

Leading the Way? Liability Management for the Alberta Oil & Gas Industry*

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INTRODUCTION

Alberta’s oil and gas liabilities – and in particular, orphan wells – remain an ongoing concern with over \$250 million in unfunded liability as at 2021.¹ The Government of Alberta and the Alberta Energy Regulator (“**AER**”) have, over time, implemented different regulatory regimes to manage end-of-life liabilities.

This paper reviews the history of Alberta’s liability management, with a particular focus on the new regime established in December 2021 by *Directive 088*.² In Part I, we examine Alberta’s liability management prior to *Directive 088*, up to and including the common law established by the *Redwater* decisions at the Alberta Court of Appeal (“**ABCA**”) and Supreme Court of Canada (“**SCC**”).³ In Part II, we provide a brief overview of *Directive 088*’s main provisions and review its initial impacts on industry and the Orphan Fund Levy. Finally, in Part III, we compare Alberta’s liability management system to world-class peers and a suggested alternative model, and consider whether the Province of Alberta is leading the way in oil and gas liability management.

PART I THE HISTORY OF ALBERTA’S LIABILITY MANAGEMENT

Growth of Liability Management

The evolution of Alberta’s history in the oil and gas industry begins when the first natural gas resources in Alberta were accidentally discovered in 1883, when the Canadian Pacific Railway drillers drilled wells seeking water and instead found gas.⁴ In 1947, Alberta

¹ Orphan Well Association, “Annual Report 2020/21” (last visited 30 March 2022) at 7, online (PDF): <orphanwell.ca/wp-content/uploads/2021/07/OWA-Annual_2020_web3.pdf> [OWA Annual Report].

² Alberta Energy Regulator, “*Directive 088: Licensee Life-cycle Management*” (1 December 2021), online (PDF): <static.aer.ca/prd/documents/directives/Directive088.pdf> [*Directive 088*].

³ *Orphan Well Association v Grant Thornton Limited*, 2017 ABCA 124 [*Redwater ABCA*]; *Orphan Well Association v Grant Thornton Ltd*, 2019 SCC 5 [*Redwater*].

⁴ Government of Alberta, “Accidental History” (last visited 7 April 2022), online: <history.alberta.ca/energyheritage/gas/creation-of-an-industry/accidental-industry/default.aspx>.

became a real player in the oil and gas industry when the Leduc oil field was discovered by Imperial Oil.⁵ While the oil and gas industry has flourished over more than 75 years, the Province of Alberta has faced a plethora of major liability management issues which are magnified due in large part to the sheer magnitude of cumulative development relative to other jurisdictions, producers not being fiscally responsible and regulatory policies being reactive rather than proactive.⁶

Issues and risks of liability management was and is a growing concern in Alberta. The industry as a whole has failed to prove fiscal responsibility with the retirement of assets which has led the Government of Alberta and the AER to implement certain legislation and regulatory regimes to manage end-of-life liabilities, including abandonment, remediation, and reclamation.⁷

While these associated regulatory programs have evolved over time, it is generally accepted that such programs in Alberta have not yet been successful. This may be, in part, due to the fact that liability management programs have been largely reactive, rather than proactive, making it challenging to keep up with the increase of liabilities.⁸ The cyclical nature of the industry makes it difficult to manage the liabilities that are associated with the oil and gas industry.

⁵ Helene de Beer, “Alberta’s end-of-life Oil and Gas Liabilities” (MPP Thesis, University of Calgary, 2016) [unpublished] at 5, online (PDF): prism.ucalgary.ca/bitstream/handle/1880/51698/de%20Beer,%20Helena%20Maria%20Elisabeth.pdf.

⁶ Office of the Parliamentary Budget Officer, “Estimated Cost of Cleaning Canada’s Orphan Oil and Gas Wells” (25 January 2022), online (PDF): <https://distribution-a617274656661637473.pbo-dpb.ca/44de649e994977a9771ff83959ba6b9563f5c1352ec3ba4f83c4d256f40a6b41>.

⁷ See e.g. “Bill 13, Energy Statutes Amendment Act, 2000”, 1st reading, Alberta Hansard, 24-4, No 9 (6 March 2000) at 246 (Mark Hlady), online (PDF): https://docs.assembly.ab.ca/LADDAR_files/docs/hansards/han/legislature_24/session_4/20000306_1330_01_han.pdf.

⁸ de Beer at 5.

Closure work has not kept pace with inactive wells,⁹ and it is clear from recent history that the systems in place to manage abandonment and reclamation obligations (“**ARO**”) are not effective in reducing the number of inactive wells and in fact, the number of inactive wells creates a cause for concern.¹⁰ Table 1 sets out the number of inactive wells on a yearly basis in Alberta.¹¹

Table 1: Inactive Wells in Alberta

Year	Number of Inactive Wells
2018	84,000
2019	89,000
2020	97,000
2021	96,000
2022	90,000 ¹²

Orphan wells¹³ are of greater concern than inactive wells that are still the legal responsibility of a licensee, because once designated as an orphan well, it falls to the Orphan Fund (discussed further below) to pay abandonment and reclamation costs.¹⁴ When the downturn in commodities pricing in 2014 shattered oil and gas prices,¹⁵ the number of orphan wells also

⁹ An inactive well is a critical sour well (perforated or not) that has not reported any type of volumetric activity (production, injection, or disposal) for six consecutive months or any other well that has not reported any type of volumetric activity (production, injection, or disposal) for 12 consecutive months.

¹⁰ Alberta Energy Regulator, “Liability Management” (last visited 13 May 2022), online: <aer.ca/providing-information/by-topic/liability-management> [Alberta Energy Regulator, “Liability Management”].

¹¹ Alberta Energy Regulator, “Liability Management”.

¹² Government of Alberta, “Oil and gas liabilities management” (last visited 13 May 2022), online: <alberta.ca/oil-and-gas-liabilities-management.aspx> [Government of Alberta, “Oil and gas liabilities management”]. The 2022 data is as of March 1, 2022, and as such it is too early to determine if the apparent reduction in inactive wells will be sustained through the end of 2022, and whether it is attributable to *Directive 088*.

¹³ An orphan well is any well (producing, suspended, abandoned or inactive) with no legally responsible parties that can be ordered to clean up the well after the licensee becomes insolvent.

¹⁴ Alberta Energy Regulator, “Well, What’s the Difference?” (4 February 2020), online: <resource.aer.ca/stories/well-whats-the-difference>.

¹⁵ Macrotrends LLC, “WTI Crude Oil Prices – 10 Year Daily Chart” (last visited 30 March 2022), online: <macrotrends.net/2516/wti-crude-oil-prices-10-year-daily-chart>. The average monthly oil price between 2015 and 2017 was under \$50 USD per barrel, compared to the average monthly benchmark oil price of \$80 USD per barrel from 2012-2015.

increased, reaching 8,600 in 2020,¹⁶ before dipping to 7,686 in May 2022.¹⁷ This was – and remains, despite the slight decrease – a serious cause for concern.

Jurisdiction Over Liability Management and the Emergence of Regulatory Bodies

The jurisdiction over liability management activities has shifted over time. In 1915, the Public Utilities Board was the first regulatory agency in Alberta followed by the passing of the *Oil and Gas Conservation Act* (“**OGCA**”) in 1938 whereby the Petroleum and Natural Gas Conservation Board was established.¹⁸ The Petroleum and Natural Gas Conservation Board’s initial mandate was to regulate oil and gas development and production, and that mandate was continued when it was renamed the Oil and Gas Conservation Board in 1957.¹⁹

In 1971, the regulator’s name was changed to the Energy Resources Conservation Board (the “**ERCB**”) and its mandate was expanded to include the regulation of pipelines, coal, and electricity.²⁰ The Government of Alberta became a force in remediation and reclamation efforts in 1971, after the first minister of environment was appointed.²¹

In 1995, the ERCB and the Public Utilities Board amalgamated to create the Alberta Energy and Utilities Board (the “**AEUB**”) to streamline the regulatory process and create a quasi-judicial agency.²² In 2008, the ERCB was established because of the realignment of the

¹⁶ Office of the Parliamentary Budget Officer at 6.

¹⁷ Government of Alberta, “Oil and gas liabilities management”.

¹⁸ RSA 2000, c O-6 [*OGCA*]; de Beer at 7.

¹⁹ *An Act to Provide for the Conservation of the Oil and Gas Resources of the Province of Alberta*, SA 1957, c 63, s 4.

²⁰ David H Breen, “Energy Resources Conservation Board” (17 July 2014), online:

<http://thecanadianencyclopedia.ca/en/article/energy-resources-conservation-board>.

²¹ de Beer.

²² Government of Alberta, “Alberta Energy and Utilities Board sous-fonds” (last visited 7 April 2022), online: *Provincial Archives of Alberta*

<https://hermis.alberta.ca/paa/Details.aspx?ObjectID=GR0074.001SF&dv=True&deptID=1>.

AEUB and the Alberta Utilities Commission.²³ The ERCB was later dissolved in 2013, upon the creation of the AER.²⁴

The Alberta Energy Regulator

A major turning point in liability management arose through the establishment of the AER with the introduction of the *Responsible Energy Development Act* (“**REDA**”) in 2013.²⁵ The AER has jurisdiction over all aspects of energy management and deals with competing priorities across a well’s lifecycle.²⁶ While previous government bodies (i.e. the Crown ministry responsible for the environment and previous energy regulators) had to work together over the years to develop liability management strategies, the AER’s broad mandate and jurisdiction provided a coordinated system for liability management that was forward looking.²⁷ The Province of Alberta and the AER’s approach for liability management was built to balance multiple interests: environmental protection, public safety, landowner interests, investment, royalties, jobs, market volatility, and more.²⁸

While the Government of Alberta passes legislation governing how liability is managed, the AER is ultimately responsible for implementing policy and providing enforcement when needed.²⁹ The AER is tasked to ensure that oil and gas producers are accountable for their ARO to fund and complete their closure work, also known as end-of-life obligations and liabilities.³⁰ The *OGCA* and the *Oil and Gas Conservation Rules* (“**OGCR**”) are prescriptive in stating that

²³ Alberta Utilities Commission, “100 years of service and counting” (last visited 7 April 2022), online: <auc.ab.ca/100-years-of-service-and-counting/>.

²⁴ *Responsible Energy Development Act*, SA 2012, c R-17.3, s 81 [REDA].

²⁵ REDA.

²⁶ REDA, s 2.

²⁷ de Beer.

²⁸ Alberta Energy Regulator, News Release, PS2018-01, “Why we are fighting: AER president and CEO Jim Ellis” (15 February 2018), online (PDF): <static.aer.ca/prd/documents/news-releases/AERPS2018-01.pdf> [Alberta Energy Regulator, “Why we are fighting”].

²⁹ Alberta Energy Regulator, “Liability Management”.

