ELECTRICITY GENERATION CHOICES: COMBINED CYCLE GAS AND WIND IN PORTUGAL

ESD.71 APPLICATION PORTFOLIO

JP Connolly

November 2006

(intentionally blank)

EXECUTIVE SUMMARY

Demand for electricity in the country of Portugal is expected to grow significantly over the next 25 years, and the country must expand its generation capacity in order to meet this demand. This paper focuses on options for generation expansion with combined-cycle gas fired (CCGF) and wind generation. Three expansion paths are explored, including:

- Building a single large CCGF plant,
- Building a smaller CCGF plant now and a second smaller plant later, allowing flexibility in the sizing of the second plant, and
- Building a smaller CCGF plant now and allowing a mix of CCGF and wind to be installed later, allowing flexibility in the total size and relative mix of CCGF/wind.

The choice of optimal strategy depends on the future demand for electricity and the future natural gas price, both of which are uncertain. Using a range of possible outcomes chosen based on historical data, a decision tree was conducted to choose the optimal expansion strategy. Based on this analysis, the third plan (small initial plant and possible CCGF and wind in the future) is optimal, with an expected net present value of $8.2 billion over the 25-year period considered.

Having chosen a small initial plant, the value of a put option on that plant was explored for the case of constant demand growth but variable gas prices. Using a lattice model, the value of such an option was found to be $500 million.

Thus the optimal expansion strategy according to decision tree analysis is via Plan 3 (small initial plant and options for gas and wind), but up to $500 million should be spent to maintain the option to close the initial gas plant in the case of high gas prices.

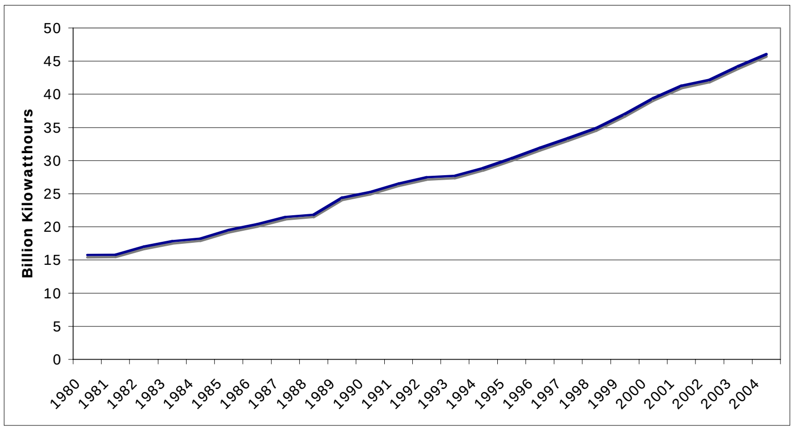
Finally, the situation was explored with a Monte Carlo simulation that includes modeling demand, gas price, and carbon price stochastically. In addition, decisions to build were evaluated every year (versus 12 years in the decision tree) and a model of imperfect investor expectations was added. Using this approach, the value of the flexibility of the third plan was calculated as $1.1 billion. This is greater than the value calculated with the decision tree, and this difference is expected. Since the simulation includes greater uncertainty and models Plan 3 as more flexible (with more frequent decision points) than the decision tree, the value of flexibility is greater.

TABLE OF CONTENTS

1 SYSTEM DESCRIPTION

Electricity demand in Portugal is rising along with increasing affluence in the country (see Figure 1). The ability to meet this rising demand, the desire to increase energy security, and the need to meet carbon restrictions imposed by the Kyoto Protocol are all motivating factors in the expansion and diversification of the country's electricity generation portfolio. Two options being pushed by the federal government are combined cycle gas fired (CCGF) generation and wind generation[1].

Figure 1. Electricity Consumed in Portugal since 1980[2]



For the scope of this project I have considered only these two generation options. Portugal has recently created an integrated deregulated gas market with Spain, but I have limited this analysis to domestic demand for two reasons. First, historical data is much more accessible for the single-country market. Second, and more importantly, the deregulated Iberian market has only existed 2 years, making the historical price sample small.

Design Levers

The principle design variables included are the relative mix of wind and CCGF generation and the sizing of new generation facilities. Capital cost models for wind and CCGF projects are derived below, based on the International Energy Agency's "Projected Costs of Generating Electricity" report[3].

A second consideration which is of interest for both technologies is site selection, but for the purpose of this analysis I have not included siting as a design parameter. Portugal imports natural gas through two pipelines across the Spanish border and is considering construction of more pipelines[4]. It also imports liquefied natural gas (LNG) via a port in Sines[5]. If costs of transmission or transportation of fuel are considered, location near one importation site or both will be a critical component in

1 International Energy Agency "Energy Policies of IEA Countries: Portugal" OECD Publications Service, France, 2004.
2 Energy Information System "International Energy Data" accessed at http://www.eia.doe.gov/emeu/international/energy.html.
3 International Energy Agency "Projected Costs of Generating Electricity" OECD Publications, France, 1998. As used in Roques et al. "Nuclear Power: A Hedge against Uncertain Gas and Carbon Prices?" *Energy Journal in press*.
4 Energy Information Administration "Country Analysis Briefs: Iberian Peninsula" accessed at http://www.eia.doe.gov/emeu/cabs/iberian.html.
5 *Id.*

determining operating costs of the CCGF generation facilities. Likewise, wind sites vary enormously in potential, and wind potential coupled with transmission costs create a complex set of design considerations for wind development.

Benefits of the System

An electricity generation system provides necessary power to individual consumers and businesses. The best system does this reliably at a low cost. Therefore cost of generation, amount generated, and reliability are the major benefits of a well-designed system. Amount generated is really a design parameter in this project, and it is related to generation cost based on the fuel used and the type of generation facility. The model of this relationship is developed below. Modeling reliability has not been done as part of this analysis.

Uncertain Contextual Factors

A number of contextual factors that could determine the optimal generation system design remain uncertain, including:

- The cost of gas, which has displayed significant volatility, and the relative costs of LNG and pipeline gas. Also of importance are potential disruptions to gas supplies due to geopolitical changes or terrorist attacks.
- The regulatory regime, especially with regards to the Kyoto Protocol and the EU Emissions Trading Scheme. Portugal could seek to achieve a significant portion of its carbon reductions in the electricity sector, or it could seek those reductions in a separate sector. Volatility in the price of carbon credits in the ETS could be a significant consideration, as well as potential value in Joint Implementation projects (a second mechanism for carbon reduction under Kyoto, whereby an investor-nation supports some or all of the costs of carbon reduction in a host-nation).
- Changes in the competitive market, including the deregulation of electricity and the integration of the market with Spain.
- Changes in alternatives to gas and wind. Oil supplies are susceptible to disruption, and hydropower generation is volatile, for example.
- Technological change in gas or wind generation technologies may create opportunities for lower capital or operating costs of generation projects.

STATEMENT OF ISSUE

Energy planners in the deregulated Portuguese electricity market face uncertainties that will influence the optimal sizing and carbon intensity of generation options. Options analysis is used to determine 1) the optimal strategy to deal with these uncertainties and 2) the value of flexibility in these design variables in the future.

2 SOURCES OF UNCERTAINTY

The three uncertainties explored in this analysis are natural gas prices, consumer demand, and the cost of carbon emissions under the EU Emissions Trading Scheme. I discuss each of these in greater detail below.

Wellhead Natural Gas Prices

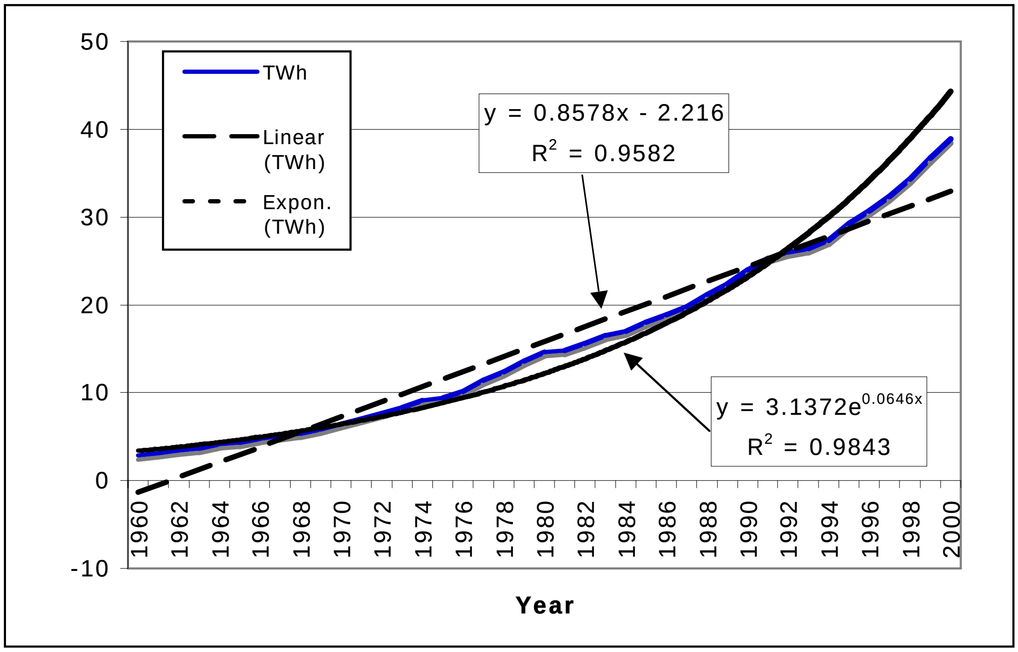
The cost to the utility of natural gas is vulnerable to geopolitical forces outside Portugal's control, and as such it displays significant volatility. The world prices are influenced by chaotic events (weather), long-term trends (depleting supplies), and unpredictable military and political developments (terrorist attacks or national power struggles). Because recent years have included these types of events (Hurricane Katrina and Russian supply disruptions, for example) we might expect the volatility in future gas prices to be similar to the volatility of recent history. It will be important, then, to use historical natural gas prices to identify both long-term trends and variance about these trends (measured as the standard deviation).

Monthly natural gas price data for Portugal was unavailable at this time, and yearly data is likely to hide much of the intra-annual variability. As a proxy, I use EU Average pipeline import prices, available from the European Commission. The data is shown in Figure 15. The average value over the time series is 3.12 $/MBtu and the maximum is the most recent price of 7.15 $/MBtu.

Electricity Demand

The demand for electricity in Portugal is expected to grow, but there are obvious uncertainties that will influence the rate and volatility of growth. Historical electricity demand and trends fit to this data are shown in Figure 2. As shown, electricity has grown steadily since 1960.

Figure 2. Annual Electricity Demand in Portugal[6]



Price of Carbon Emissions

The European Union has recently implemented the Emissions Trading Scheme (ETS), a carbon-trading scheme that allows the trading of an allowance to emit carbon. I will assume that the entity making these generation design decisions does not presently own the emissions allowances and must purchase them. The emissions trading market has existed for less than two years but it has exhibited significant volatility, introducing an important uncertainty into future design considerations.

Figure 3 presents daily prices of 3-month carbon futures as traded on the European Climate Exchange (ECX). This exchange handles a large volume of emissions trading in Europe, so I propose that the short-term futures price traded on this exchange will be representative of the real cost of emitting carbon under the ETS. The descriptive statistics for this dataset, which would be used to create the mean-reversion model, are shown in Figure 4.

6 "Summary Electricity Production and Consumption (TWh) Vol 2002 release 01" database available from the Organization for Economic Cooperation and Development . Accessed at http://caliban.sourceoecd.org.libproxy.mit.edu/vl=1184286/cl=20/nw=1/rpsv/statistic/s28_about.htm?jnlissn=16834283(note this link requires MIT Certificates).

Figure 3. Price of 3-Month Carbon Futures Traded on ECX[7]

Figure 4. Descriptive Statistics of Carbon Trading Price Data[8]

Euros per tonne C	
Mean	21.67
Standard Error	0.21
Median	21.95
Mode	22.20
Standard Deviation	2.73
Sample Variance	7.47
Kurtosis	1.03
Skewness	0.30
Range	13.20
Minimum	16.05
Maximum	29.25
Sum	3575.15
Count	165.00
Confidence Level(95.0%)	0.42

7 "ECX futures data 22 April 2005 - 29 September 2006" database available from the European Climate Exchange at http://www.ecxeurope.com/.

