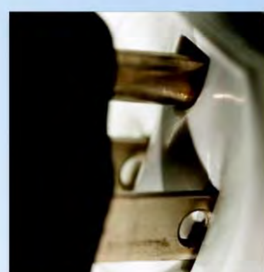
Multi-Client Study of
Potential Impacts on the AB Electricity Market of Policy Implementation Choices for the
Climate Leadership Plan

(Abbreviated Summary Report)



Prepared by:
EDC Associates Ltd.
#310, 505 - 8th Avenue S.W.
Calgary, Alberta, Canada T2P 1G2

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Disclaimer

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The EDCA Climate Leadership Multi-client Study could not have been successfully undertaken without the generously offered support, time, data and feedback from the Active Participants Steering Committee from a cross-section of load, coal, gas, wind, solar and biomass generators and implementing agencies.

EDC Associates Ltd.

#310, 505 - 8th Avenue S.W.
Calgary, Alberta, Canada T2P 1G2

www.EDCAssociates.com

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Project Background

Climate Leadership Plan

On November 22, 2015, the Alberta government released its Climate Leadership Plan ("CLP"). The CLP establishes a new provincial framework for addressing Greenhouse Gas (GHG) emissions in the Alberta electricity market. The Climate Leadership Plan[1] and subsequent announcements have broadly outlined an intended set of regulations which would mandate elimination of coal emission by 2030, incent an increase in energy production from renewables by replacing two-thirds of retiring coal capacity with renewables (to achieve a target of "up to 30%" of generation[2]), apply a much more inclusive tax on carbon and create a new performance standard[3] framework for remaining generation. The performance standard ("good as best gas") significantly increases GHG compliance costs for coal and reduces those compliance costs for combined cycle (CCGT) generation. The CLP replaces previous provincial initiatives or, for coal retirement dates, supersedes federal initiatives back to 2002.

Study Objective

The CLP also declared the government's intention to engage in further stakeholder consultations prior to implementation. This multi-client study was commissioned to provide an independent, industry vetted, quantitative assessment to help inform the government and its agencies during the policy implementation phase about the impacts and unexpected consequences of various elements of policy implementation, most of which are not yet precisely specified but are expected to be finalized by year-end 2016. The impacts of the CLP will depend on the final settings for each of several key policy elements in combination.

The study was sponsored by a Steering Committee representing 10 generators (over 75% of generation production, including all types of renewable and thermal generation (coal, cogen, combined cycle, simple cycle, hydro, wind, solar and biomass), 10 large customers who comprise 40% of the electricity consumed in Alberta, two transmission facility owners and an implementing agency (see Table 1 below and further detail in Appendix 1). This Steering Committee ranked the following as the most important objective[4] of the study:

"Prove/disprove that at least one path to success exists, a mutually acceptable compromise between four characteristics: affordably low all-in electricity costs, significantly lower emissions, acceptable reliability, and an acceptably attractive electricity and general investment climate."

Table 1 – List of Active Participants

Generators		Loads	Others
ATCO#	Naturener	Alberta Direct Connect Consumers* Association (ADC)[5]	**Transmission**
Canadian Solar	TransAlta#	Alberta Pacific Forest Industries*	**Facilities Owner**
Capital Power	TransCanada#	Suncor*	AltaLink
Enmax	Powerex		**Agency**
		*#also TFO *Also Major Generators*	AESO

The study also identifies other combinations of policy implementation choices that might have negative impacts on the interests of one or more of the constituencies and the integrity of the market .

[1] Authored by UofA Professor Andrew Leach and informed by over 500 submissions to the Climate Change Panel and various industry discussion group meetings, published Nov. 20, 2015. http://www.alberta.ca/documents/climate/climate-leadership-report-to-minister.pdf

[2] The precise definition is still uncertain. The 30% could be based on total fleet capacity or total fleet production, yielding very different amounts.

[3] Based on "good as best gas" emissions intensity

[4] Full ranked list of target objectives in Detailed Summary

[5] ADC's membership is composed of Alberta Newsprint Company, Dow Chemical Canada ULC, ERCO Worldwide, Lehigh Inland Cement, MEGlobal Canada Inc., Millar Western Forest Products Ltd, Praxair Canada Inc., Sherritt International, and West Fraser Timber.

Key Findings

The study of 57 different policy implementation combinations shows that each scenario improves or harms each of four metrics (emissions, costs, reliability, investor considerations) in different directions, but no one combination improves all four measures at the same time. The Key Finding in this Summary version of the study focuses on three main policy implementation variables (the "Big Three", explained in detail later):

1) the shape of the accelerated coal retirement schedule (Cliff, Moderate). The "Cliff" case presumes the same coal retirement schedule as the federal regulations until 2030, at which time all remaining coal is retired. The more accelerated "Moderate" case retires about 2 coal units per year, in vintage order.

2) the ultimate targeted 2030 level of renewables (4,200 MW vs. 7,200 MW)). Another hypothetical case, not one envisioned by CLP, would have the same coal retirement schedule, but would let pure market forces determine what generation was built, assumed for this case to be CCGT, the so called "Swap for Gas" case.

3) the degree of correspondence in timing of coal retirements vs renewables (matched ("linked") at 67% of coal vs. leading ("delinked") at 350 MW or 600 MW/year to achieve 4,200MW or 7,200 MW respectively)

This study quantifies the inherent trade-offs between emissions, costs, reliability and investor considerations under different policy implementation choices, yielding the following general conclusions:

- **Targeting 4,200 MW of renewable additions, timed so as to replace no more than 2/3 of the capacity of the coal units retired by any given date (either the "Cliff" or "Moderate" case) could result in a balance between electricity costs, emissions reductions, reliability, and electricity investment climate.**
- **Costs in $ Billions.** Costs to Alberta and consumers for the CLP fall into four buckets: change in wholesale pool price commodity cost, renewable energy payments, increased transmission costs and coal owner transition costs.

Table 2 – Summary of Key Impacts (First 2 Metrics) (2032)

(Run) Scenario			Emissions		Costs (2017-2032 Only) *		
Retirement Schedule	2030 Renewables Target	Pace of Renewables (MW/Yr)	Cumulative Mt	ΔMt from Pre-CLP	Δ$B from Pre-CLP (RECs + Trx)	Δ$/ΔMt	$/MWh
(1) Federal Regs	Pre-CLP 720 MW	FEOC (60)	815	-	-	-	-
(13) Moderate	Swap for Gas	FEOC (60)	704	111.1	$0.00	$0.00	$0.00
(14) Moderate	4,200 MW	Linked	677	137.6	$9.34	$67.88	$5.89
(19) Moderate	7,200 MW	Leading (600)	642	172.8	$20.09	$116.26	$12.60
(4) Cliff	4,200 MW	Linked	756	58.5	$5.19	$88.82	$3.28
(5) Cliff	4,200 MW	Leading (350)	733	81.3	$11.23	$138.16	$7.07
(12) Cliff	7,200 MW	Leading (600)	703	111.4	$20.38	$182.87	$12.76

** This table includes cumulative REC Payments and Transmission costs up to 2032, but* ***does not include any Coal Compensation Costs****, which could change by scenario, nor post-2032 REC residual payments of between $1-2 B/year, , then tapering linearly to $0 by 2050.*

 # The FEOC (Fair, Efficient, Openly Competitive) designation indicates that investments in capacity are added at a pace determined strictly by competitive market forces without the benefit of out-of-market incentives payments.

Even the most efficient combination of policy choices that meaningfully reduces emissions increases the cumulative delivered cost of electricity to the customer by $3.3-$5.9 Billion by 2030, plus $1 Billion/year for eight years, then tapering out to $0 by 2050 for Renewable Energy Credits (REC) payments alone, (disregarding costs of advancing transmission expenditures. Adding 7,200 MW of renewables would likely double the cost of REC payments, further advance transmission builds and reduce the system's resiliency to potential reliability threats.

The Swap for Gas option would require no REC payments but would still reduce incumbent coal margins, both pre-2030, by accelerating coal retirements and also post-2030, when the remaining coal plants would be stranded completely.

- **CLP implementation will also negatively impact net margins for existing generation** to varying degrees, with the extent of impact dependent on how the design elements are combined. These costs of the CLP to generators are not reflected in the costs referenced above, nor are any potential costs relating to potential compensation associated with the 2030 coal phase-out decision.
- **4,200 MW is a safer level.** If the 2030 renewables target is set at or below 4,200 MW and follows the 2/3 replacement objective, the market is not as stressed as in the 7,200 MW case and can be expected to sustain sufficient spontaneous new baseload capacity additions to ensure the currently specified electricity reliability threshold[6]. As that target moves towards 7,200 MW, price volatility will increase (more low priced-hours and more very high priced hours required to incent investment) and the reliability threshold is more likely to be challenged, but emissions reductions will be slightly larger.
- **Match renewables additions to coal retirements**. If renewable capacity additions are timed to 2/3 the pace of coal retirements, pool price and price volatility are less impacted. However, if the renewables additions significantly lead coal retirements, the number of $0/MWh price hours increases, price volatility increases and reliability starts to breach policy thresholds, the short and medium-term average pool price will fall and result in larger reductions to margins for incumbent coal generators, REC payments[7] will be higher, and the system will be less resilient to reliability events than if renewables growth is firmly linked to the pace of coal retirements, and, at higher renewables targets (especially run #12), emissions reductions will actually be lower (i.e. fewer emission reductions and higher cost) than a more balanced approach.
- **"Cliff" retirement schedule is cheaper.** If coal is retired according to the federal regulations until 2030, then all remaining coal is retired (the "Cliff" Scenario), the cost of RECs and transmission additions is lowest, the amount of carbon compliance revenues collected is higher, the margin reductions for incumbent generators are lower, with no coal transition costs for early shut down of pre-2030 coal units, but the tradeoff is a lesser reduction in emissions (Mt) because coal units remain in service longer. In contrast, as the retirement schedule is accelerated (i.e., Moderate case), emissions reductions are greater but market stressors increase (total costs to customers increase, carbon compliance revenues from coal units decrease, the wind discount increases, pre-2030 coal unit transition costs for accelerated coal shut downs increase and system reliability becomes increasingly less resilient to delays in construction of new facilities and periods of extended coincident generator outages). The Cliff scenario also presents a practical problem by packing more thermal capacity additions into fewer years at the end of the study period, increasing the risk of construction delays.
- **Even a one-year delay in additions can increase the likelihood of breaching Long Term Adequacy targets, even at the Moderate/4,200 MW of renewables level. This effect is even more pronounced at the 7,200 MW level**
- **The interaction of policy choices is complex**, with multiplicative effects and unintended and counter-intuitive consequences. This indicates the strong need for a dynamic, institutionalized implementation process that monitors outcomes against a deliberate, measured plan with prescribed contingencies, should the future unfold in unpredicted ways.

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[6] The AESO Long Term Adequacy rule sets a target level of reliability of one hour of system-wide outage in 10 years, or any equivalent combination of magnitude and duration that leads to approximately 800 MWh/year of lost load. This is similar to standards in other North-American jurisdictions.

[7] Renewable Energy Credits (REC) are proposed government mandated out-of-market payments to developers of renewable generation. Developers would offer to build subject to receipt of those credits, whose price would be set at an auction, moderated by the AESO. Those payments would be a source of revenue to wind developers but would be a cost to the CLP program and flow through to commodity prices.

- **Investor considerations are important.** The Alberta electricity market will need at least 11,000 more MW of generation capacity by 2030 (over $25 Billion of new capital investment) to meet retirements and demand growth. Most of this will be provided by private investors, who will seek policy certainty and stability, a recurring theme from all the participants throughout this process. Increased policy risk is eventually reflected in high cost of capital. This includes both **policy** certainty, which should improve once the policies have been clearly laid out, and also **market** certainty, which will likely remain unresolved in varying degrees depending on the final policy choices. The more generation that is added with the support of out-of-market payments, the less certainty unsubsidized investors have of earning a reasonable rate of return on their energy-only investments.

Research Methodology, Sensitivities and Outputs

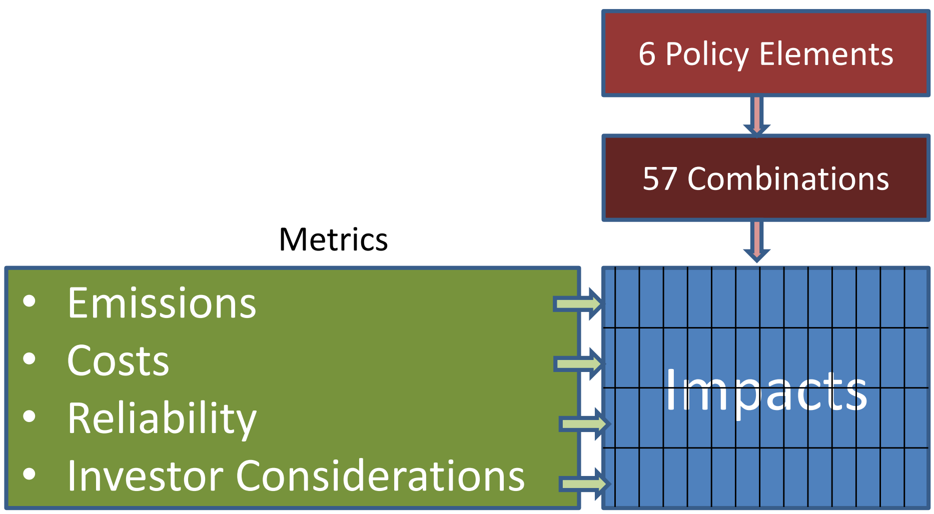
Two Reports

Given the complexity and breadth of the analysis, this analysis is reported at two different levels of detail. This Summary Report presents only the key findings and an abbreviated explanation of the methodology. The Detailed Report presents a broader spectrum of policy implementation variables, sensitivity testing and support materials.

