BC hydro

Integrated Resource Plan

Appendix 5B-2

Addendum Report
Greenhouse Gas Price Forecast-
Additional Scenarios

BC HYDRO

Addendum Report

Greenhouse Gas Price Forecast - Additional Scenarios

May 2011

1.0 ADDENDUM REPORT TO BC HYDRO GHG PRICE FORECAST

1.1 Additional scenarios for GHG forecast

In September 2009, BC Hydro engaged Black & Veatch to conduct a study of emerging policy and regulations pertaining to greenhouse gas (GHG) emissions and the potential impact on the BC Hydro system. The objective of study was to develop a series of plausible scenarios that reflect a range of GHG control requirements and global growth conditions and to forecast CO_2 prices implicit in these scenarios.

After reviewing the forecasts implicit in scenarios 1-5 from the main report, BC Hydro wished to determine if there were scenarios that would yield higher prices than those associated with Scenarios 1-3 at higher probabilities than Scenario 5. Four additional scenarios were chosen to capture a broader range of global assumptions and potentially higher prices. These scenarios are described in the following pages along with their associated CO_2 price forecasts.

Figure 1.0 below shows the assumed directional changes for the major input variable vectors and the supporting logic for the assumptions in each of the additional scenarios.

Figure 1.0 – Additional GHG Scenario Input Variables

Model Input Vectors	(vs. base)	Explanation
High Global Growth—Regional/National Actor—Scenario 6		
Electricity loads	↑↑	Higher traditional load growth + electric vehicle penetration
Fuel prices	↑↑	High growth + environmental restrictions
Fossil capacity costs	→	Base case assumptions
Nuclear penetration	→	Base case assumptions
Renewables targets	→	Base case assumptions
Efficiency penetration	→	Base case assumptions
CCS costs	↑	Delayed development of CCS due to later national action
Medium Global Growth—Regional/National National Actor—Scenario 7		
Electricity loads	→	Close to base case assumptions +plug-in electric cars
Fuel prices	↑	Environmental restrictions on production
Fossil capacity costs	→	Close to base case assumptions
Nuclear penetration	↑	More regulatory friendly toward nuclear development
Renewables targets	↑↑	National RPS targets higher than base case assumptions
Efficiency penetration	→	Base case assumptions
CCS costs	↑↑	Slow development due to later national action and technical delays
Low Global Growth—Regional Actor—Scenario 8		
Electricity loads	↓↓	Level or no growth and no PEV penetration
Fuel prices	↓	Lower fuel demands
Fossil capacity costs	→	Close to base case assumptions
Nuclear penetration	↓	Unfavorable investment climate
Renewables targets	↓	Worries about higher costs of renewables
Efficiency penetration	→	Close to base case assumptions
CCS costs	↑↑	Slow development due to no national action

Model Input Vectors	(vs. base)	Explanation
High Global Growth—Regional Actor—Scenario 9		
Electricity loads	↑↑	High traditional load growth and electric vehicle penetration
Fuel prices	→	Base case assumptions
Fossil capacity costs	↓	Low commodity prices + lower interest rates
Nuclear penetration	→	Base case assumptions
Renewables penetration	→	Base case assumptions
Efficiency penetration	→	Base case assumptions
CCS costs	↑↑	Slow development of CCS due to no national action

For purposes of modeling the additional scenarios, the same input variable vectors described in the main body of the report were used. Those vectors are summarized as follows:

- Load Growth - → indicates 1% growth, ↑ indicates 2% growth, ↓ indicates 0.5% growth, ↓↓ indicates level or no growth and no PEV penetration
- Fuel Prices - → 5.4% escalation in gas, ↑ indicates 6.2% escalation in gas, ↓ indicates 4.2% escalation in gas
- Fossil Capacity Costs - → indicates general inflation escalation, ↑ indicates prices are 25% higher than Base Case, ↓ indicates prices are 25% lower than Base Case
- Nuclear Penetration - → See Table 8.0 in the main report, ↑ indicates a 50% increase in nuclear additions, ↓ indicates a 50% decrease in nuclear additions
- Renewable Targets (excluding hydro) - → 15% by 2020, ↑ 30% by 2020, ↓ 5% by 2020
- Efficiency Penetration - → 5% by 2020, ↑ 10% by 2020, ↓ 3% by 2020
- Carbon Capture and Sequestration Cost - → See Table 1.0 in the main report, ↑ indicates a 25% increase in capital cost, ↑↑ indicates a 50% increase in capital cost, ↓ indicates a 25% decrease in capital cost

1.1.1 High Growth – Regional/National Action: Scenario 6

Scenario 6 was chosen to reflect the combination of high global growth and delayed national action not analyzed in any previous scenario. In scenario 6 it is assumed that British Columbia implements a cap and trade program and links with Western Climate Initiative partners to form a regional market until 2020 at which time a national program for both Canada and the U.S., like Waxman-Markey, is assumed to be enacted.