8 *Id.*

3 SYSTEM MODEL

System Design Parameters: Description of Flexibility

The variable system design parameters in this analysis are plant sizing and mix of gas and wind generation. A future extension of this analysis could also include the choice of LNG vs. pipeline gas and site selection. I first detail my model of the performance consequences of sizing below, and then I explain the four designs I will consider in the analysis.

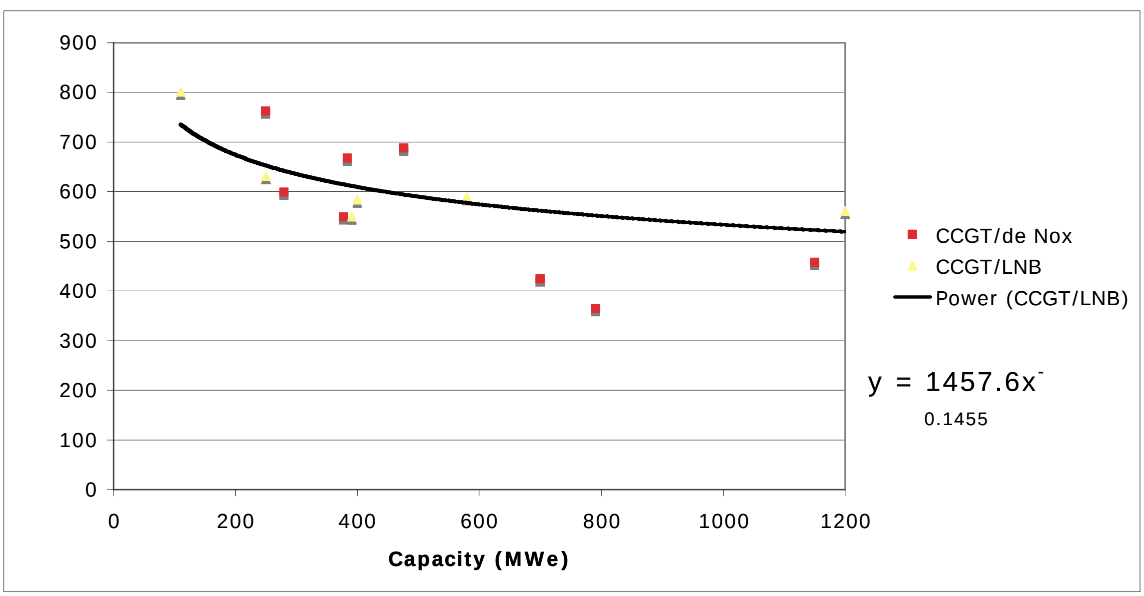
Gas Plant Sizing

The International Energy Agency's "Projected Costs of Generating Electricity" report[9] provides estimated capital costs and operating costs for a number of recently constructed combined-cycle gas-fire electricity generation plants. I have used this information to estimate a model of costs per capacity as a function of capacity. The capital cost per capacity vs. capacity for the plants reported is presented in Figure 5. From this data I have estimated the following capital cost model:

$$\text{Capital Cost per Capacity (US\$/kWe)} = 1500 \cdot C^{-0.15}$$

Where C, the capacity, is in MWe.

Figure 5. Overnight Cost vs. Capacity[10], with Proposed Model Shown



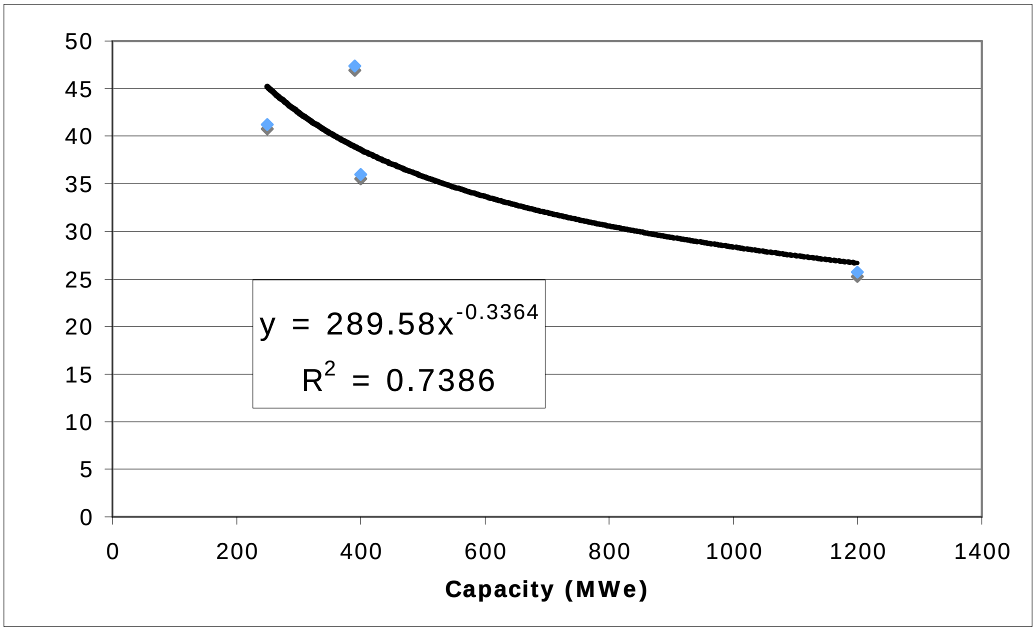
Operating and maintenance costs per capacity were also reported for the same plants, and from these I have estimated the following annual O&M cost model:

$$\text{O \& M Costs (US\$/kWe)} = 290 \cdot C^{-0.34}$$

9 International Energy Agency "Projected Costs of Generating Electricity" OECD Publications, France, 1998.
10 Id.

Figure 6 shows the cost data and model graphically.

Figure 6. O&M Costs vs. Capacity[11], with Proposed Model Shown



Wind Generation Sizing

Data for wind generation facilities is also presented in the IEA “Projected Costs of Generating Electricity” report[12]. Figure 7 presents overnight capital cost per capacity vs. capacity for 13 recently completed onshore wind facilities. Figure 8 presents O&M costs per capacity vs. capacity for these same facilities. There is no clear trend to either of these datasets (probably a reflection of the influence that site-specific factors play in determining wind costs in particular) so I will assume a constant average cost per capacity of

$$1300\ \frac{\text{US\$}}{\text{kWe}}\ \text{overnight capital cost, and}$$

$$23\ \frac{\text{US\$}}{\text{kWe}}\ \text{annual O \& M cost}$$

11 Id. – I understand this isn’t many data points when it come to asserting a model. This model is used for demonstration and should be refined in a future analysis.

12 Id.

Figure 7. Overnight Cost vs. Capacity for Wind Generation Construction[13]

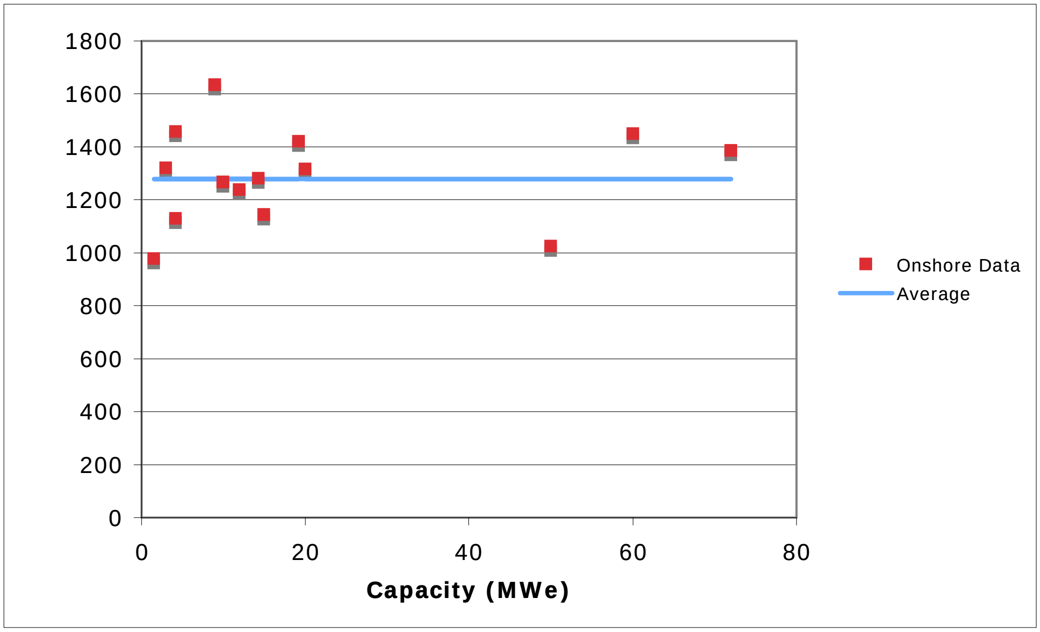
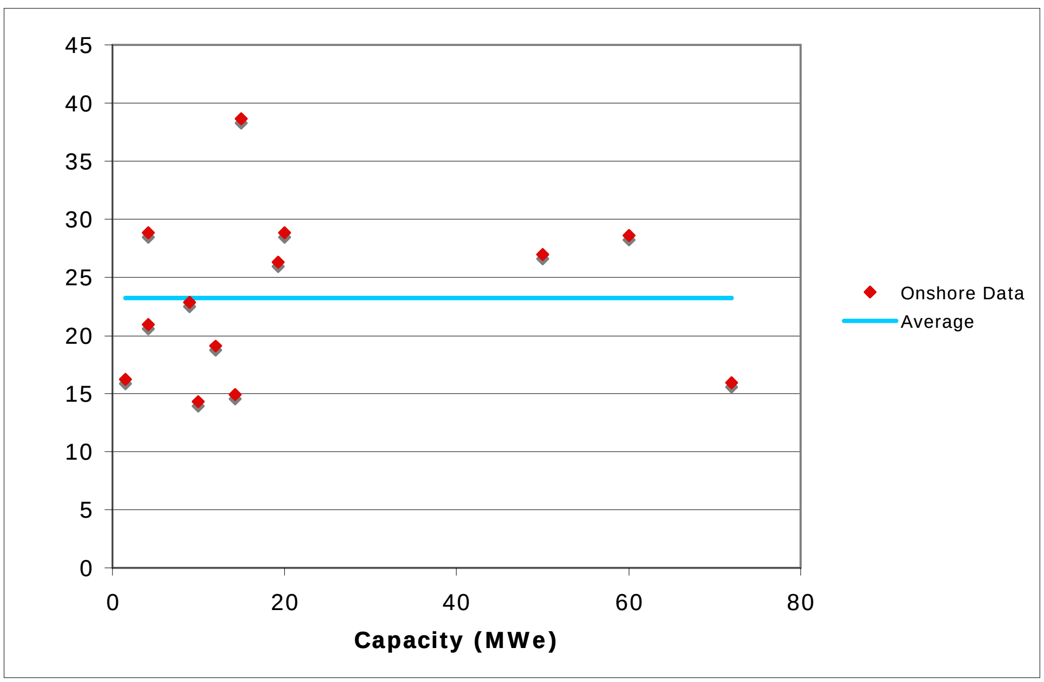


Figure 8. O&M Costs vs. Capacity for Wind Generation[14]



13 Id.
14 Id.

Design Alternatives

I will assume a 25-year time horizon, with the goal of meeting any increases in current electricity demand while maximizing profit. I will ignore the replacement of decommissioned plants in this analysis, and assume that the lifetime of the plants constructed is greater than the time horizon to be considered.

Alternative 1 – Large Gas Plants

The first alternative will be to meet the future demand increase for 25 years with one 3000 MW facility. This size is chosen to meet the 25-year demand projected by assuming a linear growth in demand with the growth rate calculated from historical data. A screenshot of the model is shown in Figure 9.

