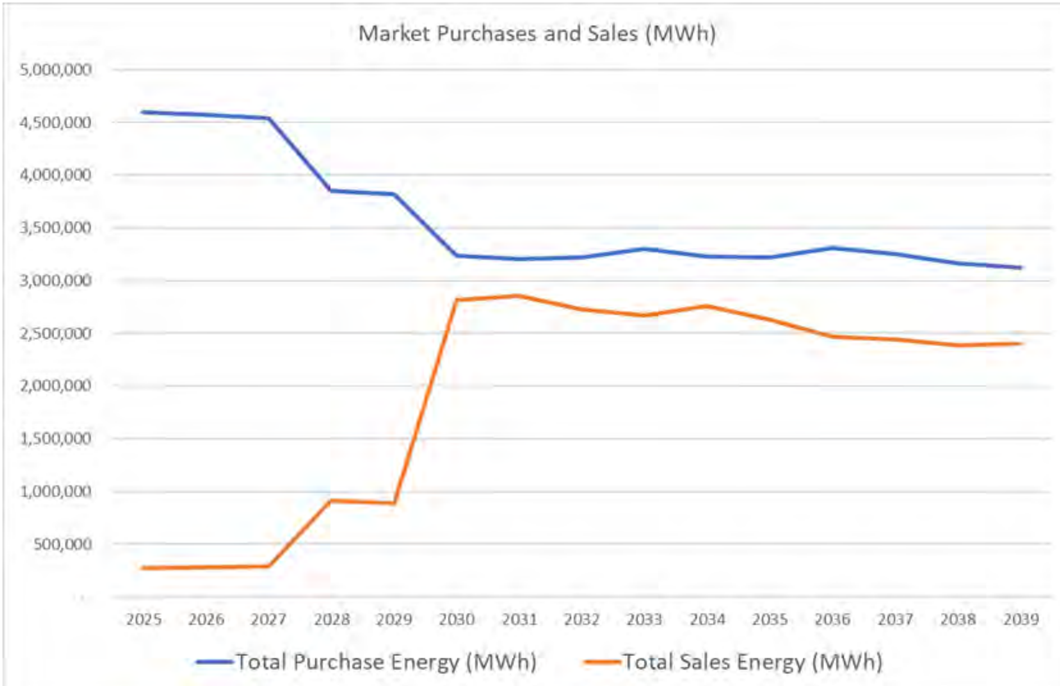


Exhibit 356: Portfolio All MISO Market Purchases and Sales as % of Demand

The risk can also be appreciated looking at the difference between purchase price (high) and sale price (low). The more purchase this portfolio needs, the higher risk it has.

