From:	Heather Hunt
To:	Katie Dykes; Scott, Robert; Hatfield, Meredith; Thomas Welch; Woodcock, Patrick C; Marion Gold; Chris Recchia; Clarke, Steven (ENE); Kates-Garnick, Barbara (ENV); Sylvia, Mark (ENE); Ann Berwick; Margaret Curran
Cc:	Heather Hunt; Ben D"Antonio; Birud Jhaveri; Ed McNamara; McCluskey, George; Nick Ucci; Speidel, Alexander; Eric Jacobi; Tracy Babbidge; Mark Quinlan; Snook, Robert D.; Jeff Bentz; Allison Smith; Dorothy Capra; todd.bianco@puc.ri.gov; Jason Marshall; Thomas Bessette
Subject:	fyi, MA AG analysis on clean energy sources
Date:	Friday, April 18, 2014 2:47:48 PM
Attachments:	MA AGO Renewable Procurement Report Final 20140414-1.pdf

The MA AG has produced a report (attached) by a consultant that looks at returns of a hydro project (Power and T) and of a wind project in a scenario where the demand curve (filed at FERC for approval) is in place. The MA AG offers that returns for hydro will be such that no long term contracts are needed. In reply to the MA AG request for views, we indicated an interest in seeing the views of folks who would invest. The MA AG indicates the report has been provided to entities such as HQ, NU, Grid, First Wind, EDP and others. We will take a look at the report as well.

The email exchange is below, for those who want to see that communication.

EMAIL EXCHANGE, FYI
JESSE/MA AH:

As I suggested at the End User meeting with NESCOE this Monday, the new demand curve is going to change a lot of investment decisions, because the capacity cost is going to be significantly higher than it has been in the past 8 auctions. Attached is a report from the AGO's consultant, Randell Johnson, evaluating the prospective returns both of a hypothetical Canadian hydroelectricity project (including the cost of the transmission lines necessary to deliver it) and of a hypothetical land-based wind project under the revised demand curve that we supported and which ISO New England has filed with the FERC for approval. We used publicly available information where available, so the hydro piece is based in part on what we know from Hydro Quebec's annual reports. We didn't want to do this based on proprietary information, since this needs to be discussed openly.

Essentially, the report concludes that a Canadian hydroelectricity project can expect to make profits that exceed a 15% internal rate of return without needing any additional payments via a long-term contract or otherwise. The expected higher capacity payments resulting from the revised demand curve lead to this result. The report also concludes that if the Production Tax Credit is not renewed, wind projects (the model is a hypothetical wind project in Maine) are likely to require some form of additional revenue support to achieve profits that would exceed a 15% internal rate of return.

Do you have any thoughts about these conclusions or about the methodology? [If I omitted anyone from the cc list who was at the meeting, please pass this on].

JASON REPLY: Thanks, Jesse. We appreciate additional and data being added to the body of work on these matters. It would be helpful to review others' reactions to the analysis, including from hydro and wind developers, investors, TOs, and others. Are you planning to ask for that input and then sharing it?

JESSE/MA AG RESPONSE TO JASON: We have shared it with the renewable developers and related interests who have been the most active in the Massachusetts legislation, i.e. Hydro Quebec, Nalcor, Brookfield Power, EDP, First Wind, National Grid, Northeast Utilities, and Janet Besser. Dan Dolan and Bob Ethier also have it. We will share any updates if we get any additional input.

Getting input from investors is a great idea. I'm don't have any contacts though. Can you put me in touch with lenders or capital investors from whom you think it would be helpful to get input?

Heather Hunt
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DCF Income Stream Analysis of MA Clean Energy Bill

4/16/2014

Prepared for the Massachusetts Attorney General's Office By:

Randell Johnson
Andrew Bachert

Table of Contents

List of Figures

List of Tables

EXECUTIVE SUMMARY

The Massachusetts Attorney General (Attorney General) has requested assistance to evaluate the cost impacts associated with entering into a power purchase agreement associated with recent legislation regarding the renewable energy purchase.

The draft legislative bill "An Act Relative to Clean Energy Resources" specifies the procurement of 18,900 GWh annually of clean energy via long-term contracts for 15- to 20-year terms. To evaluate the economic costs of this procurement, the Massachusetts Attorney General (Attorney General) has requested a Discounted Cash Flow (DCF) analysis of the financial requirements for a hypothetical generator procured from Hydro Québec (HQ) or Nalcor.

Energy Exemplar has created two discounted cash flow (DCF) models to evaluate possible long term contracts with either a hydro generation project supplied by Hydro Québec or a wind project in Maine. The purpose of the DCF models is to evaluate any additional contract payments which would be necessary, if at all, for either of these two projects assuming they first received sufficient revenues from the ISO-NE administered markets.

We have first benchmarked the DCF models as stand-alone models assuming LMP prices based on an implied heat rate with an overall efficiency of 45%. This combined with our long term natural gas prices creates a reasonable energy price stream for the DCF model. Once we have benchmarked the DCF models and results with the implied heat rates, we will run our detailed PLEXOS model to generate the income streams for these two projects to evaluate whether the projects require additional support in terms of supplemental payments.

Hydro Project

The initial results of the stand-alone DCF models suggest that the Hydro Project is self-sufficient in terms of revenues from the ISO-NE market in all but the Low Gas Case. We assumed a 2,540 MW project with a capacity factor of 85% and total capital costs of nearly C$13.0 billion Canadian dollars.

Table 1 below compares the Hydro Project for the Base, Low and High Gas cases. An additional case was also run, reducing the capacity price from $11.08/kW-Month in the Base Case to target the 15% rate return.

Table 1: Hydro Stand-alone DCF Results

HYDRO GENERATION
IMPLIED HEAT RATE: 7.58 MMBtu/MWH

Case Comparison 25-year Revenues (in $000's USD)

	Base Case	Low Case	High Case	15% IRR
IRR	18.9%	15.0%	24.0%	15.0%
Cap Price	$11.08	$11.08	$11.08	$3.74
Sup Price	$0.00	$2.24	$0.00	$0.00
Total Cap	$11.08	$13.32	$11.08	$3.74

The results in Table 1 reflect the total capacity price required to maintain a 15% internal rate of return or higher with the assumed market administered capacity price of $11.08/kW-month as the base or default capacity price. We then adjusted the additional Contract Price, or reduced the market capacity price, to reach the target 15% return.

Despite the relatively high capacity costs, the Base Case stand-alone results in a Project Internal Rate of Return of 18.9%.

To achieve the 15.0% return case, we reduced the ISO-NE administered capacity price from $11.08 /kW-Month to $3.74/kW-Month. The reason for the significant returns for this hydro generator is the absence of fuel costs while receiving energy payments based on marginal units setting the price with either natural gas or oil.

In the Low Gas cases, additional capacity payments are required to meet the 15% return threshold above the $11.08/kW-Month market payment of $2.24/kW-Month for the stand-alone.

Table 2: Hydro PLEXOS DCF Results

HYDRO GENERATION
PLEXOS Cases

Case Comparison 25-year Revenues (in $000's USD)

	Base Case	Low Case	High Case	15% IRR
IRR	20.7%	15.0%	25.6%	15.0%
Cap Price	$11.08	$9.54	$11.08	$0.35
Sup Price	$0.00	$0.00	$0.00	$0.00
Total Cap	$11.08	$9.54	$11.08	$0.35

The hydro case using PLEXOS results in sufficient revenues all cases (Base, Low and High Gas) without the need for any additional supplemental capacity revenues to reach a 15% internal rate of return (IRR) target or higher. The Base Case after tax IRR is estimated to be 20.7% assuming a capacity revenue of $11.08/kW-month from the ISO-NE market while the High Gas Case results in a 25.6% after-tax IRR and the Low Case is 15.8%. None of these cases require an additional or supplemental capacity payment stream to make the project viable with a 15% rate of return.

Wind Project

The wind project requires more supplementary capacity prices, mostly due to the lower capacity factors associated with the wind project. We assumed as a 200 MW project with an annual capacity factor of 31%. While the Wind Project did not have the large transmission lines nor HVDC connections associated with the Hydro Project, it also received significantly less revenues, both in terms of capacity payments and energy, due to its reduced capacity factors.

The DCF stand-alone results for the Wind Project requires additional or supplemental capacity payments in order to make the project achieve the 15% after tax returns for both the Base Case and Low Gas

Cases. The High Gas Case meets the 15% after tax return and therefore does not require any additional revenues.

Table 3: Wind Stand-alone DCF Result

WIND GENERATION IMPLIED HEAT RATE: 7.58 MMBtu/MWH Case Comparison 25-year Revenues in US $/kW-month			
	Base Case	Low Case	High Case
IRR	15.0%	15.0%	16.6%
Cap Price	$11.08	$11.08	$11.08
Sup Price	$8.40	$24.79	$0.00
Total Cap	$19.48	$35.87	$11.08

While the PLEXOS Wind Projects results are better than the implied heat rate case, due to the significant level of detail included in the PLEXOS model and therefore the resulting PLEXOS forecasts, we have not seen as significant an increase as the Hydro Project. This is because the Wind Project economics relies much more on the capacity and REC revenue stream than the energy revenues due to its diminished capacity factors in the energy markets.