Figure 9. Model for Plan 1

Year		**2005**	**2006**	**2016**	**2017**	**2018**	**2029**	**2030**
	Units							
Demand	TWh/yr	-	0.9	9.5	10.3	11.2	20.6	21.5
Electricity Price	$/kwh	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16
Gas Price	US$/MBTU	3.12000	3.12000	3.12000	3.12000	3.12000	3.12000	3.12000
Carbon Price	US$/kgC	0.027	0.027	0.027	0.027	0.027	0.027	0.027
System								
CCGT Cap Expansion	MWe	3,000	-	-	-	-	-	-
CCGT Deployed Cap	MWe	-	3,000	3,000	3,000	3,000	3,000	3,000
Wind Cap Expansion	MWe	-	-	-	-	-	-	-
Deployed Wind Cap	MWe	-	-	-	-	-	-	-
Deployed Wind Fraction		0	0	0	0	0	0	0
Deployed CCGT Fraction		0	1	1	1	1	1	1
CCGT Production Cap	TWh/yr	0	22.338	22.338	22.338	22.338	22.338	22.338
Wind Production Cap	TWh/yr	0	0	0	0	0	0	0
Total Production Cap	TWh/yr	0	22.338	22.338	22.338	22.338	22.338	22.338
Actual Production	TWh/yr	-	0.9	9.5	10.3	11.2	20.6	21.5
Cash Flows								
Capital Costs	mil$/yr	$ 1,354	$ -	$ -	$ -	$ -	$ -	$ -
O&M Costs	mil$/yr	$ -	$ 57	$ 57	$ 57	$ 57	$ 57	$ 57
Fuel Costs	mil$/yr	$ -	$ 19	$ 207	$ 225	$ 244	$ 451	$ 470
Carbon Costs	mil$/yr	$ -	$ 2	$ 26	$ 28	$ 31	$ 57	$ 59
Revenues	mil$/yr	$ -	$ 138	$ 1,514	$ 1,651	$ 1,789	$ 3,302	$ 3,440
Net Income	mil$/yr	$ (1,354)	$ 59	$ 1,224	$ 1,340	$ 1,457	$ 2,738	$ 2,854
Discounting								
Discounting Factor		1.00	1.10	2.85	3.14	3.45	9.85	10.83
Present Value of Costs	mil$/yr	(1,354.1)	53.9	428.9	427.0	421.9	277.9	263.4
Net Present Value	mil$	$ 7,067.09						

Alternative 2 – Small Gas Plants

The second alternative will be build a 1500MW CCGT plant and build another plant in 2017 of 1500 or 2000 MW. A screenshot of the model is shown in Figure 10.

Figure 10. Model for Plan 2

Year		2005	2006	2016	2017	2018	2029	2030
	Units							
Demand	TWh/yr	-	0.9	9.5	10.3	11.2	20.6	21.5
Electricity Price	$/kwh	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16
Gas Price	US$/MBTU	3.12000	3.12000	3.12000	3.12000	3.12000	3.12000	3.12000
Carbon Price	US$/kgC	0.027	0.027	0.027	0.027	0.027	0.027	0.027
System								
CCGT Cap Expansion	MWe	1,500	-		**1,500**			
CCGT Deployed Cap	MWe	-	1,500	1,500	1,500	3,000	3,000	3,000
Wind Cap Expansion	MWe	-	-	-	-	-	-	-
Deployed Wind Cap	MWe	-	-	-	-	-	-	-
Deployed Wind Fraction		0	0	0	0	0	0	0
Deployed CCGT Fraction		0	1	1	1	1	1	1
CCGT Production Cap	TWh/yr	0	11.169	11.169	11.169	22.338	22.338	22.338
Wind Production Cap	TWh/yr	0	0	0	0	0	0	0
Total Production Cap	TWh/yr	0	11.169	11.169	11.169	22.338	22.338	22.338
Actual Production	TWh/yr	-	0.9	9.5	10.3	11.2	20.6	21.5
Cash Flows								
Capital Costs	mil$/yr	$ 751	$ -	$ -	$ 751	$ -	$ -	$ -
O&M Costs	mil$/yr	$ -	$ 36	$ 36	$ 36	$ 72	$ 72	$ 72
Fuel Costs	mil$/yr	$ -	$ 19	$ 207	$ 225	$ 244	$ 451	$ 470
Carbon Costs	mil$/yr	$ -	$ 2	$ 26	$ 28	$ 31	$ 57	$ 59
Revenues	mil$/yr	$ -	$ 138	$ 1,514	$ 1,651	$ 1,789	$ 3,302	$ 3,440
Net Income	mil$/yr	$ (751)	$ 80	$ 1,245	$ 610	$ 1,441	$ 2,722	$ 2,839
Discounting								
Discounting Factor		1.00	1.10	2.85	3.14	3.45	9.85	10.83
Present Value of Costs	mil$/yr	(751.2)	73.0	436.3	194.4	417.5	276.4	262.0
Net Present Value	mil$	$ 7,539.23						

Alternative 3 – Large Gas Plant with Supplemental Gas and Wind Installation

The third alternative will be to build a single 1500MW CCGT plant and build a mix of CCGT and Wind (both in 500 MW increments) in 2017. A screenshot of the model is shown in Figure 11.

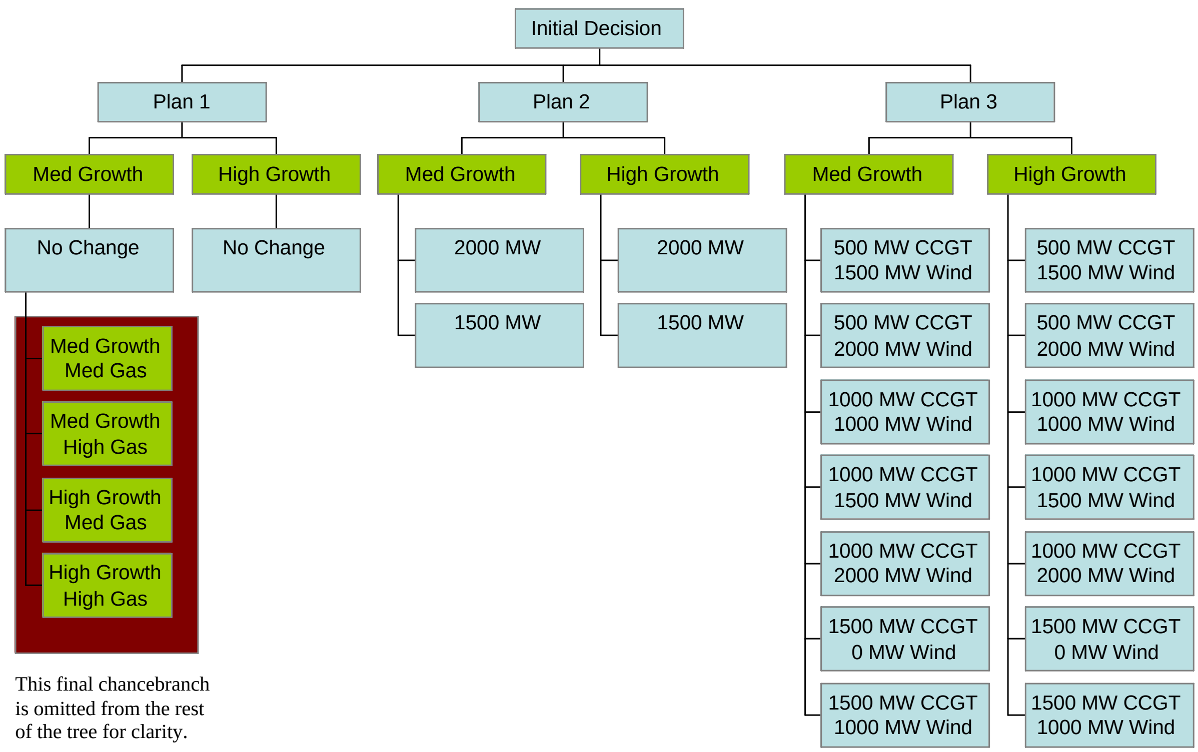
Figure 11. Model for Plan 3

Year		2005	2006	2016	2017	2018	2029	2030
	Units							
Demand	TWh/yr	-	0.9	9.5	10.3	11.2	20.6	21.5
Electricity Price	$/kwh	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16
Gas Price	US$/BTU	3.12000	3.12000	3.12000	3.12000	3.12000	3.12000	3.12000
Carbon Price	US$/kgC	0.027	0.027	0.027	0.027	0.027	0.027	0.027
System								
CCGT Cap Expansion	MWe	1,500			**500**			
CCGT Deployed Cap	MWe	-	1,500	1,500	1,500	2,000	2,000	2,000
Wind Cap Expansion	MWe	-	-	-	**2,000**	-	-	-
Deployed Wind Cap	MWe	-	-	-	-	2,000	2,000	2,000
Deployed Wind Fraction		0	0	0	0	0.5	0.5	0.5
Deployed CCGT Fraction		0	1	1	1	0.5	0.5	0.5
CCGT Production Cap	TWh/yr	0	11.169	11.169	11.169	14.892	14.892	14.892
Wind Production Cap	TWh/yr	0	0	0	0	8.76	8.76	8.76
Total Production Cap	TWh/yr	0	11.169	11.169	11.169	23.652	23.652	23.652
Actual Production	TWh/yr	-	0.9	9.5	10.3	11.2	20.6	21.5
Cash Flows								
Capital Costs	mil$/yr	$ 751	$ -	$ -	$ 2,850	$ -	$ -	$ -
O&M Costs	mil$/yr	$ -	$ 36	$ 36	$ 36	$ 94	$ 94	$ 94
Fuel Costs	mil$/yr	$ -	$ 19	$ 207	$ 225	$ 122	$ 225	$ 235
Carbon Costs	mil$/yr	$ -	$ 2	$ 26	$ 28	$ 15	$ 28	$ 30
Revenues	mil$/yr	$ -	$ 138	$ 1,514	$ 1,651	$ 1,789	$ 3,302	$ 3,440
Net Income	mil$/yr	$ (751)	$ 80	$ 1,245	$ (1,489)	$ 1,557	$ 2,954	$ 3,081
Discounting								
Discounting Factor		1.00	1.10	2.85	3.14	3.45	9.85	10.83
Present Value of Costs	mil$/yr	(751.2)	73.0	436.3	(474.5)	451.0	299.9	284.4
Net Present Value	mil$	$ 7,244.49						

4 DECISION ANALYSIS

A decision tree is constructed for the three alternatives presented above. The initial decision is which of the three plans to implement, followed by a second decision in 2017. The variability in my analysis is along three dimensions: electricity demand, price of natural gas, and price of carbon emissions. In order to simplify the analysis, I will limit uncertainty in the first phase to demand uncertainty (medium or high growth), assuming a constant gas and carbon price. After the second decision is made, demand (medium and high growth) and gas price (medium and high) will be allowed to vary. The decision tree is shown in Figure 12.

Figure 12. Structure of the Decision Tree



For the purpose of this analysis I have **assumed the probabilities** of the initial chance event to be[15]:

$$P(\text{Medium Demand Growth})_{2005\text{-}2017} = .7$$
$$P(\text{High Demand Growth})_{2005\text{-}2017} = .3$$

and the **assumed probabilities** of the second chance event are[16]:

$$P\left\langle(\text{Med Demand, Med Gas Price})_{2018\text{-}2030}\middle|\text{Med Demand}_{2005\text{-}2017}\right\rangle = .5$$
$$P\left\langle(\text{Med Demand, High Gas Price})_{2018\text{-}2030}\middle|\text{Med Demand}_{2005\text{-}2017}\right\rangle = .3$$
$$P\left\langle(\text{High Demand, Med Gas Price})_{2018\text{-}2030}\middle|\text{Med Demand}_{2005\text{-}2017}\right\rangle = .15$$
$$P\left\langle(\text{High Demand, High Gas Price})_{2018\text{-}2030}\middle|\text{Med Demand}_{2005\text{-}2017}\right\rangle = .05$$
$$P\left\langle(\text{Med Demand, Med Gas Price})_{2018\text{-}2030}\middle|\text{High Demand}_{2005\text{-}2017}\right\rangle = .35$$
$$P\left\langle(\text{Med Demand, High Gas Price})_{2018\text{-}2030}\middle|\text{High Demand}_{2005\text{-}2017}\right\rangle = .15$$
$$P\left\langle(\text{High Demand, Med Gas Price})_{2018\text{-}2030}\middle|\text{High Demand}_{2005\text{-}2017}\right\rangle = .3$$
$$P\left\langle(\text{High Demand, High Gas Price})_{2018\text{-}2030}\middle|\text{High Demand}_{2005\text{-}2017}\right\rangle = .2$$

Demand is assumed to be positively autocorrelated, meaning that medium demand is likely to be followed by more medium demand, and high by more high. Therefore, probabilities of second-stage outcomes depend on the first stage outcome as noted above.