Six Policy Element Settings Tested

Many of the policy implementation choices for specific design elements of the CLP are still not precisely specified. With so many uncertainties, EDCA extended its modeling capabilities (see Appendix 3) to analyze the effects of the CLP under different assumptions for six key policy implementation elements. For each element, EDCA mapped out a plausible range of different possible outcomes. Each element can be set independently at any number of different levels and the different policy elements could be combined in hundreds of different ways. It would not have been practical for EDCA to exhaustively test all combinations, so the Steering Committee chose a reasonably comprehensive sub-set of 57 different combinations of these six elements. The impacts for each scenario were quantified in terms of four main metrics (as illustrated in Figure 1).

Figure 1 – Quantifying Impacts



The six policy elements (and the ranges tested) are as follows:

1) the shape of the accelerated coal retirement schedule (Cliff, Moderate)
2) the fraction of retired coal that would be replaced by renewables (67% of Coal, less/more)
3) the degree of correspondence in timing of coal retirements vs renewables (matched ("linked") at 67% of coal/ leading ("delinked"))
4) the precise definition and ultimate renewables target penetration (4,200 MW, 7,200 MW)
5) the blend of renewables to be incented (percent of wind, solar, hydro, biomass, cogen)
6) auction design for RECs ($35 cap/no cap, fuel neutrality, new only/existing)

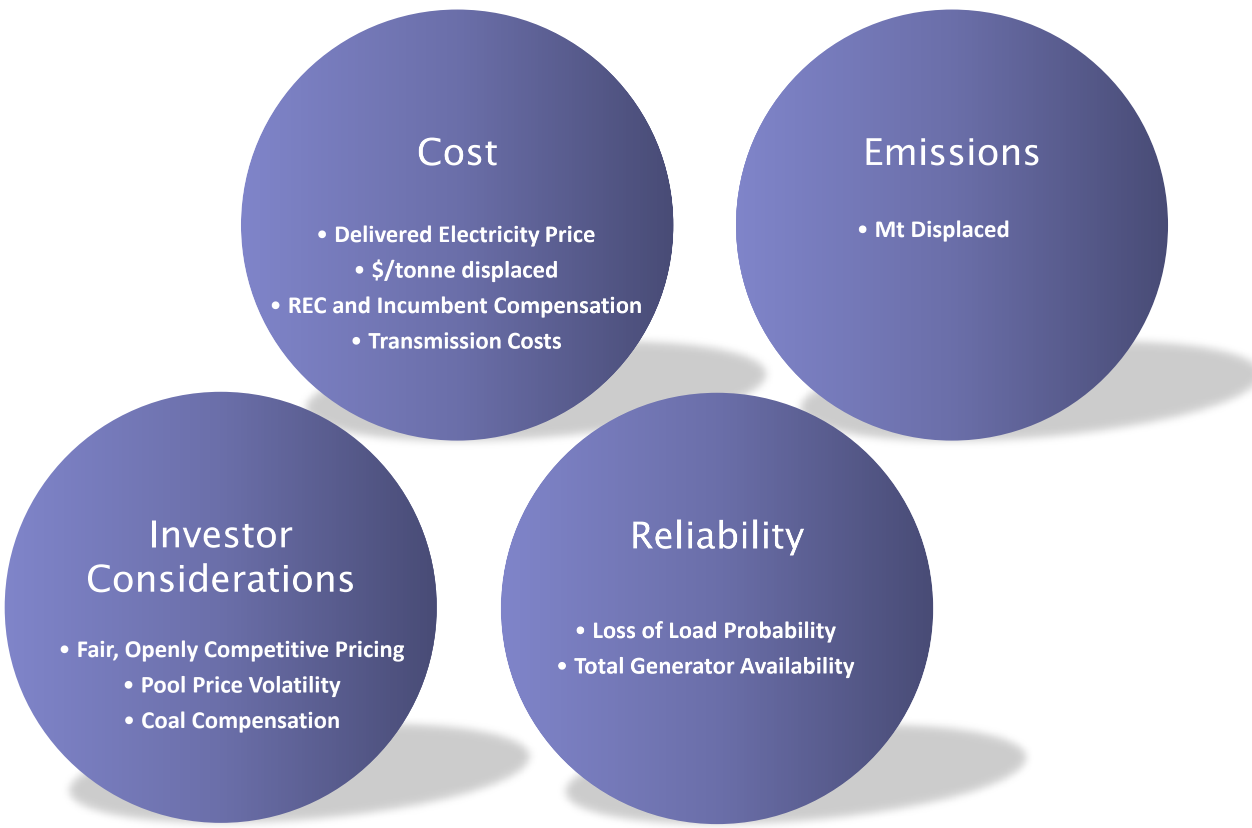
In addition, several non-policy input variables were also tested and are discussed after the Big Three (Elements 1, 2 and 3 above) findings are presented, including: alternate load and gas price forecasts, different blends of renewables, additional inter-tie capacity, less aggressive offer behaviour and alternative assumed levelized costs of various technologies (see detailed descriptions of all policy elements and exogenous parameters and their respective ranges in Appendix 2). The breadth of policy implementation choices tested should provide good coverage of a plausible range of potential final outcomes. Several other policy element choices were not tested (e.g., coal compensation options, "good as best gas" intensity, carbon price escalation rate, use of storage devices).

The exact combination of final policy implementation choices will be very critical to the costs and effectiveness of the CLP and the functioning of the competitive "energy-only" Alberta electricity market itself. Accordingly, in March 2016, EDCA undertook this multi-client funded study. This document presents the findings of that study. The analysis quantifies the potential long-term impacts of each different alternative formulation of the CLP in terms of the four key metrics.

Four Metrics

Each of these four main metrics is supported by about 25 sub-metrics (e.g., sub-metrics for the Cost category include pool price and volatility changes, Renewable Energy Credit (REC) costs, lost future margin of incumbent generators, and additional transmission costs). See Appendix 6 for a detailed list of metrics and sub-metrics.

Figure 2 – Four Main Metrics



Coal Phase-out Costs Not Included

One direct cost not taken into account in this analysis is any cost associated with compensation for the owners of coal-fired generation facilities whose operating lives are truncated as a result of the CLP induced 2030 coal phase-out. Further, the transition costs of the accelerated pre-2030 shut down of the older coal facilities contemplated in the Moderate Case are also not quantified and could be consequential. Issues regarding potential compensation, including the quantum and method of compensation, are the subject of ongoing confidential discussions with the coal owners and a Facilitator appointed by the government. **The estimated CLP implementation costs provided in this study are therefore incomplete in respect of that particular aspect of the CLP.**

Key Scenarios Studied

The Steering Committee directed which separate scenarios to run, including both simple single variable sensitivities (changing just one parameter) as well as scenarios that included combinations of several parameters. The tests were batched into nine main sensitivities. The first three batches are discussed in this report. The remaining seven batches are less impactful and are only discussed in the main report. The first three batches are:

1) **Base Scenarios**

"Pre-CLP": This scenario uses EDCA Q2-2016 Business as Usual case base variables, Specified Gas Emitters Regulation (SGER) parameters as revised in June 2015 (i.e., escalations but no switch to a performance standard), and the first 350 MW tranche of wind auction only. This model is used as a comparator to gauge and isolate the changes attributable to the CLP from projected changes that would have happened absent the CLP.

2) **Big Three Variables**

This case tested several combinations of the three most influential variables (rate of coal retirement, the ultimate renewables target and the match between coal retirements and renewables additions). It also explores the complex interactive effects (either exacerbating or ameliorating the effects of each other in combination). It tests for those combinations of policy variables that would have lesser impacts on the market and those combinations of policy choices that would create stresses for the market.

3) **Alternate Blends of Renewables**

This case tested the impacts of varying the blend of renewables incented, either wind, solar or biomass.

Big Three Variables - Ranges Tested

Three parameters have the largest impact on outcomes of the CLP implementation. This section explains the range of values for each individual parameter and describes the combinations that were tested in this study.

1. Coal Retirement Schedules

The CLP definitively mandates the retirement of the entire coal fleet by end of 2030. This truncates the lives of six coal units (Genesee 1, 2 and 3, Sheerness 1 and 2, and Keephills 3) whose mandated retirement dates under existing federal Capital Stock Turnover regulations extend beyond 2030. One large uncertainty of the CLP was that it did not specify the exact schedule of coal retirements for any of the coal generating units in Alberta with pre-CLP retirement dates between now and 2030. Three possible retirement schedules presented in this Summary Report (see Figure 3) are expected to represent a reasonable range of outcomes:

a) Federal Plan (Pre-CLP) Case (dark blue line, Figure 3)

In this sensitivity, the September 2012 Federal Climate Change Schedule would be followed across the full study period and beyond to 2061 (blue line is same as red line until 2030). The federal regulation had called for a much less aggressive timetable. By 2030, about 2,600 MW of coal would still be in service. Genesee 3 and Keephills 3 would be allowed to operate until 2054 and 2061 respectively.

b) Status Quo with Cliff at 2030 (solid red line)

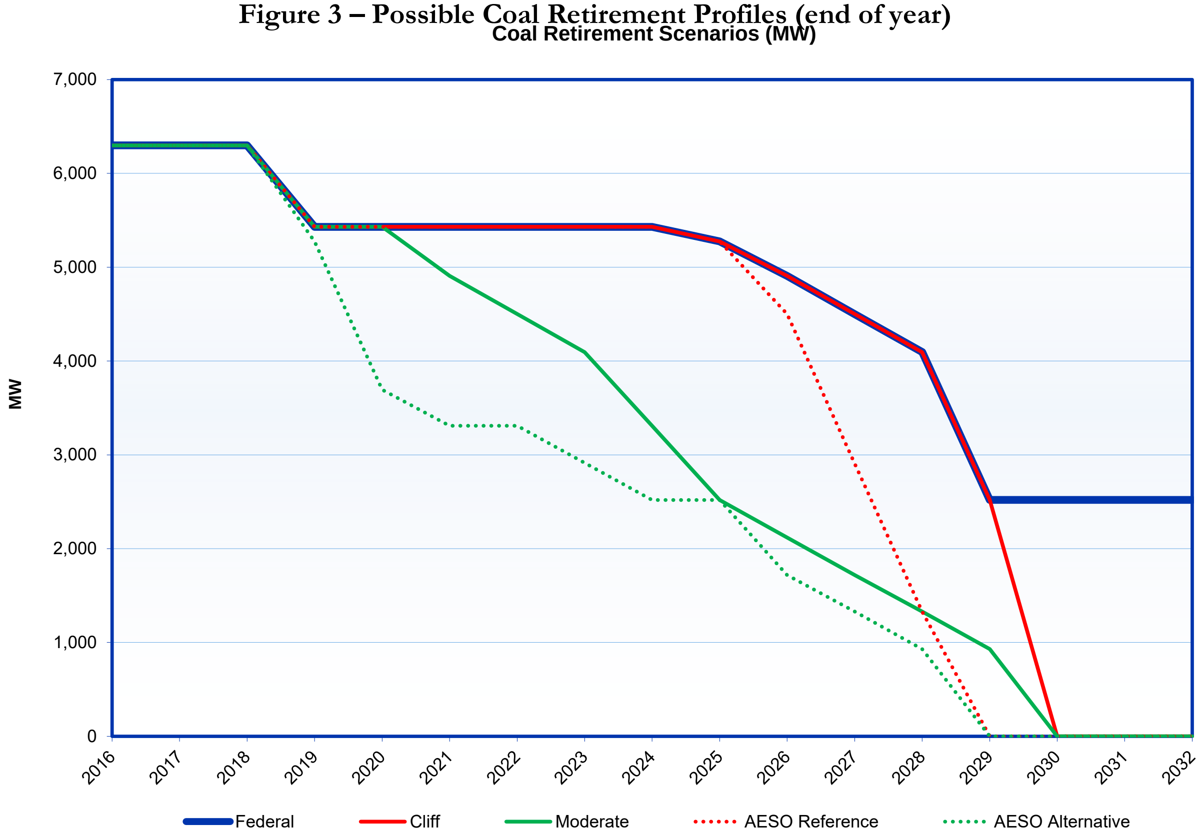
In this sensitivity, the September 2012 Federal Climate Change Schedule (blue line) would be followed until the end of 2030, after which all remaining coal (about 2,600 MW) would be simultaneously retired. In this and all other cases, units are assumed to retire at year-end.

c) Moderate Retirement Schedule (solid green)

For this third scenario, an arbitrary, somewhat more accelerated retirement path was chosen, wherein roughly 2 units per year are retired, in vintage order, beginning with Sundance #1 and #2, HR Milner and Battle River #3 at their federally prescribed lives (end of 2019). This is accelerated compared to the Pre-CLP Federal plan. The path, although fairly smooth, follows the lumpy nature of retiring generation. EDCA tested most of its runs using the Moderate (green) retirement schedule. The Cliff scenario (red) and the Moderate scenario converge after 2030.

Two other scenarios (dotted lines), both provided by the AESO in their Long Term Outlook, were tested but are only reported on in this main report. Other schedules could also easily be added or substituted.

