BChydro

Integrated Resource Plan

Chapter 5

Planning Environment

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5.1 Introduction

The IRP compares portfolios using estimated costs and trade revenues of each portfolio over the planning timeframe. These operating costs and revenues are affected by market price assumptions, including the market prices of natural gas, greenhouse gas (**GHG**) offsets, renewable energy credits (**RECs**) and electricity.

This chapter contains BC Hydro's assessment of the wholesale electricity market (referred to as the **spot market**), including the major external influences driving spot market prices. External influences are comprised of events and trends affecting the economy and electric power industry market, along with Canadian, B.C. and U.S. GHG and renewable energy policies.

Subsection 6(2) of the B.C. *Clean Energy Act* (***CEA)*** provides that BC Hydro must be self-sufficient by 2016 and each year after that by "holding the rights to an amount of electricity that meets the electricity supply obligations *solely from electricity generating facilities within the Province*" [emphasis added]. Thus BC Hydro cannot plan to rely on external markets to meet its customers' demand for electricity. Nevertheless, external markets are relevant to the IRP analysis and recommended actions for the following reasons:

- BC Hydro plans and operates its electrical system in the context of neighbouring electricity and energy markets. Electricity surpluses or shortfalls are managed through sales in and out of electricity markets. Additional flexibility in BC Hydro's Heritage hydroelectric system is optimized through market transactions. Managing contingency events frequently involves utilities relying upon each other and the market as an ultimate source of back-up power.
- As set out in Chapter 2, BC Hydro forecasts that it has near-term energy and capacity surpluses, and thus external electricity markets set the price for electricity during that time frame and inform BC Hydro's plans to manage the costs of the energy surplus

- Subsection 3(1)(d) of the *CEA* requires BC Hydro to assess the potential for B.C.-based clean or renewable resources to meet any expected export demand
- The four market price forecasts described in this chapter (natural gas, GHG, RECs and electricity) are used as an input to the portfolio modelling and risk analysis process. For example, the natural gas and GHG price forecasts inform the cost of natural gas-fired generation in B.C.

There are factors with uncertain future costs that are likely to heavily influence the direction of spot market prices. One such factor is the evolution of natural gas prices over the course of the 20-year IRP planning horizon. Given the increased role of natural gas-fired generation in the U.S. portion of the Western Electricity Coordinating Council (**WECC**) region, natural gas prices have become a critical determinant in establishing spot market electricity prices. In addition, regulation of GHG emissions and Renewable Portfolio Standards (**RPS**) result in both costs and benefits for resource options that can influence market prices. To analyze resource options across a range of future electricity prices that are driven by these factors, BC Hydro developed a series of Market Scenarios. The scenarios are largely focused on possible futures in North American or regional markets; however, where appropriate, international and B.C.- specific considerations are taken into account.

The remainder of this chapter is organized as follows:

- Section 5.2 outlines the Market Scenario framework and describes the five Market Scenarios
- Section 5.3 sets out the natural gas price forecasts, as well as the trends in these markets. Over the long term, natural gas prices are forecasted to continue to stay low as compared to historical prices due to shale gas reserves.
- Section 5.4 summarizes recent GHG legislative and policy developments. BC Hydro finds that there has been a loss of momentum in U.S. federal and state efforts to develop GHG regulation, e.g., the decision of all U.S. western

states, except California, to abandon the Western Climate Initiative (**WCI**). Section 5.4 also sets out updated GHG price forecasts.

- Section 5.5 discusses RPS requirements in the U.S. portion of the WECC, and the eligibility of B.C.-based renewables supply under the nine U.S. states in the WECC which have mandatory RPS. A forecast of the incremental value of the RECs associated with renewable electricity generation is provided.
- Section 5.6 provides the resulting spot market electricity price forecasts based on natural gas, GHG and REC price forecasts. BC Hydro's reference spot market forecast at Mid-Columbia (**Mid-C**) ranges from about $25/MWh to $40/MWh over the next 20 years.
- Section 5.7 describes the weighting factors assigned to the five Market Scenarios. These weighting factors have been updated to reflect the recent regulatory and market trends highlighted in this chapter.
- Section 5.8 contains BC Hydro's assessment that there are no suitable market opportunities that warrant development of new, additional clean or renewable resources for purposes of exporting electricity for the foreseeable future.

5.2 Market Scenario Framework

Any single 'best guess' of where market prices may go in the future is unlikely to be correct. BC Hydro uses Market Scenarios in the IRP to address the uncertainty of market prices and provide a framework to examine a wide range of possible market conditions and resulting different potential price paths that may develop over the planning horizon. Given the exposure of B.C.'s electricity sector through extensive trade with the U.S. market, these market conditions include both domestic and U.S. influences. The main market that BC Hydro transacts in is defined by the WECC region.

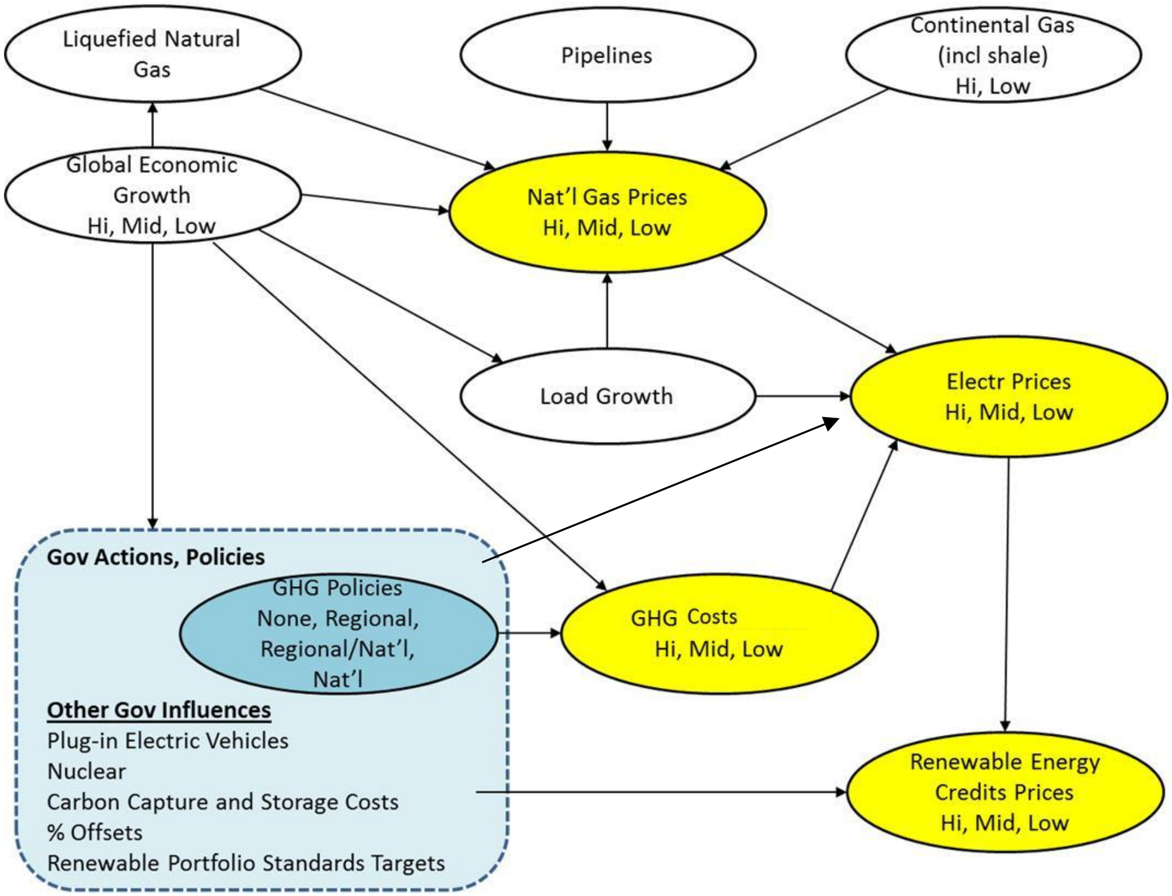
The development and use of the Market Scenarios is based on a scenario analysis approach in which a scenario is defined as a specified collection of internally consistent[1] variables across a broad range of market situations. In particular, by letting these variables take on specific values (e.g., Scenario X might include GHG prices that are 'mid', natural gas prices that are 'low' and economic growth as 'mid'), a scenario will describe a specific way in which markets might unfold.

5.2.1 Market Scenario Development Process

The influence diagram depicted in Figure 5-1 shows a view of how a number of market factors interact and highlights the four key price variables of interest (natural gas, GHG, REC and electricity prices).[2] This diagram portrays the interrelated nature of the variables used in the Market Scenarios. Some of these variables are inputs and some are outputs. The yellow ovals represent the forecast outputs, whereas the other ovals and boxes highlight some of the key input assumptions that help define each Market Scenario.

[1] An internally consistent scenario means all variables are consistent with the overall theme in the scenario.
[2] BC Hydro retained Black & Veatch (**B&V**) in 2010 to help develop market scenarios and worked with BC Hydro to produce the influence diagram.

Figure 5-1 Simple Influence Diagram for Market Prices



Four key market price variables were selected that changed across a wide, but plausible, range of values:

- Natural gas prices
- GHG prices
- REC prices
- Electricity prices

In addition, two key drivers from the influence diagram were identified that underpin the four market variables:

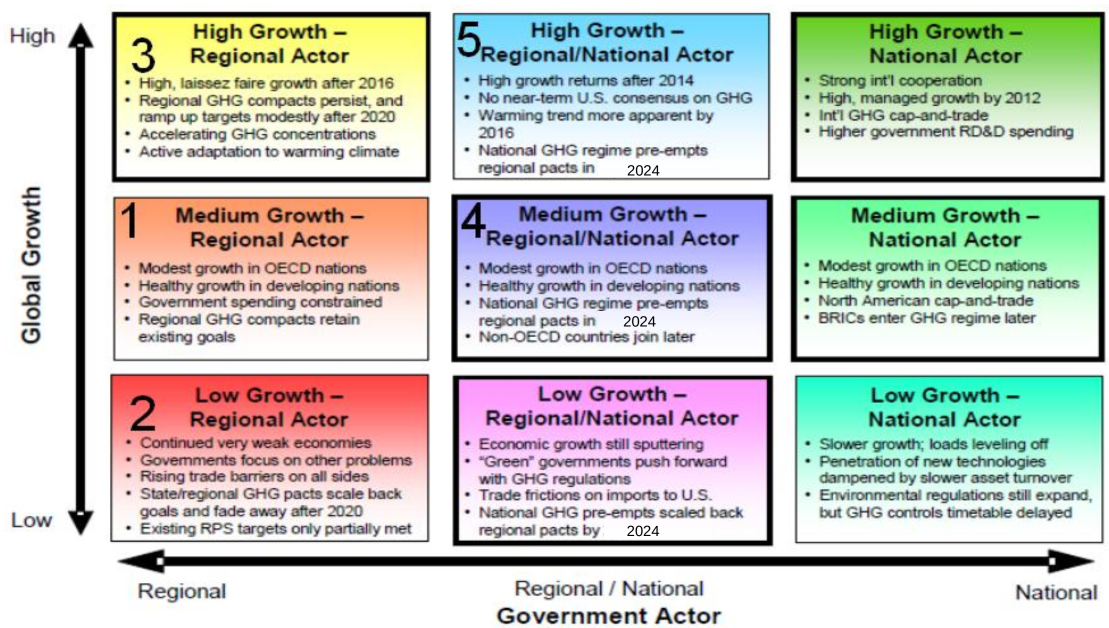
- Global economic growth (low, medium, high): Within this driver, a wide range of global economic growth rates are considered, including prolonged periods of global recession. In general, low global economic growth is assumed to stall the development of GHG regulation particularly at the national level and high global economic growth is assumed to lead to faster development of GHG regulation.
- Government policy maker (regional, regional/national, national): Within this driver, it is assumed that the level of government that is developing GHG regulation is important to GHG costs. In general, regional GHG markets are assumed to result in higher prices because of the smaller pool of available GHG compliance instruments and lack of competition, whereas the development of national regulation and international protocols results in lower prices.

