Final Report | Spring 2015

Client : Dominion Virginia

Long Term Planning for Capacity Investment & External Energy Production

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Executive Summary

Dominion Virginia Power (DVP) is a regulated electric utility monopoly that serves 2.5 million customers in Virginia and North Carolina. During the 1980s and 1990s, DVP established itself as a world class operator of nuclear power stations, and in the 2000s DVP invested heavily in natural gas in order to better support the needs of its customers during peak hours. Today, DVP is considered the lowest cost producer of nuclear-generated electricity in the nation.

As DVP's customer base grows, the company faces the added responsibility of meeting growing demand and capacity requirements. The Generation System Planning Department at DVP is tasked with the objective of identifying the optimal allocation of resources in its energy portfolio. The department must do this in an efficient and reliable manner at minimum cost while considering the future risk and resource price uncertainties. Currently, the department uses software called "Strategist" that optimizes for minimum cost but does not take quantitative measures of risk into account.

The aim of this project is to develop an optimization model that takes resource cost variability and tail risk into consideration. The first deliverable is an optimization model implemented in Gurobi using a python interface. There are two main outputs generated by this model, which represent the second and third deliverables. The first output is a mean-variance efficient frontier that consists of a set of optimal energy portfolios that have the least cost for every given level of risk. The second output of the model is the report of the tail risk analysis. This report shows the Value at Risk and Expected Shortfall for each of the energy plans. Based on the results generated from the optimization model, we recommend DVP to choose Generated Plan 4, which includes 3 Natural Gas plants, 2 Combustion Turbine plants, 167 Solar (Fixed Tilt) plants, 3 Solar (Tag Along) plants. The plan has a total expected cost of $57.74 billion and standard deviation of $4.1 billion.

The estimated cost savings during the planning horizon (2015 – 2040) are $3.3 billion, which is approximately 5.40% of total portfolio cost. Annualizing this value, we get cost savings of $171.50 million each year going forward.

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1. Client Context

The client is Dominion Virginia Power (DVP), which is a subsidiary of a larger corporation called Dominion Resources (Dominion Virginia Power, 2013). Dominion Resources is divided into three operating divisions: Dominion Virginia Power, Dominion Energy, and Dominion Generation. Dominion Resources is a publicly traded company with a market capitalization of about $40 billion and $1.7 billion in earnings last year. DVP makes up 22% of Dominion Resources' earnings making it a significant subsidiary of Dominion Resources (Dominion Virginia Power, 2013). During the 1980s and 1990s, DVP established itself as a world class operator of nuclear power stations, and in the 2000s DVP invested heavily in natural gas in order to better support the needs of its customers. Today, DVP is a regulated electric utility monopoly that serves 2.5 million customers in Virginia and North Carolina (Dominion Virginia Power, 2013).

1.1 System Description

Our team is working with DVP's Generation System Planning Department, which is tasked with planning DVP's electric generation system. DVP owns a number of power plants that provide consistent base load power. These plants include:

- Two North Anna and two Surry Nuclear reactors with a combined capacity of 3.35 gigawatts (GW)
- 18 coal facilities with a combined capacity of 4.96 gigawatts (GW)
- 4 biomass facilities with a combined capacity of 250 megawatts (MW)

DVP also owns power plants designed to provide power only at times of peak demand. These peaking plants primarily consist of:

- 41 Combustion Turbine facilities powered by natural gas or fuel oil
- 8 Combustion Cycle facilities powered by natural gas or fuel oil
- 4 natural gas – steam plants

DVP's market in Virginia and North Carolina has an annual growth rate of 1.3% in energy requirements and 1.4% in peak power requirements. DVP needs to accommodate for this increasing demand while keeping stable rates for its customers. Given the long lead times for the construction of new power plants (3-10 years depending on technology) and long service lives, DVP must take a long-term view of its energy portfolio. In other words, DVP needs a robust energy portfolio that will serve the needs of its customers over the next 15-25 years.

Currently, DVP has six existing energy plans representing the plausible paths that the company could follow to meet the future power needs of its customers, as shown in Figure 1.

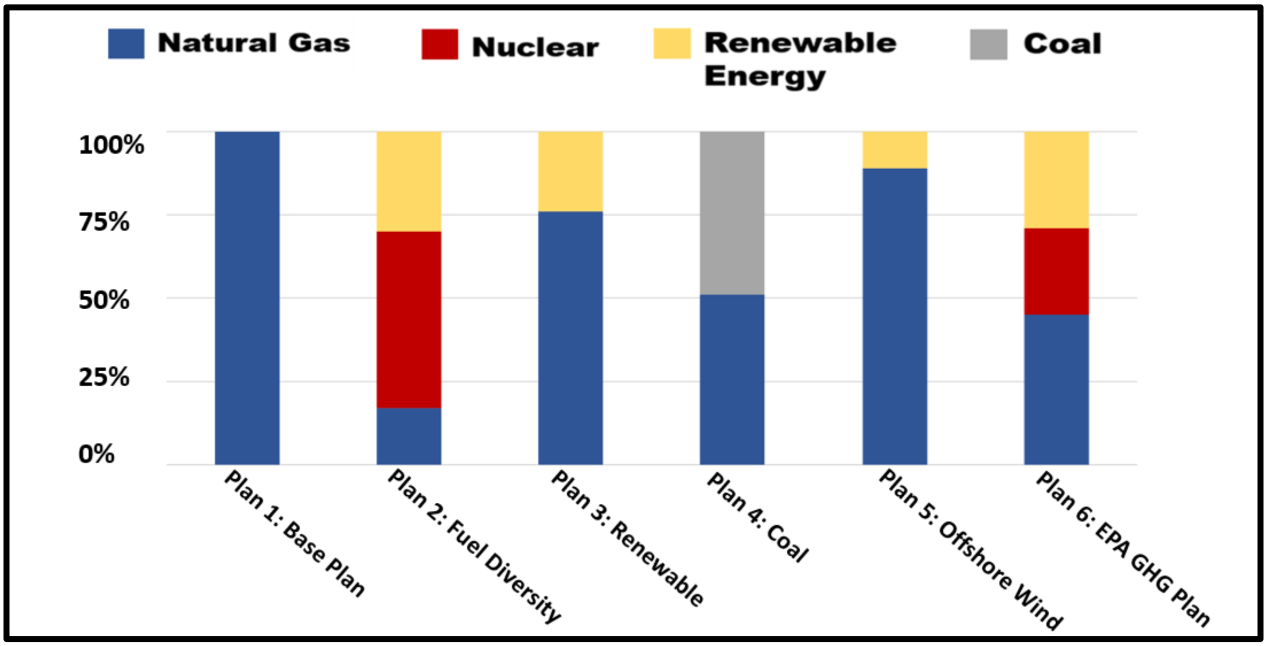

Figure 1: DVP 2014 Alternative Plans

Each alternative plan shown in Figure 1 has different resource allocations. For example: Plan B - the fuel diversity plan includes a nuclear unit being constructed along with onshore wind and solar units in the planning period. Plan C - the renewable plan includes different renewable resources along with natural gas.

Under current market conditions, there is an abundance of inexpensive shale natural gas. As a result, it is most cost-effective for DVP to rely on natural gas (Plan A) to satisfy its customer demand. However historically, natural gas has a high price volatility, which could result in unstable rates for DVP and its customers.

2. Project Scope

2.1 Problem Overview

Figure 2 describes the problems associated with our project. These problems are discussed in detailed below.

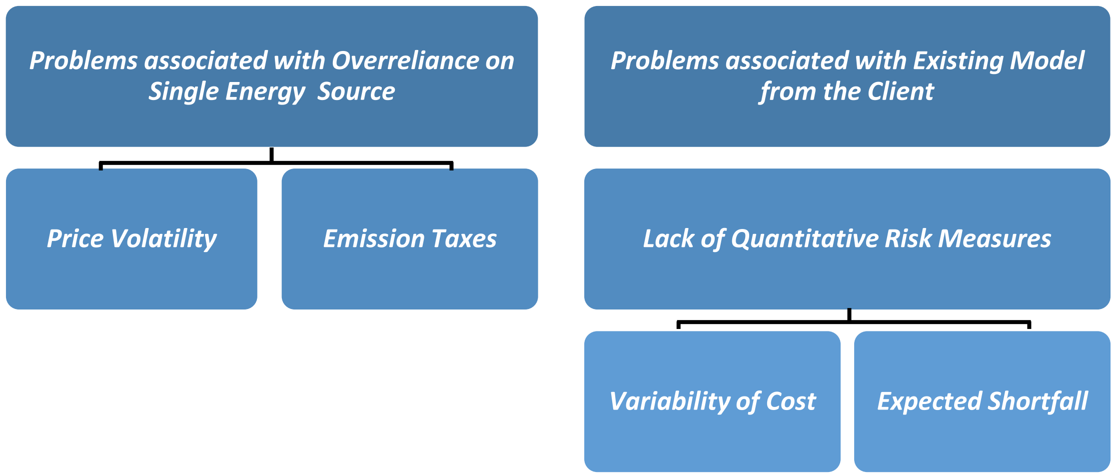

Figure 2: Project Problem Overview

I. **Price Volatility:** If our client invests too heavily in a single fuel source, DVP's customers (through rising cost of electric rates) will be exposed to price volatility. For example, historical data shows a high variability associated with the cost of natural gas, which has the potential to increase the risk of using this resource as well as the total cost of the energy portfolio.

II. **Emission Regulations:** The client has predicted that a maximum carbon emission limit will be enforced by 2020. In the case of a sub-optimal fuel portfolio, DVP might have to shut down natural gas plants in order to accommodate for these emission cap restrictions. This would be extremely costly for DVP, necessitating having an optimally diversified portfolio before potential regulatory changes are in place.

III. **Lack of Quantitative Risk Measures:** DVP's current software, "Strategist", optimizes the cost of the fuel portfolio but does not take the following risk measures into account:
   - <u>Variability of Cost:</u> DVP's current model does not take variability of the cost of resources into account, which could lead to unstable prices for their customers.
   - <u>Expected Shortfall:</u> DVP's current model does not measure tail risk.

In relation to the problems discussed above, these are the two questions that the deliverables will address for DVP.

QUESTION 1	***QUESTION 2***
What energy resource plants should be built to meet regulatory requirements?	How can the risk of alternative portfolios be quantified?