Figure 3 – Possible Coal Retirement Profiles (end of year)



2. Ultimate Renewables Target

The CLP identifies two objectives with respect to the ultimate target renewable energy level. The first is to replace two-thirds of the capacity from retiring coal units with renewable energy capacity. The second objective is to achieve up to 30% of energy from renewable sources by 2030. The two objectives represent significantly different amounts of renewable energy capacity. The first objective represents roughly 4,200 MW of capacity, given the 6,300 MW of capacity of the existing coal fleet. The renewables capacity represented by the second objective would ultimately be dependent on Alberta system load in 2030, but for the purposes of this study was assumed to be 7,200 MW.

The consequences of the CLP are expected to be more severe the higher the ultimate goal for renewables is targeted. Three different levels of renewables additions were tested:

a) Pre-CLP: No additional renewables would be incented above the approximately 60 MW/year (a cumulative addition of 720 MW by 2030, as assumed in EDCA's Business as Usual case).
b) 4,200 MW of additional renewables by 2030: This level roughly corresponds to the two-thirds of the retired coal capacity suggested in the CLP and makes renewables (i.e. existing renewables plus new renewables) roughly equivalent to 30% of fleet capacity in 2030.
c) 7,200 MW of additional renewables by 2030: Raise total renewables target, roughly equivalent to 30% of energy production by 2030 and almost 45% of capacity.

On September 14, 2016, the provincial government announced more specifics about the CLP. To help achieve their newly announced "30 by '30" target[8], the government will support 5,000 megawatts of additional Alberta renewable energy capacity (wind, solar, biomass, hydro, geo-thermal, ocean energy are all eligible per the Natural Resources Canada definition). Further details on how the program will operate will be released later this year.

[8] "30 per cent of electricity used in Alberta will come from renewable sources such as wind, hydro and solar by 2030", September 14, 2016

3. Match Between Pace of Coal Retirements and Renewables Additions

Third, the pace of coal replacement with renewables is tested at three different levels (see Figure 4).

a) Pre-CLP Case: assumes renewables are added by pure market forces, whenever federal coal retirements or load growth allow (assumed by EDCA at about 60 MW per year)

b) Matched Pace (“linked”): Renewables are added at the prescribed rate of 67% of retiring coal capacity.

c) Leading Pace (“delinked”): Renewables are added much ahead of the 67% pace, either 350 MW/year (for the 4,200 MW 2030 target) or 600 MW/year (for the 7,200 MW target), even when the coal is following the slower federal regulations. (A “Lagging” pace was also tested but only in the Detailed Report).

Figure 4 – Alternate Renewables Additions Patterns

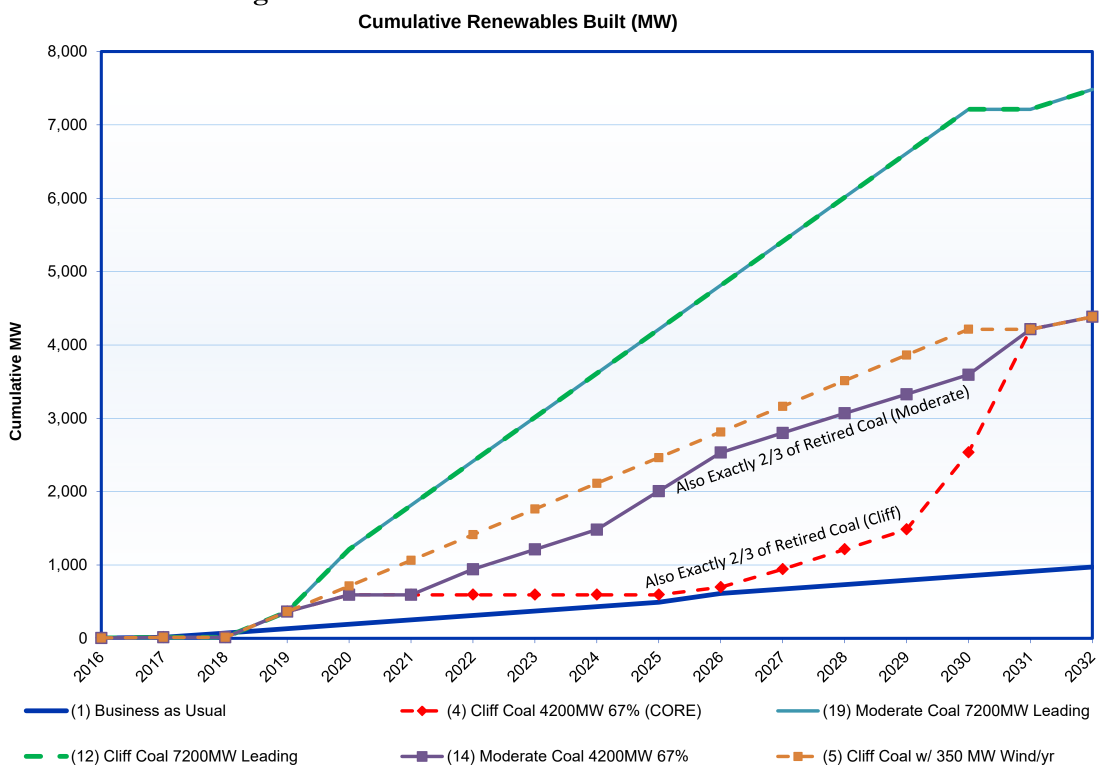


Table 3 shows the seven combinations that were tested, out of a possible 13. The numbers indicate the run number corresponding to that scenario (from the library of 57 total runs conducted for this study).

Table 3 – Big Three Scenario Matrix (Run #s)

Run Numbers Summary	Coal Retirement Schedule				
	FED Exactly	Fed, then Cliff after 2030		Moderate ~2 units/year	
Ultimate Additional Renewables	500 New MW (80 MW/Year)	4,200 MW (350 /Year)	7,200 MW (600/Year)	4,200 MW (350 /Year)	7,200 MW (600/Year)
Match of Renewables to Coal					
• Leading (350 or 600/Year)	n/a	5			19
• 67% of Coal (“Linked”)	n/a	4	12	14	
• BaU (Pre-CLP)	1			13	

Results

Big Three Policy Implementation Choices

The three policy implementation choices (the "Big Three") **with the largest impact on the first two metrics, Costs and Emissions,** are summarized in Table 4, compared to the Pre-CLP case: The impacts are then analyzed in detail for all four metrics.

Table 4 – Summary of Key Impacts (First 2 Metrics) (2032) (No Coal Transition costs)

(Run) Scenario			Emissions		Costs (2017-2032 Only) *		
Retirement Schedule	2030 Renewables Target	Pace of Renewables (MW/Yr)	Cumulative Mt	ΔMt from Pre-CLP	Δ$B from Pre-CLP (RECs + Trx)	Δ$/ΔMt	$/MWh
(1) Federal Regs	Pre-CLP 720 MW	FEOC (60)	815	-	-	-	-
(13) Moderate	Swap for Gas	FEOC (60)	704	111.1	$0.00	$0.00	$0.00
(14) Moderate	4,200 MW	Linked	677	137.6	$9.34	$67.88	$5.89
(19) Moderate	7,200 MW	Leading (600)	642	172.8	$20.09	$116.26	$12.60
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(12) Cliff	7,200 MW	Leading (600)	703	111.4	$20.38	$182.87	$12.76

* *This table includes cumulative REC Payments and Transmission costs up to 2032, but* ***does not include Coal Compensation Costs****, which could change by scenario, nor post-2032 REC residual payments of between $1-2 B/year until 2037, then tapering linearly to $0 by 2050.*
\# *The FEOC (Fair, Efficient, Openly Competitive) designation indicates that investments in capacity are added at a pace determined strictly by competitive market forces without the benefit of out-of-market incentives payments.*

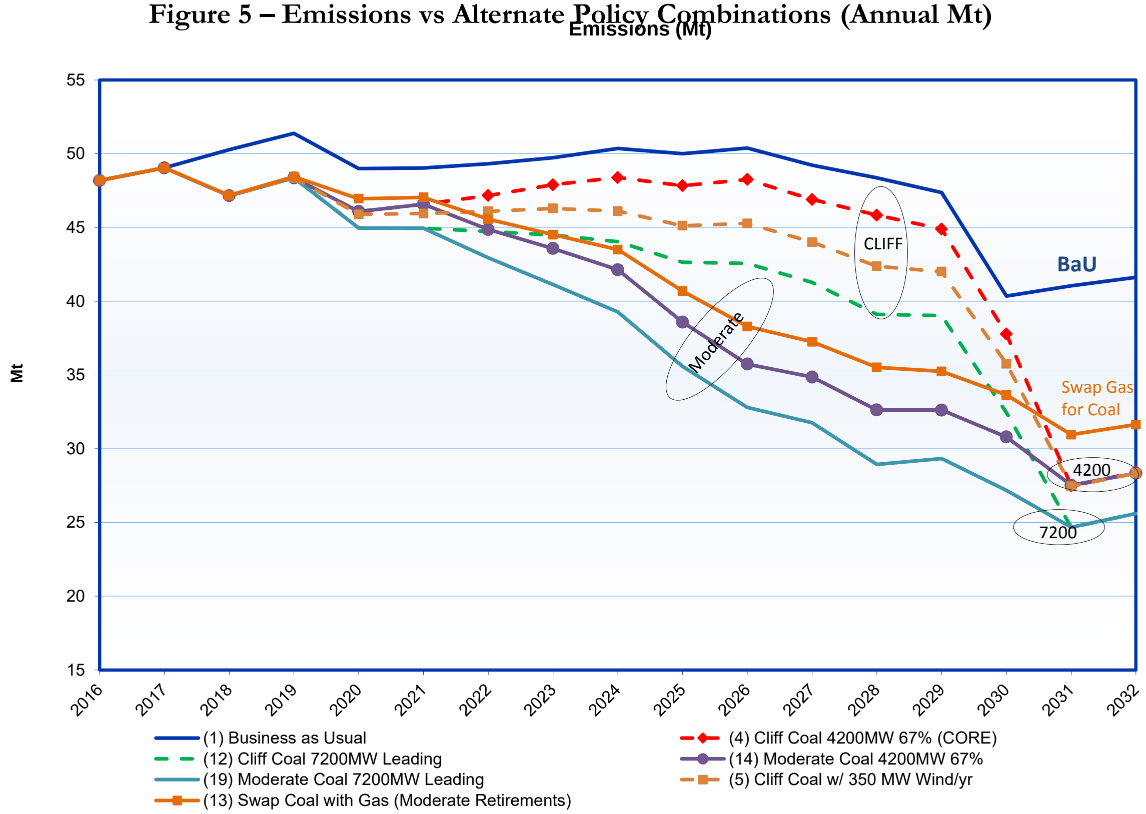
The tabulated results plus the results of the other two metrics are expanded and interpreted below, organized by the four key categories of metrics, with an embedded discussion of the difficult inherent tradeoffs between them:

Emissions Reductions

- **The existing retirement schedule from the September 2012 federal regulation ("Pre-CLP" Business as Usual case) would result in an annual reduction in 2030 of about 8 Mt/Year from 2016 levels, without any of the CLP mechanisms** (renewables incentives, incumbent compensation or additional transmission costs). Emissions would drop from the 50 Mt in 2018 to 42 Mt in 2031, after the final coal retirements (see dark blue line, Figure 5).
- **Using the accelerated Moderate coal retirement schedule** (i.e., faster than the Cliff pattern) **and paying out REC incentives to encourage 4,200 MW of new wind** (purple line) **would reduce emissions by a further 13 Mt/Year in 2030 and a cumulative reduction (2018-2032) of 137.6 Mt compared to the Pre-CLP case** (dark blue, Business as Usual).
- **Increasing the amount of new renewables from 4,200 MW to 7,200 MW would result in only a further 3.6 Mt/year in 2030** and additional cumulative emissions reductions of 35.2 Mt. (light blue line) Cliff scenarios have a lesser reduction in Mt in the front-end, but reach the same annual level of reductions in 2031.
- **Most (75%) of the reduction in emissions (10 Mt of the 13 Mt) is achievable without REC payments, simply by swapping gas generation for the retired coal** (orange line, Figure 5)**, not from incenting additional renewables.** EDCA ran this hypothetical sensitivity, one not even contemplated in the CLP, only to isolate the projected change in emissions attributable solely to the accelerated retirement of coal vis-a-vis the reduction in emissions created by paying incentives to renewables providers. It shows

that some optimized combinations with less non-renewable technologies could be constructed which yield similar reductions in emissions while minimizing costs, compared to the CLP.

Figure 5 – Emissions vs Alternate Policy Combinations (Annual Mt)



Costs

As more coal is retired, emissions fall mostly because there are fewer coal units, not because there are more renewables. By 2028, coal capacity under the Moderate retirement schedule is 40% of coal capacity in the Cliff case. Moving from 4,200 MW of renewables to the higher 7,200 MW target or adding wind faster (leading vs. matched) adds more $0/MWh offers to the merit order, causing slightly less coal to be dispatched, as evidenced by the 3-6% drop in capacity factor as wind target is increased or advanced. The faster coal is retired, the less time it sets hourly price, meaning it cannot pass through as much of its increased GHG compliance costs to the customer. Coal transition costs have not been included in most cost figures, so total program costs are well understated.

