PEMBINA institute

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Early coal phase-out does not require compensation

Briefing note

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Overview

As part of discussions around GHG emissions reductions from coal-fired generation units, owners of these units have argued that they would need compensation for lost operating opportunity. Under the meaningful and measured schedule for phase-out or stringent emissions management requirements as proposed by the Pembina Institute, however, investors have an opportunity to recoup their invested capital. Supplementary compensation is neither required nor warranted.

- The sixteen PPA coal-fired units are allowed to operate for the period deemed necessary to receive their return of invested capital, known as the Last Year of the Effective Life of the Unit (UEL) as set under the deregulation PPA-setting process.
  - Coal plant owners are receiving payments that reflect a return on their investment according to schedules agreed to by these owners.
  - No compensation is necessary where units are allowed to operate to their UEL.
  - Capital invested after deregulation is also recovered within these operating timeframes.
- Investors in merchant units built after 2001 were well aware the long-term operations of these facilities would be subject to change of law related to climate policy.

1 Introduction and relevance

Beginning in February of this year, an active conversation has taken place around the imperative to accelerate the reduction of Alberta's coal power greenhouse gas (GHG) emissions. Given the nature of the fuel source and the availability of alternatives, the feasible options have focused on both reducing operations and early closures of coal plants.

There is good reason for this. Coal is a uniquely high-emitting source of pollution both for GHGs and criteria air contaminants (CACs). As such, the externalities of coal combustion are absolutely unmatched — they can be an order of magnitude higher than other common energy sources. Fortunately, because we have readily available, competitively priced, alternative technologies for producing electricity, the best means for reducing both types of emissions are perfectly aligned — shut down coal combustion or require stringent GHG performance standards.

Moreover, very clear deadlines for phasing out conventional coal will prove very persuasive for international recognition of Alberta's new climate strategy. The international community increasingly recognizes the imperative to stop burning our highest-emitting, widely used fossil fuel to avoid wasting unnecessary emissions under a constrained global carbon budget — particularly in developed countries.[1]

[1] Increasingly, the trend is toward more and more aggressive action among developed countries to stop burning coal for electricity production. Kiri Hanks and Julie-Anne Richards, *Let Them Eat Coal* (Oxfam, 2015); E3G, *G7 climate agreement means coal phase out actions required* (2015), http://www.e3g.org/news/media-room/g7-climate-agreement-means-coal-phase-out-actions-required.

Moreover, phase-outs are valued because they are visible, physical requirements that are resistant to subsequent policy change. Indeed, in the urgent lead-up to setting clear benchmarks for action on the international stage prior to Paris, U.K. officials — in a multi-partisan effort — are considering a 2023 phase-out for coal power.[2] The economics of coal are so clear — when accounting for full costs, including those borne by society, coal is clearly not competitive — the pace of coal plant closures increasingly defines leadership on this critical climate issue. Scheduled closures also supply clearer investment signals for replacement generation.

2 Coal generation owners demand compensation for shutdowns and reduced operations

From the beginning, these conversations have been burdened with various degrees of demands for payments for early closure or even reduced operations — variously labeled "compensation", "fairness", or being "made whole." They have included heavy rhetoric such as "expropriation of assets" and "nationalization" and even implied threats of litigation.[3] Demands have even been made where the proposed dial-down was essentially set at business-as-usual (BAU) levels of coal emissions. If such demands were intended to dissuade action on coal GHGs or to make the coal GHG problem seem intractable, it seems to have succeeded under the previous provincial government.[4] Under the process instituted since the new government, industry players continue to make demands.[5]

Some industry players have implied or expressly suggested that failure to sufficiently compensate would result in litigation. However, we have yet to see a compelling argument that there is a cause of action in

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[2] Alex Morales and Rachel Morison, "U.K. Said to Consider Closing All Coal-fired Plants by 2023," *Bloomberg Business,* October 6, 2015. http://www.bloomberg.com/news/articles/2015-10-06/u-k-said-to-consider-closing-all-coal-fired-plants-by-2023

[3] See, e.g., Capital Power, *ALTE Shift* (2015), 1.

[4] See Darcy Henton, "Rival party leaders say consumers should not pay to reduce coal plant emissions," *Calgary Herald*, April 28, 2015.