2.2 Solution

To answer the client's first question, we use **Mean-Variance Portfolio Optimization** to identify the best trade-off between total portfolio cost and total risk. The optimization model will generate an efficient frontier that consists of minimum cost portfolios for every given level of risk. Each portfolio specifies when and what energy resource plants should be built for that level of risk.

Answering the client's second question requires incorporating quantitative risk measures such as **Cost Variance, Value at Risk (VaR), and Expected Shortfall**. VaR is defined as the cost level that will be exceeded with a certain confidence level (α). Expected shortfall is the expected cost of the portfolio in the worst α% of cases.

2.3 Methodology Overview

After identifying the problems in DVP's current energy portfolios, we organized and restructured the given data into spreadsheets. These spreadsheets were then used as input for the multi-period mean-variance portfolio optimization model. In order to improve the functionality of the model, expected shortfall and scenario analysis were included. After solving the model in Gurobi, the model generates a mean-variance efficient frontier. This frontier details the allocations of the different energy resources in each portfolio recommended by the model and the total cost of each respective portfolio. Tail Risk Analysis is conducted to quantitatively assess the effect of worst-case, low-probability events. Lastly, project value for the client is determined.

The flowchart (Figure 3) depicts these project steps and the following sections further discuss the details of the methodologies.

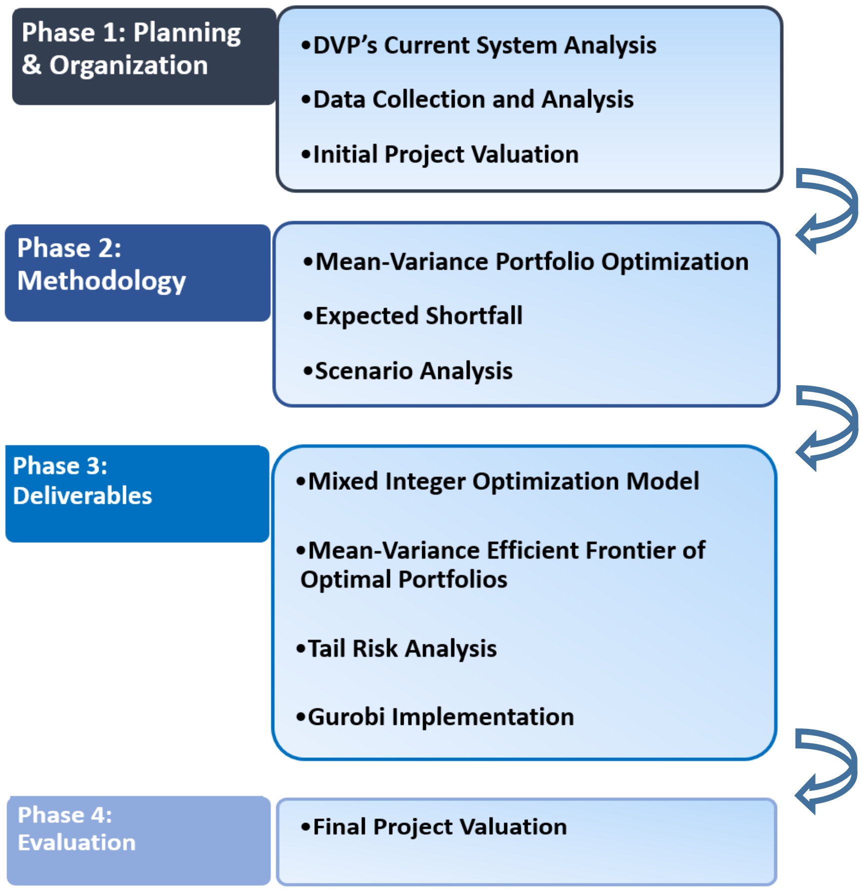

Figure 3: Methodology Flowchart

3. Data Collection and Analysis

The data from Table 1 is historical quantitative data found in the Integrated Resource Plan provided by DVP. This dataset is used to calculate the computed datasets described in Table 2 (Column 1).

Table 1: Dataset from Client

Dataset	Appendix Number	Description
Plant Types	1	Energy plants and their corresponding fuel types in DVP system
Fuel Prices	2	Daily commodity cost (natural gas, coal, oil, power purchased, nuclear) starting from 1990 to 2014
Variable O&M Cost	3	Operation and Maintenance cost for each plant type per MWh
Fixed O&M Cost	4	Fixed annual operation and maintenance cost for each plant
Construction Cost	5	Initial investment cost per plant
Demand	6	Base year energy demand and peak demand for 2015 in GWh
Unit Capacity	7	Plant generation capacity per plant type in MW
Resource Usage of Existing Plan	8	Annual usage of fuel commodities in MWh
Market Purchases Cost	9	The cost of market purchases in each year
Deferred Capacity	10	The cost of deferred capacity each year
Power Plant Efficiency	11	The amount of realized power from resource usage of plant/facility i

Table 2: Computed Dataset

Dataset	Appendix Number	Description
Projected Demand (2016 – 2040)	13	Projected energy demand (annual growth rate of 1.3%) and projected peak demand (annual growth rate of 1.4%)
Fixed Cost (FC)	14	Annual total fixed cost per KW (kilowatt) for each plant
Variable Cost (VC)	15	Total variable cost per KWh (kilowatt hour)
Correlation Coefficient between Variable Cost	16	Correlation coefficient between variable cost of different energy fuels
Covariance between Variable Cost	17	Covariance between variable cost of different energy fuels
Total Cost Variance of Existing Portfolio	18	Total cost variance of existing portfolio

The dataset in Table 3 was obtained from the paper titled "Cost and Performance Assumptions for Modeling Electricity Generation Technologies" and authored by the National Renewable Energy Laboratory.

Table 3: Dataset from External Source

Dataset	Appendix Number	Description
Lead Time	12	Average plant construction time for each plant type

These datasets are used in the optimization model to calculate the total costs, variances of the energy portfolios and to generate the mean-variance efficient frontier.

3.1 Data Analysis

- ***Correlation Coefficients between Variable Costs***

The correlation coefficients,ρ_{xy}, described in Table 2, are a measure of how changes in the price of one resource affect the price of another resource as shown in *Table 4*.

Table 4: Correlation Coefficient between Variable Cost

Fuel Type	Coal	Oil	Natural Gas	Nuclear	Biomass	PowerPurchase
Coal	1	-0.15	0	0.07	-0.47	0
Oil		1	0	-0.09	-0.18	0
Natural Gas			1	-0.31	0.02	1
Nuclear				1	-0.19	-0.31
Biomass					1	0.02
PowerPurchase						1

Inflation has been taken into account in our historical data. The inflation rates that have been used are 3% for data from 1990 to 1999, 2.56% for data from 2000 to 2009, and 2.29% for data from 2010 to 2014. It is important to note that the correlation coefficients of renewable energy resources are zero and not shown because they do not have fuel costs. The client has indicated that zero correlation between gas and coal and gas and oil can be assumed.

- ***Covariance between Variable Cost***

Using correlation coefficients data, covariance between variable costs is calculated *(Table 5).* Covariance is a measure of the degree to which the prices of two resources move in tandem. A positive covariance means that the prices of both resources move together (both up or both down). A negative covariance means that the prices move inversely.

Table 5: Covariance between Variable Cost

Fuel Type	Coal	Oil	Natural Gas	Nuclear	Biomass	PowerPurchase
Coal	40.0023	-35.8722	0	0.582407	-20.6679	0
Oil		1429.71	0	-4.47664	-47.3208	0
Natural Gas			358.9698672	-7.72639	2.6346	606.1582624
Nuclear				1.7305	-1.73778	-13.04681571
Biomass					48.34053	4.448798657
PowerPurchase						1023.561788

- ***Total Cost and Standard Deviation of Existing Portfolios***

The total cost standard deviation is a measure of risk associated with DVP's energy portfolio. The client has indicated that it is reasonable to assume that the variance of fixed cost is zero. The standard deviation associated with each resource is calculated using the *Resource Usage* and *Variable Cost* data. The total standard deviation of each portfolio is the sum of the cost standard deviation of individual resources in that portfolio.

Table 6: The Standard Deviation and Total Cost of Existing Portfolios

Plan Name	Total Cost ($ Billion)	Standard Deviation (Billion)
Base	54.63	4.64
Diversity	61.04	4.10
Coal	62.25	4.59
Renewable	59.34	4.32
Wind	61.15	4.53
EPA GHG	60.28	4.14

3.2 Data Relationship to the Model

Total Cost Variance: The cost variance of the six energy portfolios found in the IRP was calculated using the covariance and correlation data. This cost variance data is used in our mixed-integer optimization model to develop the mean-variance efficient frontier.

Total Costs: Total costs of the six energy plans in the IRP were used to validate the total costs of the optimal portfolios generated by the model.

Expected Shortfall: Random sampling of the fuel cost vectors and market purchase costs was used to calculate the expected shortfall and minimize tail risk.

4. Design Strategy

4.1 Methodology

Methodology 1: Multi-period Mean-variance Portfolio Optimization

In order to optimize DVP's energy resource allocation, the best trade-off between risk and cost across the planning horizon (25 years) is calculated by using multi-period mean-variance portfolio optimization. This methodology is used to quantify the financial benefits of diversification of DVP's energy portfolios and to calculate optimal fractional allocation of energy resources.