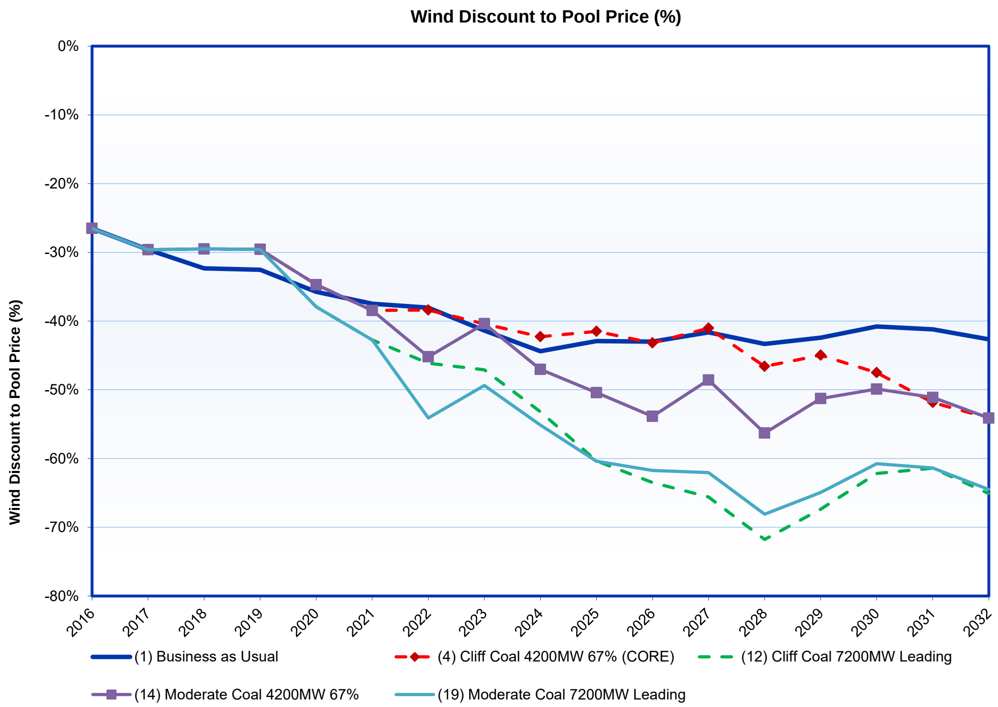
Table 5 – Summary of Cost Impacts

(Run#) Scenario			Additional Cost Sub-Metrics				
Retirement Schedule	2030 Renewables Target	Pace of Renewables (MW/Yr)	2027 Coal Capacity	2027 Coal Production (% Capacity Factor)	2027/2029% Coal as Price Setter 2018=57%	Δ$B from Pre-CLP (RECs + Trx)	Δ$/Δ Mt from Swap Gas for Coal
(13) Moderate	Swap for Gas	FEOC(60)	1,719	81%	11%/5%	0	-
(14) Moderate	4,200 MW	Linked	1,719	79%	13%/7%	9.34	$352
(19) Moderate	7,200 MW	Leading	1,719	74%	14%/8%	20.09	$325
(4) Cliff	4,200 MW	Linked	4,501	71%	40%/32%	5.19	$381
(5) Cliff	4,200 MW	Leading(350)	4,501	68%	39%/34%	11.23	$308
(12) Cliff	7,200 MW	Leading(600)	4,501	64%	37%/29%	20.38	$306

* *This table includes cumulative REC Payments and Transmission costs up to 2032, but does not include any Coal Compensation Costs, which could change by scenario, nor REC residual payments (post -2032) of between $1-2 B/year for eight years, then tapering linearly to $0 by 2050. Changes in average pool prices are minor and are not included.*

- **At the 4,200 MW renewables level, the annual costs of the program will be almost $1 Billion/year in 2030, or $68/displaced tonne, accumulating to $5-10 Billion (Cliff or Moderate cases respectively) by 2030, and will cost roughly $1 Billion/year for 8 years** (first 20-year contract starts in 2019, ends in 2038)**, then taper linearly down to $0 by 2050.** Cumulative costs for the 7,200 MW program would be double that at a $20 Billion and $2 B/year for 8 years thereafter, also tapering to $0 by 2050).
- **Moving from a Swap Gas for Coal strategy** (orange line, Figure 5, which saves 10 Mt) **to a renewables incentive strategy** (which saves an additional 3.3 Mt), **comes at an incremental cost of $265 per additional displaced tonne**, accumulating to about $7 Billion additional dollars from 2016-2030 and a continuing $1 Billion/year until the end of the first REC contracts in 2038 and tapering to $0/year by 2050 as the later vintages expire.
- **Increasing the amount of new renewables from 4,200 MW to 7,200 MW would result in only a further 3.6 Mt/year in 2030 at an additional $8.2 Billion cost or $235/additional displaced tonne** over the study period and a continuing $2 Billion/year until the end of the first REC contracts in 2038 and tapering to $0/year by 2050.
- **The level of REC subsidy needed to incent new renewables to build will need to be higher than the $35/MWh cap proposed in the report of the Climate Change Advisory Panel.** In the 4,200 MW cases, required RECs are projected to be in the $50-$70/MWh range, assuming 100% of the renewables are wind. In the 7,200 MW cases, required levels would be in the $75-$ $90/MWh range. Other renewable types (solar, biomass and hydro) will require even higher RECs than wind.
- **If the renewables target is set above 4,200 MW, the market becomes progressively more stressed.** At 4,200 MW (lines with markers, Figure 6), the market is not materially stressed. In tests at 7,200 MW (solid lines) or where the amount of new renewables gets too far ahead of the 67% substitution rate, especially in the 7,200 MW cases (green and light blue lines) several deleterious effects emerge. As wind penetration levels rise, the wind farms experience a deepening discount to pool price.

Figure 6 – Wind Discount at Various Retirement Schedules and Renewables Substitution



Over the last several years, if the market was averaging $70/MWh, wind units would only receive average revenues of about $47/MWh (a 32% "discount to pool price") since they drive down pool price in hours when they run the hardest. With the addition of 4,200 MW of new wind over the current 1,500 MW, that figure climbs to over 50%, and at 7,200 MW, over 60% discount to pool price.

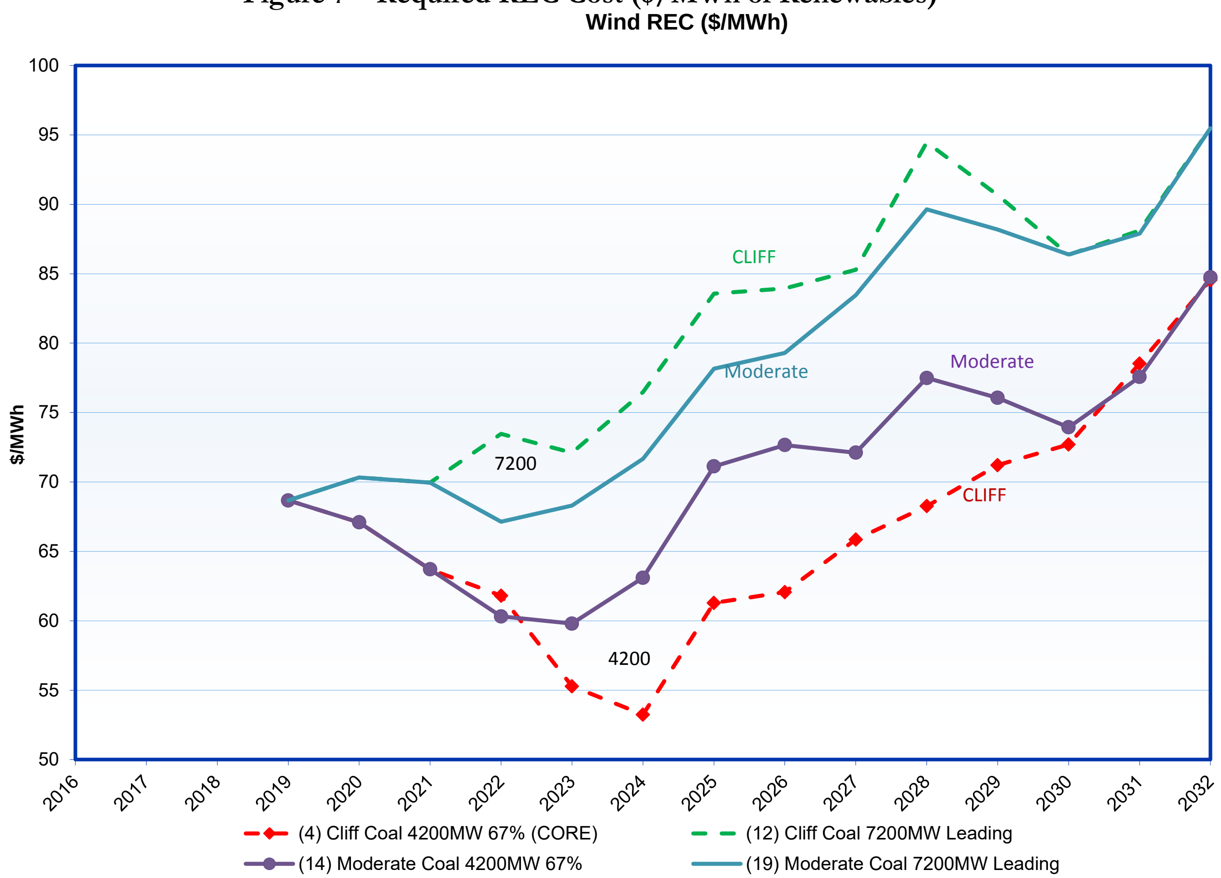
- **At 4,200 MW of renewables, the 2032 RECs will have to average around $50-70/MWh to incent that much renewables. At 7,200 MW of renewables, the level rises into in the $80-90/MWh range.**

Table 6 – Summary of Other Wind Related Cost Sub-Metrics

(Run) Scenario			Various Wind Sub-Metrics (2028)					
Retirement Schedule	2030 Renewables Target	Pace of Renewables	Pool Price ($/MWh)	Wind Discount to Pool Price (%)	Received Wind Price ($/MWh)	Wind REC* ($/MWh)	Cumulative Wind REC ($) (2016-2032)	% of Hours Settled at $0/MWh
(1) Federal Regs	Pre-CLP 720 MW	FEOC	$97.17	-43%	$55.08	$65.09	$0.00 #	0.0%
(13) Moderate	Swap for Gas	FEOC	$97.47	-47%	$52.12	$68.05	$0.00 #	0.0%
(14) Moderate	4,200 MW	Linked	$97.65	-56%	$42.68	$77.49	$6.7 B	0.1%
(19) Moderate	7,200 MW	Leading	$95.70	-68%	$30.53	$89.64	$14.8 B	12.3%
(4) Cliff	4,200 MW	Linked	$97.19	-47%	$51.92	$68.25	$4.0 B	0.0%
(12) Cliff	7,200 MW	600/yr Leading	$91.14	-72%	$25.71	$94.46	$15.1 B	21.9%
(5) Cliff	4,200 MW	350/yr Leading	$91.95	-58%	$38.62	$81.80	$8.0 B	2.7%
* Levelized Cost for 2028 Wind = $120.17	# Assumes Wind makes up shortfall by other means (i.e., not REC payments)							

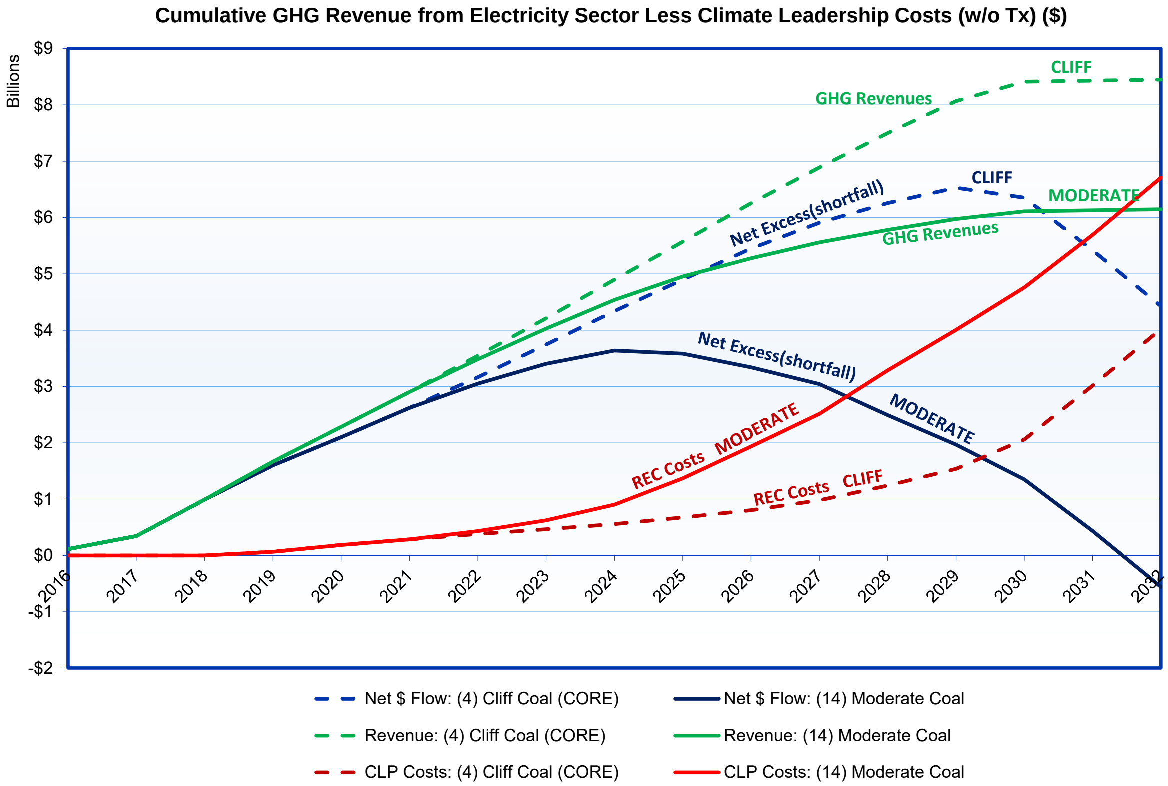
- The higher RECs nearer the study horizon will have to be paid well beyond 2032 and are estimated to be double the accumulated amounts paid prior to 2032.