[5] For examples in the public domain, see, e.g., Sheila Pratt, "Province could target coal-fired power plants for early closure, says environment minister," *Edmonton Journal,* September 8, 2015. ("Calgary-based TransAlta, which runs coal-fired plants west of Edmonton, is seeking compensation for a plant that has to close before the 50-year limit set by the federal government, CEO Dawn Farrell said."); TransAlta Corporation, *Submission to Alberta's Climate Change Advisory Panel* (TransAlta, ATCO and Maxim: 2015), 35-36 (for an accelerated 45-year-life coal retirement scenario, "In order to maintain investor confidence in market, affect plant owners be compensated for their economic losses" and "Accelerated coal retirement … would require material out-of-market compensation to affected coal plants"), 41 (showing a $4.6 billion out-of-market payment requirement for accelerated retirement); Capital Power, *ALTE Shift* (2015), 1 ("Because generators would benefit from modestly higher prices for electricity, no out-of-market compensation would need to be paid for accelerated asset retirements."), 17 ("Capital Power believes a reasonable amount of compensation would be the remaining net book value when the new GHG policy is enacted multiplied by the ratio of the reduction in economic life divided by the remaining economic life under CST."); Maxim Power *Corp, Climate Change Advisory Panel Submission* (2015), 6 ("Parties foregoing the use of their assets to support achievement of reduction targets should receive compensation for lost economic value."); ATCO Power, *Transition from Coal to Firmed Renewables: ATCO Power's Submission to the Alberta Climate Change Advisory Panel* (2015), 10 ("Mandating early shutdowns of coal plants would reduce emissions but less effectively and at greater cost than a hard cap on coal emissions. By obliging coal producers to forego operation in all hours (rather than during low value hours), the cost of reductions would be increased, increasing pressure for compensation."); EPCOR, *Panel Submission* (2015), 3 ("Investors in existing coal units must be given a fair opportunity to recover their costs and make a reasonable return on their investments. A simple and transparent approach would be to pay owners of coal units the remaining net book value of their units at the time of early retirement.").

law for mandated closures or emissions regulations that create *de facto* closure dates.[6] The government has the legal right to impose closure dates or to require stringent performance standards according to set timelines. However, compensation arguments have resumed on the premise that rules mandating closure would undermine investor confidence for further investment in generating assets in the province.

The Pembina Institute agrees that regulatory action by government should be fair and take into consideration potential impacts to all affected parties — including incumbent and entrant investors, ratepayers, environmental and human health, and taxpayers. It is reasonable that investors should have a fair opportunity for the return of their invested capital.

Under the meaningful and measured schedule for phase-out or stringent emissions management requirements as proposed by the Pembina Institute, investors will have an opportunity to recoup their invested capital. Supplementary compensation is neither required nor warranted, because:

- PPA coal-fired units are allowed to operate for the period deemed necessary to receive their return of invested capital.
    - Coal plant owners are receiving payments that reflect a return on their investment according to schedules agreed to by these owners.
    - No compensation is necessary where units are allowed to operate to their UEL (defined below).
    - Capital invested after deregulation is also recovered within these operating timeframes.
- Investors in merchant units built after 2001 were well aware the long-term operations of these facilities would be subject to change of law related to climate policy.

3 PPA coal-fired units are allowed to operate for the period deemed necessary to receive their return of invested capital

Sixteen of the eighteen coal-fired units currently in operation were in service prior to deregulation of the Alberta electric power system. For these units, the PPA structure put in place at deregulation established the dates by which these generators would be able to recover their costs. Under this system, the Alberta government can institute a schedule for unit phase-outs or stringent physical emissions management obligations that allows generators the opportunity to recover their invested capital. Compensation is thus not required.

3.1 Coal plant owners are receiving payments that reflect a return on their investment according to schedules agreed to by these owners

Prior to 1996, utilities were not permitted to charge customers market prices. Instead, prices were established by a regulator based on the utility’s cost of service, which included capital costs and operating costs. To facilitate the transition as the power supply market was deregulated in 2001, power purchase agreements were developed for each of the formerly regulated coal-fired units. The objective was to move the Alberta electric system to market-based pricing, while extending to the owners of existing assets a contracted return on their generation assets comparable to the regulated return they had previously received.

The PPAs provided a reasonable opportunity for the owners to recover costs, including capital expenditures, through depreciation and return on equity. Payment schedules were proposed by generators

[6] While the focus of this piece is on regulatory action with respect to coal units post-PPA, this lack of legal claim may be equally true for units under PPA. The PPAs that PPA buyers purchased include “change of law” provisions, which were explicitly meant to accommodate future environmental rules and forewarned of the business risk of purchasing contracts for high-emitting power.

and reviewed by the expert Independent Assessment Team to ensure that such payments would "provide the owner [of a unit] with a reasonable opportunity to recover the fixed and variable costs of generating electricity… over the effective term."[7] The PPA terms were tested before the Electric Utilities Board (EUB) where necessary to ensure they were "just and reasonable."

The terms of the PPAs were developed so as to pay the owner/operator the marginal cost of generation — — primarily fuel — for each unit of power produced — energy payment — plus a fixed monthly capacity payment comprising the annualized, unrecovered capital cost of the plants as determined by regulatory officials.[8] Capacity payments — set in Schedule C of each PPA — accounted for such items as the unit's book value, depreciation, decommissioning provision, capital additions, and fixed charges for operations, maintenance, corporate services and administration, as well as an annualized return on the PPA owner's invested capital.