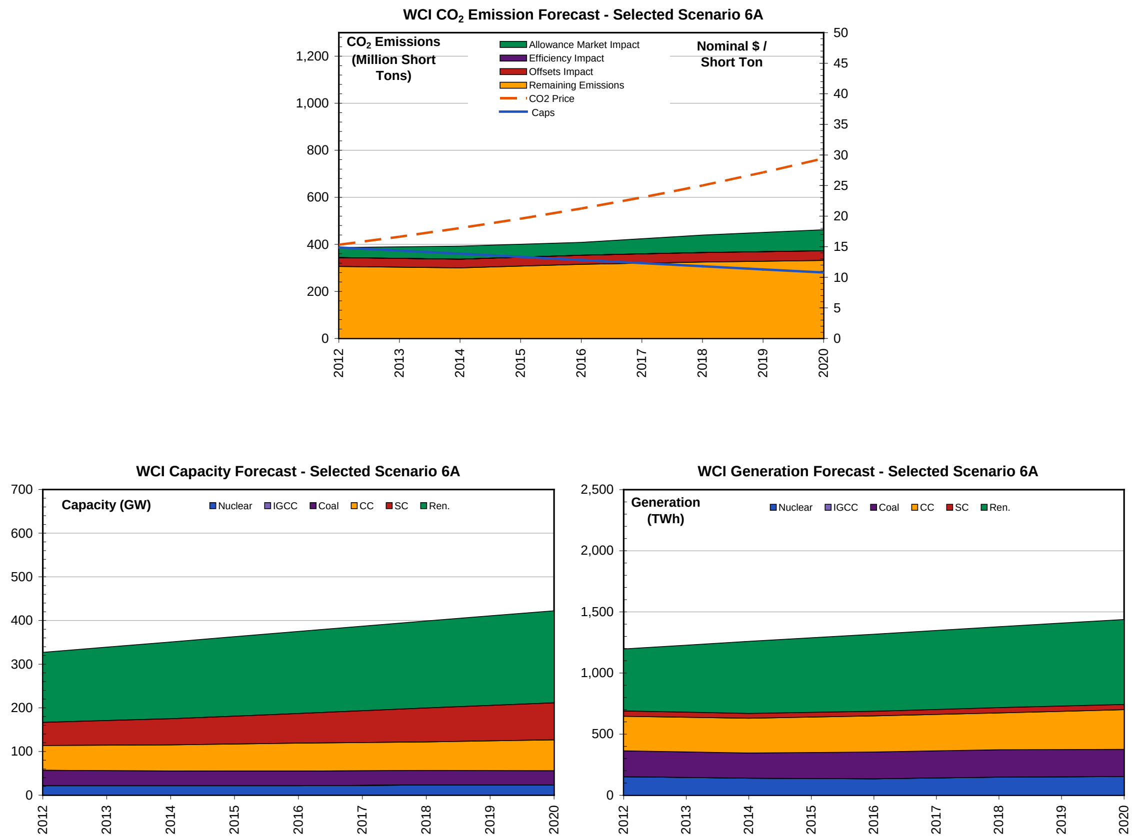
This scenario assumed high load growth in addition to an 8% increase in electric demands during off-peak times to serve electric vehicle loads. Base forecasts of gas prices, nuclear generation additions, and renewable generation additions are assumed. A 15% target reduction in CO_2 by 2020 is assumed in accordance with the Western Climate Initiative, and from there on, target reductions in CO_2 follow Waxman-Markey. The use of offsets to meet 10% of the required reduction under the Western Climate Initiative is assumed. CCS costs are assumed to increase by 25% in this scenario, making its addition uneconomical during the period of study.

After 2020 under the Waxman Markey program in Scenario 6, a more strict use of offsets is assumed (50% of the load ratio share) and interim caps were assumed to be aggressive at 25% and 65% percent of 2005 levels in 2020 and 2030, respectively.

The resulting 2012 price for CO_2 is $15/tonne. With the addition of the Waxman-Markey program, lower interim cap levels and increased loads in Scenario 6 along with the assumed premium on CCS costs, it appears practically impossible to meet the CO_2 targets regardless of the CO_2 price. Given the impracticality of such legislation under the assumptions in Scenario 6, a strict version of Waxman-Markey-like legislation would likely be rescinded once it’s implications become apparent.

Forecast capacity and generation mix, emission reduction sources and resulting CO_2 prices for Scenario 6 under WCI caps are shown in Figure 2.0.

Figure 2.0 - Selected Scenario 6 - Forecast Generation and CO_2 Prices



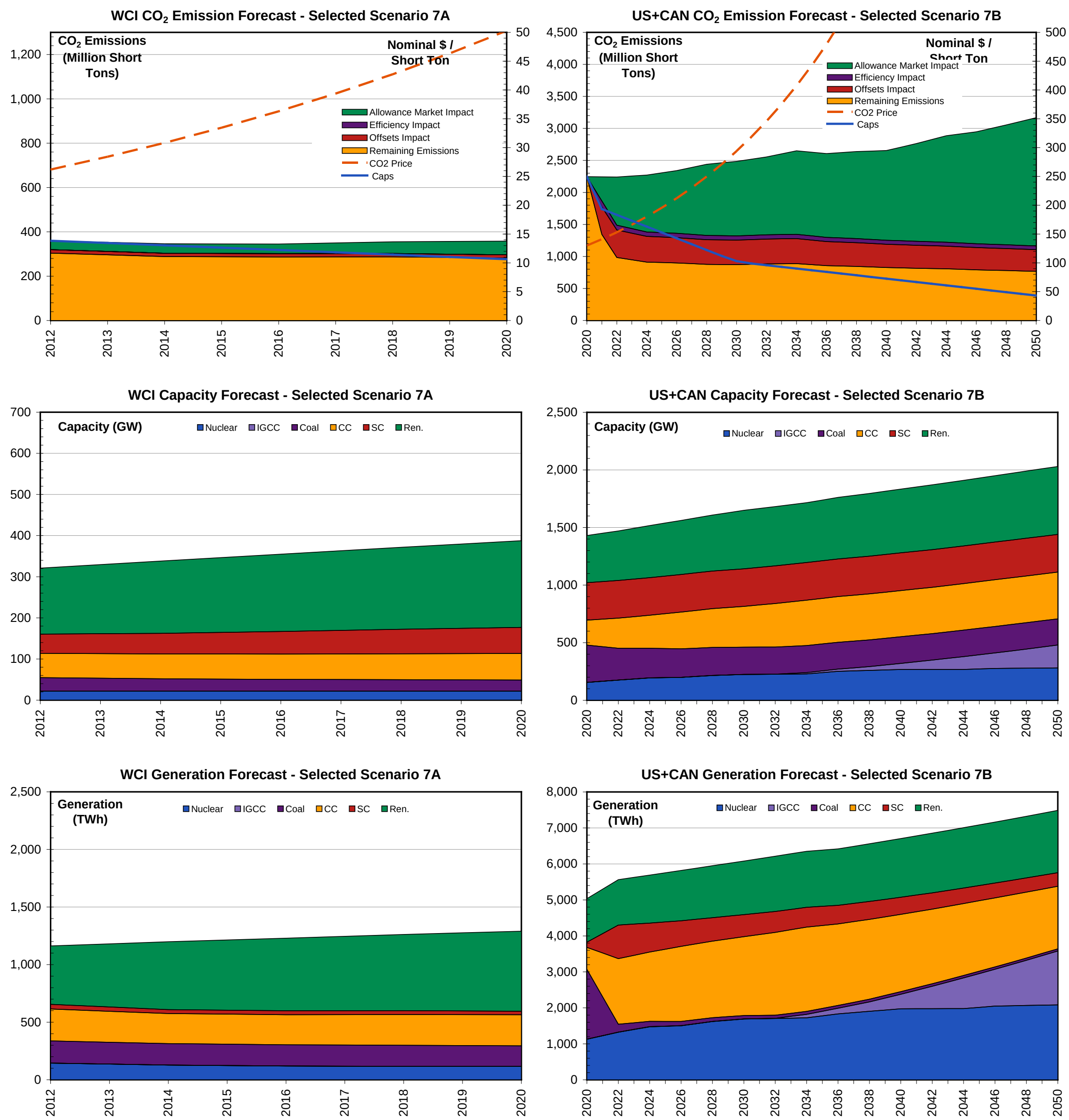
1.1.2 Medium Growth – Regional/National Action: Scenario 7