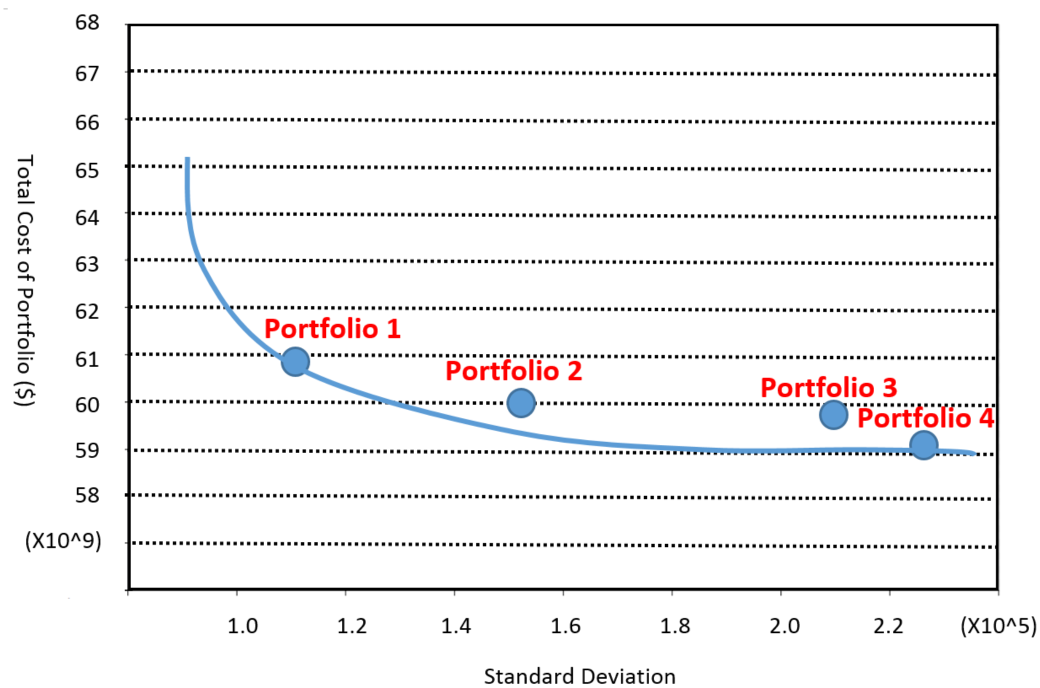

Figure 4: Mean-variance Efficient Frontier with Hypothetical Portfolio

As seen in Figure 4, the mean-variance efficient frontier enables the client to identify the optimal portfolios per level of risk. Portfolios like Portfolio 1 that lie on the efficient frontier are optimal because they provide the lowest cost for a given level of risk. Portfolios like Portfolio 2 that lie above the efficient frontier are not optimal because they provide a higher cost for a given level of risk.

Methodology 2: Expected Shortfall

To accurately account for tail risk, the mean-variance optimization model was updated to include Value at Risk and Expected Shortfall.

Value at Risk (VaR) of the energy portfolio measures the value for which the probability of the realized costs exceeding this value is greater than or equal to a confidence level (α). Expected Shortfall is Conditional Value at Risk. The VaR model identifies the losses in the upper α% case caused by risk. The problem with relying solely on the VaR model is that the scope of risk assessed is limited, since the tail end of the distribution of loss is not assessed. Therefore, if losses are incurred, the amount of the losses will be substantial in value.

Expected Shortfall is a risk assessment technique often used to specify the tail risk (the risk that a portfolio will incur the largest losses). Expected Shortfall is calculated by taking a weighted average of every value at risk exceeding the α% value at risk.

Methodology 3: Scenario Analysis

Scenario analysis is the process of estimating how the expected cost of a portfolio would change across period of time due to external events. For example, environmental regulations like emission taxes.

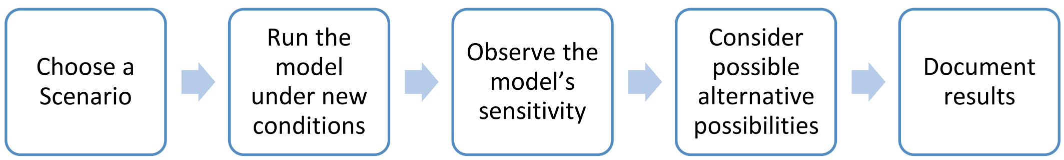

Figure 5: Scenario Analysis Process

4.2 Multi-Period Mean Variance Portfolio Optimization Model

Overview

The optimization model effectively represents a dynamic, multi-stage decision making process over the planning horizon defined by the client. At each stage, binary variables decide what and how many resources to build and keep track of the state of the system as a whole. Continuous variables keep track of our realized energy production and the cost (in a given year) to produce this energy. This model, which is implemented in Gurobi using a Python interface, produces a minimum cost optimal strategic plan for every year of the planning period given a level of acceptable risk. The model generates a mean variance efficient frontier that consists of least cost portfolios for every level of risk. The model was later updated to include Expected Shortfall to conduct tail risk analysis.

Assumptions (Refer to Appendix 17.1)

The assumptions provided by the client are included in Appendix 19.1.

Objective Function (Refer to Appendix 17.2)

The objective of this model is to minimize total cost portfolios for every given level of risk.

Decision Variable (Refer to Appendix 17.3)

NewResourcesBuilt $_{i,t}$: This variable is the number of plants of type *i* built at time *t*.

FuelUsage$_{f,t}$: Amount of fuel of type f used in period t. Measured in Terawatt hours, but more Terawatt hours of fuel will be used than the corresponding electricity gain from that fuel due to plant inefficiency.

MarketPurchases$_t$: The total amount of energy in Terawatt-hours purchased from PJM at time t.

DefCapacity$_t$: The total amount of energy in Terawatts bought in deferred capacity at time t.

VaR: The value at which the probability that the realized cost is less than this value is β.

Shortfall: The expected value of the worst-case costs. This is a measure of tail risk.

CostSamples$_k$: The samples of total cost based on randomly sampled historical fuel cost and market purchases data.

The decision variables mentioned above are the most relevant ones. For information about the other constraints, refer to the Appendix 19.2

Constraints (Refer to Appendix 17.4)

Peak Power Demand Constraint*:* This constraint ensures that model must meet peak demand (plus reserve) with plants built in the year t or in previous years.

Energy Demand Constraint*:* This constraint ensures that the model satisfies all customer demand for electricity every year.

Maximum Power Generation Constraint*:* This constraint ensures that the whole system generates less power than the sum of our constructed capacity.

Portfolio Variance Constraint: This constraint limits the total variance of net present cost by taking into account the discount factor, variance in a given year, and the maximum possible variance in the system.

Expected Shortfall Constraint: This constraint measures the tail risk and assesses the effect of worst-case low-probability events.

Lead Time Constraint: This constraint takes into account the lead time of resources built to update the current system state.

The constraints mentioned above are the most relevant ones. For information about the other constraints, refer to the Appendix 19.3

4.3 Deliverables

4.3.1 Gurobi Implementation of Model

The optimization model was run in Gurobi through a python interface. Gurobi is capable of mixed integer programming with quadratic constraints, and its python interface allows for easy extension of the model and interfaces for data input and output.

Figure 6 is a screenshot of the Gurobi implementation of the model in the python interface. The upper section is the model coded in Python. The bottom section is the model output, which includes the construction year, total cost, cost variance, value at risk and shortfall of each of the existing and generation plans.

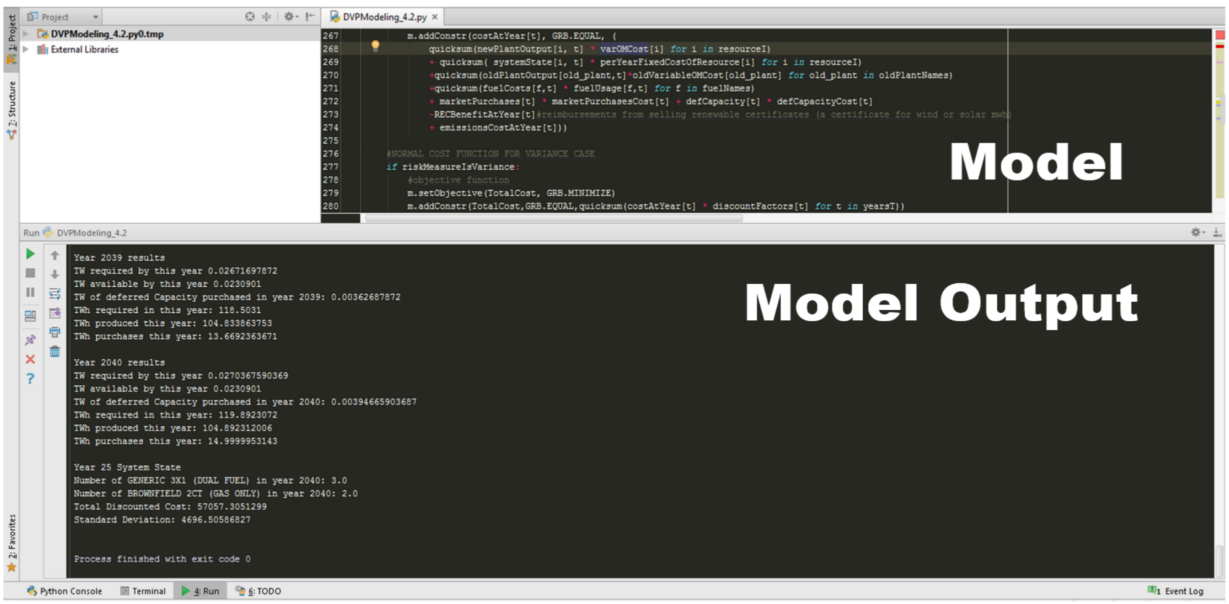

Figure 6: Screenshot of the Gurobi Implementation

For example as seen in Figure 7, Generated Plan 4, which includes 3 Natural Gas plants, 2 Combustion Turbine plants, 167 Solar (Fixed Tilt) plants, 3 Solar (Tag Along) plants. The plan has a total expected cost of \$57.74 billion, standard deviation of \$4.1 billion, Value at Risk of \$77.83 billion and Expected Shortfall of \$85.31 billion.

Generated Plan 4
Number of GENERIC 3X1 (DUAL FUEL) in year 2040: 3.0
Number of BROWNFIELD 2CT (GAS ONLY) in year 2040: 2.0
Number of SOLAR (FIXED TILT) in year 2040: 167.0
Number of SOLAR TAG ALONG in year 2040: 3.0

Total Discounted Cost (expected given projections): 58916.7329738
Standard Deviation: 4100.00026972
Expected Cost (from samples): 57736.0101197
VaR: 77833.7973684

Figure 7: The output of Generated Plan 4

4.3.2 Mean-Variance Efficient Frontier

The first output of the optimization model is a Mean Variance Efficient Frontier. This frontier is a curve that is a collection of minimum cost portfolios for every acceptable level of risk. Here the risk is the variability of cost. The client can choose a level of risk, and the frontier will provide a portfolio with the optimal allocation of resources for that level of risk.