Embedded within the terms of each unit's PPA was a specific Effective Life of Unit (ELU) and a Last Year of the Effective Life of the Unit (UEL) agreed to under contract by the generator. This provided a specific timeline for reimbursement of unrecovered capital costs — including a fair return on this capital. The ELU and UEL[9] timeframes were fundamental to the capacity payment calculations to allow the PPA owners recovery of their invested capital. Table 1 shows the deemed UEL for each unit. The Pembina phase-out schedule for the 16 PPA units is equal to the UEL date, except where those dates have already passed — for Milner and Battle River 3 and 4 — in which case the end of 2016 is recommended.

Table 1. Deemed Effective Life of Units and comparison to other unit life determinations

Unit	In-Service Date	End of PPA[10]	PPA UEL[11]	Pembina Phase-out schedule[12]	Age	Federal GHG regulations		Extra years under federal life
						Year[13]	Age	
Battle River 3	1969	2013	2013	2016	47	2019	50	6
Milner 1	1972	2012[14]	2012	2016	44	2019	47	7
Battle River 4	1975	2013	2013	2016	41	2025	50	12
Sundance 1	1970	2017	2017	2017	47	2019	49	2
Sundance 2	1973	2017	2017	2017	44	2019	46	2
Sundance 3	1976	2020	2020	2020	44	2026	50	6
Sundance 4	1977	2020	2020	2020	43	2027	50	7
Sundance 5	1978	2020	2020	2020	42	2028	50	8
Sundance 6	1980	2020	2020	2020	40	2029	49	9
Battle River 5	1981	2020	2021	2021	40	2029	48	8

[7] Balancing Pool, *Power Purchase Agreement Information*, http://www.balancingpool.ca/about-us/ppa-information/; *Electric Utilities Act*

[8] Terry Daniel, Joseph Doucet and André Plourde, "Electricity Industry Restructuring: The Alberta Experience" in *The Challenge of Electricity Restructuring* (Andrew N. Kleit, Editor: 2013).

[9] The PPA defines UEL as "2000+ELU".

[10] *Alberta Wholesale Market: A description of basic structural features undertaken as part of the 2012 State of the Market Report* (2012), 4.

[11] See Schedule C in each of the units' PPAs.

[12] Pembina Institute, *Alberta Climate Panel Submission: Briefing note for the 2015 Alberta Climate Change Advisory Panel* (2015), 7.

[13] Environment Canada, *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations* (2012).

[14] Note that the "PPA for H.R. Milner was not auctioned but terminated and the unit subsequently sold." Ibid.

Keephills 1	1983	2020	2023	2023	40	2029	46	6
Keephills 2	1983	2020	2023	2023	40	2029	46	6
Sheerness 1	1986	2020	2026	2026	40	2036	50	10
Sheerness 2	1990	2020	2026	2026	36	2040	50	14
Genesee 1	1989	2020	2029	2029	40	2039	50	10
Genesee 2	1994	2020	2029	2029	35	2044	50	15
Genesee 3	2005	N/A	N/A[15]	2030	25	2055	50	N/A
Keephills 3	2011	N/A	N/A	2030	19	2061	50	N/A

Table 1 also shows the respective "useful life" deemed under the federal regulations for requiring units to meet a good-as-gas standard of GHG emissions intensities.[16] Industry accepted good-as-gas regulatory obligations by 40 years of life through most of the 2000s[17] — within the decade after UELs were set. By comparison, we can see that the federal dates — promulgated in 2012 after being weakened from 40 to 45 years and then 45 to 50 — provide considerable extra time for windfall revenues for the generators.[18]

It is instructive that industry did not demand compensation from the federal government for the useful life dates established under the federal GHG regulation. Industry has not been clear as to why the operating lives developed under the federal approach were accepted as being sufficiently long not to require compensation, but recent proposals to further reduce operating lives would necessitate compensation. One is left to surmise it is because industry lobbied for those extended dates.[19] Regardless, the federal useful life dates are arbitrary — set at 50 years except for a few units where the federal government wished to see reductions by 2020 and 2030 — to appear more meaningful in those particular years.

While the industry was influential in weakening federal useful life dates from 40 years of life to 45 and ultimately to 50 years, that successful industry lobbying cannot now set the benchmark for when compensation is required. The federal dates were not set specifically to afford a reasonable time for recovery of invested capital. It is well within the Alberta government's ambit to seek readily available emissions reductions through accelerated phase-out or stringent physical emissions management obligations and it can ensure continued investor confidence by allowing for capital cost recovery according to the agreed-upon timelines established 15 years ago.