Scenario 7 was chosen as a variation of Scenario 3 in which technological delays increase the cost of CCS and aggressive interim CO_2 caps increase the demand for CO_2 control. Scenario 7 also assumes that British Columbia implements a cap and trade program and links with Western Climate Initiative partners to form a regional market until 2020 at which time a national program for both Canada and the United States like Waxman-Markey is assumed to be enacted.

Electric loads, fuel prices and efficiency projections are forecast using Black & Veatch's independent Base forecasts. Nuclear and renewable penetrations are assumed to be high and the electricity sector is assumed to use 50% of its load-ratio-share of offsets. Electric vehicle loads are included in the loads beginning in 2020 in all the U.S. and Canada, and CCS costs are assumed to be 50% higher than the baseline forecast. Target reductions follow an accelerated Waxman-Markey schedule, aiming to achieve a 25% drop in emissions by 2020 with respect to 2005 levels and a 65% reduction by 2030 before achieving the prescribed 83% reduction by 2050.

The resultant 2012 CO_2 price is $26/tonne. With the addition of the Waxman-Markey program and electric vehicle loads, the CO_2 price jumps to $147/tonne in 2021. CO_2 reductions are accomplished in this case by conversion of considerable amounts of generation from traditional coal to IGCC with CCS, nuclear, and natural gas. Because of the assumed premium on CCS costs, IGCC with CCS additions are delayed until after 2024. Forecast capacity and generation mix, emission reduction sources and resulting CO_2 prices for Scenario 7 are shown in Figure 3.0.

Figure 3.0 - Selected Scenario 7 - Forecast Generation and CO_2 Prices



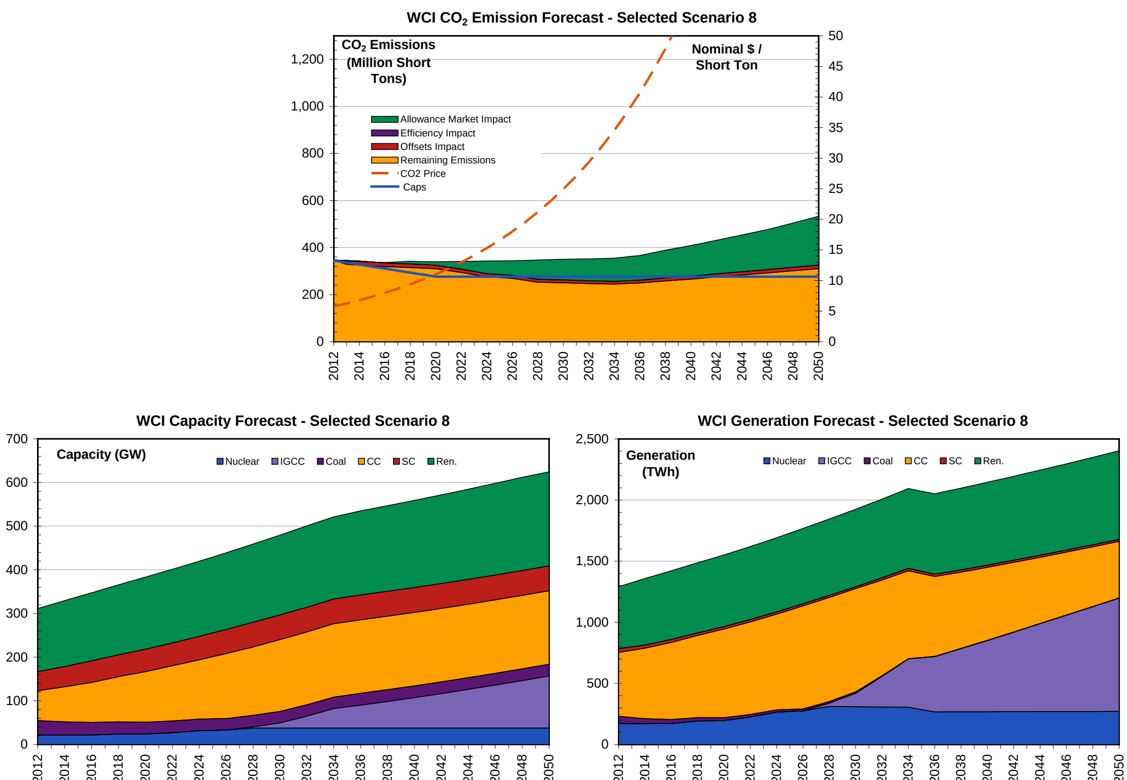
1.1.3 Low Global Growth – Regional Action: Scenario 8

Scenario 8 is a very low growth variation of Scenario 5 in which British Columbia implements a cap and trade program and links with Western Climate Initiative partners to form a regional market that determines CO_2 prices in British Columbia throughout the forecast period.