The future scenarios and plan options are explained in Table 1 and Table 2, respectively. The possible futures are also shown in Figure 13. The value for each outcome was calculated using the models shown above, and these values are presented in Table 3.

For demand forecasts, medium growth was defined as the average linear growth rate in historical electricity demand in Portugal[17] as presented above, while high growth rate was 1.5 times the medium growth rate (also applied linearly). Medium gas price was defined as the 1996-2005 average US wellhead natural gas price reported by the US Energy Information Administration, and high price was defined as the maximum price during the same period[18].

---

[15] Please note that these probabilities are asserted for demonstration purposes. They are not derived from historical data or a forecasting model, and should not be cited by others.

[16] See previous note.

17 "Summary Electricity Production and Consumption (TWh) Vol 2002 release 01" database available from the Organization for Economic Cooperation and Development . Accessed at http://caliban.sourceoecd.org.libproxy.mit.edu/vl=1184286/cl=20/nw=1/rpsv/statistic/s28_about.htm?jnlissn=16834283(note this link requires MIT Certificates).

18 Historical Natural Gas Prices were downloaded from the Department of Energy's Energy Information Administration at http://tonto.eia.doe.gov/dnav/ng/ng_pri_top.asp.

Table 1. Description of Future Scenarios

Future	2005-2017	2018-2030
1,1	Med Demand Growth	Med Demand Growth, Med Gas Price
1,2	Med Demand Growth	Med Demand Growth, High Gas Price
1,3	Med Demand Growth	High Demand Growth, Med Gas Price
1,4	Med Demand Growth	High Demand Growth, High Gas Price
2,1	High Demand Growth	Med Demand Growth, Med Gas Price
2,2	High Demand Growth	Med Demand Growth, High Gas Price
2,3	High Demand Growth	High Demand Growth, Med Gas Price
2,4	High Demand Growth	High Demand Growth, High Gas Price

Figure 13. Future Demand and Gas Price Scenarios[19]

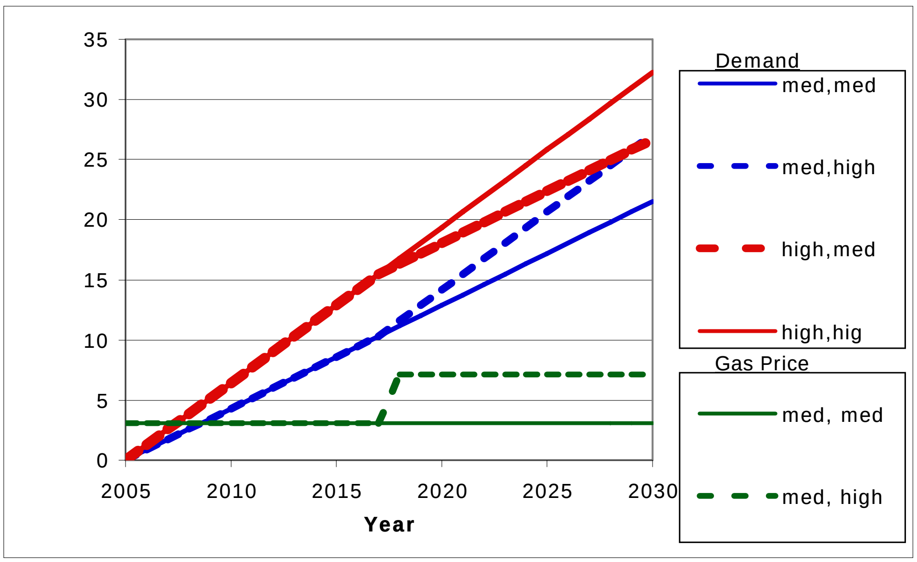


Table 2. Capacity Expansion Options for Each Plan[20]

	Capacity Expansion (MWe)			
	2005		2017	
	CCGT	Wind	CCGT	Wind
Plan 1, No Option	3000	0	0	0
Plan 2, Option 1	1500	0	1500	0
Plan 2, Option 2	1500	0	2000	0
Plan 3, Option 1	1500	0	500	1500
Plan 3, Option2	1500	0	500	2000
Plan 3, Option 3	1500	0	1000	1000
Plan 3, Option 4	1500	0	1000	1500
Plan 3, Option 5	1500	0	1000	2000
Plan 3, Option 6	1500	0	1500	0
Plan 3, Option 7	1500	0	1500	1000

[19] These scenarios are based on historical trends, as described in the text of the report. They are should be treated as hypothetical scenarios for demonstration purposes and should not be cited.
[20] These expansion plans are hypothetical examples for demonstration purposes. They are not based on real plans and should not be cited.

Table 3. Values for Each Expansion Path by Future Scenario

Future	Plan 1, No Option	Plan 2, Option 1	Plan 2, Option 2	Plan 3, Option 1	Plan 3, Option2	Plan 3, Option 3	Plan 3, Option 4	Plan 3, Option 5	Plan 3, Option 6	Plan 3, Option 7
1,1	$ 7,067	$ 7,539	$ 7,432	$ 7,417	$ 7,244	$ 7,422	$ 7,265	$ 7,090	$ 7,539	$ 7,285
1,2	$ 6,095	$ 6,567	$ 6,460	$ 6,861	$ 6,759	$ 6,728	$ 6,657	$ 6,550	$ 6,567	$ 6,556
1,3	$ 7,636	$ 8,108	$ 8,168	$ 7,974	$ 7,963	$ 8,075	$ 8,029	$ 7,902	$ 8,108	$ 8,064
1,4	$ 6,507	$ 6,979	$ 7,040	$ 7,329	$ 7,399	$ 7,269	$ 7,323	$ 7,275	$ 6,979	$ 7,218
2,1	$ 10,566	$ 10,512	$ 10,617	$ 10,412	$ 10,471	$ 10,537	$ 10,534	$ 10,411	$ 10,512	$ 10,550
2,2	$ 9,265	$ 9,211	$ 9,315	$ 9,669	$ 9,820	$ 9,607	$ 9,720	$ 9,688	$ 9,211	$ 9,574
2,3	$ 10,734	$ 10,680	$ 11,073	$ 10,577	$ 10,807	$ 10,795	$ 10,971	$ 11,032	$ 10,680	$ 11,091
2,4	$ 9,276	$ 9,222	$ 9,615	$ 9,744	$ 10,078	$ 9,754	$ 10,060	$ 10,222	$ 9,222	$ 9,998

SOLUTION: OPTIMAL STRATEGY

Combining the values presented above with the probabilities of each outcome we can solve the decision tree as shown in Figure 14. In this figure, optimal strategies at each decision point (chosen by maximizing expected value) are highlighted in blue. Working backwards:

- Plan 1 has no flexibility at decision point 2.
- Under medium demand growth from 2005-2017, Plan 2's optimal strategy at decision point 2 is the smaller option (1500 MW CCGT expansion) in 2017. Under high demand growth the optimal strategy is the larger option (2000 MW CCGT expansion) in 2017.
- Under medium demand growth from 2005-2017, Plan 3, optimal strategy at decision point 2 is a 1500 MW wind and 500 MW CCGT expansion in 2017. Under high demand growth the optimal strategy is a 1000 MW wind and 1500 MW CCGT expansion in 2017.

- Using each of the optimal strategies defined above for decision point 2 and the probabilities of chance event 1, the expected values for the choices at decision point 1 can be calculated. These are shown in Figure 14. Plan 3 is the best choice at decision point 1.

Figure 14. Solution to the Decision Tree

Decision 1	Expected Value	Chance 1	Prob of Chance 1	Decision 2*	Expected Val	Chance 2	Prob of Chanc	Value
Plan 1	$ 7,832	*Med Demand*	0.7	0 / 0	$ 6,833	*MD,MG*	0.5	$ 7,067
						MD,HG	0.3	$ 6,095
						HD,MG	0.15	$ 7,636
						HD,HG	0.05	$ 6,507
		High Demand	0.3	0 / 0	$ 10,163	*MD,MG*	0.35	$ 10,566
						MD,HG	0.15	$ 9,265
						HD,MG	0.3	$ 10,734
						HD,HG	0.2	$ 9,276
Plan 2	$ 8,221	*Med Demand*	0.7	0 / 1500	$ 7,305	*MD,MG*	0.5	$ 7,539
						MD,HG	0.3	$ 6,567
						HD,MG	0.15	$ 8,108
						HD,HG	0.05	$ 6,979
				0 / 2000	$ 7,231	*MD,MG*	0.5	$ 7,432
						MD,HG	0.3	$ 6,460
						HD,MG	0.15	$ 8,168
						HD,HG	0.05	$ 7,040
		High Demand	0.3	0 / 1500	$ 10,109	*MD,MG*	0.35	$ 10,512
						MD,HG	0.15	$ 9,211
						HD,MG	0.3	$ 10,680
						HD,HG	0.2	$ 9,222
				0 / 2000	$ 10,358	*MD,MG*	0.35	$ 10,617
						MD,HG	0.15	$ 9,315
						HD,MG	0.3	$ 11,073
						HD,HG	0.2	$ 9,615
Plan 3	$ 8,267	*Med Demand*	0.7	1500 / 500	$ 7,329	*MD,MG*	0.5	$ 7,417
						MD,HG	0.3	$ 6,861
						HD,MG	0.15	$ 7,974
						HD,HG	0.05	$ 7,329
				2000 / 500	$ 7,214	*MD,MG*	0.5	$ 7,244
						MD,HG	0.3	$ 6,759
						HD,MG	0.15	$ 7,963
						HD,HG	0.05	$ 7,399
				1000 / 1000	$ 7,304	*MD,MG*	0.5	$ 7,422
						MD,HG	0.3	$ 6,728
						HD,MG	0.15	$ 8,075
						HD,HG	0.05	$ 7,269
				1500 / 1000	$ 7,200	*MD,MG*	0.5	$ 7,265
						MD,HG	0.3	$ 6,657
						HD,MG	0.15	$ 8,029
						HD,HG	0.05	$ 7,323
				2000 / 1000	$ 7,059	*MD,MG*	0.5	$ 7,090
						MD,HG	0.3	$ 6,550
						HD,MG	0.15	$ 7,902
						HD,HG	0.05	$ 7,275
				0 / 1500	$ 7,305	*MD,MG*	0.5	$ 7,539
						MD,HG	0.3	$ 6,567
						HD,MG	0.15	$ 8,108
						HD,HG	0.05	$ 6,979
				1000 / 1500	$ 7,180	*MD,MG*	0.5	$ 7,285
						MD,HG	0.3	$ 6,556
						HD,MG	0.15	$ 8,064
						HD,HG	0.05	$ 7,218
		High Demand	0.3	1500 / 500	$ 10,216	*MD,MG*	0.35	$ 10,412
						MD,HG	0.15	$ 9,669
						HD,MG	0.3	$ 10,577
						HD,HG	0.2	$ 9,744
				2000 / 500	$ 10,395	*MD,MG*	0.35	$ 10,471
						MD,HG	0.15	$ 9,820
						HD,MG	0.3	$ 10,807
						HD,HG	0.2	$ 10,078
				1000 / 1000	$ 10,318	*MD,MG*	0.35	$ 10,537
						MD,HG	0.15	$ 9,607
						HD,MG	0.3	$ 10,795
						HD,HG	0.2	$ 9,754
				1500 / 1000	$ 10,448	*MD,MG*	0.35	$ 10,534
						MD,HG	0.15	$ 9,720
						HD,MG	0.3	$ 10,971
						HD,HG	0.2	$ 10,060
				2000 / 1000	$ 10,451	*MD,MG*	0.35	$ 10,411
						MD,HG	0.15	$ 9,688
						HD,MG	0.3	$ 11,032
						HD,HG	0.2	$ 10,222
				0 / 1500	$ 10,109	*MD,MG*	0.35	$ 10,512
						MD,HG	0.15	$ 9,211
						HD,MG	0.3	$ 10,680
						HD,HG	0.2	$ 9,222
				1000 / 1500	$ 10,455	*MD,MG*	0.35	$ 10,550
						MD,HG	0.15	$ 9,574
						HD,MG	0.3	$ 11,091
						HD,HG	0.2	$ 9,998