As shown in Figure 5-2, the global economic growth and government policy action drivers are used as the dimensions to create nine possible Market Scenarios.

BC Hydro focused on the five scenarios in Figure 5-2, which are labeled Scenarios 1 through 5. BC Hydro considers the emergence of a national GHG actor in the U.S. to be unlikely before 2023 particularly in low economic growth scenarios because establishing such a national cap-and-trade regime requires both Presidential and U.S. Congressional legislative action. This does not preclude the emergence of some U.S. federal regulatory initiatives such as U.S. Environmental Protection Agency (**EPA**) targeted sector-by-sector GHG regulation. Given that the overarching principle informing the Canadian Federal Government's GHG policies is to harmonize GHG initiatives with those of the U.S. Federal Government, BC Hydro also considers it unlikely that there will be a Canadian national cap-and-trade or GHG actor; again, this does not preclude targeted sector-by-sector GHG regulation. Therefore BC Hydro eliminated the three scenarios that assume a national GHG cap-and-trade actor beginning in 2013, and the one scenario that assumes a transition to a national GHG cap-and-trade actor in the next 10 years in low economic growth conditions. Refer to section 5.4.2 for the GHG regulatory analysis.

The five remaining Market Scenarios provide a sufficiently wide range of possible future outcomes that are adequate to test resources as described in Chapters 4 and 6. Details on Market Scenario development can be found in Appendices 5B-1 and 5B-2.

Figure 5-2 Key Market Scenarios[3]



Since the release of the draft IRP in May 2012, BC Hydro used Ventyx's spring 2012 reference and environmental market scenarios[4] to update the five Market Scenarios.

5.2.2 Description of the Five Market Scenarios

A high level description of the five Market Scenarios is set out in this section.

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3 "Regional GHG Actor" means a regional cap-and-trade program that covers Alberta, B.C. and California in the WECC. "Regional/National GHG Actor" means a linked, national cap-and-trade program that covers the U.S. and Canada and starts in 2023. "National GHG Actor" means the Canadian or U.S. federal government.

4 Ventyx uses its proprietary model called Horizons Interactive that iteratively integrates all the key electricity price market input variables to create an internally consistent market scenario.

Scenario 1: Mid Electricity Prices, with Regional Mid GHG and Mid Gas Prices – Slow, but steady, global economic growth leads to lack of National GHG regulation in favor of regional regulation

Regional initiatives similar to WCI take the lead in establishing GHG regulatory markets in California, B.C. and Alberta, and national U.S. and Canadian governments do not follow suit in the 25-year forecast period. Medium levels of economic growth reduce federal governments' ability to advance environmental initiatives.

Scenario 2: Low Electricity Prices, with Regional Low GHG and Low Gas Prices – Low economic growth delays national GHG market development

With slow economic growth and activity, this scenario envisions that GHG emissions start to fall worldwide, impacting the climate change debate and lowering public and government interest in GHG regulation. Lower natural gas prices and flat electricity load growth delay spending on renewable energy development and RPS implementation. Investments in research and development (**R&D**) and conservation are also down.

Scenario 3: High Electricity Prices, with Regional Mid GHG and High Gas Prices – High economic growth and lower international cooperation stifles national environmental initiatives, leaving regions to regulate

Although this scenario features high global economic growth, no international agreements on GHG regulation are reached due to low levels of public support for GHG regulation in the U.S. In addition to low GHG support, there is even lower public spending on renewable energy R&D. As with Market Scenario 1, California, B.C. and Alberta continue to move forward with GHG emission trading.

Scenario 4: Mid Electricity Prices, Regional/National Mid GHG and Mid Gas Prices – Mid global economic growth sees regional leaders paving the way for national GHG markets by 2024

In conjunction with mid or medium global growth, regional initiatives similar to WCI take the lead in establishing GHG regional regulatory markets, with national U.S. and Canadian governments following suit by 2024. Although there are delays in national renewable energy standards, development is strong in later years (post-2024), with the electricity prices the same as Market Scenario 1 for the first 10 years but diverging thereafter.

Scenario 5: High Electricity Prices, Regional/National High GHG and Mid Gas Prices – Delayed high economic growth and lower international cooperation stifles national environmental initiatives, leaving regions to regulate

Although this scenario assumes high global economic growth, a national GHG cap-and-trade program is delayed until at least 2024. International agreements on GHG regulation are not reached for at least 10 years due to low levels of public support for GHG regulation in the U.S., and there is lower public spending on renewable energy R&D. As with Market Scenario 3, California, B.C. and Alberta continue to move forward with emission trading, albeit under higher cost pressures for market participants, and accordingly electricity prices are the same as Scenario 3 for the first 10 years but diverge after that period.

Table 5-1 lists the high level assumptions that informed the five Market Scenarios described above. Populating the four key variables with numerical values is explored in the following sections: Natural gas prices (section 5.3), GHG offset prices (section 5.4), REC prices (section 5.5) and electricity (spot market) prices (section 5.6).

Table 5-1 Market Scenario Assumptions

Market Scenario	1 Mid Electricity Mid GHG (Regional) Mid Gas	2 Low Electricity Low GHG (Regional) Low Gas	3 High Electricity High GHG (Regional) High Gas	4 Mid Electricity Mid GHG (Regional/Nat'l) Mid Gas	5 High Electricity High GHG (Regional/Nat'l) High Gas
GHG Actor	Regional	Regional	Regional	Regional then National	Regional then National
National Cap-and-Trade Date[5]	Post-2040	Post-2040	Post-2040	2024	2024
GHG Price Level	Mid (Regional)	Low	High	Mid (Environmental)	High
Natural Gas Price Level[6]	Mid (Regional)	Low	High	Mid (Environmental)	High
Global Growth[7]	Mid	Low	High	Mid	High
Load Growth[8]	Expected	Flat	High	Expected	High
WECC Resource Build[9]	Expected Mix	More Gas, Less Coal and Renewable	Less Coal, more Renewable	Less Coal, more Renewable	Less Coal, more Renewable
RPS Targets[10]	Met	Met	Met	Met	Met

5.3 Natural Gas Price Forecast

5.3.1 Introduction

The most significant development affecting natural gas prices is the emergence of shale gas. Since 2010, long-term natural gas prices have continued to drop due to advancements in gas extraction technologies and the increase in shale gas reserves

[5] "National Cap-and-Trade Date" is the assumed year for the introduction of a national cap-and-trade system. A three-year period was used to transition from a regional scenario to a national cap-and-trade scenario.

[6] "Mid (Regional)" is B&V's 2012 spring reference case. "Mid (Environmental)" is B&V's 2012 spring environmental case. "High" and "Low" refers to B&V's spring 2012 high and low natural gas price scenarios, respectively.

[7] Global Growth "Mid" means 'expected' U.S. and Canada global demand. "High" means almost double the expected year-over-year compound global growth. "Low" means flat global growth over the forecast period.

[8] Load Growth "Expected" means 'expected' U.S. and Canada and regional electric load growth per B&V's spring 2012 reference case. "High" load growth is about two times higher than the expected scenario.

[9] WECC resource build indicates the type of long-term supply mix changes assumed by B&V in each scenario.

[10] U.S. state RPS targets are met in all scenarios.

with U.S. natural gas production increasing to record highs.[11] BC Hydro's natural gas price forecasts address these shale gas developments and potential Liquefied Natural Gas (**LNG**) exports, as well as the possibility that environmental concerns may limit shale gas development and cause natural gas prices to rise.

The natural gas price forecasts used in the IRP are: (1) an input into the development of the electricity price forecast; and (2) used to define the costs of natural gas-fired generation resource options used in the modelling and risk analysis process.

5.3.2 Forecast Methodology

In developing the IRP, BC Hydro used Ventyx's spring 2012 natural gas price forecast which is consistent with the GHG scenario assumptions listed in Table 5-1. The four natural gas price forecasts are:

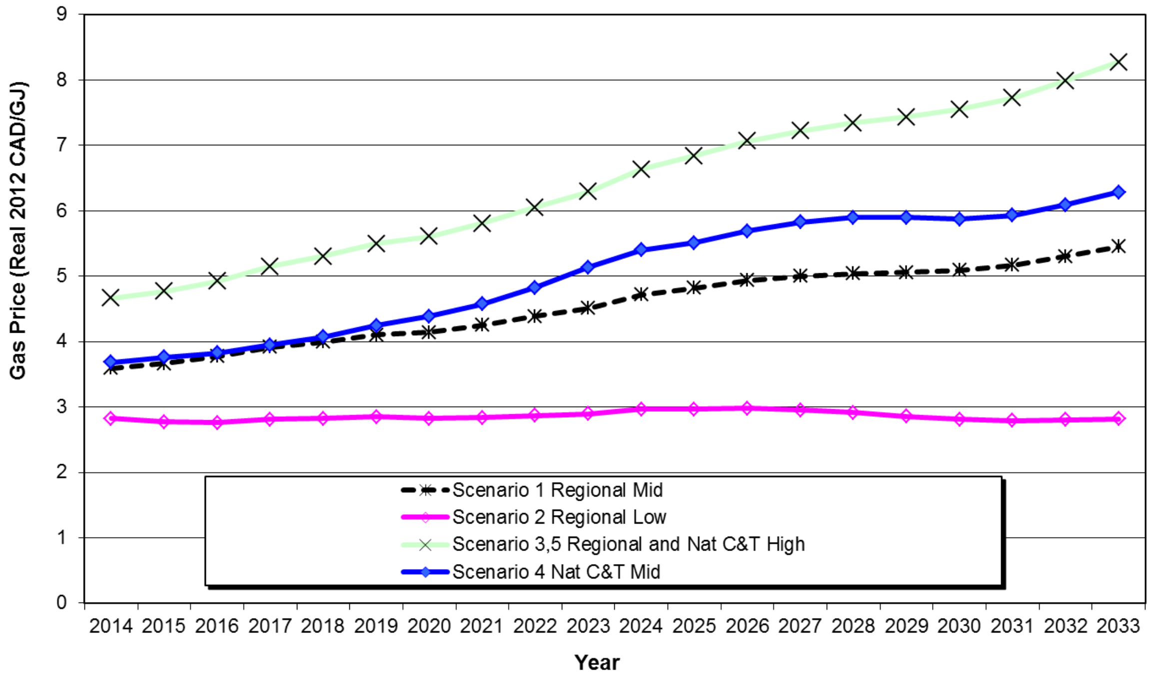
- **Scenario 1 – Mid Regional Natural Gas Price Forecast:** Ventyx's reference case, which reflects their view of market conditions and includes shale gas supply
- **Scenario 2 – Low Natural Gas Price Forecast:** Ventyx's low gas price scenario, which assumes flat global demand with limited LNG exports out of North America
- **Scenario 3 – High Natural Gas Price Forecast:** Ventyx's high gas price scenario, which assumes higher global demand with shale gas environmental issues limiting natural gas production
- **Scenario 4 – Mid Environmental Natural Gas Price Forecast:** Ventyx's environmental scenario, which includes an uplift in natural gas demand from the reference case due to additional coal-fired generation retirement

[11] Refer, for example, to U.S. Energy Information Administration (**EIA**) figures showing gas production in 2012 reaching 66 billion cubic feet per day.

- **Scenario 5 – High Natural Gas Price Forecast:** This forecast is the same as the high natural gas price in Scenario 3.

The Ventyx natural gas price forecasts are depicted in Figure 5-3.

Figure 5-3 Ventyx's Natural Gas Price Forecasts



5.3.3 Results

Table 5-2 shows the four natural gas price forecasts organized according to how they were used for the five Market Scenarios. The detailed natural gas price data tables can be found in Appendix 5A.