This scenario assumed level load growth with no electric vehicle loads. Low forecasts of gas prices and renewable generation additions are assumed. A 15% target reduction in CO_2 by 2020 is assumed and that targeted reduction is maintained throughout the forecast period. Scenario 8 assumes under the strict use of offsets, 5% of the required reduction in emissions can be met with offsets (half the current proposed WCI allowance). CCS costs are assumed to increase by 50% in this scenario relative to the Base forecast, making its addition uneconomic during the study period. Nuclear generation additions are forecast using Black & Veatch's independent Base forecasts.

The resulting 2012 price for CO_2 is \$5.75/tonne in 2012 escalating at 8.5% thereafter. Forecast capacity and generation mix, emission reduction sources and resulting CO_2 prices for Scenario 8 are shown in Figure 4.0.

Figure 4.0 - Selected Scenario 8 - Forecast Generation and CO_2 Prices



1.1.4 Low Global Growth - No GHG Prices: Scenario 8A

Scenario 8A assumes a world where National Action on GHG does not occur. Further, it assumes low economic growth and low natural gas prices. With low natural gas prices, there will be more gas fired generation and less coal fired generation resulting in the low CO_2 prices discussed for Scenario 8. As a variant to Scenario 8, it would be reasonable to assume that under these global growth conditions, the Western Climate Initiative does not gain traction resulting in no GHG prices, even at the regional level. Under such conditions, some stakeholders may also believe that RPS will not be necessary. However, RPS requirements have been implemented to accomplish a number of goals including working toward a "sustainable" energy future that does not rely on burning limited fossil fuels and reducing exposure of the population to other emissions such as mercury, particulate matter, SO_X, NO_X, etc.. RPS goals are also offered as a way to put more people to work. It is reasonable to expect that RPS goals now in place will not be reduced even if GHG concerns wane.

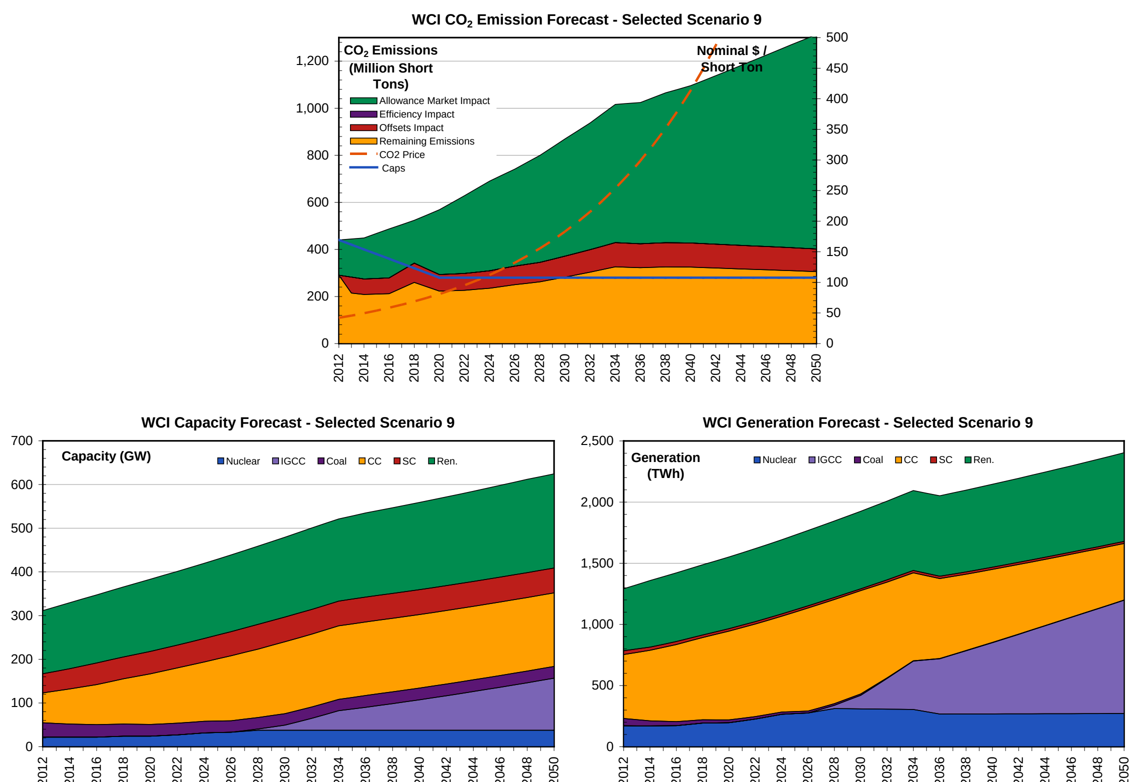
1.1.5 High Global Growth – Regional Action: Scenario 9

As in Scenario 8, Scenario 9 assumes that British Columbia implements a cap and trade program and links with Western Climate Initiative partners to form a regional market that determines CO_2 prices in British Columbia throughout the forecast period.

Like Scenario 5 in the main report, this scenario assumed high load growth in addition to an 8% increase in electric demands in the Western Climate Initiative region to serve electric vehicle loads. Base forecasts of gas prices, nuclear generation additions, and renewable generation additions are assumed. A 15% target reduction in CO_2 by 2020 is assumed along with the full use of offsets (10% of the required reduction in emissions can be met with offsets compared to 5% in Scenario 5). CCS costs are assumed to increase by 50% in this scenario, delaying its economic addition until the year 2038.

The resulting 2012 price for CO_2 is $42/tonne based on the cost to finance construction of new IGCC plants with CCS. The lack of existing coal generation in the WCI region makes it very expensive to achieve even a 15% reduction in emissions. Forecast capacity and generation mix, emission reduction sources and resulting CO_2 prices for Scenario 9 are shown in Figure 5.0.

Figure 5.0 - Selected Scenario 9 - Forecast Generation and CO_2 Prices



As discussed earlier, in all forecasts of CO_2 prices described above, an 8.5% nominal escalation in CO_2 allowance prices is implied. This escalation rate compares to the 7.5% and 10% escalation assumptions used by EIA. In all scenarios that assume regional action first followed by national action, the 8.5% escalation in Western Climate Initiative market prices applies until the Waxman-Markey provisions apply at which time there is an adjustment in price to reflect Waxman-Markey. Then the 8.5% rate applies to prices thereafter.