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[15] Genesee 3 and Keephills 3 were built as merchant units after deregulation and, as such, are not under PPAs. Section 4 discusses compensation issues with respect to these units.

[16] Environment Canada, *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations* (2012).

[17] "Canada's electricity industry has suggested an emissions performance equivalency standard (EPES) as a starting point for the discussion on new and near end-of-life plants, proposing that coal-fired plants achieve an equivalent rate of emissions intensity to that of a natural gas combined cycle (NGCC) plant… include[ing] facilities 40 or more years old meeting or exceeding the standard." Natural Resources Canada, *CCTRM: Canada's Clean Coal Technology Roadmap* (2008), 25, http://publications.gc.ca/collections/collection_2014/rncan-nrcan/M154-17-2008-eng.pdf "The industry is requesting that existing facilities be left in operation and be exempt from CO_2 emissions reductions until they reach their 40 year economic life." Ibid., 30; "[The Canadian Electricity Association] and most of its member utilities have proposed an "Emissions Performance Equivalence Standard (EPES)". Under the CEA's proposal, starting in 2008, all participating utilities would reduce to a specific standard (or better), their net emission rates from oil and coal-fired thermal units that have reached their 40-year anniversary (of commercial start up). The standard is currently defined to be that of a combined cycle natural gas turbine." Canadian Electricity Association, *Clean Electricity and the Environment: Electricity and Climate Change, Towards a Sustainable Future* (2002), 2, http://www.electricity.ca/media/pdfs/backgrounders/climatechangeE.pdf.

[18] Windfall are revenues earned after a unit owner has fully recovered its capital investment; that is, when a unit operates beyond its EUL.

[19] Mike De Souza, "Feds pressured by coal industry to weaken regulations, records reveal," *Postmedia News*, April 22, 2012.

3.2 No compensation is necessary where units are allowed to operate to their UEL

For nine of the units (shown in Table 2), UELs have either already expired or will expire by the end of their PPA. The PPA capacity payments for these units will pay out the generators' capital investment so there is no requirement for compensation if they are retired at the expiry of their PPAs. The PPAs are designed to allow the owners to fully recover their investment in these units. By the end of their respective PPAs, the various units will also no longer have the social licence to continue operating without reinvesting in cleanup technology.

Table 2. Nine units where UELs have already expired or will expire by the end of their PPA

Unit	In-Service Date	End of PPA	PPA UEL	Age
Milner 1	1972	2012	2012	40
Battle River 3	1969	2013	2013	44
Battle River 4	1975	2013	2013	38
Sundance 1	1970	2017	2017	47
Sundance 2	1973	2017	2017	44
Sundance 3	1976	2020	2020	44
Sundance 4	1977	2020	2020	43
Sundance 5	1978	2020	2020	42
Sundance 6	1980	2020	2020	40

For the remaining seven PPA units, the UEL comes after the PPA expiry at the end of 2020. But, in all cases the UEL timeline is much shorter than the overly generous deadlines proposed by the federal GHG regulations. According to the ELU determinations, they were scheduled to have some unrecovered residual value at the end of their PPAs — approximately $1 billion in total — as Table 3 shows.

Table 3. Residual value at PPA expiry and at UEL for seven remaining units

Unit	In-Service Date	Estimated NBV at 2020 PPA Expiry (Nominal dollars)	UEL	Age	Remaining years to recover capital	Residual NBV at UEL
Battle River 5	1981	29,000,000	2021	40	1	0
Keephills 1	1983	82,000,000	2023	40	3	0
Keephills 2	1983	78,000,000	2023	40	3	0
Sheerness 1	1986	141,000,000	2026	40	6	0
Sheerness 2	1990	167,000,000	2026	36	6	0
Genesee 1	1989	313,000,000	2029	40	9	0
Genesee 2	1994	300,000,000	2029	35	9	0
		$1,110,000,000				$0

Source: Schedule C for each unit's PPA

If these units are allowed to continue to operate out to their PPA UEL deadlines and then retired, no compensation is required. The full and fair recovery of the PPA owner's investment at UEL is as was anticipated and agreed to at the start of deregulation. Again, the PPA UEL deadlines were developed in consultation with the generators as part of the deregulation process during the late 1990s and tested through a fair and just process. The owners of these units entered into PPAs that scheduled repayment of capital according to these UELs. For the UEL timeframe remaining after the expiry of their 20-year PPAs, they took on the merchant risk of being able to recover their residual capital while also accepting the opportunity to generate an even higher return through market pricing. Although it is reasonable for government to allow these units to continue to operate as merchant plants out to their UEL dates because of prior agreement, operation beyond UEL is unnecessary and compensation for phase-out at UEL is unjustifiable. Consumers have paid for the units from their inception and the owners have been fairly compensated over the operating lives. The public is in a position to insist that these units be retired at the point when invested capital has been repaid to the owners.

