Strengthening TIER for Alberta's Low-Carbon Growth:

Measuring credit oversupply risks in Alberta's carbon market

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CLEAN PROSPERITY

About Clean Prosperity

Clean Prosperity is a Canadian climate policy organization. We advocate for practical climate solutions that reduce emissions and grow the economy.

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Abbreviations

AER	Alberta Energy Regulator
AESO	Alberta Electric System Operator
CCfD	Carbon contract for difference
CCIR	Carbon Competitiveness Incentive Regulation
CCO	Carbon credit offtake
CCUS	Carbon capture, utilization, and storage
CGF	Canada Growth Fund
CO_2e	Carbon dioxide equivalent
DER	Distributed energy resource
ECCC	Environment and Climate Change Canada
EGDF	Electricity grid displacement factor
EOR	Enhanced oil recovery
EPA	Environment and Protected Areas
EPC	Emissions Performance Credit
ERED	Emissions Reduction and Energy Development
ERP	Emissions Reduction Plan
GHG	Greenhouse gas emissions
HPB	High-performance benchmark
ICE	Intercontinental Exchange
IRA	Inflation Reduction Act
ITC	Investment tax credit
LCFS	Low-carbon fuel standard
Mt	Megatonne (one million tonnes)
NPV	Net present value
REC	Renewable Energy Credit
REP	Renewable Energy Program
TIER	Technology Innovation and Emissions Reduction

Foreword: Why this research is important for Alberta's low-carbon economic growth

By Adam Sweet, Director for Western Canada, Clean Prosperity

Countries around the world are in a generational race to attract low-carbon investment. From decarbonized petrochemical manufacturing to capturing, utilizing, and storing carbon, the global opportunity for new projects represents hundreds of billions of dollars worth of investment. Alberta is in this race and can win it. New multi-billion dollar low-carbon energy and carbon removal projects have recently been announced, such as Dow Chemical's carbon-neutral petrochemical plant in Alberta's Industrial Heartland and Entropy's carbon capture, utilization, and storage (CCUS) facility in Northern Alberta. However, low-carbon project proponents still need greater certainty about the economic viability of their projects in order to invest in Alberta.

Investors, both foreign and domestic, are assessing Alberta's market potential not just today but for 2030 and beyond, given the long lead times on these major projects. They are considering classic investment questions such as siting requirements, social acceptability, tax rates, and labour availability. Investors are also evaluating the potential revenue they can generate in Alberta from selling the carbon credits they produce, as this revenue is critical to their business cases, particularly given the generous subsidies for low-carbon investment on offer in the United States.

In Alberta, carbon credits are generated through the province's industrial carbon pricing system, the Technology Innovation and Emissions Reduction (TIER) Regulation. TIER and the TIER carbon credit market form the backbone of Alberta's low-carbon economy. TIER is Canada's largest emissions reduction system, covering a quarter of Canada's total emissions, over half of Canada's emissions from large industrial emitters, and about 60% of Alberta's emissions overall. It is also foundational to Alberta's climate plan – the Emission Reduction and Energy Development (ERED) Plan – and the TIER carbon credit market is Canada's largest and one of the largest in North America, in terms of emissions covered.

TIER works by setting emissions intensity benchmarks for industrial facilities across Alberta. The benchmark defines how much a facility can emit for each unit of production — tonnes of carbon dioxide emitted per tonne of hydrogen produced, per megawatt hour of electricity generated, and so on. If an industrial facility's emissions intensity is below the benchmark, the facility earns carbon credits, called emission performance credits (EPCs). Companies can also create another kind of carbon credit, called an offset, by undertaking activities that reduce or displace emissions, such as CCUS or renewable energy generation. These carbon credits (i.e., EPCs and offsets) can be bought and sold between companies in the TIER carbon market. Companies buy credits to avoid paying into the Government of

Alberta's TIER Fund (at a higher cost than buying a credit). Credit sales are an important source of revenue for low-carbon investments.

Investors pay close attention to the current and projected future values of these carbon credits. If investors believe that demand for credits will exceed supply, they can have confidence that the value of the carbon credits their project generates will be sufficient to support their business case. However, if they believe that supply will be greater than demand, leading to lower credit prices, they will lose a critical revenue stream and may not proceed with the project.

This paper examines the outlook for the TIER carbon market. The analysis uses publicly available plans and data from the provincial and federal governments, along with market data available from various private but accessible sources. In other words, the inputs to our analysis mirror those available to investors when making an investment decision.

To secure Alberta's share of low-carbon investments, it is imperative that investors have confidence that they can generate predictable revenue through the TIER carbon market. By advancing policies to ensure that TIER will not become oversupplied with credits, we will not only attract critical low-carbon investments, but also drive economic growth in the province. Let's seize the opportunity to position Alberta as a global leader in low-carbon economic growth.

Executive summary

The Technology Innovation and Emissions Reduction (TIER) carbon credit market faces significant challenges that threaten its ability to support low-carbon economic growth in Alberta. The primary issue is the lack of confidence in the future value of emission performance credits (EPCs) and offsets (collectively referred to as carbon credits), which is crucial for justifying investments in low-carbon projects. The current uncertainty about the long-term value of carbon credits prevents TIER from working as intended to incent decarbonization projects and achieve emission reductions across Alberta industry.

This paper builds on Clean Prosperity's earlier analysis of the TIER carbon market, published in October 2022, which modelled projections for net obligations (total compliance obligations less EPCs and offsets in a given year) to 2030 – including under the then-proposed 2% annual benchmark tightening.[1]

Since then, a number of key government policy shifts have taken place, impacting the outlook for the TIER carbon credit market:

- The Government of Alberta increased the annual benchmark tightening from 1% to 2%, with the oil sands subject to a 4% annual tightening rate in 2029-2030;
- The Government of Alberta published its climate plan titled Emissions Reduction and Energy Development Plan (April 2023)[2];
- The federal government published the draft Clean Electricity Regulations (August 2023) and a subsequent update (February 2024)[3]; and
- The federal government published a regulatory framework outlining the proposed design of the oil and gas sector emissions cap.[4]

This paper examines the risk of a credit oversupply in TIER's carbon market under these policies and targets. The paper models three scenarios for TIER's market balance in 2030 under current benchmark tightening rates:

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[1] Grant Bishop & Michael Bernstein (2022), Tightening TIER for Alberta's decarbonization. Available online: https://cleanprosperity.ca/alberta-carbon-pricing-system-needs-an-important-fix/

[2] Available online: https://www.alberta.ca/emissions-reduction-and-energy-development-plan

[3] Available online: https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/clean-electricity-regulation.html

[4] Available online: https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/oil-gas-emissions-cap.html

- an Emissions Reduction Plan (“ERP”) scenario, reflecting federally proposed policies (specifically, the oil and gas emissions gap and the Clean Electricity Regulations) and target reductions under the federal 2030 ERP;
- an Emissions Reduction and Energy Development (“ERED”) scenario, reflecting target reductions presented by the Alberta government’s ERED Plan; and
- a “Status Quo” scenario, where emission intensity is “frozen” at current levels for all sectors while allowing production output to grow.

These scenarios are not intended as predictions but instead illustrate the potential for a future carbon credit oversupply, which in turn would depress prices for EPCs and offsets. We find that the TIER market is likely to face an oversupply by 2030 under any meaningful decarbonization scenario with the current rules for benchmark tightening. This risk is evident to investors, as the market prices for credits have diverged significantly below the headline carbon price – the discount has risen from roughly 5% in 2020 to nearly 40% in 2024.

Consistent with the findings of our 2022 paper, this updated analysis again shows that a 2% tightening rate would be insufficient to avoid an oversupply of EPCs and offsets in 2030 under our modelling scenarios. If TIER benchmarks are only tightened by 2% each year and facilities achieve the emission reductions targeted in the federal ERP and implied by the oil and gas emissions cap and Clean Electricity Regulations, the market will face an oversupply of 25 Mt of credits in 2030. If TIER benchmarks are only tightened 2% each year and facilities meet the emission reductions targeted in Alberta’s ERED Plan, the market will face an oversupply of 27 Mt of credits in 2030. Additionally, in our Status Quo scenario, where facilities’ emission intensities remain at current levels, the TIER market can absorb 30 Mt of credits in 2030 before tipping into oversupply. However, we also show that this available capacity for additional reductions could be exhausted if just some of the proposed low-carbon projects announced in Alberta move forward. Currently, there are about 60 Mt worth of proposed carbon capture, utilization, and storage projects in Alberta by 2030. If half of this sequestration capacity moves forward, TIER will be oversupplied with credits.

For the long-term viability of TIER, the Alberta government must provide certainty for investors that the TIER market will not be oversupplied. In other words, the Alberta government must ensure that the demand for carbon credits will consistently exceed the newly created credits. This requires a commitment that reductions in emission intensity will not consistently outpace the rate of tightening benchmarks. For project proponents to undertake investments in long-term decarbonization based on future credit prices, market participants must be confident that the TIER market will be balanced – regardless of what emissions reductions are actually achieved.

That is why we recommend that the Alberta government:

1. Review TIER stringency and the rate of benchmark tightening at least every two years to preemptively address any emergent oversupply of EPCs and offsets.
2. Adopt a policy rule like adaptive tightening for TIER stringency that would automatically trigger changes to stringency based on market conditions (i.e., to accelerate tightening of benchmarks to keep up with a rapid reduction of emission intensities).
3. Increase transparency of the TIER market through regular publication of price statistics for traded EPCs and offsets.
4. Participate in guaranteeing the long-term value of EPCs and offsets under TIER through carbon contracts for difference (CCfDs).

Paper overview

This paper proceeds with the following chapters:

Chapter 1 provides a brief introduction to TIER, overviewing how emitters' obligations are determined, how credits and offsets are created, and how companies meet their compliance obligations.

Chapter 2 presents recent trends in the TIER carbon market, highlighting the widening price discount for EPCs/offsets and the declining share of net obligations relative to TIER-regulated emissions.

Chapter 3 demonstrates how carbon price uncertainty impacts investment decisions and how a price guarantee, such as CCfDs, can alleviate that risk.

Chapter 4 explains the vulnerability of TIER's design to an oversupply of EPCs and offsets and shows how adaptive tightening of benchmark stringency can alleviate this risk and strengthen the market for credits/offsets.

Chapter 5 presents the projected oversupply of EPCs and offsets under modelling for three scenarios for net obligations (i.e., the "ERP", "ERED", and "Status Quo" scenarios).

1. Introduction to the TIER Framework

Takeaways

- TIER establishes benchmarks for emission intensity (i.e., emissions per unit of output) for large industrial emitters. Emitters either face a compliance obligation for emissions exceeding their allowance or receive credits if emissions fall below this allowance.
- Under TIER, various quantification protocols provide for the creation of offsets for activities deemed to reduce emissions.
- Facilities can meet their compliance obligations by acquiring credits and/or offsets, which can be traded between emitters.
- The TIER regime will be reviewed next in 2026 by both federal and provincial governments.

1.1 How obligations and credits are calculated under TIER

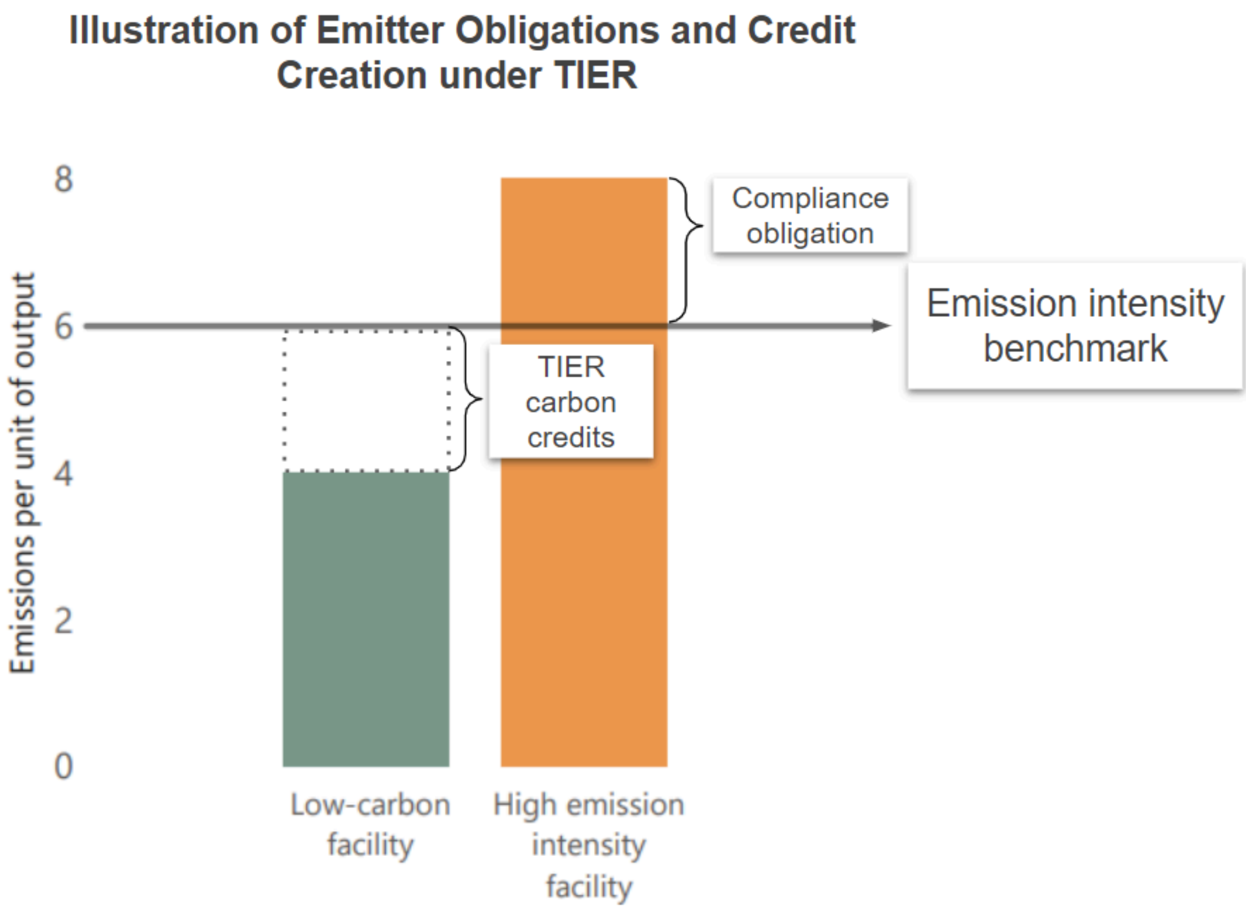
Implemented in 2020 (to supersede the previous industrial carbon pricing regime), Alberta's Technology Innovation and Emissions Reduction (TIER) Regulation is an output-based carbon pricing system that regulates greenhouse gas (GHG) emissions from Alberta's industrial sector. The TIER regime provides for the trading of credits and offsets between emitters.

Under TIER, regulated facilities in certain trade-exposed industries receive "free" emissions allowances up to a limit determined by an emission intensity benchmark (i.e., emissions per unit of output). This means an emitter only pays the carbon price on emissions exceeding the applicable emission intensity benchmark.

Conversely, if an emitter's emission intensity falls below the benchmark, they receive credits, known as Emissions Performance Credits (EPCs), under TIER. These credits can be traded to other emitters to meet their compliance obligations.

Figure 1 illustrates the obligations incurred by a hypothetical high emission intensity facility (i.e., emission intensity above its benchmark) and the credits created by a hypothetical low emission intensity facility (i.e., emission intensity below its benchmark).

Figure 1: Emitters can incur obligations or create EPCs under TIER



Under TIER, emission intensity benchmarks in most industries (notably except power generation) are calculated based on each individual facility's historical emission performance. This is known as a *facility-specific* benchmark, and differs from other output-based pricing systems that use *product-specific* benchmarks where every facility producing the same product receives the same benchmark.[5]

Specifically, a TIER-regulated facility can apply for a benchmark based on its historical emission intensity from 2013-2015.[6] The benchmark in a given year is then calculated using a target emission intensity reduction for that year, generally beginning with a 10%

[5] TIER's predecessor industrial pricing regime, the Carbon Competitiveness Incentive Regulation, used product-specific benchmarks. Under TIER, power generation facilities continue to be subject to a product-specific high-performance benchmark.

[6] See subsection section 8.2.3 of "Standard for developing benchmarks: Technology Innovation and Emissions Reduction regulation." Available online: https://open.alberta.ca/publications/standard-developing-benchmarks-tier-version-2

reduction in 2020 and tightening by an additional 1% annually for 2021-2022 and 2% annually for 2023 and beyond.[7]

Notably, TIER allows a facility to apply a high-performance benchmark (HPB) to its production instead of using its facility-specific benchmark. HPBs are based on the average emission intensity of the top-performing 10% of facilities in a given sector for a particular product.[8] This flexibility ensures that facilities with a low emission intensity are not penalized by TIER's default facility-specific benchmarking approach.

Figure 2 illustrates the implications of applying facility-specific benchmarks across oil sands facilities. The figure illustrates the estimated facility-specific benchmarks and emission intensities in 2022 across oil sands facilities.[9] As illustrated, facility-specific benchmarks are significantly higher for more emission-intensive facilities. This facility-specific approach reduces the compliance costs that more emission-intensive facilities face compared to a product-specific benchmarking approach (i.e., a uniform benchmark for all producers).[10]

Conversely, facilities with lower emission intensities have relatively more stringent facility-specific benchmarks compared to more emission-intensive facilities. To create EPCs, these less emission-intensive facilities must emit below either the relevant HPB (e.g., for mining or in situ) or the relatively more stringent facility-specific benchmarks.

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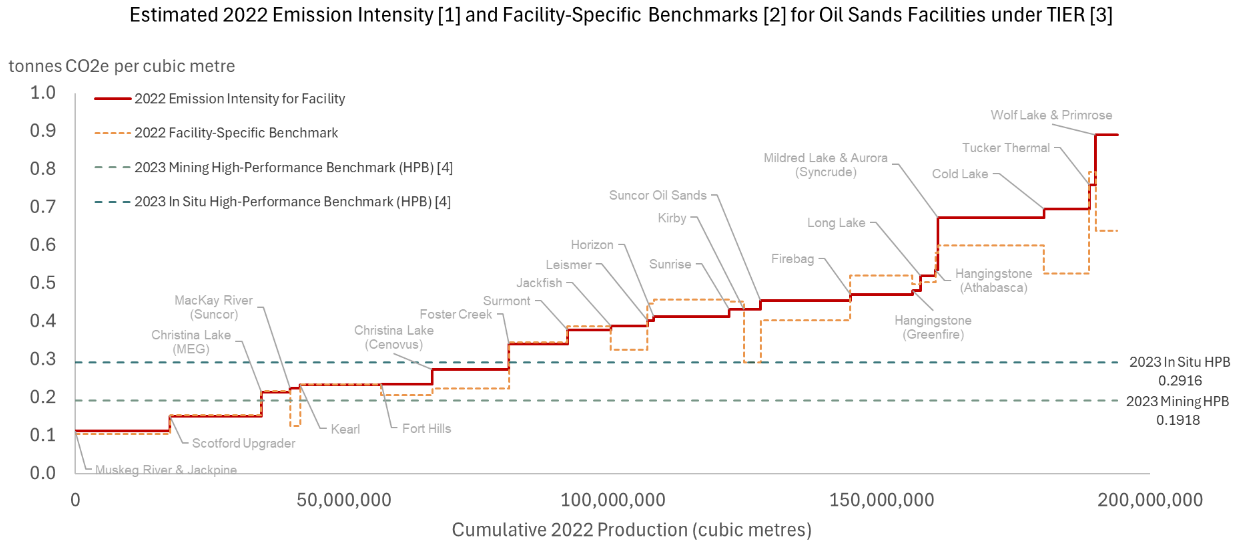
[7] See: ibid, section 8.2. Note that oil sands facility-specific benchmarks (mining and upgrading) were assigned a more stringent target reduction for 2021 (17%) and face a benchmark tightening schedule of 2% for 2023-2028 and 4% in 2029-2030 (see: ibid, section 8.5). For simplicity of this explanation, we have omitted discussion that the facility-specific benchmarks under TIER include both tightening and non-tightening components (see: ibid, section 8.2.5). The non-tightening components includes non-combustion industrial process emissions and the attributed indirect emissions from electricity consumption. The emission intensity reduction target for a given year only applies to the tightening component of the facility-specific benchmark.

[8] See: ibid, section 8.1.1.