Table 5-2 Natural Gas Price Forecast Scenarios (Real 2012 US$/MMBTU at Sumas)

Market Scenario	1	2	3	4	5
	Mid Electricity Mid GHG (Regional) Mid Gas	Low Electricity Low GHG (Regional) Low Gas	High Electricity High GHG (Regional) High Gas	Mid Electricity Mid GHG (Regional/Nat'l) Mid Gas	High Electricity High GHG (Regional/Nat'l) High Gas
2014	3.7	2.9	4.8	3.8	4.8
2015	3.7	2.8	4.9	3.8	4.9
2016	3.9	2.8	5.0	3.9	5.0
2020	4.2	2.9	5.7	4.5	5.7
2025	4.9	3.0	7.0	5.6	7.0
2030	5.2	2.9	7.7	6.0	7.7

BC Hydro tracks and compares its natural gas price forecasts against other external forecasts, such as those produced by the U.S. EIA and other consultants. A graphical depiction of how BC Hydro's natural gas price forecasts compare against the U.S. EIA's 2013 forecast (at Henry Hub[12]), three consultant forecasts and Ventyx's updated spring 2013 forecast is provided in Figure 5-4. BC Hydro's Scenario 1 mid forecast is based on Ventyx's spring 2012 forecast. Note that Ventyx's 2013 forecast is down in the short term but is up in the long term. BC Hydro's Scenario 1 forecast is slightly higher than U.S. EIA's 2013 forecast for most of the forecast period, but in the middle of the three consultant forecasts.

[12] Henry Hub is a distribution hub in Louisiana on the natural gas pipeline system; it is a pricing point for natural gas future contracts.

Figure 5-4 Natural Gas Price Forecast Comparison – BC Hydro vs. External Forecasts

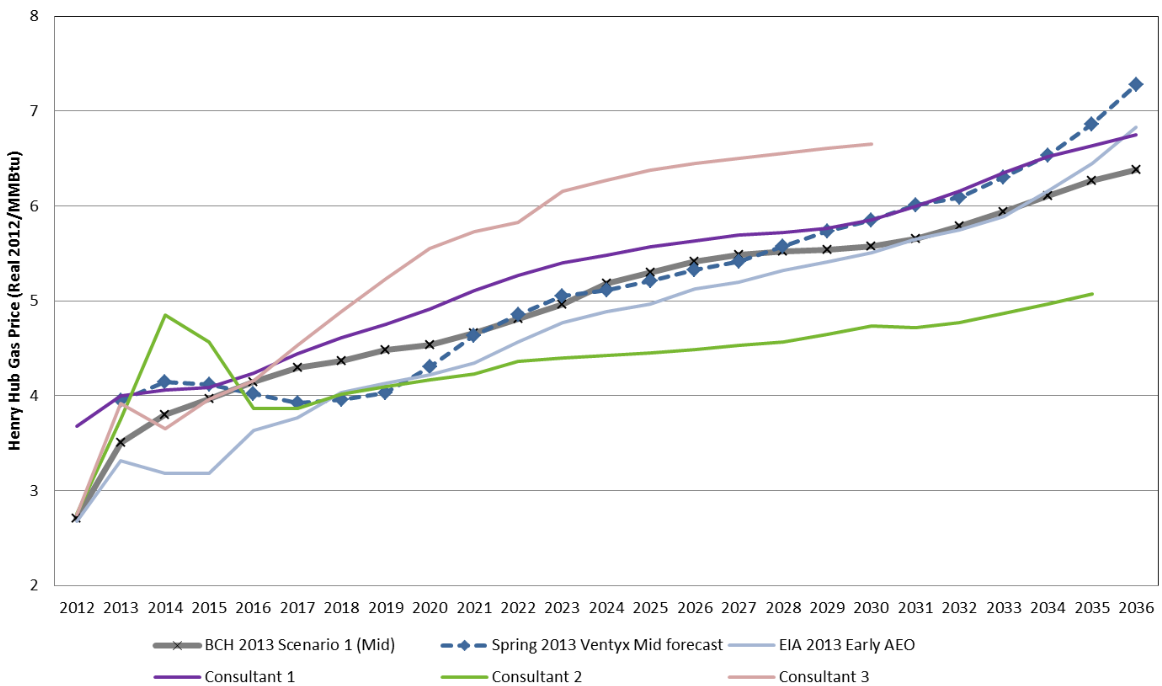
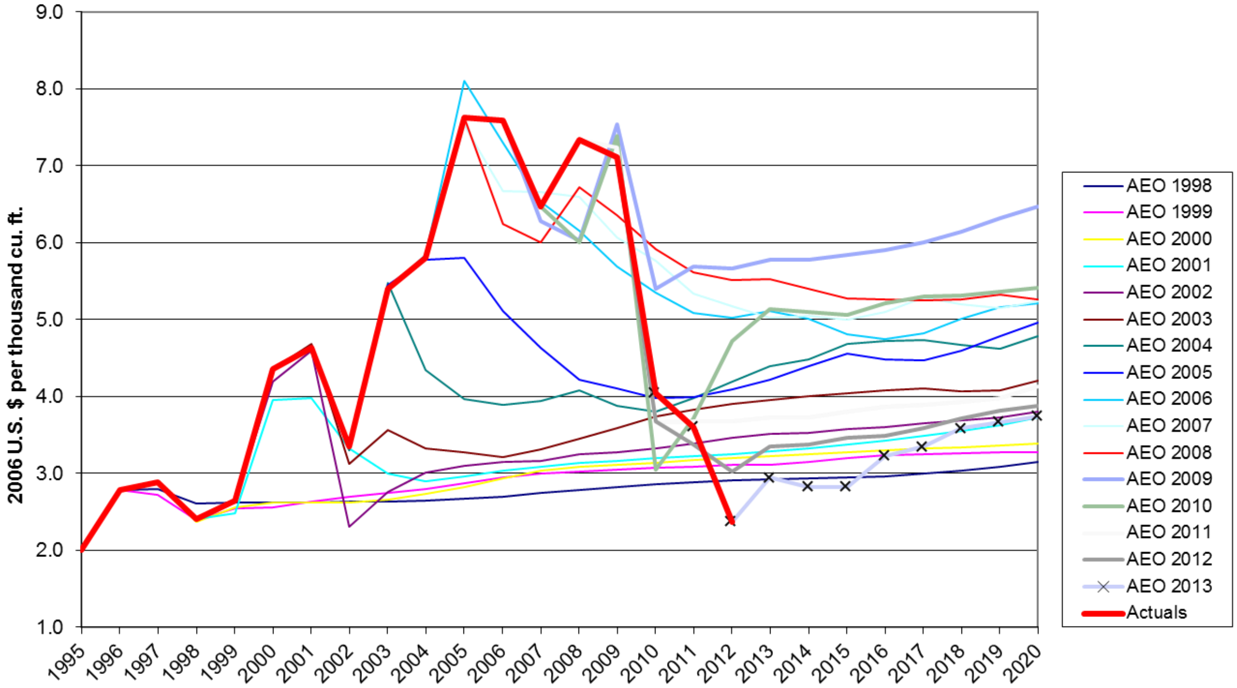


Figure 5-5, which compares past EIA forecasts to realized spot market prices, is indicative of the challenges in forecasting long-term energy prices. It is apparent that the EIA forecasts have been influenced by current conditions, with the result being that when natural gas spot market prices are low (such as currently), the long-term price forecast tends to be low and vice versa.

Figure 5-5 Comparison of EIA Natural Gas Price Forecast U.S. Average Wellhead Price



5.4 GHG Price Forecasts

5.4.1 Introduction

Since the electricity sector is a significant source of GHG emissions in North America[13], a market price on GHG emissions through regulation or otherwise presents financial risks and opportunities that utilities need to consider in long-term planning. BC Hydro retained B&V in 2011 to: (i) review North American and international GHG regulation developments; and (ii) develop a GHG price forecast based on the price of GHG emission allowances, the main market instrument used under GHG emissions trading (cap-and-trade) systems. BC Hydro has updated this work as summarized in sections 5.4.2 (GHG regulatory and policy developments) and 5.4.3 (GHG offset price forecasts).

[13] GHG emissions from electricity are primarily from the combustion of coal and natural gas, and vary widely from region to region depending on generation resource mix. The electricity sector emits approximately 42 per cent of GHGs in the U.S., 17 per cent in Canada, and about 2 per cent in B.C.

5.4.2 GHG Regulatory and Policy Developments

Over the past couple of years, GHG regulatory policies have been developing slowly. This section covers Canadian, B.C. and U.S. federal and WECC state developments.

5.4.2.1 Canada – Federal Regulatory Framework

The overarching principle informing the Canadian Federal Government's GHG policies is to harmonize GHG initiatives with those at the U.S. federal level. Under the Copenhagen Accord, the Federal Government inscribed a GHG emission reduction target that is aligned with the U.S. federal target, this being 17 per cent below 2005 levels by 2020. The Canadian Federal Government is implementing a sector-by-sector approach to reducing GHG emissions in major emitting sectors as one means of achieving this target.

On September 12, 2012, the Canadian Federal Government published the *Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations.*[14] These regulations generally take effect on July 1, 2015. Regulated coal-fired generating stations are barred from, on average, producing GHG emissions with an intensity of more than 420 tonnes of carbon dioxide equivalent for each gigawatt hour (**CO_2e/GWh**) of electricity produced during the calendar year.[15] The 420 tonnes of CO_2e/GWh performance standard is the GHG emission intensity level of an older vintage Combined Cycle Gas Turbine (**CCGT**).

BC Hydro understands that Environment Canada is beginning to examine whether and how to regulate GHG emissions from natural gas-fired generators. BC Hydro is engaged in this review through the Canadian Electricity Association.

[14] SOR/2012-167.
[15] The performance standard in the draft Regulations was 375 CO_2**e**/GWh.

5.4.2.2 Province of B.C.

B.C. has a legislated target of reducing GHG emissions to at least 33 per cent below 2007 levels by 2020 and at least 80 per cent below 2007 levels by 2050, as set out in the 2007 *Greenhouse Gas Reduction Targets Act*[16] (***GGRTA***). Two regulations have been enacted under *GGRTA*: (1) the Carbon Neutral Government Regulation[17], which provides in subsection 4(3) that the 'carbon-neutral public sector' provisions of *GGRTA* do not apply to BC Hydro's thermal electricity generating facilities (rather, they apply to BC Hydro corporate functions such as its vehicle fleet); and (2) the Emissions Offset Regulation[18] setting out requirements for GHG reductions and approvals from projects or actions to be recognized as emission offsets for purposes of fulfilling the B.C. Government's commitment to a carbon-neutral public sector from 2010 onwards. Offsets for carbon-neutral public sector purposes must be sourced in B.C. The Pacific Carbon Trust (**PCT**) is the sole supplier of offsets to the public sector at $25/tonne for purposes of the carbon neutral commitment, and also provides offsets to the private sector.

The B.C. Government passed the *Greenhouse Gas Reduction (Cap and Trade) Act*[19] in 2008, which would enable reductions in GHG emissions through a cap-and-trade system and contemplates eventual linkage of a B.C. cap-and-trade system to other systems (refer to section 5.4.2.3). The Reporting Regulation,[20] which came into force on January 1, 2010, requires facilities (including electricity generating facilities) emitting 10,000 tonnes or more of GHGs per year to register with the B.C. Ministry of Environment, collect emissions data and report GHG emissions. The development of a B.C. cap-and-trade system would come into force through regulation(s). In 2010, the B.C. Government released consultation papers in

16 S.B.C. 2007, c.42. The B.C. Government also established GHG reduction targets of 6 per cent below 2007 levels by 2012 and 18 per cent by 2016 pursuant to Ministerial Order 286 (2008).
17 B.C. Reg. 392/2008.
18 B.C. Reg. 393/2008.
19 S.B.C. 2008, c.32.
20 B.C. Reg. 272/2009.

respect of two proposed regulations: (1) an Emissions Trading Regulation to establish the rules by which GHG emissions may be traded under a B.C. cap-and-trade system (entails significant oversight of the government distribution of allowances and the spot/cash market for compliance units); and (2) a Cap and Trade Offsets Regulation to set out the requirements applying to project-based GHG emission reductions for them to be recognized as offsets, and eligible for use by regulated emitters to satisfy their compliance obligations in B.C.[21] To date neither of these two proposed regulations has been brought into force. While B.C. continues to monitor WCI regulatory developments, it has not yet made a final decision as to whether to institute a cap-and-trade program.