³⁰ REDA, s 2.

licensee holders are responsible for the costs associated with the end-of life obligations and explicitly mandate the licensee holder to comply with the AER's liability management directives.³¹

Though the licensee liability rating (“**LLR**”) system has been in place since 2002, the release of *Directive 006 (Licensee Liability Rating Program)* (“**Directive 006**”) in 2013 enabled the AER to update the LLR program to: (1) measure whether a company can address its regulatory liability obligations, (2) calculate a ratio of a company's deemed assets and deemed liabilities, and (3) decide on licence transfers and security collections.³² The presumed intent of the LLR program was to stem the tide of the rising financial burden of liability management with a real-time assessment of a company's financial health. The centerpiece of the AER's regulatory framework was the LLR, which was designed to:

- prevent the costs to suspend, abandon, remediate, and reclaim a well, facility, or pipeline in the LLR program from being borne by the Alberta public, should a licensee become defunct; and
- minimize the risk to the Orphan Fund [defined below] posed by the unfunded liability of licences in the program.³³

³¹ *OGCA*, s 29; *Oil and Gas Conservation Rules*, Alta Reg 151/1971 [*OGCR*]; Alberta Energy Regulator, “Directive 001: Requirements for Site-Specific Liability Assessments in Support of the ERCB's Liability Management Programs” (6 June 2012), online (PDF): <static.aer.ca/prd/documents/directives/Directive001.pdf> [*Directive 001*]; Alberta Energy Regulator, “Directive 006: Licensee Liability Rating (LLR) Program” (1 December 2021), online (PDF): <static.aer.ca/prd/documents/directives/Directive006.pdf> [*Directive 006*] (creating the licensee liability rating program); Alberta Energy Regulator, “Directive 024: Large Facility Liability Management Program (LFP)” (24 February 2016), online (PDF): <static.aer.ca/prd/documents/directives/Directive024.pdf> (creating the large facility liability management program); Alberta Energy Regulator, “Directive 075: Oilfield Waste Liability (OWL) Program” (11 April 2016), online (PDF): <static.aer.ca/prd/documents/directives/Directive075.pdf> [*Directive 075*].

³² *Directive 006* at 3-4, 21.

³³ *Directive 006* at 2.

A licensee management rating (“**LMR**”), which is the ratio of a company’s assets to liabilities, was used to assess liability in three of the AER’s liability management programs: (1) LLR program (*Directive 006*); (2) large facility liability Management Program (*Directive 024*); and (3) oilfield waste liability program (“**OWL**”) (*Directive 075*).³⁴ Under the LLR program, a company’s LMR was calculated on a monthly basis.³⁵ Deemed assets were calculated from the amount of production and deemed liabilities were calculated from the sum of the costs to suspend, abandon, remediate and reclaim all wells and facilities.³⁶ A security deposit was required by the AER from companies with a LMR of less than 1.0, meaning the value of deemed assets were less than deemed liabilities.³⁷

The Inadequacies of the LLR Framework

Under the LLR regime, a licensee’s financial health was irrevocably linked to its LMR. The AER posted licensees’ LMRs publicly, which attracted opposition to operations, surface rights boards applications, and impacted the due diligence of lenders and prospective purchasers. Furthermore, the AER had very little discretion regarding the LMR. If, for example, a licensee’s production was shut-in for several months for a plant turnaround, the company’s LMR would drop and could trigger security deposit requirements.

In addition, there was growing evidence that the LMR did not capture a licensee’s risk of insolvency. For example, the AER has seen licensees with LMRs greater than 2.0 (and in one instance, a licensee with a LMR of 30) have become insolvent. These insolvencies seriously

³⁴ Alberta Energy Regulator, “Liability Management Rating and Reporting” (last visited 3 April 2022), online: aer.ca/regulating-development/project-closure/liability-management-programs-and-processes/liability-management-rating-and-reporting [Alberta Energy Regulator, “Liability Management Rating and Reporting”].

³⁵ *Directive 006* at 3-4.

³⁶ *Directive 006* at 13-20.

³⁷ *Directive 006* at 4.

brought into question the predictive value of the LMR in a company fulfilling its end-of-life obligations.³⁸

The AER attempted to address insolvency risk in *Directive 067* by adding broad latitude to consider unreasonable risk factors and requiring financial statements.³⁹ However, the AER remained at an inherent disadvantage as it was limited to the information to which it had access, leaving much uncertainty as to the true financial health of licensees.

This uncertainty was compounded by the fact that some licensees had poor records of their assets, which were not properly tracked and transferred through the chain of mineral transactions over the years and that there was likely incorrect reporting of information. While licensees are required to accurately report production volumes to Petrinex,⁴⁰ such reporting may not accurately reflect the true financial health and status of a licensee if well and pipeline lists were not accurate and ARO were underreported, making it difficult, if not impossible, for the AER to identify any discrepancies and update its own records.

One further shortcoming of the LLR system was that only operated assets and liabilities were considered in the LLR calculation. An oil and gas producer's LLR was based on its licensee status rather than an assessment of its assets and liabilities related to its aggregate working interests, which number could be misleading as to the true financial health of the company.

The Orphan Fund

The orphan fund (“**Orphan Fund**”) was created pursuant to the *OGCA* and *OGCR* and is intended to, *inter alia*, pay for the suspension, abandonment and reclamation costs of orphan

³⁸ Alberta Energy Regulator, “Liability Management”.

³⁹ *Directive 067*.

⁴⁰ Petrinex is Canada's Petroleum Information Network and is a joint strategic organization for reporting and maintaining volumetric production data and other management and exchange of "data of record" information essential to the operation of the petroleum sector. It can be accessed online: <petrinex.ca>.

wells, facilities, facility sites, and well sites where suspension, abandonment, or reclamation work is carried out by the AER.⁴¹

Pursuant to a calculation outlined in the *OGCA* and *OGCR*, for each fiscal year, the AER prescribes a levy (the “**Orphan Fund Levy**”) based on:

- estimated costs for the fiscal year for carrying out suspension, abandonment, remediation, and reclamation;
- anticipated claims from defaulting working interest participants (“**WIPs**”);
- payment of any debts arising from the previous year’s operations; and
- any surplus for emergency and nonbudgeted expenditures the AER deems necessary.⁴²

The Orphan Fund Levy is allocated amongst licensees included in the LLR and the OWL programs and payable to the AER by licensee holders and approval holders of well, facility or unreclaimed sites.⁴³ Accordingly, the Orphan Fund is funded by the oil and gas industry to prevent closure costs being borne by the Government of Alberta and ultimately, Alberta taxpayers. It is important to note that the Orphan Fund Levy is assessed against the licensee or approval holder and not WIPs so the immediate obligation remains with the licensee regardless of whether the WIPs contribute their working interest proportion.⁴⁴

The Orphan Fund Levy is calculated and approved by the Government of Alberta, the Alberta Oil and Gas Orphan Abandonment and Reclamation Association (a non-profit society better known as the Orphan Well Association or “**OWA**”), the Canadian Association of Petroleum

⁴¹ *OGCA*, Part 11 & s 70(1); Alberta Energy Regulator, “Orphan Well Association” (last visited 30 March 2022), online: <aer.ca/regulating-development/project-closure/liability-management-programs-and-processes/orphan-well-association> [Alberta Energy Regulator, “Orphan Well Association”].

⁴² *OGCA*, ss 73-74.

⁴³ *OGCA*, ss 73-74; *OGCR*, ss 16.520-16.531; *Directive 006*, s 7.

⁴⁴ *OGCA*, s 74(1).

Producers (“CAPP”) and the Explorers and Producers Association of Canada.⁴⁵ For the fiscal year of 2021/2022, the AER prescribed a \$70 million Orphan Fund Levy.⁴⁶ An Orphan Fund Levy was issued for large facilities for the first time in 2021/2022, increasing the levy costs and reflecting the AER’s concern regarding the closure of current and future orphaned facilities.⁴⁷ In addition to the Orphan Fund Levy, the Government of Alberta provides loans to the OWA. Overall funding, or the combination of the Orphan Fund Levy and government loans to the OWA, increased by 187% in 2021/2022 to \$392.2 million.⁴⁸ While this is a significant increase, the total remaining closure cost as of March 31, 2021 is estimated to range between \$650 million and \$700 million.⁴⁹

In 2020, *the Liabilities Management Statutes Amendment Act* amended the OGCA to expand the types of expenses upon which the Orphan Fund could be applied. These amendments were made to allow for more effective management and accelerated clean-up of sites that do not have responsible owners.⁵⁰ The notable changes are as follows:

- The OWA may provide care for sites when a licensee is unable to provide ongoing reasonable care and implement measures to prevent impairment or damage to their assets.
- The OWA may manage, maintain, operate (for a limited time), and sell assets for potential transition to a new responsible party.

⁴⁵ Alberta Energy Regulator, “Orphan Well Association”; *Directive 075* at 6.

⁴⁶ Alberta Energy Regulator, “Bulletin 2021-09: 2021/22 Orphan Fund Levy – LLR and OWL Programs” (6 April 2021), online (PDF): <aer.ca/regulating-development/rules-and-directives/bulletins/bulletin-2021-09> [Alberta Energy Regulator Bulletin 2021-09].

⁴⁷ Alberta Energy Regulator Bulletin 2021-09.

⁴⁸ OWA Annual Report at 7.

⁴⁹ OWA Annual Report at 7.

⁵⁰ 2nd Sess, 30th Leg, Alberta, 2020 (assented to 4 April 2020), SA 2020, c 4; “Bill 12, Liabilities Management Statutes Amendment Act, 2020”, 1st reading, Alberta Hansard, 30-2, Day 12 (31 March 2020) at 297 (Hon. Sonya Savage), online (PDF): <https://docs.assembly.ab.ca/LADDAR_files/docs/hansards/han/legislature_30/session_2/20200331_1330_01_han.pdf>.

- Where a licensee has ceased operations, the OWA may apply to appoint a receiver to assist in transitioning assets to new responsible parties, who will assume the associated regulatory and liability obligations. This will reduce the remaining end-of-life obligations for the insolvent licensee.
- The OWA may now enter into agreements to conduct work on behalf of remaining WIPs when directed by the AER.⁵¹

A driving force for the overhaul of the LLR regime was that the Orphan Fund is administered by the OWA which is financed by industry and taxpayers.⁵² This means that compliant, low-risk and responsible (both in the legal and colloquial sense) oil and gas producers and taxpayers end up funding the liabilities of irresponsible producers.

Adapting to Redwater ABQB Decision

In June 2016, the AER introduced Bulletin 2016-16 in response to the *Redwater* Court of Queen’s Bench decision.⁵³ Bulletin 2016-16, along with the revision and clarification in Bulletin 2016-21, imposed a minimum post-transfer LMR of 2.0 on any license transferee. Transfers to licensees with a post-transfer LMR of between 1.0 and 2.0 were approved at the AER’s discretion; the AER had to be satisfied that the transferee could meet its licensing obligations before granting its approval.⁵⁴

⁵¹ Alberta Energy Regulator Bulletin 2021-09.

⁵² Alberta Energy Regulator, “Orphan Well Association” (the levy on industry is proportionate to a licensee’s liabilities).

⁵³ Alberta Energy Regulator, “Bulletin 2016-16: Licensee Eligibility – Alberta Energy Regulator Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision” (20 June 2016), online (PDF): <static.aer.ca/prd/documents/bulletins/Bulletin-2016-16.pdf>.

⁵⁴ Alberta Energy Regulator, “Bulletin 2016-21: Revision and Clarification on Alberta Energy Regulator’s Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision” (8 July 2016), online (PDF): <static.aer.ca/prd/documents/bulletins/Bulletin-2016-21.pdf> [Alberta Energy Regulator Bulletin 2016-21].

As the price of oil dropped and the industry experienced economic upheaval, the orphan well count continued to grow. Landowners continued to be left with idle equipment and facilities on their land after operators became defunct.

Some instances were egregious and drew very little regulatory response prior to insolvency. For example, Lexin Resources Ltd. (“**Lexin**”), disregarded numerous AER orders and was cited for 276 site inspections in 2016.⁵⁵ Lexin admitted to the AER that it had financial difficulties, did not have access to its sour gas wells due to its surface lease rental arrears, was not maintaining its Mazeppa sour gas plant, was not monitoring for sour gas leaks, and could no longer respond to emergencies.⁵⁶ Lexin failed to pay the security deposit in accordance with the AER’s LLR program. The AER shut-in the facility and petitioned Lexin into receivership, but Lexin ultimately defaulted on more than \$71 million in reclamation security and Orphan Fund levies.⁵⁷

Another insolvency that attracted attention was Sequoia Resources Corp. (“**Sequoia**”). In 2016, Perpetual Energy Inc., Perpetual Operating Trust, and Perpetual Operating Corp. (the “**Perpetual Group**”) held non-producing wells (the “**Assets**”) with approximately \$5-6 million in asset value and \$229 million in ARO and municipal tax liability.⁵⁸ The ABCA stated that the Assets were transferred to Sequoia through a multi-step transaction (the “**Transaction**”) as follows:

⁵⁵ Tracy Johnson & Kyle Bakx, “Lexin Resources and the dark side of Alberta’s downturn”, *CBC News* (24 April 2017), online: <cbc.ca/news/canada/calgary/lexin-resources-what-went-wrong-1.4038838>.