[9] Alberta's Ministry of Environment and Protected Areas does not publish facility-specific benchmarks. The illustrated facility-specific benchmarks were estimated using publicly available data and the target emission intensity reduction for 2022 under the TIER Standard for Developing Benchmarks (see section 8.2 of: https://open.alberta.ca/publications/standard-developing-benchmarks-tier-version-2). In general, historical data (including for emissions, production, and, where available, electricity generation, consumption, and exports) was leveraged to compute the average emission intensity during 2013-15 (or the most recent full operating years) for each facility. Facility-specific benchmarks were aligned with any EPCs issued as well as with aggregate obligations and EPCs for the given subsector.

[10] For elaboration on potential economic distortions resulting from TIER's approach to assigning facility-specific benchmarks, see: Grant Bishop. August 2019. *Too TIER-ed? Alberta's Proposed Re-design of Carbon Pricing for Large Emitters*. C.D. Howe Institute. Available online: https://www.cdhowe.org/public-policy-research/too-tier-ed-albertas-proposed-re-design-carbon-pricing-large-emitters

Figure 2: Emission intensity across oil sands facilities varies considerably, and high-performance benchmarks can prevent low emission intensity facilities from being penalized by facility-specific benchmarks



Sources: AER (ST-39 and ST-53 reports), AESO (Metred Volumes and Historical Generation), Alberta Carbon Registries, ECCC (GHG Reporting Program), Alberta EPA (TIER Compliance Reporting)

Notes: [1] Emission intensity estimated from production and emissions for 2022 and adjusted for electricity generation, consumption and exports (where data available)
[2] Facility-Specific Benchmarks estimated from 2013-15 (or earliest full operating years) data and calibrated for most recent Emissions Performance Credits (if any) issued for given facility, applying target emission reduction for 2022 following TIER Standard for Benchmarks (i.e., 12% for in situ and 18% for mining & upgrading)
[3] Emissions and net obligations across facilities aligned with subsector totals in TIER Compliance Reporting; although producing synthetic crude oil, Scotford Upgrader included in subsector
[4] 2023 High Performance Benchmarks for In Situ and Mining Oil Sands facilities established in Ministerial Order 03/2024 (Environment & Protected Areas) on 30 January 2024

1.2 How offsets are created under TIER

Under TIER, projects that have voluntarily reduced their emissions can create emissions offsets. These offsets, like EPCs, can be transferred and applied against an emitter's compliance obligation under TIER.

To be an eligible offset project, the project must meet one of 18 approved quantification protocols published by the Alberta Ministry of Environment and Protected Areas (EPA).[11] Eligible offset projects include wind and solar electricity generation, CO_2 capture and storage in deep saline aquifers and through enhanced oil recovery (EOR), reduced methane from pneumatic devices, vent gas reductions, waste heat recovery, and landfill gas capture.[12] Using data from the Alberta Carbon Registries,[13] Figure 3 illustrates the annual creation of new offsets by project type. In recent years, the bulk of offsets have come from facilities converting to non-venting pneumatic devices in the oil and gas sector, the

[11] See: Alberta's Ministry of Environment and Protected Areas. Alberta Emission Offset System. Available online: https://www.alberta.ca/alberta-emission-offset-system

[12] Projects for conservation cropping (until 2021) and tillage system management (until 2011) projects were previously significant sources of offsets before being phased out.

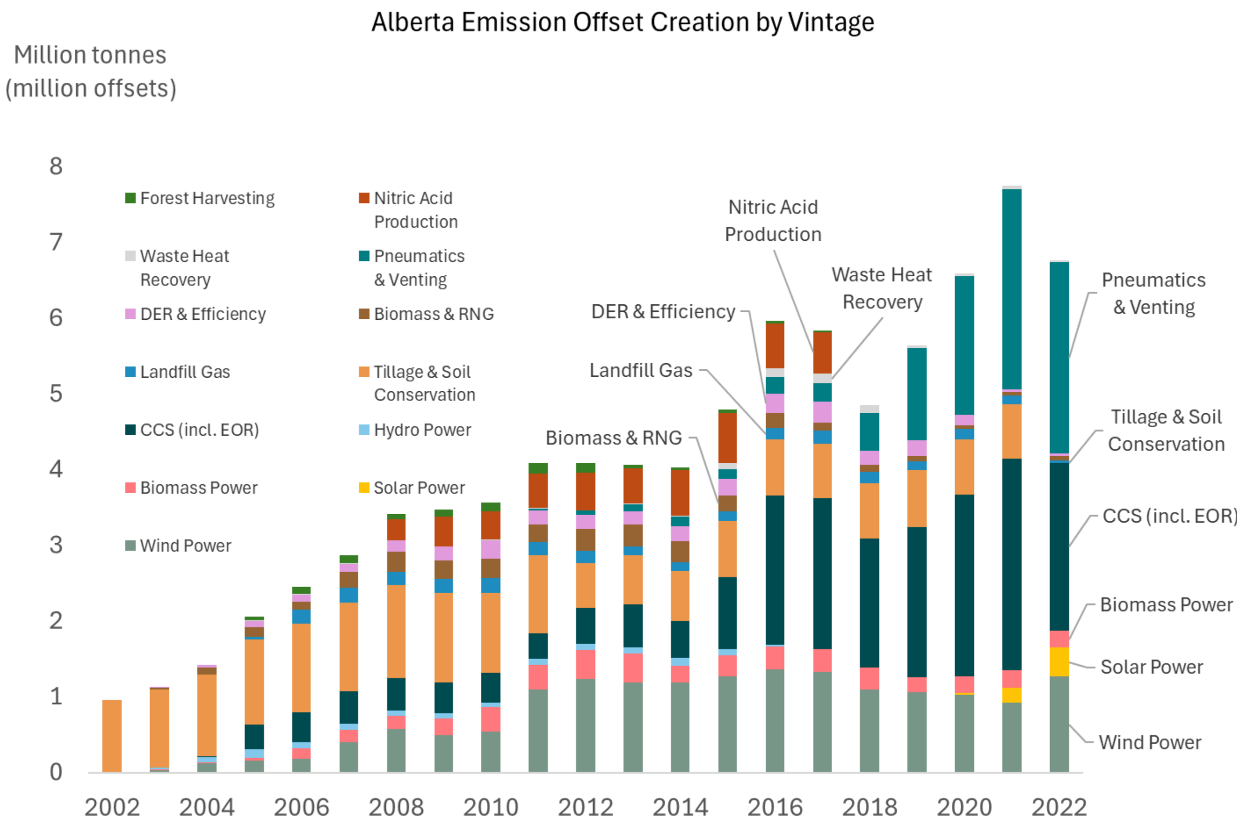
[13] Alberta Emissions Offset Registry Listing. Available online: https://alberta.csaregistries.ca/GHGR_Listing/AEOR_Listing.aspx

implementation of carbon capture, utilization, and storage (CCUS), and the production of wind-powered electricity.

Notably, rather than the emission intensity benchmark applicable to other power generation facilities, new renewable wind and solar generation projects are eligible to create offsets at an advantageous electricity grid displacement factor (EGDF).[14]

[14] Although other power generation (including hydro) is credited at a high-performance benchmark (0.3700 tonnes CO_2e per MWh in 2022 and declining to 0.3108 t/MWh in 2030), wind and solar receive offsets based on a specified EGDF. The EGDF in effect from 2020 to 2022 was 0.53 t/MWh (prescribed in version 2.0 of the Carbon Offset Emission Factors Handbook). This was reduced to 0.52 t/MWh for 2023 (see version 3.0 of the Carbon Offset Emission Factors Handbook) and will decline according to a schedule in the present Carbon Offset Emission Factors Handbook until converging with the electricity HPB in 2030 (see version 3.1 of the Carbon Offset Emission Factors Handbook). Renewable generation projects initiated in 2023 or earlier are "grandparented" to use the EGDF in effect at initiation. However, projects in 2024 and after must use the scheduled EGDF corresponding to the offset vintage (i.e., for the year when generating power from the renewable project). The EGDF is intended to reflect emissions reductions through displacement of electricity emissions from both an "operating margin" (as the average emission intensity of marginal generation) and a "build margin" (as the production-weighted average emission intensity of newly built generation).

Figure 3: Offsets can be created by projects that reduce emissions under an approved quantification protocol



Source: Alberta Carbon Registries (as of 9 April 2024)

1.3 Compliance under TIER

A TIER-regulated facility may satisfy a share of its obligation by acquiring and retiring EPCs or offsets.[15] For 2023 and prior years, the maximum share was 60%. This limit increases by 10% annually until 2026, when a facility may retire EPCs or offsets to satisfy 90% of its obligation. It must otherwise purchase TIER Fund credits by paying the headline carbon price for the remaining emissions that exceed its benchmark.

The headline carbon price is set at \$80/tonne of CO_2 for 2024 and will increase by \$15 each year until it hits \$170/tonne in 2030 – set by a Ministerial Order from Alberta's Minister of Environment and Protected Areas and corresponding to the federal government's carbon

[15] The maximum share of a facility's obligation in a given year that may be satisfied by retiring EPCs or offsets is prescribed by TIER, s.13(9).

price schedule.[16] Payments for TIER Fund credits are directed to the TIER Fund, a portion of which is allocated to provincial debt and deficit reduction, while another portion supports decarbonization initiatives for industry.

Box A: Banking and expiry of TIER EPCs and offsets

EPCs and offsets issued under TIER can be banked to be used in future years (although these durations were notably shortened following the Alberta government's 2022 review of TIER). EPCs issued from 2017 to 2022 must be used within eight years of the year of issue, while EPCs issued in 2023 and after must be used within five years. From the year of the offsetting activity, offsets from 2017 to 2022 must be used within a nine-year period, and offsets from 2023 and after must be used within a six-year period.[17]

Significant banking has occurred within the TIER market: over 20 million offsets are presently issued and active while almost 27 million EPCs are issued and active, with another 6.5 million EPCs requested but yet to be issued (i.e., based on the discrepancy between presently issued EPCs in the Alberta Carbon Registries[18] and the total requested EPCs reportedly requested from TIER compliance reporting.)[19]

Roughly 39 million of the total 53 million presently banked EPCs and offsets will expire by 2030. As shown below in Figure 4, the number of expiring offsets and EPCs will accelerate in the coming years, rising to 13 million expiries in 2030. Depending on the extent of realized reductions in emission intensity by TIER-regulated facilities (and consequent demand for EPCs and offsets), this accelerating expiration could threaten prices for EPCs and offsets.

Nonetheless, for the modelling in this paper, we do not assess banking behaviour. Instead, we projected "net obligations" (i.e., obligations minus EPCs and offsets) across TIER-regulated facilities based on the EPCs and offsets that would be created in a given year under the stated assumptions for the particular scenario. In part, this approach is a consequence of using sector-level assumptions for reductions of emissions and emission intensity (i.e., we do not model obligations or EPCs created by each facility).

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[16] See: Ministerial Order 062/2022 [Environment and Protected Areas]. 21 December 2022. Available online: https://open.alberta.ca/publications/epa-062-2022

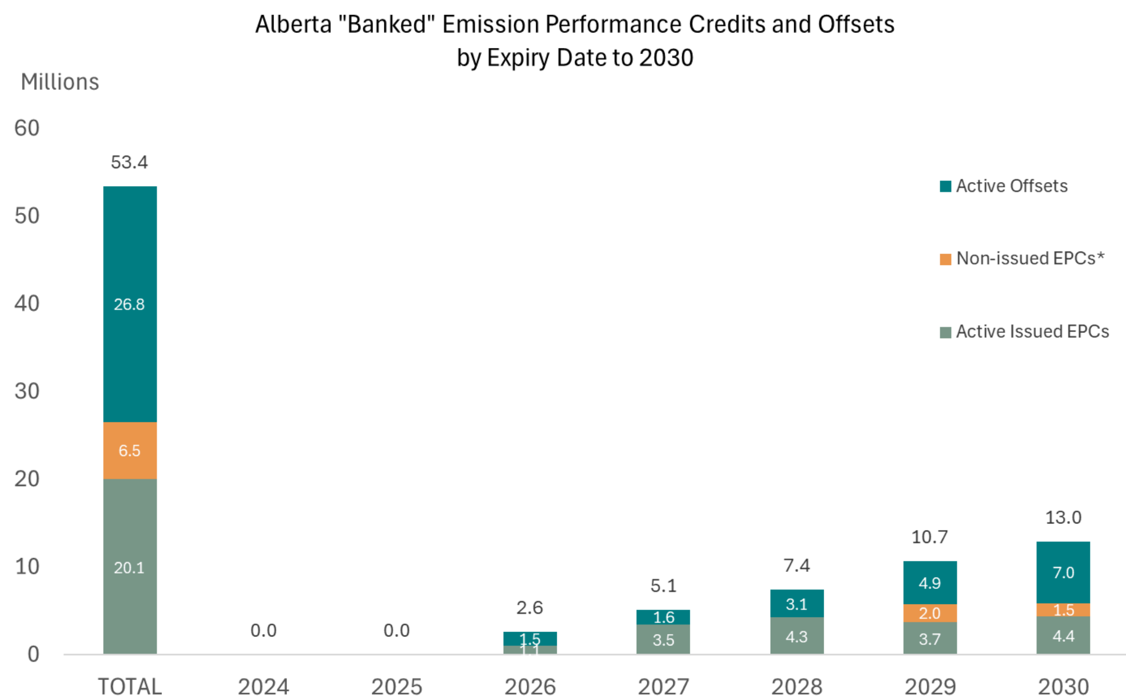
[17] Technology Innovation and Emissions Reduction Regulation, Alta Reg 133/2019, s 13(5)-(6).

[18] Available at: https://alberta.csaregistries.ca/

[19] Based on summaries of compliance results under TIER for 2020, 2021 and 2022. Available at: https://open.alberta.ca/dataset/alberta-industrial-greenhouse-gas-compliance

More importantly, our approach follows from the reasoning that, despite participants' ability to bank EPCs and offsets for years after issuance, an oversupply of EPCs and offsets relative to obligations in any year should immediately depress prices. Indeed, market anticipation of any future oversupply should also comparatively depress prices in advance. To sustain prices of EPCs and offsets near the "headline" carbon price, market participants must be confident that obligations will exceed the creation of EPCs and offsets overall.

Figure 4: Expiry of presently "banked" EPCs and offsets will accelerate in coming years



Sources: Alberta Carbon Registries (as of 19 April 2024); Alberta Environment & Protected Areas, Alberta Industrial Greenhouse Gas Compliance

Note: * Non-issued EPCs calculated from requested EPCs reported in Alberta Industrial Greenhouse Gas Compliance reporting
(i.e., Issued EPCs in Alberta Carbon Registries are less than requested EPCs reported in Alberta Industrial Greenhouse Gas Compliance reporting
Therefore, non-issued EPCs assumed equal to requested EPCs minus issued EPCs for given vintage corresponding to expiry year)

1.4 Review of TIER benchmark tightening

When legislated in 2019, the TIER regulation required a review of the regime by the end of 2022.[20] Alberta's government undertook a review in 2022, publishing a discussion document and soliciting feedback on various aspects of the regime.[21] The 2022 proposals to update TIER included increasing the rate of benchmark tightening from 1% to 2% and introducing annual tightening of the high-performance benchmark for electricity. Following this review, TIER was amended by order-in-council in December 2022[22], and new standards were published to implement the increased pace of benchmark tightening.

Concurrently, in 2022, the Government of Canada was evaluating provincial carbon pricing systems for equivalence with the federal government's minimum national standards for 2023-2030.[23] The federal criteria for equivalence included ensuring that "output-based pricing systems for industry are sufficiently stringent to create strong markets that maintain a clear price signal across all covered emissions that is aligned with the minimum carbon price". In November 2022, the federal government announced that Alberta's TIER would continue to apply to industrial emitters in the province – indicating that TIER met the federal criteria for equivalence.[24]

The present TIER legislation requires that the regime be reviewed before the end of 2026.[25] Similarly, the federal government will conduct an assessment of provincial carbon pricing systems in 2026 to confirm that they continue to meet the federal benchmark criteria for 2027–2030, taking stringency into account as the primary factor.[26]

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[20] See: Technology Innovation and Emissions Reduction Regulation, Alta Reg 133/2019, s 39 (Version between Aug 25, 2020 and Jan 3, 2023). Available online: https://canlii.ca/t/9lw0#sec39
[21] See: https://www.alberta.ca/technology-innovation-and-emissions-reduction-regulation-review
[22] See: https://kings-printer.alberta.ca/documents/Orders/Orders_in_Council/2022/2022_403.html
[23] See: https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/carbon-pollution-pricing-federal-benchmark-information.html
[24] See: https://www.canada.ca/en/environment-climate-change/news/2022/11/the-government-of-canada-strengthens-pollution-pricing-across-the-country.html
[25] Technology Innovation and Emissions Reduction Regulation, Alta Reg 133/2019, s 39. Available online: https://canlii.ca/t/9lw0#sec39
[26] See: https://www.gazette.gc.ca/rp-pr/p2/2023/2023-07-05/html/sor-dors129-eng.html

2. TIER pricing and compliance trends

Takeaways

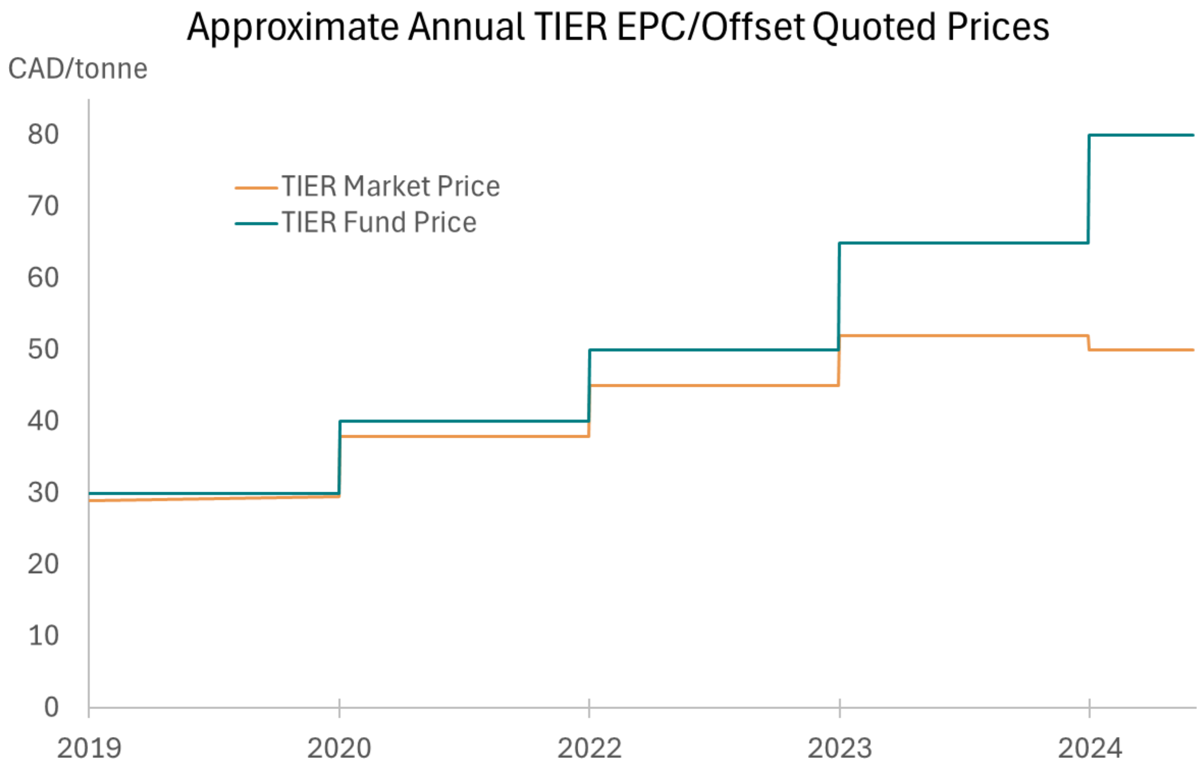
- Credits and offsets under TIER appear to be trading at a significant and widening discount relative to the TIER Fund (or "headline") price.
- This widening discount indicates that market participants anticipate low credit/offset prices in the future – either because government fails to increase the headline carbon price as scheduled and/or because the market for credits and offsets is oversupplied.
- Declining net obligations (i.e., total obligations minus credits and offsets created) relative to TIER-regulated emissions correspond to reductions in emission intensities that outpace benchmark tightening across TIER-regulated facilities.