Although residual net book value (NBV) capital is likely be recovered directly by the owners under a range of different power pool price scenarios, there is a risk that market prices will not suffice to provide investment recovery. Generators may demand compensation because they may not be confident in their ability to recover the residual investment prior to the UEL via merchant operation in Alberta's energy-only market. One option for PPA owners to choose would be for the Balancing Pool to enter into capacity contracts for capital payments — with reserve margin provisions — that would allow these units to continue under a modified PPA until their UEL. To cover the $1.1 billion in residual NBV at end-of-PPA in this option, consumers would pay $1.75/MWh (0.18 ¢/kWh) — around $13/year for a typical residential household.[20] Such a mechanism would: create the potential for even greater GHG reductions by operating units only at a level that ensures overall system stability; and/or allow for any market revenues from operation of these units to flow back to the public through the Balancing Pool to partly or fully recover the capacity payments.

3.3 Capital invested after deregulation is also recovered within these operating timeframes

Embedded within the PPA capacity payments were allowances for maintenance capital expenditures — "unit capital additions" — intended to ensure reliable unit performance during the PPA period. These payments were designed to provide PPA owners a reasonable opportunity — but not a guarantee — to recover their capital expenditure costs. While some such costs incurred by the PPA owners may not have been anticipated, there were undoubtedly other expenditures included in the PPA schedule that did not happen, but for which the owners were compensated — thus balancing out in the end.

Generators have also made investments in several units to increase a unit's power generation capacity beyond that committed to under the PPA. Known as efficiency "uprates", such improvements allow these generators to earn supplementary revenues from the electricity market. For some units, these investments involved replacing turbine blades — a relatively low cost and one that in some cases was anticipated and covered within the PPA capacity payments. For other units, a more extensive upgrade was required involving supplemental capital from the owner.

A review of public documents shows since 2000, approximately $276 million has been invested to uprate eleven units. It is evident from Table 4 that based on an industry norm of 10-year straight-line depreciation the residual net book value of these uprates will be zero at UEL with only a minor balance left for Sundance 3.

Table 4. Capital depreciation of uprates implemented since deregulation

Unit	Uprate		Capital Cost ($ millions)	Detail	Residual Depreciation* ($ millions)		PPA Expiry	PPA UEL	Info source
	MW	year			at end of PPA contract	at PPA UEL			
SD6	44	2001	$30	More significant upgrade	$0	$0	2020	2020	TA AIF or Website
GN1	15	2005	$8	Replace blades	$0	$0	2020	2029	Estimated cost
SH1	15	2005	$6	Replace blades	$0	$0	2020	2026	Estimated cost

[20] If recovered from load over a 10-year period. The $1.75/MWh is comparable to the $1.40/MWh cost for mercury abatement requirement that has been in place for several years.

GN2	15	2006	$8	Replace blades	$0	$0	2020	2029	Estimated cost
SH2	15	2006	$6	Replace blades	$0	$0	2020	2026	Estimated cost
BR5	15	2006	$6	Replace blades	$0	$0	2020	2021	Estimated cost
SD4	53	2007	$60	More significant upgrade	$0	$0	2020	2020	Estimated cost
SD5	53	2009	$75	More significant upgrade	$0	$0	2020	2020	TA AIF or Website
KH1	12	2012	$26	More significant upgrade	$5.2	$0	2020	2023	TA AIF or Website
KH2	12	2012	$26	More significant upgrade	$5.2	$0	2020	2023	TA AIF or Website
SD3	15	2012	$25	More significant upgrade	$5.0	$5.0	2020	2020	TA AIF or Website
			$276		$15.4	$5.0			

* 10-year straight line

Furthermore, generators appear to have enjoyed substantial financial returns on their uprate investments. Utilizing average historical pool prices, Table 5 shows per unit returns on investment (ROI) that range from 18% to 100% per annum — not including capacity payments.[21] This would allow these investments to be repaid in one to five years with an average of 2.6 years. By the time units have reached their UEL, the initial investment of $276 million could generate more than $1.6 billion in gross profit.