*Decision 2 is shown as (Wind Capacity Expansion/CCGT Capacity Expansion)

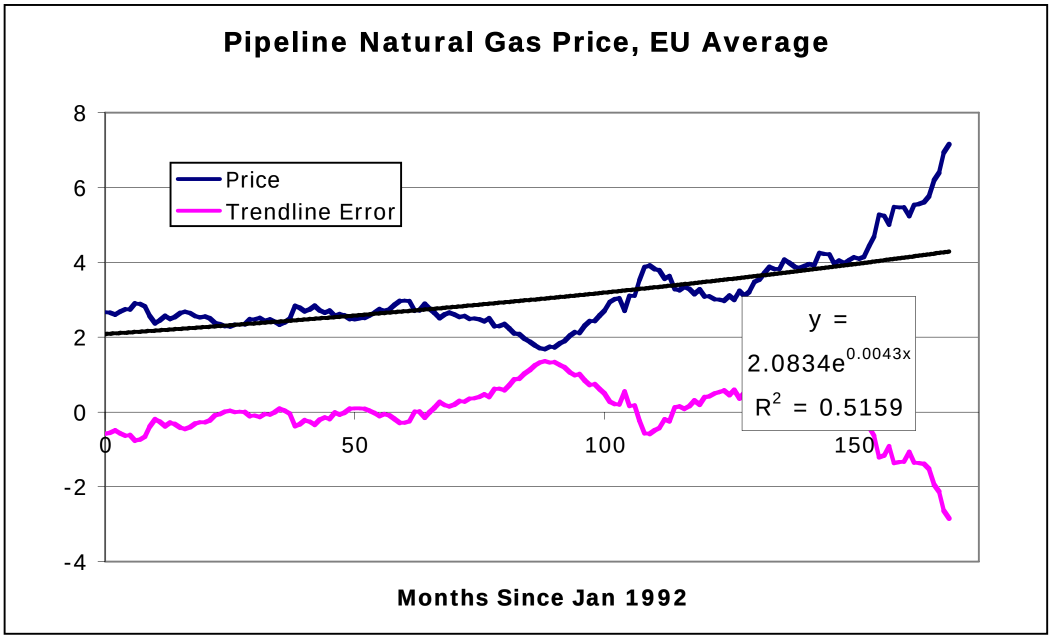
6 VALUATION OF PUT OPTION ON INITIAL INVESTMENT

The value of maintaining a single put option on the initial 1500 MW plant (Plan 2 or 3 above) was then explored using a lattice model and a simple dynamic program. The results of this analysis are presented in the following sections.

Growth Trend and Volatility

Monthly natural gas prices from 1992 to 2006, available from the International Energy Agency[21], are presented in Figure 15. The line shown is an exponential fit, with growth rate r = .0043 per month.

Figure 15. Historical Natural Gas Prices, Trendline, and Trendline Error.



The difference between actual price and the trend is also shown in Figure 15. I calculate the standard deviation of the differences to be 0.67, or 9.3% of the most recent price ($7.15/MBtu in February 2006).

Analysis Inputs and Assumptions

As presented in above, natural gas prices rise at an average rate of .43% per month, with a volatility of 9.3% around that trend, with a current price of around 7.15 $/MBtu. I explore the sensitivity of the results to starting price in the last section.

For this analysis a time step of one year is used, starting in 2006, with 25 periods considered to 2030. The capital cost of constructing the plant is not included in this analysis. Since the option to be valued is simply a put, the capital cost is equal for both the flexible and inflexible designs and the option

21 "Energy Prices and Taxes - Natural Gas Import Costs Vol 2006 release 02" database available from the Organization for Economic Cooperation and Development . Accessed at http://caliban.sourceoecd.org.libproxy.mit.edu/vl=1184286/cl=20/nw=1/rpsv/statistic/s29_about.htm?jnlissn=1683626x (note this link requires MIT Certificates).

value depends only on the difference in the expected operating costs of the flexible and inflexible designs.

Plant Without Flexibility

A lattice model of future price evolution was developed using these parameters, shown in Table 4, and used to evaluate the expected value of the plant without flexibility. The probabilities and prices given by the lattice model are shown in Table 5 and Table 6 respectively.

Table 4. Parameters of Lattice Model

Parameter	Value	Units
delta t =	1	year
Starting Price =	7.15	\$/Mbtu
Rate of Appreciation =	0.0516	frac change per year
variance =	9%	%
$u = e \exp(\sigma\sqrt{\Delta t}) =$	1.0985	
$d = e \exp(-\sigma\sqrt{\Delta t}) =$	0.9103	
$p = 0.5 + 0.5\,(v/\sigma)\,\sqrt{\Delta t} =$	0.7745	

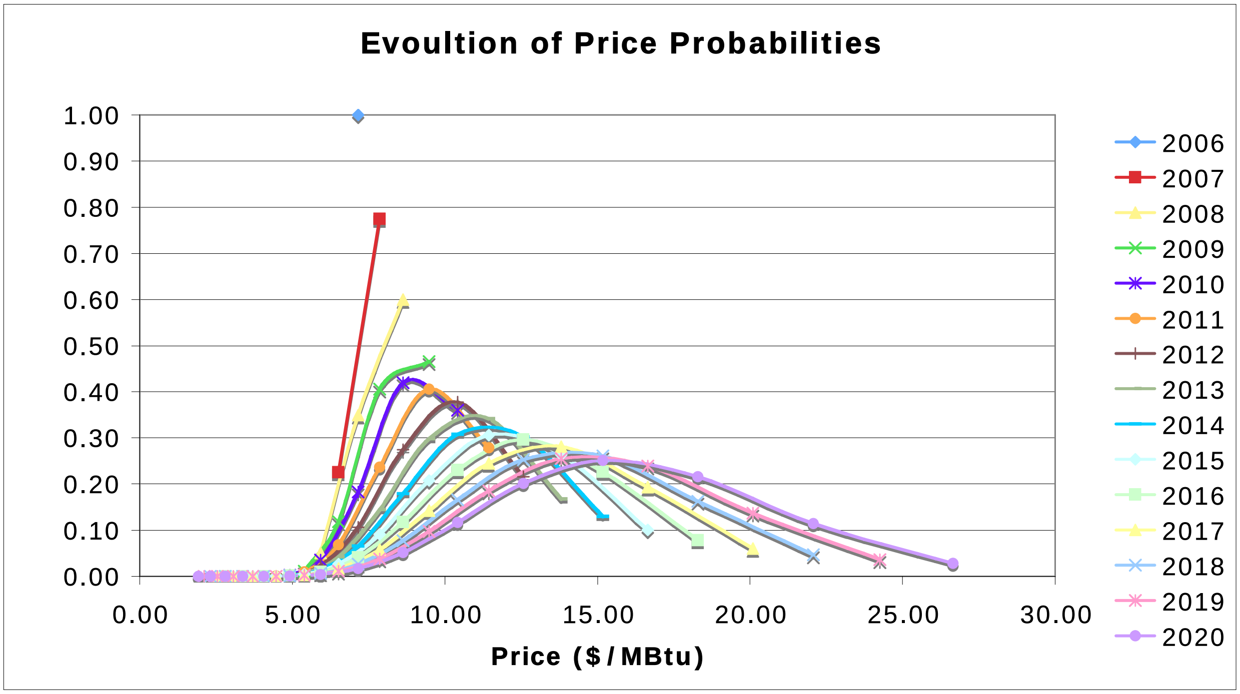
Table 5. Probability Lattice

ORIGINAL PROBABILITY LATTICE																								
2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1.00	0.77	0.60	0.46	0.36	0.28	0.22	0.17	0.13	0.10	0.08	0.06	0.05	0.04	0.03	0.02	0.02	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00
	0.23	0.35	0.41	0.42	0.41	0.38	0.34	0.30	0.26	0.23	0.19	0.16	0.14	0.11	0.09	0.08	0.06	0.05	0.04	0.04	0.03	0.02	0.02	0.02
		0.05	0.12	0.18	0.24	0.27	0.30	0.31	0.31	0.30	0.28	0.26	0.24	0.22	0.19	0.17	0.15	0.13	0.11	0.10	0.08	0.07	0.06	0.05
			0.01	0.04	0.07	0.11	0.14	0.18	0.21	0.23	0.24	0.25	0.25	0.25	0.24	0.23	0.22	0.20	0.19	0.17	0.15	0.14	0.12	0.11
				0.00	0.01	0.02	0.04	0.07	0.09	0.12	0.14	0.17	0.19	0.20	0.21	0.22	0.22	0.22	0.22	0.21	0.20	0.19	0.18	0.17
					0.00	0.00	0.01	0.02	0.03	0.04	0.06	0.08	0.10	0.12	0.14	0.15	0.17	0.18	0.19	0.20	0.20	0.20	0.20	0.19
						0.00	0.00	0.00	0.01	0.01	0.02	0.03	0.04	0.05	0.07	0.08	0.10	0.11	0.13	0.14	0.15	0.16	0.17	0.18
							0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.02	0.03	0.04	0.06	0.07	0.08	0.10	0.11	0.12	0.13
								0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.02	0.03	0.04	0.05	0.06	0.07	0.08
									0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.02	0.03	0.03	0.04
										0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.02
											0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
													0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
														0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
															0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
																0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
																	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
																		0.00	0.00	0.00	0.00	0.00	0.00	0.00
																			0.00	0.00	0.00	0.00	0.00	0.00
																				0.00	0.00	0.00	0.00	0.00
																					0.00	0.00	0.00	0.00
																						0.00	0.00	0.00
																							0.00	0.00
																								0.00

Table 6. Price Lattice (\$/MBtu)

Price Lattice																								
2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
7.15	7.85	8.63	9.48	10.41	11.44	12.57	13.80	15.16	16.66	18.30	20.10	22.08	24.26	26.65	29.28	32.16	35.33	38.81	42.64	46.84	51.45	56.52	62.09	68.21
	6.51	7.15	7.85	8.63	9.48	10.41	11.44	12.57	13.80	15.16	16.66	18.30	20.10	22.08	24.26	26.65	29.28	32.16	35.33	38.81	42.64	46.84	51.45	56.52
		5.92	6.51	7.15	7.85	8.63	9.48	10.41	11.44	12.57	13.80	15.16	16.66	18.30	20.10	22.08	24.26	26.65	29.28	32.16	35.33	38.81	42.64	46.84
			5.39	5.92	6.51	7.15	7.85	8.63	9.48	10.41	11.44	12.57	13.80	15.16	16.66	18.30	20.10	22.08	24.26	26.65	29.28	32.16	35.33	38.81
				4.91	5.39	5.92	6.51	7.15	7.85	8.63	9.48	10.41	11.44	12.57	13.80	15.16	16.66	18.30	20.10	22.08	24.26	26.65	29.28	32.16
					4.47	4.91	5.39	5.92	6.51	7.15	7.85	8.63	9.48	10.41	11.44	12.57	13.80	15.16	16.66	18.30	20.10	22.08	24.26	26.65
						4.07	4.47	4.91	5.39	5.92	6.51	7.15	7.85	8.63	9.48	10.41	11.44	12.57	13.80	15.16	16.66	18.30	20.10	22.08
							3.70	4.07	4.47	4.91	5.39	5.92	6.51	7.15	7.85	8.63	9.48	10.41	11.44	12.57	13.80	15.16	16.66	18.30
								3.37	3.70	4.07	4.47	4.91	5.39	5.92	6.51	7.15	7.85	8.63	9.48	10.41	11.44	12.57	13.80	15.16
									3.07	3.37	3.70	4.07	4.47	4.91	5.39	5.92	6.51	7.15	7.85	8.63	9.48	10.41	11.44	12.57
										2.79	3.07	3.37	3.70	4.07	4.47	4.91	5.39	5.92	6.51	7.15	7.85	8.63	9.48	10.41
											2.54	2.79	3.07	3.37	3.70	4.07	4.47	4.91	5.39	5.92	6.51	7.15	7.85	8.63
												2.31	2.54	2.79	3.07	3.37	3.70	4.07	4.47	4.91	5.39	5.92	6.51	7.15
													2.11	2.31	2.54	2.79	3.07	3.37	3.70	4.07	4.47	4.91	5.39	5.92
														1.92	2.11	2.31	2.54	2.79	3.07	3.37	3.70	4.07	4.47	4.91
															1.75	1.92	2.11	2.31	2.54	2.79	3.07	3.37	3.70	4.07
																1.59	1.75	1.92	2.11	2.31	2.54	2.79	3.07	3.37
																	1.45	1.59	1.75	1.92	2.11	2.31	2.54	2.79
																		1.32	1.45	1.59	1.75	1.92	2.11	2.31
																			1.20	1.32	1.45	1.59	1.75	1.92
																				1.09	1.20	1.32	1.45	1.59
																					0.99	1.09	1.20	1.32
																						0.90	0.99	1.09
																							0.82	0.90
																								0.75

Figure 16. Probability Evolution Over Time (Shown to 2020 only)



Value of Plant Under Uncertainty Without Flexibility

The net present value of the plant was calculated using the probability and price evolutions presented above. A constant linear growth in demand was assumed, using the medium growth of .86 TWh/yr from the previous decision analysis, and production in each period is the minimum of capacity and demand. Production is shown in Table 7.