Exhibit 357: Portfolio All MISO Market Purchases and Sales Prices $/MWh

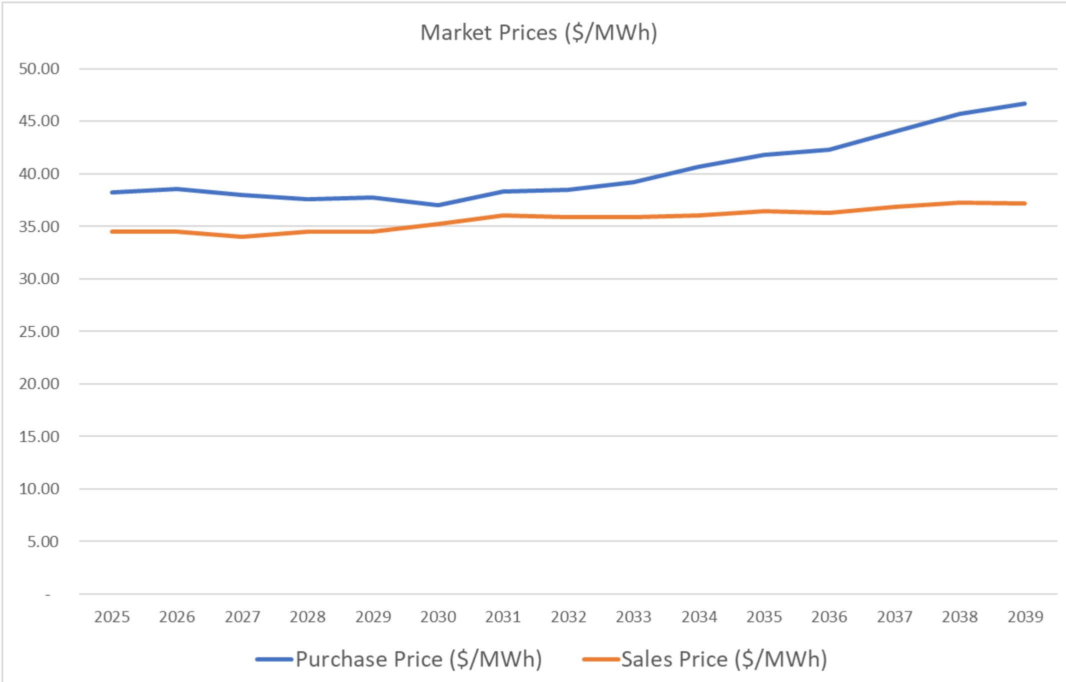
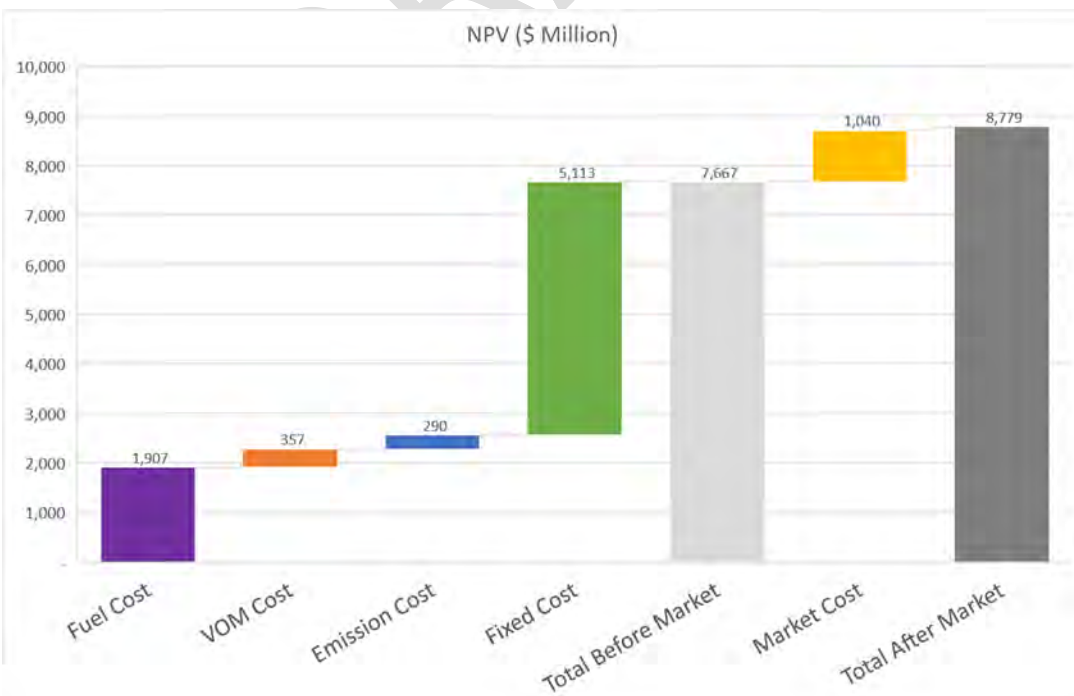


