

LEADING THE WAY? LIABILITY MANAGEMENT FOR THE ALBERTA OIL AND GAS INDUSTRY

JEREMY BARRETTO, JEFF DAVIDSON,
CHRIS McLELLAND, TAMARA PRINCE, AND ALYSHEA SURANI*

This article examines Alberta's oil and gas liability management system, with a particular focus on the new regime established in 2021 by the Alberta Energy Regulator's Directive 088. The article begins by examining liability management in Alberta prior to Directive 088, up to and including the Redwater decisions of the Alberta Court of Appeal and the Supreme Court of Canada. It then provides a brief overview of Directive 088's main provisions and reviews its initial impacts on industry and the Orphan Fund Levy. Finally, it compares Alberta's liability management system to that of its world-class peers and a suggested alternative model, and considers whether Alberta is leading the way in oil and gas liability management.

TABLE OF CONTENTS

I.	INTRODUCTION	487
II.	THE HISTORY OF ALBERTA'S LIABILITY MANAGEMENT	488
	A. GROWTH OF LIABILITY MANAGEMENT	488
	B. JURISDICTION OVER LIABILITY MANAGEMENT AND THE EMERGENCE OF REGULATORY BODIES	490
III.	THE CURRENT STATE OF <i>DIRECTIVE 088</i>	499
	A. A NEW LIABILITY MANAGEMENT FRAMEWORK	499
	B. INITIAL FEEDBACK, ISSUES, AND IMPACT OF <i>DIRECTIVE 088</i>	508
IV.	LIABILITY MANAGEMENT THROUGHOUT THE WORLD AND THE FUTURE OF LIABILITY MANAGEMENT IN ALBERTA	512
	A. AUSTRALIA	512
	B. THE UNITED KINGDOM	514
	C. NORWAY	516
	D. THE UNIQUENESS OF ALBERTA'S LIABILITY REGIME	516
	E. AN ALTERNATIVE MODEL: PAY-AS-YOU-GO	519
	F. IS ALBERTA A WORLD LEADER IN OIL AND GAS LIABILITY MANAGEMENT?	520

I. 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

* Jeremy Barretto is a partner at Cassels Brock & Blackwell LLP and serves as chair of the firm's national regulatory law group. Jeff Davidson is legal counsel at Canadian Natural Resources Limited. Chris McLelland is a partner in the business law group, Tamara Prince is a partner in the litigation group and the firm's General Counsel and Chief EDI Officer, and Alyshea Surani is an associate in the litigation group at Cassels Brock & Blackwell LLP. The authors would like to thank Natalie Thompson and Neil Burnside, associates at Cassels Brock & Blackwell LLP, for their efforts in the preparation of this article.

¹ Orphan Well Association, "Annual Report 2020/21" at 7, online: <orphanwell.ca/wp-content/uploads/2021/07/OWA-Annual_2020_web3.pdf> [OWA Annual Report].

Alberta and the Alberta Energy Regulator (AER) have, over time, implemented different regulatory regimes to manage end-of-life liabilities.

This article reviews the history of Alberta's liability management, with a particular focus on the new regime established in December 2021 by *Directive 088: Licensee Life-Cycle Management*.² In Part II, 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 and Supreme Court of Canada.³ In Part III, 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 IV, 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.

II. THE HISTORY OF ALBERTA'S LIABILITY MANAGEMENT

A. GROWTH OF LIABILITY MANAGEMENT

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

The issues and risks of liability management were, and are, growing concerns 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

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

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

⁴ "Accidental History," online: *Alberta Culture and Tourism* <history.alberta.ca/energyheritage/gas-creation-of-an-industry/accidental-industry/default.aspx>.

⁵ Hélène ME de Beer, *Alberta's End-of-Life Oil and Gas Liabilities* (MPP Thesis, University of Calgary, 2016) [unpublished] at 5, online: <prism.ucalgary.ca/bitstream/handle/1880/51698/de%20Beer,%20Helena%20Maria%20Elisabeth.pdf>.

⁶ Canada, Parliamentary Budget Officer, *Estimated Cost of Cleaning Canada's Orphan Oil and Gas Wells* (Ottawa: Parliamentary Budget Officer, 25 January 2022) at 6, 8, 14, 16–17, online (pdf): <distribution-a617274656661637473.pbo-dpb.ca/44de649e994977a9771ff83959ba6b9563f5c1352ec3ba4f83e4d256f40a6b41> [PBO, *Estimated Cost*].