Table 4: Wind PLEXOS DCF Results

WIND GENERATION PLEXOS Base Case New England Gas Case Comparison 25-year Revenues (in $000's USD)			
	Base Case	Low Case	High Case
IRR	15.0%	15.0%	16.6%
Cap Price	$11.08	$11.08	$11.08
Sup Price	$6.90	$21.80	$0.00
Total Cap	$17.98	$32.88	$11.08

Nonetheless, the Base Case requires an additional revenue of $6.90/kW-month to reach the target 15% return while the Low Gas case requires nearly $22/kW-month. As in the previous results, the High Gas Case does not require additional or supplemental capacity revenues to meet the target 15% rate of return.

1. INTRODUCTION

The Massachusetts Attorney General (Attorney General) has requested assistance to evaluate the cost impacts associated with entering into a power purchase agreement associated with recent legislation regarding the renewable energy purchase.

The draft legislative bill "An Act Relative to Clean Energy Resources" specifies the procurement of 18,900 GWh annually of clean energy via long-term contracts for 15- to 20-year terms. To evaluate the economic costs of this procurement, the Massachusetts Attorney General (Attorney General) has requested a Discounted Cash Flow (DCF) analysis of the financial requirements for a hypothetical generator procured from Hydro Québec (HQ) or Nalcor. This document specifies the procedure and findings of that DCF analysis.

Creating a suitable DCF analysis will entail tasks such as determining pricing streams of hypothetical new generators (given ISO-NE's newly developed demand curve), what long-term contract pricing support would be necessary if any, whether or not contract subsidies are required and how much, and the minimum contract price that would earn a reasonable rate of return. Additionally, the analysis should compute the rate of return the hydro generator would provide should a generator just rely on market clearing prices, and find the level of onshore wind subsidy required for reasonable return.

Analysis Methods

We propose a dual currency (i.e., US and Canadian) DCF analysis to analyze the internal rate of return for the hypothetical generator.

Using PLEXOS, we aim to create robust and reasonable forecasts of variables such as future energy revenues and capacity market revenues that the hypothetical generator will receive. The software will be used to make 8760-hour production cost/revenue simulations for the hypothetical generator and over a 25-year time horizon.

Using the simulation method described above, the following outputs from PLEXOS will be fed into a discounted cash flow (DCF) spreadsheet:

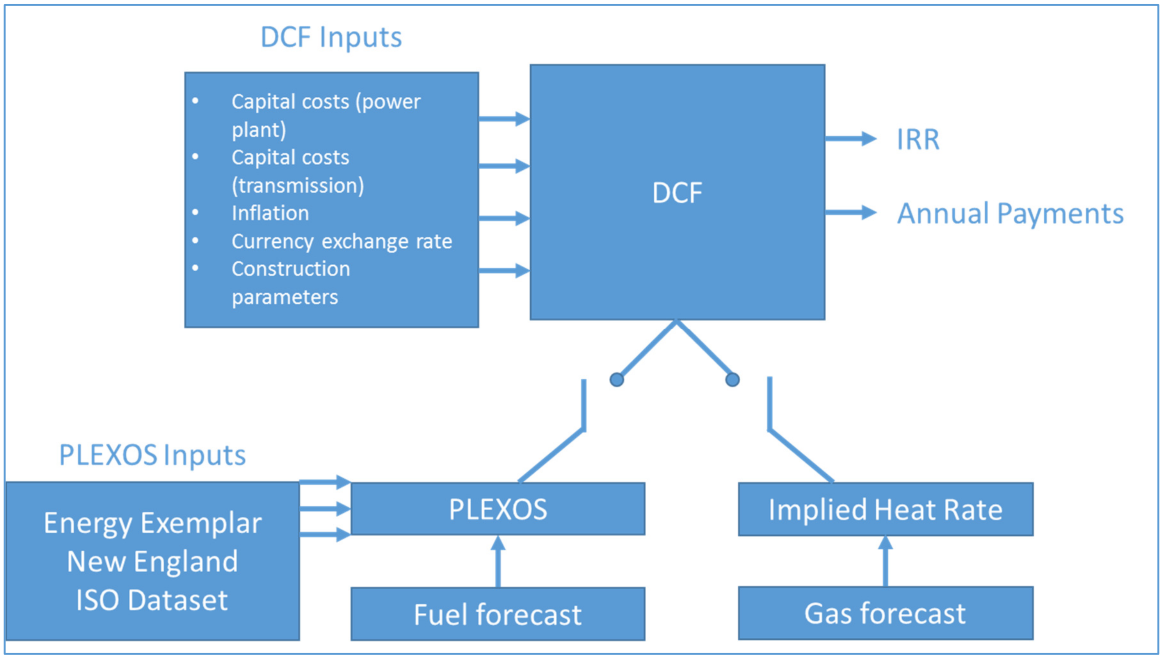
- monthly dispatch of the proposed unit in MWh and monthly average energy prices in $/MWh; and
- capacity payments in $/kW-month.

From this analysis, we will solve for whatever additional contract payments, if any, will be required to make this project feasible.

Figure 1 below outlines the two methods we have developed for this analysis, first using implied heat rates to benchmark the DCF models and then using the outputs of PLEXOS into the DCF models. The implied heat rates uses our long term natural gas forecasts for the New England markets to estimate the LMP prices received by both projects. In this case we assumed capacity factors for both projects, 85% for the Hydro Project and 31% for the Wind Project.

After this is complete, we will use PLEXOS to derive both the prices (including LMP and capacity) as well as the MWh dispatch for energy inputs into the DCF models. In this case, both prices and the dispatch results are fed into the DCF, which is then used to calculate any necessary supplemental payments for both projects.

Figure 1: DCF analysis modeling structure



PLEXOS Assumptions

The current proposed ISO-NE capacity demand curve is used to forecast capacity market revenue for the hypothetical generator.

We will use the New England dataset as created by Energy Exemplar. This dataset represents generators in high detail, and includes both the ISO-NE CELT load forecast and a fuel forecast. The ISO-NE CELT load forecasts energy and peaks for a duration of ten years; these estimates are extrapolated to 40 years using average growth rates in energy and peaks over the last three years of the forecast.

The Energy Exemplar ISO-NE Dataset also contains a 40-year nuclear forecast based on historical refueling cycles, derates, and forced outage rates. These estimates were based on data from the Nuclear Regulatory Commission. Wind power output is estimated from NREL wind power data from the EWITS study from 2006 data.

The likely returns can rise or fall with, given that natural gas sets the marginal cost of electricity in New England and that Canadian resources are predominantly hydroelectric. As such, we propose a high gas price and a low gas price sensitivity based upon the 40-year natural gas price forecast.

We assume the size of the hydro hypothetical generator capacity will be 2538 MW $(18{,}900{,}000/(8760 * 0.85) = 2538\ MW)$, assuming an 85% annual capacity factor over 8760 hours. Similarly, the hypothetical wind generator will be assumed at a capacity of 200 MW, with annual capacity factor of around 31%.

For load, we used the latest 50 / 50 ISO New England CELT[1] forecast through 2022. We then took the growth factors for the last three years (2019 through 2022) and forecasted out the remaining years through 2054 for both energy and peak load. For those regions with negative or no load growth in the last three years of the CELT forecast, we substituted a growth of a quarter of 1 percent (0.25%) per annum.

Discounted Cash Flow Analysis

The macroeconomic assumptions of this model reflect the typical development structure in the US, including:

- Overnight costs for hydro generation will be derived from the EIA cost by technology type tables in the AEO, to which the New England regional multiplier is applied. Capital costs based on overnight costs will be thus modeled.
- For the HQ hydro generator, we will assume the costs of HQ – New England transmission line construction will also need to be financed, so the overall project can earn a reasonable rate of return. We will assume two 1200 MW HVDC lines running from the HQ/New England border to Boston.
- Data on per mile transmission line costs data will be taken from the EIPC report (as prepared by ISO-NE).
- Typical owner's costs during construction will include interest during construction (IDC), startup costs and development costs, among others.
- Assume a project construction window of three years, with commercial operation date (COD) of January 2018.
- ISO-NE Administered capacity payments of $11.08/kW-Month are assumed as a flat monthly capacity payment throughout the life of the projects. In some cases we reduced this administered capacity price to reach at 15% target return (see results).
- An additional supplemental capacity payment or Contract Price is used to calculate the targeted rate of return for both projects. In some cases, no additional capacity payments are necessary (see results).
- For onshore wind analysis, no PTCs are assumed and RECs will be assumed between $40 and $60 /MWh.
- The contract life is assumed to be 25 years, which is the period of time any supplemental or additional Contract payments are made. Although the current draft legislation provides for contracts with 15- to 20-year terms, we assume that the contracts provide the purchaser with an option to extend the contract (as was provided in the Cape Wind contracts). However, the economic life of the project (for NPV and IRR calculations) is assumed to be 40 years for the Hydro Project and 25 years for the Wind Project. If the economic life exceeds the contract life, it is assumed the Project will continue to receive both the administered Capacity Payments and Energy Revenues for the remaining years of the Project life.

[1] New England load forecast using a 50/50 load forecast/assumption where there is a 50% chance of exceeding the 50/50 peak load forecast.