1.2 Summary

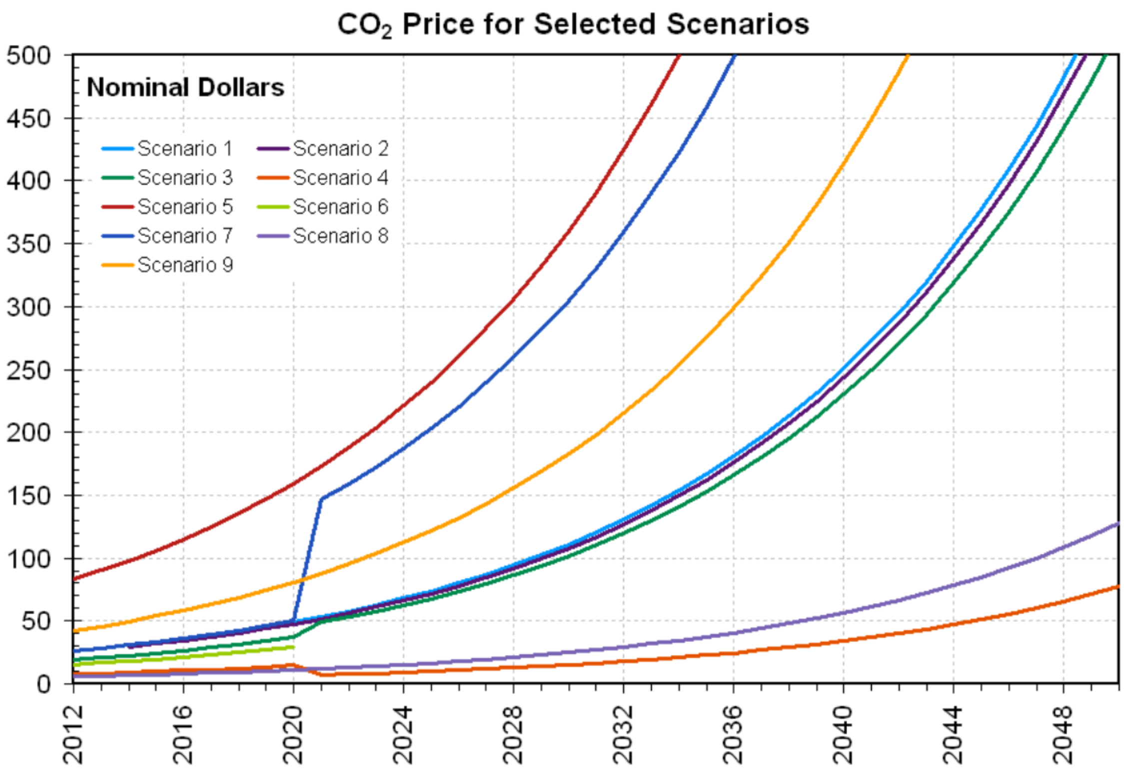
The carbon price forecasts generated by the Black & Veatch carbon model for the nine scenarios are summarized in nominal and real terms in the following Figure 6.0 and in Tables 1.0 and 2.0 below. From these figures and tables, the forecast for Scenario 8 results in low CO_2 prices, falling slightly above those of Scenario 4. The main driving forces for both of these scenarios are level load growth and low gas prices, which result in no need for IGCC and much lower CO_2 prices. As compared to Scenario 4 that assumes the evolution of GHG controls from a regional to a national program, Scenario 8 assumes the GHG controls evolve on a regional basis only with a smaller WCI trading region in which CO_2 emissions are low to begin with and the marginal cost of even 15 percent further control is high.

Results for Scenario 7 are towards the higher end of the price range, slightly below those of Scenario 5, the highest. Because Scenario 7 is based on formation of a regional and then a national market for CO_2 allowances, compared to a regional only market in Scenario 5, Scenario 7 prices are below those of Scenario 5. However, higher interim caps in Scenario 7 push CO_2 prices up markedly in 2020 and keep prices above those in other national or regional/national scenarios for the remainder of the forecast period.

CO_2 prices for Scenario 9 fall in between those of Scenario 7 and those of Scenarios 1, 2 and 3, which are very similar to each other. The upward push on prices from the assumption of the smaller regional trading area in Scenario 9 positions its forecast above those of Scenarios 1, 2 and 3. The lower interim caps in Scenario 7 along with the strict use of offsets result in higher CO_2 prices for Scenario 7 than for Scenario 9 even though Scenario 9 assumes a regional only program.

The projection of CO_2 prices for Scenario 6 starts relatively low in 2012 under an assumed regional GHG program. However, with the addition of the Waxman-Markey program and in particular aggressive interim CO_2 caps, and with increased loads and the assumed premium on CCS costs; it becomes practically impossible to meet the assumed CO_2 caps after 2020 at any CO_2 price.