Table 5. Estimated net revenues from uprates

Unit	Uprate		Capital Cost ($ millions)	Capital Cost per kW ($/kW)	MWh generated per annum*	Annual Net Revenues** ($ millions)	Payback (years)	ROI (annual)	Gross Profit to end of PPA ($ millions)	Gross Profit to PPA UEL ($ millions)	ROI over total period
	MW	year									
SD6	44	2001	$30	$682	347,000	$17	1.76	57%	$323	$323	1077%
GN1	15	2005	$8	$533	118,000	$6	1.33	75%	$90	$144	1800%
SH1	15	2005	$6	$400	118,000	$60	1.00	100%	$90	$126	2100%
GN2	15	2006	$8	$533	118,000	$6	1.33	75%	$84	$138	1725%
SH2	15	2006	$6	$400	118,000	$6	1.00	100%	$84	$120	2000%
BR5	15	2006	$6	$400	118,000	$6	1.00	100%	$84	$90	1500%
SD4	53	2007	$6	$1,132	418,000	$21	2.86	35%	$273	$273	455%
SD5	53	2009	$75	$1,415	418,000	$21	3.57	28%	$231	$231	308%
KH1	12	2012	$26	$2,167	95,000	$5	5.20	19%	$40	$55	212%
KH2	12	2012	$26	$2,167	95,000	$5	5.20	19%	$40	$55	212%
SD3	15	2012	$25	$1,667	118,000	$6	4.17	24%	$48	$48	192%
			$276	**$1,045**	**2,081,000**	**$105**	**2.58**	**57%**	**$1,387**	**$1,603**	**1053%**

* 90% capacity factor[22]

**Net Pool Price x MWh; net pool price of $50 is calculated as the average pool price ($60) minus a charge of $10 that allows for variable costs such as excess energy charge (speed, no-load at 10% of PP), SGER ($15/tonne), Hg abatement ($1.40/MWh), pool trading ($0.40/MWh), etc.

[21] These are estimated returns on the entire investment. If a portion of the investment were debt financed, then the return on the investors' equity (ROE) through debt leveraging would be even higher. Whether ROI or ROE, such returns are substantially higher than "regulated rates of return" commonly provided to generators (ROE ranging from 6-10%).

[22] Historical power pool prices have been very supportive of strong revenue opportunities for uprate generation. There may be times when the incremental uprate capacity is not used (e.g. when the Pool price drops below the long-run variable cost of uprate generation, such as $10/MWh), but the frequency of these events is low. Availability of uprate capacity does not necessarily depend on the full rated capacity of a unit being accessed as the PPA owner and buyer may make economic arrangements to allow the uprate capacity to be lower in the stacking order than the PPA capacity for that unit. Furthermore, it is common for coal units to bid in a portion of its generation at low (even zero) prices in order to be positioned to ramp up quickly to take advantage of rising prices.

As such, if coal units are allowed to operate to their UEL there is no basis for industry to call for compensation for incremental capital investments in PPA units made since deregulation. These investments have provided their owners with the opportunity for significant financial returns and will have a net book value of zero at UEL.

4 Investors in merchant units built after 2001 were well aware the long-term operations of these facilities would be subject to change of law related to climate policy

Genesee 3 and Keephills 3 were built and brought into service after deregulation. Through a number of venues, they had fair warning at and since the time of investment that more stringent climate policy was possible and, indeed, likely to impact their operations. This would have informed their investment expectations and calculation of business risks and opportunities.

The two units — commissioned in 2005 and 2011 respectively — came into service 13 and 19 years after the Rio Earth Summit, wherein Canada signed onto and subsequently ratified the United Nations Framework Convention on Climate Change (UNFCCC). The UNFCCC articulated the clear objective to stabilize GHG concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system.[23] Developed countries committed to taking the lead.[24] By ratifying the convention, Canada bound itself internationally to formulate and implement measures to mitigate climate change and to "adopt national policies and take corresponding measures to mitigate climate change."[25] Given coal-fired generation's exceptionally high emissions intensity in comparison to other generation options — and the ready availability of alternatives during the planning, construction and operations of these plants — the potential impact of these commitments under international law on coal investments has been clear for nearly 25 years.

Merchant unit developers also received more precise warning the imposition of additional greenhouse gas obligations would be possible over the lives of the units, including:

- a consensus decision — by a multi-stakeholder group to which Capital Power and TransAlta are party — to acknowledge the potential for future GHG management obligations;
- clear statements included in the approval documents for these merchant units; and
- clear articulations from the environmental community that increasing stringency on GHG management would be necessary.

In 2003, the Clean Air Strategic Alliance (CASA) Electricity Project Team (EPT) made a number of consensus recommendations forming the Emissions Management Framework.[26] Both TransAlta and EPCOR — Capital Power's predecessor as generation owner — were members of the EPT that negotiated these recommendations by consensus and were represented on the CASA board that approved the framework by consensus.[27] Five of the recommendations focused on greenhouse gas emissions. Recommendation 25 made a specific requirement for new coal units — that they must offset their GHGs to a good-as-gas intensity level. This recommendation also clearly stated, "It is recognized that future national or international greenhouse gas reduction commitments may result in additional management

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[23] United Nations, *United Nations Framework Convention on Climate Change* (1992), Article 2.

[24] Ibid., Article 3.1.

[25] Ibid., Article 4.1(b), 4.2(a).