- For the Hydro Project, we have assumed a simplified tax depreciation schedules of straight-line over the life of the Project (40 years) and a tax rate of 25% due to the financial structure of Hydro Québec. For the Wind Project, we have assumed an accelerated depreciation tax schedule and standard US and state corporate tax rates are assumed.
- For the Hydro Project, a 30-year financing term with an assumed debt-to-equity profile of 70% with a single senior debt tranche assumed. The mortgage payments follow a backend loaded repayment profile.
- Equity after tax return is assumed at of 15%. We can also provide a range of IRR, along with the corresponding contract pricing.

Implied Heat Rate

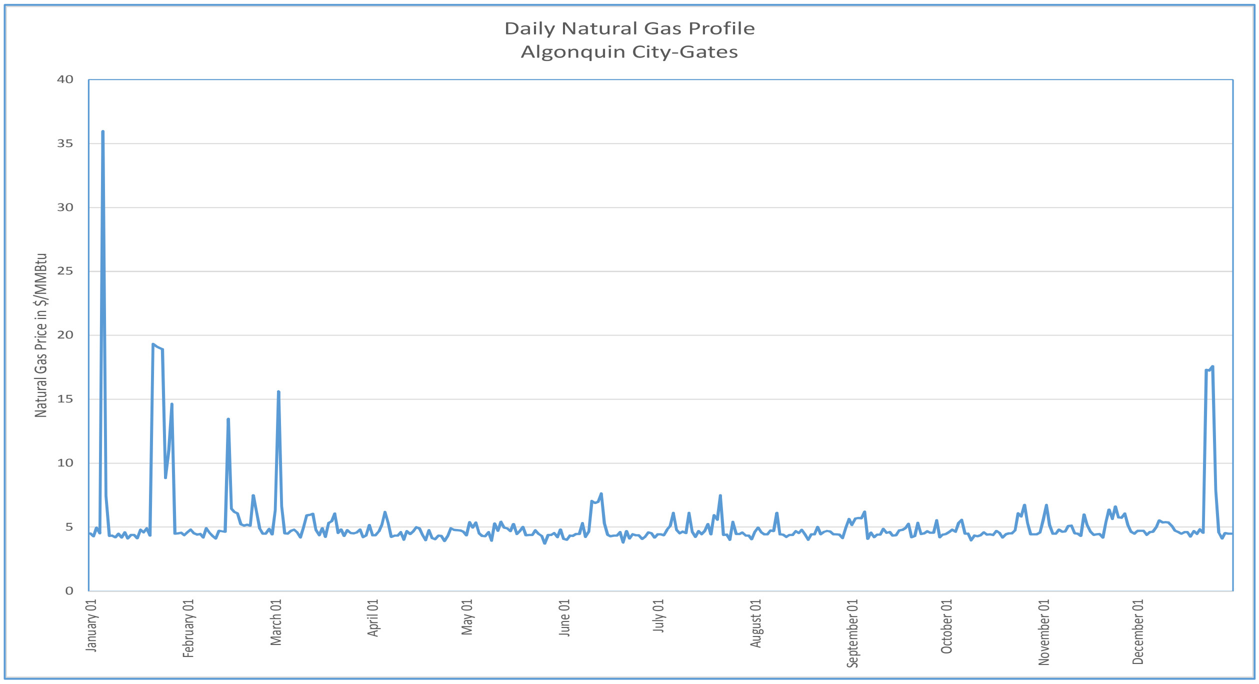
For the stand-alone analysis, Energy Exemplar employed an implied heat rate as a proxy for long term price forecast of the ISO-NE system LMP prices. The Implied Heat rate used our natural gas forecast of both Algonquin and Dracut natural gas hubs in $/MMBtu (weighted 50% each) for the 40-year period and assumed a 45% efficiency to calculate a corresponding LMP price in $/MWh.

The Implied Heat Rate is calculated as follows: Conversion factor of 3.413 MMBtu/MWh (assuming a 100% efficiency) divided by an assumed efficiency of 45% = 7.58 MMBtu/MWh. The implied heat rate is then multiplied times the natural gas price to provide a $/MWh. For example, a natural gas price of $4.00/MMBtu * 7.58 MMBtu / MWh = $30.34/MWh.

Fuel Price Forecasting

Historical gas price data dating back up to ten years was first used to test the viability of the AR (1) and ARCH model forecasts. These models can be used to forecast both daily fluctuations in fuel prices, as well as broader, random shocks. Long-term fuel price trends were determined through the use of AEO forecasts as developed by the US government Energy Information Agency. AEO forecasts provide yearly estimates of low frequency trends. Generally, AEO forecasts take the form of monotonically-increasing yearly step functions, the steepness and non-linearity of which is determined by long-term macroeconomic estimates. In these cases, AEO forecasts must first be overlaid with AR (1) forecasts. Beyond this, daily price volatilities can be added to the model.

Figure 2: Example of Daily Natural Gas Profile for Algonquin Price Forecast



Issues of seasonality in price forecasting are modeled through the use of a Hodrick-Prescott (HP) filter, which is essentially a band-pass filter, applied to time series data. HP filters have the capacity to tease cyclical components from historical data. A year, representative of the pricing point being forecasted, is selected. After the cyclical components are teased out, they are subtracted from the original price data to isolate the trend component. These trend lines take roughly the same shape in all cases: two peaks bookending the year, with one peak in the summertime.

Macroeconomic forecasting

We used ARCH models with AR (1) overlays and conditional heteroskedasticity to model trends for the US/Canadian exchange rate and the LIBOR. Ten-year historical data is used to fit and test the model, and predictions are made using previous period values as determinants of both present period value and standard deviation in the future period. Such models base their forecasts on stochastic processes with successive iterations on previous periods—prices today can be predicted with relative accuracy using prices from yesterday. Similarly, if an unusually high value is shown in the previous period, the ARCH model will almost surely provide a similarly unusually high value in the present period, thus accounting for persistent shocks to currency and LIBOR values.

Forecasts are also prepared for Canadian and US CPI values. Values dating back to 1994 are used to fit and test the model. As these values are strongly correlated with long-term economic growth rates, these models merely take the form of simple logarithmic progressions. In principle, an ARCH or AR (1) overlay may be used to reflect shocks, but, in reality, long-term price data is far more immune to shocks than fuel price or even currency data.

2. Hydro Discounted Cash Flow Analysis

The DCF employed here is a project based financial analysis of a potential hydro generator by Hydro Québec. The model assumes project, operating and financing costs are in Canadian dollars and revenues are in US dollars (and converted back to Canadian dollars). It is a monthly model, both for the construction period as well as the operating period with the ability to either feed in monthly dispatch and energy prices or fixed schedule of prices.

We assumed an initial foreign exchange rate of Canadian $0.90 / USD and forecast monthly exchange rates over the 25-year contract term. We also assumed a regional cost multiplier for both capital and operating costs of 1.20 for the Quebec region.

We have made the following capital cost assumptions:

- Capacity of 2,540 MW;
- overnight capital costs of US$2,936/kW;
- Total transmission line costs of US$1.6 million per mile for 200 miles;
- HDVC converter station of US$550 million; and
- Along with the owner's costs (interest during construction, startup O&M and so forth), the total project capital costs are C$12,889 million.

Table 5: Hydro Project Summary of Construction Costs Sources and Uses

USES of FUNDS			(in C$000's)
Development Costs and Fees			10,000
Closing/ Financing Costs			11,500
Engineering, Procurement, Construction	2,936	USD $/kW	9,943,253
Transmission Line	1,600,000	USD $/mile	426,667
HVDC Connection	550,000	USD	733,333
Electrical Interconnect			15,000
Owner's Start Up Costs	14.30	USD$/kW-Yr	96,859
Contingency	10%		1,049,328
Energy Revenues During Construction			(155,763)
Interest during Construction			634,970
Bank Fees during Construction			95,978
Other Owner Costs During Construction			59,179
TOTAL	**check:**	12,920,304	**12,920,304**
TRANSMISSION LINE			
Voltage of Line HVDC		HVDC	
Length of Transmission Line		200	Miles
HQ Regional Multiplier		1.20	
SOURCES of FUNDS			**(in C$000's)**
Financial Close	01-Jan-15		
Senior Debt	70.0%		9,044,213
Equity	30.0%		3,876,091
Total			**12,920,304**

Source: Energy Exemplar DCF Analysis

We have assumed project financing will fund 70% of the project with a term of 30 years and an interest rate of 250 basis points over long term risk free rates of 1.50% with a monthly back-end loaded customized amortization schedule. We have chosen 70% leverage for the Hydro Project, as this is consistent with the overall company capital structure of Hydro Québec.

Table 6: Hydro Project Financing Assumptions

CONSTRUCTION FINANCING			(in C$000's)
Loan Commitment			9,044,213
Interest Rate during Construction	4.00%		634,970
Bank Fees during Construction			
Commitment Fee	0.25%		28,146
Underwriting Fee	0.75%		67,832
Agency Fee			75
TERM FINANCING			**(in C$000's)**
Senior Debt			
Commitment			9,044,213
Interest Spread			2.50%
Treasury Index (15 yr)			1.50%
Total Interest Rate			4.00%
Term (years)	30	Yrs	
Payment Method:	2		Customizd
1=levelized; 2=customize; 3=mortgage			
Debt Service Reserve LC fee			0.25%

Source: Energy Exemplar DCF Analysis

For the operating costs, we have assumed a Fixed Operating costs for hydro generation based on the EIA estimated plant costs of US$14.30/kW-Year plus a variable operating costs of US$2.50/MWh.