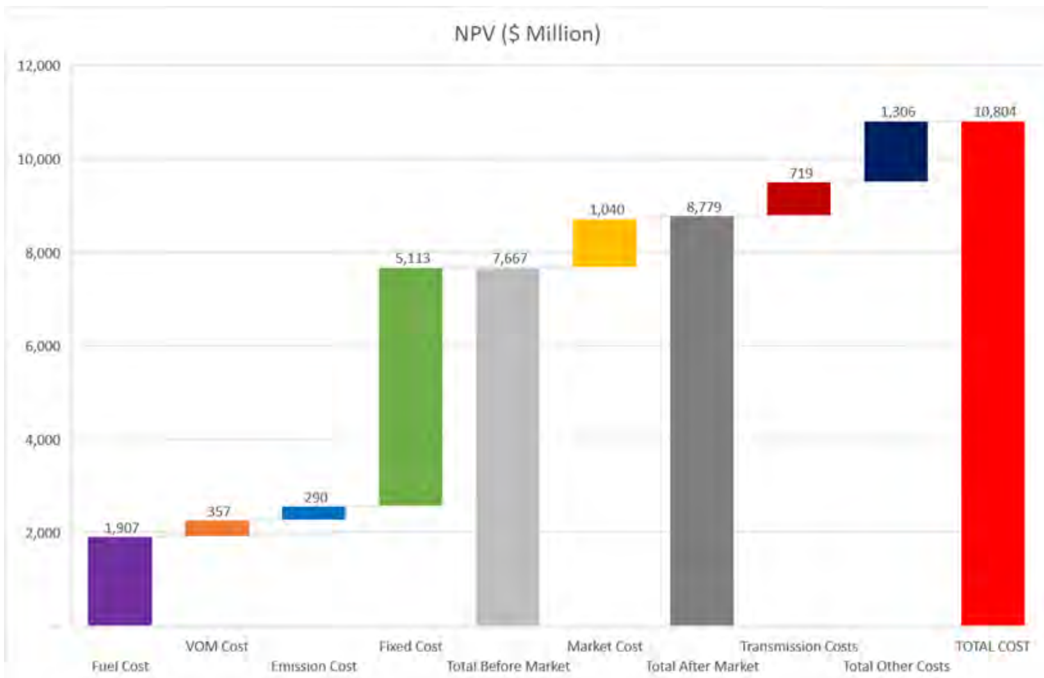
Exhibit below shows the supply side total NPV for 2025-2039, which is about $8.8 billion in 2018 $. Fixed cost is the largest component, followed by fuel and market costs.

Exhibit 358: Portfolio All MISO Generation Resource NPV 2018 $



The total NPVRR of this portfolio is approximately $10.8 billion for 2025-2039 in 2018 $.

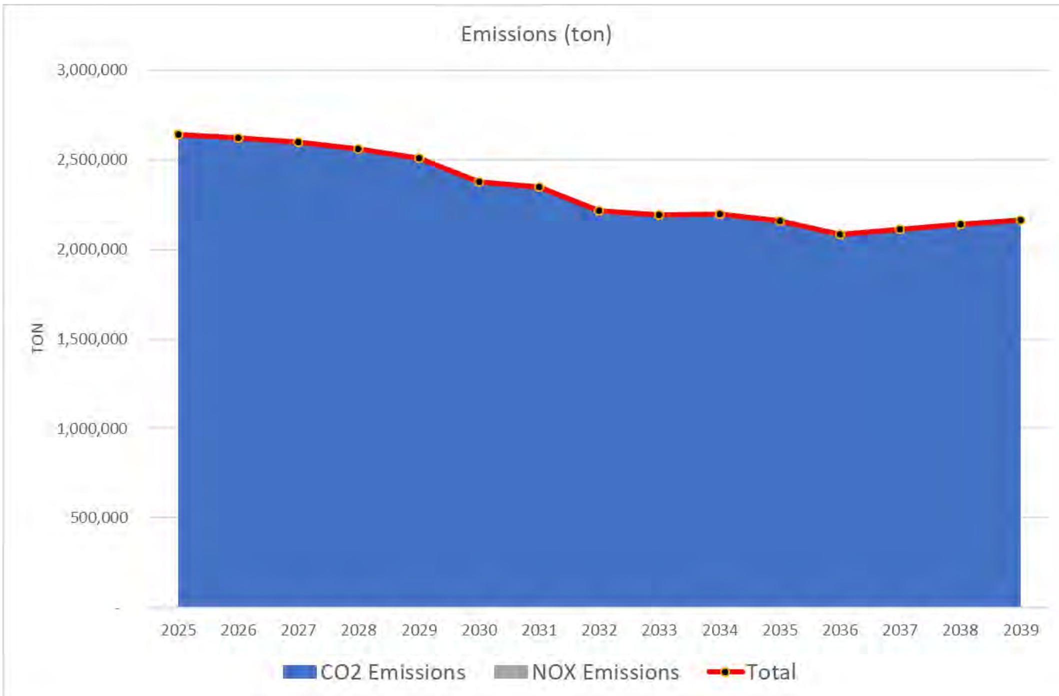
Exhibit 359: Portfolio All MISO All NPVRR with Other Components 2018 $