[26] Clean Air Strategic Alliance Electricity Project Team, *An Emissions Management Framework for the Alberta Electricity Sector: Report to Stakeholders* (2003).

[27] Ibid, 40.

obligations."[28] This was included within the text of the recommendation itself, not just in the explanatory verbiage around the recommendation. Given CASA's consensus process, Capital Power and TransAlta explicitly "recognized" the possibility that climate policy changes would result from commitments made to national and international climate processes — such as the Paris climate conference process underway.

Further work by the CASA EPT on the greenhouse gas management issue resulted in a July 2004 report by its Greenhouse Gas Allocation Subgroup committee. This report presented a conceptual mechanism for managing GHGs in the electric power industry that was subsequently adopted by the CASA board by consensus. Both TransAlta and Capital Power (EPCOR) were represented on this committee — indeed, the industry co-chair was EPCOR's senior vice-president of environment. Key concepts agreed to within the report included: application of a specified intensity limit to transitional units[29] up to the end of design life — defined as 40 years for coal plants — to be followed by a revised specified intensity limit reflecting the standards in place at that time. This report also explicitly recognized that "future national or international greenhouse gas reduction commitments could result in additional management obligations."

The EPT consensus acknowledgement of further GHG management obligations that came out of the framework development process reflected clear signals made to the generators in their approvals processes. The EUB decisions — in 2001 for Genesee 3 and in 2002 for what became Keephills 3 — included clear statements foreseeing policy change. In particular, the EUB directed each operator to fulfill its commitment to offset GHG emissions to the "good-as-gas" standard subsequently reflected in CASA EPT framework Recommendation 25. But in doing so, the EUB also recognized the possibility that future policy change could impact even these commitments.

The Board made identical or near-identical statements signaling the potential for future action in both approvals decisions:

> The Board also directs these offsets to be updated to correspond to any future changes in emissions standards for coal-fired power plants or a corresponding gas-fired power plant. The Board notes AENV's intent to consider the introduction of emission objectives related to greenhouse gases as part of its post-2005 emission standards.[30]
>
> …
>
> The Board recommends that since changes to the current source emission standards are reasonably foreseeable, it is prudent for proponents of new power plants to incorporate flexibility into their projects so that compliance could be assured within a reasonable timeframe.[31]
>
> …
>
> The Board noted in its EPCOR Genesee 3 decision (Decision No. 2001-111) that exempting new coal fired power plants from future and stricter environmental standards (grandfathering) would not be appropriate. The Board believes this conclusion is also applicable in this Keephills 3 and 4 Application. The Board views that orderly implementation of expected revisions to source emissions and mercury standards is appropriate for the TransAlta's Keephills 3 and 4 project.[32]

Other participants in the approvals processes made clear the expectations that greater action would be necessary. A group of interveners called the Clean Energy Coalition made clear in the Genesee hearing

[28] Ibid, 10.

[29] "Transitional unit" referred specifically to Genesee 3 and Keephills 3: units that had received approval but were not yet fully constructed and commissioned.

[30] Electric Utilities Board, *490 MW Genesee Power Plant Expansion Application No. 2001173* (Decision 2001-111), 19; Electric Utilities Board, *TransAlta Energy Corporation 900-MW Keephills Power Plant Expansion*, (Decision 2002-014), 69 (added "reasonable foreseeable" to "future changes…").

[31] Keephills Decision, 75.

[32] Ibid, 68.

that offsetting emissions to a “good-as-gas” standard was not acceptable and that emissions should be offset entirely — stating that this had been an earlier EPCOR commitment.[33] The coalition also noted that the “good-as-gas” offsetting was unlikely to allow EPCOR to meet its own target of reducing GHG emissions 6% below 1990 levels.[34] The provincial environment department indicated “the subject of greenhouse gas emission objectives would be discussed with stakeholders as part of the consideration of post-2005 standards for coal power plants.”[35] Moreover, the Government of Alberta “noted that greenhouse gas emissions, such as CO_2, were not currently a regulated air emission in the province. The importance in taking a leadership role in encouraging of greenhouse gas emissions in the province was recognized.”[36]

Generators receive approvals under the Environmental Protection and Enhancement Act (EPEA) for a limited period of time — often ten years. At the expiry of the approval, generators must apply for renewals. Such approvals are subject to amendment by Alberta Environment and Parks. The approvals regularly include a provision making explicit the possibility of change in law and the obligation to comply with these changes, for example: “Notwithstanding any terms, conditions or requirements of this approval, all terms and provisions of the Alberta Environmental Protection and Enhancement Act and its regulations as amended from time to time must be complied with by the approval holder at all times.” In other words, a generator’s licence to operate — issued by the provincial government — is at all times subject to changes in environmental law. Investors have fair warning the approvals generators have to operate could be altered by new environmental obligations and that those approvals are not permanent.