Figure 8 shows the mean-variance efficient frontier without emission constraints. The red dots on the efficient frontier represent the optimal portfolios for every level of risk. The green dots represent the six existing plans, which are not optimal because we can find portfolios that have a lower cost for the level of risk.

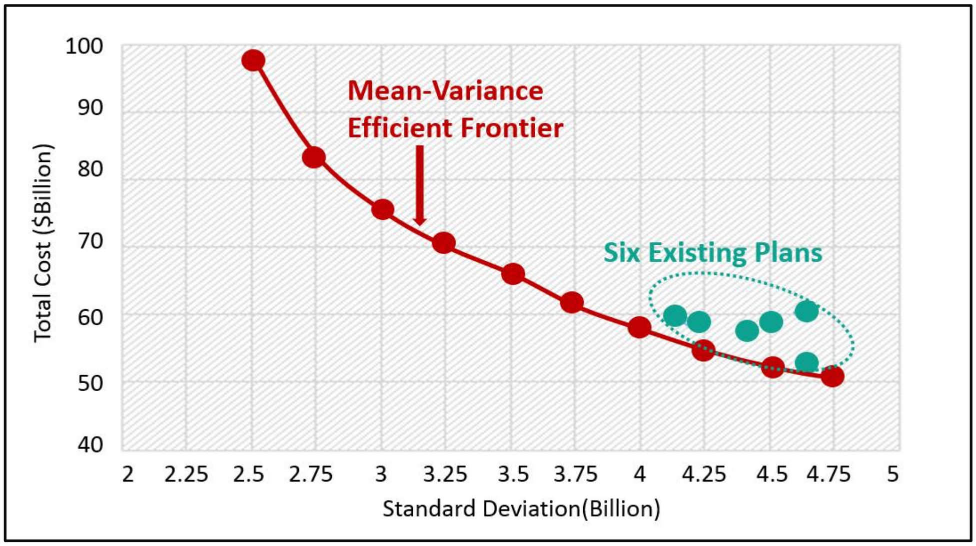

Figure 8: Mean-Variance Efficient Frontier without Emission Cost

After Scenario analysis is conducted to include the effect that emissions have on the model, the frontier is shifted upward as seen in Figure 9.

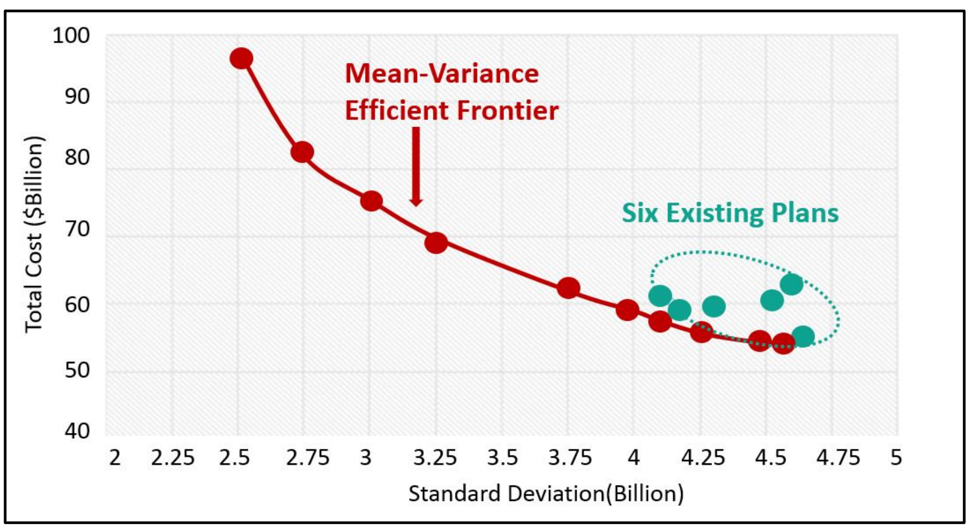

Figure 9: Mean-Variance Efficient Frontier with Emission Cost

4.3.3 Report on Tail Risk Analysis

The model was later updated to include the Expected Shortfall and Value-at-Risk measures of tail risk. Table 7 is the report of Value at Risk and Expected Shorted for each plan.

Table 7: Value at Risk and Expected Shortfalls for Each Existing Plans and Generated Plans

Plan Name	Total Cost ($ Billion)	Value at Risk ($ Billion)	Expected Shortfall $ Billion)
Base	54.63	78.85	87.70
Diversity	61.04	80.39	87.62
Coal	62.25	85.49	94.74
Renewable	59.34	80.74	88.72
Wind	61.15	84.59	93.02
EPA GHG	60.28	79.84	87.22
Generated Plan 1	54.28	77.70	86.00
Generated Plan 2	54.33	77.20	85.32
Generated Plan 3	56.21	77.45	85.30
Generated Plan 4	57.74	77.83	85.31
Generated Plan 5	59.04	78.43	85.64
Generated Plan 6	62.62	80.54	87.04
Generated Plan 7	66.28	82.60	87.76
Generated Plan 8	70.07	85.53	89.53
Generated Plan 9	75.08	89.26	91.68
Generated Plan 10	82.19	93.61	94.77
Generated Plan 11	96.50	103.61	105.45

Figure 10 shows that changing the fuel mix of an energy portfolio does not significantly contribute to a reduction in tail risk. This conclusion suggests that when shortfall is used as a risk measure, the minimum cost plan is the best one for this system.

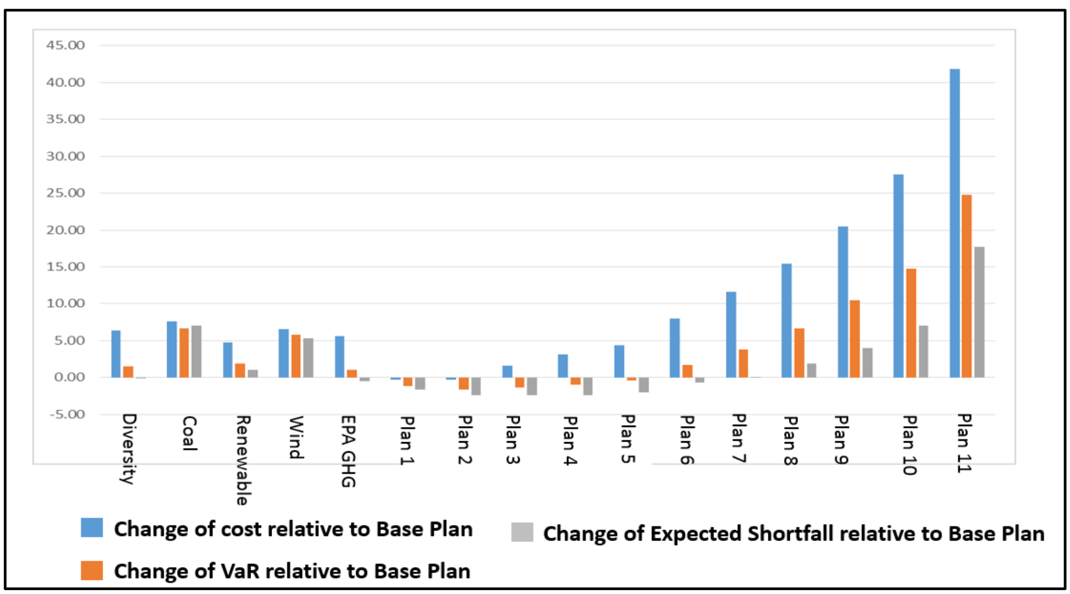

Figure 10: The Effect of Cost Change on Tail Risk

Minimizing expected cost relative to the expected shortfall does not produce very meaningful results. In fact, at low levels of shortfall, the model builds portfolios that include many coal plants. This is not commensurate with a low risk plan as validated by industry expert opinions. For this reason, the results suggest that variance of cost is a better risk measure than expected shortfall for this kind of system. However, expected shortfall is a valuable metric to report for each of the plans on the efficient frontier because it provides an estimate of the worst-case costs DVP may incur.

5. Project Value:

We recommend Generated Plan 4 because it has the same level of standard deviation as the client's preferred plan, but has a lower cost. The cost savings provided to DVP is $171.7 million/year in perpetuity.

Project Valuation Methodology:

Project value is determined by the difference in cost between the client's preferred plan and the plan on the efficient frontier at the same level of risk.

Producing valid project value requires generating a least-cost plan and comparing it to the client's least-cost plan. Our least-cost plan is generated by our MVP model when the model is run without the portfolio variance constraint. Once the MVP model can replicate the least-cost plan of the client's model, the model will produce valid results with the portfolio variance constraint.

With a validated MVP model, a list of generated plans can be compiled and an efficient frontier can be created. The results of this efficient frontier are then validated by expert opinion. With lower levels of risk, the frontier should include plans that produce more renewables and nuclear power. With higher levels of risk, the frontier should include plans that produce almost entirely natural gas.

Cost-Risk Tradeoff:

The client has asked for different options for strategic investment over the planning period of 2015 to 2040. Table 8 provides a list of options each with a different cost, standard deviation, value-at-risk, and expected shortfall.

Table 8: List of Portfolio Alternatives

Plan Name	Total Cost ($ Billion)	Standard Deviation (Billion)	Value at Risk ($ Billion)	Expected Shortfall $ Billion)
Base	54.63	4.64	78.85	87.70
Diversity	61.04	4.10	80.39	87.62
Coal	62.25	4.59	85.49	94.74
Renewable	59.34	4.32	80.74	88.72
Wind	61.15	4.53	84.59	93.02
EPA GHG	60.28	4.14	79.84	87.22
Generated Plan 1	54.28	4.57	77.70	86.00
Generated Plan 2	54.33	4.50	77.20	85.32
Generated Plan 3	56.21	4.25	77.45	85.30
Generated Plan 4	57.74	4.10	77.83	85.31
Generated Plan 5	59.04	4.00	78.43	85.64
Generated Plan 6	62.62	3.75	80.54	87.04
Generated Plan 7	66.28	3.50	82.60	87.76
Generated Plan 8	70.07	3.25	85.53	89.53
Generated Plan 9	75.08	3.00	89.26	91.68
Generated Plan 10	82.19	2.75	93.61	94.77
Generated Plan 11	96.50	2.50	103.61	105.45

The tradeoff between these options is best visualized by the frontier in Figure 11.