⁵⁶ Johnson & Bakx.

⁵⁷ Dan Healing, “Lexin Resources bankruptcy leads to millions in rising costs for Orphan Well Association”, *Edmonton Journal* (10 November 2017), online: <edmontonjournal.com/business/energy/lexin-resources-bankruptcy-leads-to-millions-in-rising-costs-for-orphan-well-association/wcm/a6aca780-5980-469c-bb0d-d668bac1ce6e>.

⁵⁸ *PricewaterhouseCoopers Inc v Perpetual Energy Inc*, 2022 ABCA 111 at paras 61, 63 [*Perpetual Energy* 2022].

(1) Perpetual Operating Trust transferred beneficial interest in the Assets to Perpetual Energy Operating Corp. (“**PEOC**”).

(2) Perpetual Operating Corporation was created as the new trustee for Perpetual Operating Trust.

(3) Perpetual Energy Inc. sold all of its shares of PEOC to 1986114 Alberta Ltd. (“**198Co**”), a company wholly owned by Kailas Capital Corp. (“**Kailas**”), for \$1.00.

(4) PEOC changed its name to Sequoia Resources Corp.⁵⁹

During the Transaction, PEOC briefly held legal and beneficial title to certain profitable assets before transferring legal title to Perpetual Operating Corporation, though it retained (did not transfer) a 1% working interest in other producing wells.⁶⁰

The end result of the Transaction is that Kailas, through its subsidiary 198Co, became the new parent corporation of Sequoia, which owned the legal and beneficial interests in and to the Assets.⁶¹ The structure of the Transaction has generated commentary, including implications that Sequoia likely had a much higher LLR than it should have and that the AER effectively gave Sequoia credit for the value of the profitable well as if it held a 100% interest, even though it only held a 1% interest.⁶² Sequoia declared bankruptcy approximately 18 months later, by which time all of the ARO liability for the unprofitable Sequoia assets had been cleansed from the Perpetual Group’s balance sheets.⁶³

⁵⁹ *PricewaterhouseCoopers Inc v Perpetual Energy Inc*, 2021 ABCA 16 at paras 6-7 [*Perpetual Energy* 2021].

⁶⁰ *Perpetual Energy* 2021 at paras 7-9.

⁶¹ *Perpetual Energy* 2021 at para 8.

⁶² *Perpetual Energy* 2021 at paras 8-9; Drew Yewchuk, “The Sequoia Bankruptcy Part 1: The Motion to Strike and the Interveners” (January 18, 2021), online (PDF): ABlawg, <ablawg.ca/wp-content/uploads/2021/01/Blog_DY_Sequoia_Part_1.pdf>.

⁶³ *Perpetual Energy* 2021 at paras 7-8.

The case is still ongoing as the ABCA ruled that the bankruptcy of Sequoia will be returned to the Court of Queen's Bench because, among other errors, the trial judge failed to account for the impact unreclaimed facilities have on the value of an energy company.⁶⁴ The ABCA stated that “[e]nd-of-life obligations could be loosely thought of as asbestos in the walls of a house...It will need to be rectified sooner or later, and someone will have to pay for it ... until then, however, the house is worth less than a similar asbestos-free house.”⁶⁵

The Implications of the Redwater ABCA Decision

The orphan well problem was magnified in the 2017 ABCA decision in *Orphan Well Association v Grant Thornton Limited* (“**Redwater**”). With support from CAPP, the AER and OWA advocated that abandonment work should take priority over repaying creditors. The ABCA disagreed, holding that secured creditors of a bankrupt operator have the first right of priority to the proceeds from the sale of the bankrupt's wells.⁶⁶ Accordingly, the proceeds were distributed to the secured creditors first rather than towards the reclamation of the bankrupt debtor's inactive wells, thereby leaving its wells orphaned without any industry participant assuming responsibility for them. In the wake of the *Redwater* decision, thousands of oil and gas wells were disclaimed to the OWA, while the debtor companies were not held accountable for cleaning up their mess, drawing the ire of the industry and the public alike.⁶⁷

In 2018, the AER issued a statement outlining the disturbing issues with liability management in the Province of Alberta, stating that oil and gas producers were incentivised to walk away from thousands of wells while the receivers of insolvent companies were selling off

⁶⁴ *Perpetual Energy* 2022 at para 3.

⁶⁵ *Perpetual Energy* 2022 at para 54.

⁶⁶ *Redwater ABCA* at para 91.

⁶⁷ Orphan Well Association, “OWA Inventory Lists” (last visited 2 May 2022), online: orphanwell.ca/about/orphan-inventory/ (as of 1 May 2022, there are 1,758 orphan wellbores for decommissioning).

profitable assets, disclaiming unprofitable and liability-ridden assets, and making creditors whole at the expense of environmental liabilities.⁶⁸ The AER further cautioned that the ABCA's decision in *Redwater* not only affects the industry as a whole but also the AER's ability to enforce its rules.⁶⁹

Redwater SCC

In 2019, the SCC heard the appeal of the *Redwater* decision.⁷⁰ The SCC's decision was highly anticipated by oil and gas stakeholders since the Court dealt with the conflicts and the interplay between the abandonment and reclamation provisions of the *OGCA* and the insolvency law in the *Bankruptcy and Insolvency Act* ("**BIA**").⁷¹ While the ABCA held that the federal bankruptcy law trumped the provincial laws, the SCC disagreed.⁷² The doctrine of federal paramountcy was not triggered because, in the view of the SCC, the federal scheme under the *BIA* is "concerned solely with the personal liability of the trustee, and not with the liability of the bankrupt estate."⁷³ As a result, the SCC held that "there is no operational conflict or frustration of purpose between the Alberta legislation and s. 14.06 of the *BIA*."⁷⁴

Having found that there is no conflict between the federal and provincial legislation, the SCC turned to the assessment of whether the regulator was asserting claims provable in bankruptcy. In determining that regulatory claims are not provable claims, the SCC applied a three-prong test that was first developed in *Newfoundland and Labrador v AbitibiBowater Inc.*⁷⁵

For a claim to be a provable claim under the *BIA*:

⁶⁸ Alberta Energy Regulator, "Why we are fighting".

⁶⁹ Alberta Energy Regulator, "Why we are fighting".

⁷⁰ *Redwater*.

⁷¹ RSC 1985, c B-3.

⁷² *Redwater* at paras 129-31.

⁷³ *Redwater* at para 77.

⁷⁴ *Redwater* at para 77.

⁷⁵ 2012 SCC 67.

- (1) there must be a debt, a liability or an obligation to a creditor;
- (2) the debt, liability or obligation must be incurred before the debtor becomes bankrupt; and
- (3) it must be possible to attach a monetary value to the debt, liability, or obligation.⁷⁶

Under the three-prong test, regulatory obligations, such as end-of-life obligations, are not provable claims because neither the Government of Alberta nor the AER are considered “creditors”, and as a result, such obligations cannot be stayed nor subject to a claims procedure order under the *BIA*.⁷⁷

The role of the trustee in bankruptcy evolved with respect to addressing end-of-life obligations, where the Court did not allow the trustee to ignore a company’s environmental liabilities.⁷⁸ The trustee in the SCC *Redwater* decision was directed to use the proceeds from the sale of Redwater’s assets to address Redwater’s end-of-life obligations.⁷⁹

The decision made by the SCC was significant and had implications for a multitude of stakeholders and profoundly changed the functioning of the insolvency system.⁸⁰ For practical purposes, the regulatory obligations following the SCC decision were treated as priority claims before any distribution was made to creditors.⁸¹ In the short and long term, the decision was to curb the influx of liabilities to the Orphan Fund and uphold the polluter-pays principle. The

⁷⁶ *Redwater* at para 37.

⁷⁷ *Redwater* at paras 135-36, 159.

⁷⁸ *Redwater* at para 160.

⁷⁹ *Redwater* at para 163.

⁸⁰ Alberta Energy Regulator, “Redwater Decision” (last visited 7 April 2022), online: <aer.ca/protecting-what-matters/holding-industry-accountable/redwater>.

⁸¹ Frank Spizzirri & Sheldon Title, “SCC’s Final Word in the *Redwater Energy Corp.* Bankruptcy” (April 2019) Am Bankr Inst J 36, online (PDF): <abi-org-corp.s3.amazonaws.com/journals/international1_04-19.pdf>.

polluter-pays principle is a well-recognized tenet of Canadian environmental law which assigns the responsibility for remedying environmental damage to the polluter, thereby incentivizing companies to be environmentally responsible in the course of operations.⁸² The finality of the SCC decision paved the way for a new liability management system to be developed.

PART II THE CURRENT STATE OF *DIRECTIVE 088*

A New Liability Management Framework

On July 30, 2020, the Government of Alberta announced its new liability management framework (the “**Liability Management Framework**”).⁸³ The Liability Management Framework: (1) upholds the polluter-pays principle, (2) establishes five-year rolling spending targets for reclamation and (3) provides a process to address legacy and post-closure sites.⁸⁴ The amendments also allow landowners or First Nations to opt-in or nominate inactive or abandoned wells and facilities for closure.⁸⁵ The Liability Management Framework is part of a suite of policies designed to ensure the oil and gas industry is able to meet environment obligations in a flexible and cost-effective manner.⁸⁶

On December 17, 2020, the Government of Alberta amended the *OGCR* and *Pipeline Rules* to allow the AER to set closure spend targets to support timely inventory reduction, request closure plans from licensees, impose terms and conditions on the closure plans, direct the timing

⁸² *Redwater* at paras 29, 291.

⁸³ Government of Alberta, “Liability Management Framework” (July 2020), online (PDF): <alberta.ca/assets/documents/energy-liability-management-framework.pdf> [Government of Alberta, “Liability Management Framework”].

⁸⁴ Government of Alberta, “Liability Management Framework”.

⁸⁵ Government of Alberta, “Landowner and Indigenous Community Site Nomination” (last visited 5 May 2022), online: <alberta.ca/landowner-and-indigenous-community-site-nomination.aspx> [Government of Alberta, “Landowner and Indigenous Community Site Nomination”]; Jeremy Barretto, Danielle Maréchal & Christopher W McLelland, “Alberta’s New Oil and Gas Liability Management Framework” (6 August 2020), online: <cassels.com/insights/albertas-new-oil-and-gas-liability-management-framework/>.

⁸⁶ “Bill 12, Liabilities Management Statutes Amendment Act, 2020”, 3rd reading, Alberta Hansard, 30-2, Day 14 (2 April 2020) at 406 (Mike Ellis), online (PDF): <https://docs.assembly.ab.ca/LADDAR_files/docs/hansards/han/legislature_30/session_2/20200402_0900_01_han.pdf>.

and priority of the work, and request licensee financial and reserves information.⁸⁷ Concurrently with the changes to the *OGCR* and *Pipeline Rules*, the AER released Bulletin 2020-26.⁸⁸

The AER released *Directive 088* on December 1, 2021, following consultation with stakeholders.⁸⁹ Although effective management of licensee risk is still a work-in-progress for the AER, *Directive 088* is the final piece of the new Liability Management Framework, and overhauls the way the AER manages licensee risk but still remains a work-in-progress.