Figure 7 – Required REC Cost ($/MWh of Renewables)



- **Cumulative GHG revenues will not be sufficient to pay REC Costs.** Revenues from GHG Compliance costs (green lines), mostly from coal, will reduce over time as more coal is retired. REC costs (red lines) will increase over time as more wind is added. Under the Cliff scenario, GHG revenues receipts are larger for a longer time period and REC costs accumulate slower than in the more accelerated Moderate Coal retirement schedule. Figure 8 does not include any extra transmission (Trx) costs

Figure 8 – Cumulative GHG Revenues Less REC Costs (before Trx) ($B)



Eventually, the GHG revenue inflows are not sufficient to keep up with the REC outflows, requiring another source of funding. Revenues from GHG compliance costs, mostly from coal facilities, drop off abruptly after 2025 and dry up completely once the remaining coal units are all retired in 2030. In the Moderate Coal Retirement case, cumulative revenues from GHG compliance costs may not quite cover the cumulative subsidy paid out to renewable generators (see Figure 8, blue lines are the cumulative net of GHG revenues minus REC payments). The Wind RECs may continue to be paid out well beyond the study horizon and would quickly accumulate after the revenues from compliance costs run out. These outflows do not include any other required payments for rebates, transmission capital or any other costs. Some additional source(s) of funding, either a rider on electricity or a multi-billion dollar draw on general tax revenues will be required to fund this sizable shortfall. Including the direct and hidden costs, this could be the same order of magnitude as today's full energy costs. In the Cliff case (dashed lines), coal continually pays more into the fund than under the Moderate Retirement Schedule (solid lines), so the fund lasts longer.

EDCA calculated the amount of REC required by renewables by first determining the annual revenue required by a developer to cover the repayment and return on its capital cost. This amount was compared to the expected actual revenue that the renewable unit would receive from the energy only market in any given year of the forecast. Any shortfall would have to be recovered across all the MWh expected to be produced in that year by that unit, yielding a different "levelized cost" for each renewable type. The levelized cost calculation is very dependent on several assumptions. For example, wind was assumed to have a capital cost of $2,080/kW, a 60/40 debt ratio, 7% interest rate, and 15% after tax equity return, $24.40/MWh Variable O&M, 36% capacity factor, a $12/MWh GHG offset credit[9], and a 33% discount to pool price (growing in higher penetration scenarios). This would yield a $90.56/MWh levelized cost (in year 2020) which would require an average pool price of over $140/MWh to be profitable without a subsidy (see Appendix 4, Table 11 for comparative levelized costs for all generator types).

- **A pre-2030 coal retirement schedule faster than the federal regulations (i.e., the Moderate case, ~2 units/year in vintage order) would provide the greatest incremental cumulative reductions in emissions, but would be more costly** relative to the CLP "core" case, and at this pace, would not materially impact market metrics. However, this accelerated coal retirement will more quickly reduce the collection of GHG performance standard compliance payments, increase the cost of the RECs and reduce margins for incumbent coal owners. The Cliff scenario allows for the longest operation of coal units, resulting in the least reduction in margins to the incumbent coal generators. It also collects the most carbon compliance payments, but does not reduce emissions as quickly.

- **Cogeneration is an economic source of emissions reduction.** Increasing levels of cogeneration, even though they are not officially "zero emitters", can provide significant incremental emissions reductions with a delivered cost of power at or below competing thermal technologies. From previous work, EDCA has the view that abundant steam host opportunities for additional cogeneration host sites exist in Alberta. However, since cogen hosts need security of steam supply, cogens may increase the number of $0/MWh offers, contributing to the "surplus power" issue. Since cogen hosts use about 2/3 of their electricity production behind-the-fence, not all cogen capacity is available to the grid. A variety of other considerations beyond the economics of power prices may also influence investment decisions.

- **Similarly**, although its total potential is much smaller than cogen, **biomass is** also much less intermittent than other renewables and could be **a useful, cost effective addition to the renewables fleet**.

- **Incremental investment for transmission facilities will be required to integrate additional renewable generations assumed for this study.** The AESO long-term transmission plan can accommodate up to 4,200 MW of renewable generation. To date, the AESO has already executed part of the plan by adding substantial new transmission capacity in southern Alberta as wind and solar resources have been built. Although some of the remaining approved and/or planned, but not yet executed transmission projects are expected to be built to integrate 4,200 MW of additional renewables, the magnitude of such investment is highly dependent on the location and type of new renewable projects. It is estimated that such incremental investment over the 15 years could range from $1.0 Billion if new renewables are located in areas where transmission capacity is available, to $3.1 Billion if more renewables are located in area requiring new transmission. Although not studied in this analysis, some renewables may be connected at the distribution level, which may reduce the impact on the transmission system. A material increase in transmission investment beyond what the AESO has planned may be required to integrate the additional renewable generation assumed in the 7,200 MW cases.

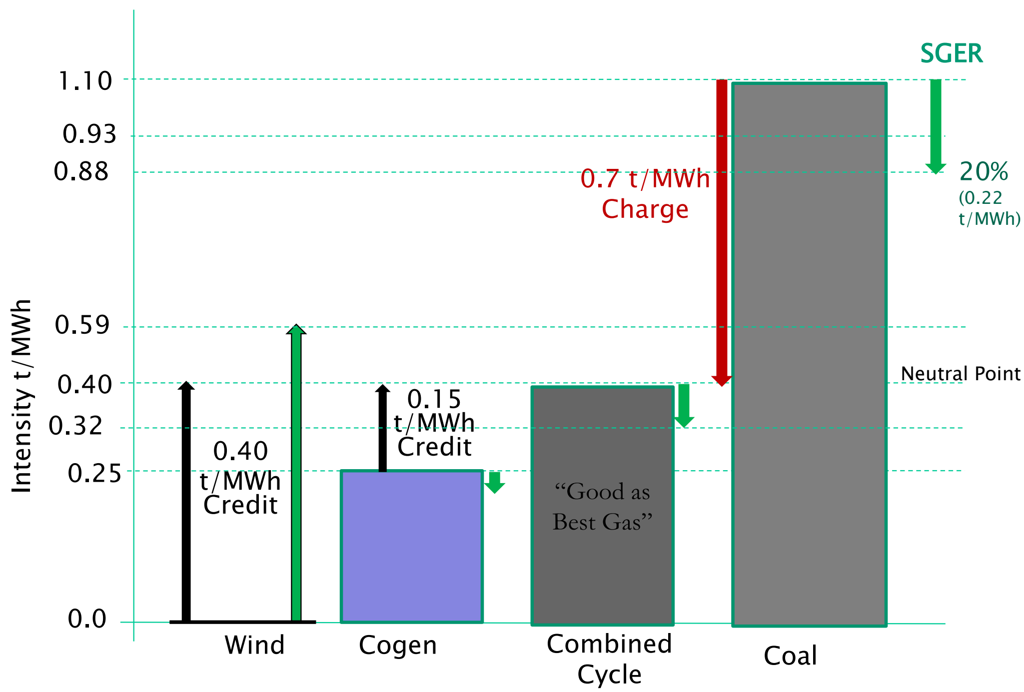
- **Incumbent coal units face the preponderance of decreases in margins** under the CLP. In the pre-2030 period, the margin impact results from the effect of the new performance standards and any acceleration in coal retirements. The government's announcement of the CLP included a commitment to not unnecessarily strand capital with respect to the six units whose operating lives were truncated as a result of the 2030 coal phase-out element of the CLP. There is a separate effect in the post-2030 period for the six units whose operating lives will be shortened by the 2030 coal phase-out decision. Issues relating to the 2030 coal phase-out are currently the subject of discussions between the Coal Facilitator appointed by the Government of Alberta and the owners of the six affected units. Given the confidential and sensitive nature of those discussions, the Study does not provide any analysis, estimates or quantification regarding potential compensation, including options for determining compensation.

[9] $30/t times the 0.4 t/MWh performance standard. Existing wind farms currently earn 0.59 t/MWh, the stipulated average marginal grid emissions intensity of the displaced unit.

Because of this exclusion, any quoted cost figures are therefore incomplete and significantly below the true cost of CLP. The impact of the CLP in reducing generator margins and in reducing the operating lives of units are societal costs of the CLP and should be fully reflected in an assessment of total costs.

- **Coal Dispatch will drop slightly because of higher GHG compliance costs.** The Performance Standard was only tested at the 0.40 t/MWh value. The CLP has yet to prescribe the actual performance standard based on a "good-as-best gas" emission intensity. For the purposes of this exercise, the model has provisions to test different "neutral points" (e.g., 0.25, 0.369, 0.42, 0.50 t/MWh), but only tested the 0.40 t/MWh value. As that standard is set lower, it increases compliance costs for the highest intensity units the most. For emissions above that allowed level, emitters would pay a compliance penalty of $30/t[10].

Figure 9 – Change in Emission Costs/Credits SGER vs Performance Standard.



If a coal unit had a current intensity of 1.1 t/MWh, it would have to pay on a 0.7 t/MWh overage, at $30/t, which would be $21/MWh in 2018 (red arrow). That is a $14/MWh change from the current SGER requirement for a 20% reduction (0.22 t/MWh or $6.60/MWh) under the SGER prevailing in 2018 (green arrow). A combined cycle gas unit, by definition, would be able to exactly meet the "good as best gas" standard, so its GHG charge under the performance standard system would drop to $0/MWh compared to its pre-CLP 2018 SGER obligation of $2.40/MWh, based on 20% of its assumed 0.40 t/MWh (i.e., 0.08 t/MWh * $30/t).

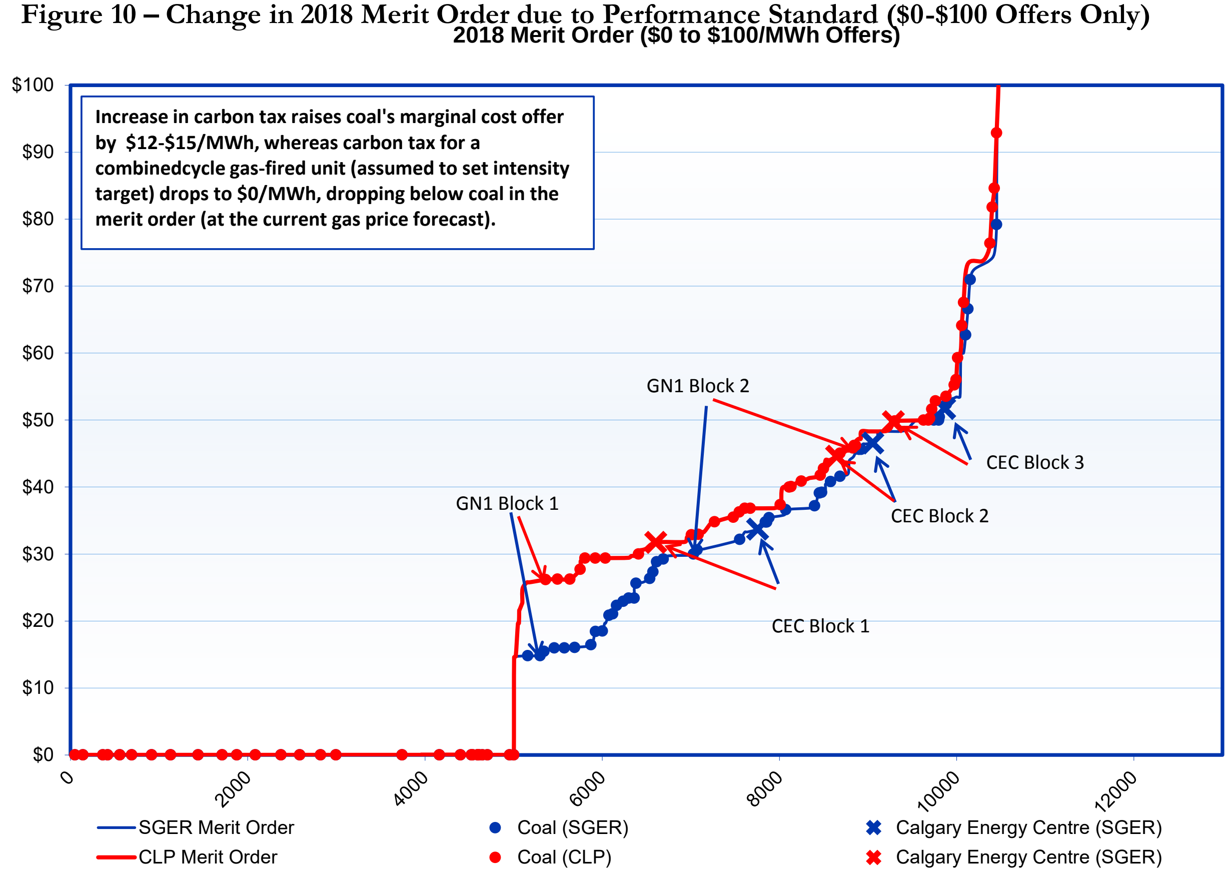
Under SGER, existing wind units are paid 0.59 t/MWh produced. If they were paid up to the new "good as best gas" line, their credit would actually drop to only 0.4 t/MWh.