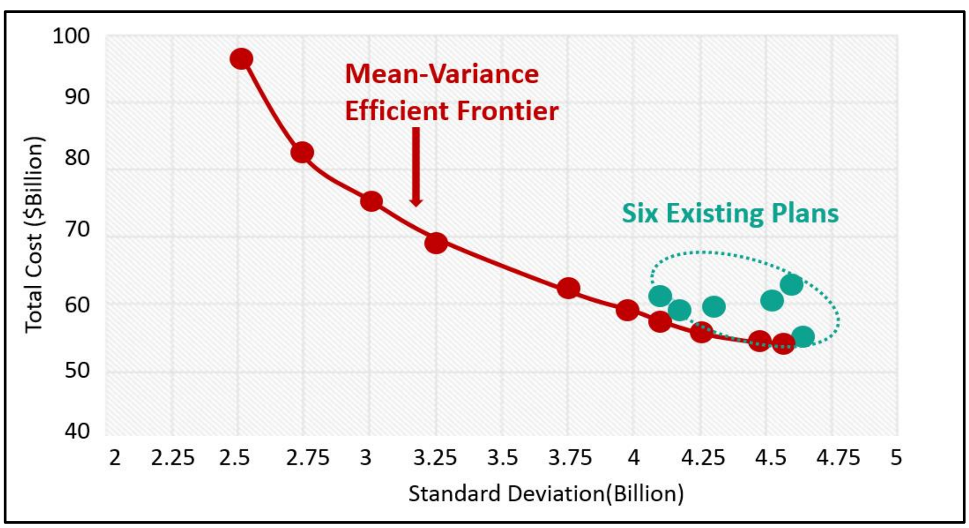

Figure 11: Mean-Variance Efficient Frontier with Emission Cost

Cost Savings:

DVP wants to use an energy portfolio that has a level of quantitative and qualitative risk commensurate with their preferred plan, the Diversity Plan.

Our recommendation to DVP is to use Generated Plan 4 instead of their Diversity Plan as their strategic plan over the next twenty-five years. Generated Plan 4 is as follows:

Year	Resources Built in Year			
2015				
2016	10 SOLAR (FIXED TILT)			
2017	10 SOLAR (FIXED TILT)			
2018	10 SOLAR (FIXED TILT)	1 GENERIC 3X1 (DUEL FUEL)	1 SOLAR TAG ALONG	
2019	10 SOLAR (FIXED TILT)			
2020	10 SOLAR (FIXED TILT)	2 BROWNFIELD 2CT (GAS ONLY)		
2021	10 SOLAR (FIXED TILT)			
2022	10 SOLAR (FIXED TILT)			
2023	10 SOLAR (FIXED TILT)			
2024	10 SOLAR (FIXED TILT)			
2025	10 SOLAR (FIXED TILT)			
2026	10 SOLAR (FIXED TILT)			
2027	10 SOLAR (FIXED TILT)			
2028	10 SOLAR (FIXED TILT)			
2029	9 SOLAR (FIXED TILT)			
2030	1 SOLAR (FIXED TILT)			
2031	1 GENERIC 3X1 (DUEL FUEL)	1 SOLAR TAG ALONG		
2032				
2033				
2034	2 SOLAR (FIXED TILT)			
2035	1 SOLAR (FIXED TILT)			
2036	9 SOLAR (FIXED TILT)			
2037	5 SOLAR (FIXED TILT)			
2038	10 SOLAR (FIXED TILT)			
2039	1 GENERIC 3X1 (DUEL FUEL)	1 SOLAR TAG ALONG		
2040				

The cost of this plan is \$57.736 billion with a standard deviation of \$4.1 billion, value-at-risk of \$77.834 billion, and expected shortfall of \$85.310 billion.

The Diversity Plan (Plan B) has a cost of \$61.038 billion with a standard deviation of \$4.1 billion, value-at-risk of \$80.390 billion, and expected shortfall of \$87.616 billion.

The cost savings provided to DVP is

$61.04 billion - $57.74 billion = $3.3 billion

If we annualize this value by multiplying by r_{wacc} , the annual cost saving would be

$3.3 billion X 0.052 = ~171.5 Million/Year

in perpituity.

Justification of Project Value:

Both the Diversity Plan and Generated Plan 4 include a mix of renewable energy and natural gas, but the Diversity Plan includes the construction of a nuclear power plant and Generated Plan 4 does not. This is the central reason why the cost of Generated Plan 4 is significantly lower than the Diversity Plan.

While nuclear plants are an excellent means by which to reduce the exposure of an energy portfolio to fuel-price risk, there are much cheaper plants/facilities to build that serve the same purpose. For example, the fixed cost per megawatt of capacity of a nuclear plant is $8,442,000 while the cost of a fixed tilt solar facility is $2,261,000 and the cost of an off shore wind farm is $7,050,000. Both solar and wind have zero fuel cost as opposed to the low, yet still nonzero fuel cost for nuclear. The nuclear plant is a better base load plant because it can be run continuously, as opposed to solar or wind facilities which only run when the sun shines or the wind blows. Nevertheless, the disadvantage of the high cost of nuclear plants outweighs the benefits. This is especially true because there are plants already existing in the system that can cover base load if necessary. The results of our model are commensurate with these conclusions.

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Appendices

Appendix Number	Description
1	Plant Types (Provided by DVP)
2	Fuel Prices (Provided by DVP)
3	Construction Cost (Provided by DVP)
4	Base Year Demand (Provided by DVP)
5	Unit Capacity (Provided by DVP)
6	Resource Usage of Existing Plan (Provided by DVP)
7	Market Purchases Cost (Provided by DVP)
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9	Power Plant Efficiency (Provided by DVP)
10	Lead Time (Provided by external source)
11	Projected Demand (Created)
12	Fixed Cost (Created)
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14	Correlation Coefficient between Variable Cost (Created)
15	Covariance between Variable Cost (Created)
16	Total Cost Variance of Existing Portfolio (Created)
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• 17.2	Objective Function
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• 17.4	Constraints

Appendix 1 - Plant Types

PLANT NAME	ENERGY TYPE
SOUTHSIDE 3X1 (S3X1)	Natural Gas
SOUTHSIDE 3X1 (SIEMENS)	Natural Gas
SOUTHSIDE 3X1 (GE)	Natural Gas
GENERIC 3X1 (DUAL FUEL)	Natural Gas
GENERIC 3X1 (GAS ONLY)	Natural Gas
CC CHESTERFIELD	Natural Gas
CC POSSUM POINT 7	Natural Gas
BROWNFIELD 2CT (DUAL FUEL)	Natural Gas
BROWNFIELD 2CT (GAS ONLY)	Natural Gas
GREENFIELD 2CT (DUAL FUEL)	Natural Gas
GREENFIELD 2CT (GAS ONLY)	Natural Gas
BROWNFIELD 1CT (DUAL FUEL)	Natural Gas
GREENFIELD 4CT (DUAL FUEL)	Natural Gas
SCPC W/CCS	Coal
IGCC W/CCS	Coal
SCPC (NO CCS)	Coal
IGCC (NO CCS)	Coal
BIOMASS	Biomass
ON SHORE WIND	No Fuel Cost
SOLAR (FIXED TILT)	No Fuel Cost
SOLAR (TRACKING)	No Fuel Cost
SOLAR TAG ALONG	No Fuel Cost
OFF SHORE WIND	No Fuel Cost
OFF SHORE WIND (DEMO)	No Fuel Cost
NUCLEAR	Nuclear
FUEL CELL	Natural Gas

Appendix 2 - Fuel Prices

Year	YrMo	Date	$/mmbtu Natural Gas	$/ton Coal	$/gal Light Oil	$/bbl Heavy Oil	$/mwh Pwr
1990	199001	01/02/90	#N/A	#N/A	1.02	#N/A	#N/A
1990	199001	01/03/90	#N/A	#N/A	1.01	#N/A	#N/A
1990	199001	01/04/90	#N/A	#N/A	0.93	#N/A	#N/A
1990	199001	01/05/90	#N/A	#N/A	0.85	#N/A	#N/A
1990	199001	01/08/90	#N/A	#N/A	0.75	#N/A	#N/A
1990	199001	01/09/90	#N/A	#N/A	0.73	#N/A	#N/A
1990	199001	01/10/90	#N/A	#N/A	0.74	#N/A	#N/A
1990	199001	01/11/90	#N/A	#N/A	0.77	#N/A	#N/A
1990	199001	01/12/90	#N/A	#N/A	0.77	#N/A	#N/A
1990	199001	01/15/90	#N/A	#N/A	0.71	#N/A	#N/A
1990	199001	01/16/90	#N/A	#N/A	0.69	#N/A	#N/A
1990	199001	01/17/90	#N/A	#N/A	0.64	#N/A	#N/A
1990	199001	01/18/90	#N/A	#N/A	0.64	#N/A	#N/A
1990	199001	01/19/90	#N/A	#N/A	0.65	#N/A	#N/A
1990	199001	01/22/90	#N/A	#N/A	0.62	#N/A	#N/A
1990	199001	01/23/90	#N/A	#N/A	0.60	#N/A	#N/A
1990	199001	01/24/90	#N/A	#N/A	0.60	#N/A	#N/A
1990	199001	01/25/90	#N/A	#N/A	0.60	#N/A	#N/A
1990	199001	01/26/90	#N/A	#N/A	0.60	#N/A	#N/A
1990	199001	01/29/90	#N/A	#N/A	0.61	#N/A	#N/A
1990	199001	01/30/90	#N/A	#N/A	0.61	#N/A	#N/A
1990	199001	01/31/90	#N/A	#N/A	0.59	#N/A	#N/A
1990	199002	02/01/90	#N/A	#N/A	0.58	#N/A	#N/A
1990	199002	02/02/90	#N/A	#N/A	0.59	#N/A	#N/A
1990	199002	02/05/90	#N/A	#N/A	0.57	#N/A	#N/A
1990	199002	02/06/90	#N/A	#N/A	0.57	#N/A	#N/A
1990	199002	02/07/90	#N/A	#N/A	0.57	#N/A	#N/A
1990	199002	02/08/90	#N/A	#N/A	0.55	#N/A	#N/A
1990	199002	02/09/90	2.05	#N/A	0.55	#N/A	#N/A
1990	199002	02/12/90	2.05	#N/A	0.56	#N/A	#N/A