Figure 6.0 - Forecast CO_2 Prices



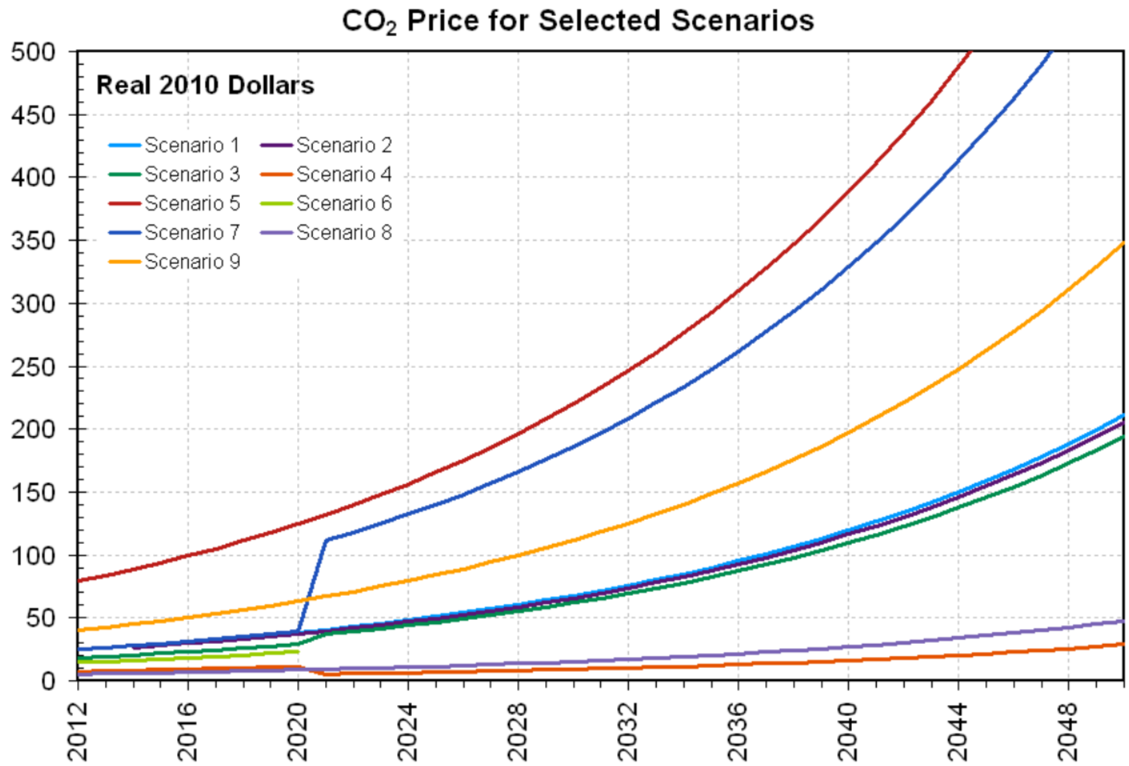

CO_2 Price for Selected Scenarios
Real 2010 Dollars
Scenario 1
Scenario 2
Scenario 3
Scenario 4
Scenario 5
Scenario 6
Scenario 7
Scenario 8
Scenario 9
0
50
100
150
200
250
300
350
400
450
500
2012
2016
2020
2024
2028
2032
2036
2040
2044
2048

Table 1.0 - Forecast CO_2 Prices (Nominal $)

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	Scenario 7	Scenario 8	Scenario 9
2012	-	-	***19.16***	***7.66***	***83.02***	***15.33***	***26.18***	***5.75***	***42.15***
2013	-	-	20.79	8.32	90.08	16.63	28.41	6.24	45.73
2014	***30.07***	***29.24***	22.56	9.02	97.74	18.04	30.82	6.77	49.62
2015	32.63	31.73	24.47	9.79	106.05	19.58	33.45	7.34	53.84
2016	35.40	34.42	26.55	10.62	115.06	21.24	36.29	7.97	58.41
2017	38.41	37.35	28.81	11.52	124.84	23.05	39.37	8.64	63.38
2018	41.68	40.52	31.26	12.50	135.45	25.01	42.72	9.38	68.77
2019	45.22	43.97	33.92	13.57	146.96	27.13	46.35	10.17	74.61
2020	49.06	47.70	36.80	14.72	159.46	29.44	50.29	11.04	80.95
2021	53.23	51.76	***48.83***	***7.23***	173.01	***N/A***	***146.48***	11.98	87.84
2022	57.76	56.16	52.98	7.85	187.72	***N/A***	158.93	13.00	95.30
2023	62.67	60.93	57.48	8.52	203.67	***N/A***	172.43	14.10	103.40
2024	67.99	66.11	62.36	9.24	220.98	***N/A***	187.09	15.30	112.19
2025	73.77	71.73	67.66	10.02	239.77	***N/A***	202.99	16.60	121.73
2026	80.05	77.83	73.42	10.88	260.15	***N/A***	220.25	18.01	132.07
2027	86.85	84.44	79.66	11.80	282.26	***N/A***	238.97	19.54	143.30
2028	94.23	91.62	86.43	12.80	306.25	***N/A***	259.28	21.20	155.48
2029	102.24	99.41	93.77	13.89	332.28	***N/A***	281.32	23.00	168.70
2030	110.93	107.86	101.74	15.07	360.53	***N/A***	305.23	24.96	183.04
2031	120.36	117.03	110.39	16.35	391.17	***N/A***	331.18	27.08	198.59
2032	130.59	126.97	119.78	17.74	424.42	***N/A***	359.33	29.38	215.48
2033	141.69	137.77	129.96	19.25	460.50	***N/A***	389.87	31.88	233.79
2034	153.74	149.48	141.00	20.89	499.64	***N/A***	423.01	34.59	253.66
2035	166.80	162.18	152.99	22.66	542.11	***N/A***	458.97	37.53	275.22
2036	180.98	175.97	165.99	24.59	588.19	***N/A***	497.98	40.72	298.62
2037	196.36	190.92	180.10	26.68	638.18	***N/A***	540.31	44.18	324.00
2038	213.06	207.15	195.41	28.95	692.43	***N/A***	586.23	47.94	351.54
2039	231.17	224.76	212.02	31.41	751.29	***N/A***	636.06	52.01	381.42
2040	250.81	243.87	230.04	34.08	815.15	***N/A***	690.13	56.43	413.84
2041	272.13	264.59	249.60	36.98	884.43	***N/A***	748.79	61.23	449.02
2042	295.26	287.08	270.81	40.12	959.61	***N/A***	812.43	66.43	487.19
2043	320.36	311.49	293.83	43.53	1,041.18	***N/A***	881.49	72.08	528.60
2044	347.59	337.96	318.81	47.23	1,129.68	***N/A***	956.42	78.21	573.53
2045	377.14	366.69	345.90	51.25	1,225.70	***N/A***	1,037.71	84.86	622.28
2046	409.19	397.86	375.31	55.60	1,329.88	***N/A***	1,125.92	92.07	675.17
2047	443.98	431.68	407.21	60.33	1,442.92	***N/A***	1,221.62	99.89	732.56
2048	481.71	468.37	441.82	65.45	1,565.57	***N/A***	1,325.46	108.39	794.83
2049	522.66	508.18	479.37	71.02	1,698.65	***N/A***	1,438.12	117.60	862.39
2050	567.09	551.38	520.12	77.06	1,843.03	***N/A***	1,560.36	127.59	935.69