An Overview of Directive 088

Directive 088, along with its companion Licensee Life-Cycle Management Manual 023 (“**Manual 023**”), provides a regulated management system throughout the energy resource development lifecycle for Alberta oil and gas license-holders.⁹⁰ The directive will apply to any licensee or approval holder of sites or infrastructure governed by the *OGCA* or the *Pipeline Act*.⁹¹

Directive 088 prescribes, among other things:

1. a holistic assessment of a licensee’s capabilities and performance across the energy development life cycle (the “**Holistic Licensee Assessment**”);
2. a licensee management program, which determines how licensee management will occur across the energy development life cycle (the “**Licensee Management Program**”);
3. an inventory reduction program, which sets mandatory spend targets for closure activities and spends by licensees (the “**Inventory Reduction Program**”);
4. updated application requirements related to the license transfer process; and

⁸⁷ Alberta Energy Regulator, “Bulletin 2020-26: Changes to Oil and Gas Conservation Rules and Pipeline Rules” (17 December 2020), online (PDF): <static.aer.ca/prd/documents/bulletins/bulletin-2020-26.pdf> [Alberta Energy Regulator Bulletin 2020-26]; *OGCR*; *Pipeline Rules*, Alta Reg 91/2005 [*Pipeline Rules*].

⁸⁸ Alberta Energy Regulator Bulletin 2020-26.

⁸⁹ *Directive 088*.

⁹⁰ Alberta Energy Regulator, “Manual 023: Licensee Life-Cycle Management” (May 2022), online (PDF): <static.aer.ca/prd/documents/manuals/Manual023.pdf> [Manual 023].

⁹¹ *Directive 088* at 1; RSC 2000, c P-15 [*Pipeline Act*].

5. the first phase of improvements to security collection.⁹²

The transition away from the LLR program is an ongoing process, and both the Liability Management Framework and *Directive 088* will evolve subject to initial returns, results and feedback from industry.⁹³ Additional changes are expected throughout the course of 2022.

The Holistic Licensee Assessment

The Holistic Licensee Assessment will essentially replace the LMR as the assessment tool. While corporate LMRs remain in place, they will be only one of many factors used as a business intelligence tool by the AER.⁹⁴

Directive 088 details how the AER will holistically assess each licensee to determine whether to approve license transfers or pursue specific regulatory action. Multiple factors will be taken into account, including financial statements, capabilities, unreasonable risk factors (as listed in *Directive 067*), and any other factors required in the circumstances.⁹⁵ Any information provided to the AER by the licensee, whether in an application, amendment, or report, may be used in the Holistic Licensee Assessment.⁹⁶

Furthermore, the AER is not limited to the information provided by the licensee. The AER may consider any other factors based on the information it has available, including through inspection, audits, compliance assessments, previous transfer decisions, or statements of concern raised on a transfer application.⁹⁷

⁹² Alberta Energy Regulator, “Bulletin 2021-45: New Requirements and Guidance Related to Liability Management” (1 December 2021), online (PDF): <static.aer.ca/prd/documents/bulletins/Bulletin-2021-45.pdf>.

⁹³ Alberta Energy Regulator, “Liability Management Rating and Reporting”.

⁹⁴ Despite being no longer applicable to the soon-to-be rescinded *Directive 006*, LMR will continue to be referenced in *Directives 001, 011, 024, and 075*.

⁹⁵ *Directive 088* at 2.

⁹⁶ *Directive 088* at 2.

⁹⁷ Manual 023 at 1, 18.

The AER has very broad discretion through the Holistic Licensee Assessment based on the information available at the time of assessment, creating broad latitude for the regulator and uncertainty for the licensee. *Directive 088* uses broad inclusionary language which demonstrates that the Holistic Licensee Assessment is not limited to the prescribed assessment criteria.⁹⁸ It remains unclear as to what deliverable the licensee will receive from the AER supporting its assessment.

Under the *OGCR*, the AER must keep financial information confidential for 5 years and reserves information will be kept confidential for 15 years.⁹⁹ Each licensee will have access to its own information on file with the AER but not that of any other party, unlike LMRs, which were publicly accessible up until February 2020.

The Licensee Capability Assessment

The Holistic Licensee Assessment includes some prescribed assessment factors; arguably the most important is the licensee capability assessment (“**Licensee Capability Assessment**”). The Licensee Capability Assessment was introduced as part of the Liability Management Framework and is now part of the Liability Management Program.

The Licensee Capability Assessment is designed to assess the ability of licensees to meet their liability and regulatory obligations throughout the energy development life cycle. It will consider the licensee’s financial and liability risk, but it will also compare a licensee to its peers based on asset lifespan, financial capability, closure, administrative, operational and compliance history.¹⁰⁰

⁹⁸ *Directive 088* at 2 (“any other factors as appropriate in the circumstances”).

⁹⁹ *OGCR*, s 12.152(2).

¹⁰⁰ Manual 023 at 1-9.

Beyond the Holistic Licensee Assessment, the Licensee Capability Assessment will also guide license eligibility under *Directive 067* as well as regulatory decisions under *Directive 088*.¹⁰¹ The risk factors used in the Licensee Capability Assessment also determine, in part, whether security will be required by the AER, while the performance factors are used to determine the amount of such security.¹⁰²

Risk Factors

The risk factors in the Licensee Capability Assessment are used to assess the level of financial capability and magnitude of liability for the licensee. These factors are intended to be predictive and reflect the ability of the licensee to manage its regulatory and liability obligations. Currently, there are two risk factors: (1) level of financial distress, and (2) magnitude of liability.¹⁰³

The licensee's level of financial distress is determined from a selection of widely accepted financial industry parameters and ratios that measure profitability over time, access to cash and the impact of debt on operations.¹⁰⁴ Overall, it measures a licensee's financial ability to address its liabilities.

The value of each financial distress parameter is normalized to a value between 0 and 100 based on the ranges identified in Manual 023.¹⁰⁵ The normalized values are then weighted and added together to produce an overall assessment of the licensee's level of financial distress as low, medium, or high.¹⁰⁶

¹⁰¹ *Directive 088* at 3.

¹⁰² *Directive 088* at 8.

¹⁰³ Manual 023 at 2-3.

¹⁰⁴ Manual 023 at 2-3.

¹⁰⁵ Manual 023 at 3.

¹⁰⁶ Manual 023 at 3.

The magnitude of liability factor is a relative assessment of the licensee's total liabilities.¹⁰⁷ The licensee's magnitude of liability is estimated using their abandonment, remediation and reclamation liability, as set forth in *Directive 011*, and site-specific liability as set forth in *Directive 001*.¹⁰⁸ Licensees are grouped based on the results of each parameter as low (less than \$25 million), medium (between \$25 million and \$150 million) or high (greater than \$150 million).¹⁰⁹ These groups are set so that 80% of the licensees hold only 10% of the total liabilities and represent the "low risk" group.¹¹⁰ The bulk of liabilities are thus held by the remaining 20% of licensees in the "medium" and "high" risk groups.

Performance Factors

Unlike risk factors, the performance factors are assessed relative to the licensee's peer group based on business type, size and production portfolio.¹¹¹ Performance is assessed by way of lifespan, closure, operations and administration metrics, and are based on a three-calendar year performance window.¹¹² Each performance parameter is weighted and the licensee is tiered, with tier 1 constituting the top 25% top quartile, tier 2 constituting the middle 50% and tier 3 constituting the bottom 25% quartile.¹¹³

Overall, the Licensee Capability Assessment builds a licensee profile which reflects the capability, risk, and performance of the licensee. The risk and performance factors are not set in

¹⁰⁷ Manual 023 at 3.

¹⁰⁸ Alberta Energy Regulator, "Directive 011: Licensee Liability Rating (LLR) Program Updated Industry Parameters and Liability Costs", 31 March 2015, online (PDF): static.aer.ca/prd/documents/directives/Directive011_March2015.pdf; *Directive 001*.

¹⁰⁹ Manual 023 at 3.

¹¹⁰ Alberta Energy Regulator, "Liability Management Framework – Licensee Capability Assessment" (8 June 2021) at 5m49s, online (video): *YouTube* <youtu.be/mmaZGb2eQy0?t=349>.

¹¹¹ Primary business activity is deemed to be one of the following: producers, pipelines, midstream, or waste management. Producer size is deemed to one of the following: micro, junior, intermediate, or large/major. Primary production type is deemed to one of the following: dry gas, liquid rich gas, light-medium oil, heavy oil/bitumen, or mixed: Manual 023 at 4-5.

¹¹² Manual 023 at 6-9.

¹¹³ Manual 023 at 6.

stone and will be modified or recalibrated with updates to Manual 023 as the AER deems necessary.¹¹⁴

The Licensee Management Program

The goal of the Licensee Management Program is to allow the AER to continually monitor and manage licensees throughout the energy development life cycle.¹¹⁵ Licensees must provide the AER with all information requested under the Liability Management Program and submit a site-specific liability assessment as directed by the AER.¹¹⁶

The Licensee Capability Assessment will assist the AER by identifying high risk licensees which require proactive action in the form of specific engagement. High risk licensees can be addressed through education, encouragement to follow industry best practices or, if necessary, specific regulatory action, such as modifying licensee eligibility under *Directive 067*.¹¹⁷

The Inventory Reduction Program

Closure means the permanent end of operations and includes the abandonment, remediation and reclamation of well sites, facilities, facility sites, and pipelines.¹¹⁸ Previously there was no regulatory requirement for the timing of closure obligations (although *Directive 013* has included suspension requirements for quite some time).¹¹⁹ The Inventory Reduction Program is the result of an effort to attend to closure obligations on an ongoing basis rather than allowing liabilities to accumulate and vest in the OWA upon insolvency of a licensee. It sets annual mandatory and voluntary closure spend targets for every licensee. The AER has the authority

¹¹⁴ Manual 023 at 10.

¹¹⁵ *Directive 088* at 4.

¹¹⁶ *Directive 001* at 3, 9.

¹¹⁷ *Directive 088* at 4.

¹¹⁸ *Directive 088* at 2.

¹¹⁹ *Directive 013*.

under the *OGCR* and the *Pipeline Rules* to establish “closure quotas” setting forth a minimum amount of closure work and/or spend.¹²⁰

Closure quotas will be determined by the licensee’s proportion of inactive liabilities and level of financial distress.¹²¹ The AER will publish annual industry-wide spending targets and in July of every year, will release the licensee-specific mandatory and voluntary targets on OneStop, the new interface for viewing and reporting closure spending.¹²² Each licensee must report its closure activities and spends for the previous calendar year by March 31.¹²³

Licensees may forego meeting their annual mandatory closure targets in a given year if they provide the AER with a security deposit equal to the amount of the mandatory target by January 31 of that year.¹²⁴ Failure to either meet the mandatory annual target or provide a security deposit for that amount will trigger an automatic Holistic Licensee Assessment to determine whether the AER should demand security and in what amount.¹²⁵ One would have to assume that this security could potentially be greater than the mandatory target as a punitive measure for not paying the security deposit in the first instance. Factors include the licensee’s rate of closure activities, compliance with mandatory and voluntary closure spend targets, and outstanding amount of closure spend required to meet closure spend targets.¹²⁶ Ultimately, the Inventory Reduction Program is designed to be flexible, allowing licensees to choose sites and activities to maximize efficiencies.

¹²⁰ *Directive 088* at 4; *OGCR*, s 3.014; *Pipeline Rules*, s 82.1.

¹²¹ *Manual 023* at 10.

¹²² Alberta Energy Regulator, “Onestop Tool” (last visited 29 March 2022), online: <www1.aer.ca/onestop/>.

¹²³ *Directive 088* at 5.

¹²⁴ *Directive 088* at 5.

¹²⁵ *Directive 088* at 5.

¹²⁶ *Manual 023* at 20-21.