- **The volatility of prices will be much higher across the year (more very low priced hours and much higher high-priced hours)**, although average pool prices will be relatively unchanged from the Pre-CLP case. Generators will have to earn a larger fraction of their revenues in fewer, higher-priced hours. This higher pool price volatility will change perceived risks for new generator developers and could stall or encourage investment, depending on the developer.

[10] Escalating at inflation plus some increment, suggested in the Climate Leadership Plan at an additional 2% above inflation.

- **Prices will be about $5/MWh higher than in the Pre-CLP Case for the first few years, but slightly lower in the later years**. Figure 10 shows how the lower (left) side of the 2018 merit order curve will be shifted up as coal units begin to pay emissions costs using the performance standard instead of the SGER target used in the Pre-CLP case costs (an increase of $13/MWh in the front-end of the study period, expanding to a $16/MWh increase in the back-end).

Figure 10 – Change in 2018 Merit Order due to Performance Standard ($0-$100 Offers Only)

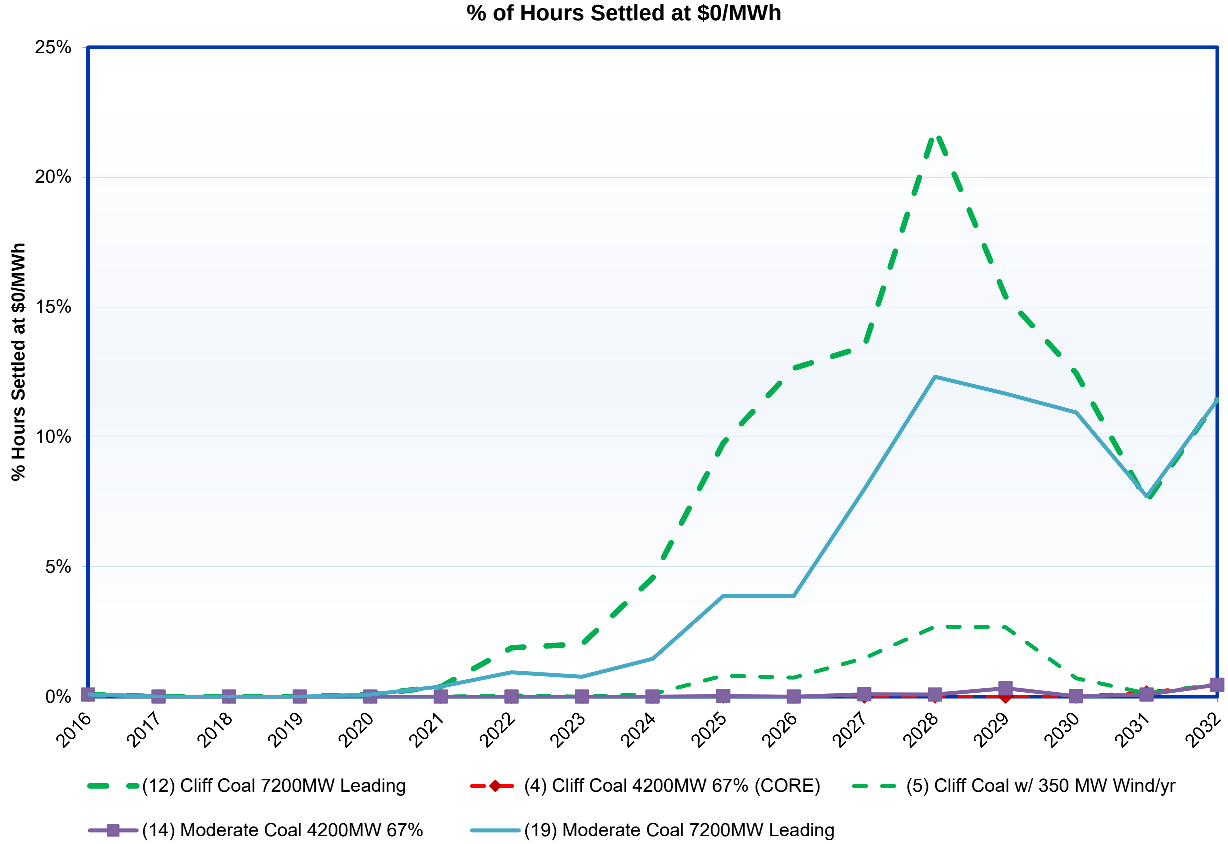


- While coal is still on the margin setting prices in a good fraction of the hours, they will be able to pass through some of their increased GHG compliance costs to the energy customer. In later years, coal will rarely be on the margin and must absorb this cost, impacting margins. Combined Cycle marginal costs will be slightly lower in the later years as the gas emissions charges drop from the old SGER target of 20% of gas emissions (0.4 t/MWh), to nothing (i.e., "good as best gas"). The Xs designate the re-positioning of three offer blocks of a combined cycle unit (Calgary Energy Centre) and two offer blocks of a coal plant (GN1) using SGER (blue) versus the performance tax (red).

- **At higher levels of renewables, a much greater fraction of hours will settle at $0/MWh.** At present, of the maximum 12,500 MW of capacity that shows up in a given hour, about 7,500 MW of that generation is offered in at $0/MWh (wind, "must-run" coal, some hydro, cogens) in every hour. Even with only 1,500 MW of wind, a few times a year, that 7,500 MW is more than the total load, so the price in that hour settles at $0/MWh. As more renewables are added, all at $0/MWh, the number of $0/MWh hours increases (see Figure 11). In all Moderate cases (when coal is retired earlier), and in all cases with a 4,200 MW renewables target, this is not a major issue (<1% of hours). However, in the Cliff cases, if renewables additions are added faster than 67% of coal retirements ("leading"), the number of $0/MWh hours starts to increase. At the 4,200 MW level, if renewables are added ahead of the coal schedule, $0/MWh hours rise to 2%, still manageable. However, at the 7,200 MW level, it climbs to almost 20% of hours settling at $0/MWh.

- **Significant wind is curtailed at higher renewables targets.** Some jurisdictions, including Alberta, have a priority system to ration over-subscribed \$0/MWh generation[11]. At the existing 1,500 MW of renewables, and even at the 4,200 MW level, this is not a large issue. But, as the renewables penetration rises above the 4,200 MW level or renewables additions lead coal retirements, all of it offering at \$0/MWh, the number of \$0/MWh hours progressively increases, rendering a fraction of the additional wind ineffective.

Figure 11 – Increase in \$0/MWh Settlement Hours (7,200 MW)



At 7,200 MW of renewables, this leads to an equivalent average hourly curtailment of 100 MW of wind in every hour (85% of hours have no excess \$0/MWh offers but the remaining 15% of hours see up to 2,500 MW of excess \$0/MWh offers), rendering that average amount of extra wind unusable in those hours. Wind developers will need to factor that increased idle time into their project economics, thus increasing the subsidy required to attract renewables.

Post-2032 Obligations

- **These REC payments continue well past the end of the coal phase out in 2030**, as long as the length of the REC contracts require. EDCA calculated the cumulative and yearly REC payments at two different levels of wind costs. In the first case, wind costs were assumed to escalate at 2%/year and the capacity factor would maintain a flat 38% of nameplate (current average is below 35%). In the second case, wind costs were assumed to fall at 2%/year and capacity factor to rise by 0.004%/year to reach 42% by 2032. The residual payments after 2032 were about \$2 Billion/year in the escalating first case and about half that in the second deflating case.

[11] The current AESO rule is to curtail surplus \$0/MWh power on a pro-rata basis. EDCA modeled the pro-rata process, which affects the actual dispatch and the actual emissions reductions.

Of course, for any wind developed later in the study timeframe, their 20-year contracts would project progressively further into the post-2032 period covered explicitly by the study in a staircase of RECs liabilities diminishing to $0/year in 2049, roughly equivalent to 10 years of full payments.

The estimated cash value of the REC liabilities before and after 2032 change considerably depending on the choice of levelized cost (see Table 7). The annual REC payments amount tops out (in 2032) in this latter case at $800 Million/year compared to $1.4 Billion/year in the base levelized costs case and accumulates to $6 Billion by 2032 and $18 Billion by 2049.

Table 7 – REC Liability from 2019-2049 under Two Levelized Cost Assumptions ($B)

Cumulative REC Liability ($B)	Using EDCA Levelized Cost Estimate ($ Billion)	Reduced Levelized Cost Assumptions ($ Billion)
2032- Single Year	$1.5	$0.9
2019-2032	9.3	6.2
2032-2049	21.3	11.7
2019-2049	30.6	17.9

To avoid being harsh on the renewables program, the levelized cost of wind was calculated by amortizing the capital costs over 25 years, but assuming the developer would only expect a guarantee for a 20-year period at that rate. If the developer did not feel comfortable with the risk of only a 20-year REC, the required REC payments would have to be even higher up-front. If the REC program ends before the rolling 20-year assumed contract length, the REC payments required inside the 2032 timeframe would have to be proportionately higher (i.e., the approximately the same amount of life-cycle RECs would have to be collected one way or the other to incent a developer to build).

All figures in the above table assume a 4,200 MW level of 2030 renewables. If the target was set at 7,200 MW, these figures would roughly double.

Investor Considerations

- **Private investment needs policy certainty to enable future investment in generation,** a recurring theme from all the participants throughout this process. This includes both **policy** certainty, which should improve once the policies have been clearly laid out, and also **market** certainty, which will likely remain unresolved in varying degrees depending on the final policy choices. Until the first uncertainty is relieved, the development community will have to factor the uncertainty into their investment decisions. So, although restoring policy certainty is urgent, the policy choices must also be clearly informed and have full regard for the long-term consequences to all parties, including the potential for investors to make a return on their investments. Developers may assess Alberta electricity market risks differently under some policy combinations than under others.
- **Generation buildout will need $25-$30 Billion of new capital and years of lead-time.** The development of at least 11,000 MW of new generation by 2030 to replace coal retirements and meet natural growth in demand is unprecedented in Alberta. Much of the $25-$30 Billion is expected to be provided by merchant investment. Depending on how much coal is replaced simultaneously, much of it at the same location, the approval and building logistics will be challenging. Typical development time, albeit different by technology (shorter for wind, much longer for hydro), would include 2-3 years of permitting and approvals and another 2-3 years for procurement and construction. Given this time exposure, commitment of the development community to this scale of undertaking requires sustained investor confidence that must be enabled by fair, compensatory and steady policy development. It is possible that new generation will not always keep pace with this replacement schedule. Scenario results show that even a one-year delay in generation additions results in large price excursions and increasing reliability concerns in certain scenarios.