Table 7: Hydro Project Summary of Operating Properties and Costs

POWER PLANT PERFORMANCE FACTORS				
Capacity (MW)			2,540	MW
OPERATING EXPENSE				
O&M Variable Costs ($/MWh)			3.33	C$/MWh
O&M Fixed Costs	14.30	USD$/kW-Yr	48,429	C$000's
Project G&A			3,000	C$000's
Insurance			2,000	C$000's
Property Tax			1,000	C$000's

Source: Energy Exemplar DCF Analysis

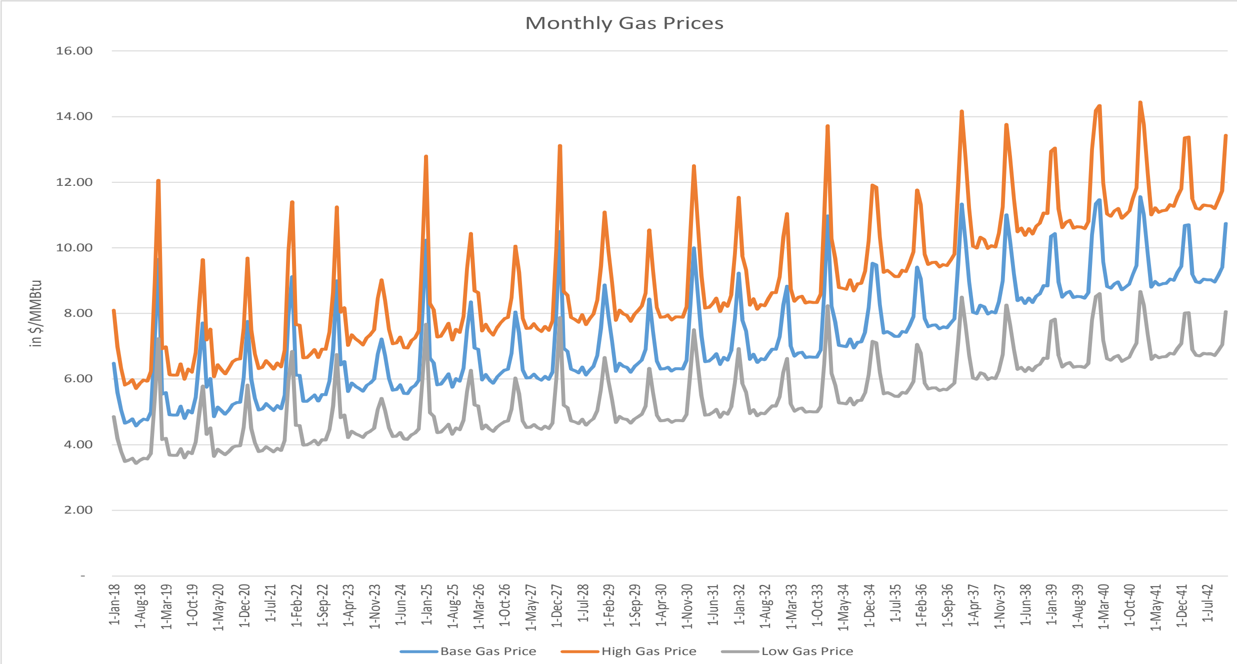
For this first case we incorporated three natural gas price forecast (Base, High and Low) from our New England PLEXOS model and then calculated an LMP based on an implied heat rate (see table below).

Table 8: Hydro Project Initial Revenue Assumptions

Implied Heat Rate			
Assume Implied Natural Gas Heat Rate		1	YES
1 = Use Implied Heat Rate; 0 = No			
Assumed Efficiency		45%	
Conversion Factor		3.413	MMBtu/MWh
Implied Heat Rate		7.58	MMBtu/MWh

Source: Energy Exemplar DCF Analysis

Figure 3: Monthly Natural Gas Price Forecast

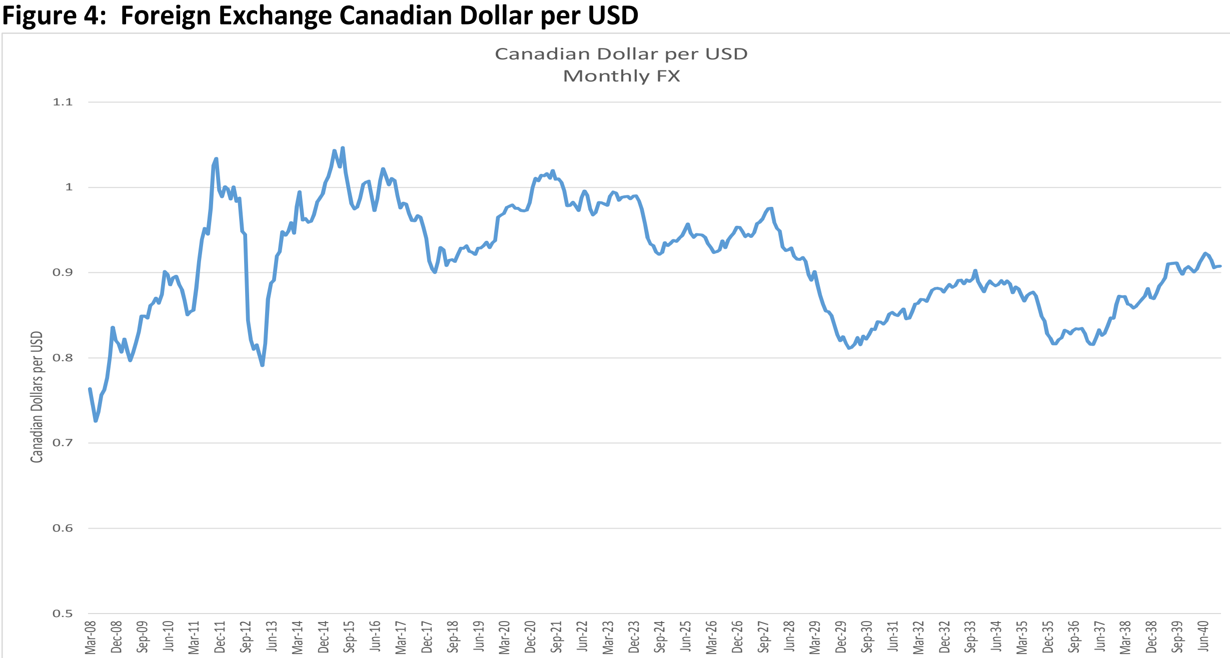


Data source: Energy Exemplar Gas Forecast

The base case implied heat rate results in an average real LMP of US$54.82/MWh over 25 years. The High Gas and Low Gas cases results in real LMP of $68.53/MWh and $41.12/MWh over 25 years.

For this analysis, it is assumed that only energy prices escalate at CPI (assumes both Canadian and US CPI equals 2.0%) and that the capacity prices are not escalated.

Figure 4: Foreign Exchange Canadian Dollar per USD



Data source: Energy Exemplar

We have made simplifying assumptions with regards to the project book and taxable income as well as tax rates.

While we have assumed a flat 25% project tax rate and a 40-year straight line tax depreciation, neither of these assumptions necessarily apply specifically to Hydro Québec, which is a government owned company and as such does not pay corporate tax, but rather, production royalties and other fees. Furthermore, Hydro Quebec typically enjoys the benefit of cheaper financing costs as the government of Quebec provides guarantees for its outstanding debt, reducing the risks to the borrowers.

Table 9: Hydro Project Tax and Depreciation Assumptions

DEPRECIATION & AMORT		**(in C$000's)**	
Depreciation Base		12,910,304	
Tax Depreciation	SL	40	Years
Book Depreciation	SL	40	Years
TAX ASSUMPTIONS			
Federal Income Tax Rate		25.00%	
State Tax Rate (Franchise Tax)		0.00%	
Combined Tax Rate		25.00%	

Source: Energy Exemplar DCF Analysis

3. Wind Project Discounted Cash Flow Analysis

For the Wind Project DCF, we have assumed a project based financial analysis of a potential wind generator in Maine. The model assumes project, operating and financing costs are in US dollars and revenues are in US dollars.

We have assumed a regional cost multiplier for both capital and operating costs of 1.05 for the state of Maine.

We have made the following capital cost assumptions:

- Capacity of 200 MW;
- overnight capital costs of US$2,213/kW; and
- Along with the owner's costs (interest during construction, startup O&M and so forth), the total project capital costs are US$552.5 million.

Table 10: Wind Project Summary of Construction Costs Sources and Uses

Construction Costs and Sources and Uses of Funds			
Stated in US$000's			
USES of FUNDS			**(in US$000's)**
Development Costs and Fees			10,000
Closing/ Financing Costs			5,000
Engineering, Procurement, Construction	2,213	USD $/kW	464,730
Transmission Line	-	USD $/mile	-
HVDC Connection	-	USD	-
Electrical Interconnect			10,000
Owner's Start Up Costs	39.55	USD$/kW-Yr	4,153
Contingency	10%		48,388
Energy Revenues During Construction			(4,753)
Interest during Construction			11,044
Bank Fees during Construction			3,983
Other Owner Costs During Construction			1,367
TOTAL	**check:**	553,913	**553,913**
TRANSMISSION LINE			
Voltage of Line HVDC		NA	
Length of Transmission Line		-	Miles
ISONE Regional Multiplier		1.05	
SOURCES of FUNDS			**(in US$000's)**
Financial Close	01-Jul-15		
Senior Debt	75.0%		415,435
Equity	25.0%		138,478
Total			**553,913**

Source: Energy Exemplar DCF Analysis

For the revenues in the Wind Case, we have assumed the following:

- Capacity payments from the ISO-NE administered of $11.08/kW-Month and a qualified capacity factor of 19%. It is assumed that the capacity payments do not escalate.