The *Greenhouse Gas Reduction (Emission Standards) Statutes Amendment Act*[22] amends the *Environmental Management Act*[23] to require that new natural gas-fired generation facilities acquire and retire compliance offsets at least equal to the amount of GHG emissions that are created. To date, no regulation has been enacted to bring these provisions into force. However, Policy Action No. 18 of the 2007 BC Energy Plan provides that new natural gas-fired generation is to have net zero GHG emissions; this policy will likely be implemented through the B.C. *Environmental Assessment Act* (***BCEAA***). New gas-fired electricity generation facilities with a nameplate capacity of equal to or greater than 50 MW trigger *BCEAA* and require an Environmental Assessment Certificate (**EAC**) to proceed. The Environmental Assessment Office (**EAO**) has the power to impose a 100 per cent offset requirement as part of EAC conditions. For example, section 21 of *BCEAA* provides that the EAO executive director may seek policy clarification and direction from the B.C. Ministers of Environment and of Energy and Mines. The policy clarification and direction must be reflected in the environmental assessment

[21] http://www.env.gov.bc.ca/cas/mitigation/ggrcta/emissions-trading-regulation/index.html#intentions.

[22] S.B.C. 2008, c.20.

[23] S.B.C. 2003, c.53. To date one regulation, the Landfill Gas Management Regulation, B.C. Reg. 391/2008, has been enacted; this regulation establishes province-wide criteria for landfill gas capture from municipal solid waste landfills.

conducted by the EAO. Government agencies may also identify relevant policy for the EAO executive director, who then must ensure that the EAO recommendations reflect this policy. For these reasons, a 100 per cent offset requirement is assumed for new natural gas-fired generation in the Chapter 6 portfolio analysis. Offset costs are discussed further in section 5.4.2.3.

B.C.'s carbon tax[24] applies to the purchase or use of natural gas and other fuels within the province. The current tax rate is $30 per tonne of CO_2e emissions. The Provincial Government committed to freezing the carbon tax at this level for five years as part of the June 26, 2013 Throne Speech.[25]

5.4.2.3 U.S. – Federal, Regional and State Initiatives

To date, no U.S. federal legislative GHG proposal has successfully been passed by both the House of Representatives and the Senate for consideration by the U.S. President. On February 14, 2013, the *Climate Protection Act of 2013* was introduced into the U.S. Senate which would, among other things, impose a carbon fee of $20 per ton on coal, oil and natural gas producers beginning in 2014. It is unlikely this bill will become law in the near future given the current realities of the U.S. Congress.

The EPA has taken steps to regulate GHG emissions under authority of the U.S. *Clean Air Act*:

- New Power Plant GHG Performance Standards – On March 27, 2012, the EPA proposed a Carbon Pollution Standard for new power plants that would for the first time set U.S. national limits on the amount of GHGs that power plants can emit. Under the proposal, new fossil fuel-fired electricity generating stations greater than 25 MW must meet an output-based standard of 1,000 pounds of CO_2 per megawatt-hour (lb CO_2/MWh gross). The EPA selected this threshold

[24] *Carbon Tax Act*, S.B.C. 2008, c.40.
[25] *Speech from the Throne*, June 26, 2013, page 4; www.leg.bc.ca/40th1st/Throne_Speech.pdf.

based on the performance of widely-used natural gas combined cycle technology. Thus, CCGTs could meet this standard, but new coal-fired electricity generators could only meet this standard using Carbon Capture and Sequestration. This carbon pollution proposal does not apply to Simple Cycle Gas Turbines, existing units or new electricity generating facilities that have permits and start construction within 12 months. While the EPA is proposing a standard of 1,000 lb CO_2/MWh, it is soliciting public comment on a range from 950 lb to 1,100 lb CO_2/MWh (430 to 500 kg/MWh).[26]

- Guidance for Best Available Control Technology (**BACT**) – As of July 1, 2011, new facilities that would emit more than 100,000 tons per year of CO_2e must undergo an analysis of emissions-lowering technology before receiving a permit under the U.S. *Clean Air Act*. Proposals must conduct a BACT analysis, which is a five-step process to regulate GHG emissions. The EPA guidance document does not identify what constitutes BACT for specific types of facilities, and does not establish absolute limits on a permitting authority's discretion when issuing BACT determinations for GHGs. State and local authorities review BACT analyses and issue air permits on a case-by-case basis.

Legal challenges to various EPA GHG-related regulations have begun.[27]

At the regional and WECC U.S. state level, six states formally withdrew from WCI in November 2011 (New Mexico, Arizona, Washington, Oregon, Montana and Utah), leaving California, British Columbia, Manitoba, Ontario and Quebec as the remaining partners. To date, only California and Quebec have adopted regulations respecting a cap-and-trade system for GHG emissions based on the rules established by the

[26] PacifiCorp, 2013 IRP, page 34; www.pacificorp.com. In June 2013 the U.S. President requested that the EPA develop regulations for existing fossil-fired electricity generating facilities.

[27] Reuters, April 19, 2013. Some of the legal challenges question the authority of the EPA to regulate GHG emissions under the proposals listed above in respect of electricity generating facilities. The U.S. Court of Appeals for the District of Columbia ruled in favour of the EPA in 2012.

WCI.[28] As noted above, B.C. is monitoring developments before deciding whether to enact the regulation on cap-and-trade. On April 19, 2013, the California's Air Resources Board (**CARB**, the GHG regulator) approved the linking of California's cap-and-trade program with Quebec's program to start January 1, 2014.

California's cap-and-trade program came into force on January 1, 2013, with enforceable compliance obligations beginning on that date. CARB is to hold auctions of GHG emission permits for the cap-and-trade program. CARB has held three quarterly GHG allowance auctions so far, with GHG price settlements ranging from US$10.09/tonne to US$14.00/tonne.[29] The prices at which these auctions can settle at are collared by an Auction Reserve Price on the downside (referred to as the **floor price** and currently US$10.71/tonne) and by an Allowance Price Containment Reserve on the upside (referred to as the **ceiling price** and currently evenly tiered at $40, $45 and $50/tonne).

5.4.3 GHG Price Forecasts

5.4.3.1 Forecast Methodology

BC Hydro used modelling that was conducted by Ventyx for their spring 2012 reference and environmental scenarios to update the five Market Scenarios described in section 5.2. To meet the GHG reduction and avoidance measures, Ventyx's model included:

- Efficiency improvements
- Additional renewable capacity
- Retirement of inefficient coal-fired units
- Additional natural gas-fired CCGT units in place of new coal-fired units

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[28] http://www.westernclimateinitiative.org/news-and-updates/139-quebec-adopts-cap-and-trade-regulation.

[29] CARB, "California Air Resources Board Quarterly Auction 3, May 2013: Summary Results Report (June 5, 2013 Update)"; www.arb.ca.gov.

- Reduced operation of existing coal-fired units
- Increased operation of existing gas-fired units
- Additional nuclear capacity, in regions where this exists or is allowed

As emission caps decrease, GHG prices increase as the supply of emission allowances decreases over time, which leads to increased use of lower GHG-emitting electricity generation resources.

5.4.3.2 Results

Table 5-3 summarizes the $/tonne GHG prices for the five Market Scenarios used in the IRP. The detailed GHG data tables can be found in Appendix 5A.

Table 5-3 GHG Price Forecast by Market Scenario (Real C$2012 per Tonne of CO_2e)

	Scenario 1			Scenario 2			Scenario 3			Scenario 4	Scenario 5
	Mid Electricity Mid GHG (Regional) Mid Gas[30]			Low Electricity Low GHG (Regional) Low Gas[31]			High Electricity High GHG (Regional) High Gas[32]			Mid Electricity Mid GHG (Reg/Nat'l) Mid Gas[33]	High Electricity High GHG (Reg/Nat'l) High Gas[34]
	BC	Calif.	WECC Other	BC	Calif.	WECC Other	BC	Calif.	WECC Other	BC, Calif. and WECC Other	BC, Calif. and WECC Other
2014	30	19.5	0.0	30	12.3	0.0	30	67.5	0.0	Same as Scenario 1 to 2023	Same as Scenario 3 to 2023
2015	30	21.9	0.0	30	12.8	0.0	30	70.2	0.0		
2016	30	24.7	0.0	30	13.3	0.0	30	73.0	0.0		
2020	30	39.9	0.0	30	15.5	0.0	30	85.4	0.0		
2025	30	46.7	0.0	30	18.9	0.0	30	103.9	0.0	25.3	103.9
2030	30	51.5	0.0	30	23.0	0.0	30	126.4	0.0	40.4	126.4
2035	30	55.8	0.0	30	26.4	0.0	30	145.1	0.0	54.8	145.1

5.4.3.3 Discussion of Results

The five GHG price forecasts provide a wide range of possible future GHG offset prices that capture a range of economic and policy scenarios: two high, two mid and a low forecast. The GHG price forecasts reflect the increase in uncertainty in implementation of GHG policies, particularly in the short term at the federal level in the U.S. and Canada.

BC Hydro benchmarked the GHG prices from the five Market Scenarios against a number of external, publicly available forecasts, which are shown graphically in Figure 5-6.

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30 Ventyx Spring 2012 Reference Scenario for all GHG forecasts.

31 Ventyx Spring 2012 Low Scenario for B.C. and rest of WECC; and CARB floor price for California.

32 Ventyx Spring 2012 High Scenario for B.C. and rest of WECC; and CARB ceiling price for California. Note that the $67.5 to $145 per tonne figures result from the escalation as per legislation (5 per cent + inflation) of the CARB ceiling price for 2012 described in section 5.4.2.3, converted to $CDN and metric tonnes.

33 Ventyx Spring 2012 Environmental Scenario for all of WECC after 2023.

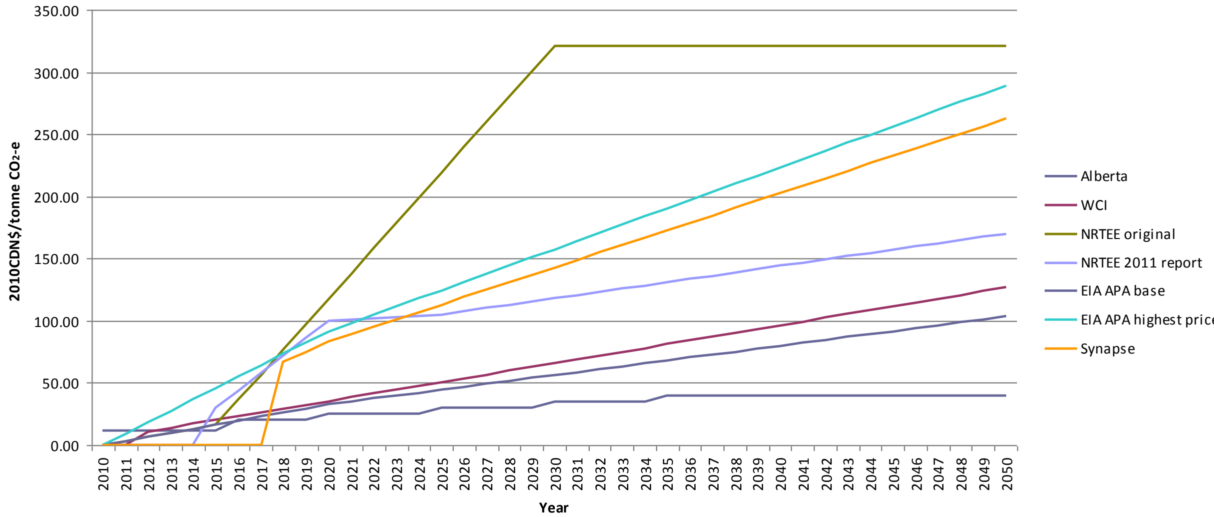
34 Ventyx Spring 2012 High Scenario with California ceiling price for all of the WECC after 2023.

The external GHG price forecasts examined include:

- WCI Regional Cap-and-Trade Program Economic Analysis Update (July 2010)
- National Roundtable on the Environment and the Economy (**NRTEE**) "Getting to 2050" (2009) 'Fast and Deep scenario' (labeled 'NRTEE original' on Figure 5-6), and NRTEE's "Climate Prosperity – Parallel Paths: Canada-U.S. Climate Policy Choices" 2011 report 'Start 2015 scenario'
- U.S. EIA "Energy Market & Economic Impacts of the *American Power Act of 2010*", base case forecast and highest price forecasts
- Synapse Energy Economics Inc., "2011 Carbon Dioxide Price Forecast", mid-price forecast
- Carbon prices in Alberta's existing regulatory system of GHG emission intensity targets for industrial sectors, which allows compliance flexibility through the use of offsets and investment in a technology fund at a current cost of $15 for every tonne of GHG emissions above the individual emitter's limit

The forecasts listed above were adjusted to a common unit (2010 C$/tonne). Where the original reports only included prices for certain years within their respective forecast period, price trajectories to 2050 were determined through straight-line interpolation and extrapolation.