Mandatory Closure Spend and Targets

Starting on January 1, 2022, licensees with inactive infrastructure will be required to meet an individual annual AER-determined mandatory target. Targets are based on the licensee's liability, historical closure spending, disclosed financial information, and are available in the OneStop closure report by July 31 for the following year. The historical spend analysis is based on the two-year average closure spends of the licensee.¹²⁷ The expected industry target increase is 5% annually and licensees can use their current targets to estimate future targets.¹²⁸

Industry-wide closure spend targets are a five-year rolling target based on inactive liability and historical closure spending for previous years and the target and forecasts are released on the AER website annually.¹²⁹ Currently, \$422 million and \$443 million are set for industry-wide spend targets for 2022 and 2023 respectively, while \$465 million, \$489 million, and \$513 million are projected spend targets for 2024-2026.¹³⁰

As a general rule, a licensee can meet their spending obligations by paying for eligible activities at inactive or abandoned sites, or active sites where a well or facility has been shut-in but has not met the inactive criteria. Licensees can also abandon and remediate pipelines, so long as it results in an abandoned status.¹³¹ However, well and facility suspensions, pipeline discontinuations as well as their associated installations, and remediation on active sites are not considered eligible spend activities.

¹²⁷ If a licensee does not participate in an Area Based Closure Program, their estimated *Directive 011* spends will be used.

¹²⁸ Alberta Energy Regulator, "Liability Management Framework: Inventory Reduction Program" (Presentation delivered at the 'Focused Engagement Sessions on Directive 088', Calgary, 16 February 2022) [unpublished] [Alberta Energy Regulator, "Focused Engagement Sessions on Directive 088"].

¹²⁹ Manual 023 at 10; Alberta Energy Regulator, "Inventory Reduction Program" (last visited 25 May 2022), online: <aer.ca/regulating-development/project-closure/liability-management-programs-and-processes/inventory-reduction-program>.

¹³⁰ Alberta Energy Regulator, "Bulletin 2021-23: Mandatory Closure Spend Targets" (8 June 2021), online (PDF): <static.aer.ca/prd/documents/bulletins/bulletin-2021-23.pdf>.

¹³¹ Manual 023 at 14.

Voluntary Closure Spend

Licensees may be eligible for incentives if they choose to spend more than their mandatory closure spend target. Licensees can qualify for incentives by committing to a voluntary spend target equal to the mandatory target plus 0.3% and participate in an Area Based Closure Program project.¹³² Incentives include deadline extensions for the removal of surface equipment and other specified materials associated with surface abandoned (cut & capped) well licenses and eligibility to apply to receive the maximum three-year extension for expired Crown mineral lease wells.¹³³ A licensee's voluntary target expires at the end of each calendar year and must be renewed to maintain the licensee's eligibility for the voluntary target incentives.¹³⁴

Reporting and Compliance

Licensees may elect to report their closure spend either on an ongoing basis or upon completion of a closure milestone within a calendar year.¹³⁵ Licensees who do not meet their mandatory or voluntary spend targets are deemed to be noncompliant. Enforcement mechanisms include request for security and loss of incentive eligibility for licensees who fail to meet their voluntary targets.¹³⁶

License Transfers

The new Liability Management Program will transition the license transfer application process from the LLR program to *Directive 088*. *Directive 006* was amended concurrently with *Directive 088*.¹³⁷ Subsequent phases of implementation will include additional changes to

¹³² Alberta Energy Regulator, "Focused Engagement Sessions on Directive 088". The Area Based Closure Program is intended to create closure efficiencies by encouraging licensees to collaborate with other nearby operators, reducing the unit cost of closure: see Manual 023 at 13.

¹³³ Manual 023 at 11-12 (both incentives are subject to certain conditions imposed by the AER).

¹³⁴ Manual 023 at 12.

¹³⁵ Manual 023 at 14.

¹³⁶ Manual 023 at 16-17.

¹³⁷ *Directive 006* at 1.

Directive 006 and other AER directives related to liability management. Eventually *Directive 006* will be rescinded in its entirety.¹³⁸

A license transfer application (“**LTA**”) may be submitted by the transferor, the transferee or any consultant or agent working on behalf of either party.¹³⁹ Any LTA will trigger an immediate Holistic Licensee Assessment of both the transferor and transferee. The AER will consider the entire package of licenses, including abandonment, reclaimed and reclamation-exempt sites to ensure they are being held by a responsible party that can address, manage and monitor present conditions or future issues related to public safety or the environment.¹⁴⁰ If inactive licenses are included in the LTA, then the transferor must update their reported closure activities and spends prior to submitting the LTA.¹⁴¹

The LTA process represents a significant deviation from the previous formula-based LMR regime. The AER will conduct the Holistic Licensee Assessment and issue a decision that the LTA is approved, approved with conditions, denied or incomplete. No estimated timeline is provided for the completion of this process and the AER will not provide preliminary determinations of expected security requirements or LTA approvals which creates considerable uncertainty of LTA success.¹⁴² Security may be required from either or both the transferor and transferee; the assessment of the amount of security considers the licenses transferred and those remaining with the transferor.¹⁴³

In addition, the transferor and transferee must make a Transfer Application Declaration (“**TAD**”) to the AER prior to the LTA’s approval. In the TAD, the transferor must declare that

¹³⁸ Alberta Energy Regulator, “Liability Management”.

¹³⁹ *Directive 088* at 6.

¹⁴⁰ *Directive 088* at 5.

¹⁴¹ *Directive 088* at 6.

¹⁴² *Directive 088* at 7.

¹⁴³ Manual 023 at 21.

the information is complete, accurate, and binding, while the transferee must declare that it holds valid surface access and mineral rights, has the right to produce, inject, or dispose of fluids for all licensed active wells, is a WIP in all wells and facilities, and accepts and assumes all obligations and responsibilities of a licensee at law.¹⁴⁴

The AER will consider the entire LTA package and may reject LTAs that do not include licenses that have received reclamation certification or are abandoned and classified as “*reclamation exempt*”.¹⁴⁵ This is another deviation from the prior system, where reclamation exempt licenses could not be transferred; as part of *Directive 088*, such licenses must be transferred.¹⁴⁶ The goal is to ensure, through the Holistic Licensee Assessment, that abandoned, reclaimed, and reclamation-exempt sites are managed and monitored and that any future issues will be addressed.¹⁴⁷

Conditions for approval may include the submission of financial statements at specified intervals, a commitment to reactivate wells within a specified timeline, a commitment to improve compliance performance, security deposits, additional oversight and reporting, or any other conditions determined appropriate by the AER.¹⁴⁸ Beginning on the date of the transfer, the transferee assumes liability for the wells, facilities, or pipelines to which the LTA pertains.

Security Deposits

The AER has broad and subjective authority to require a deposit.¹⁴⁹ In assessing whether to demand a security deposit as a condition to LTA approval or as part of the Inventory Reduction

¹⁴⁴ For pipeline licenses, the transferor must also declare that it has collected and retained all records required at law and provided them to the transferee as of the effective date of the license transfer.

¹⁴⁵ *Directive 088* at 7.

¹⁴⁶ AER licenses that are classified as Issued, Amended, Discontinued, Suspension, Abandoned, RecCertified or RecExempt are all eligible to be transferred. Cancelled or Re-Entered licenses are not eligible for transfer: see *Directive 088* at 5.

¹⁴⁷ *Directive 088* at 5.

¹⁴⁸ Manual 023 at 20.

¹⁴⁹ *OGCR*, s 1.100.

Program, the AER will consider the Holistic Licensee Assessment, whether the licensee poses an unreasonable risk pursuant to Section 4.5 of *Directive 067* or any other factor the AER considers appropriate.¹⁵⁰ A request for refund of the security deposit will trigger another Holistic Licensee Assessment of the licensee, using the same assessment criteria.

Once it is determined that security is required, the amount of security required may reflect the licensee's *Directive 011* liability, *Directive 001* site-specific liability, present value of future cash flows based on its reserves and economic analysis, or any other amount that the AER considers appropriate in the circumstances.¹⁵¹ The maximum amount of security that can be requested is the amount of the licensee's total liabilities, including the cost of care, custody, ending operations and abandonment and reclamation of the sites.¹⁵²

In the first phase of implementation of the Liability Management Framework, the Holistic Licensee Assessment will apply to the Licensee Management Program, Inventory Reduction Program, and LTAs. The broader security framework will replace *Directive 006* security collection in future phases.¹⁵³

Ceasing Operations

Directive 088 reinforces the existing obligations on licensees and their directors and officers when ceasing operations due to insolvency or for any other reason.¹⁵⁴ Licensees who cease operations are expected to engage in an orderly wind-down of operations.¹⁵⁵

¹⁵⁰ Alberta Energy Regulator, "*Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licenses and Approvals*" (7 April 2021), online (PDF): <static.aer.ca/prd/documents/directives/Directive067.pdf> [*Directive 067*].

¹⁵¹ Manual 023 at 20-21.

¹⁵² *Directive 088* at 8.

¹⁵³ Manual 023 at 20.

¹⁵⁴ Manual 023 at 22.

¹⁵⁵ Manual 023 at 23.

The AER will maintain a first-priority lien over all other liens, charges, rights of set-off, mortgages and other security interests in respect of the licensee's debt on any interests the licensee has in any wells, facilities, pipelines, land or interests in land, including mines and minerals, equipment and petroleum substances.¹⁵⁶ In addition, licensees remain responsible for adhering to AER regulations, including:

- initiating an immediate emergency response when called;¹⁵⁷
- maintaining insurance for all AER-licensed properties;¹⁵⁸
- either obtaining approval from the AER to transfer licences, approvals, and permits to an eligible party¹⁵⁹ or completing abandonment and completing reclamation of all sites;¹⁶⁰ and
- refraining from and ensuring creditors refrain from removing any equipment without the AER's consent.¹⁶¹

Initial Feedback, Issues, and Impact of *Directive 088*

Directive 088 became effective on December 1, 2021, so licensees have limited experience with assessment and licence transfers. The AER spent months soliciting, reviewing and responding to stakeholder feedback prior to releasing *Directive 088*.¹⁶² The AER will

¹⁵⁶ *OGCA*, s 103.

¹⁵⁷ Alberta Energy Regulator, "Directive 071: Emergency Preparedness and Response Requirements for the Petroleum Industry" (2 February 2017) at 12, online (PDF): static.aer.ca/prd/documents/directives/Directive071.pdf.

¹⁵⁸ *Directive 067*, s 4.2.

¹⁵⁹ *Directive 067*, s 4.2.; *Directive 088*; *OGCR*; *Pipeline Rules*.

¹⁶⁰ *OGCA*, s 27; *Pipeline Act*, s 23; Alberta Energy Regulator, "Directive 020: Well Abandonment" (21 April 2021), online (PDF): static.aer.ca/prd/documents/directives/Directive020.pdf; *Environmental Protection and Enhancement Act*, RSA 2000, c E-12, s 137 [*EPEA*].

¹⁶¹ Manual 023 at 22.

¹⁶² Alberta Energy Regulator, "Draft Directive: Licensee Life-Cycle Management (released June 2021) Stakeholder Feedback and AER Response" (last visited 29 March 2022), online (PDF): static.aer.ca/prd/documents/directives/Directive088_WWH.pdf.

continue to solicit feedback from stakeholders as *Directive 088* is executed in practice.¹⁶³ *Directive 088* will also impact the transactional markets, particularly from a due diligence and licence transfer perspective.

Impact on Due Diligence

While the AER will continue to track corporate LMRs, they will not be made publicly available. Licensees will have access to the following AER reports for their own company:

- Liability Assessment Report which contains the inactive liability estimates used to calculate closure targets.
- Licensee Capability Assessment which outlines the License Capability Assessment profile and results, including the results for individual parameters within the risk and performance factors.
- Closure Activity and Spend which includes a summary of closure activity, closure targets, closure spend, and WIPs.