Moreover, it is through these approvals that the provincial government has implemented new environmental regulations for existing plants, such as mercury emission abatement requirements as well as end-of-design-life — 40 years of age — NO_x and SO_2 emissions intensity limits. The impermanence of the approvals and the precedent for using amendments to implement policy changes further demonstrate the fair warning that generators have had — the province can ratchet up emissions management obligations and retain the formal legal authority to do so via EPEA approvals. This is also true of GHG policy.

As a case in point, when Capital Power later applied to the AUC to remove the condition for GHG offsets during its approval renewal in 2011, the AUC made the following findings about this “future changes” provision: “as GHG emission standards for either coal or natural gas power plants changed over time, the amount of offsets required to achieve natural gas equivalency would also change, but only if the standards went up. The second sentence of Clause 10 addresses the possibility that there will be future changes in the technology available to limit GHG emissions for either coal or natural gas power plants and makes it a condition of the approval that GP3 comply with any higher standards arising from technological change.”[37] This interpretation further demonstrates the widely accepted acknowledgement that GHG policy stringency was expected to rise.

As such, the resulting EUB approvals for these two coal plant expansions should not be taken as evidence that there was a reasonable investment expectation that these units would be exempted from potential future climate change policy impacts and/or allowed to operate for some extended period — such as the federal government’s lifespans — without more stringent GHG management obligations. To the contrary, the decisions explicitly acknowledged possibility for increasing stringency. The EUB, and its successor the AUC, have largely made their approvals decisions based on requirements that new generation would meet the minimum policies and standards established by the provincial government. But this was never

[33] Genesee Decision, 14, 54.

[34] Ibid, 54.

[35] Ibid, 15.

[36] Ibid, 58.

[37] Alberta Utilities Commission, *Amendment to Genesee 3 Power Plant Approval No. U2010-32* (Decision 2011-026), 15.

intended to preclude subsequent provincial action — particularly where approval decisions made clear the possibility of more stringent action.

With this history in mind, we can more clearly understand the investments made in these two units as business risks calculated to generate significant profits by exploiting an inexpensive fuel source in a period of higher electricity prices resulting from high natural gas prices. These Alberta-based corporations made these investments knowing that climate policy would likely change in the future in a way that would be unfavourable to coal-fired electricity. The investments may reflect misplaced confidence that climate policy stringency could be delayed longer than is reasonable under science-based limits.

Admittedly, the principles underlying "fairness" or "reasonable investment expectations" with respect to the two merchant units are less clear-cut and less quantitative than for the PPA units. The balance of what length of operations satisfies investment expectations was not previously determined as with the PPA EUL process. While consumers have no obligation to these merchant unit investors and bear no risk associated with stranded investments in Alberta's deregulated market, it may be appropriate for some limited compensation for accelerated depreciation of these units such as through capacity payments by the Balancing Pool — similar to the concept previously suggested in Section 3.2. With residual NBV for these two units estimated at an upper limit of $1.3 billion at the end of 2030 — assuming straight-line depreciation over 40 years and failing to account for fair warning and externalities — these capacity payments would cost consumers $1.00/MWh (0.1 ¢/kWh) — around $7/year for a typical residential household.[38] Any solution should recognize the fair warnings to investors that climate policy change was possible and indeed likely, and also account for the externalized costs these merchant units impose on society as well as the reasonable costs they should be expected to absorb to manage their impacts to air quality.

5 Conclusion: Alberta can implement a measured coal phase-out schedule while maintaining investor confidence in the electricity system

New investors can still have confidence in the Alberta electricity system under the Pembina Institute's proposal for a meaningful but measured phase-out schedule. For the existing units that have been under PPAs, the generators will receive a reasonable opportunity to earn a return on their investment and will have their invested capital paid out. With respect to the two merchant units, there was fair warning at all times — including at the time of the initial investment decision — to inform investment expectations that subsequent change in law on GHG emissions would be possible and, indeed, likely. Depending on the pace of the resulting phase-out or emissions performance schedule — and if the Government of Alberta deems it necessary —, transitional measures may be put in place for these merchant units to ensure the correct balance of public interest through capacity payments.

A clear and unambiguous commitment to a responsible GHG management policy provides regulatory certainty. Having a credible GHG policy that can stand the test of time is essential to facilitating new investment. Investors will respond to the supply–demand signals created in the Alberta electricity system and will have greater confidence in the business parameters of those investments when credible policy is in place that lives up to national and international expectations.

In this way, the Government of Alberta can meet its objective of phasing out coal plants to demonstrate real, tangible action on the international stage. It can do so in a credible and cost-effective manner, and it can maintain investor confidence in the Alberta electricity system.

[38] If recovered from load over a 20-year period.