Environmental

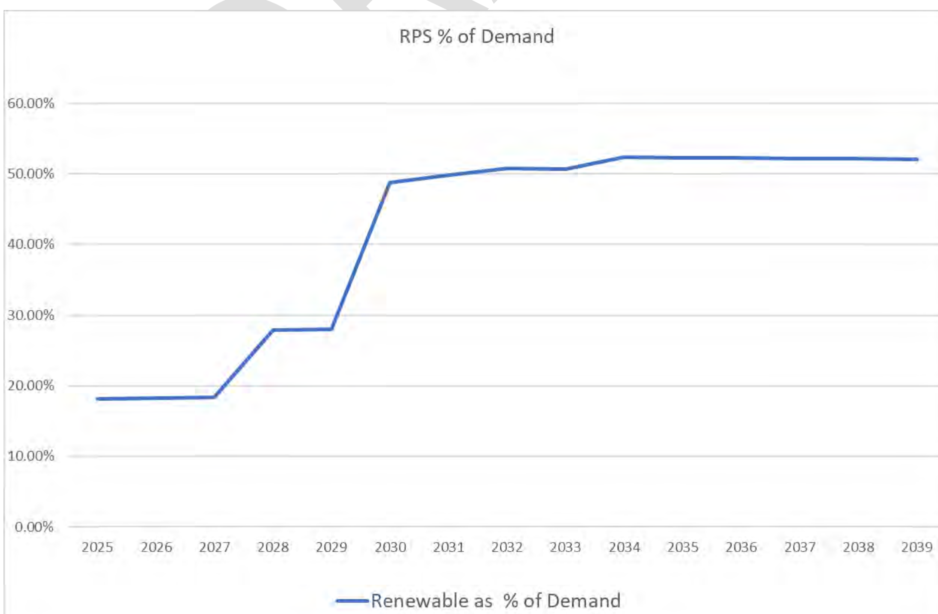
The emission from this portfolio is shown in the graph below. The emission is low compared with other Portfolios due to high renewable and low thermal nature in this portfolio.

Exhibit 360: Portfolio All MISO Total Emission by Year



This RPS as of demand in energy of this portfolio starts at about 20% and reaches 53% in 2039 as lots of renewable generation are built in this portfolio.

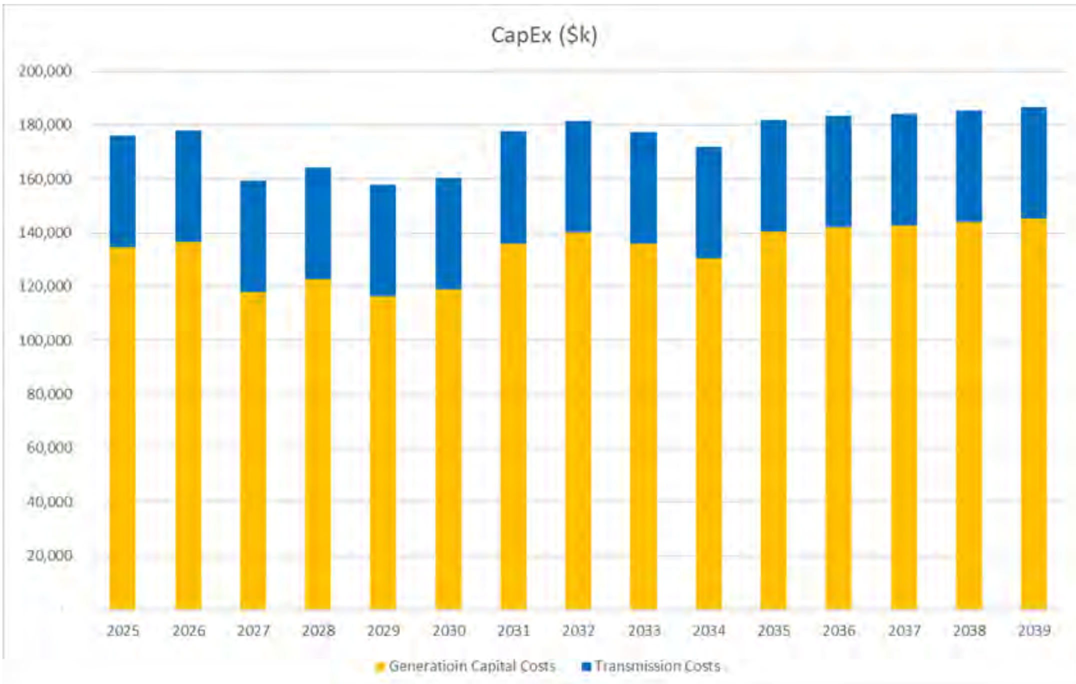
Exhibit 361: Portfolio All MISO RPS by Year