Figure 5-6 Comparison of Publicly Available GHG Price Forecasts



- BC Hydro also examined both the B.C. carbon tax rate of $30 per tonne of CO_2e emissions and PCT's $25/tonne price for offsets offered to the public sector for purposes of the carbon-neutral commitment. As described below, BC Hydro utilized the carbon tax as it applies more broadly than PCT pricing.

The GHG price forecasts are used in the IRP analysis in a number of ways:

- As an input to the electricity price forecast, as it is applied to all CO_2-emitting resources in the WECC under a national cap-and-trade scenario and only to Alberta[35], B.C. and California CO_2-emitting resources in the regional scenarios. This has the effect of uplifting electricity prices
- As an adder to B.C. CO2-emitting resources (natural gas-fired generation), as an expected future regulatory cost in the Chapter 6 portfolio analysis. BC Hydro's analysis assumes that natural gas-fired generation in B.C. would incur the maximum of either the B.C. carbon tax ($30 per tonne of CO2e emissions) or the GHG prices shown in Table 5-3.

[35] Alberta GHG price was set at $15/tonne for the regional assessment in the electricity price forecast.

5.5 RPS Requirements and REC Price Forecasts

5.5.1 Introduction

A Renewable Portfolio Standard is a mechanism that places an obligation on electricity suppliers to include a specified percentage of electricity from renewable energy resources such as wind and solar. Currently, 29 U.S. states and the District of Columbia have adopted mandatory RPS requirements, and an additional eight U.S. states have RPS goals. Of the 11 U.S. states that are wholly situated within the WECC region, nine have mandatory RPS requirements and two (Idaho and Wyoming) do not. The RPS requirements vary considerably by state with respect to resource eligibility, allowance for unbundled RECs and enforcement arrangements. The use of unbundled RECs separates the attributes of renewable electricity (e.g., generator emissions) from the electricity itself, creating an entirely separate market for the renewable attribute alone, which is unencumbered by the physical constraints of the transmission grid.

REC price forecasts are used to estimate incremental revenue that would result from the sale of the clean or renewable electricity that is surplus to BC Hydro's system need and is RPS-eligible energy. These results inform the export analysis in section 5.8 and the portfolio trade-off analysis in Chapter 6.

5.5.2 RPS Summary and Forecast Methodology

5.5.2.1 WECC U.S. State RPS Summary

In 2011, BC Hydro retained B&V to provide an overview of RPS developments by U.S. state. B&V's findings are documented in the report attached as Appendix 5C. The RPS state requirements in WECC states are summarized in Table 5-4. While there are some ambitious RPS targets in these states, there are restrictions on hydro resources and delivery requirements.

Table 5-4 RPS Summary for WECC States

WECC State	Target and Ramp	Hydro Eligibility[36]	Delivery Requirement	ACP[37]	Carve-Outs[38]
Arizona	15 per cent by 2025; 0.5 per cent ramp for 2010-2015, 1 per cent for 2015-2025	<10 MW if run of river or incremental upgrades	Power must be delivered to state since unbundled RECs not allowed	None[39]	4.5 per cent DG by 2012
California	33 per cent by 2020; at least 1 per cent ramp annually	Small and conduit <30 MW; must not have "an adverse effect on instream beneficial uses"	Delivery to an in-state hub; tradable RECs allowed up to 25 per cent of RPS requirement, declining to 10 per cent by 2017[40]	None[41]	None
Colorado	30 per cent by 2020 and each following year (investor owned utilities)	10 MW or less, and hydroelectric resources in existence on January 1, 2005 with a nameplate capacity rating of 30 MW or less	Tradable RECs are permitted	None[42]	None

[36] Most states designate solar, wind, geothermal and ocean/tidal to be RPS eligible resources. Other resources like hydro, biomass and waste-to-energy depend on the state and the type of fuel or technology used.

[37] The Alternative Compliance Payment (**ACP**) mechanism provides participating entities with an option to obtain the required amount of renewable energy, RECs or make the specified compliance payment. ACPs effectively set a ceiling price.

[38] In per cent of total customer sales, not of the RPS requirement, unless otherwise noted.

[39] Customer surcharges to comply with the RPS must be approved by the Arizona Corporation Commission; this could create a de facto future limit on price.

[40] Rule-making has begun to allow tradable RECs, but is currently in the process of modification before enactment.

[41] The ACP mechanism in California was deleted under Senate Bill 2 (SB 2-1X). For the IRP analysis, BC Hydro used the previous ACP price of $50/MWh.

[42] Colorado State may impose ACP but amounts are not specified.

WECC State	Target and Ramp	Hydro Eligibility[36]	Delivery Requirement	ACP[37]	Carve-Outs[38]
Montana	15 per cent by 2015; 1 per cent ramp for 2010 to 2015	New <10 MW and is not a new water diversion	Must be delivered to Montana; specifies eligibility as Montana or other states	$10/MWh	75 MW of "community renewable energy projects"[43]
Nevada	25 per cent by 2025; 3 per cent ramp every two years	Run of river <30 MW; dams must be existing and used for irrigation only	Power must be delivered into Nevada	None	1.25 per cent solar through 2015; 1.5 per cent thereafter
New Mexico	20 per cent by 2020; 1 per cent ramp per year	All facilities online after July 1, 2007	Power must be delivered to New Mexico; "preference" given to New Mexico facilities	None[44]	4 per cent each wind and solar; 0.6 per cent distributed generation by 2020
Oregon	25 per cent by 2025; 1 per cent ramp per year for 2015 to 2025	Efficiency upgrades to existing facilities made after 1994 eligible	Bundled RECs must be located within the U.S.; unbundled anywhere in WECC (limited to 20-50 per cent of compliance)	$50/MWh[45]	20 MW small solar by 2020
Utah	20 per cent by 2025; no interim targets	Any size or timing allowed for in-state; out of state limited to upgrades and <50 MW	Delivery to WECC	None	None
Washington	15 per cent by 2020; 6 per cent step changes every five years	Efficiency improvements after March 1999	Must be delivered to WA on a real time basis	$50/MWh	None

43 Projects under 25 MW in size with a controlling interest from local owners.

44 Customer rate increases are limited to 2 per cent per year through 2011, rising by 0.25 per cent per year through 2015.

45 Can be adjusted every even-numbered year.

BC Hydro also asked B&V to provide a report on renewable market competitiveness in 2011, specifically focusing on Alberta, Washington, Oregon and California. This report is attached as Appendix 5D. The report analyzes the ability of each jurisdiction to meet its RPS or other GHG-reducing requirements with in-state resources. If it seemed likely that there was a gap between the in-state renewable energy resource capacity and the RPS requirements, the competitiveness of B.C. resources was examined. One of the conclusions of the B&V report was that California is the primary potential market for B.C. renewable energy resources. Challenges with accessing the California RPS market are discussed in section 5.5.3.

5.5.2.2 Forecast Methodology

BC Hydro retained B&V in 2011 to help develop the REC price forecasts and to provide an objective view as to what the value of RECs would be in the future for each of the five Market Scenarios. B&V concluded that RPS legislation in most WECC states allows a limited amount of out-of-state renewable electricity products. Currently most of the out-of-state RPS-eligible energy space is pre-contracted under long-term contracts, which leaves little room for additional out-of-state RPS energy. Therefore, the 2011 REC price forecast only represents the value of in-state RPS eligible energy and is calculated by the difference between the delivery cost of building new RPS-eligible facilities and the wholesale (spot) electricity market price.

B&V’s in-state REC price forecasts were not updated because BC Hydro is continuing to use the long-term expected California Senate Bill 2, First Extraordinary Session (**SB 2-1X**) Product Content Category 3 out-of-state REC price of up to $4/MWh as described in section 5.5.3. Currently these Category 3 out-of-state REC prices are around $1.25/MWh. The 2011 unbundled REC price forecast can be found in Appendix 5C.

5.5.3 Discussion of Results

B.C. resources currently have challenges accessing RPS markets in the U.S. because of delivery and resource eligibility requirements. This is particularly the case for the California where SB 2-1X (signed in April 2011) contains California's RPS resource eligibility and delivery requirements.

With respect to resource eligibility, the California Energy Commission (**CEC**) is required to evaluate the "eligibility" of B.C.-based low-impact hydroelectric generation and to report to the California legislature as part of implementing SB 2-1X. In March 2013, a CEC-retained consultant released a report[46] analyzing the regulatory requirements for inclusion of B.C. run-of-river facilities in California's RPS. To be considered eligible for California's RPS, projects located outside the U.S. must be developed and operated in a manner that is as protective of the environment as a similar facility located in California. The CEC consultant concluded that while B.C. run-of-river facilities "going through a full environmental assessment in British Columbia must adhere to similar regulatory requirements as those in California … a [B.C.] run-of-river hydroelectric project would have to meet additional requirements to be considered eligible for California's [RPS]". The CEC consultant also concluded that "benefits [of B.C. run-of-river] do not warrant changing existing statutory requirements to categorically allow all run-of-river hydroelectric projects in British Columbia to become eligible for California's [RPS]".

The consultant notes that the CEC is considering the following requirements for B.C.-based run-of-river projects requesting eligibility[47]:

- The project must be less than 30 MW
- The project must complete an environmental assessment or development plan with a cumulative impact assessment based on the Agency's "Cumulative Effects Assessment Practitioners Guide"[48]

[46] "Analysis of Regulatory Requirements for Including British Columbia Run-of-River Facilities in the California Renewables Portfolio Standard" by Suzanne Phinney and Emily Capello (**Aspen Environmental Group Report**), March 2013 (CEC -300-2013-006).

[47] Aspen Environmental Group Report, pages 1-3 and 66.

[48] Published by the Canadian Environmental Assessment Agency.

- Instream flow requirements must be sufficient to not compromise the river ecosystem based on volume or timing of streamflow
- The project should obtain EcoLogo certification[49]
- Documentation (which may or may not be EcoLogo) must be provided to show the project was analyzed, constructed and operated to protect the environment in a similar manner as would be required of a California project
- Transparency during the environmental review and monitoring process should be comparable with Federal Energy Regulatory Commission standards

With respect to delivery requirements, SB 2-1X allows for RPS requirements to be met from three Product Content Categories or ‘buckets’. The price ranges set out for each of the three buckets have been obtained from discussions with Powerex and other sources:

- Category 1: This is a bundled REC product, meaning the associated renewable energy from facilities interconnected to a California balancing authority or otherwise meeting certain deliverability requirements. If a California retail seller is purchasing a Category 1 product from outside of California, they must be able to prove they have scheduled the electricity into a California balancing authority without substituting electricity from another source. This criterion requires the retail seller to purchase energy and the associated RECs from a renewable facility and, for out-of-state facilities, demonstrate the energy has been transmitted via dynamic scheduling or a continuous transmission schedule from the facility into a California balancing authority. This marks a reduction in flexibility from the previous rules which allowed the separate purchase of energy and RECs, which then could be bundled together in a

[49] EcoLogo is an environmental standard and certification mark founded in 1988 by the Government of Canada.

contract to satisfy the RPS compliance mandates of retail sellers.[50] This category represents the largest market for California RPS products, as SB 2-1X significantly restricts the eligibility of the other two categories. Category 1 currently attracts the highest prices of up to $20/MWh to $30/MWh; however, the enhanced delivery requirements incur expensive transmission costs.