Table 7. Production at Each Stage on the Lattice (TWh/Yr)

Production																								
2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
0.86	1.72	2.58	3.44	4.30	5.16	6.02	6.88	7.74	8.60	9.46	10.32	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17
	1.72	2.58	3.44	4.30	5.16	6.02	6.88	7.74	8.60	9.46	10.32	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17
		2.58	3.44	4.30	5.16	6.02	6.88	7.74	8.60	9.46	10.32	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17
			3.44	4.30	5.16	6.02	6.88	7.74	8.60	9.46	10.32	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17
				4.30	5.16	6.02	6.88	7.74	8.60	9.46	10.32	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17
					5.16	6.02	6.88	7.74	8.60	9.46	10.32	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17
						6.02	6.88	7.74	8.60	9.46	10.32	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17
							6.88	7.74	8.60	9.46	10.32	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17
								7.74	8.60	9.46	10.32	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17
									8.60	9.46	10.32	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17
										9.46	10.32	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17
											10.32	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17
												11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17
													11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17
														11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17
															11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17
																11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17
																	11.17	11.17	11.17	11.17	11.17	11.17	11.17	11.17
																		11.17	11.17	11.17	11.17	11.17	11.17	11.17
																			11.17	11.17	11.17	11.17	11.17	11.17
																				11.17	11.17	11.17	11.17	11.17
																					11.17	11.17	11.17	11.17
																						11.17	11.17	11.17
																							11.17	11.17
																								11.17

The value of the plant in a given year is calculated as the difference between sales (capacity times price) and the sum of non-fuel operating expenses, fuel cost, and carbon emissions cost, or

$$Value = (\text{Prdxn kwh} * 0.16\frac{\$}{\text{kwh}}) - (\text{Prdxn kwh} * \text{O \& M Costs}\frac{\$}{\text{kwh}}) - (\text{Prdxn kwh} * \text{Fuel Cost}\frac{\$}{\text{kwh}}) - (\text{Prdxn kwh} * \text{Carbon Cost}\frac{\$}{\text{kwh}})$$

O&M costs. Fuel, carbon emissions, and O&M costs are functions of production as presented in the decision analysis above, with the medium values from the decision analysis. Fuel cost is calculated in the lattice model. Carbon cost is assumed to be constant at .027 $/kg. The net plant revenues for each price calculated in the lattice model are presented in Table 8.

Table 8. Net Plant Revenue Lattice (million $)

Net Revenue for Each Price Possibility																								
2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
92	176	250	313	363	398	417	417	395	349	276	170	30	-141	-327	-533	-758	-1006	-1278	-1577	-1906	-2267	-2663	-3098	-3577
	192	277	352	416	469	508	531	536	521	483	419	325	184	30	-141	-327	-533	-758	-1006	-1278	-1577	-1906	-2267	-2663
		299	384	461	528	583	625	653	664	655	626	571	454	325	184	30	-141	-327	-533	-758	-1006	-1278	-1577	-1906
			411	498	576	645	704	750	782	798	796	774	677	571	454	325	184	30	-141	-327	-533	-758	-1006	-1278
				528	617	697	768	830	879	916	938	942	862	774	677	571	454	325	184	30	-141	-327	-533	-758
					650	740	822	896	960	1014	1055	1082	1015	942	862	774	677	571	454	325	184	30	-141	-327
						775	867	951	1028	1095	1153	1197	1142	1082	1015	942	862	774	677	571	454	325	184	30
							903	997	1083	1162	1233	1293	1247	1197	1142	1082	1015	942	862	774	677	571	454	325
								1034	1129	1218	1300	1372	1335	1293	1247	1197	1142	1082	1015	942	862	774	677	571
									1168	1264	1355	1438	1407	1372	1335	1293	1247	1197	1142	1082	1015	942	862	774
										1303	1401	1493	1467	1438	1407	1372	1335	1293	1247	1197	1142	1082	1015	942
											1439	1538	1516	1493	1467	1438	1407	1372	1335	1293	1247	1197	1142	1082
												1575	1557	1538	1516	1493	1467	1438	1407	1372	1335	1293	1247	1197
													1591	1575	1557	1538	1516	1493	1467	1438	1407	1372	1335	1293
														1637	1591	1575	1557	1538	1516	1493	1467	1438	1407	1372
															1620	1606	1591	1575	1557	1538	1516	1493	1467	1438
																1632	1620	1606	1591	1575	1557	1538	1516	1493
																	1643	1632	1620	1606	1591	1575	1557	1538
																		1653	1643	1632	1620	1606	1591	1575
																			1662	1653	1643	1632	1620	1606
																				1671	1662	1653	1643	1632
																					1679	1671	1662	1653
																						1686	1679	1671
																							1692	1686
																								1698

The expected values for each time period are then calculated as the sumproduct of the values above and their associated probabilities. These sums are then discounted and summed across all time periods to find the net present value of $3.8 billion. This analysis is shown in Table 9.

Table 9. Expected Value Lattice for Inflexible Plant (million $)

	Net Revenue x Probability																					
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
	92	136	150	145	131	111	90	70	51	35	21	10	1	-5	-9	-12	-13	-13	-13	-12	-12	-11
		43	97	143	174	190	191	181	162	137	109	81	53	25	3	-13	-26	-34	-40	-43	-45	-45
			15	45	84	125	160	186	201	203	194	175	149	108	70	36	5	-21	-43	-60	-74	-84
				5	18	40	69	102	134	162	184	195	196	172	143	110	75	40	6	-26	-56	-82
					1	6	16	32	54	80	107	134	156	160	156	144	125	101	72	40	6	-28
						0	2	6	14	25	42	61	83	99	110	117	119	114	103	86	64	37
							0	1	2	5	11	19	31	43	55	67	77	84	88	87	81	70
								0	0	1	2	4	8	14	20	28	37	45	53	60	64	65
									0	0	0	1	2	3	6	9	13	19	25	31	37	42
										0	0	0	0	1	1	2	4	6	9	12	16	21
											0	0	0	0	0	0	1	1	2	4	6	8
												0	0	0	0	0	0	0	1	1	2	3
													0	0	0	0	0	0	0	0	0	1
														0	0	0	0	0	0	0	0	0
															0	0	0	0	0	0	0	0
																0	0	0	0	0	0	0
																	0	0	0	0	0	0
																		0	0	0	0	0
																			0	0	0	0
																				0	0	0
																					0	0
																						0
Sum of Values	92	180	262	338	408	472	529	577	618	649	670	681	680	620	556	489	418	342	263	179	91	(2)
Discount Factor	1.00	1.10	1.21	1.33	1.46	1.61	1.77	1.95	2.14	2.36	2.59	2.85	3.14	3.45	3.80	4.18	4.59	5.05	5.56	6.12	6.73	7.40
Present Value	92	163	216	254	279	293	298	296	288	275	258	239	217	180	146	117	91	68	47	29	14	(0)
Net Present Value	3,794																					

Valuation of Option to Close

The option to permanently close the plant was added to the model. At any stage, if the expected value of the future is negative, the option to close the mine is exercised. The resulting strategy lattice from the conditions examined above is shown in Table 10.

Table 10. Strategy Lattice

Strategy																								
2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
0	0	0	0	0	0	0	0	0	0	0	0	0	STOP	STOP	STOP	STOP	STOP	STOP	STOP	STOP	STOP	STOP	STOP	
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	STOP	STOP	STOP	STOP	STOP	STOP	STOP	STOP	STOP	
		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	STOP	STOP	STOP	STOP	STOP	STOP	STOP	
			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	STOP	STOP	STOP	STOP	STOP	
				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	STOP	STOP	STOP	
					0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	STOP	
						0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
							0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
								0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
									0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
										0	0	0	0	0	0	0	0	0	0	0	0	0	0	
											0	0	0	0	0	0	0	0	0	0	0	0	0	
												0	0	0	0	0	0	0	0	0	0	0	0	
													0	0	0	0	0	0	0	0	0	0	0	
														0	0	0	0	0	0	0	0	0	0	
															0	0	0	0	0	0	0	0	0	
																0	0	0	0	0	0	0	0	
																	0	0	0	0	0	0	0	
																		0	0	0	0	0	0	
																			0	0	0	0	0	
																				0	0	0	0	
																					0	0	0	
																						0	0	
																							0	

Taking any probabilities after exercising the put option out of the previous probability table yields the unscaled (i.e. probabilities do not sum to 1) probability lattice shown in Table 11.

Table 11. Adjusted Probabilities After Applying Strategy

Partial PROBABILITY LATTICE																								
2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1.00	0.77	0.60	0.46	0.36	0.28	0.22	0.17	0.13	0.10	0.08	0.06	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	0.23	0.35	0.41	0.42	0.41	0.38	0.34	0.30	0.26	0.23	0.19	0.16	0.14	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		0.05	0.12	0.18	0.24	0.27	0.30	0.31	0.31	0.30	0.28	0.26	0.24	0.22	0.19	0.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
			0.01	0.04	0.07	0.11	0.14	0.18	0.21	0.23	0.24	0.25	0.25	0.25	0.24	0.23	0.21	0.16	0.00	0.00	0.00	0.00	0.00	0.00
				0.00	0.01	0.02	0.04	0.07	0.09	0.12	0.14	0.17	0.19	0.20	0.21	0.22	0.22	0.22	0.21	0.16	0.00	0.00	0.00	0.00
					0.00	0.00	0.01	0.02	0.03	0.04	0.06	0.08	0.10	0.12	0.14	0.15	0.17	0.18	0.19	0.19	0.19	0.14	0.00	0.00
						0.00	0.00	0.00	0.01	0.01	0.02	0.03	0.04	0.05	0.07	0.08	0.10	0.11	0.13	0.14	0.15	0.16	0.16	0.12
							0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.02	0.03	0.04	0.06	0.07	0.08	0.10	0.11	0.12	0.13
								0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.02	0.03	0.04	0.05	0.06	0.07	0.08
									0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.02	0.03	0.03	0.04
										0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.02
											0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
													0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
														0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
															0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
																0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
																	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
																		0.00	0.00	0.00	0.00	0.00	0.00	0.00
																			0.00	0.00	0.00	0.00	0.00	0.00
																				0.00	0.00	0.00	0.00	0.00
																					0.00	0.00	0.00	0.00
																						0.00	0.00	0.00
																							0.00	0.00
																								0.00

Then the probabilities are rescaled so that the sum of probabilities at each time step is equal to 1. The resulting probabilities are shown in Table 12.