Table 2.0 - Forecast CO_2 Prices (Real 2010 dollars)

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	Scenario 7	Scenario 8	Scenario 9
2012	-	-	***18.24***	***7.29***	***79.02***	***14.59***	***24.92***	***5.47***	***40.12***
2013	-	-	19.30	7.72	83.65	15.44	26.38	5.79	42.47
2014	***27.24***	***26.49***	20.43	8.17	88.55	16.35	27.93	6.13	44.95
2015	28.84	28.04	21.63	8.65	93.73	17.30	29.56	6.49	47.59
2016	30.53	29.68	22.90	9.16	99.22	18.32	31.29	6.87	50.37
2017	32.31	31.42	24.24	9.69	105.02	19.39	33.12	7.27	53.32
2018	34.21	33.26	25.66	10.26	111.17	20.52	35.06	7.70	56.44
2019	36.21	35.21	27.16	10.86	117.68	21.73	37.11	8.15	59.74
2020	38.33	37.27	28.75	11.50	124.57	23.00	39.29	8.62	63.24
2021	40.57	39.45	***37.21***	***5.51***	131.86	***N/A***	***111.64***	9.13	66.94
2022	42.95	41.76	39.39	5.84	139.58	***N/A***	118.17	9.66	70.86
2023	45.46	44.20	41.70	6.18	147.75	***N/A***	125.09	10.23	75.01
2024	48.12	46.79	44.14	6.54	156.40	***N/A***	132.41	10.83	79.40
2025	50.94	49.53	46.72	6.92	165.55	***N/A***	140.16	11.46	84.05
2026	53.92	52.43	49.45	7.33	175.24	***N/A***	148.36	12.13	88.97
2027	57.08	55.50	52.35	7.76	185.50	***N/A***	157.05	12.84	94.18
2028	60.42	58.74	55.41	8.21	196.36	***N/A***	166.24	13.59	99.69
2029	63.95	62.18	58.66	8.69	207.85	***N/A***	175.97	14.39	105.52
2030	67.70	65.82	62.09	9.20	220.02	***N/A***	186.27	15.23	111.70
2031	71.66	69.68	65.73	9.74	232.90	***N/A***	197.18	16.12	118.24
2032	75.86	73.75	69.57	10.31	246.53	***N/A***	208.72	17.07	125.16
2033	80.30	78.07	73.65	10.91	260.96	***N/A***	220.94	18.07	132.49
2034	85.00	82.64	77.96	11.55	276.24	***N/A***	233.87	19.12	140.24
2035	89.97	87.48	82.52	12.23	292.41	***N/A***	247.56	20.24	148.45
2036	95.24	92.60	87.35	12.94	309.53	***N/A***	262.05	21.43	157.14
2037	100.81	98.02	92.46	13.70	327.64	***N/A***	277.39	22.68	166.34
2038	106.71	103.76	97.88	14.50	346.82	***N/A***	293.63	24.01	176.08
2039	112.96	109.83	103.61	15.35	367.12	***N/A***	310.82	25.42	186.39
2040	119.57	116.26	109.67	16.25	388.61	***N/A***	329.01	26.90	197.30
2041	126.57	123.07	116.09	17.20	411.36	***N/A***	348.27	28.48	208.85
2042	133.98	130.27	122.89	18.21	435.44	***N/A***	368.66	30.15	221.07
2043	141.83	137.90	130.08	19.27	460.93	***N/A***	390.24	31.91	234.01
2044	150.13	145.97	137.69	20.40	487.91	***N/A***	413.08	33.78	247.71
2045	158.92	154.51	145.75	21.59	516.47	***N/A***	437.26	35.76	262.21
2046	168.22	163.56	154.29	22.86	546.71	***N/A***	462.86	37.85	277.56
2047	178.06	173.13	163.32	24.20	578.71	***N/A***	489.95	40.06	293.81
2048	188.49	183.27	172.88	25.61	612.58	***N/A***	518.63	42.41	311.00
2049	199.52	193.99	183.00	27.11	648.44	***N/A***	548.99	44.89	329.21
2050	211.20	205.35	193.71	28.70	686.40	***N/A***	581.13	47.52	348.48

2.0 ADDITIONAL GHG MODEL INFORMATION

The following paragraphs provide additional information regarding the assumptions used in the Carbon Model and/or the mechanics of the model itself.

2.1 Offset Assumptions

In accordance with both the Waxman-Markey and WCI provisions, offsets are assumed to be used to provide a portion of the compliance requirements each year. The use of offsets was assumed to be in accordance with either "Flexible" or "Strict" assumptions regarding the competitive availability or allowable use of offsets by the electric power sector. Flexible and Strict assumptions under Waxman-Markey are based on the following conditions:

- Under Flexible offset conditions, the electric sector will be able to compete for 39% of the 2 billion tonnes of available annual offsets consistent with the industry's current load ratio share of emissions.
- Under Strict offset conditions, further limits are assumed to be placed on the use of offsets or the electric industry is less able to compete for available offsets such that the electric industry is restricted to using approximately 20% of the total 2 billion tonnes of available offsets.
- Other provisions within Waxman-Markey limit the annual use of offsets to a slowly declining percentage of required reductions starting with 31%. In all Waxman- Markey scenarios, the most restrictive of the availability or maximum allowable offsets is applied.

Flexible and Strict assumptions under the WCI are based on the following conditions:

- Under the WCI, the electric sector will be able to meet 50% of its required annual emission reductions with offsets. Fifty % of a 15% reduction target is a 7.5% annual reduction met with offsets. For purposes of this analysis, Flexible offset assumptions mean a 10% reduction in emissions covered by offsets.
- Under Strict offset conditions, further limits are assumed to be placed on the use of offsets such that Strict offset assumptions mean a 5% reduction in emissions covered by offsets.

Because both domestic and international offsets are assumed to be less expensive than offsets, their increased or reduced availability is assumed to reduce or increase the need to implement more expensive compliance measures. Offsets are in effect assumed to raise the covered area caps.