- Category 2: This is also a bundled REC product and refers to the product coming from renewable facilities not directly connected to a California balancing authority and delivering power using firming and shaping. Out-of-state generators represent the biggest suppliers of the Category 2 product. Load-serving entities can use Category 2 RECs to satisfy up to one-half of current RPS obligations, which is reduced to 25 per cent by 2017. The oversupply of renewable energy already constructed in the WECC region results in sufficient resources to meet the majority of this need. Recent market prices for this product have been around $4/MWh.
- Category 3: This is an unbundled product (or tradable REC) meaning that the REC is separated from the energy to meet RPS requirements. According to SB 2-1X, the use of tradable REC transactions signed after June 10, 2010 will be capped at 25 per cent for the compliance period ending December 31, 2013, and will shrink to 10 per cent by 2017. Tradable RECs are the least expensive REC product on the market, as existing supply has kept recent prices relatively low at about $1.25/MWh.

Because of the high delivery costs and transmission requirements associated with Category 1, it will be challenging for B.C. resources to deliver this product. As the size of the ‘out-of-state’ market associated with Categories 2 and 3 will shrink over the next few years, it is expected that REC prices will remain low due to excess supply.

[50] Under previous rules, firmed and shaped energy was categorized as the same as renewable energy from an in state generator.

For the IRP portfolio analysis, BC Hydro applied the following assumptions:

- Eligibility – The resource options analysis in Chapter 3 demonstrates that the technically or economically feasible B.C.-based clean or renewable resources are Site C, Resource Smart upgrades to existing BC Hydro hydroelectric facilities, pumped storage, run-of-river hydro, biomass and wind. Of these resources, only wind and biomass are assumed to be eligible for REC sales. BC Hydro will monitor developments in CEC's assessment of the eligibility of low impact hydroelectric generation but it is currently considered to be ineligible.
- Prices – REC prices are capped at $4/MWh, based on the range of recent out-of-state REC prices and the expectation that excess supply will constrain prices over the next few years. The WECC power supply situation is discussed in section 5.8.
- REC Sales – BC Hydro will only sell RECs to the extent that the underlying energy is surplus to customer needs

5.6 Electricity Price Forecast

5.6.1 Introduction

WECC's electricity and natural gas markets are closely linked since natural gas has become the predominant fuel for new electricity generation. This is due to natural gas-fired generation's operational flexibility and relatively high variable operating costs, which typically place it last in the order of generation resources to be dispatched. As such, natural gas-fired generation is the marginal market resource and low gas prices are likely to drive low electricity market prices through most periods in a year.

Five electricity price forecasts were developed for the IRP based on the Ventyx Market Scenarios. The sales and purchases assumed to be made in the analysis are based on pricing at two external trading hubs – the Mid-C and the Alberta Energy

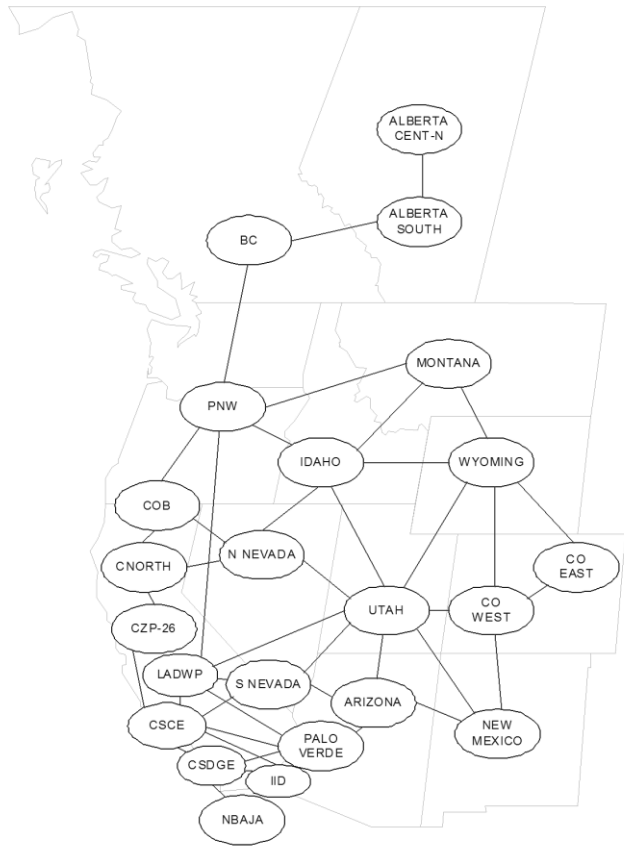
System Operator hubs. In each case, wheeling and losses are captured from the B.C. delivery point to the respective hub.

5.6.2 Forecast Methodology

Electricity prices are modelled under a computer simulation of the hourly supply-demand balance for the WECC regional market. The dispatch cost of the marginal resource at the point where supply and demand are in equilibrium determines the market price for that hour. Monthly and yearly average prices are obtained by aggregating the computed hourly prices. The electricity and natural gas prices are calculated for the next 25 years.

The electricity price forecasts were developed using a two-stage process. In the first stage, Ventyx compiled a database of scenarios of loads and resources in the WECC region. These scenarios include underlying assumptions for demand-side measures, clean or renewable resources and conventional resources in each region (refer to Figure 5-7) and correspond to the Market Scenarios.

Figure 5-7 WECC Transmission Area Configuration



In the second stage, BC Hydro made certain modifications to the Ventyx database with respect to the B.C. area, including additional precision with respect to BC Hydro resources. BC Hydro then simulated the impact of the natural gas and GHG price forecasts described in sections 5.3 and 5.4, respectively, on the WECC region. For the two national cap-and-trade scenarios, BC Hydro assumed that a U.S. national cap-and-trade program will not be implemented any earlier then 2023, and therefore Scenarios 4 and 5 are the same as Scenarios 1 and 3 respectively, up until 2023.

5.6.3 Results

The electricity price forecasts for Mid-C in U.S. dollars are provided in Figure 5-8 and Table 5-5. The detailed electricity price forecast data tables can be found in Appendix 5A.

1 **Figure 5-8 Electricity Price Scenarios at Mid-C**

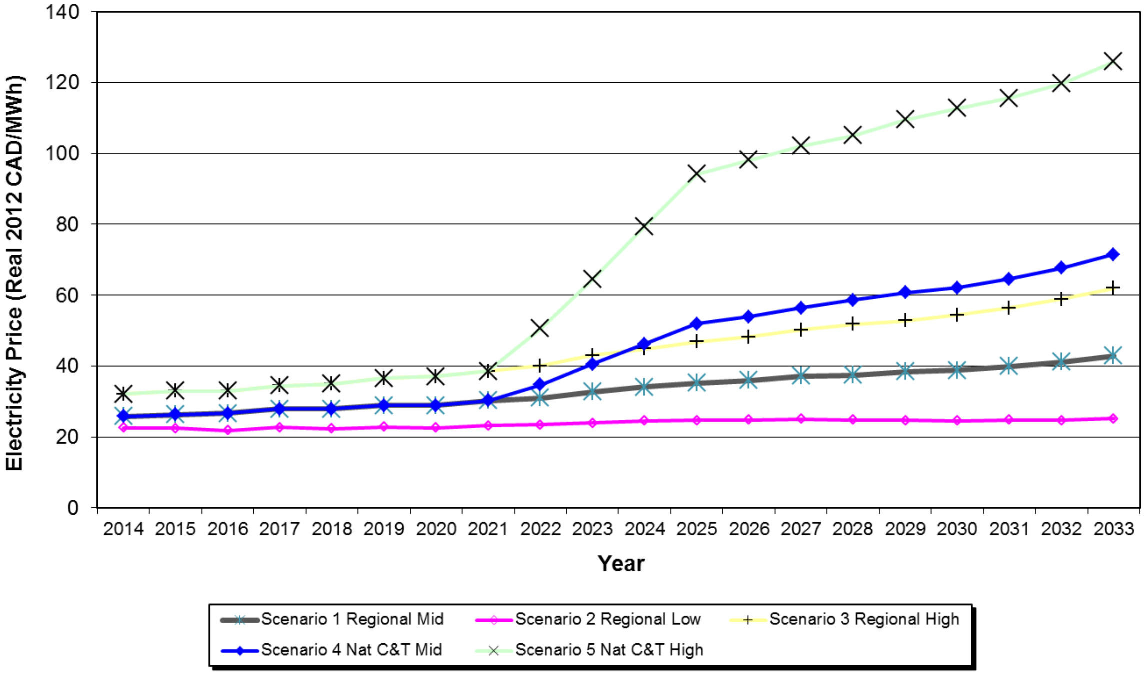


Table 5-5 Electricity Price Forecasts by Market Scenario (Real 2012 US$/MWh at Mid-C)

Market Scenario	1	2	3	4	5	
	Mid Electricity Mid GHG (Regional) Mid Gas	Low Electricity Low GHG (Regional) Low Gas	High Electricity High GHG (Regional) High Gas	Mid Electricity Mid GHG (Region/Nat'l) Mid Gas	High Electricity High GHG (Region/Nat'l) High Gas	
2007	55.7	55.7	55.7	55.7	55.7	Historical
2008	62.9	62.9	62.9	62.9	62.9	
2009	33.9	33.9	33.9	33.9	33.9	
2010	33.5	33.5	33.5	33.5	33.5	
2011	23.2	23.2	23.2	23.2	23.2	
2012	18.6	18.6	18.6	18.6	18.6	
2013	21.8	21.8	21.8	21.8	21.8	
2014	25.0	21.9	31.1	25.0	31.1	Forecast
2015	25.5	21.7	31.9	25.5	31.9	
2016	25.8	21.2	32.0	25.8	32.0	
2020	28.0	21.9	36.0	28.0	36.0	
2025	34.2	24.0	45.4	50.3	91.2	
2030	37.6	23.8	52.7	60.1	109.3	

5.6.4 Discussion of Results

As Table 5-5 shows, there is a wide range of possible future electricity market prices, which is viewed as being appropriate for use in long-term electricity planning as there can be significant variability and volatility with electricity prices.

Scenario 1 is BC Hydro's reference scenario and reflects current market conditions being prolonged over the long term. Currently there is an energy oversupply in the WECC due to:

- Slower electricity demand growth since the 2008 recession
- Increases in clean or renewable electricity generation driven by U.S. federal and state policies such as RPS and the U.S. tax incentives discussed in section 5.8.2

Scenario 1 aligns with the Northwest Power and Conservation Council's Mid-C electricity price forecast 'No Federal CO_2 Policy' scenario.[51] In interpreting these results, it is important to note that BC Hydro's electricity price forecasts are based on spot market price forecasts, and do not necessarily reflect the cost of building new supply. In addition, they indicate yearly averages and do not show seasonal variability that is embedded in the forecast details.

5.7 Market Scenario Weightings

5.7.1 Introduction

Weighting factors are used in the IRP to assign a relative probability to each Market Scenario and are part of the overall modelling and risk analysis process described further in Chapter 4. There have been some significant and important developments to the policy and market context over the last year:

- Long-term natural gas prices continue to be low due to shale gas reserves and advancements in gas extraction technology (section 5.3)
- Slower implementation of U.S. national and regional GHG policies and regulations (section 5.4)
- Changes to California's RPS requirements (section 5.5)
- Lower electricity demand growth since the 2008 recession (section 5.6)
- Oversupply of renewables in WECC due to U.S. tax incentives (section 5.8)

The process of developing the weighting factors, the results and the process used to update the weighting factors are described in the following section.

[51] Northwest Power and Conservation Council's (**NPCC**), Draft Sixth Power Plan Mid-Term Assessment Report; http://www.nwcouncil.org/library/2012/2012-13.pdf. NPCC is a regional organization (Idaho, Montana, Oregon and Washington) that develops a 20-year regional power plan to balance energy and environmental needs. Mid-C electricity prices under the NPCC's 'Delayed Federal CO_2 Policy' scenario return to a $50/MWh to $60/MWh level from 2020 onward.

5.7.2 Market Scenario Weighting Factors

In 2011, BC Hydro worked with B&V to assign relative likelihoods to each of the five Market Scenarios.[52] This exercise considered the relative likelihood of the whole scenario and not the underlying variables or drivers. These estimates were developed using a Modified Delphi method, which systematically assists experts to reach a consensus on the relative probabilities.