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Year	YrMo	Date	$/mmbtu Natural Gas	$/ton Coal	$/gal Light Oil	$/bbl Heavy Oil	$/mwh Pwr
2003	200308	08/06/03	4.72	30.80	0.82	27.50	#N/A
2003	200308	08/07/03	4.74	30.80	0.85	28.65	#N/A
2003	200308	08/08/03	4.85	30.80	0.83	28.65	#N/A
2003	200308	08/09/03	5.03	#N/A	#N/A	#N/A	#N/A
2003	200308	08/10/03	5.03	#N/A	#N/A	#N/A	#N/A
2003	200308	08/11/03	5.03	#N/A	0.83	28.45	#N/A
2003	200308	08/12/03	5.08	31.00	0.82	27.95	#N/A
2003	200308	08/13/03	5.07	31.25	0.80	27.15	#N/A
2003	200308	08/14/03	5.18	31.50	0.81	27.15	#N/A
2003	200308	08/15/03	5.12	31.50	0.80	27.15	#N/A
2003	200308	08/16/03	4.84	#N/A	#N/A	#N/A	#N/A
2003	200308	08/17/03	4.84	#N/A	#N/A	#N/A	#N/A
2003	200308	08/18/03	4.84	#N/A	0.79	27.25	#N/A
2003	200308	08/19/03	4.94	32.25	0.78	27.25	#N/A
2003	200308	08/20/03	5.00	32.35	0.79	#N/A	#N/A
2003	200308	08/21/03	5.03	32.35	0.82	#N/A	#N/A
2003	200308	08/22/03	5.14	32.35	0.82	#N/A	#N/A
2003	200308	08/23/03	5.24	#N/A	#N/A	#N/A	#N/A
2003	200308	08/24/03	5.24	#N/A	#N/A	#N/A	#N/A
2003	200308	08/25/03	5.24	32.85	0.82	27.70	#N/A
2003	200308	08/26/03	5.27	33.15	0.82	28.05	#N/A
2003	200308	08/27/03	5.09	33.25	0.80	27.30	#N/A
2003	200308	08/28/03	5.11	33.50	0.80	27.58	#N/A
2003	200308	08/29/03	4.94	34.00	0.82	27.40	#N/A
2003	200308	08/30/03	4.94	#N/A	#N/A	#N/A	#N/A
2003	200308	08/31/03	4.94	#N/A	#N/A	#N/A	#N/A
2003	200309	09/01/03	4.88	#N/A	#N/A	#N/A	#N/A
2003	200309	09/02/03	4.88	33.75	0.75	26.40	#N/A
2003	200309	09/03/03	4.62	34.00	0.76	26.33	#N/A
2003	200309	09/04/03	4.68	34.00	0.75	25.83	#N/A
2003	200309	09/05/03	4.70	34.10	0.75	25.33	#N/A

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Year	YrMo	Date	$/mmbtu Natural Gas	$/ton Coal	$/gal Light Oil	$/bbl Heavy Oil	$/mwh Pwr
2014	201412	12/02/14	3.89	53.55	1.98	57.65	38.44
2014	201412	12/03/14	3.74	53.00	1.96	57.35	35.59
2014	201412	12/04/14	3.63	52.95	1.95	56.90	41.14
2014	201412	12/05/14	3.55	52.90	1.95	56.40	37.49
2014	201412	12/06/14	3.43	52.75	#N/A	#N/A	32.52
2014	201412	12/07/14	3.43	#N/A	#N/A	#N/A	35.36
2014	201412	12/08/14	3.43	#N/A	1.89	54.30	41.52
2014	201412	12/09/14	3.50	52.75	1.92	55.10	40.43
2014	201412	12/10/14	3.62	52.75	1.89	52.70	41.90
2014	201412	12/11/14	3.61	52.25	1.90	51.90	42.96
2014	201412	12/12/14	3.67	51.65	1.86	49.90	40.58
2014	201412	12/13/14	3.58	50.75	#N/A	#N/A	33.07
2014	201412	12/14/14	3.58	#N/A	#N/A	#N/A	30.69
2014	201412	12/15/14	3.58	#N/A	1.83	48.70	35.52
2014	201412	12/16/14	3.67	50.55	1.81	47.10	34.29
2014	201412	12/17/14	3.57	50.55	1.85	47.85	35.03
2014	201412	12/18/14	3.66	51.50	1.78	46.30	39.21
2014	201412	12/19/14	3.69	51.50	1.82	48.30	38.39
2014	201412	12/20/14	3.43	51.50	#N/A	#N/A	37.55
2014	201412	12/21/14	3.43	#N/A	#N/A	#N/A	34.95
2014	201412	12/22/14	3.43	#N/A	1.77	47.45	36.63
2014	201412	12/23/14	3.04	51.50	1.82	48.65	30.67
2014	201412	12/24/14	2.97	51.40	1.75	46.90	26.38
2014	201412	12/25/14	2.75	51.40	#N/A	#N/A	26.66
2014	201412	12/26/14	2.75	#N/A	#N/A	#N/A	28.98
2014	201412	12/27/14	2.75	51.40	#N/A	#N/A	27.10
2014	201412	12/28/14	2.75	#N/A	#N/A	#N/A	25.82
2014	201412	12/29/14	2.75	#N/A	1.68	45.40	31.72
2014	201412	12/30/14	3.00	51.50	1.70	45.35	33.96
2014	201412	12/31/14	3.14	51.00	1.71	44.55	37.73

Appendix 3 – Construction Cost

PLANT NAME	Construction Cost $/KW
SOUTHSIDE 3X1 (S3X1)	$ 833
SOUTHSIDE 3X1 (SIEMENS)	$ 907
SOUTHSIDE 3X1 (GE)	$ 830
GENERIC 3X1 (DUAL FUEL)	$ 863
GENERIC 3X1 (GAS ONLY)	$ 855
CC CHESTERFIELD	$ 973
CC POSSUM POINT 7	$ 1,002
BROWNFIELD 2CT (DUAL FUEL)	$ 467
BROWNFIELD 2CT (GAS ONLY)	$ 436
GREENFIELD 2CT (DUAL FUEL)	$ 492
GREENFIELD 2CT (GAS ONLY)	$ 513
BROWNFIELD 1CT (DUAL FUEL)	$ 581
GREENFIELD 4CT (DUAL FUEL)	$ 452
SCPC W/CCS	$ 5,755
IGCC W/CCS	$ 10,431
SCPC (NO CCS)	$ 3,497
IGCC (NO CCS)	$ 6,572
NUCLEAR	$ 8,442
ON SHORE WIND	$ 4,795
OFF SHORE WIND	$ 7,050
OFF SHORE WIND (DEMO)	$ 14,044
SOLAR (FIXED TILT)	$ 2,611
SOLAR (TRACKING)	$ 2,812
SOLAR TAG ALONG	$ 2,120
BIOMASS	$ 5,442
FUEL CELL	$ 5,699

Appendix 4 – Base Year Demand

Year	EnergyDemand (GWh)	PeakDemand (MW)
2015	84712	20157

Appendix 5 - Unit Capacity

PLANT NAME	Plant Capacity (MW)
SOUTHSIDE 3X1 (S3X1)	1565.5
SOUTHSIDE 3X1 (SIEMENS)	1423.7
SOUTHSIDE 3X1 (GE)	1566.5
GENERIC 3X1 (DUAL FUEL)	1565.5
GENERIC 3X1 (GAS ONLY)	1450.6
CC CHESTERFIELD	1451
CC POSSUM POINT 7	1451
BROWNFIELD 2CT (DUAL FUEL)	456.8
BROWNFIELD 2CT (GAS ONLY)	456.8
GREENFIELD 2CT (DUAL FUEL)	456.8
GREENFIELD 2CT (GAS ONLY)	456.8
BROWNFIELD 1CT (DUAL FUEL)	228.4
GREENFIELD 4CT (DUAL FUEL)	913.6
SCPC W/CCS	640
IGCC W/CCS	503
SCPC (NO CCS)	800
IGCC (NO CCS)	629
NUCLEAR	1453
ON SHORE WIND	93
OFF SHORE WIND	504
OFF SHORE WIND (DEMO)	11.126
SOLAR (FIXED TILT)	20
SOLAR (TRACKING)	20
SOLAR TAG ALONG	35
BIOMASS	50
FUEL CELL	13.3

Appendix 6 – Resource Usage of Existing Plan

Plan A: Base Plan	Resource Usage $/MWh
3,132 MW of CC capacity (two CCs)	17833608
914 MW of CT capacity (two banks of 2 CTs – 457 MW per bank)	1601328
Plan B: Fuel Diversity	
1,453 MW North Anna 3 nuclear facility;	11710017.6
247 MW (nameplate) of onshore wind;	865488
12 MW (nameplate) Offshore Wind Demonstration Project;	42048
520 MW (nameplate) of generic solar;	819936
39 MW (nameplate) of solar tag comprised of two units; And selec	61495.2
1,566 MW of CC capacity (one CC);	8916804
457 MW of CT capacity (one bank of 2 CT units).	800664
Plan C: Renewable	
• 247 MW (nameplate) of onshore wind;	865488
• 500 MW (nameplate) of offshore wind;	1752000
• 12 MW (nameplate) Offshore Wind Demonstration Project;	42048
• 1,300 MW (nameplate) of generic solar;	1576.8
• 39 MW (nameplate) of solar tag. And selects:	61495.2
• 1,566 MW of CC capacity (one CC);	8916804
• 914 MW of CT capacity (two banks of 2 CT units – 457 MW per b	1601328
Plan D: Coal	
• 1,920 MW of coal CCS (three 640 MW units); And selects:	10932480
• 1,566 MW of one CC;	8916804
• 457 MW CT capacity (one bank of 2 CT units).	800664
Plan E: Offshore Wind	
• 500 MW of offshore wind in the Planning Period (1,500 MW ove	1752000
• 12 MW (nameplate) Offshore Wind Demonstration Project. And	42048
• 3,132 MW of CC capacity (two CCs);	17833608
• 914 MW of CT capacity (two banks of 2 CT units - 457 MW per b	1601328
Plan F: EPA GHG Plan	
• 247 MW (nameplate) of onshore wind;	865488
• 12 MW (nameplate) Offshore Wind Demonstration Project;	42048
• 39 MW (nameplate) of solar tag;	61495.2
• 1,453 MW North Anna 3 nuclear facility;	11710017.6
• 1,300 MW (nameplate) of generic solar. And selects:	2049840
• 1,566 MW of CC capacity (one CC);	8916804
• 914 MW of CT capacity.	1601328