2.1 Growing discount for credits versus the headline carbon price reflects market uncertainty

Currently, TIER lacks any officially compiled or published pricing data for traded EPCs and offsets, in contrast with other major carbon markets (see Chapter 2.1.1). This lack of transparency is an important concern for the TIER market, potentially hindering market efficiency. The lack of widely available and regularly updated pricing data creates an information asymmetry that privileges established incumbents and discourages new entrants to Alberta's carbon market.

Nonetheless, market participants occasionally provide pricing information based on their transactions to third parties. Such historical pricing quotes from market participants revealed a growing discount in the prices of EPCs and offsets compared to the headline carbon price from the TIER Fund.

Figure 5: Over the past year, the price discount for EPCs and offsets relative to the price of TIER Fund credits has widened[27]



Source: Quotes during respective year from anonymous market participants

As shown in Figure 5, while the price of credits and offsets has consistently risen with the scheduled increases in the headline carbon price, the difference between the market price of EPCs/offsets and the headline price has widened over the past year. The discount for the EPC/offset market price has increased from roughly 10% in 2021 to 37.5% in 2024. This increasing discount indicates heightened uncertainty among market participants about the future market prices of EPCs and offsets.

As discussed in Chapter 1, the TIER Fund price is scheduled to increase annually, reaching $170/tonne in 2030. A ministerial order sets out these increases,[28] which align with the

[27] Reflects average of various prices each year collected by the authors from a range of market participants (both reports of traded prices or broker quotes).
[28] See: Ministerial Order 062/2022 [Environment and Protected Areas]. Available online: https://open.alberta.ca/publications/epa-062-2022

federal government's schedule for minimum national carbon prices.[29] For an emitter with obligations under TIER, acquiring EPCs and offsets from the market is the alternative to buying TIER Fund credits at the headline carbon price.

Therefore, EPCs and offsets (which have expiry dates up to nine years after issuance) should reflect market participants' expectations of future carbon prices. If the government's commitment to its schedule for future headline carbon prices is credible and participants believe the TIER market will remain balanced, these instruments should, at minimum, trade close to the current year's fund price.[30]

Conceptually, if market participants trust that the government will indeed increase the headline carbon price as scheduled, EPCs and offsets should trade at a premium to the current year's fund price.[31] This is because if investors anticipate higher fund prices in the future, they should be willing to pay more for the EPCs and offsets purchased today, recognizing their increased value in the future as the carbon price escalates.

However, EPCs and offsets are trading below the headline carbon price – and with a growing discount. This growing discount indicates that market participants anticipate low market prices for EPCs and offsets in the future – either because government fails to increase the TIER Fund price as scheduled or because the market for EPCs and offsets is oversupplied.

2.1.1 Alberta's TIER lacks the price transparency of peer carbon pricing systems in other countries

Price transparency is critical for any well-functioning market. When prices are readily accessible, buyers and sellers can quickly and accurately assess the value of carbon credits and make decisions accordingly. A transparent market facilitates price discovery and enables fair pricing dynamics, preventing established incumbents from leveraging information asymmetry against new entrants – such as project developers seeking to evaluate project economics. And critically, price transparency fosters market confidence, providing investors with clear information on market conditions and potential returns.

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[29] See: Update to the Pan-Canadian Approach to Carbon Pollution Pricing 2023-2030. Available online: https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/carbon-pollution-pricing-federal-benchmark-information/federal-benchmark-2023-2030.html#toc3

[30] Based on data from the Alberta Carbon Registries, the overwhelming majority of EPCs and offsets transferred during recent years have expiry dates in 2026 or later. Transactions during 2023 were weighted towards EPCs and offsets with longer durations to expiry. The longer the duration to expiry, the greater should be the value of the EPC or offset.

[31] If the scheduled $95/tonne price for 2025 is perfectly credible, a market participant should be willing to pay a premium to the present $80/tonne TIER Fund price for 2024 in order to purchase a newly issued EPC or offset (i.e., which could be retired next year instead of paying $95/tonne to the TIER Fund). For example, if a $95/tonne price in 2025 was perfectly credible, any market participant with a 10% cost of capital should be willing to purchase an EPC or offset with an expiry in 2025 or later for $86.

Price transparency is a prerequisite for a broad-based CCfD program (see Chapter 3.2.1), where contracts are struck against market prices for EPCs and offsets. The 2024 federal budget indicated that credit price transparency is a key piece to developing off-the-shelf CCfDs, allowing them to sign more deals more quickly.[32]

Certain carbon markets in Canada publish pricing data for traded credits (e.g., Quebec's cap-and-trade, which is integrated with California's market, and the BC Low Carbon Fuel Standard). However, Canada's largest carbon market – Alberta's TIER – along with the federal Output-Based Pricing System do not yet publish credit pricing data

TIER lacks any officially and regularly published statistics on the prices of credits and offsets exchanged between participants. Although the ownership of all issued credits and offsets is publicly recorded in the Alberta Carbon Registries, the province does not mandate the reporting of the price or fair value of consideration of these transactions. Price statistics are only irregularly available from market participants who may choose to publish their own data.

While Intercontinental Exchange (ICE) has recently launched futures contracts for TIER EPCs and offsets,[33] participation in these contracts remains uncertain, and ICE's futures pricing will not record prices on the full universe of EPCs and offsets transferred between TIER market participants. Moreover, at the time of writing, ICE has not yet made statistics on pricing or volumes for its EPC/offset contracts regularly or publicly available.

To improve transparency in the TIER market, the Alberta government should collect transaction prices and regularly report summary statistics. Ideally, the Alberta government would report average, median, maximum, and minimum prices, along with traded volumes during a given month or quarter. Implementing such collection and reporting within the current system for transferring credits and offsets would be straightforward – simply requiring that the market participants stipulate the price or fair value of consideration. This transparency is clearly needed – particularly given the evident widening discount on TIER EPCs and offsets compared to the headline price.

Publishing these summary statistics would not compromise market-sensitive data. Other major carbon markets successfully report price data without adverse effects. For instance, prices are published for auctions under the European Union's Emission Trading System,[34] the Regional Greenhouse Gas Initiative,[35] and the joint California and Quebec

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[32] Budget 2024 states "Increased credit price transparency would greatly improve market functioning and provide greater investment certainty, unlocking more decarbonization projects." See: Budget 2024 at s. 4.1. Available online: https://budget.canada.ca/2024/report-rapport/chap4-en.html#s4-2
[33] See: https://www.ice.com/events/webinar/introducing-alberta-tier-futures-on-ice-ngx
[34] See: https://www.eex.com/en/market-data/environmentals/eu-ets-auctions
[35] See: https://www.rggi.org/auctions/auction-results

Cap-and-Trade Program.[36] The price transparency under these programs supports active secondary and futures markets without revealing sensitive information.[37]

Furthermore, jurisdictions with low carbon fuel standards (LCFS) programs, such as those in California, Washington, Oregon, and British Columbia, collect and publish average prices. The British Columbia LCFS publishes a monthly summary with average, maximum, and minimum credit prices (typically within the week following the previous month's end).[38] The California LCFS publishes a weekly log identifying individual transactions with volumes and prices. British Columbia and California also report whether the credit transfer is part of a forward or spot purchase agreement. Oregon[39] and Washington[40] similarly publish price and volume statistics for LCFS credit trading promptly after the month-end.

2.2 TIER compliance trends demonstrate a risk of credit oversupply

If emitters' compliance obligations (demand for credits) are consistently less than the EPCs and offsets created annually (supply of credits), TIER will face an oversupplied market. Such an oversupply of EPCs and offsets would materialize if reductions in emission intensities across TIER-regulated facilities outpace the tightening of benchmarks. In turn, declining net obligations as a share of TIER-regulated GHGs indicate that emission intensities across facilities are declining more rapidly than benchmarks are tightening.

Figure 6 plots recent data on aggregate compliance obligations for TIER-regulated facilities, along with the creation of EPCs and offsets for 2020-2022.[41] Figure 6 also depicts "net obligations," representing total compliance obligations minus EPCs and offsets created in the given year as a percentage of total TIER-regulated emissions.

The graph illustrates a significant decline in net obligations as a share of total regulated emissions since TIER was established in 2020. Since the emission intensity benchmarks

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[36] See: https://ww2.arb.ca.gov/our-work/programs/cap-and-trade-program/auction-information

[37] The European Energy Exchange provides clearing for "spot" prices on secondary emissions allowance trading as well as a futures market for allowances (see: https://www.eex.com/en/markets/environmental-markets/eu-ets-spot-futures-options); ICE maintains a futures market for California Carbon Offsets (see: https://www.ice.com/products/71544060/California-Carbon-Offset-Futures); and Regional Greenhouse Gas Initiative reports prices for secondary market transactions (see: https://www.rggi.org/allowance-tracking/rggi-coats) with ICE maintaining a futures market (see: https://www.ice.com/products/71090479/Regional-Greenhouse-Gas-Initiative-Allowance-Auction-Clearing-Price).

[38] See: https://www2.gov.bc.ca/gov/content/industry/electricity-alternative-energy/transportation-energies/renewable-low-carbon-fuels/credits-market

[39] See: https://www.oregon.gov/deq/ghgp/cfp/pages/monthly-data.aspx

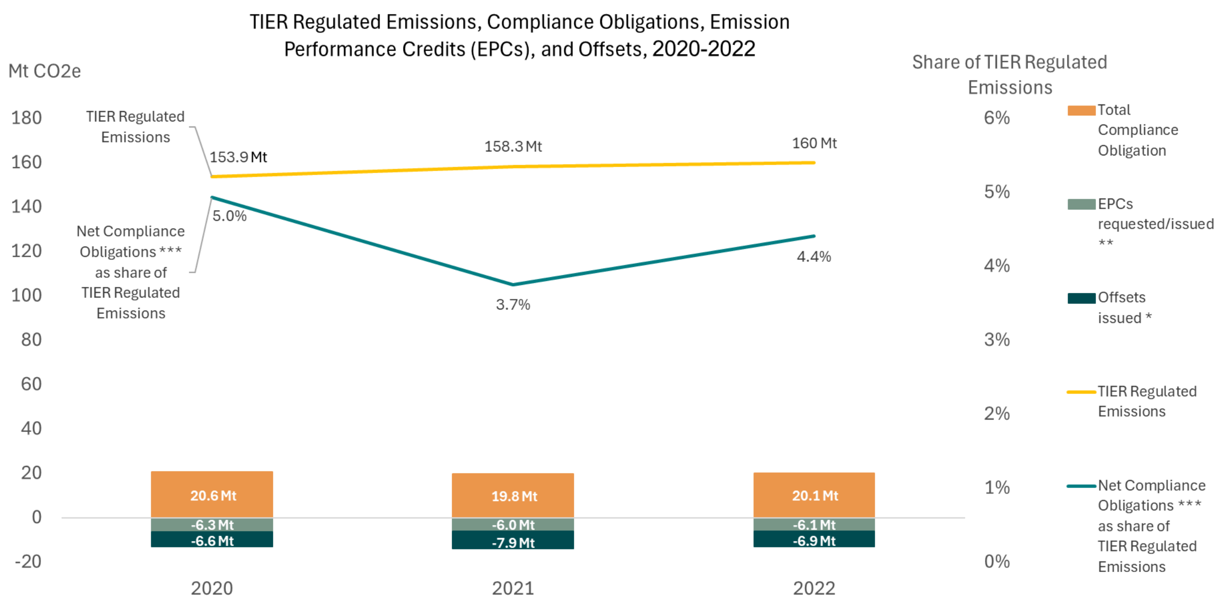
[40] See: https://www.ezview.wa.gov/site/alias__1962/37916/clean_fuel_standard_data__reports.aspx

[41] Based on compliance reporting for TIER published by EPA. See: Alberta industrial greenhouse gas compliance (7 November 2023). Available online: https://open.alberta.ca/dataset/alberta-industrial-greenhouse-gas-compliance

under TIER are tightened annually, this decline indicates that, in aggregate, emission intensity declined more rapidly across TIER-regulated emitters than the pace of emission intensity benchmark tightening. Table 1 shows the implied changes in emission intensity for each sector from 2020 to 2022 based on the compliance reporting and target reductions under TIER.[42]

If emission intensity reductions consistently outpace benchmark tightening, TIER will ultimately face a credit/offset oversupply.

Figure 6: Net obligations as a share of total regulated emissions have declined under TIER



Sources: Alberta Environment & Protected Areas ("Alberta industrial greenhouse gas compliance"), Alberta Carbon Registries
* Offsets calculated from total issued offsets by vintage year in Alberta Carbon Registries (as of 9 April 2024)
** EPCs for 2020-21 based on reported EPCs requested in EPA Compliance Summary (note that differs from currently issued EPCs in Alberta Carbon Registries as of 9 April 2024)
*** Net Obligations calculated as Total Compliance Obligation less EPCs and Offsets issued for compliance year

[42] Based on the compliance reporting of net obligations (obligations subtracting EPCs) and regulated emissions of each sector and the target reductions applicable to each sector in a given year (i.e., used to determine an emitter's facility-specific benchmark), the emission intensity relative to a reference emission intensity can be computed for any sector in a given year. The percentage change in emission intensity between any years can then be computed from these values. Appendix B elaborates the relevant equations for these calculations.

Table 1: Implied change in emission intensity for sectors under TIER in 2021/2022 [1]

Sector	Annual 2020-21	Annual 2021-22	Cumulative 2020-22
Oil Sands	-2.9%	0.8%	-2.1%
In Situ	-1.8%	-1.0%	-2.8%
Mining & Upgrading	-4.5%	2.6%	-2.0%
Oil & Gas [2]	-1.4%	-0.9%	-2.2%
Industry [3]	-1.2%	2.1%	0.9%
Power Generation	-5.4%	-8.6%	-13.6%

[1] The annual change in emission intensity for each sector is computed using the equations explained in Appendix B based on reporting of net obligations of each sector in the TIER compliance summaries published by Alberta Environment & Protected Areas and the annual target emission intensity reductions under TIER
[2] Oil & Gas includes Aggregated Oil & Gas, Pipelines, and Gas Plants
[3] Industry includes all other reported sectors under TIER

3. Carbon price uncertainty and the role of a price guarantee

Takeaways

- Uncertainty surrounding the future value of carbon credits and offsets will deter investors from committing to significant decarbonization projects.
- CCUS projects, for example, could enjoy comparably high incentives in Alberta relative to the US. However, if offset values crash, CCUS projects in the province would ultimately be unprofitable.
- Carbon contracts for difference (CCfDs) provide a price guarantee for future credit/offset values that can enable project proponents to make large capital investments despite risks about future carbon prices.
- A broad-based CCfD program can assure market participants that the government is committed to maintaining the integrity of carbon markets.
- The government can avoid paying out these contracts as long as it fulfills its commitment to ensure a well-functioning TIER market.

3.1 Carbon price uncertainty plays a crucial role in investment decisions

Risks perceived by project proponents about the future prices for EPCs and offsets impact final investment decisions for decarbonization projects – particularly those requiring significant upfront capital investments. Uncertainty about future carbon prices – whether from a future government removing industrial carbon pricing or halting scheduled increases (sometimes called "stroke of pen" risk), and/or from a potential EPC/offset oversupply – is deterring proponents from undertaking these investments. Without a credible commitment from government on future policy or a contractually guaranteed price for EPCs and offsets, these large decarbonization projects are unlikely to be built.

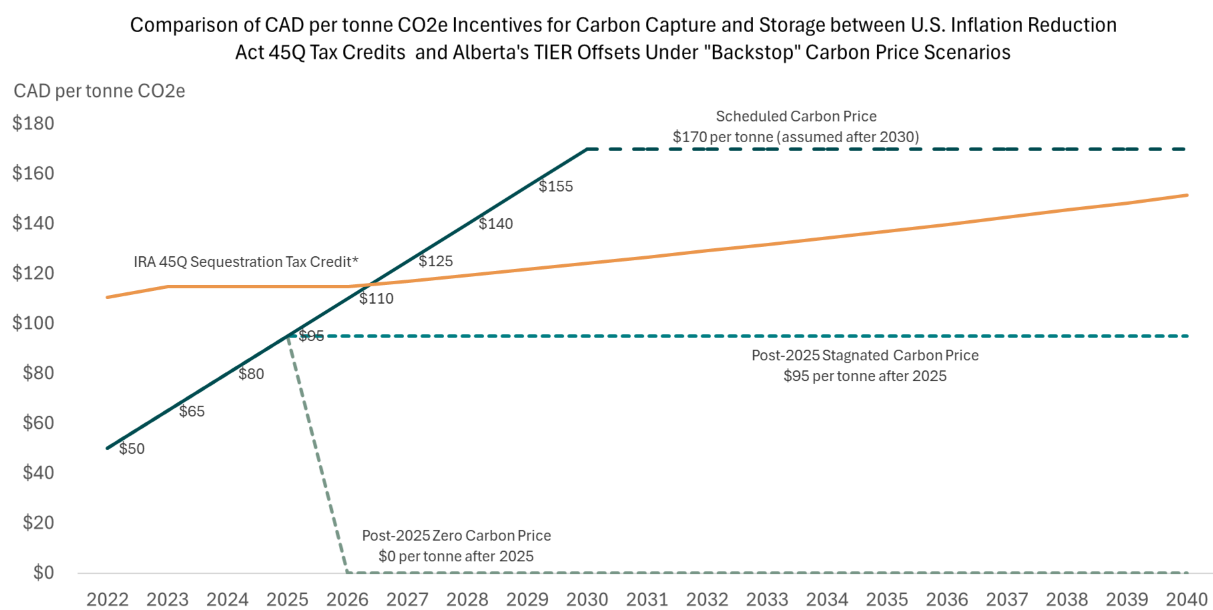
For example, proponents of CCUS projects face a material risk that a future government could forgo scheduled increases or eliminate carbon pricing entirely. A CCUS project in Alberta would earn only marginal returns if carbon prices stagnated after 2025 and would incur large losses if a future government cancelled carbon pricing or if EPC/offset values collapsed.

To illustrate this impact, we show the net present value (NPV) of a hypothetical CCUS project across different carbon price scenarios:

1. Alberta increasing the carbon price as presently scheduled (i.e., to \$170/tonne in 2030);[43]
2. The carbon price stagnating at the 2025 level[44] of \$95/tonne; and
3. A collapse in the market value of EPCs and offsets (i.e., no carbon price) after 2025.

For comparison, we also include the NPV of the same hypothetical CCUS project located in the US, where the project would receive a 45Q sequestration tax credit under the US Inflation Reduction Act (IRA.) Figure 7 shows these price scenarios.

Figure 7: Three price scenarios for the TIER compliance fund price compared with US IRA 45Q



Note: * Under U.S. Inflation Reduction Act, 45Q provides transferable, inflation-adjusted tax credit for CO2 sequestered in secure geological storage of up to USD 85 per tonne (if meeting wage and apprenticeship requirements) in 2022 dollars for projects constructed before 2033. For comparison with Canada's scheduled carbon prices, 45Q tax credit value converted at historical exchange rate and 1.35 CAD/US for future years with nominal value increased at assumed 2% long-term U.S. GNP price deflator.

Using these price scenarios (Figure 7), we model a hypothetical and illustrative CCUS project entering operation in 2025 with a 15-year project lifetime, sequestering 1 Mt of CO_2 each year.[45] The upfront capital costs are set at \$700 per tonne of CO_2 sequestered, and the

[43] Values are given in Canadian dollars unless otherwise specified.
[44] The year 2025 is chosen as the year where the carbon price stagnates in this scenario due its alignment with the federal election where a new government could conceivably take office and choose to halt the scheduled escalation of the carbon price.
[45] Note that the modelling assumptions that we use for this illustrative example are not intended to represent an actual CCUS project. An actual CCUS project would involve many technical nuances, complexities around timing for cashflows (e.g., outlays for materials, receipt of tax credits), and uncertainties around project delivery that we have not represented here. This example uses stylized and minimal assumptions to simply illustrate how the net present value of a CCUS project would generally be impacted by uncertainty around the value of EPCs/offsets and compare

annual operating expenses are set at 3.5% of those capital costs.[46] Based on Shell's disclosed project details for its Quest CCUS project, our modelled project represents an approximate 35% cost improvement on Quest.[47] We assume this hypothetical CCUS project also receives the CCUS investment tax credit (ITC) announced in the 2022 federal budget.[48]

Figure 8 depicts the annual cashflows for an Alberta-based project that benefits from the federal CCUS ITC and is able to sell its offsets at a 10% discount to the scheduled federal carbon price.