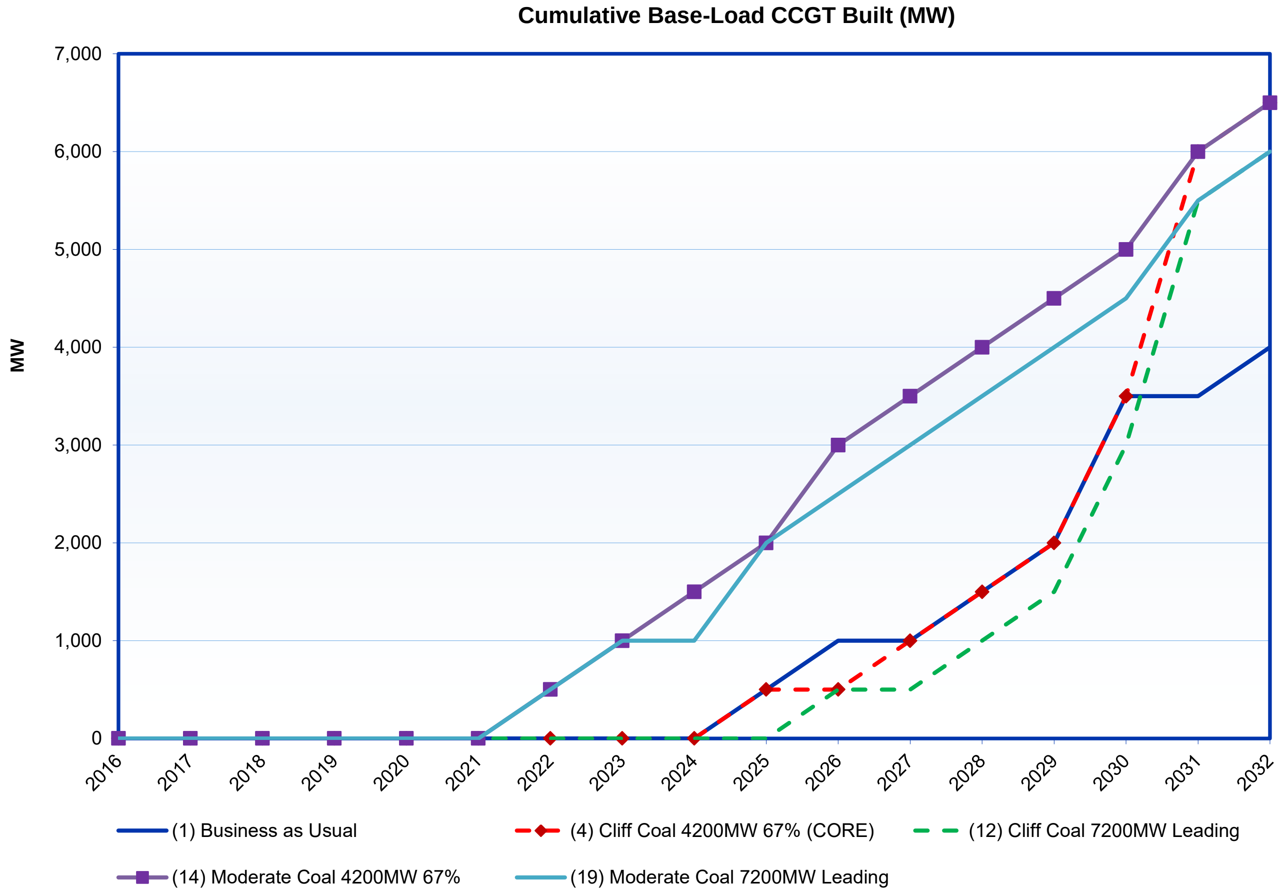
Table 8 – Summary of Investor Metrics

(Run)	Scenario		Investment Related Metrics			
Retirement Schedule	2030 Renewables Target	Pace of Renewables	$0/MWh % Hours (2028)	% Hours to Collect 50% of Revenue (2029)	Cumulative Capacity Additions (MW)	Cumulative Capacity Addition Costs ($)
(1) Federal Regs	Pre-CLP 720 MW	FEOC	0%	10%	6,223	$12.9 B
(14) Moderate	4,200 MW	Linked	0.1%	8%	12,134	$24.7 B
(19) Moderate	7,200 MW	Leading	12.3%	7%	14,734	$30.7 B
(13) Moderate	Swap for Gas	FEOC	0%	10%	8,723	$17.1 B
(4) Cliff	4,200 MW	Linked	0%	12%	12,134	$24.7 B
(5) Cliff	4,200 MW	Leading (350)	2.7%	8%	12,134	$24.7 B
(12) Cliff	7,200 MW	Leading (600)	21.9%	6%	14,734	$30.7 B

- **Sufficient Room Exists for Economic Development of Dispatchable Generation.** EDCA models show that additional dispatchable generation may be economic even earlier under CLP than under the Pre-CLP case. First, since the CLP currently recommends that wind capacity only replaces two-thirds of retired coal capacity, it still leaves one-third to be absorbed by new dispatchable generation. Furthermore, since one MW of wind capacity actually only produces one-half as much electricity as one MW of coal and 1 MW of solar only produces about one-quarter as much, that leaves additional room for gas generation. Finally, wind and solar output depend on weather conditions, creating an inherent unpredictability, intermittency and rapid ramp rates which require that some amount of other highly reliably dispatchable generation capacity, likely natural gas or interties, be available when renewables are not, either as base generation or as an Ancillary Service.

- **Increased Price Volatility Allows Economic Development**. In higher renewables scenarios, the addition of renewable resources creates an excess of $0/MWh offers in many hours. By itself, this would reduce average pool prices and discourage additional dispatchable generation. However, because of their inherent intermittency and high correlation, renewables also tend to produce at low levels in the same hours, creating more instances of supply scarcity. This polarizes pool prices into both much lower and much higher values, reducing the number of hours in which thermal generation can recover their fixed costs through scarcity pricing but allowing them to price aggressively in those hours. Dispatchable generation can earn more revenue in fewer hours without significant enough a reduction in the amount of available generation to cause reliability problems. This increased price volatility may be perceived by some developers as higher risk which they may reflect as a higher required hurdle rate, further delaying additions (not modeled in this study). These fewer but larger price excursions may also create some perception of increased political risk that the government or its agencies would increase price mitigation in those high-priced hour on which investors would be relying for an adequate return on investment.

Figure 12 – Cumulative Base-Load CCGT Additions (MWh)

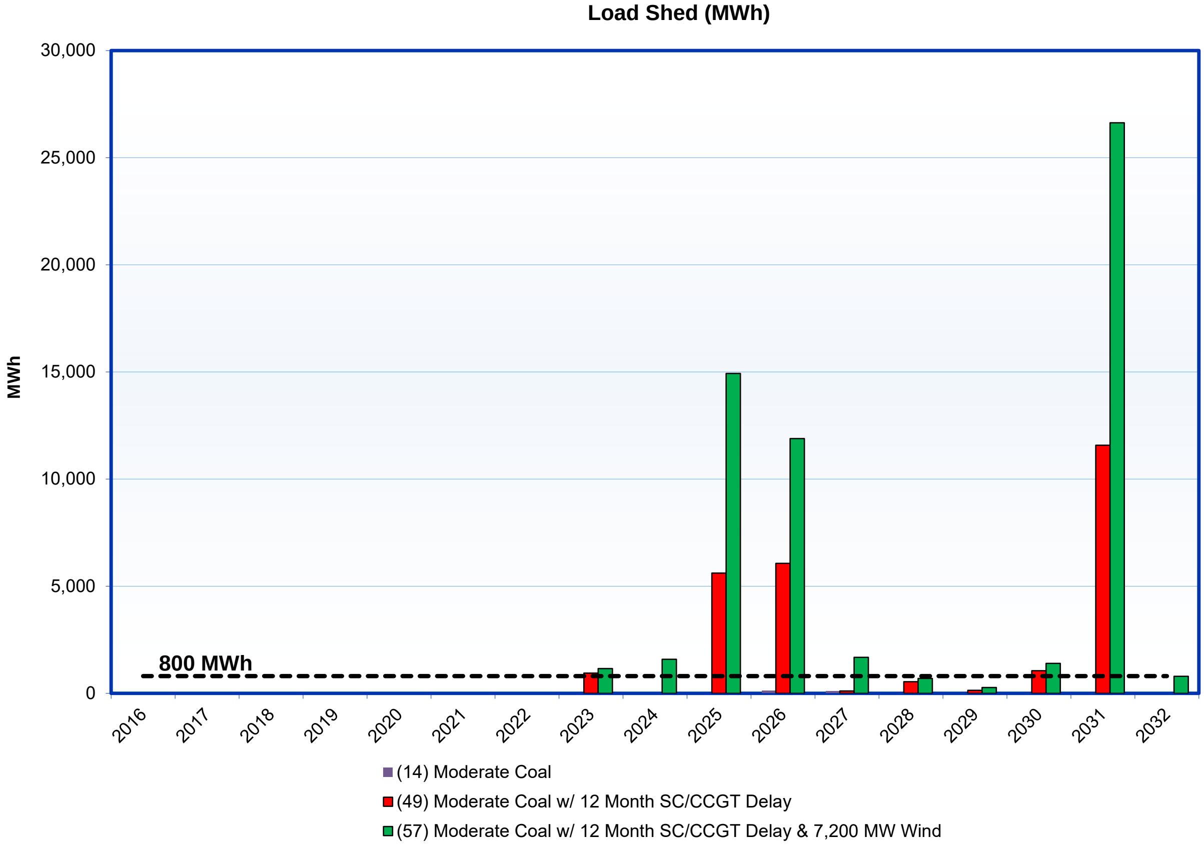


Reliability

- **In the slower coal retirement cases and those cases with the lower target renewables level, breaches of the established LTA reliability metrics are minimal.** However, this is a very sensitive parameter. If generation is delayed by as little as one year, it does begin to breach the prescribed threshold for the Alberta reliability standard of 800 MWh[12] of lost load per year. As the target level of renewables rises to the 7,200 MW level, or if renewables are substituted ahead of the pace of coal retirements, this reliability threshold is breached more easily.
- **Just a one-year delay in additions can increase the likelihood of breaching Long Term Adequacy targets**, even at the Moderate/4,200 MW of renewables level. This effect is even more pronounced at the 7,200 MW level.

[12] AESO Long Term Adequacy threshold is set to the equivalent of one hour of full system outage in 10 years, or approximately 800 MWh of involuntary lost load/year.

Figure 13 – Load Shed MWh with Delayed Baseload – Moderate Coal/ 4,200 MW of Renewables



CONCLUSIONS (Big Three)

- **Targeting 4,200 MW of renewable additions, timed so as to replace no more than 2/3 of the capacity of the coal units retired by any given date (either the "Cliff" or "Moderate" case) could result in a balance between electricity costs, emissions reductions, reliability, and electricity and general investment climate.**
- **Even the most efficient combination of policy choices that meaningfully reduce emissions invariably increase customer electricity costs by billions of dollars. (Cumulative $5-$20 Billion by 2030 plus $1-2 Billion/year out to 2049, depending on the scenario tested). This does not include CLP transitions costs associated with early shut down of pre-2030 coal facilities.**
- **Renewables additions should be matched to coal retirements at 67%.** For scenarios where renewables additions significantly lead coal retirements, emissions reductions are actually less and costs are higher than in scenarios with less renewables, but well-matched timing to coal retirement.
- **The "Cliff" Retirement Schedule is cheaper and collects more carbon payment revenues but does not reduce cumulative emissions through 2030.**
- **The interaction of policy choices is complex and indicates the strong need for a dynamic, institutionalized implementation process that monitors outcomes against a deliberate, measured plan with prescribed contingencies.**
- **Investors need policy fairness, certainty and stability to ensure the private investment is available to fulfill the capital requirements (11,000 MW costing over $20 Billion) needed for baseload generation.**

Blend Effects

The Steering Committee instructed EDCA to test the impact of different blends of renewable technology types on the various metrics.

- **Blend Effects: The addition of a small fraction of solar facilities softens the wind discount**. Solar produces more energy in the high-priced mid-day hours (earning a 50% premium to pool price), which indirectly softens the wind discount somewhat, even moreso at the higher 7,200 MW renewables level.

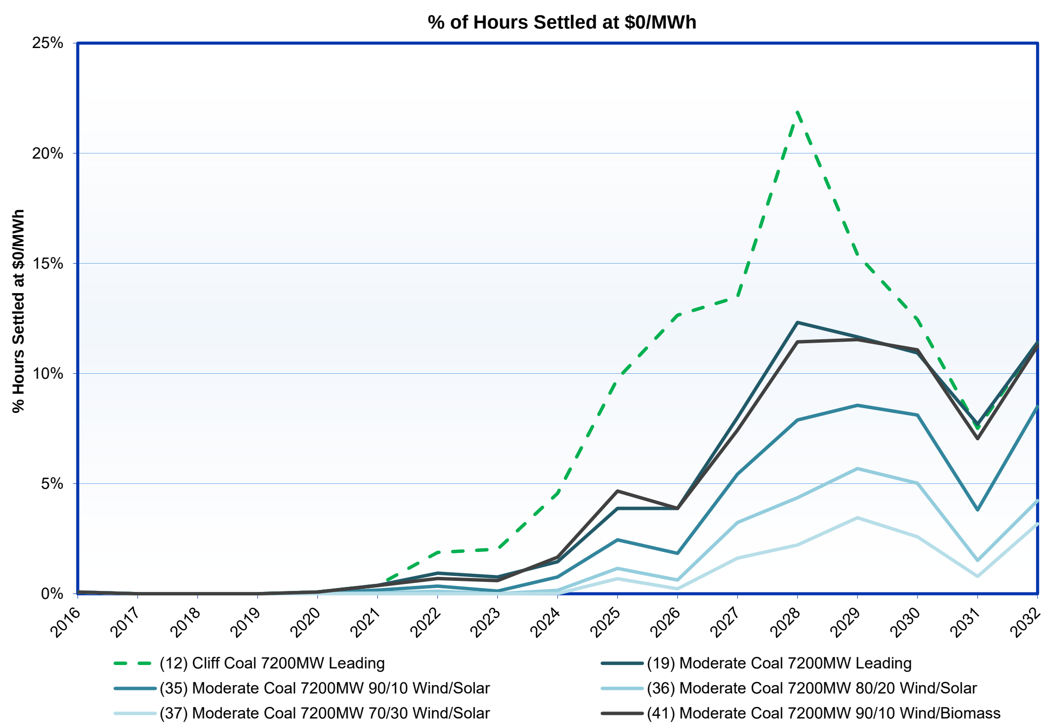
- **However, if solar is added above 10% of the renewables mix, it lowers mid-day prices** to the point that it too begins to experience a discount to pool price and makes it harder to incent needed baseload investment without creating reliability concerns. Adding extra solar past that level may also raise subsidy payments without correspondingly reducing emissions.

Impacts are shown for seven metrics in turn, as the blend of renewables changes:

1. Number of $0/MWh hours (Figure 14)
2. Wind Discount to pool price (Figure 15)
3. Required REC price ($/MWh) paid on each produced MWh of renewable energy (Figure 16)
4. Total REC dollars paid out annually ($/year) (Figure 17 (4,200MW) and Figure 18 (7,200MW))
5. MW of curtailed Capacity
6. Pool Price Effects
7. The blend of different renewable technology types has impacts on costs.