- Average real energy LMP of $54.82/MWh escalated at 2.0% and an energy capacity factor of 31% per annum;
- Renewable Energy Credits (RECs) of $50/MWh assuming a capacity factor of 31%;
- And supplemental capacity factor in $/kW-month (see results) with a capacity factor of 31%.

We have assumed project financing will fund 75% of the project with a term of 20 years and an interest rate of 250 basis points over long term risk free rates of 1.50% with a monthly mortgage style repayment.

Table 11: Wind Project Financing Assumptions

CONSTRUCTION FINANCING			(in US$000's)
Loan Commitment			415,435
Interest Rate during Construction	4.00%		11,044
Bank Fees during Construction			
Commitment Fee	0.25%		868
Underwriting Fee	0.75%		3,116
Agency Fee			75
TERM FINANCING			**(in US$000's)**
Senior Debt			
Commitment			415,435
Interest Spread			3.00%
Treasury Index (15 yr)			1.50%
Total Interest Rate			4.50%
Term (years)	20	Yrs	
Payment Method:	3		Mortgage
1=levelized; 2=customize; 3=mortgage			
Debt Service Reserve LC fee			0.25%

Source: Energy Exemplar DCF Analysis

For the operating costs we have assumed a Fixed Operating costs for hydro generation based on the EIA estimated plant costs of $39.55/kW-Year and no variable operating costs.

Table 12: Wind Project Summary of Operating Properties and Costs

POWER PLANT PERFORMANCE FACTORS				
Capacity (MW)			200	MW
OPERATING EXPENSE				
O&M Variable Costs ($/MWh)			0.00	US$/MWh
O&M Fixed Costs	39.55	USD$/kW-Yr	9,492	US$000's
Project G&A			1,000	US$000's
Insurance			500	US$000's
Property Tax			500	US$000's

Source: Energy Exemplar DCF Analysis

We used the same three natural gas price forecast (Base, High and Low) from our New England PLEXOS model and then calculated an LMP based on an implied heat rate as described in the Hydro Case above.

The base case implied heat rate results in an average real LMP of US$53.53/MWh over 25 years (note that the average gas price differs from the hydro case as the operating year begins 1 year earlier). The High Gas and Low Gas cases results in real LMP of $67.88/MWh and $43.33/MWh.

We have made simplifying assumptions with regards to the project book and taxable income as well as tax rates.

Table 13: Wind Project Tax and Depreciation Assumptions

INVESTMENT/OPERATING ASSUMPTIONS			
Investment Date		01-Jul-15	
Construction Months		18	Months
Commercial Operation Date		01-Jan-17	
Project Economic Life		25	Years
Contract Term		25	Years
DEPRECIATION & AMORT		**(in US$000's)**	
Depreciation Base		543,913	
Tax Depreciation	MACRS	20	Years
Book Depreciation	SL	40	Years
TAX ASSUMPTIONS			
Federal Income Tax Rate		32.00%	
State Tax Rate (Franchise Tax)		8.00%	
Combined Tax Rate		37.44%	

Source: Energy Exemplar DCF Analysis

For the Wind Case, due to the lower capacity factors associated with the variable wind resource, the Project results require additional supplemental capacity revenues in addition to the ISO-NE capacity market revenues (see results below for more details).

4. HYDRO STAND-ALONE RESULTS

The stand-alone hydro case results in sufficient revenues in both the Base Case and High Gas Case without the need for any additional supplemental capacity revenues to reach a 15% internal rate of return (IRR) target or higher. The Base Case after tax IRR is estimated to be 18.9% assuming a capacity revenue of $11.08/kW-month from the ISO-NE market while the High Gas Case results in a 24.0% after-tax IRR. Neither of these cases require an additional or supplemental capacity payment stream to make the project viable with a 15% rate of return.

Table 14: Hydro Stand-alone Results

HYDRO GENERATION IMPLIED HEAT RATE: 7.58 MMBtu/MWH Case Comparison 25-year Revenues (in $000's USD)				
	Base Case	Low Case	High Case	15% IRR
IRR	18.9%	15.0%	24.0%	15.0%
Cap Price	$11.08	$11.08	$11.08	$3.74
Sup Price	$0.00	$2.24	$0.00	$0.00
Total Cap	$11.08	$13.32	$11.08	$3.74

Source: Energy Exemplar DCF Analysis

However, in the Low Gas Case, we estimate that a supplemental capacity revenue, in addition to the $11.08/kW-month market rate from ISO-NE, will be required. We estimate in the low gas case that an additional $2.24/kW-month or annual payments of $63.8 million is required to target a 15% after tax IRR, everything else equal.

In the Base Case, we have assumed the following revenue assumptions:

- Capacity Payment of $11.08/kW-Month; and
- LMP Energy based on an 85% capacity factor and real average LMP of $54.82/MWh.

We have assumed no escalation for the capacity prices but have assumed an annual inflation for LMP and reserves escalation of 2.0% per annum. We have also assumed costs escalate at 2.0% annual inflation as well. We have also not assumed any reserve revenue stream for the Hydro Project as it will connect to the ISO-New England system via a DC line.

The IRRs and payment streams shown here reflect the three sets of natural gas price forecasts which were used as inputs, both in the Hydro Generator Evaluation Model. The base case natural gas forecast represents prices taken from the daily Dracut and Algonquin prices as provided by ICE, and a 40-year price forecast derived from those prices.

The low and high gas prices cases represent two bands around the base case natural gas price forecast- 75% and 125% of the base case forecasts respectively. Across the time series, these bands maintain largely stable ratios relative to one another. Figure 4 charts the results of the payment streams for the three base cases.

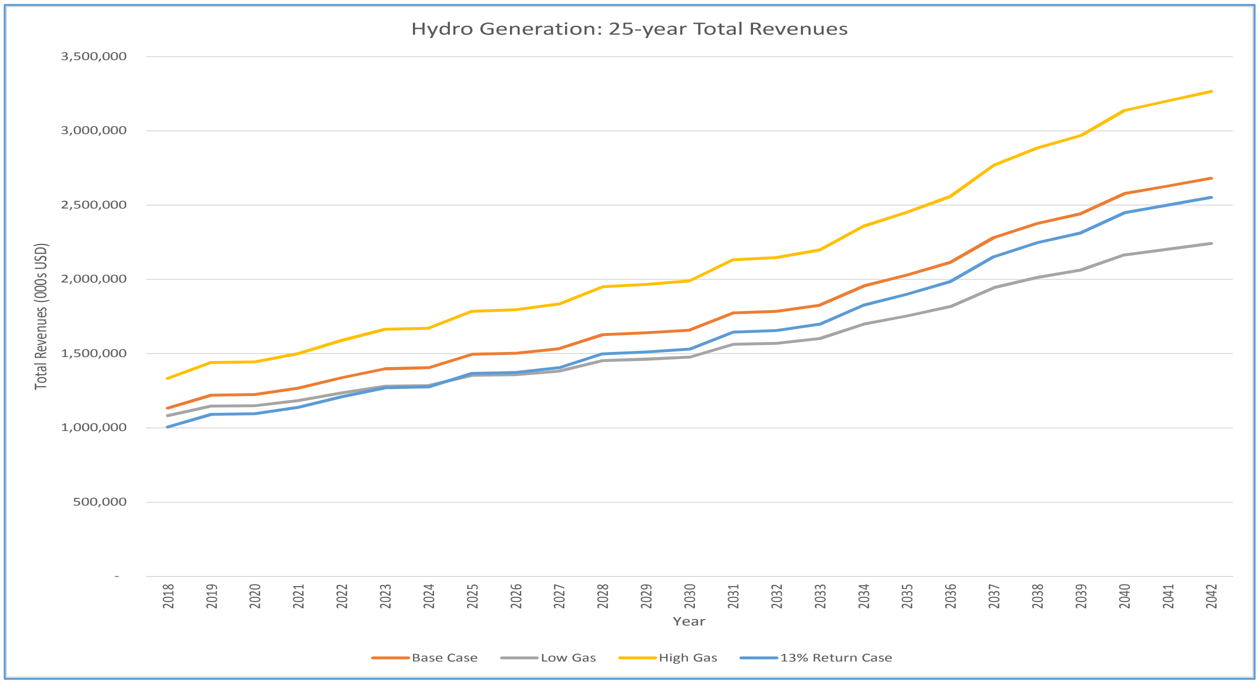
Table 15: Hydro Base Case Summary and Comparison Cases