In developing the 2013 Market Scenarios, BC Hydro assigned weighting factors to the scenarios. BC Hydro reviewed the four variables associated with the five Market Scenarios and ranked the scenarios from most likely to least likely, as follows:

- Market Scenario 1, which is based on Ventyx's spring 2012 reference forecast, is the most likely scenario
- Market Scenario 5 (high electricity price, high GHG price due to national government GHG regulation and high natural gas price) is the least likely based on shale gas development and the stalled development of GHG regulation at the U.S. federal level (with the resulting slower development of Canadian federal GHG regulation given that the Government of Canada's position that it will harmonize GHG regulation with U.S. federal government actions)
- Market Scenario 4 is not likely as it assumes a national GHG cap-and-trade program
- Market Scenarios 2 and 3 assume regional as opposed to national GHG cap-and-trade regulation. BC Hydro determined that Market Scenario 2 was more likely than Market Scenario 3 as lower natural gas prices would are expected to prevail over the IRP planning horizon.

The results are shown in Table 5-6.

[52] Likelihoods are not to be taken as the probability that one scenario will occur. Given the infinite ways market prices can unfold, the chance that any one of these scenarios will exactly occur is essentially zero. The use of the term 'relative likelihood' emphasizes that these judgments are made in relation to the other scenarios.

Table 5-6 Final 2012 Updated Relative Likelihoods[53]

Market Scenario	1	2	3	4	5
	Mid Electricity Mid GHG (Regional) Mid Gas	Low Electricity Low GHG (Regional) Low Gas	High Electricity High GHG (Regional) High Gas	Mid Electricity Mid GHG (Region/Nat'l) Mid Gas	High Electricity High GHG (Region/Nat'l) High Gas
Relative Likelihood	60%	20%	15%	4%	1%

5.8 Electricity Export

5.8.1 Introduction and Definition of 'Export'

The *CEA* in subsection 2(n) sets an objective for the province to "be a net exporter of electricity from clean or renewable resources with the intention of benefiting all British Columbians and reducing greenhouse gas emissions in regions in which British Columbia trades electricity while protecting the interests of persons who receive or may receive service in British Columbia". Sections 3(1)(d) and 3(1)(e) of the *CEA* set out the following requirement for what the IRP must include with respect to meeting this objective:

> (d) a description of:
>
> (i) the expected export demand during a defined period
>
> (ii) the potential for British Columbia to meet that demand
>
> (iii) the actions the authority has taken to seek suitable opportunities for export of electricity from clean or renewable resources
>
> (iv) the extent to which the authority has arranged for contracts for the export of electricity and the transmission or other services necessary to facilitate those exports
>
> (e) if the authority plans to make an expenditure for export, a specification of the amount of the expenditure and a rationale for making it.

[53] Ventyx weights their Low Gas Scenario (input into Scenario 2), Reference Scenario (input into Scenario 1) and High scenarios (input into Scenario 3) in isolation with a 10%, 80%, 10% weight respectively.

These requirements are addressed in this chapter.

Traditionally, BC Hydro built its system to meet domestic electricity demand, while Powerex conducted trade using surplus capability in the BC Hydro system, as it existed from time to time, which provided benefits such as lower electricity rates and hundreds of millions of dollars of Provincial revenue. This trade activity has, and continues to result in, both imports and exports of electricity. These trade-related exports are not the focus of the *CEA*'s objective to be a net exporter of electricity, and BC Hydro and Powerex will continue this trade activity to the benefit of BC Hydro's ratepayers and the Province.

The *CEA*'s reference to exports is in the context of developing new clean or renewable generation resources in B.C. beyond domestic need for the express purpose of exporting the electricity from those resources to electricity markets outside of B.C. Therefore, it is necessary to distinguish between:

(a) Exports that arise through the sale of surplus capability and the firm and non-firm energy associated with acquiring resources to meet domestic load self-sufficiency requirements; versus

(b) Exports that come from the acquisition of additional generation resources and investment in transmission for the purpose of selling electricity in the U.S. over and above the self-sufficiency requirements. The use of the term 'export' in the balance of this section refers to this type of export.

5.8.2 Market Opportunities

There are two types of potential export market opportunities: the spot electricity market and the RPS market. The following sections describe these market opportunities which are defined as:

- **Electricity (Spot) Market** – refers to the generation and usage of all electricity that does not have to meet a RPS. It is and will continue to be the largest market for electricity. There are currently no restrictions on the type of generation that can be used to meet demand in this market. It is served by utilities' self-generation, long-term contracts and spot market transactions.

- **RPS Market** – Section 5.5 describes the RPS markets in the WECC U.S. states

5.8.2.1 Electricity Market

Opportunities in this market are governed by the overall supply/demand balance and the price of natural gas. Because of North American shale gas developments, natural gas prices have come down in recent years, and as per BC Hydro's Scenario 1 mid natural gas price forecast will be about $4/MMBTU over the next decade, which equates to about $30/MWh power prices as described in section 5.6. With the exception of Alberta, the combination of the economic recession and the addition of electrical generation for RPS/renewable compliance purposes in neighbouring jurisdictions have resulted in an excess supply of generation with reserve margins at relatively high levels when compared to the past decade. This keeps prices relatively low due to capacity shortfalls. Lower prices generally imply lower spreads between market regions than has been experienced over the past decade.

There are two areas where market opportunities may arise. First, the increase in non-dispatchable power generation (i.e., wind) to the grid has the potential to increase price volatility. Recent experience has shown that prices can be driven to low levels, even into negative market prices. This can create a daily spread (i.e., buying power during an hour when prices are lower and selling it back when prices are higher) and regional spread (i.e., buying in a lower-priced region and selling to a higher-priced region). However, these market opportunities now typically are of shorter duration and are much less predictable than in the past due to lower natural gas prices and other market conditions. Real-time market intelligence systems and the ability to transact quickly are key to capturing opportunities in this area. These opportunities relate more to system capacity and flexibility as opposed to outright energy sales. In a depressed market price environment, having a surplus energy position will reduce system flexibility and make it difficult to avoid selling into low-priced periods.

The second opportunity is associated with the potential passage of any U.S. federal or WCI climate change legislation which aims to reduce GHG emissions and/or establish a price on CO_2. The value of these opportunities will be affected by the specifics of the rules, but generally would involve market sales of clean or renewable energy to parties using GHG-intensive energy (e.g., coal) to displace such non-clean resources. While this carbon market opportunity is more aligned with a surplus energy position, there remains a large policy uncertainty. As discussed in section 5.4, U.S. federal GHG legislation appears to be stalled; there remains uncertainty regarding EPA proposals to regulate GHG emissions of new power plants; and the regional WCI is not proceeding as originally envisioned. That said, as discussed earlier, California has implemented cap-and-trade in the electricity sector with electricity prices rising by about $6/MWh to $7/MWh since implementation, taking into consideration the value of the carbon market in California.

In addition, any market opening for sales of clean or renewable capacity-backed resources is expected to be quite limited given price competition from CCGTs which are lower priced than B.C.'s clean or renewable resources. Finally, the types of clean or renewable resources that B.C. is best suited to provide to this market (e.g., large and small hydro) are not the types of resources that are currently acceptable in the RPS market as described in section 5.5.2.

5.8.2.2 RPS/Renewable Compliance Market

Given the current market conditions for electricity and the cost of B.C.'s clean or renewable resources set out in Chapter 3, the expectation is that exports beyond B.C.'s self-sufficiency energy would be sold into the RPS compliance market. In general, this market is driven by compliance concerns rather than broad economic competition and as a result prices tend to be higher as they reflect the full cycle costs of new construction. There is also more room for deal customization in the RPS/compliance market than in the regular electricity market.

However, there are a number of hurdles. First, as described in sections 5.5.1 and 5.5.2, hydroelectric resources are generally not eligible for RPS purposes. As discussed in section 5.5.3, California remains by far the largest market for renewable compliance resources due to its sheer size and the aggressiveness of its RPS targets. However, California utilities are constrained in procuring certain B.C.-based resources such as run-of-river hydro which are not recognized as “renewable”. Much of the electricity generated in B.C. is not eligible to be sold into this market. Approximately 50 per cent of the contracted energy volumes for EPAs awarded in BC Hydro’s Clean Power Call were for run-of-river projects. Much of the surplus energy arising from B.C. self-sufficiency is not eligible to be sold into this market segment.

A second key issue is U.S. government tax incentives. Canadian resources are at a significant cost disadvantage of at least 25 per cent due to various U.S. tax credits and accelerated depreciation programs. The U.S. federal government offers:

- Investment Tax Credit of 30 per cent of the initial investment to solar developers
- Production Tax Credit of 2.1 cents per kWh to wind and geothermal developers
- Accelerated depreciation under a five-year ‘Modified Accelerated Cost Recovery System’

Canada offers accelerated depreciation on a less aggressive basis, and does not have a comparable tax credits. While the U.S. tax incentives are set to expire over the next few years, the U.S. Congress has acted several times in recent years to retain them. Reduction of these incentives would improve the competitiveness of B.C. clean or renewable energy in U.S. markets.

A third key issue is competition from other renewable resource producers within the WECC region. Certain states such as Wyoming and Montana have good wind regimes which, coupled with the tax credits and a small local demand, create a very price competitive pool of resources located relatively close to the main RPS market in California. However, these states lack integration capability and appropriate transmission infrastructure. Furthermore, there has been an oversupply of wind energy in the Pacific Northwest in recent years due to federal U.S. tax incentives. Within California, significant efforts have been made by state agencies to streamline siting and permitting of solar facilities to take advantage of U.S. federal stimulus funding. Compliance filings by the major California utilities show a significant portion of future RPS demand will be met by in-state solar developments. Given the relative immaturity of this market segment, there is still a relatively higher attrition and/or cost risk associated with these solar projects.

5.8.3 Demand for Clean or Renewable B.C. Resources

BC Hydro retained B&V to examine the market competitiveness and acceptance of B.C. clean or renewable energy products in the markets of California, Washington, Oregon and Alberta. B&V's report is attached as Appendix 5D. B&V assessed the potential demand for renewable energy to meet both RPS requirements, as well as carbon markets in Alberta and the U.S. The competitiveness of B.C. clean or renewable energy products was also tested against several market and product sensitivities using B&V's Renewable Energy Market model.

5.8.3.1 Demand in Export Markets

The B&V study assessed the potential demand for renewable energy in three key U.S. states with RPS requirements, as summarized in Table 5-7.

Table 5-7 RPS Market Potential

	RPS Target	Flat Growth (GWh)	High Growth (GWh)	Restrictions Impacting B.C. Renewable Resources
California	By 2020	39,000	80,800	• Require direct connection or dynamic transfer to the California balancing authority for Category 1 producers • Firmed and shaped energy is required for Category 2 producers • Eligibility of B.C.-based run-of-river hydro subject to CEC review
Washington	By 2020	6,000	8,800	• Delivery on a real-time basis
Oregon	By 2025	3,500	8,100	• Bundled RECs must be U.S.-sourced; unbundled RECs subject to utility cap

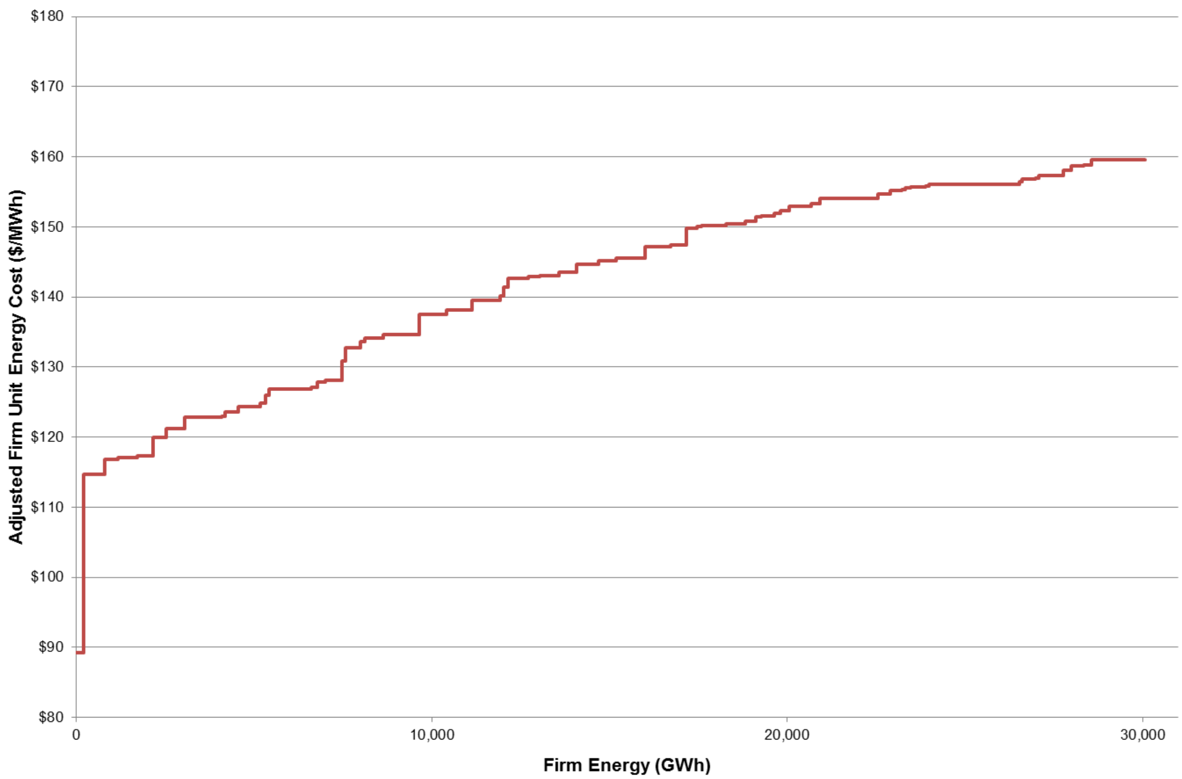
5.8.3.2 Availability and Cost of B.C. Renewable Resources

The market competitiveness analysis in the B&V report was performed assuming that the lowest cost potential resources identified in B.C. are available for export before domestic use.