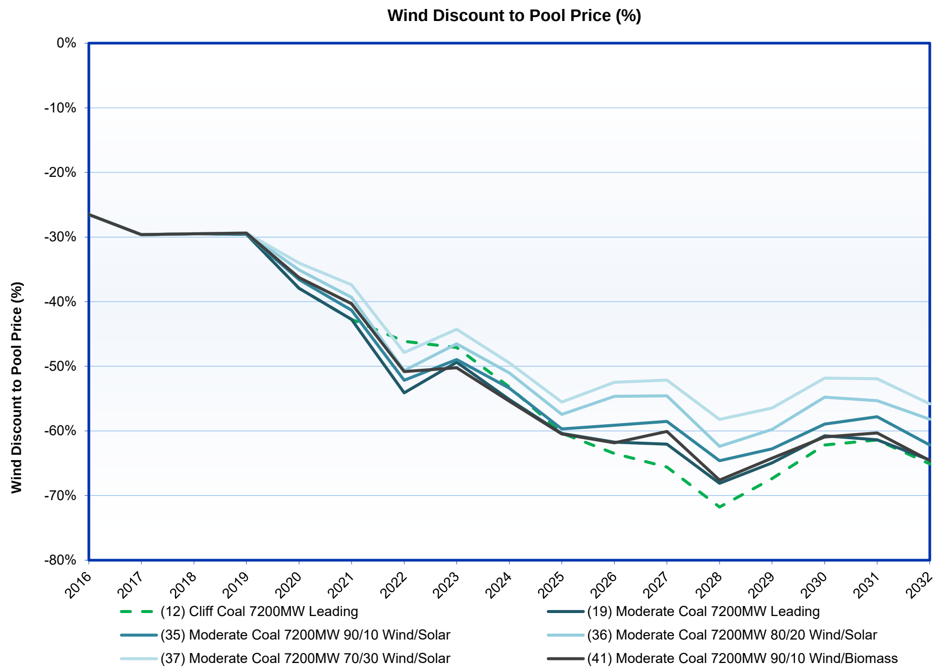
The blend of different renewable technology types has direct and indirect impacts on costs. As wind is replaced in turn by more solar (moving from dashed green at 100% wind to lighter shades of blue lines at 10, 20, 30%), fewer hours settle at $0/MWh hours, mostly because there is less wind. In the 4,200 MW cases (not shown), very few hours settle at $0/MWh, regardless of the blend of non-wind. Choosing biomass (dark grey line) instead of solar makes little difference at a 10% blend.

Figure 14 – Impact of Different Blends of Renewables on $0/MWh Hours %



As the blend of non-wind renewables increases, the alternative renewable displaces some wind, reducing the wind discount (Figure 15) and therefore reducing REC prices (Figure 16). Other renewable types either run in different hours than wind (solar runs mostly on-peak and biomass (grey line) runs in all hours at high capacity). A blend tempers the inverse price effects of swings in wind and reduces wind's overall % discount to pool price (see Figure 15).

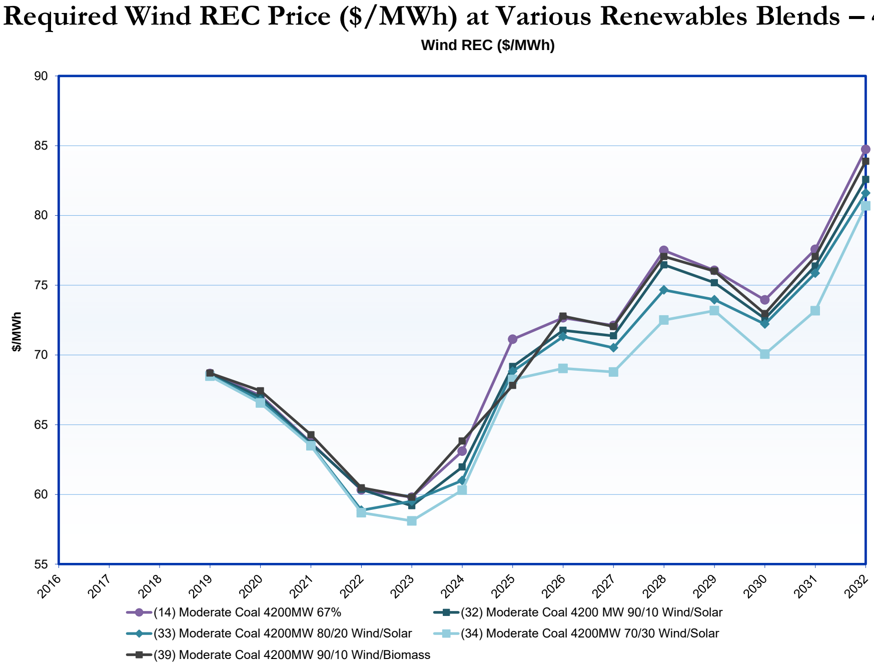
Figure 15 – Wind Discount to Pool Price at Various Blends of Renewables (7,200 MW)



- This reduces the shortfall between the revenues wind has to receive to be economic and its actual receipts from pure energy sales and thereby reduces the price ($/MWh) of the REC payment required to incent them to build. However, the lower solar capacity factor reduces the displacement of thermal resources (mostly gas-fired) and therefore lessens emissions reductions. As the blend of non-wind is increased, to a point, the required REC payment actually decreases slightly.

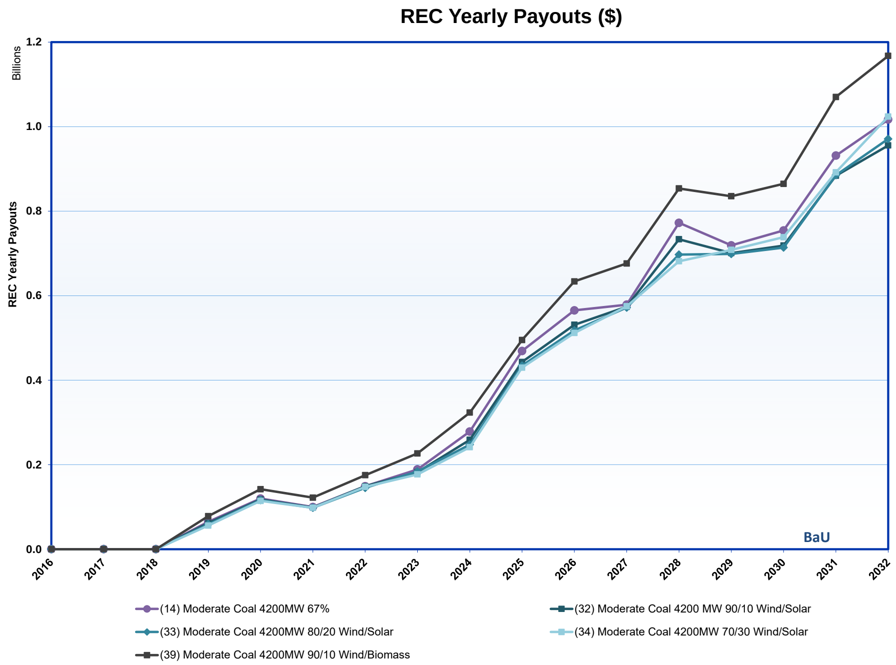
- Figure 16 shows the REC price for wind only. REC payments for solar are 40-80% higher than wind, rising as the blend increases.

Figure 16 – Required Wind REC Price ($/MWh) at Various Renewables Blends – 4,200MW



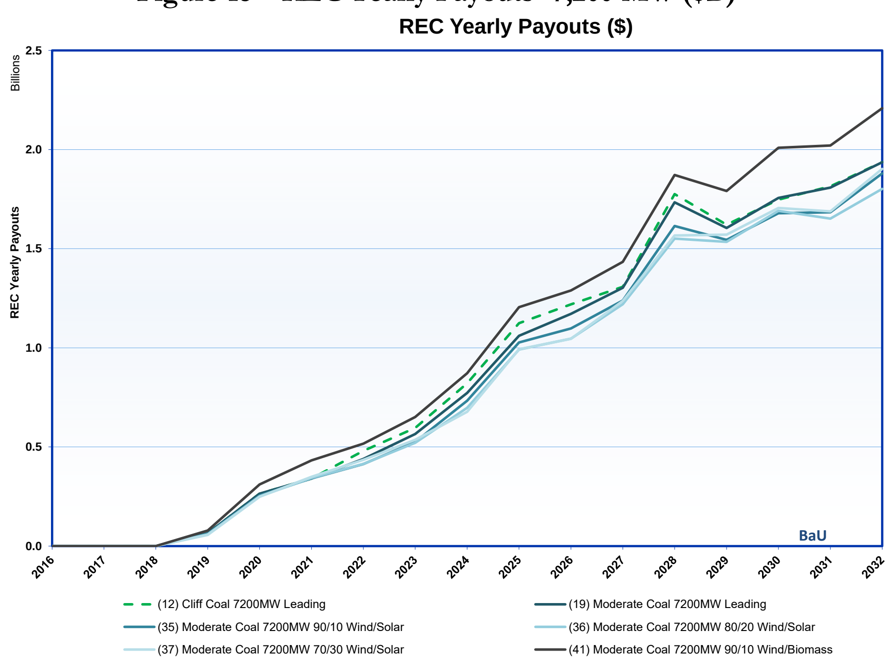
- **The 10% Biomass blend had the best emissions reductions but was also the most expensive.** At the 4,200 MW level, REC payouts reached about $1 Billion/year by 2032, slightly less as more solar was added, but almost $1.2 Billion for 10% biomass (top gray line, Figure 17). Biomass requires roughly the same REC price as wind at the 90%/10% wind/biomass blend level, but since a MW of biomass creates over double the MWh in a year as a MW of wind, it earns double the REC credits and displaces double the emissions.

Figure 17 – REC Yearly Payouts -4,200 MW



- At the 7,200 level (Figure 18), the costs ($2.2 Billion/year in 2032, $17 Billion cumulative) were almost double those at 4,200 MW because of the increased level of MWh produced, but the spread of the 10% biomass case (top dark gray line) above the other cases was somewhat mitigated by the large number of curtailed $0/MWh hours.

Figure 18 – REC Yearly Payouts -7,200 MW ($B)



Other Scenarios Reported only in the Main Report

Some other non-policy factors were also tested but are only presented in the main report. Their effect was not as large as those from the "Big Three" policy implementation parameters:

1) **Alternate Load Forecast** (Q2, AESO Base, High, LTO Reference (AESO Base with faster than moderate coal retirements) and LTO Alternate (AESO Base with slower than moderate coal retirements and 7,200 MW Wind, 1000 solar, 300 Hydro). Most emissions changes were attributable to the change in electricity consumed rather than from Climate Leadership Plan initiatives.

2) **Gas Price** (35% lower, 25% higher). Gas prices flow through to pool price more directly as more coal is retired. Different policy implementation choices did change the timing but did not significantly alter overall findings.

3) **Different non-wind blends** (less CCGT, 90/5/5 wind/solar/biomass/hydro, two levels of more Cogen or more simple cycle and less CCGT). More or less simple cycle had little effect on most metrics, but adding cogens improved emissions at significantly lower cost than incenting more "zero-emitter" renewable technologies.

4) **Alternate Offer Strategies**

    a. pre-2020 (while the Balancing Pool has offer control of PPAs),
    b. post-2020 at less aggressive

    Generally, if generator offers became more aggressive, the market would be less stressed. If generators offered less aggressively, eventually investment was delayed and reliability was stressed. The Steering Committee was not unanimously expecting a change in offer behaviour in either direction, except for assets held by the Balancing Pool. In the 2017-2020 period when the Balancing Pool holds the PPA coal units, they may continue to exhibit their current "marginal cost" offer behaviour. At that level of offers, besides likely requiring a new payment from customers, the behaviour may stifle near-term investment.

5) **Less Aggressive Generation Additions** (1 year delay). Any delays in baseload generation significantly increased the frequency and severity of breaches of the Long Term Adequacy reliability thresholds in the year it occurred.

6) **Additional Tie Capacity** (flat fixed volume and just more tie capacity). Additional tie capacity reduced the cost of emissions reductions, but also reduced the number of Alberta-based gas-fired generation.

7) **Varying Levelized Cost Parameters**

    Depending on the forward view of prices for future wind, solar and biomass, the RECs could change significantly.

Untested Parameters

Some policy levers were identified but to date have only been tested at one value, but may be fruitful future topics of analysis:

1) Allowing both existing and new renewables to earn RECs

2) Relaxing the 2030 date for the post-2030 coal assets (e.g., the remaining six coal units or the two newest units (KH3 and GN3) are forced to retire at 2035 instead of 2030

3) The preliminary test of additional inter-tie capacity undertaken in this study uncovered a number of thorny follow-on questions which were considered important but out of scope for this study: who would own and pay for the cost of new tie capacity, how would it be recovered over time, how it would play into any national (East-West) electricity strategy, seams issues between a regulated and a deregulated jurisdiction, the impacts for the investment signal in Alberta, how reliability could be quantified if import supply could be diverted/unavailable/curtailed in favor of other uses of the energy.

4) Development of a large-scale hydro project, lowering the need for other renewables

5) Creating a capacity market to ensure long-term supply adequacy if energy prices become insufficient

Appendices

The full length Summary report contains six appendices providing additional detail on the finer workings of the study. These appendices are only included in the original Summary report provided to Active and Passive subscribers but not in this Abbreviated version. Similarly, a companion Excel spreadsheet containing all 60+ runs and a quick comparison tool are also only provided to the Active and Passive subscribers. For further detail on ordering the complete Summary report or the comprehensive Detailed report, visit our website at:

www.edcassociates.com.

Appendix 1: Multi-Client Participants Summary

Appendix 2: Detailed List of Tested Sensitivities

Appendix 3: EDCA's Forecast Process and Methodology

Appendix 4: Levelized Cost Calculation

Appendix 5: Final Scenario Matrix

Appendix 6: Detailed List of Metrics