HYDRO GENERATION IMPLIED HEAT RATE: 7.58 MMBtu/MWH Base Case 25-year Revenue (in $000's USD)				
Year	Capacity Payment	Supplemental Capacity Payment	Energy Payment	Total
2018	337,718	-	796,454	1,134,173
2019	337,718	-	882,461	1,220,179
2020	337,718	-	886,329	1,224,048
2021	337,718	-	930,568	1,268,286
2022	337,718	-	1,000,349	1,338,068
2023	337,718	-	1,060,879	1,398,598
2024	337,718	-	1,066,842	1,404,560
2025	337,718	-	1,158,199	1,495,918
2026	337,718	-	1,165,653	1,503,372
2027	337,718	-	1,196,358	1,534,077
2028	337,718	-	1,290,673	1,628,391
2029	337,718	-	1,303,147	1,640,865
2030	337,718	-	1,321,405	1,659,124
2031	337,718	-	1,435,798	1,773,516
2032	337,718	-	1,447,172	1,784,891
2033	337,718	-	1,489,073	1,826,791
2034	337,718	-	1,616,906	1,954,624
2035	337,718	-	1,691,894	2,029,612
2036	337,718	-	1,776,368	2,114,087
2037	337,718	-	1,944,578	2,282,296
2038	337,718	-	2,037,908	2,375,627
2039	337,718	-	2,104,405	2,442,124
2040	337,718	-	2,239,248	2,576,966
2041	337,718	-	2,291,083	2,628,801
2042	337,718	-	2,342,783	2,680,502

HYDRO GENERATION IMPLIED HEAT RATE: 7.58 MMBtu/MWH Case Comparison 25-year Revenues (in $000's USD)				
	Base Case	Low Case	High Case	15% IRR
2018	1,134,173	1,003,334	1,333,286	910,450
2019	1,220,179	1,067,839	1,440,794	996,456
2020	1,224,048	1,070,740	1,445,630	1,000,324
2021	1,268,286	1,103,919	1,500,928	1,044,563
2022	1,338,068	1,156,256	1,588,155	1,114,345
2023	1,398,598	1,201,653	1,663,818	1,174,875
2024	1,404,560	1,206,125	1,671,271	1,180,837
2025	1,495,918	1,274,643	1,785,467	1,272,194
2026	1,503,372	1,280,234	1,794,785	1,279,649
2027	1,534,077	1,303,262	1,833,166	1,310,354
2028	1,628,391	1,373,998	1,951,059	1,404,668
2029	1,640,865	1,383,354	1,966,652	1,417,142
2030	1,659,124	1,397,048	1,989,475	1,435,401
2031	1,773,516	1,482,842	2,132,465	1,549,793
2032	1,784,891	1,491,373	2,146,684	1,561,167
2033	1,826,791	1,522,798	2,199,059	1,603,068
2034	1,954,624	1,618,673	2,358,851	1,730,901
2035	2,029,612	1,674,914	2,452,586	1,805,889
2036	2,114,087	1,738,270	2,558,179	1,890,363
2037	2,282,296	1,864,427	2,768,440	2,058,573
2038	2,375,627	1,934,425	2,885,104	2,151,904
2039	2,442,124	1,984,297	2,968,225	2,218,400
2040	2,576,966	2,085,429	3,136,778	2,353,243
2041	2,628,801	2,124,306	3,201,572	2,405,078
2042	2,680,502	2,163,081	3,266,198	2,456,779

Source: Energy Exemplar DCF Analysis

Figure 5: Hydro Generation 25-year Payment Streams



Source: Energy Exemplar DCF Analysis

5. HYDRO WITH PLEXOS RESULTS

The PLEXOS case has higher results than the stand-alone DCF using implied heat rates, with about a 200 basis point increase in rate of returns for each scenario. While both the implied heat rate case and PLEXOS use the same starting natural gas prices, PLEXOS includes an in-depth analysis of the electric market for New England, including hourly imports / exports profiles for neighboring regions, all of the existing generation, maintenance and forced outages including nuclear fuel outage profiles, multiple fuels including three different fuel oils, and so forth. It is the addition of multiple fuels, include fuel oil for peaking units, which creates the higher energy prices in this case.

The hydro case using PLEXOS results in sufficient revenues all cases (Base, Low and High Gas) without the need for any additional supplemental capacity revenues to reach a 15% internal rate of return (IRR) target or higher. The Base Case after tax IRR is estimated to be 20.7% assuming a capacity revenue of $11.08/kW-month from the ISO-NE market while the High Gas Case results in a 25.6% after-tax IRR and the Low Case is 15.8%. None of these cases require an additional or supplemental capacity payment stream to make the project viable with a 15% rate of return.

Table 16: Hydro PLEXOS Results

HYDRO GENERATION
PLEXOS Cases

Case Comparison 25-year Revenues (in $000's USD)

	Base Case	Low Case	High Case	15% IRR
IRR	20.7%	15.8%	25.6%	15.0%
Cap Price	$11.08	$11.08	$11.08	$0.35
Sup Price	$0.00	$0.00	$0.00	$0.00
Total Cap	$11.08	$11.08	$11.08	$0.35

Source: Energy Exemplar DCF Analysis

In the 15% target IRR Case, we reduced the market based capacity payment from $11.08/kW-month to $0.35/kW-month to achieve the 15% after tax return.

In the Base Case, we have assumed the following revenue assumptions:

- Capacity Payment of $11.08/kW-Month; and
- LMP Energy based on an 85% capacity factor and real average LMP of $54.82/MWh.

We have assumed no escalation for the capacity prices but have assumed an annual inflation for LMP and reserves escalation of 2.0% per annum. We have also assumed costs escalate at 2.0% annual inflation as well. We have also not assumed any reserve revenue stream for the Hydro Project as it will connect to the ISO-New England system via a DC line.

The IRRs and payment streams shown here reflect the three sets of natural gas price forecasts which were used as inputs, both in the Hydro Generator Evaluation Model. The base case natural gas forecast represents prices taken from the daily Dracut and Algonquin prices as provided by ICE, and a 40-year price forecast derived from those prices.

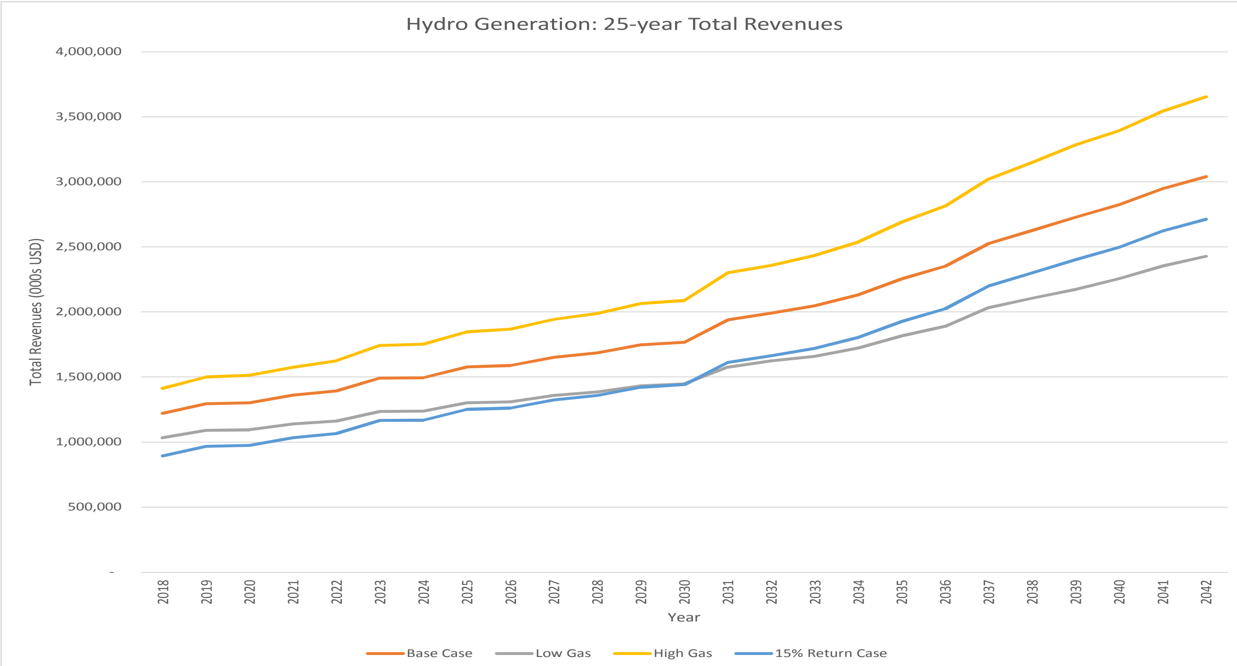
The low and high gas prices cases represent two bands around the base case natural gas price forecast- 75% and 125% of the base case forecasts respectively. Across the time series, these bands maintain largely stable ratios relative to one another. Figure 4 charts the results of the payment streams for the three base cases.