While oil and gas producers will still likely have to provide representations and warranties regarding their LMR in transaction agreements and lending facilities, there is no means of independently verifying these numbers other than requesting that the company provide a printout from the Digital Data Submission system as of a particular date. However, licensees could be asked to provide any of the reports above for due diligence purposes.

Impact on Mineral Transactions

Directive 088 will undoubtedly impact the license transfer process, but it remains to be seen what the timing for LTA approvals will be and whether LTA approvals will increase, decrease, or remain the same. The LTA process in *Directive 088* is more robust than it was

¹⁶³ Alberta Energy Regulator, “Liability Management”.

previously but transactional parties still have many of the same challenges and will have to continue to account for timing and expectations in aligning LTA approval and closing.

Transactional parties will need to continue to account for the LTA process in oil and gas asset purchase and sale agreements. Before the implementation of *Directive 088*, buyers and sellers of oil and gas assets would typically agree to detailed licence transfer mechanics in their purchase and sale agreements to attempt to plan around LTA uncertainty. The parties would often request discretionary *Directive 006* approval from the AER if the purchaser's post-closing LMR was below 2.0. Either concurrently with a discretionary waiver application or after discretionary approval was granted, the parties would submit the LTAs to the AER and each party would covenant to provide a security deposit and any other undertakings, information or documentation if required by the AER to ensure that the LTAs would be approved.

The parties inevitably faced the challenge of having to align the timing of LTA approval with closing. In some cases, the LTA approval could be a condition to closing. Alternatively, parties would close on the assumption that the LTA would be approved post-closing. In the event that the LTA was not approved, the parties would have to undo the transaction, a risk most producers were not willing to accept. Sometimes the seller would hold the assets in trust for the purchaser pending the LTA approval. A 99%/1% ownership structure was occasionally used, whereby the parties would close the transaction and agree to enter into a reconveyance agreement if the LTA application was not approved.¹⁶⁴ As part of the reconveyance, 1% of the legal and beneficial title to the assets would be reconveyed to the seller, who would remain as licensee until such time as the LTA was approved and the purchaser would retain 99% of the legal and beneficial title to the assets. The seller would hold the 1% interest in trust for the purchaser without incurring

¹⁶⁴ The *OGCA* requires every licensee to hold a working interest in the well or facility: *OGCA*, ss 16-17.

any cost obligation or liability vis-à-vis the purchaser and the parties would use commercial best efforts to continue to work towards obtaining LTA approval.¹⁶⁵ The parties would also typically enter into a contract operating agreement or rely on extended interim provisions whereby the seller would contract operate the assets until such time as the LTA was approved, sometimes with a fee paid to the seller.¹⁶⁶

Some parties would find other creative workarounds to complete their asset deals. Bulletin 2016-21 states that the transferee must demonstrate “that they have a LMR of 2.0 or higher immediately following the transfer...”.¹⁶⁷ One such strategy involved delivering a letter of credit to the AER in an amount sufficient to raise the company’s LMR to above 2.0. The license transfers would be completed on this basis and the company would then immediately request a partial refund of the security deposit and allow their LMR to drop below 2.0 again but keep it slightly above 1.0. This outcome underscored the ineffectiveness of the LMR regime and exposed its flaws and potential for circumvention rather than a true focus on financial health and accountability for ARO.

One significant difference in the *Directive 088* LTA process is that the AER is no longer offering pre-submission consultations. Previously, as part of requesting discretionary *Directive 006* approval, parties would meet in person with AER representatives to present their case as to why the LTA should be approved and usually walked away from the meeting with a good comfort level as to whether the LTA would be successful. Overall, the Holistic Licensee Assessment and

¹⁶⁵ Other strategies were attempted – one such strategy was the rolling transfer of assets. The parties would transfer as many of the assets as possible until the purchaser’s LMR reached 2.0. For the remaining assets that could not be transferred due to the purchaser’s post-transfer LMR dropping below 2.0, the seller would retain legal title and a 1% beneficial interest with the remaining 99% of the beneficial interest conveyed to the purchaser.

¹⁶⁶ *OGCA*, ss 11-12 (well and facility operations may only be performed by the licensee).

¹⁶⁷ Alberta Energy Regulator Bulletin 2016-21 at 2.

the inability to communicate with or gain insight from the AER increases the uncertainty of all LTAs under *Directive 088*. As such, the new process adds uncertainty to mineral transactions.

Working Interest Information

Directive 088 requires LTA applicants to provide the full legal name and contact information of each WIP and the breakdown of working interest percentages for every well and facility included in the application.¹⁶⁸ The AER previously had knowledge of the licensee, but would not normally have any insight into the other legal WIPs or beneficial WIPs.¹⁶⁹ However, under *Directive 088*, transacting parties will now update the AER on WIPs every time there is a license transfer.¹⁷⁰ Presumably, this additional information is required to be provided by LTA applicants so that the AER can expand the net of potentially liable parties it can pursue in the event of ARO default by the licensee.

Parties are always averse to providing any representation or warranty as to mineral title and will be cautious with any statements made with respect to title. This requirement raises the questions of what form of statement will be required by the AER and will it be acceptable to the LTA parties? The LTA parties will not warrant title and will reasonably insist that any statements are qualified by their knowledge or the records in their possession. Similarly, the AER will want to ensure that their approval of the LTA is not deemed to be their acknowledgment of title or relied on by other parties as evidence of title.

It is unclear whether any title dispute or admitted uncertainty would compromise the LTA. *Directive 088* does not account for the situation where there is a title dispute, either due to

¹⁶⁸ *Directive 088* at 6.

¹⁶⁹ The AER could determine current legal WIPs by conducting Crown or freehold lease searches from the Ministry of Energy or the Land Titles Office respectively and, in rare circumstances, receive updated information as to beneficial WIPs if it was disclosed by the licensee or requested by the AER in conjunction with a *Directive 067* section 18(g) Schedule 1 filing due to a significant change to the working interest parties.

¹⁷⁰ *Directive 088* at 8.

historical discrepancies in land records or where a joint venture partner withholds its consent to disposition of a working interest on the basis that it is reasonably withheld due to concerns of the transferee to meet its financial obligations. In that case, not all parties may recognize novation of the transferee into the joint venture agreements. This may result in a situation where the contractual arrangements between the parties do not reflect the transfer approved by the AER which may attract statements of concern by aggrieved parties.

Impact on the Orphan Fund Levy

In order to assess the potential impact of *Directive 088*, we must first consider the purpose and impact of the Orphan Fund Levy. Fundamentally, the Orphan Fund Levy taxes licensees proportionately based on their liabilities, which typically correlates with the number of wells and facilities owned.¹⁷¹ The Orphan Fund Levy disproportionately affects larger producers with more wells and facilities and more ARO, regardless of their own level of stewardship or risk of default. Certain licensees are subsidizing the past and future defaults of its competitors who have failed to use responsible business practices, such as setting aside its closure costs in a reserve fund, and yet are still held responsible for their own ARO costs.

Unlike traditional taxes where there is a tangible public benefit, such as being able to use roads, schools or the health care system, there is no such tangible benefit for contributors to the Orphan Well Fund. Levy payors are paying for the environmental remediation on Crown or private lands for which they hold no surface access or mineral rights. These funds could otherwise be put towards their own closure costs or the capital necessary to develop future production.

The Orphan Fund Levy disincentivizes taking responsibility for one's own end-of-life obligations and puts the onus on the AER's assessment and monitoring capabilities to obtain

¹⁷¹ Alberta Energy Regulator, "Orphan Well Association".

sufficient security deposits prior to licensee default. However, the onus on the AER is merely from a public image standpoint as it typically cannot be named as a litigation party.¹⁷² The Orphan Fund Levy not only backstops industry default but also any design, assessment, or monitoring errors of the AER in its new Liability Management Framework.

The AER needs to ensure that new entrants and especially current industry participants who have shown good stewardship and fiscal responsibility and have historically attended to their own ARO without funding from others are properly incentivized. It is critical to ensure that responsible actors do not come to view the OWA as an insurance policy to which they are now forced to pay premiums for competitors' past and future liabilities via the Orphan Fund Levy and then default on their own ARO as a corporate exit strategy to avoid being held doubly responsible for both their own and others' ARO.

In April 2020, the Canadian federal government announced that \$1.7 billion would be allocated to the cleaning up of orphan and inactive oil and gas wells.¹⁷³ These funds were distributed to oil and gas producers to assist them with their own ARO, paying between 25% and 100% of total cleanup costs (depending on the producer's ability to pay).¹⁷⁴

Perhaps one measure of the success of the new Liability Management Framework is the time it takes for the AER to discontinue the Orphan Fund Levy. If the new Liability Management Framework is as effective as advertised and a more robust model is not determined to be required by the AER, then the Orphan Fund Levy ought to be discontinued as soon as all existing orphan

¹⁷² *Ernst v Alberta Energy Regulator*, 2017 SCC 1 at paras 51-57, referring to *Energy Resources Conservation Act*, RSA 2000, c E-10, s 43 (the AER has statutory immunity against any action or proceeding under the legislation which grants its authority and in which it has acted in good faith); see also *REDA*, s 27.

¹⁷³ Government of Canada, News Release, "Prime Minister announces new support to protect Canadian jobs" (17 April 2020), online: *Prime Minister's Office* <pm.gc.ca/en/news/news-releases/2020/04/17/prime-minister-announces-new-support-protect-canadian-jobs>.

¹⁷⁴ "Alberta unveils process for paying out \$1 billion in oilfield cleanup grants", *CBC News* (24 April 2020), online: <cbc.ca/news/canada/calgary/kenney-wells-remediation-money-ottawa-alberta-1.5543935>.

liabilities are paid, and industry should not have to continue to fund future obligations. It would encourage investment and incentivize new entrants to the oil and gas industry if participants did not have to pay a retroactive tax to fund prior obligations of others or future obligations of others, which should be properly mitigated by the new Liability Management Framework.

PART III LIABILITY MANAGEMENT THROUGHOUT THE WORLD AND THE FUTURE OF LIABILITY ANAGEMENT IN ALBERTA

This section compares *Directive 088* to regulatory regimes from other jurisdictions around the world to evaluate the comprehensiveness and robustness of the new Liability Management Framework. Based on feedback from stakeholders, including CAPP, we have chosen jurisdictions for comparison that are renowned for being world leaders in liability management: Australia, the United Kingdom (North Sea), and Norway. There may be other successful liability regimes in other jurisdictions that we have not considered, however this analysis should provide a good indication of the robustness of the AER's Liability Management Framework relative to a peer group of first-in-class regulators.

Given the choice, many oil and gas producers elect to defer addressing their ARO as long as possible, largely because it is expensive and ties-up money that could be spent elsewhere. When commodity prices are high, contractors and equipment are too expensive to perform abandonments; conversely, when commodity prices are low, revenues are not high enough to justify the abandonments.¹⁷⁵ However, delaying decommissioning can increase costs, jeopardize safety, and create exposure for default risk.

¹⁷⁵ Peter Milne, "Australia's oil and gas industry will create a \$76B clean-up bill" (14 May 2020), online: *Boiling Cold* <boilingcold.com.au/australias-oil-and-gas-industry-will-create-a-76b-clean-up-bill/>.