Chapter 3 of the IRP provides a summary of BC Hydro's assessment of the resource option potential in B.C. Based on this assessment, Figure 5-9 provides an energy supply curve for identified clean or renewable resources in B.C. The relevant energy price for export purposes is a function of BC Hydro's domestic energy needs under various load scenarios. For the high incremental load scenarios (mid gap without LNG but including the Fort Nelson load scenario as described in Chapter 2 and the general electrification scenario discussed in Chapter 6), BC Hydro's energy gap could be about 12,000 GWh[54] by F2033. Accordingly, the supply curve suggests that renewable resources developed explicitly for export markets would have a firm adjusted unit energy cost (**UEC**) at point of interconnection (i.e., before any transmission-related costs) in excess of $140/MWh.[55]

[54] The high incremental load scenario would be higher if renewable energy is used to serve future LNG loads.
[55] B&V's market competitiveness report used BC Hydro resource option data from 2010. Since then the unit energy cost for clean or renewable energy in B.C. has increased.

Figure 5-9 Supply Curve for Potential Clean Resources in B.C.



5.8.3.3 Transmission Constraints

Transmission capacity from within B.C. to destination markets is required to export clean or renewable energy. Current transmission lines are fully subscribed by firm transmission rights holders. Furthermore, the availability of non-firm transmission capacity has been dwindling due to increasing competition from power producers. BC Hydro expects that it will be able to manage the export of available electricity, however transmission limits could reduce the economic value received for those exports.

5.8.3.4 Competitiveness of B.C. Resources

The demand for B.C. clean or renewable resources and their relative competitiveness in export markets can best be ascertained by referring to the "Summary of Findings" in the B&V report, as follows:

“Demand for BC resources would increase if: (i) overall demand for renewables in the western interconnection increases or, (ii) the relative competitiveness of BC resources improves. The overall demand may increase if there are changes in one or more market conditions. Similarly, there are a number of factors that could change the relative competitiveness of BC resources.

Market Conditions

- Certain scenarios show that REC prices may increase higher than currently established ACP [Alternative Compliance Payment] levels if either (i) the PTC goes away, (ii) energy prices are relatively low, or (iii) there is a strong RPS demand due to high load growth. In some states, utilities have the option to pay the ACP in lieu of procuring renewable energy or do not have to procure renewable energy if the rate impact limit is exceeded. In order for renewable energy projects to be built under these particular market conditions, there must be strong political will by states to achieve RPS targets at any cost by setting aside ACP caps or rate impact limits.
- If BC Hydro could demonstrate direct connection to California balancing authorities or be able to dynamically transfer more energy, the province would qualify for a larger market segment, instead of just the firmed/shaped product portion. This could be achieved through building additional transmission capacity or increasing the utilization of existing transmission to the U.S.[56]
- Limitations on the amount of shaped/firmed products that can be sold into markets like California need to be lifted, though this alone does not determine whether BC projects can be competitive with projects from Washington and Oregon state that are also supplying shaped/firmed products to California.

Relative Cost of BC Resources

- The scenario in which U.S. projects receive no special tax incentives provides a level playing field for BC renewable resources compared to U.S. renewable resources. The ACP caps or rate impact limits currently in many of the RPS states would also need to be lifted or increased.
- Some higher class resources in Montana and Wyoming appear to be more attractive than wind from BC. Thus, in order for BC resources to

[56] Refer to subsequent discussion regarding a new transmission line in section 5.8.4.2.

compete, there needs to be a change in the assumptions about the costs of developing remote resources in Montana and Wyoming. For example, a lack of development of transmission capacity to deliver remote resources to load could make access to the very best resources in Montana and Wyoming more difficult or costly than expected.

- If the cost for solar PV [photovoltaic] projects after 10 years does not drop as significantly as assumed in the REM model and solar PV projects are not developed to the level modeled, especially in California, this would potentially be of benefit to the competitiveness of BC resources."

BC Hydro can try to sell REC-only products, though this market segment is expected to be highly competitive and much lower value, since there is no delivery requirement and it is limited to 10 per cent of the total RPS for California.

As for using BC renewables to address the carbon market in the U.S., there is considerable uncertainty as to how that will play out in the future since carbon markets in the west (including California) are either not well defined (outside of California) or details are still being developed (in California). Alberta will not be an export market for carbon offsets, given restrictions on imported offsets."

5.8.4 Export Activities and Actions

The following section describes a number of BC Hydro and Powerex export-related activities undertaken since the *CEA* was brought into force in 2010. Most of the activities have been terminated or deferred given unfavourable market conditions.

5.8.4.1 Anchor Tenant Transaction with PG&E

Powerex and Pacific Gas & Electric (**PG&E**) held discussions regarding the potential for a sale of approximately 4,000 GWh/year of RPS-eligible energy that would be the anchor transaction for the Canada-Northwest-California (**CNC**) transmission line running from a location near Castlegar in south-eastern B.C. to San Francisco, California. This transaction was abandoned given the changes in California's RPS eligibility as set out by the California Public Utilities Commission and in legislation (Senate Bill 2-1X), the current oversupply of RPS eligible renewable supply within the WECC and PG&E's success in procuring in-state RPS eligible resources.

5.8.4.2 New Transmission

The CNC transmission line would have allowed 1,500 MW to 3,000 MW of power to flow from B.C. to markets in the south. The CNC line was expected to cost in the $4 to $7 billion range and take eight to 10 years to permit and construct. This project was being pursued in partnership with PG&E and Avista Corp. Attempts were made to obtain Bonneville Power Administration to participate in the project but their support was not forthcoming. BC Hydro’s approach to developing the CNC line was contingent on the outcome of the anchor-tenant energy transaction with PG&E. In the absence of securing an energy deal, the transmission line becomes a significantly more risky undertaking. As a result, the CNC partners have abandoned the CNC project for the foreseeable future.

5.8.4.3 Firming and Shaping Transactions

Powerex has been pursuing various firming and shaping transactions to build a portfolio of renewable resources and services and customer relationships to advance its ability to make future sales. These can be stand-alone transactions or transitional sales to the PG&E anchor tenant transaction.

5.8.4.4 Low Carbon Energy Sales

California continues to push forward on implementing its GHG cap-and-trade program. Powerex has successfully obtained “asset controlling supplier” status from CARB for BC Hydro’s portfolio of resources. This results in a much lower carbon intensity for energy delivered into California from BC Hydro’s resources compared to “unspecified” resources. Electricity prices in California reflect the price of carbon thereby adding around $6/MWh to $7/MWh.[57]

[57] California ISO, Department of Market Monitoring, Quarterly Report on Market Issues and Performance (May 2013).

5.8.4.5 BC Hydro's Generation Regulation Tariff

BC Hydro is considering a Generation Regulation Tariff which would allow BC Hydro to be compensated for capacity required to respond to moment-to-moment variations in intermittent clean or renewable generation. The design of the tariff would seek to meet market requirements and not negatively impact BC Hydro's ratepayers consistent with the B.C. Government's directions under the *CEA*. Current market conditions have reduced the near-term need to have this tariff in place.

5.8.4.6 Policy Advocacy

BC Hydro and Powerex have been supporting the B.C. Government with its policy advocacy work with California. Consultants were retained to continue to advance B.C. interests regarding resource eligibility within California. Powerex continues to work with the Western Renewable Energy Generation Information System on the registration of renewable resources.

5.8.4.7 Ongoing REC Transactions

Powerex continues to engage in short-term REC transactions in the WECC. These transactions provide experience to understand and influence emerging markets such as the California RPS. Powerex also applied to the CEC to have the Dokie Wind power facility in B.C. certified as "renewable"; this certification is now in place ensuring that energy from this facility is now eligible to be sold in the California RPS market.

5.8.5 Conclusions

Since the enactment of the *CEA*, the prospects of export sales of clean or renewable energy in excess of that required to meet B.C. self-sufficiency requirements have diminished considerably. Further, the prospects of such sales are not expected to materially improve over the short to medium term. The reasons include a significant recent increase in renewable energy resources in the WECC, the persistence of tax incentives available to U.S. producers, and the enactment of RPS standards in potential markets, particularly California, that exclude many clean or renewable B.C. resources.

Table 5-8 summarizes how the four export-related elements contained in Section 3(1)(d) of the *CEA* have been addressed in this section.

Table 5-8 Meeting *CEA*'s Export-Related IRP Requirements

Required Section 3(1)(d) Description	How Met in the IRP?
(i) The expected export demand during a defined period	• The B&V report identified potential demand for 48,500 GWh to 97,700 GWh of RPS energy in California, Washington and Oregon • Additional carbon market opportunities may exist for B.C. clean or renewable resources to displace GHG-intensive electricity in the U.S. • Access to the RPS and carbon markets in the U.S. is constrained by out-of-state restrictions and energy delivery rules
(ii) The potential for British Columbia to meet that demand	• BC Hydro's resource options assessment identified a large potential for development of clean or renewable resources with an estimated firm UEC cost of at least $140/MWh at the point of interconnection • Ability to serve U.S. demand is subject to the availability and cost of transmission capacity • Competitiveness of clean or renewable B.C. resources is hampered by eligibility restrictions, U.S. tax incentives and competition from other energy producers in WECC that are closer to the prime U.S. markets
(iii) The actions the authority has taken to seek suitable opportunities for export of electricity from clean or renewable resources	• No further export-focused actions are warranted beyond those already taken to date • Conducted anchor tenant discussions with PG&E • Pursued development of CNC transmission line • Pursuing various firming and shaping transactions • Pursuing transactions that would benefit from cap-and-trade programs in California and B.C. • Considering a Generation Regulation Tariff • Supporting Province's policy advocacy in California • Engaging in short-term REC transactions in WECC to potentially influence emerging RPS markets
(iv) The extent to which the authority has arranged for contracts for the export of electricity and the transmission or other services necessary to facilitate those exports	• BC Hydro pursued contracts for the proposed CNC transmission line and an anchor tenant transaction with PG&E; these initiatives have been abandoned due to changes in RPS eligibility in California and the current oversupply of eligible renewable energy within WECC

BC Hydro concludes that, aside from monitoring, there are no actions BC Hydro should be taking because there are no suitable opportunities for the export of electricity from clean or renewable B.C. resources for the foreseeable future.

Consequently, BC Hydro does not perceive, at this time, any value in continuing to investigate and develop potential market opportunities for export sales. In response to section 3(1)(e) of the *CEA,* current market conditions do not warrant expenditures for export, and no expenditures are planned as part of the Recommended Actions.