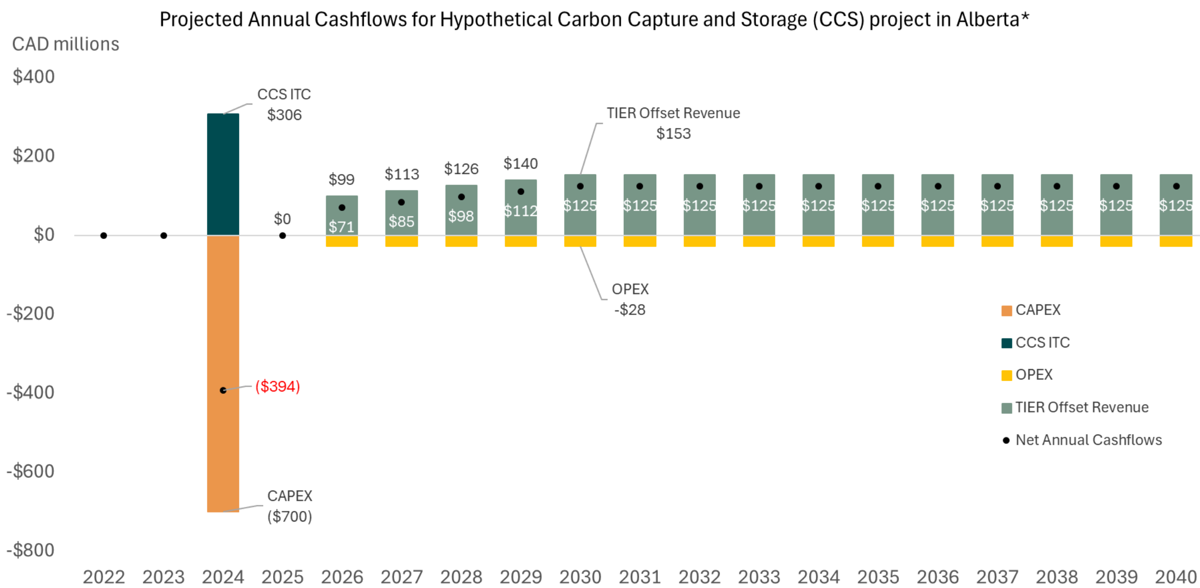
with a project funded by 45Q tax credits under the U.S. IRA. Although a CCUS project would also likely have a significantly longer life (in the order of 25 to 30 years), we nonetheless use a 15-year horizon given the 12-year horizon for 45Q crediting under the IRA (i.e., to avoid a large mismatch in the horizon for crediting driving differences in the project NPV).

[46] This CCUS project is approximately based on Shell's Quest facility, which is used as a model because of its public disclosure of capital and operating costs. The assumption of a 35% cost improvement on Quest is an illustrative assumption that would reflect "learning-by-doing" improvements in costs. The costs involved in CCUS projects could differ widely – particularly depending on the configuration for capture (e.g., whether pre/post-combustion).

[47] Shell's Quest facility reports a capital expenditure of $1,100 per sequestered CO_2 tonne. See: Quest Carbon Capture and Storage project: Annual Report, 2022. Available online: https://open.alberta.ca/publications/quest-carbon-capture-and-storage-project-annual-report-2022

[48] We assume the CCUS ITC provides a refundable amount in the year of the investment expense equal to 50% of the investment in equipment for capture of CO_2 and 37.5% of investment in equipment for transportation and storage. Admittedly, a proponent's timing of outlays for materials may be years in advance of ultimate receipt of funds for ITCs. Based on the composition of capital spending on the Quest facility, we have assumed that 50% of capital outlays for the hypothetical CCUS project are on capture equipment with the remainder on transportation and storage. This yields a rebate equal to a blended 43.75% of the overall capital expense. See: Budget 2022 (7 April 2022), Government of Canada, at Section 3.2. Available online: https://www.budget.canada.ca/2022/report-rapport/chap3-en.html#2022-2

Figure 8: Annual cashflows for a hypothetical CCUS project in Alberta



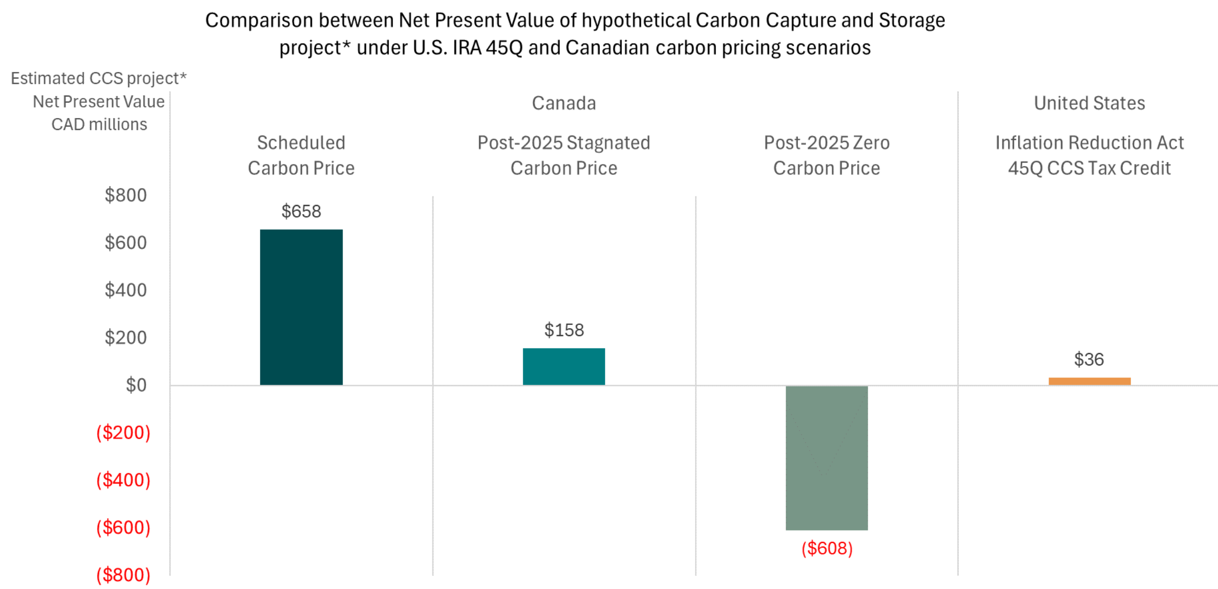
Note: * Assumed 15-year, 1 Mt CO2e/year CCS project with CAD 700 million upfront CAPEX and annual OPEX as 4% of CAPEX.
CCUS Investment Tax Credit assumed as 43.75% of CAPEX (i.e., CAPEX split between 50% on capture and 50% on transport and storage).
Value of offsets under Alberta TIER assumed equal to 90% of scheduled carbon price in given year.

As illustrated in Figure 9, our modelled hypothetical CCUS project in Alberta achieves an NPV exceeding $650 million. This estimate assumes a 5% cost of capital[49] and the monetization of TIER offsets at 90% of the scheduled carbon price. In contrast, the NPV for this hypothetical project is much smaller under the US IRA 45Q tax credit at approximately $40 million. This demonstrates that if the proponent could be confident that it could sell its offsets under TIER at or near the scheduled carbon price, the incentives in Alberta provide substantially more value relative to what is on offer in the US.

That said, the project proponent faces the risk that a future government will not adhere to the scheduled increases in the carbon price or that the value of offsets could be depressed by an oversupplied TIER market. If the value of offsets collapsed (the "zero carbon price" scenario), the project's NPV would sharply decline, rendering the investment unprofitable. Therefore, despite the potential profitability of the project, the conditions that would make it so – selling TIER offsets close to the scheduled carbon price — are uncertain, and this risk will deter proponents from undertaking the project.

[49] This admittedly represents an unreasonably low cost of capital for a project with such risks – particularly for present capital markets. For this hypothetical project, Figure 10 shows the break-even EPC/offset value required at higher (arguably more realistic) rates for a proponent's cost of capital. Nonetheless, 5% is comparable to the nominal discount rate used in the computation of the levelized cost per tonne for the Quest project. See Annex on "Applicable Reported Costs for the Project" to Quest Carbon Capture and Storage project: Annual Report, 2022. Available online:
https://open.alberta.ca/publications/quest-carbon-capture-and-storage-project-annual-report-2022

Figure 9: The NPV of CCUS projects in Canada is contingent on the trajectory and value of the carbon price



Note: * Net Present Value calculated for 15-year, 1 Mt CO2e/year CCS project with CAD 700 million upfront CAPEX and OPEX as 4% of CAPEX, assuming 5% cost of capital.
For Canadian scenarios, CCS Investment Tax Credit applied (assumed as 43.75% of CAPEX) and offset value assumed equal to 90% of carbon price in given year.
For U.S. IRA, 45Q tax credit valued at 95% of face value of given year's nominal value (i.e., USD 85/tonne inflated at assumed U.S. CPI and converted to CAD).

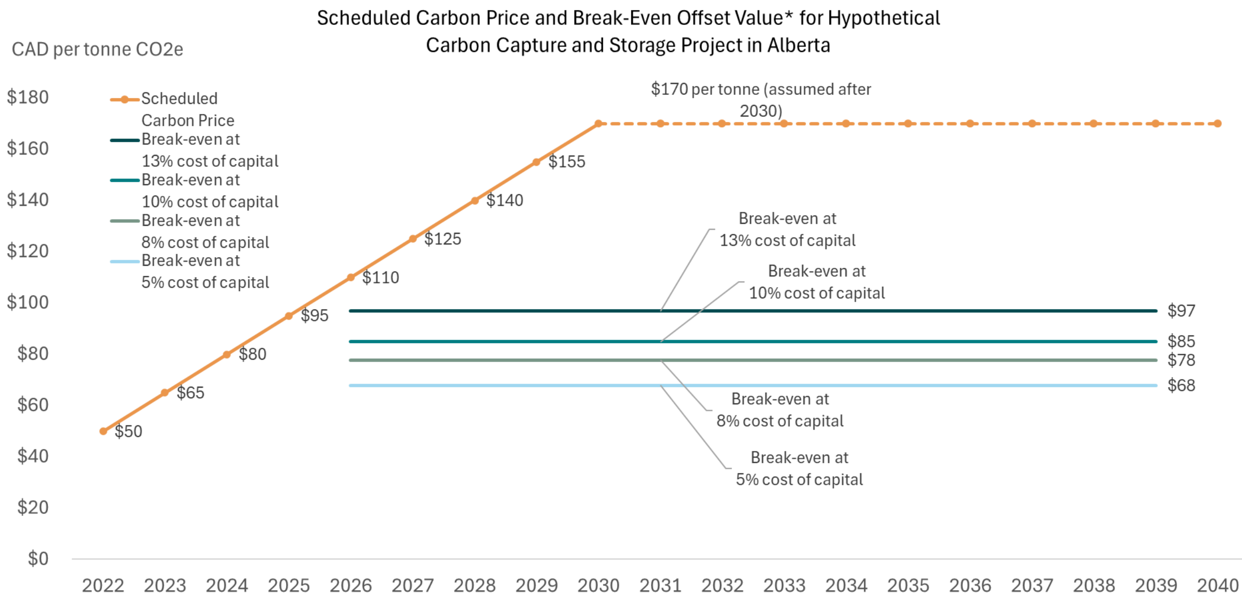
3.2 A price guarantee for carbon credits can enable investments in decarbonization projects

The differing net present values for the hypothetical project under each price scenario in the previous section underscore how a price guarantee for carbon credits and offsets can advance a project to a positive final investment decision.

An investor should be willing to undertake a project with a sufficiently positive NPV. For instance, even in the "stagnated carbon price" scenario (i.e., where the carbon price remains at $95/tonne from 2025 onwards), the project nonetheless sees a positive NPV and could move forward as a profitable project. However, this positive NPV depends on the certainty that the value of offsets will remain at $95/tonne.

Figure 10 illustrates the offset values at which our hypothetical CCUS project will break even (i.e., 0 NPV) at different cost of capital assumptions. At an 8% cost of capital, the project will break even if offsets are valued at $78/tonne. At a 10% cost of capital, the break-even offset value is $85/tonne.

Figure 10: Break-even offset value for a hypothetical CCUS project by cost of capital



Note: * Break-even offset value calculated for 15-year, 1 Mt CO2e/year CCS project entering operation in 2026 with CAD 700 million upfront CAPEX, CCS Investment Tax Credit applied (assumed as 43.75% of CAPEX), and OPEX as 4% of CAPEX

If a proponent was offered a risk-free guarantee that it would receive its break-even price for the credits or offsets it creates, the project should be an economic investment, and the proponent should be willing to enter into such a contract. Government can provide such a guarantee through a financial instrument called carbon contracts for difference (CCfDs).

3.2.1 CCfDs provide a price guarantee for EPCs and offsets

CCfDs are a tool available to government to de-risk low-carbon investments. There are several ways that CCfDs can be designed. For example, CCfDs can be tied to the headline carbon price and designed to address the risk that the headline carbon price does not rise to $170/tonne as scheduled.[50] CCfDs can alternatively be tied to credit prices, designed to address the risk that credit markets are oversupplied and guarantee a minimum value for the credits generated by a project. It is this type of CCfD that we envision for the TIER market.

[50] For an overview of headline price CCfDs and credit price CCfDs, see the Clean Prosperity's three-part article series, Implementing Carbon Contracts for Difference. Available online: https://cleanprosperity.ca/why-uncertainty-regarding-the-value-of-future-carbon-credits-is-a-policy-problem-that-needs-solving/

In short, this style of CCfD is an agreement with a low-carbon project proponent that guarantees the future value of carbon credits.[51] By contracting with a proponent, a government guarantees that project proponents will receive a certain credit price for a specified period of time (e.g., 10-15 years to correspond with a project's life).

If the average market price for EPCs/offsets falls below the agreed-upon price in the contract, the government will bridge the gap and pay the difference to the project proponent. Conversely, if the average market price exceeds the contract price, the proponent must pay the difference to the government.

In essence, CCfDs serve as insurance for project proponents. By transferring the risk of low credit prices to government, CCfDs enable low-carbon project proponents to undertake investments that rely on carbon credits to generate revenue.

While CCfDs represent a contingent liability for government, their design also allows government to avoid payouts. By maintaining the carbon price trajectory (to $170/tonne by 2030) and ensuring that carbon markets operate efficiently (i.e., preventing an oversupplied market), government can ensure that the average market price for EPCs/offsets remains greater than the contract price. In short, CCfDs offer government a tool with minimal financial risk to provide industry with certainty and unlock investment in decarbonization projects.

In this way, CCfDs can provide a credible signal that government is committed to ensuring that carbon markets operate efficiently. Because these contracts impose a fiscal cost on government if credit and offset prices collapse, CCfDs provide a credible commitment that government will adhere to scheduled carbon price increases and tighten benchmarks to avoid an oversupply of credits and offsets.

[51] For a more detailed exploration of CCfD design, see Clark et al. October 2022. Closing the Carbon-Pricing Certainty Gap. Clean Prosperity and the Canadian Climate Institute. Available online: https://cleanprosperity.ca/wp-content/uploads/2022/10/Closing_the_Carbon-Pricing_Certainty_Gap.pdf

Box B: The present state of carbon contracts for difference in Canada

The Government of Canada has designated the Canada Growth Fund (CGF) to enter into CCfDs to support low-carbon projects. The CGF is a $15 billion public fund tasked with accelerating the deployment of decarbonization and low-carbon projects. CGF has allocated $7 billion for bespoke CCfD deals negotiated with individual project proponents.

To date, CGF has executed two CCfD-style deals in Alberta, structured as carbon credit offtake (CCO) agreements. CGF has also signed one CCfD based on the headline carbon price with Markham District Energy in Ontario.

In December 2023, CGF signed a CCO with Calgary-based carbon capture company Entropy. Under the offtake structure, CGF will purchase carbon credits directly from Entropy at the contract price (initially $86.50 per tonne) with the intent to resell them later, ideally at a profit. In June 2024, CGF signed its second CCO with Gibson Energy and Varme Energy, Alberta-based companies looking to build Canada’s first waste-to-energy facility with carbon capture. Under this deal CGF will buy carbon credits at an initial price of $85 per tonne.

After these deals, CGF has less than $6 billion left with which to sign CCfDs and offtake agreements. Without additional funding, the number of deals that can be signed remains limited to a handful of projects.

The offtake agreements signed with Entropy, Gibson, and Varme contrast with the CCfD we describe in this paper. The CCfD we have in mind would not require the government to take possession of carbon credits but would instead settle the difference a proponent would receive for its credits in the market based on the contract price, or provide a project proponent with a put option to sell to the government if market prices sunk below the contract strike price.

4. TIER's oversupply risk and how "adaptive" tightening can ensure a balanced market

Takeaways

- If emitters reduce emission intensity faster than benchmarks tighten, the creation of EPCs and offsets will exceed emitters' total obligations, leading to an oversupplied market.
- Introducing adaptive tightening, a mechanism that tightens benchmarks at the pace of industrial decarbonization in Alberta, could prevent credit/offset oversupply. This approach strengthens the market for credits and offsets by ensuring net positive obligations under TIER.

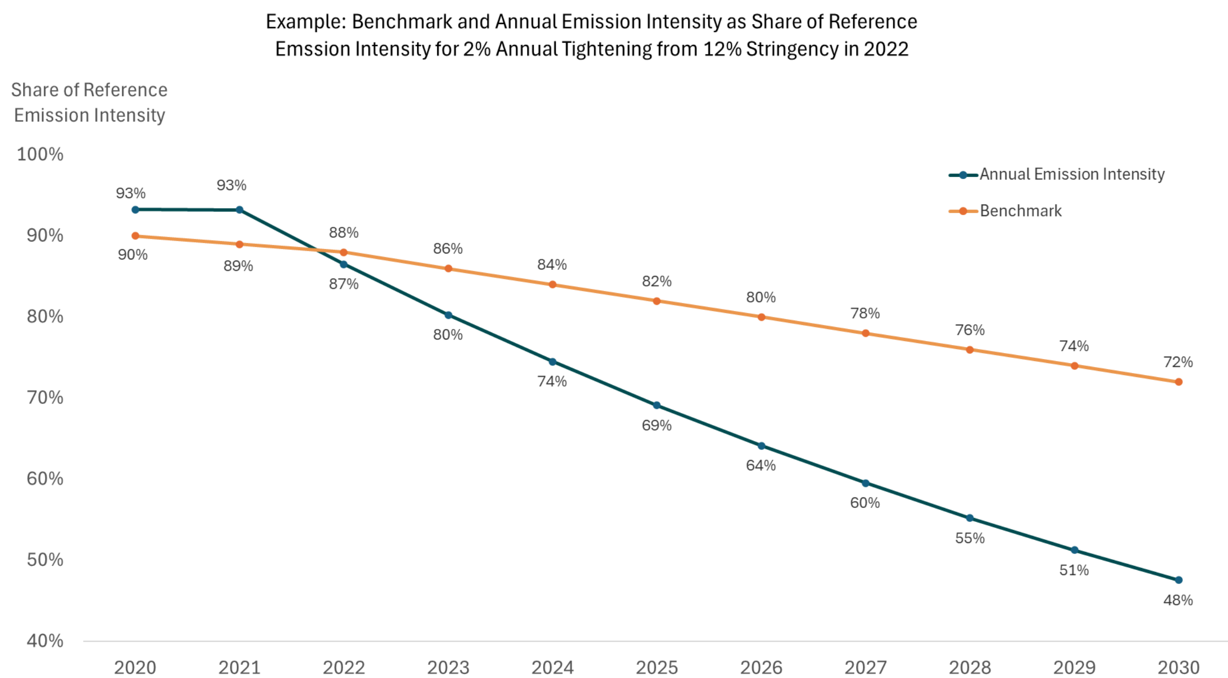
4.1 TIER is vulnerable to an oversupply of EPCs and offsets and a collapse in prices

For the TIER market to support credit and offset prices that closely track the headline carbon price, TIER-regulated emitters must consistently have aggregate obligations that exceed the availability of credits and offsets. In other words, the market demand for credits must exceed the supply. However, as investments in decarbonization reduce an emitter's emission intensity, aggregate net obligations will decline unless benchmarks tighten.

The annual benchmark tightening under TIER aims to address the possibility of negative net obligations (i.e., an oversupplied market). However, since the tightening rate is fixed (generally at 2% annually), TIER nonetheless faces the risk that emission intensities across facilities could decline faster than that fixed tightening rate.