Australia

Decommissioning liability has been one of the Australian government's biggest concerns since the finalization of Northern Oil & Gas Australia's ("NOGA") liquidation proceedings in 2020. NOGA's offshore oilfields experienced malfunctions and corrosion as its facility neared end-of-life and the company could not demonstrate sufficient financial assurance to cover its liabilities in the event of an oil spill.¹⁷⁶ A subsequent review of the NOGA liquidation recommended changes to Australia's decommissioning framework.¹⁷⁷

Decommissioning liabilities will cost AUD\$76 billion (approximately CAD\$76 billion) over the next 30 years to safely abandon oil and gas wells, pipelines and platforms in Australia.¹⁷⁸ Australian taxpayers could bear up to 58% of the cost of offshore decommissioning, as the expense is deductible against company income tax.¹⁷⁹

The Australian government's objective is to ensure the decommissioning of Australia's offshore oil and gas assets is managed effectively and the costs of decommissioning an offshore project remain with the entity or entities who are responsible for, or had the capacity to influence, the carrying out of the project.¹⁸⁰ Australia overhauled its liability regime effective March 3, 2022 with changes similar to the new Liability Management Framework such as information gathering power and increased control over changes in titleholders.¹⁸¹ The changes include previous titleholders and their related parties retaining trailing liability where the current or immediate

¹⁷⁶ Steve Walker, "Review of the Circumstances that Led to the Administration of the Northern Oil and Gas Australia (NOGA) Group of Companies" (June 2020), online (PDF): <industry.gov.au/sites/default/files/2020-08/review-of-circumstances-that-led-to-the-administration-of-noga-executive-summary-and-recommendations.pdf> at 4-5.

¹⁷⁷ Walker at 9.

¹⁷⁸ Milne.

¹⁷⁹ Tax incentives include the ability to claim a refund from previously paid Petroleum Resource Rent Taxes.

¹⁸⁰ Australian Department of Industry, Science, Energy and Resources, "Trailing liability" (last visited 4 April 2022), online: <industry.gov.au/data-and-publications/trailing-liability-for-decommissioning-of-offshore-petroleum-property-guidelines/trailing-liability> [Australian Department of Energy, "Trailing liability"].

¹⁸¹ Australian Department of Energy, "Trailing liability".

former titleholder fails to decommission or if issues arise in relation to a previously decommissioned property.¹⁸² The regulator in South Australia uses a financial security matrix similar to *Directive 088*.¹⁸³

The commissioned review report of the NOGA liquidation concluded that despite the Government of Australia having a number of checks and balances to ensure titleholders decommission their assets at end-of-life, “the current situation is vulnerable” because none of the regulatory controls contemplates a liquidation.¹⁸⁴ The review report noted that the division of responsibility between titleholders, responsible for environmental protection, and operators, responsible for health and safety, creates a gap in legislation which is concerning as Australia’s offshore industry matures and late-life assets are passed from established major oil producers to smaller, less substantial titleholders.¹⁸⁵ It appears that Australia took similar measures to Alberta, having recently encountered its own catastrophic insolvency event. The review report advocated for a policy of “trailing liability” similar to the United Kingdom, where former titleholders have continuing liability but only as a backstop.¹⁸⁶ Trailing liability was subsequently included and then expanded in the March 2022 revisions to the Australian decommissioning framework.¹⁸⁷

¹⁸² Australian Department of Energy, “Trailing liability”.

¹⁸³ South Australia Department for Energy and Mining, “Petroleum and Geothermal Energy Act 2000 Environmental Liability Management Policy” (approved 24 August 2020) at 2, online (PDF): <petroleum.sa.gov.au/data/assets/pdf_file/0008/305819/PGE-Act-Environ~ity-Management-Policy-APPROVED.pdf>.

¹⁸⁴ Walker at 7.

¹⁸⁵ Walker at 7-8.

¹⁸⁶ Walker at 7.

¹⁸⁷ Australian Department of Industry, Science, Energy and Resources, “Amendments to enhance offshore oil and gas decommissioning” (24 Feb 2022), online: <industry.gov.au/news/amendments-to-enhance-offshore-oil-and-gas-decommissioning>.

The United Kingdom

The United Kingdom (“UK”) has adopted a policy whereby former owners can only be liable for decommissioning offshore installations or pipelines in which they had an economic interest at the time they sold their interest.¹⁸⁸ The rationale is that former owners ought not to be liable for installations and pipelines commissioned after they sold their interest in a field and from which they derive no economic benefit.¹⁸⁹

The UK government can issue a notice to certain persons under section 29 of the *Petroleum Act 1998* (a “**Section 29 Notice**”) to either submit a decommissioning program for the government’s approval or, failing that, fund and complete the decommissioning program prepared by the government.¹⁹⁰ Persons liable to receive a Section 29 Notice include the current license holders, current managers (or operators) or current owners of the installations or pipelines and their associated persons (such as affiliates and entities in which 50% or more of shares are held).¹⁹¹

However, unlike in Canada, the regulator can hold former owners liable for decommissioning liability under section 34 of the *Petroleum Act 1998* and therefore sellers need a mechanism to achieve a clean break with the purchaser in an oil and gas asset transaction.¹⁹² This mechanism is typically letters of credit or guarantees in favour of the seller for any decommissioning amounts for which the UK government might hold the seller liable in the future.

¹⁸⁸ Jameela Bond, Alistair Calvert, and Alastair Young, “Decommissioning Oil and Gas Wells in the UK – High Court Delivers Important Judgment with Ramifications for M&A Deals and the Provision of Decommissioning Security” (2 June 2021), online: *JDSupra* <[jdsupra.com/legalnews/decommissioning-oil-and-gas-wells-in-2466612/](https://www.jdsupra.com/legalnews/decommissioning-oil-and-gas-wells-in-2466612/)>.

¹⁸⁹ Bond et al.

¹⁹⁰ *Petroleum Act 1998* (UK), s 29.

¹⁹¹ *Petroleum Act 1998* (UK), s 29.

¹⁹² Bond et al. Former owners can only be named if they fall within the category of persons to whom a Section 29 Notice in relation to the relevant installations or pipelines could have been given at some time since the giving of the first Section 29 Notice in relation to that installation or pipeline.

Apache v Esso

In *Apache v Esso*, the English High Court recently clarified the extent to which prior owners could be liable and security that purchasers are required to post in favour of sellers following the purchase of oil and gas wells.¹⁹³ An ExxonMobil subsidiary sold oil and gas assets to Apache in 2011. Apache provided security to ExxonMobil, but the security did not extend to any new assets.¹⁹⁴ When Section 29 Notices were issued for new wells, ExxonMobil argued that they could be held liable for those wells and demanded additional security.¹⁹⁵

The English High Court found in favour of Apache and determined that sellers cannot be liable for decommissioning wells not drilled or not intended to be drilled at the time of closing.¹⁹⁶ As such, Apache was not required to provide ExxonMobil with any additional security for the new wells.

The UK marketplace has grappled with this decision's implication for sellers, like ExxonMobil, seeking to achieve a "clean break". Traditionally, decommissioning liability was fully allocated to the buyer via security – often in the form of an irrevocable, on-demand letter of credit accompanied by a decommissioning security agreement. However, decommissioning liability has been a major barrier for sellers.¹⁹⁷

To attract buyers, sellers have needed to become more comfortable retaining some of the decommissioning liability. For example, in two recent deals, sellers agreed to maintain liability for transferred assets in return for either future payments or simply as part of a transaction's

¹⁹³ *Apache UK Investments Limited v Esso Exploration and Production UK Limited*, [2021] EWHC 1283 (Comm).

¹⁹⁴ Bond et al.

¹⁹⁵ Bond et al.

¹⁹⁶ Bond et al.

¹⁹⁷ Ron Bousso and Karolin Schaps, "Oil firms may retain clear-up costs for hard-to-sell N. Sea assets", *Reuters* (21 July 2015), online: <[reuters.com/article/oil-northsea-ma-idUSL5N1002UC20150721](https://www.reuters.com/article/oil-northsea-ma-idUSL5N1002UC20150721)>.

consideration.¹⁹⁸ Both deals also did not refer to any arrangements regarding decommissioning security.

Retaining some liability could increase the total tax relief available for the asset. Under UK tax rules, operators can claim decommissioning costs against previously paid corporation tax or petroleum revenue tax.¹⁹⁹ In most cases, it is much simpler for the seller, who has paid tax on the production of the asset to date, to claim this relief. As such, it is sometimes commercially advantageous for the seller to retain some liability if they are compensated in some form.

However, sharing liabilities between parties creates additional deal complexity. Parties will need to consider who will ultimately perform the decommissioning, and how much say the other party will have in how it is carried out. Both parties will need to clearly set out the scope of the liability retained by the seller. For example, if the buyer modifies or replaces existing infrastructure, does that transfer the liability back to the buyer? Sellers may also need to consider the risk that the buyer will operate the asset in a way that increases any decommissioning liabilities that they retained.

Norway

In Norway, the *Petroleum Act* gives the Ministry of Petroleum and Energy (the “**Ministry**”) broad rights to require security from production licensees.²⁰⁰ In practice, the Ministry requires licensees to provide an unlimited parent company guarantee for the benefit of the

¹⁹⁸ Rita Brown, “Enquest strikes \$50m North Sea decom deal with BP” (31 January 2018), online: [Energy Voice <energyvoice.com/oilandgas/north-sea/162411/enquest-strikes-50m-north-sea-decom-deal-bp/>](http://energyvoice.com/oilandgas/north-sea/162411/enquest-strikes-50m-north-sea-decom-deal-bp/); Shell, News Release, “Shell to sell package of UK North Sea assets to Chrysaor for up to \$3.8bn” (31 January 2017), online: shell.com/media/news-and-media-releases/2017/shell-to-sell-package-of-uk-north-sea-assets-to-chrysaor.html.

¹⁹⁹ UK Department for Business, Energy & Industrial Strategy, “Oil and gas in the UK – offshore decommissioning” (22 January 2019), s 2.11, online (PDF): nao.org.uk/wp-content/uploads/2019/01/Oil-and-gas-in-the-UK-offshore-decommissioning.pdf.

²⁰⁰ *Act 29 November 1996 No. 72 relating to petroleum activities* (Norway), s 10-7.

Norwegian State to secure all obligations in relation to the petroleum activities.²⁰¹ The licensee must also submit a decommissioning plan to the Ministry two to five years before the license expires, is relinquished, or the use of a facility ceases.²⁰²

In the context of asset transactions, sellers remain secondarily liable for decommissioning costs if the purchaser defaults which is based on their share of the installations at the time of the sale.²⁰³ All inter-company petroleum operations must be conducted through a single legal entity so that special-purpose entities cannot be created and then default.²⁰⁴

The Ministry requires a guarantee from the seller in a share sale for decommissioning costs, which is structured as a surety and can be provided by the seller, its parent, or an ultimate parent, at the government's discretion.²⁰⁵ However the parent company guarantee is returned if the parent ceases to hold more than 50% of shares in the target.²⁰⁶ This raises the question of who then replaces the parent guarantee.

A seller's liability in a share sale is unlimited up to the full pre-tax value of its share of decommissioning costs but is purely financial with no performance obligations.²⁰⁷ Conversely, a seller's liability in an asset sale is limited to the post-tax value of its share of decommissioning costs, with the tax losses covered by the Norwegian government.²⁰⁸

²⁰¹ UK Department for Business, Energy & Industrial Strategy, "Guidance Notes: Decommissioning of Offshore Oil and Gas Installations and Pipelines" (November 2018), online (PDF): https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/760560/Decom_Guidance_Notes_November_2018.pdf [UK Department of Energy Guidance Notes].

²⁰² UK Department of Energy Guidance Notes.

²⁰³ Advokatfirmaet BAHR AS, "Oil and Gas in Norway: An Introduction" (January 2019), online (PDF): <https://bahr.no/wp-content/uploads/2019/01/Oil-and-Gas-in-Norway-January-2019-1.pdf> at 6, 8.

²⁰⁴ Advokatfirmaet BAHR AS at 8.

²⁰⁵ Penelope Warne, "Inside track to decommission off Norway" (Energy Voice, 28 August 2018), online: <https://energyvoice.com/oilandgas/north-sea/180094/inside-track-to-decommission-off-norway/>.