2.2 Other Industry Assumptions

Because both Waxman-Markey and WCI address industries apart from the electric sector, transportation and other industry, the market for CO_2 allowances involves the costs of compliance for these other industries as well. For purposes of this analysis, compliance costs for these other industries were assumed to be similar to those of the electric industry. In addition, when plug-in electric vehicles are included, much of the transportation industry is also covered by the model. Finally, the electric industry dominates CO_2 emissions in all sectors covered by Waxman-Markey making the electric industry representative of a large part of the overall program.

2.3 Renewable Resource Assumptions

In all scenarios modeled for this report, varying levels of intermittent renewable resources were assumed to be added. In modeling these additions, the contribution of each resource to dependable or "firm" generating capacity (20% of installed capacity in the case of solar generation) was counted as meeting additional capacity requirements each year. As a result, capacity was added each year in addition to the renewable generation such that the overall foreseeable cost of generation is minimized while the 15 % capacity reserve margin was maintained. Most often, the economically determined complementary generation additions are gas fueled. However, the selection of combined cycle or simple cycle additions is based on that technology that yields the lowest overall cost of generation in each region. Other renewable integration costs were not included in the model; but, they are expected to be a small part of the total cost of renewable generation integration.

2.4 PEV Penetration and Load Growth

Growth in electricity use obviously has the potential to increase GHG production and the demand for CO_2 allowances. Electricity demand growth can come from two sources: increases in demand from conventional uses and increases in consumption from new uses. Because the forecast load growth rates used in the Carbon model reflect expectations in conventional electric uses due to population growth and changes in industrial mix; they do not reflect the impact of a major shift in energy use by the transportation sector – the use of plug-in electric vehicles. Therefore, in scenarios where a shift to PEVs is assumed, the impact on forecast electric use must be added separately. Changes in electric load growth to meet conventional uses affects both the peak demand for electricity as well as energy use every hour of the year going forward. For this growth, the model has to build more generating capacity to accommodate increasing peak demand. PEV penetration just uses more energy to charge vehicles during the off-peak hours. No additional generating capacity is required to accommodate PEV penetration. Existing and generators built for load growth are run more during off-peak hours.

2.5 Natural Gas and CO_2 Allowance Prices

While many input assumptions are varied in each of the nine scenarios, it is generally apparent that CO_2 allowance prices are positively correlated with natural gas prices. This is because low gas prices allow for a shift in electric generation from coal generation to lower carbon emitting gas generation with a smaller inducement in the form of a CO_2 price. In fact, the construction of new gas generating capacity to meet growth in place of new coal generating capacity is one of the lowest cost CO_2 abatement measures available and it is even lower cost when gas prices are low. However, it is not possible to achieve an 83% reduction in CO_2 emission levels by switching to natural gas alone, because gas generation still emits approximately half as much CO_2 per MWH as coal generation. Eventually, more expensive measures will need to be applied to meet the proposed cap. In the mean time, low gas prices will yield lower CO_2 prices.

2.6 Impacts of Allowance Auctions

While many recent GHG control proposals have called for the allocation of a portion of available CO_2 allowances to load serving entities in an effort to defray the costs of control to end users, these allocations clearly do not directly impact the marginal cost of control and therefore the CO_2 allowance price. However, to the extent, revenue from the sale of allocated allowances is used to reduce rates to consumers; there may be a feedback impact on load growth assuming some price elasticity of demand for electricity. The Carbon model does not explicitly include a price feedback loop in forecasting CO_2 prices for the various scenarios since the industry does not have a good estimate of the future price elasticity of electric demand in a "new world" of CO_2 control. The impact of such a feedback loop would be a slight dampening in future CO_2 prices for the high cost scenarios assuming these high cost scenarios would reduce load growth relative to the medium or low cost scenarios.

2.7 CO_2 Prices and Emission Reductions in the US and Canada

As described in the main body of this report, a premise of this forecast has been that under a national GHG control program, the US and Canada would constitute a combined market for CO_2 allowances with a combined allowance trading area. There is only one price within a trading area, and Canada's emissions from all sectors are relatively small compared to those of the US. As a result, the US dominates the trading area. Because Canada's electric sector starts out much lower in emissions than the US, its marginal cost of further control is much higher than that of the US. Hence, the US will control for both countries for a long time until the marginal cost of US control is similar to that of Canada. During the period of US reductions for both countries, Canada will see few reductions itself and will not meet specific targeted reductions for just Canada. By combining the trading areas, however, Canada and the US together take advantage of opportunities to meet combined GHG reductions at a lower cost than they would should they implement separate cap and trade programs.

2.8 Interaction of GHG Control and Other EPA Controls

Regional and national legislative proposals are not the only sources of future GHG control. The US EPA now has regulatory control over GHG emissions from electric generators in the US and is beginning to enact specific regulations aimed at reducing future electric GHG emissions. In addition, EPA is also promulgating regulations aimed at further reducing other emissions like SO_x, NO_x, mercury and particulate matter.

Other EPA regulations currently being finalized are assumed to impact CO_2 emissions indirectly regardless of assumptions regarding national or regional legislative CO_2 programs. With regard to such EPA regulations as the Utility MACT, the Clean Air Transport Rule, new Ozone standards, new SO_2 standards, new ash disposal rules and new effluent standards; recent independent evaluations by Black & Veatch yielded estimates of 10 to 15 % of the existing coal fleet that would find it more economic to shut down by 2020 than to continue operation under these new non-CO_2 regulations. This independent estimate of existing coal plant retirements is relatively consistent with the economic retirements that occur in this report's scenarios based on National or Regional CO_2 action. Were these new EPA regulations to imply more GW of coal unit retirements, GHG prices may come down slightly because the baseline emissions are effectively reduced. However, in order to ultimately achieve an 83% reduction in emissions, any additional retired units are likely not running much in the model anyway and their exclusion would have little impact on the marginal cost of CO_2 control and allowances.

In scenarios where National GHG legislation is assumed, such legislation is assumed to override EPA GHG regulations and separate EPA requirements are not modeled. In scenarios where no National action is included, EPA regulations of CO_2 are assumed to be more lenient than the applicable regional controls. As a result of the previous assumptions, direct EPA controls of CO_2 are assumed to have no direct impact on forecast CO_2 emissions or prices.