Table 12. Rescaled Probability Lattice, After Applying Strategy

Rescaled Probabilities																								
2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1.00	0.77	0.60	0.46	0.36	0.28	0.22	0.17	0.13	0.10	0.08	0.06	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	0.23	0.35	0.41	0.42	0.41	0.38	0.34	0.30	0.26	0.23	0.19	0.16	0.14	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		0.05	0.12	0.18	0.24	0.27	0.30	0.31	0.31	0.30	0.28	0.26	0.25	0.22	0.22	0.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
			0.01	0.04	0.07	0.11	0.14	0.18	0.21	0.23	0.24	0.25	0.26	0.26	0.28	0.26	0.28	0.21	0.00	0.00	0.00	0.00	0.00	0.00
				0.00	0.01	0.02	0.04	0.07	0.09	0.12	0.14	0.17	0.19	0.21	0.24	0.25	0.29	0.29	0.32	0.25	0.00	0.00	0.00	0.00
					0.00	0.00	0.01	0.02	0.03	0.04	0.06	0.08	0.10	0.12	0.15	0.17	0.22	0.23	0.30	0.30	0.36	0.28	0.00	0.00
						0.00	0.00	0.00	0.01	0.01	0.02	0.03	0.04	0.05	0.07	0.09	0.13	0.15	0.20	0.22	0.30	0.31	0.39	0.30
							0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.03	0.04	0.06	0.07	0.11	0.13	0.19	0.21	0.30	0.32
								0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.03	0.05	0.06	0.10	0.12	0.18	0.20
									0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.02	0.04	0.05	0.09	0.11
										0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.03	0.05
											0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.02
												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
													0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
														0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
															0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
																0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
																	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
																		0.00	0.00	0.00	0.00	0.00	0.00	0.00
																			0.00	0.00	0.00	0.00	0.00	0.00
																				0.00	0.00	0.00	0.00	0.00
																					0.00	0.00	0.00	0.00
																						0.00	0.00	0.00
																							0.00	0.00
																								0.00

The expected values, calculated as above, are shown in Table 13. The NPV of the plant with flexibility is \$4.3 Billion.

__Table 13. Expected Value Lattice with Flexibility__

Expected Values x Rescaled Propabilities																					
2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
92.18	136.23	149.88	145.27	130.53	110.99	90.04	69.73	51.21	35.05	21.42	10.26	1.38	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	43.31	96.59	142.74	174.50	190.27	191.48	180.90	161.73	136.99	109.31	80.80	52.99	26.15	3.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		15.18	45.38	84.34	124.64	159.99	186.08	200.63	203.09	194.17	175.44	148.75	112.34	72.80	39.92	4.96	0.00	0.00	0.00	0.00	0.00
			4.71	17.68	39.63	68.73	101.57	134.11	162.48	183.53	195.07	195.73	178.88	148.63	125.07	85.36	51.08	6.35	0.00	0.00	0.00
				1.37	6.17	16.21	32.29	54.01	79.82	107.34	133.76	156.09	165.74	161.35	162.94	141.84	131.24	93.22	59.77	7.43	0.00
					0.38	2.00	6.03	13.59	25.38	41.50	61.33	83.47	102.29	114.38	132.86	134.38	148.24	133.99	134.11	98.27	66.51
						0.10	0.62	2.10	5.27	10.87	19.50	31.38	44.67	57.34	75.92	87.32	109.89	114.61	136.11	126.88	135.36
							0.03	0.18	0.69	1.92	4.34	8.46	14.20	21.11	31.97	41.69	59.21	69.64	93.69	100.23	126.43
								0.01	0.05	0.22	0.67	1.63	3.32	5.81	10.16	15.11	24.24	32.00	48.19	57.73	82.02
									0.00	0.01	0.07	0.22	0.57	1.20	2.46	4.22	7.71	11.46	19.29	25.72	40.62
										0.00	0.00	0.02	0.07	0.18	0.45	0.91	1.92	3.24	6.13	9.12	15.96
											0.00	0.00	0.01	0.02	0.06	0.15	0.37	0.73	1.56	2.61	5.08
												0.00	0.00	0.00	0.01	0.02	0.06	0.13	0.32	0.60	1.32
													0.00	0.00	0.00	0.00	0.01	0.02	0.05	0.11	0.28
														0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.05
															0.00	0.00	0.00	0.00	0.00	0.00	0.01
																0.00	0.00	0.00	0.00	0.00	0.00
																	0.00	0.00	0.00	0.00	0.00
																		0.00	0.00	0.00	0.00
																			0.00	0.00	0.00
																				0.00	0.00
																					0.00

Sum of Values	92	180	262	338	408	472	529	577	618	649	670	681	680	648	586	582	516	534	465	499	429	474
Discount Factor	1.00	1.10	1.21	1.33	1.46	1.61	1.77	1.95	2.14	2.36	2.59	2.85	3.14	3.45	3.80	4.18	4.59	5.05	5.56	6.12	6.73	7.40
Present Value	92	163	216	254	279	293	298	296	288	275	258	239	217	188	154	139	112	106	84	82	64	64
Net Present Value	4,301																					

Therefore, the value of the option is simply the difference in NPV of expected values with and without flexibility, or about $.5 billion.

Sensitivity to Initial Price

The sensitivity of the above analysis to initial price was explored by plugging in values from $4/MBtu and $15/MBtu to the spreadsheet model. The results are shown in Table 14.

__Table 14. Sensitivity to Initial Price__

Gas Price ($/Mbtu)	Value of Option (Million $)
4	27
5	94
6	237
7	496
8	838
9	1234
10	1672
11	2173
12	2786
13	3467
14	4261
15	4975

7 EXTENSION: MONTE CARLO SIMULATION AND INVESTOR BEHAVIOR

While the decision analysis and lattice valuation presented above may yield sufficiently useful results for planners and investors, I extended the model again to include:

- stochasticity in the forecasts (rather than the deterministic forecast above),
- annual simulation of investor choice (rather than a 12-year choice period as above), and
- explicit modeling of investor expectations at decision points.

The general methodology is to model real future demand, gas price, and carbon price using geometric brownian motion. Investors are modeled as having a time lag in their perception of these variables and in the trends investors observe in order to make forecasts at decision points. Investors make decisions to maximize their expected Net Present Value based on their forecasts. A Monte Carlo simulation is then run and expected Net Present Values of the three plans are compared.

FUTURE PRICES AND DEMAND

Future gas price, carbon price, and demand were modeled using the standard geometric brownian motion formulation. The parameters of these models were based on the gas price, carbon price, and demand datasets presented above, and are shown in Table 15[22].

Table 15. Parameters of Stochastic Demand, Gas Price, and Carbon Price Models

Demand Trend		
Exp. Growth Rate	0.015	/yr/yr
StdDev	1.58	TWh/yr
Initial Value	40	TWh/Yr
Gas Trend		
Exp. Growth Rate	0.0043	/yr
StdDev	0.67	US$/BTU
Initial Value	3.12	US$/BTU
Carbon Trend		
Exp. Growth Rate	0	/yr
StdDev	0.00352625	US$/kgC
Initial Value	0.027135	US$/kgC

The evolution of each value is modeled in Excel as

$$V_{t+1} = \mathrm{MAX}(0, \mathrm{V_t} + \mathrm{V_t} * \mathrm{GrowthRate} + \mathrm{NORMINV}(\mathrm{RAND}(), 0, \mathrm{StdDev}))$$

where the MAX() function prevents price and demand from being less than zero.

[22] Note that for this portion of the analysis I chose to use the historical average gas price as a starting point, rather than the most recent price. This assumption should be revisited in a future analysis. The focus of this portion of my work is more a proof of concept for myself.

INVESTOR BEHAVIOR

Investor Expectations

As in previous analyses[23,24], I model investors as boundedly rational and limited in their ability to perceive current conditions and forecast accurately. By this, I mean that investors must make decisions with imperfect and backward-looking information. Roques *et al* does this by using the average of the previous five years as the investor's price forecast. I modify that approach following Sterman[25] to allow

- a delay in the investors perception of the "present condition"
- the ability to model investor forecasting with delays as expectations change.

This is done with the formulation described by Sterman[26], as follows (to skip the details and see how this model behaves, go to Figure 17):

$$PPC_{t_o} = INPUT_{t_o} / (1 + TPPC * TREND_{t_o})$$
$$PPC_t = PPC_{t-1} + (INPUT_{t-1} - PPC_{t-1}) / TPPC$$
$$RC_{t_o} = PPC_{t_o} / (1 + THRC * TREND_{t_o})$$
$$RC_t = RC_{t-1} + (PPC_{t-1} - RC_{t-1}) / THRC$$
$$ITREND_t = [(PPC_{t-1} - RC_{t-1}) / RC_{t-1}] / THRC$$
$$TREND_{t_o} = \text{exponential trend from 2000-2005} \quad \text{(see note)}^{27}$$
$$TREND_t = TREND_{t-1} + (ITREND_{t-1} - TREND_{t-1}) / TPT$$

Where

INPUT = Input Variable (units)

TREND = Investor-perceived fractional growth rate (1/time)

ITREND = Indicated trend in the input (1/time)

RC = Investor-perceived Reference Condition in the input (units)

PPC = Perceived Present Condition (units)

TPT = Time to Perceive Trend, a first-order time constant (time units)

THRC = Time Horizon for the Reference Condition, a first-order time constant (time units)

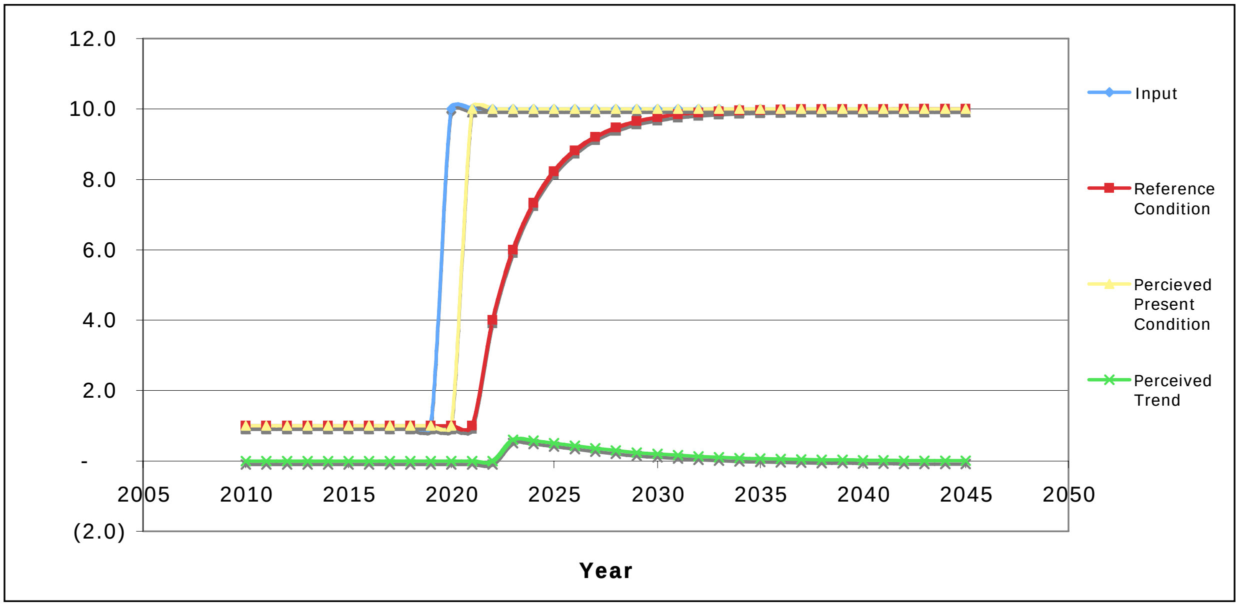
TPPC = Time to Perceive Present Condition, a first-order time constant (time units)

---

23 Roques et al. "Nuclear Power: A Hedge against Uncertain Gas and Carbon Prices?" *Energy Journal in press*.
24 Ford, Andrew. "Cycles in Competitive Electricity Markets: A Simulation Study of the Western United States." Energy Policy, Vol 27, 1999.
25 Sterman, John D. "Business Dynamics," Chapter 16. Irwin-McGraw Hill, Boston, MA. 2000.
26 *Id.*
27 The first decision (and first forecasts) are made in year 2010, 5 years after the start of the simulation.

TPT, THRC, and TPPC all determine the first-order delay in the response of investor perception/ expectation to a change in the actual value. In my analysis I assume values of 5, 3, and 1 year respectively[28]. Figure 17 shows the response of this model to a step change in the input. Using the time constants indicated above, there is a 1-year delay in the investor's perception of the present condition. The reference condition (the investor's perception of how business usually was and therefore compared to the present condition to forecast expectations) adjusts with a 3-year time constant. The investor's forecasted growth rises above zero (after a perception delay) and then decays to zero as the investor becomes accustomed to the new level of the input.