Figure 11 illustrates this risk using a hypothetical emitter. If an emitter's emission intensity in 2020 is 93% of its reference emission intensity but declines between 4%-7% annually until 2030, it would create a small surplus of EPCs in 2022 and continue to create a growing surplus each year.

Figure 11: If an emitter reduces its emission intensity more rapidly than the benchmark tightens, it will create an increasing surplus of EPCs

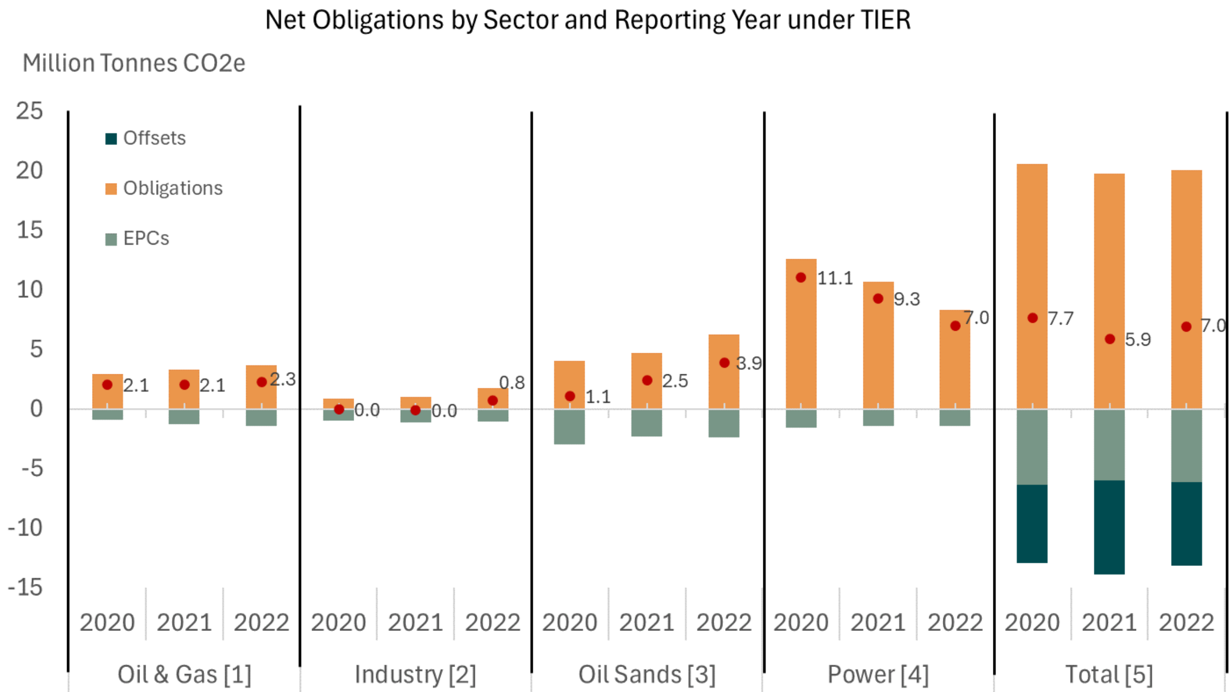


The risk is that, across the TIER market, many emitters achieve faster reductions in emission intensity than the pace at which benchmarks tighten. This would result in aggregate EPC and offset surpluses, while fewer emissions face a carbon price (i.e., fewer aggregate obligations).

Notably, since the establishment of TIER, facilities in power generation (specifically coal and gas power plants) have comprised a large share of obligations during the first three years of TIER – as shown in Figure 12 based on TIER reporting for 2020-22. However, the rapid decarbonization of Alberta power generation (with the closure or conversion of coal-fired generation) means this sector has significantly reduced its compliance obligations.

Further incentives and requirements under the proposed federal Clean Electricity Regulations, will further push power generators to decarbonize – beyond any price incentive under TIER. Similarly, the proposed federal cap on emissions from the oil and gas sector, if implemented, would increase the incentives for oil and gas facilities to reduce their emission intensities.

Figure 12: Net obligations under TIER by sector



Source: Alberta Environment & Protected Areas (EPA), TIER Compliance Reports for 2020-22; Alberta Carbon Registries (ACR)
Notes: [1] Oil & Gas includes Aggregated Oil & Gas, Conventional Oil, Gas Plants and Pipelines
[2] Industry includes Refining and other industrial sectors
[3] Oil Sands includes In Situ and Mining & Upgrading
[4] Power includes Coal, Gas, Cogen, Hydro and Wind in TIER Compliance Reports
[5] Net Oblgations for Total calculated including offsets created in each reported year (based on total issued for vintage as of May 2024)

4.2 Adaptive tightening is one mechanism that could ensure a balanced market

To safeguard against the risk of an oversupplied TIER market (i.e., from a tightening rate that is outpaced by emission intensity reductions), the Alberta government should adopt an "adaptive" approach to tightening benchmarks. Such an adaptive approach would accelerate the annual tightening of benchmarks if overall reductions in emission intensity outpace tightening. This adaptive approach would anchor expectations for net positive obligations (i.e., demand for credits exceeds the supply of credits) under TIER while responding flexibly to a variety of future conditions.

To implement such an adaptive approach, a rule could be applied where TIER benchmarks would be tightened in the next year to the extent that net obligations as a share of TIER-regulated emissions fall below some minimum threshold (e.g., 5%). Committing to a rule for accelerating benchmark tightening would ensure that a market balance would be restored in future years and thereby anchor expectations for market participants.

Figure 13 provides a stylized example of how adaptive tightening ensures a net positive obligation even as emission intensity varies.

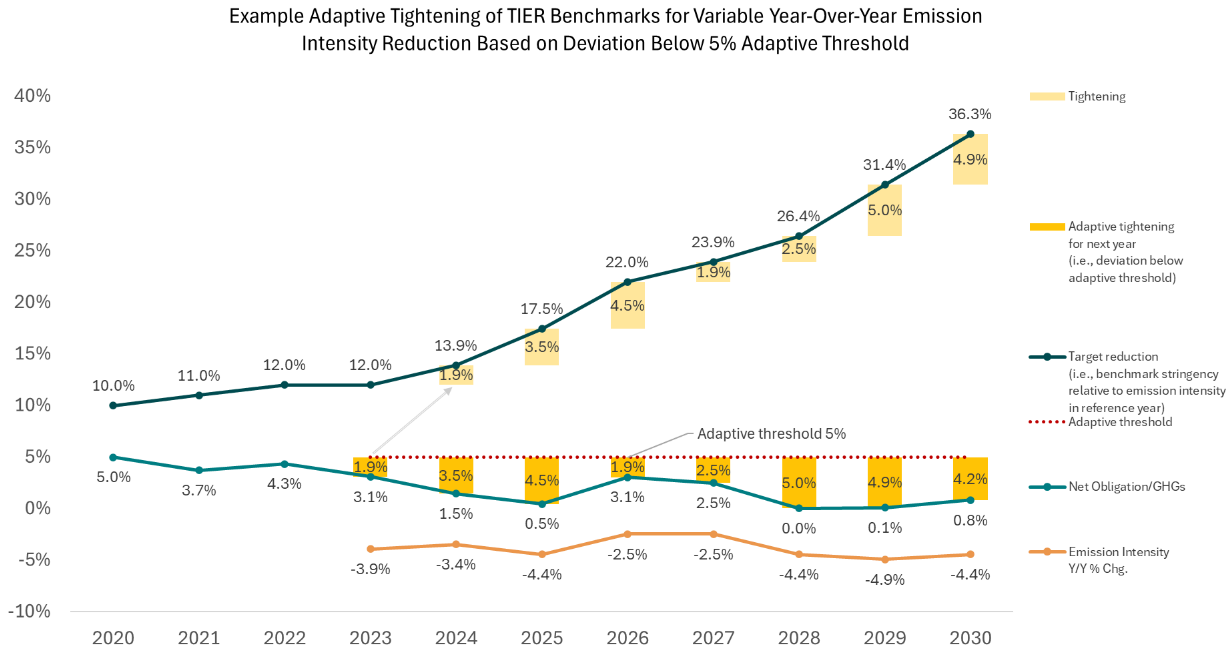
In this example, adaptive tightening (i.e., the addition to the target reduction in the next year) is determined by the extent to which the net obligations as a share of total emissions deviates below the adaptive threshold of 5%.

Here, overall emission intensity declines unpredictably, with its percentage year-over-year decline varying between years. As emission intensity declines, the benchmark stringency must "keep up" in order to maintain a net positive obligation (and sustain the marginal carbon price incentive). By calibrating tightening to the previous year's deviation of net obligations as a share of total emissions below the adaptive threshold (here, 5%), the rule provides a buffer.

As a brief explanation of this stylized example, consider the (illustrative) 3.9% emission intensity reduction for 2023. This results in net obligations of 3.1% of total TIER-regulated GHGs. For the next year, the adaptive rule requires an increase in the target reduction by 1.9% (i.e., the 5% adaptive threshold minus 3.1%) and the target reduction in 2024 will therefore increase from 12% in 2023 to 13.9% in 2024 (i.e., 12% plus 1.9%).

Figure 13 shows how the benchmark stringency tightens to compensate for the degree to which net obligations relative to total TIER-regulated GHGs deviate below the threshold. This rule ensures that, over the long term, benchmarks will always face tightening that will maintain (or restore) positive net obligations across emitters.

Figure 13: Stylized example of adaptive tightening of TIER benchmarks where larger declines in emission intensity are met with proportionate tightening increases



This rule should instill confidence among market participants that, even if one year sees an accelerated decline in emission intensity that produces an oversupply of credits (i.e., negative net obligation) for the given year, the benchmark stringency will be adaptively tightened to compensate. That is, any deviation of net obligations as a share of emissions below the adaptive threshold will boost the extent of tightening in the next year, ultimately restoring net positive obligations.[52]

Importantly, in order to successfully implement such an adaptive rule, no individual participant must be capable of significantly influencing the decline in aggregate emission intensity.[53] If no participant can influence the degree of tightening for the next year, every participant has a strong incentive to accelerate and maximize its own annual reductions in emission intensity.

[52] Some may recognize possible inspiration for this approach from the well-known "Taylor Rule" to guide central bank policy for a targeted inflation rate.

[53] This also requires no coordination between market participants that would limit reductions in aggregate emission intensity. Any such collusion would presumably contravene the criminal conspiracy provisions of Canada's Competition Act.

5. TIER net obligation balance for modelled scenarios

Takeaways

- For the ERP scenario, we find that the projected reductions in emission intensity (based on proposed federal regulatory measures and targets) would result in a negative net obligation (i.e., oversupply of credits and offsets versus obligations) of 25 Mt in 2030.
- For the ERED scenario, we find that the projected reductions in emission intensity (based on the Alberta government's illustration of 33% reduction over 2020-30) result in a negative net obligation (i.e., oversupply of credits and offsets versus obligations) of 27 Mt in 2030.
- Compared with the ERP scenario, the deeper oversupply for the ERED scenario results from greater assumed reduction in emission intensity in key sectors.
- For the Status Quo scenario, we find that TIER could accommodate an additional 30 Mt of reductions in 2030 before tipping into an oversupply.

5.1 Overview of scenarios

To illustrate the risk of an oversupplied TIER market, we model three scenarios for net obligations under TIER to 2030:

1. an Emissions Reduction Plan ("ERP") scenario, in which we project reductions in emission intensity across TIER-regulated sectors based on the assumed impact of proposed federal regulatory measures (i.e., the oil and gas emissions cap, and the Clean Electricity Regulations) and government targets from the federal 2030 ERP;
2. an Emissions Reduction and Energy Development ("ERED") scenario, in which we project reductions in emission intensity consistent with projections in the Alberta government's ERED Plan;
3. and a "Status Quo" scenario in which emission intensity is held constant at 2022 levels across all sectors (2024 for power generation).

In both the ERP and ERED scenarios, we show the extent of the oversupply of EPCs and offsets reflected as negative net obligations for TIER as a whole. This oversupply results from reductions in emission intensities implied by federal targets and projections in the ERP scenario and Alberta government targets and projections in the ERED scenario, without an accelerated tightening of benchmarks.

To contrast with the ERP and ERED scenarios, we also model a Status Quo scenario that approximates a business-as-usual environment, in which industry does not meet the emission intensity reductions implied by either the federal ERP or Alberta's ERED plan. In this scenario, we show the supply-demand balance for EPCs and offsets that would result if the emission intensity of each TIER-regulated sector were "frozen" at its 2022 level (2024 for the power generation sector), but the output of each sector was permitted to grow. This scenario shows the "buffer" that would be available to absorb emission reductions under TIER's current tightening rules. In other words, this scenario shows the maximum amount of additional emission reductions the TIER market could accommodate without tipping into oversupply under TIER's current tightening rules.

It is important to note that these scenarios are not predictions. Rather, they are intended to illustrate the implications for the TIER market based on federal and provincial targets and projections, as well as a business-as-usual environment. Table 2 specifies the source for the assumptions in each scenario. Table 3 summarizes the estimated relative emission intensity in 2020[54] and the assumed 2020-30 emission intensity reduction for each sector.

These scenarios highlight the risk of a future oversupply that project proponents would perceive when evaluating decarbonization investments. As discussed in Chapter 3, if proponents anticipate the potential for an oversupplied EPC/offset market – and consequent future collapse in market prices – they will not move forward with critical decarbonization projects.

These scenarios underscore the importance of tightening TIER benchmarks adaptively to ensure that net obligations remain positive. Without a credible commitment from the Alberta government to accelerate tightening, many rational forward-looking proponents will be discouraged from making critical decarbonization investments in Alberta.

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[54] Using the equations elaborated in Appendix B and the reporting from the TIER Compliance Summary, we estimate the aggregate emission intensity for each sector in 2020 relative to emitters' reference emission intensity. This approach allows us to model net obligations at the sector level, using the assumed reductions in emission intensity over 2020-30 across the given sector.

Table 2: Summary of emissions, production, emissions intensity, and benchmark tightening assumptions under three modelling scenarios

	ERP scenario	ERED scenario	Status Quo scenario
		Emissions	
Power Generation	Decline as projected under the "Decarbonization by 2035" scenario under the Alberta Electric System Operator's (AESO) Updated 2024 Long-Term Outlook	Decline as projected under the "Decarbonization by 2050" scenario under AESO's Updated 2024 Long-Term Outlook	Decline with declining generation by gas-fired facilities (assumed at a constant emission intensity with no CCUS abatement) based on projections under AESO Updated 2024 Long-Term Outlook
Oil Sands, Oil & Gas	Decline in alignment with the proposed federal oil and gas emissions cap	Decline based on the Alberta Energy Regulator's (AER) production growth forecast in their ST98: Alberta Energy Outlook and decline in emission intensity under Alberta's ERED plan	Grow based on the AER's production growth forecast in their ST98: Alberta Energy Outlook and constant emission intensity (2022 levels)
Industry	Decline according to the bottom-up analysis under the federal ERP (i.e., based on projected 2019-30 declines by Heavy Industry sub-sector to adjust for Alberta's industrial composition)	Decline based on illustrated indexed GHG growth and emission intensity under Alberta's ERED plan	Grow based on economic growth assumptions and constant emission intensity (2022 levels)
		Production	
Power Generation	Grows as projected under the "Decarbonization by 2035" scenario under AESO's Updated 2024 Long-Term Outlook	Grows as projected under the "Decarbonization by 2050" scenario under AESO's Updated 2024 Long-Term Outlook	Declining generation by gas-fired facilities and growing renewables generation based on projections under AESO Updated 2024 Long-Term Outlook
Oil Sands, Oil & Gas	Grows according to production growth under the Canada Energy Regulator's Canada Net-Zero scenario	Grows according to production growth under the AER's Alberta Energy Outlook (ST-98) report	Grows according to production growth under the AER's Alberta Energy Outlook (ST-98) report

Industry	Grows according to 2020-30 GDP growth projected under ERP (i.e., 2.5% average annual GDP growth)	Grows based on illustrated indexed GDP growth under Alberta's ERED plan	Grows 2.5% annually (consistent with economic growth assumed in both the federal ERP and Alberta ERED)
Emission intensity			
Power Generation	Declines as calculated using the "Decarbonization by 2035" scenario under AESO's Updated 2024 Long-Term Outlook	Declines as calculated using the "Decarbonization by 2050" scenario under AESO's Updated 2024 Long-Term Outlook	Held constant for gas-fired generation at 2024 level (i.e., assuming phase-out of coal generation but no additional CCUS-based abatement of thermal assets) based on AESO Updated 2024 Long-Term Outlook
Oil Sands, Oil & Gas	Declines in a straight-line trajectory to align with above sectoral emission and production assumptions	Declines based on illustrated indexed GHGs per unit of GDP under Alberta's ERED plan	Held constant at 2022 levels
Industry	Declines according to 2019-30 emissions reductions (based on the bottom-up percentage reductions by Heavy Industry sub-sector) and assumed annual 2020-30 GDP growth under the federal ERP	Declines based on illustrated indexed GHGs per unit of GDP from under Alberta's ERED plan	Held constant at 2022 levels
Benchmark tightening	Status quo (2% annually, with oil sands facilities subject to a 4% annual tightening in 2029-2030)	Status quo (2% annually, with oil sands facilities subject to a 4% annual tightening in 2029-2030)	Status quo (2% annually, with oil sands facilities subject to a 4% annual tightening in 2029-2030)

To illustrate the market balance for each scenario, we present net obligations across TIER facilities in aggregate – defined as TIER-regulated facilities' obligations minus EPCs and offsets created in the given year. Our modelling approach abstracts from the facility-level details (for which we lack published facility-specific benchmarks); instead we model reductions in emission intensity to 2030 based on assumptions about the respective sector. Both scenarios implicitly integrate reductions in emission intensity that could be attributable to the roll-out of CCUS.[55]

[55] The degree of CCUS abatement is not expressly included in these scenarios, which are based on the assumed reduction of emission intensity by sector. That is, the modelling for these scenarios does not take a position on how reductions in emission intensity for a particular sector are achieved (i.e., whether by CCUS or other technologies for decarbonization).

The projected oversupply under both scenarios results from assumed emission intensity reductions by 2030 exceeding the pace of tightening of benchmarks (Table 3). As a brief orientation to Table 3, consider the net obligations for oil sands mining: Based on TIER compliance reporting, the emission intensity across oil sands mining in 2020 had already declined to approximately 86% of the reference emission intensities.[56] The target emission intensity reduction by 2030 for oil sands mining is 38% of emitters' reference emission intensities.[57] Therefore, if emission intensity across oil sands mining is less than 62% (100%-38%) of emitters' reference emission intensities in 2030, this sector will have negative net obligations (i.e., oil sands mining will create more EPCs than any obligations within the sector). That is, in terms of the 2020 to 2030 timeframe, if the emission intensity of oil sands mining declines by more than 28%, this sector will produce a surplus of EPCs.[58]

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[56] This follows from the net obligations of this sector from the compliance reporting published by the Alberta Ministry of Environment and Protected Areas (see: https://open.alberta.ca/dataset/alberta-industrial-greenhouse-gas-compliance) and the 10% emission intensity reduction target in 2020 (see section 8.2 of the Alberta TIER benchmark standard: https://open.alberta.ca/publications/standard-developing-benchmarks-tier-version-2). The equations from computing this relative emission intensity are elaborated in Appendix B.

[57] In our sector-level modelling, we ignore the distinction between tightening and non-tightening components of facility-specific benchmarks. We lack comprehensive data across sectors in order to segregate the non-tightening component (e.g., for robustly estimating emitters' electricity consumption for a given sector). Nonetheless, our modelling approach would conservatively understate the extent of any oversupply. This is because, by assuming that the reduction target applies to the entirety of benchmarks across a given sector, our modelling then annually tightens benchmarks at a greater rate than if benchmarks include a non-tightening component. That is, we assume benchmarks tighten at a more rapid pace than they actually will in future years.

[58] The 28% reduction follows from the 10% emission intensity reduction in 2020, added to the 1% tightening rate in 2021 and 2022, and the 2% tightening rate for 2023-2030.