²⁰⁶ Warne

²⁰⁷ Warne.

²⁰⁸ Warne.

The Uniqueness of Alberta’s Liability Regime

The primary difference between Alberta and the international jurisdictions reviewed is the interplay between the transactional and regulatory markets. Decommissioning liability in Australia, the UK and Norway intertwine a transactional “clean break” system and a “trailing liability” regulatory system – a disconnect between the two liability regimes, which creates deal issues any time a well or facility is sold. Upon conveyance of the asset, the seller walks away with a “clean break” and the purchaser assumes all ARO. This mirrors the commercial market liability standard used in oil and gas asset purchase and sale agreements in Alberta.

However, international regulators can still hold previous owners accountable in the event the current owner defaults, creating a “trailing liability” for the seller. Sellers have historically demanded a letter of credit, guarantee, decommissioning security agreement or other form of security from the purchaser to ensure that it is made whole in the event the regulator compels them to fund and perform the abandonment operations.²⁰⁹ Providing security for such liabilities has, in recent years, become a significant negotiating point in mineral transactions.²¹⁰

In contrast, the Alberta regulator has a pooled risk system where viable producers are responsible for the liabilities of non-viable producers. In practice, the AER holds the current licensee liable with respect to enforcement of its directives, orders and regulations with the powers granted to it under the *REDA* and then turns to the Orphan Well Fund upon default by that licensee.²¹¹ However, this is where a distinction needs to be made between the legislation in Alberta and the AER’s enforcement of the legislation. The legislation in Alberta actually permits

²⁰⁹ Bond et al.

²¹⁰ “Australia's new offshore oil and gas decommissioning framework” (9 June 2021), online: *Gilbert + Tobin* <gtlaw.com.au/knowledge/australias-new-offshore-oil-gas-decommissioning-framework>

²¹¹ *REDA*.

trailing liability even if it is not enforced by the AER. Section 31 of the *OGCA* states the following:

Deemed working interest participant

31(1) Where

- (a) a transaction occurs that results in a person no longer being a working interest participant in a well or facility,
- (b) the successor working interest participant is a person other than the licensee of the well or facility, and
- (c) the successor working interest participant fails to pay its proportionate share of the suspension costs, abandonment costs, remediation costs and reclamation costs, the Regulator may deem the person referred to in clause (a) to continue to be a working interest participant for the purposes of sections 27 to 30 and Part 11 if subsection (2) applies.

(2) The Regulator may deem as provided in subsection (1) if

- (a) in the case of a well, the transaction occurred after the well ceased to meet the economic limit test set out in the regulations or rules, or
- (b) in the case of a facility, the transaction occurred after the facility ceased operation or after the facility has throughput that is less than the rate prescribed in the regulations as sufficient to warrant deeming the facility to be active.²¹²

In this provision, Alberta legislators have permitted, if not directed, the regulator to enforce “trailing liability” (sometimes referred to as “look back” liability in Canada) against former WIPs. This provision is limited to transactions where the successor WIP is not the licensee and defaults on its working interest participant share of ARO. It is also limited to instances where at the time of closing the transaction, the well failed to meet the economic limit test referred to in the *OGCA* or the facility had ceased operations or had less throughput than the rate prescribed as sufficient for it to remain active. In other words, the “look back” liability is only applicable if the well or facility is deemed to be unproductive or inactive at the time of the transaction. A “Look Back Order” could be difficult to enforce if long removed up-chain WIPs are defunct or unknown. As

²¹² *OGCA*, s 31.

far as we are aware, this provision of the *OGCA* has never been enforced by the AER and the AER has never pursued any “look back” liability against oil and gas producers.

In her 2017 thesis, Heather Lilles outlined the following instances where current WIPs could be held jointly and severally liable:

- (1) The AER is unlikely to utilize the formal contaminated site provisions in Division 2 of Part 5 of the *Environmental Protection and Enhancement Act* (“*EPEA*”).²¹³
- (2) The AER will likely name the licensee and all WIPs in a Section 27 Abandonment Order and pursue all WIPs, as defined in the *OGCA*, to conduct and pay for the costs of abandonment operations.²¹⁴
- (3) In the event a licensee is bankrupt, all WIPs will likely be named by the AER, on a joint and several basis, in a Section 113 Release environmental protection order and ordered to conduct clean-up operations.²¹⁵
- (4) There may continue to be circumstances where the AER will first look to the last licensee on record with the AER before turning to other related parties. For example, this may be the case with respect to the reclamation and conservation of specified land pursuant to Part 6 of *EPEA*.²¹⁶
- (5) Where an operator under a Canadian Association of Petroleum Landmen (“*CAPL*”) joint operating agreement becomes insolvent, the AER is likely to order all joint operators,

²¹³ Heather Lilles, *The Statutory Liabilities of Joint Operators and Non-Participating Parties* (LLM Thesis, University of Calgary, 2017) at 150 [unpublished], online (PDF):

prism.ucalgary.ca/bitstream/handle/11023/3577/ucalgary_2017_lilles_heather.pdf >; *EPEA*.

²¹⁴ Lilles at 156. We are not aware of any instances where the AER has pursued this course of action.

²¹⁵ Lilles at 168.

²¹⁶ Lilles at 168. We are not aware of any instances where the AER has pursued this course of action.

on a joint and several basis, to address releases and other environmental non-compliance events.²¹⁷

Licensees can submit a working interest claim (“**WIC**”) to the AER for a defaulting WIP’s proportionate share of incurred costs.²¹⁸ The WIC must be submitted to the AER once the work has been completed and suspension, abandonment, remediation, reclamation and reasonable care and measures costs are eligible for reimbursement from the Orphan Fund.²¹⁹

The risk to industry extends beyond just funding the Orphan Fund. While standard CAPL joint operating agreements stipulate several liability proportional to one’s working interest, the AER could hold all parties accountable, jointly and severally, for environmental liabilities. Therefore, compliant working interest participants could end up jointly and severally liable for the abandonment and environmental liabilities of their defaulting joint venture partners. For this reason, many established operators who can afford to do so prefer to only entertain financially creditworthy and vetted joint interest partners or to own and operate 100% and avoid joint venture partners altogether. We are not aware of any instances where a prior licensee or WIP has been held liable for any ARO (the North American equivalent of “decommissioning”) obligations however this possibility remains in the AER’s enforcement arsenal.

An Alternative Model – Pay-As-You-Go

Although we examined the liability regulatory regimes in Australia, the UK, and Norway, they govern offshore wells – which typically achieve greater production than onshore wells and are operated by major oil and gas producers. Alberta’s liability management system rates favourably with all of them, but it also needs to consider Alberta’s specific circumstances, namely

²¹⁷ Lilles at 214.

²¹⁸ *OGCA*, s 70.

²¹⁹ Orphan Well Association, “Working Interest Claims (WICs)” (last visited 13 May 2022), online: orphanwell.ca/producers/working-interest-claims/.

a greater number of wells, all of which are onshore and a prolific junior oil and gas industry with greater risk for default than more established companies.

The streamlining of the transactional and regulatory liability regimes in Alberta is more efficient and, in our view, a better system. But if the new Liability Management Framework in Alberta fails to reduce the number and magnitude of defaults and wells and facilities being contributed to the Orphan Fund, would an even more robust system be needed? If it comes to this, the AER could consider a “pay-as-you-go” model of ARO liability management, although such a model would not be without flaws.

In a “pay-as-you-go” model, both the productive life of the well and the estimated ARO costs would be modelled following the drilling, completion and initial production of the well. The ARO costs would be tracked throughout the productive life of the well and paid annually to the AER, as escrow agent, by the licensee. This ensures that the licensee receives the benefit of the production while meeting their obligation to set aside ARO costs as the asset declines in value. The AER would release the funds to the final licensee once abandonment costs are incurred. Alternatively, if the final licensee defaults, funds are available for the abandonment operation.

Payments could be made in equivalent tranches proportional to the estimated number of productive years of the asset. Alternatively, a more equitable model would be to correlate the payments to the production decline so that the economic benefit is proportional to the liability cost. The AER and industry have the expertise to oversee these models and the public should be receptive as it exemplifies the true essence of the “polluter pays” model. Essentially, the licensee would be paying off the abandonment costs in real-time over the amortization period of the well in a manner that is proportional to the economic benefit derived from it.

Notionally, under the “pay-as-you-go model”, the least amount of decommissioning funds would be owing at the time when the default risk is the greatest. For example, for a given well, the risk of default would be greatest at the end of its production life, but production is at its lowest and the licensee would be making the smallest contributions to the well’s ARO costs. Any top-up needed from the Orphan Fund would be negligible. In an asset transaction, an adjustment could be made to the purchase price to account for the fact that the seller has already contributed to a certain percentage of ARO costs as of the effective date of closing. If other jurisdictions adopted a “pay-as-you-go” model, it would alleviate any perceived need for trailing liability.

Though critics may claim that the “pay-as-you-go” model ties up capital which could otherwise be deployed or pay for operating expenses, the model is functionally similar to a security deposit. The difference is that it would be done year-to-year as opposed to when a Holistic Licensee Assessment is triggered and conducted by the AER.

This model could also provide relief in lending markets, where risk-averse lenders have come to terms with the *Redwater* SCC decision and their lack of first-in-priority status in insolvency claims. The AER could also reallocate resources away from monitoring the financial health of producers in real-time and limit their involvement to assessing ARO costs and serving as a government escrow agent. Additionally, if a “pay-as-you-go” model is implemented, the number of new orphaned wells should trend towards zero and over time, and the Orphan Fund Levy would no longer be necessary. The liability would be linked to the asset as opposed to a company or a license.

The LMR regime was in many ways a soft “pay-as-you-go” model which was particularly onerous to junior oil and gas producers and impacted their ability to obtain financing. If the AER were to implement a hard “pay-as-you-go” model, it is fair to assume that it would be even more

onerous to junior oil and gas producers and would significantly impact the industry as a whole. Therefore, the “pay-as-you-go” model would need to be prospective and address only current and go-forward liability. Any attempt to make such a model retrospective could be economically devastating to producers and would likely not be welcomed by industry. While we are currently not aware of any jurisdiction that administers a “pay-as-you-go” model, it may be necessary to implement this type of model to alleviate the burden on compliant members of industry and taxpayers if defaults continue in Alberta.

Is Alberta a World Leader in Oil and Gas Liability Management?

The new Liability Management Framework and *Directive 088* should empower and provide the AER with the information and business intelligence needed to effectively monitor licensees and proactively enforce as necessary. However, the success of the model remains dependent on the monitoring prowess, timeliness, and expertise of AER personnel. The AER needs to recognize potential default and react and enforce prior to the default actually occurring.

The AER does not invoke “Look Back Orders” or joint and several environmental liability in the ordinary course. However, there is no certainty that their position on this will remain unchanged and oil and gas producers should be aware that the AER has numerous legislative options available at its disposal. If the number of new orphaned wells does not decrease significantly, or if non-compliance and default continue to plague the industry, then we would recommend consideration of alternatives, such as the AER enforcing “look back” liability against former WIPs or implementing a prospective “pay-as-you-go” model as a last resort.

Alberta has established itself as a world leader in oil and gas liability management. As far as we are aware, Alberta has a model that is as sophisticated and robust as any other model in the world and is leading the way in oil and gas liability management. However, there are

limitations with any model and being a world leader in liability management does not relieve the Province of Alberta of addressing the 90,000 inactive wells or provide absolute prevention against future ARO defaults.²²⁰ Only through cooperation and a commitment from the AER and oil and gas producers to uphold the “polluter pays” principle will the Province of Alberta overcome its inactive and orphan well crisis.

²²⁰ Government of Alberta, “Oil and gas liabilities management”.