Appendix 7 – Market Purchases Cost

Year	Cost of Market Purchases millions of $/TWh	
2015	$	45.35
2016	$	46.95
2017	$	48.78
2018	$	50.38
2019	$	52.84
2020	$	55.17
2021	$	56.52
2022	$	57.88
2023	$	59.22
2024	$	61.44
2025	$	63.85
2026	$	66.10
2027	$	68.98
2028	$	71.15
2029	$	75.00
2030	$	77.92
2031	$	82.70
2032	$	87.76
2033	$	92.68
2034	$	97.96
2035	$	103.83
2036	$	107.17
2037	$	110.54
2038	$	115.03
2039	$	119.56
2040	$	124.11

Appendix 8 – Deferred Capacity

Year	RTO ($/kW-yr)	RTO (millions of $/TW-yr)
2015	$ 48.12	$ 48,120.00
2016	$ 32.41	$ 32,412.45
2017	$ 32.72	$ 32,721.92
2018	$ 40.79	$ 40,787.06
2019	$ 51.17	$ 51,173.34
2020	$ 63.93	$ 63,933.80
2021	$ 79.77	$ 79,774.05
2022	$ 77.86	$ 77,856.73
2023	$ 75.70	$ 75,696.03
2024	$ 73.81	$ 73,813.65
2025	$ 71.81	$ 71,810.75
2026	$ 69.97	$ 69,965.52
2027	$ 68.10	$ 68,095.74
2028	$ 66.35	$ 66,352.73
2029	$ 64.65	$ 64,647.37
2030	$ 63.01	$ 63,012.10
2031	$ 62.61	$ 62,613.66
2032	$ 62.25	$ 62,252.72
2033	$ 61.89	$ 61,889.31
2034	$ 61.52	$ 61,523.19
2035	$ 61.12	$ 61,119.59
2036	$ 60.69	$ 60,692.33
2037	$ 60.23	$ 60,226.66
2038	$ 60.05	$ 60,053.95
2039	$ 59.83	$ 59,825.35
2040	$ 59.54	$ 59,544.59
2041	$ 59.23	$ 59,229.87
2042	$ 58.90	$ 58,902.35
2043	$ 58.53	$ 58,534.89
2044	$ 57.40	$ 57,398.48
2045	$ 54.77	$ 54,769.49
2046	$ 52.24	$ 52,241.14
2047	$ 49.84	$ 49,838.81
2048	$ 47.54	$ 47,540.65
2049	$ 45.35	$ 45,354.17
2050	$ 43.27	$ 43,266.74

Appendix 9 – Power Plant Efficiency

Plants	Power Plant Efficiency
SOUTHSIDE 3X1 (S3X1)	0.5124
SOUTHSIDE 3X1 (SIEMENS)	0.4972
SOUTHSIDE 3X1 (GE)	0.5127
GENERIC 3X1 (DUAL FUEL)	0.5124
GENERIC 3X1 (GAS ONLY)	0.4988
CC CHESTERFIELD	0.4988
CC POSSUM POINT 7	0.4988
BROWNFIELD 2CT (DUAL FUEL)	0.3773
BROWNFIELD 2CT (GAS ONLY)	0.3773
GREENFIELD 2CT (DUAL FUEL)	0.3773
GREENFIELD 2CT (GAS ONLY)	0.3773
BROWNFIELD 1CT (DUAL FUEL)	0.3773
GREENFIELD 4CT (DUAL FUEL)	0.3773
SCPC W/CCS	0.3082
IGCC W/CCS	0.3135
SCPC (NO CCS)	0.3853
IGCC (NO CCS)	0.3919
NUCLEAR	0.3247
ON SHORE WIND	1
OFF SHORE WIND	1
OFF SHORE WIND (DEMO)	1
SOLAR (FIXED TILT)	1
SOLAR (TRACKING)	1
SOLAR TAG ALONG	1
BIOMASS	0.3247
FUEL CELL	0.3899

Appendix 10 - Lead Time

PLANT TYPE	LEAD TIME	
Onshore wind	6 months/50MW	2 months/10MW
Offshore wind	32 months	
Solar	6 months	
Natural gas	36 months	
Coal	72 months	

<u>Appendix 11 – Projected Demand (Created)</u>

Year	EnergyDemand (GWh)	PeakDemand (MW)
2015	84712	20157
2016	85813.256	20439.198
2017	86928.82833	20725.34677
2018	88058.9031	21015.50163
2019	89203.66884	21309.71865
2020	90363.31653	21608.05471
2021	91538.03965	21910.56748
2022	92728.03416	22217.31542
2023	93933.49861	22528.35784
2024	95154.63409	22843.75485
2025	96391.64433	23163.56741
2026	97644.73571	23487.85736
2027	98914.11727	23816.68736
2028	100200.0008	24150.12098
2029	101502.6008	24488.22268
2030	102822.1346	24831.0578
2031	104158.8224	25178.69261
2032	105512.8871	25531.1943
2033	106884.5546	25888.63102
2034	108274.0538	26251.07186
2035	109681.6165	26618.58686
2036	111107.4775	26991.24708
2037	112551.8747	27369.12454
2038	114015.0491	27752.29228
2039	115497.2447	28140.82437
2040	116998.7089	28534.79591

Appendix 12– Fixed Cost (Created)

$$FC = \frac{Fixed\ O\&M\ Cost + Construction\ Cost}{Projected\ Demand}\ (\$/kW - year)$$

PLANT NAME	FIX COST $/kW-yr
SOUTHSIDE 3X1 (S3X1)	138.9111229
SOUTHSIDE 3X1 (SIEMENS)	151.6937686
SOUTHSIDE 3X1 (GE)	138.5512686
GENERIC 3X1 (DUAL FUEL)	134.9213661
GENERIC 3X1 (GAS ONLY)	153.502842
CC CHESTERFIELD	211.7535365
CC POSSUM POINT 7	215.3982544
BROWNFIELD 2CT (DUAL FUEL)	66.84928465
BROWNFIELD 2CT (GAS ONLY)	62.38008324
GREENFIELD 2CT (DUAL FUEL)	77.11932927
GREENFIELD 2CT (GAS ONLY)	86.55394454
BROWNFIELD 1CT (DUAL FUEL)	90.45499173
GREENFIELD 4CT (DUAL FUEL)	72.27676947
SCPC W/CCS	754.4924834
IGCC W/CCS	1386.441899
SCPC (NO CCS)	464.8752541
IGCC (NO CCS)	880.8956349
NUCLEAR	1135.510979
ON SHORE WIND	647.2298467
OFF SHORE WIND	1323.895417
OFF SHORE WIND (DEMO)	2301.530529
SOLAR (FIXED TILT)	329.3943767
SOLAR (TRACKING)	362.0890573
SOLAR TAG ALONG	274.6402859
BIOMASS	908.5589684
FUEL CELL	1040.032534

Appendix 13 – Variable Cost (Created)

$$VC = \frac{Variable\ O\&M\ Cost + Fuel\ cost}{Projected\ Demand}\ (\$/kWh)$$

PLANT NAME	VARIABLE COST $/Mwh
SOUTHSIDE 3X1 (S3X1)	73.74832294
SOUTHSIDE 3X1 (SIEMENS)	76.29440311
SOUTHSIDE 3X1 (GE)	73.75984285
GENERIC 3X1 (DUAL FUEL)	73.85314514
GENERIC 3X1 (GAS ONLY)	75.70848071
CC CHESTERFIELD	75.91040922
CC POSSUM POINT 7	75.67019168
BROWNFIELD 2CT (DUAL FUEL)	107.1514984
BROWNFIELD 2CT (GAS ONLY)	108.157607
GREENFIELD 2CT (DUAL FUEL)	107.1514984
GREENFIELD 2CT (GAS ONLY)	108.157607
BROWNFIELD 1CT (DUAL FUEL)	108.1572206
GREENFIELD 4CT (DUAL FUEL)	106.7128868
SCPC W/CCS	140.8015509
IGCC W/CCS	131.4288199
SCPC (NO CCS)	75.90016166
IGCC (NO CCS)	66.13279533
NUCLEAR	12.36327113
ON SHORE WIND	5.872179462
OFF SHORE WIND	-11.14574498
OFF SHORE WIND (DEMO)	-11.14574498
SOLAR (FIXED TILT)	-10.19029602
SOLAR (TRACKING)	-10.19029602
SOLAR TAG ALONG	-10.19029602
BIOMASS	55.32699599
FUEL CELL	69.17911959

Appendix 14 - Correlation Coefficient between Variable Cost (Created)

$$\rho_{xy} = \frac{E(xy) - E(x)E(y)}{\sqrt{E(x^2) - E(x)^2}\sqrt{E(y^2) - E(y)^2}}$$

X and Y are variable cost of two different fuels

Fuel Type	Coal	Oil	Natural Gas	Nuclear	Biomass	PowerPurchase
Coal	1	-0.15	0	0.07	-0.47	0
Oil		1	0	-0.09	-0.18	0
Natural Gas			1	-0.31	0.02	1
Nuclear				1	-0.19	-0.31
Biomass					1	0.02
PowerPurchase						1

Appendix 15 - Covariance between Variable Cost (Created)

$$\mathrm{COV}(\mathrm{x}, \mathrm{y}) = \rho_{xy}\sigma_x\sigma_y$$

σ_x and σ_y are the standard deviations of two different fuel prices

Fuel Type	Coal	Oil	Natural Gas	Nuclear	Biomass	PowerPurchase
Coal	40.0023	-35.8722	0	0.582407	-20.6679	0
Oil		1429.71	0	-4.47664	-47.3208	0
Natural Gas			358.9698672	-7.72639	2.6346	606.1582624
Nuclear				1.7305	-1.73778	-13.04681571
Biomass					48.34053	4.448798657
PowerPurchase						1023.561788