Table 3: Estimated 2020 emission intensity (EI) and 2020-30 reduction by sector and scenario

Sector	Sector relative 2020 EI [1]	2030 EI reduction target (share of reference EI) [2]	ERP scenario		ERED scenario	
			Assumed EI reduction 2020-30	Modelled net obligations in 2030	Assumed EI reduction 2020-30	Modelled net obligations in 2030
Industry	90%	28% (72%)	-43%	-6.6 Mt	-33%	-3.9 Mt
Oil & Gas	97%	28% (72%)	-26%	-0.1 Mt	-33%	-2.8 Mt
Oil Sands (In situ)	98%	32% (68%)	-38%	-3.8 Mt	-33%	-1.5 Mt
Oil Sands (Mining & Upgrading)	86%	38% (62%)	-26%	0.9 Mt	-33%	-2.3 Mt
Power Plants [3]	0.60 t/MWh	0.31 t/MWh	-38%	-3.4 Mt	-44%	-3.7 Mt
Offsets [4]				-12.5 Mt		-12.6 Mt
Net Obligations				-25.4 Mt		-26.9 Mt

Notes:
[1] Sector emission intensity in 2020 expressed as proportion of reference emission intensity (computed using equations elaborated in Appendix B using TIER compliance reporting).
[2] Emission reduction targets based on annually tightening emission reduction targets specified in the TIER Benchmark Standard (see section 8.2).
[3] Note that Power Plants do not include offsetting renewable generation.
[4] As explained in Appendix A5, projected offsets include offsetting renewable generation and a baseline projection of offsets based on project-level outlooks from disclosure in the Alberta Carbon Registries.

5.2 ERP scenario

For the ERP scenario, we find that the projected reductions in emission intensity (based on proposed regulatory measures and targets) result in a negative net obligation (i.e., oversupply of credits and offsets versus obligations) of 25 Mt in 2030.

Figure 14 presents this modelling, illustrating the modelled emissions of each broad sector regulated under TIER, as well as the net obligations (i.e., emitters' aggregate obligations minus EPCs and offsets created in the given year).[59]

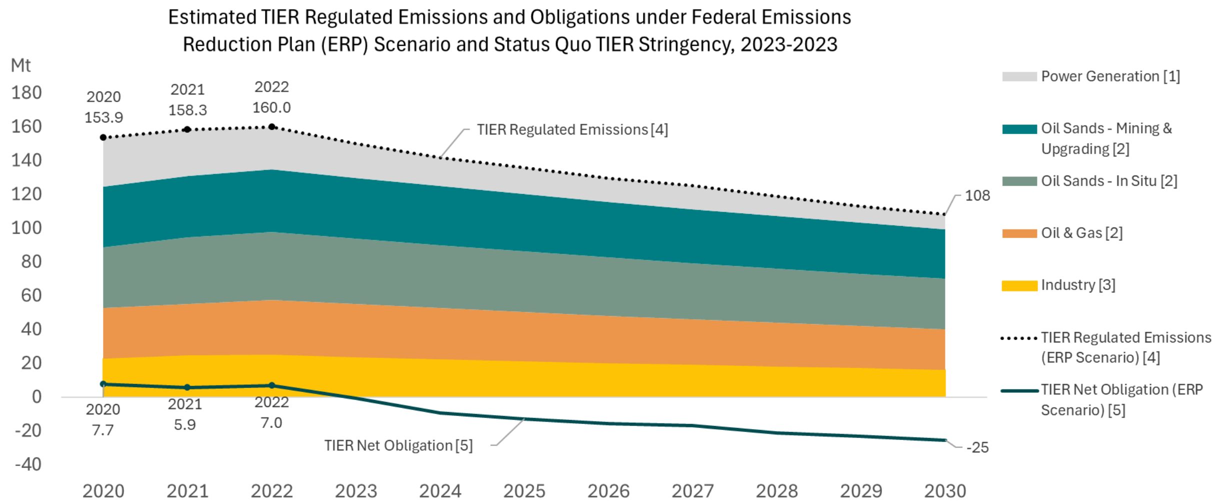
Our modelling notably adopts a simplifying "straight-line" assumption for the reduction in emission intensity until 2030.[60] With such a trajectory for reductions in emission intensity across regulated sectors, Alberta would face the risk of an oversupplied TIER market imminently.

Again, this modelling does not reflect a projection or prediction for the trajectory of emission intensity in each sector and for the net obligation balance under TIER in aggregate. However, the aim of the ERP scenario is to show the consequence for negative net obligations under TIER based on the assumed impact of proposed federal regulations and targets. That is, if TIER-regulated emitters successfully reduced emission intensity as targeted and benchmarks under TIER were only tightened at the presently prescribed pace, the market for credits/offsets under TIER would be oversupplied.

[59] Note that we employ a "net obligations" approach for modelling each sector's balance rather than separately projecting obligations, EPCs, and offsets (excepting the baseline offsets discussed in Appendix A) since we lack facility-level emission intensity and benchmark data. Briefly, without facility-level data, we cannot model the separate obligations incurred or EPCs created in each sector. Additionally, under TIER, emissions sequestered with CCUS can either create EPCs or offsets (depending on the relationship with a given facility); however, for TIER in aggregate, the impact of sequestering emissions should be identical regardless of what instrument is created. Therefore, we have estimated emission intensity at the sector level, based on the Compliance Summary reporting and following the calculations described in Appendix A of our earlier paper (See: "Tightening TIER for Alberta's decarbonization" (2022). Available online: https://cleanprosperity.ca/alberta-carbon-pricing-system-needs-an-important-fix/), and modelled this sector-level net obligation balance to 2030 based on the assumed reductions in emission intensity for each sector.

[60] That is, unless a specific year-by-year projection is provided (e.g., as in the AESO Net-Zero Pathways modelling), our modelling interpolates emission and production (and corresponding emission intensity) in any subsequent year from the most recent reported datapoint based on the respective 2030 point projection/target.

Figure 14: Under the ERP scenario, TIER will be oversupplied by 25 Mt of EPCs and offsets by 2030



Sources: Alberta Environment & Protected Areas, Alberta industrial greenhouse gas compliance; Alberta Carbon Registries; Alberta Emissions Reduction & Energy Development Plan (ERED); Canada Energy Regulator (CER) Canada Energy Future (CEF); and Alberta Electric System Operator (AESO) 2024 Updated Long-term Outlook (LTO)

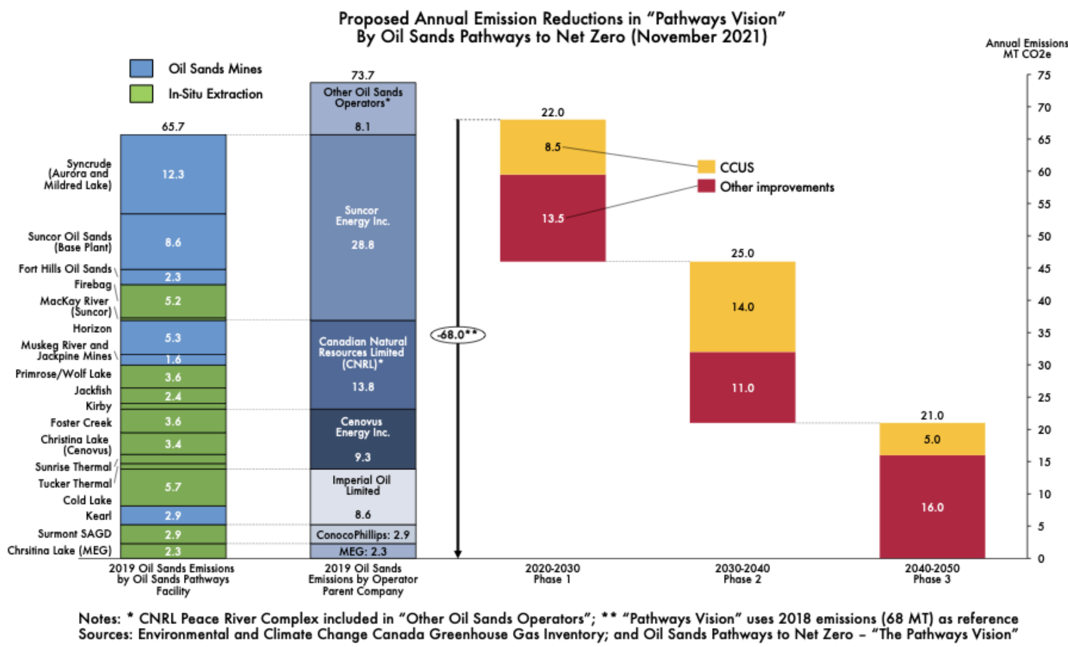
Notes: [1] Power generation GHGs based on "Decarbonization by 2035" scenario in AESO LTO (adjusted for allocation of cogeneration emissions based on TIER reporting);
[2] Oil Sands and Oil & Gas GHGs assume production growth based on CER CEF Canada Net-Zero Scenario and approx. 20% emission reduction over 2019-30 (based on federal Oil & Gas cap);
[3] Industry GHGs based on projected proportional industry-level emissions declines in federal ERP, weighted by Alberta's industrial composition of GHGs;
[4] TIER Regulated Emissions aggregates estimated regulated emissions of each sector; and
[5] TIER Net Obligation represents Compliance Obligation less Emission Performance Credits and Offsets, and estimated using annual benchmark stringency by sector tightening at 2% annually and High-Performance Benchmark for power generation (incl. cogen), netting projected offsets based on currently offsetting projects (from documentation in Alberta Emission Offset Registry)

Box C: Pathways Alliance plans and federal Emissions Reduction Plan

Figure 15 shows the plans announced in November 2021 by an organization now known as the Pathways Alliance, a consortium of producers responsible for the majority of oil sands production. The published plan indicated 22 Mt of reductions relative to these producers' 2020 emissions in the first phase from 2020 to 2030 – split between 8.5 Mt through CCUS and 13.5 Mt of other improvements (e.g., improved processes, electrification and fuel substitution, energy efficiency).

This 22 Mt of targeted emissions reductions by 2030 represents approximately 33% of the 65.7 Mt of emissions in 2019 from facilities operated by the member companies of the Pathways Alliance. Therefore, while presented only for reference, the 33% emission reduction targeted by Pathways is proportionately much larger than the 20% reduction for all oil and gas emissions from 2019 levels under the proposed federal oil and gas emissions cap.

Figure 15: Pathways Alliance intends to implement 22 Mt of emission reductions through CCUS and other improvements by 2030 and plans to achieve net-zero by 2050



5.3 ERED scenario

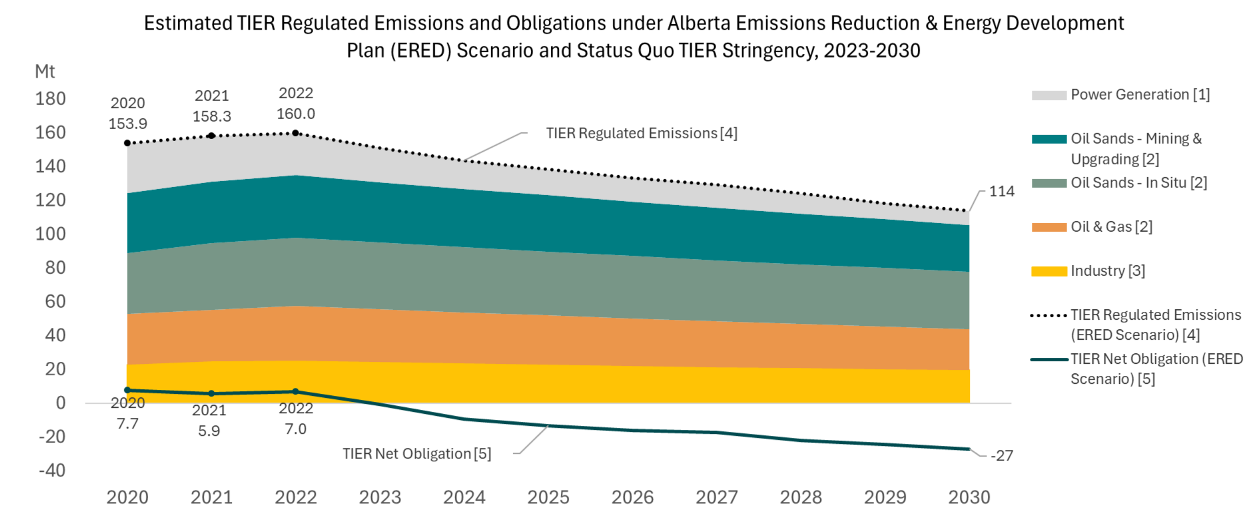
For the ERED scenario, we find that the projected reductions in emission intensity (based on the Alberta government's illustration of 33% reduction over 2020-30) result in a negative net obligation (i.e., oversupply of credits and offsets versus obligations) of 27 Mt in 2030. This oversupply would indeed be deeper than our projection under the ERP scenario despite greater emissions under this scenario. This is a consequence of the deeper emission intensity reductions for key sectors (specifically oil & gas and oil sands mining) assumed under this ERED scenario than under the ERP scenario.

Again, our aim is not prediction but instead to show the consequence of other published projections – for this ERED scenario, the 33% reduction of GHGs/GDP illustrated in the Alberta government's Emissions Reduction and Energy Development Plan (reproduced as

Figure A1 in Appendix A)[61] and the decarbonization of Alberta electricity by 2050 modelled by the AESO.[62]

Our modelling shows that the emission intensity reductions anticipated under Alberta's ERED would be inconsistent with maintaining emitter obligations greater than the annually created EPCs and offsets under TIER in 2030. Indeed, while admittedly applying a smooth "straight-line" path of annual emission intensity reductions, our results for the ERED scenario imply that the TIER market would tip into oversupply within the coming years.

Figure 16: Under emission intensity reductions envisioned under the Alberta ERED Plan, TIER credits/offsets would be oversupplied by 27 Mt in 2030



Sources: Alberta Environment & Protected Areas, Alberta industrial greenhouse gas compliance; Alberta Carbon Registries; Alberta Energy Regulator (AER) Alberta Energy Outlook (ST-98); Alberta Emissions Reduction & Energy Development Plan (ERED); and Alberta Electric System Operator (AESO) 2024 Updated Long-term Outlook (LTO)

Notes: [1] Power generation GHGs based on "Decarbonization by 2050" scenario in AESO LTO (adjusted for allocation of cogeneration emissions based on TIER reporting);
[2] Oil Sands and Oil & Gas GHGs assume production growth based on AER ST-98 and approx. 33% reduction in emission intensity over 2020-30 (based on ERED);
[3] Industry GHGs based on indexed GDP growth (approx. 28% growth over 2020-30) and GHG/GDP decline (approx 33% reduction over 2020-30) in ERED;
[4] TIER Regulated Emissions aggregates estimated regulated emissions of each sector; and
[5] TIER Net Obligation represents Compliance Obligation less Emission Performance Credits and Offsets, and estimated using annual benchmark stringency by sector tightening at 2% annually and High-Performance Benchmark for power generation (incl. cogen), netting projected offsets based on currently offsetting projects (from documentation in Alberta Emission Offset Registry)

5.4 Status Quo scenario

For the Status Quo scenario, we model net obligations under TIER based on growing output while holding emission intensity constant at current levels across sectors.[63] Such a scenario

[61] See p.11 of Alberta Government (2024), Emissions Reduction and Energy Development Plan. Available online: https://open.alberta.ca/publications/alberta-emissions-reduction-and-energy-development-plan
[62] See Alberta Electric System Operator (2024), 2024 Updated Long-Term Outlook Preliminary Results. Available online: https://www.aesoengage.aeso.ca/forecasting-insights#folder-141824-28747
[63] For all sectors other than electricity, we maintain the sectoral emission intensity from the 2022 TIER reporting. For power generation, we maintain the 2024 emission intensity for gas-fired generation and the generation profile across fuel types from the AESO 2024 Long-Term Outlook (i.e., assuming the phase-out of coal generation but no additional CCUS-based abatement of thermal generation).

would result in a net positive obligation of 30 Mt in 2030, which would represent approximately 18% of the total projected 169 Mt of TIER-regulated GHGs.

This Status Quo scenario could be considered as an approximation of the additional emission reductions that could be absorbed under TIER's current tightening rates before the market for EPCs and offsets under TIER becomes oversupplied.

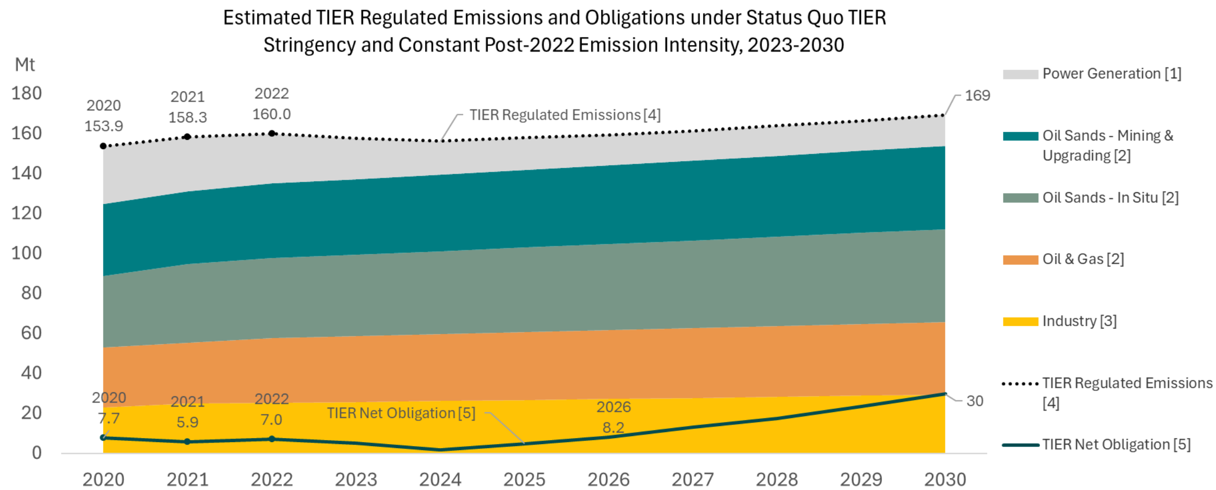
Alternatively, while a range of technologies could be employed sector by sector or facility by facility to reduce emission intensity, this 30 Mt "buffer" could be considered the upper limit of CCUS penetration that could occur by 2030 without causing an oversupply of EPCs/offsets.

For comparison with this modelled 30 Mt buffer, Figure 18 in Box D shows the current inventory of announced CCUS projects in Alberta, along with the respectively announced sequestration capacity and in-service date of each project. These proposed projects potentially total 60 Mt of sequestration capacity by 2030.

While it is unlikely that all 60 Mt of sequestration capacity from proposed CCUS projects would be operationalized, this total provides a comparison with the 30 Mt buffer in this scenario. If half of the proposed CCUS sequestration capacity is realized, the TIER market will face oversupply from CCUS alone, before considering other decarbonization initiatives.

For additional comparison with the modelled 30 Mt buffer, the Pathways Alliance plans to reduce 22 Mt of emissions annually by 2030 through a mix of CCUS (8.5 Mt) and other improvements (13.5 Mt). If achieved, the reductions proposed by the Pathways Alliance would comprise more than two-thirds of the buffer projected under this Status Quo scenario.

Figure 17: Under the Status Quo scenario, TIER will have a 30 Mt "buffer" in 2030 to accommodate additional GHG reductions before tipping into oversupply



Sources: Alberta Environment & Protected Areas, Alberta industrial greenhouse gas compliance; Alberta Carbon Registries; Alberta Energy Regulator (AER) Alberta Energy Outlook (ST-98); Alberta Emissions Reduction & Energy Development Plan (ERED); and Alberta Electric System Operator (AESO) 2024 Updated Long-term Outlook (LTO)

Notes: [1] Power generation by renewables and gas-fired facilities based on AESO LTO (adjusted for allocation of cogeneration emissions based on TIER reporting) but emission intensity for gas-fired generation held constant at 2024 level (i.e., no CCUS abatement of thermal assets);
[2] Oil Sands and Oil & Gas GHGs assume production growth based on AER ST-98 and constant emission intensities from 2022 onwards;
[3] Industry GHGs based on assumed GDP growth (2.5% annually and approx. 28% growth over 2020-30) and constant emission intensity from 2022 onwards;
[4] TIER Regulated Emissions aggregates estimated regulated emissions of each sector; and
[5] TIER Net Obligation represents Compliance Obligation less Emission Performance Credits and Offsets, and estimated using annual benchmark stringency by sector tightening at 2% annually and High-Performance Benchmark for power generation (incl. cogen), netting projected offsets based on currently offsetting projects (from documentation in Alberta Emission Offset Registry)

Box D: Proposed carbon capture, utilization, and storage

The ERP and ERED scenarios above are based on assumed reductions in emission intensity from different TIER-regulated sectors and do not assume specific volumes of CCUS. Again, the aim of the above scenarios is to illustrate implications for an oversupply of EPCs and offsets under TIER based on assumptions for reduced emission intensity. That is, the scenarios do not take a position on *how* emission intensity reductions would actually be achieved but instead model the implications of other projections for reductions of Alberta's emissions and emission intensity.