Table 17: Hydro PLEXOS Base Case Summary and Comparison Cases

HYDRO GENERATION PLEXOS Base Case New England Gas Base Case 25-year Revenue (in $000's USD)					HYDRO GENERATION PLEXOS Cases Case Comparison 25-year Revenues (in $000's USD)				
Year	Capacity Payment	Supplemental Capacity Payment	Energy Payment	Total		Base Case	Low Case	High Case	15% IRR
2018	337,718	-	882,596	1,220,314	2018	1,220,314	1,031,618	1,412,171	893,264
2019	337,718	-	956,880	1,294,598	2019	1,294,598	1,089,156	1,499,211	967,548
2020	337,718	-	963,970	1,301,689	2020	1,301,689	1,093,109	1,512,812	974,638
2021	337,718	-	1,021,518	1,359,236	2021	1,359,236	1,138,541	1,574,155	1,032,186
2022	337,718	-	1,054,187	1,391,905	2022	1,391,905	1,160,603	1,624,235	1,064,855
2023	337,718	-	1,154,405	1,492,124	2023	1,492,124	1,235,304	1,742,634	1,165,073
2024	337,718	-	1,156,800	1,494,518	2024	1,494,518	1,237,938	1,751,219	1,167,468
2025	337,718	-	1,239,573	1,577,291	2025	1,577,291	1,300,731	1,846,474	1,250,241
2026	337,718	-	1,250,591	1,588,309	2026	1,588,309	1,309,438	1,867,292	1,261,259
2027	337,718	-	1,312,492	1,650,211	2027	1,650,211	1,356,387	1,943,517	1,323,160
2028	337,718	-	1,347,916	1,685,634	2028	1,685,634	1,383,823	1,987,446	1,358,584
2029	337,718	-	1,409,728	1,747,446	2029	1,747,446	1,430,607	2,064,261	1,420,396
2030	337,718	-	1,429,481	1,767,199	2030	1,767,199	1,446,424	2,087,975	1,440,149
2031	337,718	-	1,600,624	1,938,342	2031	1,938,342	1,575,161	2,300,211	1,611,292
2032	337,718	-	1,652,529	1,990,247	2032	1,990,247	1,623,820	2,358,435	1,663,197
2033	337,718	-	1,709,141	2,046,860	2033	2,046,860	1,658,436	2,434,342	1,719,809
2034	337,718	-	1,792,573	2,130,292	2034	2,130,292	1,721,771	2,538,366	1,803,241
2035	337,718	-	1,916,285	2,254,003	2035	2,254,003	1,815,325	2,691,831	1,926,953
2036	337,718	-	2,014,129	2,351,847	2036	2,351,847	1,889,386	2,814,313	2,024,797
2037	337,718	-	2,189,558	2,527,277	2037	2,527,277	2,033,401	3,021,222	2,200,226
2038	337,718	-	2,289,412	2,627,130	2038	2,627,130	2,105,301	3,148,934	2,300,080
2039	337,718	-	2,390,711	2,728,429	2039	2,728,429	2,173,479	3,283,442	2,401,379
2040	337,718	-	2,486,574	2,824,293	2040	2,824,293	2,254,918	3,393,341	2,497,242
2041	337,718	-	2,610,627	2,948,345	2041	2,948,345	2,353,110	3,542,806	2,621,295
2042	337,718	-	2,702,786	3,040,505	2042	3,040,505	2,428,398	3,653,993	2,713,454

Source: Energy Exemplar DCF Analysis

Figure 6: Hydro Generation 25-year Payment Streams



Source: Energy Exemplar DCF Analysis

6. WIND STAND-ALONE RESULTS

Even though the Wind Project has significantly lower capital costs, the Wind Project also has significantly lower revenue potential in that it has lower capacity factors in both the energy market as well as capacity markets. The stand-alone wind case using implied heat rates results in insufficient revenues in both the Base and Low Gas cases due to the lower capacity factors associated with wind. However, the energy revenues in the High Gas case does provide sufficient revenues from the energy market and RECs to reach the target 15% rate of return without any supplemental or additional contract revenues.

The supplemental capacity payment prices range from nil in the High Gas case to $24.79/kW-Month in the Low Gas Case. The Base Case requires a small supplemental capacity payment of $8.40/kW-Month, or $3.8 million per annum and the Low Gas Case requires $24.79/kW-Month or $11.3 million per annum for the project returns to reach 15.0% after tax. However, the High Gas Case has sufficient revenues from the ISO-NE administered markets and does not require any supplemental capacity payments.

Table 18: Wind Stand-alone Results

WIND GENERATION IMPLIED HEAT RATE: 7.58 MMBtu/MWH Case Comparison 25-year Revenues in US $/kW-month			
	Base Case	Low Case	High Case
IRR	15.0%	15.0%	16.6%
Cap Price	$11.08	$11.08	$11.08
Sup Price	$8.40	$24.79	$0.00
Total Cap	$19.48	$35.87	$11.08

Source: Energy Exemplar DCF Analysis

In the Base Case, we have assumed the following revenue assumptions:

- Capacity Payment of $11.08/kW-Month;
- LMP Energy based on a 31% capacity factor and real average LMP of $53.53/MWh;
- Renewable Energy Credits (RECs) based on $50/MWh; and
- Supplemental Capacity Payments as outlined in the table above.

We have assumed no escalation for the capacity prices, but have assumed an annual inflation for LMP escalation of 2.0% per annum. We have also assumed costs escalate at 2.0% annual inflation as well.

Table 19: Base Case Summary

WIND GENERATION IMPLIED HEAT RATE: 7.58 MMBtu/MWH Base Case 25-year Revenue (in $000's USD)					
Year	Capacity Payment	Supplemental Capacity Payment	Energy Payment	REC Payments	Total
2018	5,052	3,830	22,376	28,234	59,493
2019	5,052	3,830	22,648	28,799	60,330
2020	5,052	3,830	25,094	29,375	63,352
2021	5,052	3,830	25,204	30,045	64,132
2022	5,052	3,830	26,462	30,563	65,908
2023	5,052	3,830	28,446	31,174	68,504
2024	5,052	3,830	30,168	31,798	70,848
2025	5,052	3,830	30,337	32,524	71,744
2026	5,052	3,830	32,935	33,084	74,902
2027	5,052	3,830	33,147	33,746	75,776
2028	5,052	3,830	34,020	34,421	77,324
2029	5,052	3,830	36,702	35,206	80,791
2030	5,052	3,830	37,057	35,813	81,753
2031	5,052	3,830	37,576	36,530	82,989
2032	5,052	3,830	40,829	37,260	86,972
2033	5,052	3,830	41,152	38,111	88,146
2034	5,052	3,830	42,344	38,768	89,994
2035	5,052	3,830	45,979	39,543	94,405
2036	5,052	3,830	48,111	40,334	97,328
2037	5,052	3,830	50,513	41,254	100,651
2038	5,052	3,830	55,297	41,966	106,145
2039	5,052	3,830	57,951	42,805	109,639
2040	5,052	3,830	59,842	43,661	112,386
2041	5,052	3,830	63,676	44,657	117,216
2042	5,052	3,830	65,150	45,428	119,460

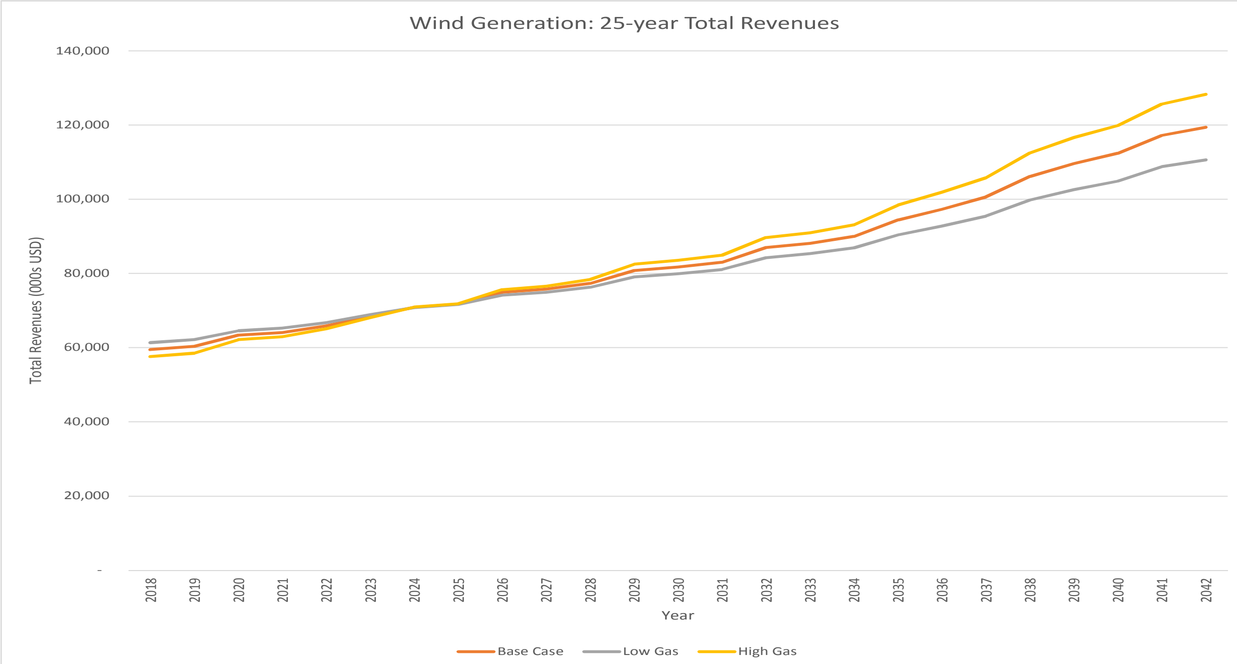
Source: Energy Exemplar DCF Analysis

Table 20: Wind Generation Case Total Revenue Comparison

WIND GENERATION IMPLIED HEAT RATE: 7.58 MMBtu/MWH Case Comparison 25-year Revenues in US$000's			
Year	Base Case	Low Case	High Case
2018	59,493	61,373	57,617
2019	60,330	62,142	58,523
2020	63,352	64,552	62,156
2021	64,132	65,305	62,964
2022	65,908	66,766	65,054
2023	68,504	68,866	68,146
2024	70,848	70,780	70,921
2025	71,744	71,633	71,859
2026	74,902	74,142	75,667
2027	75,776	74,963	76,593
2028	77,324	76,293	78,360
2029	80,791	79,090	82,498
2030	81,753	79,963	83,548
2031	82,989	81,068	84,913
2032	86,972	84,239	89,710
2033	88,146	85,332	90,965
2034	89,994	86,882	93,111
2035	94,405	90,384	98,430
2036	97,328	92,774	101,887
2037	100,651	95,496	105,810
2038	106,145	99,795	112,500
2039	109,639	102,625	116,657
2040	112,386	104,899	119,877
2041	117,216	108,771	125,666
2042	119,460	110,647	128,279