Capital Expenditure

Total capital expenditures on generation and transmission are shown in the graph below. We annualized these capital costs from 2025 to 2039 by year and it's about $170 million per year on average for this portfolio. Most of the capital costs are on the generation side.

Exhibit 362: Portfolio All MISO Annualized Capital Expenditure by Year



Appendix E: Glossary

All-in Capital Cost	The capital costs for building a facility within the plant boundary, which includes equipment, installation labor, owners' costs, allowance for funds used during construction, and interest during construction.
Appalachia Basin	Marcellus Shale Play and Utica Shale Play.
Average Demand	Average of the monthly demand in megawatts.
Average Heat Rate	The amount of energy used by an electrical generator to generate one kilowatt hour (kWh) of electricity.
Baseload Heat Rate	The amount of energy used by an electrical generator to generate one kilowatt hour (kWh) of electricity at baseload production. Baseload production is the production of a plant at an agreed level of standard environmental conditions.
Breakeven Cost	Average price of gas required to cover capital spending (ideally adjusted to regional prices.
BTU	British Thermal Unit = unit of energy used typically for fuels.
CF	Capacity Factor. The output of a power generating asset divided by the maximum capacity of that asset.
CC or CCGT	Combined Cycle unit
CCS	Carbon Capture and Sequestration
CT	Combustion Turbine
DER	Distributed Energy Resources, distributed generation, small scale decentralized power generation or storage technologies
DS	Distributed Solar
Dth	Dekatherm (equal to one million British Thermal Units or 1 MMBtu)
EFT	Enhanced Firm Transportation (varies by pipeline but can include short- or no-notice changes to day-ahead nominations of fuel delivery
EE	Energy Efficiency
FID	Final Investment Decision
FOM	Fixed operations and maintenance costs
FT	Firm Transportation. FT capacity on a natural gas pipeline is available 24/7 and is more expensive than interruptible transportation (IT) capacity but unused FT capacity can be sold on secondary market.
Futures	Highly standardized contract. Natural gas futures here are traded on the New York Mercantile Exchange (NYMEX) or Chicago Mercantile Exchange (CME).
GT	Gas Turbine same as CT
PPA	Power Purchase Agreement: contract to purchase the power from a generating asset
IPP	Independent Power Producer
IRP	Integrated Resource Plan
LNG	Liquified natural gas
LOLE	Loss of load expectation
LOLH	Loss of load hours,

LTCE	Long Term Capacity Expansion Plan: optimization process to select generation.
MMBTu	million British Thermal Units, unit of energy usually used for fuels.
MWh	unit of energy usually electric power = 1 million watts x hour
MW	unit of power = 1 million watts
Peak Demand	The maximum demand in megawatts (MW) for a year.
PV	Photovoltaic generation
Reserve Margin	The amount of electric generating capacity divided by the peak demand.
SMR	Small Modular Reactor
"Sweet Spot" Core Acreage	Areas within a natural gas play that offer the highest production at least cost.
Utility Scale	large grid-connected power generation, could be solar, gas, diesel, etc.
VOM	Variable operations and maintenance costs
Wheeling	a transaction by which a generator injects power onto a third-party transmission system for delivery to a client (load)
WTG	Wind Turbine Generator