Nonetheless, to achieve such emission intensity reductions, CCUS projects would likely be critical to reducing the emissions from Alberta facilities, and CCUS projects with significant annual capacity for sequestration of emissions have been proposed.

Figure 18 shows the current inventory of announced CCUS projects in Alberta, along with the respectively announced sequestration capacity and in-service date of each project.[64] As shown, such proposed annual sequestration capacity potentially totals 60 Mt by 2030.

Importantly, Figure 18 presents the announced sequestration capacity and in-service date of each project without any judgment of whether the particular proponent will be capable of entering operation with that capacity by the given date. When announced, certain new CCUS projects indicated potential to be operational by 2024, but, to our knowledge, these projects have yet to enter construction. Indeed, despite the significant proposed volumes of annual sequestration capacity, most of these projects have not yet announced final investment decisions.[65]

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[64] The projects shown in Figure 18 include those listed by the Government of Alberta as under evaluation for its first and second competitions to develop carbon storage hubs (see: https://www.alberta.ca/carbon-capture-utilization-and-storage-carbon-sequestration-tenure). From only desktop research (i.e., no direct consultation with proponents), we have surveyed public announcements regarding sequestration capacity and in-service dates for the listed projects. The corresponding references to company statements and press releases are available on request. The sequestration capacity for the CCUS proposed by the Pathways Alliance is based on the details of proposed reductions by 2030 – of which 8.5 Mt are to be achieved by CCUS – in "The Pathways Vision" (published in November 2021).

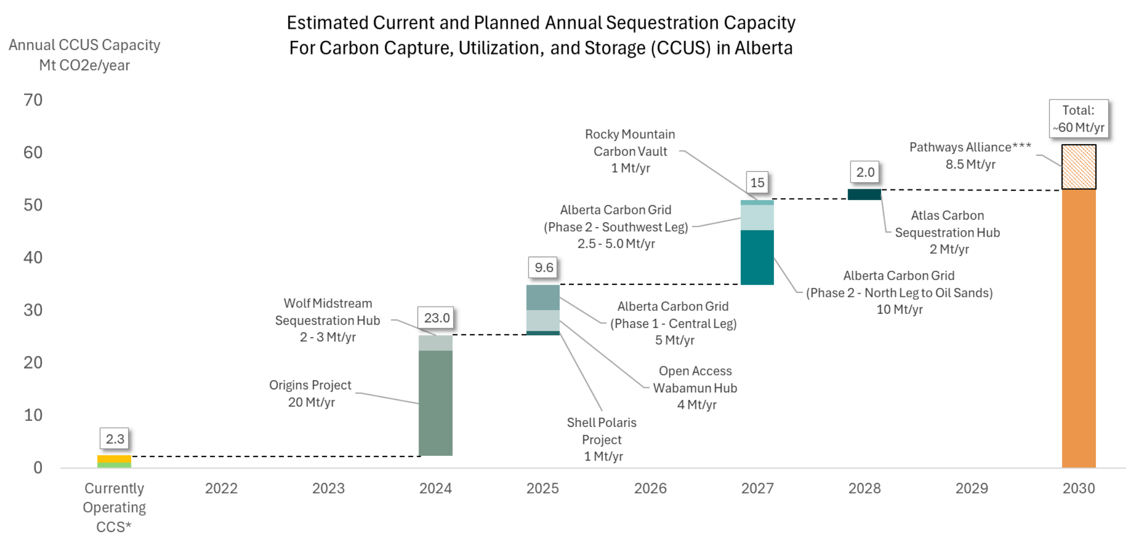
[65] On June 26, 2023, Shell announced a positive final investment decision for its Polaris project, and ATCO EnPower and Shell together announced a positive final investment decision for their Atlas Carbon Storage Hub. (see: https://www.shell.com/news-and-insights/newsroom/news-and-media-releases/2024/shell-to-build-carbon-capture-and-storage-projects-in-canada.html and https://www.atco.com/en-ca/about-us/news/2024/123013-atco-enpower-to-proceed-with-atlas-carbon-storage-hub-a-signific.html, respectively).

Additionally, no adjustment has been made for the potential overlap between projects (e.g., overlapping target reservoirs for sequestration or sources of sequestered emissions), but certain projects (particularly those in Alberta's "Industrial Heartland") would likely be mutually exclusive.

Nonetheless, while it is unlikely that all 60 Mt of sequestration capacity from proposed CCUS projects would be operationalized, the lack of announced progress on these proposed CCUS projects indicates obstacles to proponents reaching final investment decisions. From informal discussions with various CCUS proponents, uncertainty around the value of EPCs and offsets under TIER remains a critical obstacle to moving ahead with final investment decisions and into construction on proposed CCUS projects.

For TIER to provide incentive for such large investments in CCUS or other decarbonization projects, a proponent must be confident that a project will deliver a positive net present value. If proponents perceive a risk that the build-out of CCUS or other decarbonization projects would result in an oversupply of EPCs and offsets under TIER, the expected net present value of the project is correspondingly reduced.

Figure 18: Estimated Current and Planned CCUS in Alberta



Sources: Alberta Carbon Registries (ACR); Alberta Major Projects Inventory; Quest annual reports, Pathways Alliance and various company webpages/press releases

Notes: * Assumed annual sequestration by Shell's Quest CCS (1.1 Mt/yr) from 2019 annual report; Enhance Energy's Clive EOR (1.0 Mt/yr) and AlphaBow's Prentiss EOR (0.2 Mt/yr) estimated from emission offset credits vintage in ACR; WhiteCap's Joffre EOR (0.04 Mt/yr) from company disclosure.
** Certain CCUS projects not included where no published anticipated in-service dates or estimated annual sequestration.
*** Pathways Alliance ("Pathways Vision") does not specify in-service date but assumed by 2030.

Conclusion

This paper has exhibited the risk of an oversupplied market for EPCs and offsets under TIER based on the status quo tightening of benchmark stringency. We show that TIER faces an oversupply of EPCs and offsets for the reductions in emission intensity implied by both the federal 2030 ERP (including the proposed oil and gas emissions cap and Clean Electricity Regulations) and Alberta's ERED Plan. And in a business-as-usual scenario, the TIER system could easily tip into oversupply if proposed emission reduction projects come online.

This underscores the "chicken and egg" problem facing proponents of decarbonization projects under TIER. If the market for credits and offsets faces the risk of oversupply, uncertainty around prices for these instruments will diminish the expected value for investing in these projects. This uncertainty facing the TIER market means that critical decarbonization projects may not be built, potentially causing Alberta to fall short of its emission reductions target.

To mitigate this uncertainty, governments can guarantee the value that proponents will receive from future EPCs and offsets through carbon contracts for difference (CCfDs). Notably, structuring CCfDs requires reliable and regularly published statistics for market prices, and TIER presently lacks such transparency.

In offering broad-based CCfDs available to any participant in the TIER market, the contracting government has a vested interest in ensuring that a credit/offset oversupply does not materialize, which would result in significant fiscal costs to government. Providing these guarantees therefore requires governments to commit to tightening stringency to safeguard against any oversupply.

For the long-term viability of TIER, the Alberta government must anchor the expectations of market participants that the TIER market will not be oversupplied. In other words, the Alberta government must ensure that emitters' obligations will consistently exceed the newly created EPCs and offsets. This requires a commitment that reductions in emission intensity will not consistently outpace the rate of tightening benchmarks. For project proponents to undertake investments in long-term decarbonization based on future credit or offset prices, market participants must be confident that the TIER market will be balanced – regardless of what emissions reductions are actually achieved.

That is why we recommend that the Alberta government:

1. Review TIER stringency and the rate of benchmark tightening at least every two years to preemptively address any emergent oversupply of EPCs and offsets.

2. Adopt a policy rule like adaptive tightening for TIER stringency that would automatically trigger changes to stringency based on market conditions (i.e., to

accelerate tightening of benchmarks to keep up with a rapid reduction of emission intensities).

3. Increase transparency of the TIER market through regular publication of price statistics for traded EPCs and offsets.
4. Participate in guaranteeing the long-term value of EPCs and offsets under TIER through carbon contracts for difference (CCfDs).

Appendix A: Modelling approach

A1. Sector-level modelling

Our modelling of net obligations for TIER is based on assumptions at each sector-level for assumed changes under each scenario by 2030 in emissions, production, and emission intensity, along with the current parameters for benchmark tightening for each sector under the TIER Regulation (e.g., 2% per year from 2023).

For each sector, using the equations elaborated in Appendix B, we use the reporting of GHG emissions and net obligations (i.e., obligations minus EPCs) from the published TIER Compliance Summaries for 2020-22[66] to derive the given sector's overall emission intensity relative to its reference emission intensity in each year.

From the TIER Compliance Summaries, we have aggregated the level of reporting to sector definitions that correspond with production growth assumptions used in the ERP and ERED scenarios and which face distinct target emission intensity reductions and benchmark tightening rates under TIER:

- Under "Industry", we include Agroindustry, Chemical, Coal Mines, Distilling, Fertilizer, Food Processing, Forest Products, Landfills, Manufacturing, and Refineries.
- Under "Oil & Gas", we include Aggregated Oil & Gas, Conventional Oil, Pipelines, and Gas Plants.
- For "Oil Sands", we model Mining & Upgrading and In Situ separately.
- For "Power Generation", we include the emissions and net obligations of the Coal, Cogen, Gas, Hydro, and Wind facilities as reported in the TIER Compliance Summaries.[67]

A2. AESO projections for electricity generation

We use the AESO's generation projections from its 2024 Long-Term Outlook for "Decarbonization by 2035" for our ERP scenario and "Decarbonization by 2050" for the ERED scenario.[68] The AESO's 2024 Long-Term Outlook projections for "Decarbonization by

[66] Available at: https://open.alberta.ca/dataset/alberta-industrial-greenhouse-gas-compliance
[67] We highlight that the TIER reporting for "Cogen" facilities in the Power Generation sector does not include cogeneration plants integrated with facilities in other sectors (e.g., oil sands). That is, the "Cogen" emissions reported in (and generation implied from) TIER Compliance Summaries does not align with all cogeneration facilities for which AESO reports and projects generation. Additionally, "Wind" in the TIER Compliance Summaries does not include wind generation that creates offsets, assigns renewable electricity credits (RECs) to buyers in foreign jurisdictions, or contracted under Alberta's Renewable Electricity Program (REP).
[68] Available at: https://www.aesoengage.aeso.ca/forecasting-insights

2035" aim to model the proposed parameters of the draft federal Clean Electricity Regulations.

Notably, because of different definitions for the "Power" sector under TIER, we have had to make several assumptions to relate AESO projections to the Power sector under TIER. Specifically, AESO projects generation across all cogeneration facilities while TIER only reports "Cogen" within the Power sector for only cogeneration plants that are not integrated with facilities in other sectors (e.g., for TIER, a cogeneration facility that is integrated with an in situ oil sands facility is not reported under "Cogen" in the TIER Compliance Summaries). To bridge AESO's projections for cogeneration to "Cogen" facilities under TIER, we derive Cogen generation in 2022 (i.e., based on the HPB for electricity, GHG emissions and net obligations for Cogen in the TIER Compliance Summary) and, based on AESO's historical generation statistics, we assume Cogen represents a constant share of all cogeneration under AESO's projections.

Wind generation also differs in treatment under TIER. Older "legacy" wind facilities create EPCs, while new projects create offsets. As well, certain wind facilities already assign Renewable Energy Credits (RECs) to buyers in foreign jurisdictions or have contracted under Alberta's Renewable Electricity Program (REP). Based on the treatment of individual wind facilities, we assume legacy wind facilities that create EPCs and non-offsetting wind facilities (i.e., those assigning RECs or contracted under Alberta's EPCs) sustain their 2023 generation into future years. That is, for future years, we assume legacy wind generates EPCs at the electricity HPB. For offsets from wind in future years, we subtract the 2023 legacy and non-offsetting generation from wind generation projected by AESO to which we apply the EGDF for the given year.[69]

A3. Scenario assumptions for industry

For the ERP scenario, we have derived the implied change in emission intensity for 2019-30 from projected emissions by sub-sector in the "Bottom-up Analysis" and annual GDP growth rates under the 2030 ERP published by Environment and Climate Change Canada (ECCC).[70]

To relate this 2019-30 target emission reductions in the ERP across industries to the 2020-30 interval (i.e., to use the 2020 TIER Compliance Summary as the starting point for our modelling), we adjust for the 2019-20 change in emissions for each of the industries

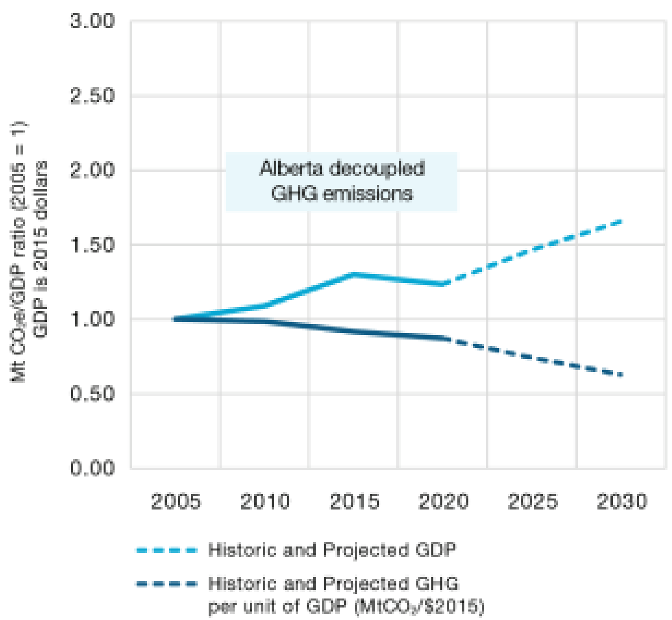
[69] Note that renewable generation projects initiated in 2023 or earlier are "grandparented" to use the EGDF in effect at initiation. Therefore, using the EGDF for the given year for computing offsets from all offsetting wind generation represents a conservative assumption for offsets from wind (i.e., since some offsetting generation will be grandparented under a more favourable EGDF).

[70] See tables 6.7 in Annex 5 of ECCC's 2030 ERP. Available at: https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/climate-plan-overview/emissions-reduction-2030/plan/annex-5.html

under the Industry sectors using Alberta-level data from the National Inventory Reporting[71] by ECCC. Using this data also allows us to better adjust the weighting for national-level changes in emissions from the ERP to the Alberta industrial composition.

For the ERED scenario, we use the indexed 2020-30 changes in emissions, GDP, and emission intensity from Alberta's ERED Plan.[72] The relevant figure showing indexed GDP growth and reduction of emission intensity (Mt CO_2e/GDP) is reproduced below as Figure A1. Based on this figure, we extract that the ERED projects a 33% reduction in emission intensity across Alberta's economy.

Figure A1: Projected emission intensity of GDP under Alberta's ERED Plan



A4. Scenario assumptions for Oil & Gas and Oil Sands

The ERP scenario reflects assumptions based on the federal 2030 ERP, including the proposed oil and gas emissions cap. Therefore, based on the published target reductions in the federal government's July 2022 discussion paper for the oil and gas emissions gap,[73] for

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[71] Available at:
https://www.canada.ca/en/environment-climate-change/services/climate-change/greenhouse-gas-emissions/inventory.html

[72] See p.11 of Alberta's ERED. Available at:
https://www.alberta.ca/emissions-reduction-and-energy-development-plan

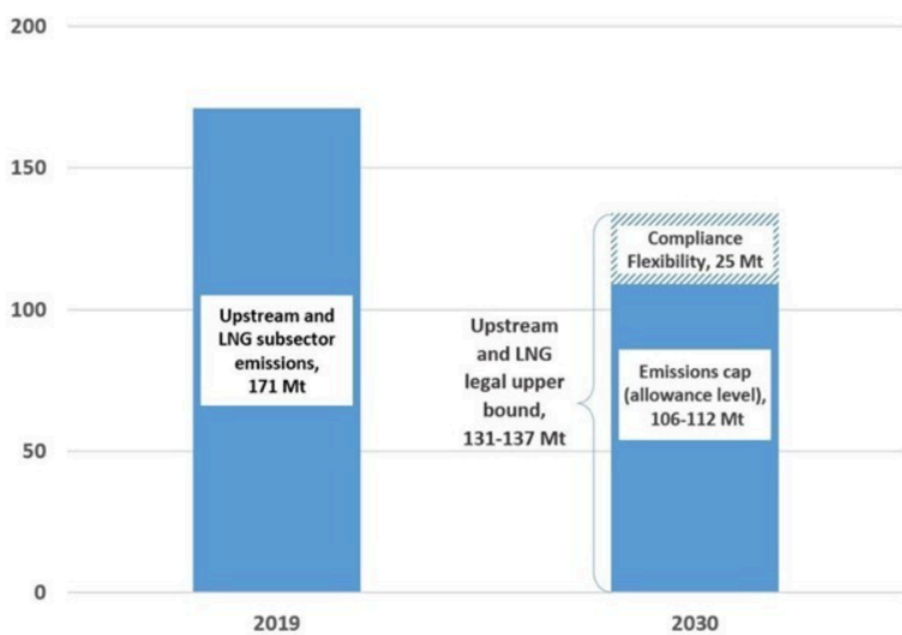
[73] Available at:
https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/oil-gas-emissions-cap/regulatory-framework.html

the ERP scenario, we assume a 20% reduction from 2019 to 2030 in GHG emissions for each of the Oil & Gas and Oil Sands sectors. The relevant graphic from this discussion paper (showing the reduction from 171 Mt in 2019 to 137 Mt in 2030) is provided below as Figure A2.

To relate this 2019-30 target reduction for oil and gas to the 2020-30 interval (i.e., to use the 2020 TIER Compliance Summary as the starting point for our modelling), we adjust for the 2019-20 change in emissions for each of Oil & Gas and Oil Sands sectors using data from the Greenhouse Gas Reporting Program[74] and the National Inventory Reporting[75] by ECCC.

For production of each of Oil & Gas and Oil Sands sectors under the ERP scenario, we have used the corresponding petroleum production from the "Canada Net-Zero" scenario in Canada Energy Regulator's Energy Futures 2023 report.[76]

Figure A2: Required GHG reduction under proposed federal oil and gas emissions cap



For the Oil & Gas and Oil Sands sectors under the ERED scenario, we assume the 33% reduction in emission intensity for 2020-30 implied by Alberta's ERED Plan (i.e., as reproduced in Figure A1 above). For the corresponding petroleum production in each sector, we use the projections provided by the Alberta Energy Regulator in its 2023 Alberta

[74] Available at: https://open.canada.ca/data/en/dataset/a8ba14b7-7f23-462a-bdbb-83b0ef629823
[75] Available at: https://www.canada.ca/en/environment-climate-change/services/climate-change/greenhouse-gas-emissions/inventory.html
[76] Available at: https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2023/

Energy Outlook (ST-98 report).[77] For each of the Oil & Gas and Oil Sands sectors, we compute the change in emissions based on the 33% reduction in emission intensity over 2020-30 and the 2020-30 projected growth in the respective petroleum product.

A5. Offset treatment

The modelling for both scenarios also incorporates a "baseline" view of offsets based on both (a) the existing registry of offset projects and the project-level estimates of offsets that will be generated over these projects' lives;[78] and (b) the projected creation of offsets from new renewable generation.[79] This baseline view of offsets to 2030 is shown in Figure A3. For the projections in each of our scenarios, these baseline offsets have been deducted for the net obligations shown.

Figure A3 also shows the 24.7 Mt of presently "banked" active offsets (i.e., issued and not yet retired) held as of May 2024 by TIER market participants. These banked offsets are in addition to 20.1 Mt of presently banked EPCs and 6.5 Mt of potentially yet-to-be-issued EPCs.[80] The additional overhang of such banked active offsets and EPCs could further exacerbate price volatility within an oversupplied TIER market – particularly as increasing volumes of EPCs and offsets expire in the coming years (see Box A above for a discussion of offset and EPC banking).