Figure 17. Response of Reference Condition, Perceived Present Condition, and Perceived Trend to Step Change in Input



Investor Decisionmaking

At each time-step in the model, investors use their perceptions and expectations to maximize their net present value by building or not building a new generation facility. The options available at each decision are determined by the plan being analyzed. These plans mirror the 3 plans examined above, and their decisions are as follows[29]:

- In Plan 1, average growth in demand is assumed, and the investor commits to building large CCGT plants (3000 MW) on a fixed schedule to supply that demand. There is no flexibility in size or timing of construction, and hence no decision.
- In Plan 2, the investor makes a decision each year. If the forecast demand for the next year is greater than the current generation capacity, the investor constructs new generation capacity to meet that demand, in 500MW increments of CCGT.

[28] These values are asserted and should not be cited.
[29] These plans are for illustrative purposes and should not be cited.

- In Plan 3, the investor makes two decisions each year. First (and as in Plan 2), if the forecast demand for the next year is greater than the current generation capacity, the investor constructs new generation capacity to meet that demand, in 500MW increments. Next, the investor compares the 25-year[30] Net Present Values of building that capacity as CCGT or wind, using the investor's forecast of demand, carbon price, and gas price (as modeled above) as inputs to the cost model. The investor selects to expand using whichever technology maximizes his net present value.

Two models of investor forecasting were created. In one, the investor expects that demand, carbon price, and gas price will all grow geometrically (Forecasting 1). In the second, demand is expected to grow geometrically while expected gas and carbon prices are held constant as the Reference Condition in that time step (Forecasting 2).[31]

RESULTS

A Monte Carlo simulation with demand, price, and investor behavior models as described above was run with N=4920 simulations and a 40-year time horizon. The average expected values for the plans are reported in Table 16.

Table 16. Expected Value of Three Plans

Plan	Value (Million $)
Plan 1	$ 6,035.35
Plan 2	$ 6,862.30
Plan 3 - Forecasting 1	$ 7,105.50
Plan 3 - Forecasting 2	$ 7,096.27

According to this analysis, the value of Plan 2's flexibility as compared to Plan 1, then, is approximately $800 million. Adding the ability to develop wind in addition to CCGT (as in Plan 3) adds another $240 million expected value. Note that since the trends and time horizon are slightly different than the decision analysis presented above, this result is not perfectly comparable to the decision analysis results. However, the difference in the value of flexibility found with this method is not surprising, since:

- Demand and gas price are modeled stochastically in this analysis, allowing a greater range of outcomes than the eight scenarios considered in the decision analysis and therefore more uncertainty, and
- Uncertain evolution of carbon price is allowed in this model, while it was held constant in the decision analysis, adding another dimension to the uncertainties.

Because this simulation includes significantly more uncertainty (range of possible outcomes and number of uncertain variables) than the decision analysis, it is not surprising that the analysis assigns a higher value to flexibility.

The distribution of simulated outcomes for each plan is shown in Figure 18 (Plan 3 with the 1st Forecasting method is omitted for clarity). The cumulative distribution functions are shown in Figure 19. Adding flexibility shifts the curves away from negative outcomes and toward positive ones.

[30] This time horizon is assumed and should not be cited.
[31] Please see the attached Excel workbook for the implementation of this.

Figure 18. Distribution of Simulated Outcomes

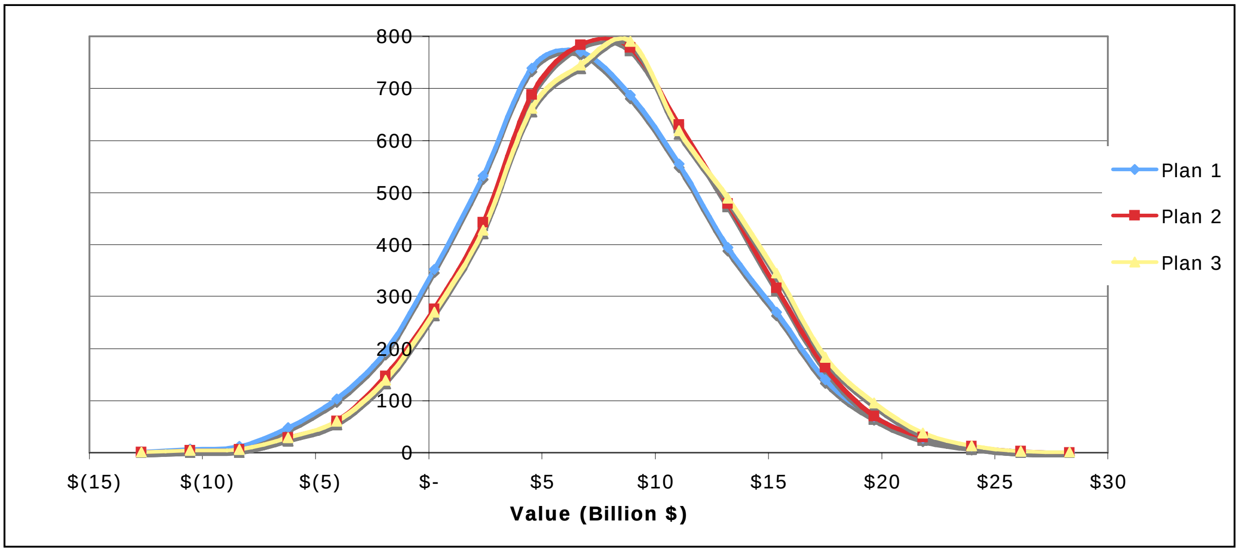
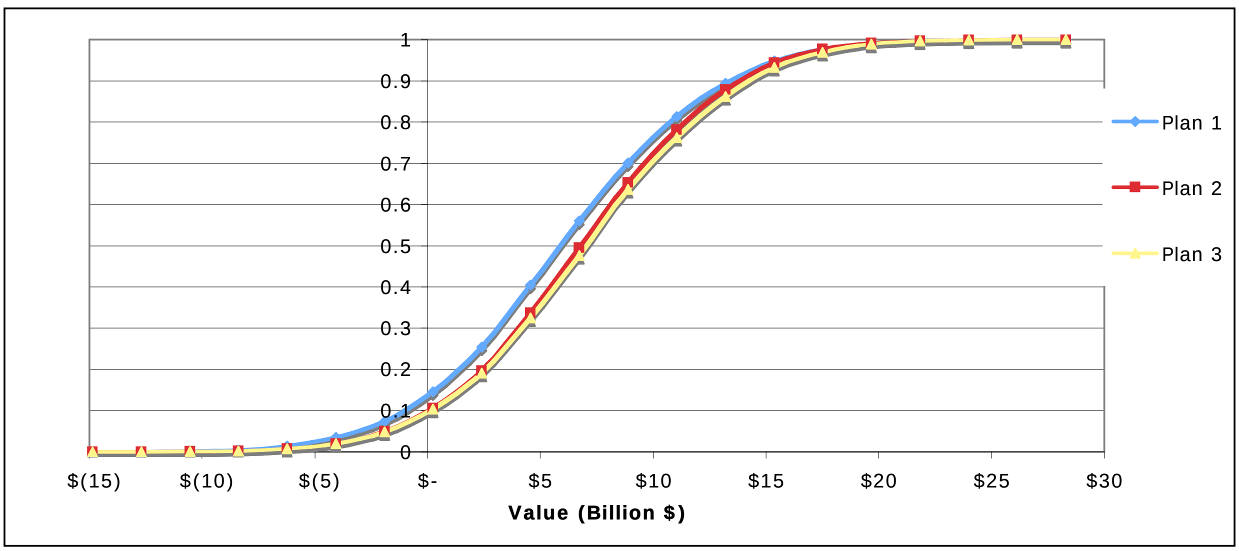


Figure 19. Probability Distribution Function of Simulated Outcomes



8 CONCLUSION

Demand for electricity in the country of Portugal is expected to grow significantly over the next 25 years, and the country must expand its generation capacity in order to meet this demand. This paper has presented options for generation expansion with combined-cycle gas fired (CCGF) and wind generation. Three expansion paths were explored, including:

- Building a single large CCGF plant,
- Building a smaller CCGF plant now and a second smaller plant later, allowing flexibility in the sizing of the second plant, and
- Building a smaller CCGF plant now and allowing a mix of CCGF and wind to be installed later, allowing flexibility in the total size and relative mix of CCGF/wind.

The choice of optimal strategy depends on the future demand for electricity and the future natural gas price, both of which are uncertain. Using a range of possible outcomes chosen based on historical data, a decision tree was conducted to choose the optimal expansion strategy. Based on this analysis, the third plan (small initial plant and possible CCGF and wind in the future) is optimal, with an expected net present value of $8.27 billion over the 25-year period considered.

It is interesting to note, though, that the expected value of choosing Plan 2 is $8.22 billion, very close to the Plan 3 value. This is important because, while I have included all the capital costs of construction in my cost model, I have not included any costs incurred to maintain future flexibility. Specifically, the generator might have to purchase options from landowners that would allow the merchants to purchase the land in the future and develop wind generation facilities. The analysis I have presented suggests that the maximum value the generator should be willing to pay for such an option is $8.27 billion - $8.22 billion = $50 million. Because carbon cost uncertainty was omitted from the analysis for simplicity, I would expect this value to be a lower bound.

Having chosen a small initial plant, the value of a put option on that plant was explored for the case of constant demand growth but variable gas prices. This determines how much the generator should be willing to pay in order to maintain the flexibility to close the facility in the future. Using a lattice model and dynamic program to determine revenues with and without this flexibility, the value of such an option was found to be $500 million.

Thus the optimal expansion strategy is via Plan 3 – small initial plant and options for gas and wind. If options must be purchased to develop wind in the future, instead of just CCGF (as in Plan 2), the generator should be willing to pay up to $50 million to maintain this flexibility. If there are costs associated with maintaining the option to close the initial facility at any time, the generator should be willing to pay up to $500 million to maintain this flexibility.

If, on the other hand, maintaining these options requires no extra cost, the generator earns an extra $400 million (approx 5%) net present value by choosing strategy 3, the most flexible plan, over strategy 1, the least flexible. Additionally, the generator gains $500 million in expected value by being able to close the plant at will rather than committing to operating it until 2030.

As an alternative to the decision tree/lattice approach, I also developed a Monte Carlo simulation to model stochastic demand, gas price, and carbon price, in addition to including a behavioral model of investors as boundedly rational with imperfect forecasts. Because it includes

- stochastic uncertainty (rather than scenarios),
- a greater number of uncertain variables (by including carbon price), and
- more flexibility in the flexible plans (by allowing decisions every year instead of every 12 years),

this simulation assigns a higher value to flexibility ($1.07 billion when comparing Plan 3 to Plan 1) than the decision tree and lattice method. Because of the multiple uncertainties and year-to-year (but imperfect) decisionmaking experienced in real liberalized electricity markets, I expect this simulation approach (with more refinements and calibration) to produce the most realistic results.

9 COURSE REFLECTIONS

Where do you see the most use for a flexible approach to design, and valuation of options?

I can imagine making use of the concepts from this class in a wide variety of situations – obviously including large capital investments such as the power plant I have analyzed above, as well as some of the examples for class. Now that I understand the concept from using such a textbook example, though, I would be interested in applying these concepts to policy design. Reducing carbon emissions, for example, might be done in the US through a variety of mechanisms, and it’s unclear which will minimize social cost. By designing a flexible approach (i.e. not committing to a single mechanism) unexpected technology developments can be taken advantage of in the future. Using the methods from the course, one could explore how valuable those options might be, and use that analysis to inform how much should be spent on developing emerging technologies that might be worth using in the future.

What have I learned in doing this portfolio?

This has been a great learning experience. Doing these analyses from scratch, on a system of my choice, helped me think through the approach and how some concepts might be useful in my own research and work. More deeply, though, the fact that we had to create the scenarios from scratch, rather than use textbook problems, forced me to think about the kind of systems that this approach is most useful for, what kind of data is needed for the approach, and how useful the end results are. Had the problem been outlined for us with data, models, etc. already developed, I don’t think I would have gained as deep an understanding of when/how to use this in the real world.