Source: Energy Exemplar DCF Analysis

Figure 7: Wind Generation 25-year Payment Streams



7. WIND CASES PLEXOS RESULTS

The Wind Project does not enjoy as much of an increase in revenues, and therefore return on equity, from the PLEXOS case as did the Hydro Project. This is because the Wind Project relies much more on the capacity and REC payments, and conversely less on the energy revenues due to reduced capacity factors. Nonetheless, the PLEXOS results for the Wind Project are higher than the implied heat rate case for the reasons described above.

In this case, the supplemental capacity payment prices range from nil to $21.80/kW-mo. The Base Case requires a small supplemental capacity payment of $6.9/kW-month, or $3.1 million per annum and the Low Gas Case requires $21.80/kW-month or $9.9 million per annum for the project returns to reach 15.0% after tax. However, the High Gas Case has sufficient revenues from the ISO-NE administered markets and does not require any supplemental capacity payments.

Table 21: Wind PLEXOS Results

WIND GENERATION
PLEXOS Base Case New England Gas

Case Comparison 25-year Revenues (in $000's USD)

	Base Case	Low Case	High Case
IRR	15.0%	15.0%	16.6%
Cap Price	$11.08	$11.08	$11.08
Sup Price	$6.90	$21.80	$0.00
Total Cap	$17.98	$32.88	$11.08

Source: Energy Exemplar DCF Analysis

In the Base Case, we have assumed the following revenue assumptions:

- Capacity Payment of $11.08/kW-Month;
- LMP Energy based on a 31% capacity factor and real average LMP of $53.53/MWh;
- Renewable Energy Credits (RECs) based on $50/MWh; and
- Supplemental Capacity Payments as outlined in the table above.

We have assumed no escalation for the capacity prices but have assumed an annual inflation for LMP escalation of 2.0% per annum. We have also assumed costs escalate at 2.0% annual inflation as well.

Table 22: Wind PLEXOS Base Case Summary

WIND GENERATION

PLEXOS Base Case New England Gas

Base Case 25-year Revenue (in $000's USD)

Year	Capacity Payment	Supplemental Capacity Payment	Energy Payment	REC Payments	Total
2018	5,052	3,146	23,913	27,489	59,601
2019	5,052	3,146	23,826	28,093	60,118
2020	5,052	3,146	25,763	28,600	62,562
2021	5,052	3,146	25,510	29,173	62,882
2022	5,052	3,146	27,910	29,757	65,866
2023	5,052	3,146	28,174	30,411	66,783
2024	5,052	3,146	30,655	30,959	69,813
2025	5,052	3,146	30,822	31,580	70,600
2026	5,052	3,146	34,278	32,212	74,689
2027	5,052	3,146	33,934	32,920	75,052
2028	5,052	3,146	36,377	33,513	78,088
2029	5,052	3,146	36,744	34,185	79,127
2030	5,052	3,146	38,487	34,869	81,554
2031	5,052	3,146	40,029	35,635	83,863
2032	5,052	3,146	41,137	36,278	85,614
2033	5,052	3,146	42,507	37,005	87,711
2034	5,052	3,146	50,846	37,745	96,790
2035	5,052	3,146	52,254	38,575	99,027
2036	5,052	3,146	53,602	39,270	101,071
2037	5,052	3,146	57,419	40,057	105,675
2038	5,052	3,146	60,202	40,859	109,260
2039	5,052	3,146	65,437	41,757	115,393
2040	5,052	3,146	69,360	42,510	120,068
2041	5,052	3,146	74,238	43,362	125,799
2042	5,052	3,146	78,509	44,229	130,937

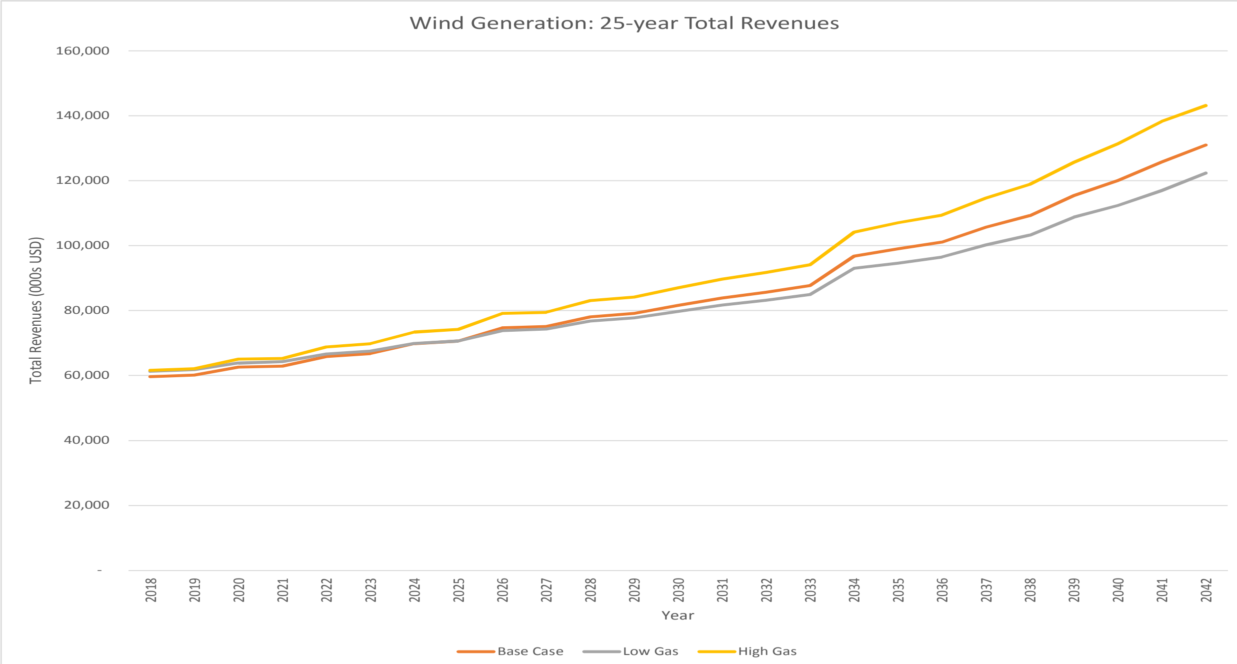
Source: Energy Exemplar DCF Analysis

Table 23: Wind Generation Case Total Revenue Comparison

WIND GENERATION PLEXOS Base Case New England Gas Case Comparison 25-year Revenues in US$000's			
Year	Base Case	Low Case	High Case
2018	59,601	61,284	61,649
2019	60,118	61,848	62,114
2020	62,562	63,842	65,032
2021	62,882	64,201	65,281
2022	65,866	66,613	68,804
2023	66,783	67,474	69,811
2024	69,813	69,875	73,358
2025	70,600	70,607	74,247
2026	74,689	73,841	79,146
2027	75,052	74,298	79,451
2028	78,088	76,748	83,068
2029	79,127	77,711	84,192
2030	81,554	79,719	87,020
2031	83,863	81,665	89,708
2032	85,614	83,157	91,718
2033	87,711	84,933	94,137
2034	96,790	93,041	104,153
2035	99,027	94,602	107,086
2036	101,071	96,533	109,438
2037	105,675	100,224	114,678
2038	109,260	103,275	118,898
2039	115,393	108,752	125,680
2040	120,068	112,342	131,431
2041	125,799	116,982	138,279
2042	130,937	122,374	143,157

Source: Energy Exemplar DCF Analysis

Figure 8: Wind Generation 25-year Payment Streams



8. CONCLUSIONS

We have found the Hydro Project requires few if any additional capacity revenues to make the project viable with a 15% rate of return. We used PLEXOS as well as an implied heat rate to create realistic revenue streams in the New England energy markets (LMP in $/MWh) as well as the existing capacity market as administered by ISO New England. We then used a Discounted Cash Flow model to calculate the necessary returns for such a large scale project. Despite the significant capital costs, from this analysis, only the Low Gas Case scenario would require some sort of supplemental or additional contract payments to the independent power producer for this Hydro Project.

The Wind Project could require more support in terms of additional capacity payments to make that project viable. This is due to the fact that the Wind Project has such low capacity factors (in terms of both energy as well as capacity markets) that additional support would be required in both the Base Case and Low Gas Cases.

While this is a detailed study of the project economics, any further discussions with either the developers of the Hydro and Wind Projects could require further refinement of these assumptions and results.