[77] Available at: https://www.aer.ca/providing-information/data-and-reports/statistical-reports/st98

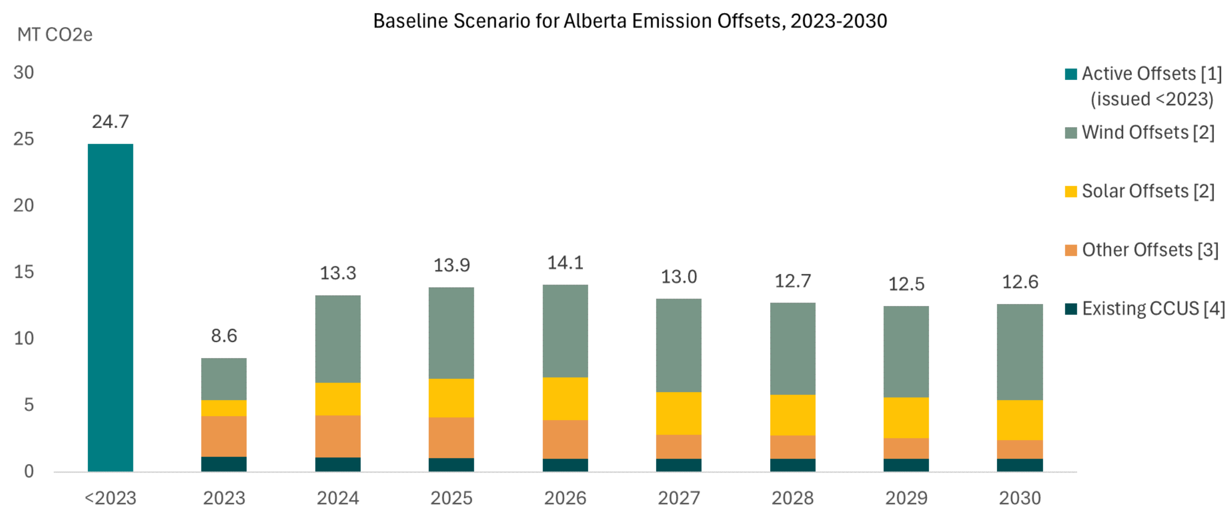
[78] The developer of an offset project must submit a project plan, which is published in the Alberta Carbon Registries and includes an estimate of offsets that will be created over the project's life. We have compiled these estimates and aggregated them for a "baseline" projection of offsets. Offset project documents are available through the Alberta Carbon Registries' online interface: https://alberta.csaregistries.ca/GHGR_Listing/AEOR_Listing.aspx

[79] We use the AESO projections for wind and solar generation to estimate the offsetting from renewables in each of the scenarios (i.e., using projections from the AESO's Updated 2024 Long-Term Outlook "Decarbonization by 2035" scenario for the ERP scenario and its "Decarbonization by 2050" scenario for the ERED scenario). We conservatively use an EGDF of 0.52 in 2024-25, which we then assume declines to 0.37 for 2026 onwards (therefore likely overstating the degree to which the EGDF would decrease following its 2025 review/update and understating the offsets that such volumes of renewable generation would create). Note that a significant share of wind generation (approximately 4.4 TWh in 2023) is ineligible for offsets under TIER — either because the respective facilities have otherwise contracted their environmental attributes (i.e., RECs used in other jurisdictions), participated in AESO's REP or the facility entered operation prior to the present project window for offsets. We have used metered volumes from AESO for these facilities to estimate the 4.4 TWh generation by that offset-ineligible capacity in 2023 and removed that amount from the projected wind generation under the AESO's 2024 Long-Term Outlook for our estimate of future offset-eligible wind generation.

[80] The quantities of banked offsets and EPCs presently reported in the Alberta Carbon Registries likely understates the actual banking because of lags in the issuance of offsets (for which emission reductions have been achieved in prior years but for which verification remains pending) and EPCs (which have been claimed in prior years' compliance reporting by TIER-regulated facilities but have also yet to be issued). For example, 6.3 Mt of EPCs were requested in 2020 (see Compliance Summary for 2020, available at: https://open.alberta.ca/dataset/alberta-industrial-greenhouse-gas-compliance) but only 4.1 Mt of EPCs have yet been issued for that vintage year in the Alberta Carbon Registries. Similarly, 6.0 Mt of EPCs were requested in 2021 but only 4.1 Mt have yet been issued.

Our modelling of the TIER market balance nonetheless projects net obligations (i.e., obligations minus creation of new offsets and EPCs) in each future year, and, for consistency,[81] we do not expressly incorporate these banked offsets into our calculation of any oversupply.

Figure A3: Baseline Scenario for 2023-2030 Alberta Emission Offsets



Sources: Alberta Carbon Registries (ACR); Alberta Electric System Operator (AESO) Long-Term Outlook (LTO); and Alberta Environment & Parks (AEP) Proposed Electricity Grid Displacement Factor (EGDF)

Notes: [1] 24.7 Mt of active offsets (i.e., not retired, pending retirement or cancelled) issued prior to 2023 in ACR as of May 2024
[2] Offsets from existing CCUS Projects from estimated annual emission reductions over offset period in respective Project Plan (available in ACR)
[3] Projected wind and solar offsets based on annual MWh renewable generation in AESO LTO (shown here for "Decarbonization by 2035" assumed in ERP scenario) at assumed 0.52 t/MWh EGDF for 2023-24 and scheduled EGDF thereafter (based on Carbon Offset Emission Factors Handbook), and note that 2023 wind generation from facilities contracted for Renewable Energy Credits or participating in Alberta's Renewable Energy Program deducted from eligible generation for offsets
[4] Other Offsets from estimated annual emission reductions over offset period in respective Project Plan (available in ACR) from, e.g., pneumatic devices, biomass, conservation cropping

[81] In Figure A3, we show the projected volumes of offsets and EPCs expiring in future years. However, to add expiring EPCs and offsets into our calculation of any oversupply for those future years would be inconsistent with how we have calculated net obligations: any newly created offsets and EPCs would similarly have a horizon to expiry and would not necessarily be retired to fulfill obligations in the year of issuance. Nonetheless, if the creation of new offsets and EPCs consistently exceed obligations, market participants would view the TIER market as oversupplied. That is, a surplus of EPCs and offsets in a given year would need to be compensated by future deficits. For a projection of deepening negative net obligations (as our modelling shows for both the ERP and ERED scenarios), new EPCs and offsets would increasingly exceed emitters' obligations – even without considering expiring EPCs and offsets.

Appendix B: Equations to model net obligations under TIER

We lack granular emission intensity data for each TIER-regulated facility from which to estimate net aggregate annual obligations. However, leveraging sector-level reporting of past obligations under TIER, we use projected emission reductions, assumed production growth, and the extent of benchmark tightening to estimate each sector's net obligation in future years.

Specifically, considering the interval from 2021 to 2030: for a given year, i (defined as the number of years since the 2021 base-year), each sector's net obligation, O_i, will be defined by its emissions, E_i, minus its allocation, A_i, such that:

$$O_i = E_i - A_i$$

In turn, the allocation, A_i, is computed according to that year's benchmark, b_i, multiplied by the annual production, Y_i, such that:

$$A_i = b_i Y_i$$

As well, annual emission intensity, e_i, will be equal to the annual emissions, E_i, divided by annual production, Y_i, such that:

$$e_i = \frac{E_i}{Y_i}$$

And therefore:

$$Y_i = \frac{E_i}{e_i}$$

And consequently:

$$A_i = b_i\left(\frac{E_i}{e_i}\right)$$

So therefore, for a given year, i, the net obligation can then be expressed in term of annual emissions, the year's benchmark and emission intensity as follows:

$$O_i = E_i - b_i\left(\frac{E_i}{e_i}\right)$$

And:

$$O_i = E_i\left(1 - \frac{b_i}{e_i}\right)$$

We assume, for the 2021-30 interval, that each sector's emissions decline at some annual emission reduction rate, r, from emissions in the base-year (i.e., 2021), E_0, and that production grows at some annual growth rate, g, from production in the base-year, Y_0, such that emission intensity in a given year can be expressed as:

$$e_i = \frac{E_0(1+r)^i}{Y_0(1+g)^i}$$

And so:

$$e_i = e_0 \frac{(1+r)^i}{(1+g)^i}$$

Additionally, for Alberta's TIER system, the benchmark is initially set at initial stringency, s, which is a proportion of the historical emission intensity – assumed as the sector's reference emission intensity, e_R. The benchmark also evolves with an annual tightening amount, t, such that the year's benchmark, b_i, is given by:

$$b_i = e_R(1 - (s + it))$$

For example, if the initial stringency is 11% and the tightening amount is 1%, the benchmark will be 87% of the reference emission intensity in 2023 (i.e., two years after the 2021 base-year).

To simplify, we assume the sector's emission intensity in the base-year is some share, θ, of the reference emission intensity (i.e., reflecting the sector's reduced emission intensity from the reference emission intensity that has already occurred by the base-year) such that:

$$e_0 = \theta e_R$$

And therefore:

$$b_i = \frac{e_0}{\theta}(1 - (s + it))$$

Substituting these equations into that for the net obligation in a given year yields:

$$O_i = E_i\left(1 - \frac{\frac{e_0}{\theta}(1-(s+it))}{e_0\frac{(1+r)^i}{(1+g)^i}}\right)$$

Therefore, even without an explicit emission intensity for the sector, the obligation in a given year can then also be expressed in terms of the year's emissions (E_i), the emission reduction rate (r), the production growth rate (g), the initial stringency (s), the tightening amount (t) and base-year share of reference emission intensity (θ) as follows:

$$O_i = E_i\left(1 - \frac{(1+g)^i(1-(s+it))}{\theta(1+r)^i}\right)$$

Additionally, although we lack direct values for each sector's reference emission intensity, we know the obligations, emissions, and stringency relative to the reference emission intensity (i.e., value for initial stringency, s) in the base-year. Therefore, we can calculate θ from the ratio between emissions and obligations according to the following relationship (from the above equations):

$$\frac{O_i}{E_i} = 1 - \frac{e_R}{e_i}(1 - (s + it))$$

So, in the base year, i=0, this relationship yields:

$$\frac{O_0}{E_0} = 1 - \frac{e_R}{e_0}(1 - s)$$

And therefore:

$$\theta = \frac{1-s}{1-\frac{O_0}{E_0}}$$

As an example for estimating θ for a sector,[82] where obligations are 4.5% of emissions in the base-year and initial stringency is 11%:

$$\theta = \frac{1-11\%}{1-4.5\%} = \sim 93\%$$

As an example for estimating a sector's net obligation, consider a sector with an emission reduction rate of -1% and growth rate of 1% (i.e., emission intensity declining by roughly 2% annually). As well, assume that the initial stringency is 11%, tightens by 1% annually and that θ is 99%. Therefore, in the ninth year (i.e., 2030), the net obligation will be defined by:

$$O_i = E_i\left(1 - \frac{(1+1\%)^9(1-(11\%+9\times1\%))}{(99\%)(1-1\%)^9}\right) = E_i(\sim 3\%)$$

That is, the net obligation will be roughly 3% of the annual emissions in that ninth year.

In contrast, assuming the same initial stringency, tightening rate and θ of 99%, for a sector with an emission reduction rate of -5% and growth rate of 3% (i.e., emission intensity declining by roughly 8% annually), the obligation will be -67% of the emissions (i.e., credits equal to 67% of the emissions).

[82] The 2021 "initial" stringency of 11% is presented here since we define 2021 as the base-year. However, we have calculated θ from the observed data for 2020 (with the 10% initial stringency), reported in the TIER summary for 2020. As explained in the first section of this paper, we have estimated the emissions in 2021 from data on output for 2021, holding all sectors' emission intensities constant (except for electricity) from 2020. Therefore, θ is the same for 2021 and, since we apply the growth rates and emission reductions from the ERP over 2021-30, we have simplified this explanation by referring to 2021 as the base-year.

The calculation is as follows:

$$O_i = E_i\left(1 - \frac{(1+3\%)^9(1-(11\%+9\times1\%))}{(93\%)(1-5\%)^9}\right) = E_i(\sim -\ 67\%)$$

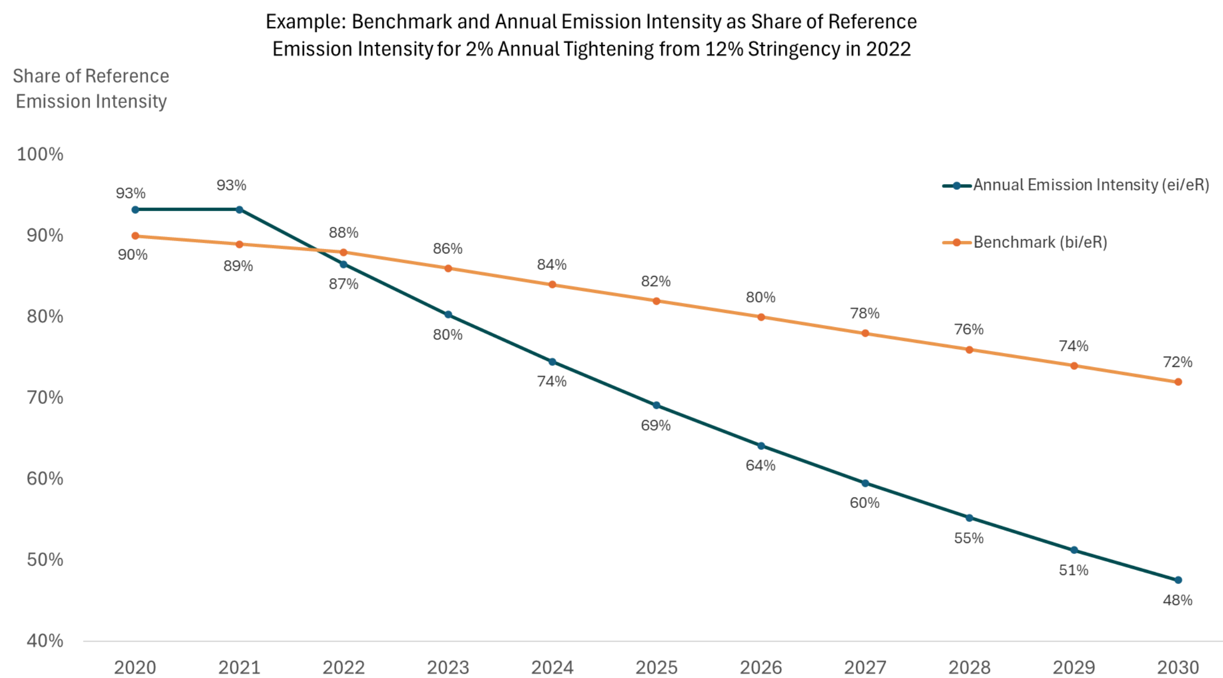
Therefore, we use the assumed 2021-2030 annual growth rates and emission reduction rates for sectors from ECCC's ERP, and, with our estimate of each sector's TIER-regulated emissions, we can then estimate each sector's obligation in the given year, adjusting for the sector's evolving emission intensity leveraging these derived relationships.

Figure B1 provides an example for the "Industry" sector under the 2% tightening (from 2023 onwards) and emission intensity declining by 7.2% (from 2022 onwards), assuming 2.5% annual output growth and 4.9% annual emissions reductions (over 2021-2030) based on the projections from ECCC's ERP. Figure B1 shows how, relative to this sector's reference emission intensity, this sector's annual emission intensity (e_i/e_R) and the benchmark (b_i/e_R) would evolve to 2030.[83]

In this example, Industry has a net positive obligation in 2021 but, with e_i/e_R less than b_i/e_R from 2022-30, will have a net negative obligation (i.e., credits/offsets exceeding obligations) over that interval.

[83] Note that in our modelling, because emission intensity is based on rates of change (i.e., an annual output growth rate and an annual emission reduction rate), e_i/e_R evolves geometrically while, because the tightening of the benchmark is by specified percentage points each year (here, five percentage points annually), b_i/e_R evolves arithmetically over the 2021-30 interval.

Figure B1: Illustration of benchmark tightening and improving emission intensity for Industry

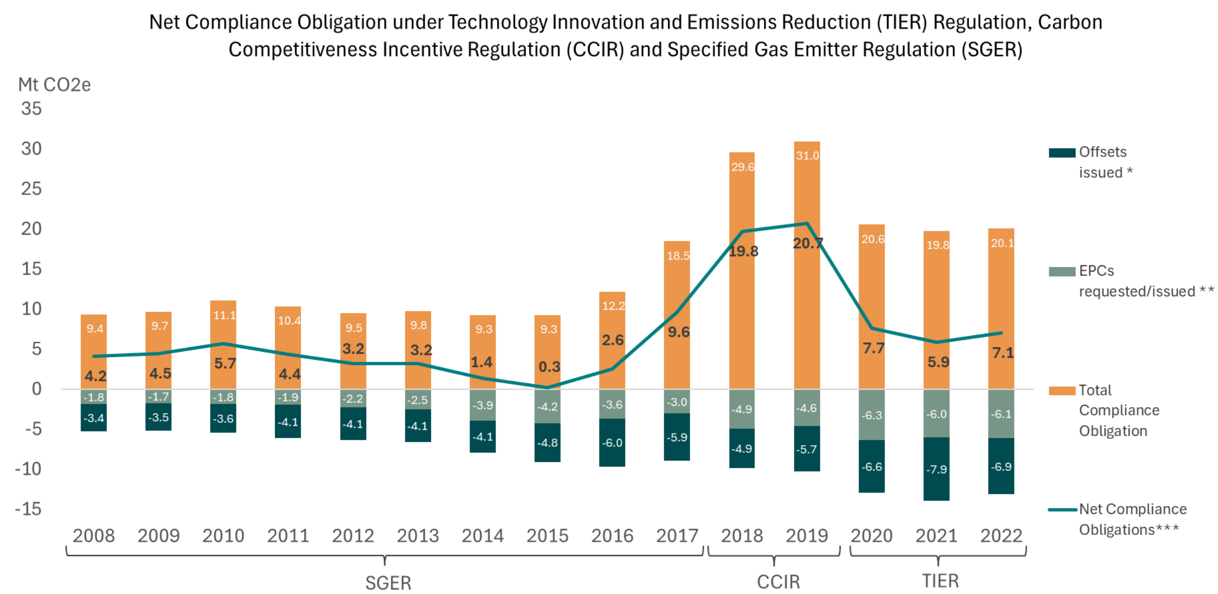


Appendix C: TIER's move to facility-specific benchmarks increased the risk of credit oversupply

By replacing product-specific benchmarks with facility-specific benchmarks, TIER reduced the overall stringency of Alberta's industrial carbon pricing. Specifically, net compliance obligations as a share of total emissions are lower under TIER than its predecessor industrial carbon pricing regime.

To illustrate, Figure C1 shows data for obligations, EPCs, and offsets under Alberta's previous industrial carbon pricing regimes since 2007 – including the Carbon Competitiveness Incentive Regulation (CCIR), in effect from 2018 to 2019, and the Specified Gas Emitters Regulation, in effect from mid-2007 to 2017.

Figure C1: Net Obligations have declined under TIER



Sources: Alberta Environment & Protected Areas (EPA) "Summary of 2020 compliance results under the Technology Innovation and Emissions Reduction (TIER) Regulation"; Environment and Climate Change Canada (ECCC) "Greenhouse Gas Reporting Program (GHGRP) - Facility Greenhouse Gas (GHG) Data"

* Offsets calculated from total issued offsets by vintage year in Alberta Carbon Registries (as of 9 April 2024)
** EPC requested for 2020-21 from EPA Compliance Summary and for years prior to 2020 calculated from total EPCs issued by vintage year in Alberta Carbon Registries (as of 9 April 2024)
*** Net Compliance Obligations calculated as Total Compliance Obligation less EPCs and Offsets issued for compliance year

TIER's lower stringency relative to CCIR results from the shift from a product-specific benchmark under CCIR to a facility-specific benchmark under TIER. While under CCIR, all facilities producing the same product received emissions allowances at the same benchmark, the applicable facility-specific benchmark under TIER is based on a given facility's historic emission intensity (although an efficient facility can opt into an HPB as described in Chapter 1.1).

By significantly reducing emitters' obligations relative to the regulated emissions, this shift to facility-specific benchmarks under TIER exacerbated the risk that the market for EPCs and offsets could become oversupplied. That is, under TIER's facility-specific benchmark, higher emission facilities face significantly lower obligations than those faced when subject to product-specific benchmarks under CCIR. While this reduces compliance costs for higher emission facilities, the facility-specific benchmarks under TIER also result in comparatively lower aggregate obligations to absorb EPCs or offsets created by decarbonization projects.