Appendix 16 – Total Cost Variance of Existing Portfolio (Created)

$$\mathrm{Var}\ (\mathrm{CostAtYear}_t) = Var[\textstyle\sum_i (\mathrm{ResourceUsage}_{i,t} * \mathrm{VariableCost}_{i,t}) + \sum_i \mathrm{FixedCost}_{i,t} +$$

$$MarketPurchases_t * MarketPurchasesCost_t + DefCapacity_t * DefCapacityCost_t]$$

$$= Var \sum_i (\mathrm{ResourceUsage}_{i,t} * \mathrm{VariableCost}_{i,t}) + 0$$

$$= \sum_i \sum_j \mathrm{ResourceUsage}_{i,t} * \mathrm{ResourceUsage}_{j,t} * Cov(\mathrm{VariableCost}_{i,t} * \mathrm{VariableCost}_{j,t})$$

Energy Plan	Variance	Standard Deviation
Plan A: Base Plan	50890625358.6	225589.5
Plan B: Fuel Diversity	11425436431.9	106889.8
Plan C: Renewable	25445312679.3	159515.9
Plan D: Coal	12371712406.9	111228.2
Plan E: Offshore Wind	50890625358.6	225589.5
Plan F: EPA GHG Plan	23855048037.1	154450.8

Appendix 17 - Mixed Integer Program Notation

17.1 - Assumptions:

- Variability (standard deviation) of **Net Present Cost** (Net Present Value of portfolio cost) is an acceptable measure of risk
- Historical fuel cost covariance is a reasonable estimate for future fuel cost covariance.
- Total variance of Net Present Cost of a portfolio can be computed as a linear combination (adjusted by r_{wacc}) of yearly cost variances.
- In addition there are a number of cost assumptions given to us by the client (e.g. O&M costs have 0 variance)
- Cost is i.i.d. over time
- The variance and covariance of fuel cost is constant over time
- Construction lead time is constant over time and occurs strictly in discrete intervals.
- Cov($Resource_1$, $Resource_2$) = Cov($FuelCost_1$, $FuelCost_2$) (e.g. the only cost component that affects covariance is fuel cost)
- Randomly sampled fuel cost vectors from the distribution of historical fuel costs are a reasonable estimate of future fuel costs.
- The only stochastic component of total portfolio cost is fuel cost and market purchases cost.

17.2 - Objective Function:

$$Minimize\ \alpha * \sum_{k} \left(\frac{CostSamples_k}{100}\right) + (1 - \alpha) * Shortfall$$

Where 100 is the number of samples of total cost from historical data and

$$CostSamples_k \geq \sum_t (DiscountFactor_t * (\sum_f (FuelUsage_{f,t} * CostVectorSamples_{k,f,t}) + \sum_i (VariableOperationsCostOfOldPlant_i * OldPlantOutput_{i,t}) + \sum_i (VariableOperationsCostOfNewPlant_i * NewPlantOutput_{i,t}) + \sum_i (NewPlantsSystemState_{i,t} * FixedCostOfNewPlant_{i,}) + MarketPurchases_t * MarketSamples_{k,t} + DefCapacity_t * DefCapacityCost_t + EmissionsCost_t) \ \forall_k$$

17.3 - Variable Definitions:

Decision Variables:

- *NewResourcesBuilt*$_{i,t}$: This variable is the number of plants of type *i* built at time *t*. For example, if *NewResourcesBuilt*$_{1,5}$ = 1, that means in 2020 our model builds one 1.5 GW Combined Cycle natural gas plant. This value should always be an integer.

- *NewPlantOutput*$_{i,t}$: Amount of energy produced by all plants constructed in the planning period of type i in year t (Terawatt hours).

- *OldPlantOutput*$_{i,t}$: Amount of energy produced during period t by preexisting plant i. This includes usage from plants that are already under construction at the start of the planning period (Terawatt hours).

- *FuelUsage*$_{f,t}$: Amount of fuel of type *f* used in period *t*. Measured in Terawatt hours, but more Terawatt hours of fuel will be used than the corresponding electricity gain from that fuel due to plant inefficiency.

- *NewPlantsSystemState*$_{i,t}$: The total number of plants *i* constructed during the planning period by time *t*.

- *MarketPurchases*$_t$: The total amount of energy in Terawatt-hours purchased from PJM at time t.

- *DefCapacity*$_t$: The total amount of energy in Terawatts bought in deferred capacity at time t

- *VaR*: The value at which the probability that the realized cost is less than this value is β.

- *Shortfall*: The expected value of the worst-case costs. This is a measure of tail risk.

- *CostSamples*$_k$: The samples of total cost based on randomly sampled historical fuel cost and market purchases data.
- *EmissionsCost*$_t$ *:* The total emissions cost in year t

Parameters:

- r_{wacc}: Weighted Average Cost of Capital. This is analogous to the rate of return a company can expect from investing funds internally and can be used for net present value calculations. According to the client, DVP's r_{wacc} is 5.2 % for the purposes of generation planning.

- *ReserveMargin*: Amount of capacity above projected peak demand (as a percentage of peak demand) the utility must maintain, as required by the regulatory body (in this case PJM). PJM's required reserve margin is 11.2%.

- Var_{max}: Maximum acceptable variance of the net present portfolio cost. Running this model multiple times with different Var_{max} should generate an efficient frontier. Represents the acceptable risk level.

- β: This is the confidence level of the expected shortfall calculation. It is also the probability that the cost is less than the value at risk.

- α: This value is a tool used to create an efficient shortfall frontier. α = 0 is a minimum shortfall plan. α = 1 is a minimum cost plan.

17.4 - Constraints:

Peak Power Demand Constraint:

$$(1 + ReserveMargin) * PeakDemand_t \leq \sum_i (OldUnitsCap_i) + \sum_i \left(NewUnitsCap_i * NewPlantsSystemState_{i,t}\right) + DefCapacity_t \qquad \forall t$$

Our model must meet peak demand (plus reserve) with plants built in the year t or in previous years.

Energy Demand Constraint:

$$EnergyDemand_t \leq \sum_i (NewPlantOutput_{i,t}) + \sum_i (OldPlantOutput_{i,t}) + MarketPurchases_t \quad \forall t$$

Our model must be able to meet all customer demand for electricity every year.

Maximum Power Generation Constraint:

$$NewPlantOutput_{i,t} \leq NewUnitsCap_i * SystemState_{i,t} * NewEquivalentAvailability_i * 8760 \qquad \forall i, t$$

$$OldPlantOutput_{i,t} \leq OldUnitsCap_i * OldEquivalentAvailability_i * 8760 \quad \forall i, t$$

We cannot generate more power than the sum of our constructed capacity. 8760 is the number of hours in a year. It is used to convert power to energy.

Fuel Usage Constraint

$$FuelUsage_f \geq \sum_{i\ \in fuel\ f} \frac{OldPlantOutput_i}{OldPlantEfficiency} + \sum_{i\ \in fuel\ f} \frac{NewPlantOutput_i}{NewPlantEfficiency}$$

A given fuel usage is how much of a fuel (eg. Natural Gas) is actually consumed
by the system $i\ \varepsilon\ fuel\ f$ is the set of plants that consumes fuel f.

Emissions Cost

$$EmissionsCost_t \geq \sum_f FuelUsage_{f,t} * FuelCarbonCosts_{f,t} \qquad \forall_t$$

Plants that pollute have a cost associated with the amount of pollution.

Maximum Onshore Wind Constraint:

$$\sum_{\boldsymbol{t}} (NewResourcesBuilt_{19,t} * NewUnitCap_{19}) \leq 0.00025$$

We can only build a total of 250 MW of onshore wind over the planning period.

Maximum Offshore Wind Constraint:

$$\sum_{\boldsymbol{t}} (NewResourcesBuilt_{22,t} * NewUnitCap_{22} + ResourcesBuilt_{23,t} * NewUnitCap_{23}) \leq 0.002$$

We can only build a total of 2000 MW of offshore wind over the planning period.

Maximum Solar Constraint:

$$\sum_{i=24}^{26} (NewResourcesBuilt_{i,t} * NewUnitCap_i) \leq 0.0002 \qquad \forall t$$

We can only build a total of 200 MW of solar during each year.

Solar Tag along Constraint:

$$NewResourcesBuilt_{24,t} \leq \sum_{i=1}^{7} NewResourcesBuilt_{i,t} \quad \forall t$$

Solar tag alongs (24) can only be built with combined cycle plants(1-7). So the number of constructed tag alongs needs to be less than or equal to the total number of constructed combined cycle plants in every year.

Portfolio Variance Constraint:

$$Var_{max} \geq \sum_{t} (DiscountFactor_t^2 * VarInYear_t)$$

where

$$VarInYear_t = \sum_i \sum_j (FuelUsage_{a,t} * FuelUsage_{b,t} * FuelCovariance_{a,b}) + \ MarketPurchase_t^2 \ * MarketVar + 2 * \ \sum_f (FuelUsage_{f,t} * \ MarketPurchase_t \ * \ MarketCovWithFuel_f)$$

We can see that is a reasonable formula for variance by examining variance of a year's cost. (Currently neglecting market purchases).

$$CostAtYear_t = \ \sum_i \left(ResourceUsage_{i,t} * VariableCost_{i,t}\right) + \sum_i (NewPlantSystemState_{i,t} * FixedCost_i)$$

$$Var(CostAtYear_t) = Var(\sum_i ResouceUsage_{i,t} * VariableCost_{i,t}\,) + 0 \ = \ \sum_i \sum_j ResourceUsage_{i,t} * ResourceUsage_{j,t} * Cov(VariableCost_{i,t}\,, VariableCost_{j,t})$$

Expected Shortfall:

$$s_k \ \geq \ CostSamples_k - \ VaR$$

$$s_k \ \geq 0 \qquad \forall_k$$

$$Shortfall = VaR + \frac{1}{(1-\ \beta) * 100} * \sum_k s_k$$

Expected Shortfall is the expected value of the highest costs. For a given confidence level, β, we can determine the average costs that occur in the highest (1 – β) % of cases. The 100 in the denominator is the number of samples. For α = 1, shortfall is calculated as the average of the highest 5 values in $CostSamples_k$ and Value-at-Risk is calculated as the 5th highest value in $CostSamples_k$.

Lead Time Constraint:

$$NewPlantSystemState_{i,t} = NewPlantSystemState_{i,t-1} + NewResourcesBuilt_{i,t-LeadTime_i} \quad \forall i, t$$

Resources take time to build, thus we update the system state according to the lead time of each resource. t = 0 is handled as a special case in the code.