⁷ See e.g. Alberta, Legislative Assembly, "Bill 13, Energy Statutes Amendment Act, 2000," 1st reading, *Alberta Hansard*, 24-4 (6 March 2000) at 246 (Mark Hlady), online: <docs.assembly.ab.ca/LADDAR_files/docs/hansards/han/legislature_24/session_4/20000306_1330_01_han.pdf>.

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.

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 (AROs) are not effective in reducing the number of inactive wells.¹⁰ Table 1 sets out the number of inactive wells on a yearly basis in Alberta.

**TABLE 1:
INACTIVE WELLS IN ALBERTA¹¹**

Year	Number of Inactive Wells
2018	84000
2019	89000
2020	97000
2021	96000
2022	90000 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

⁸ de Beer, *supra* note 5 at 19.

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 "Liability Management," online: *Alberta Energy Regulator* <aer.ca/providing-information/by-topic/liability-management>.

¹¹ *Ibid.*

¹² "Well Status," online: *Alberta Energy Regulator* <aer.ca/providing-information/data-and-reports/data-hub/well-status>. The 2022 data is as of 1 March 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*, *supra* note 2.

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 Resource, "Well, What's the Difference?" (4 February 2020), online: *Alberta Energy Regulator* <resource.aer.ca/stories/well-whats-the-difference>.

¹⁵ "WTI Crude Oil Prices – 10 Year Daily Chart," online: <macro trends.net/2516/wti-crude-oil-prices-10-year-daily-chart>. The average monthly oil price between 2015 and 2017 was under US\$50 per barrel, compared to the average monthly benchmark oil price of US\$80 per barrel from 2012–2015.

wells also 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.

B. 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 Resources Conservation Act* 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 (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 (AEUB) to streamline the regulatory process and create a quasi-judicial agency.²²

In 2000, the AEUB created a new liability management system, with the creation of Licensee Liability Ratings (LLR). LLRs were to be “a basic measure of the risk that a licensee will be unable to address its [ARO]” by comparing a licensee's total inventory of wells with a certain level of production against all wells and facilities producing below a certain level.²³ The LLR framework was first outlined in *Guide 69: Energy Development Licence Transfer* in 2000.²⁴ In 2004, the AEUB issued *Directive 006: Licensee Liability Rating (LLR) Program and Licence Transfer Process*, to replace, *inter alia*, *Guide 69*.²⁵ *Directive 006* included a stated purpose “to minimize the risk to the Orphan Fund posed by unfunded well, facility, and pipeline [ARO].”²⁶

¹⁶ PBO, *Estimated Cost*, *supra* note 6 at 3.

¹⁷ “Orphan Inventory,” online: *Orphan Well Association* <orphanwell.ca/about/orphan-inventory> (as of 1 May 2022).

¹⁸ de Beer, *supra* note 5 at 7.

¹⁹ *The Oil and Gas Conservation Act*, SA 1957, c 63, s 4.

²⁰ David H Breen, “Energy Resources Conservation Board” (7 February 2006), online: <thecanadianencyclopedia.ca/en/article/energy-resources-conservation-board>.

²¹ de Beer, *supra* note 5 at 7–8.

²² “Alberta Energy and Utilities Board Sous-Fonds,” online: *Provincial Archives of Alberta* <hermis.alberta.ca/paa/Details.aspx?ObjectID=GR0074.001SF&dv=True&deptID=1>.

²³ Alberta Energy and Utilities Board, *Interim Directive 2000-11: Energy Development Licence Transfer Requirements and Monthly Corporate Licensee Liability Rating* (Calgary: Alberta Energy and Utilities Board, 24 October 2000) at 2.

²⁴ Alberta Energy and Utilities Board, *Guide 69: Energy Development Licence Transfer* (Calgary: Alberta Energy and Utilities Board, October 2000) [*Guide 69*].

²⁵ Alberta Energy and Utilities Board, *Directive 006: Licensee Liability Rating (LLR) Program and Licence Transfer Process* (Calgary: Alberta Energy and Utilities Board, 1 June 2004).

²⁶ *Ibid* at 1.

In 2008, the ERCB was established because of the realignment of the AEUB and the Alberta Utilities Commission.²⁷ In 2009, the ERCB revised *Directive 006* to include, in addition to each licensee's LLR, a Liability Management Rating (LMR). Each month, the ERCB (and later the AER) would calculate an LMR, the ratio of a licensee's deemed assets to deemed liabilities, under three of the ERCB's liability management programs: (1) the LLR program (*Directive 006*); (2) the Large Facility Liability Management Program (*Directive 024: Large Facility Liability Management Program (LFP)*); and (3) the Oilfield Waste Liability (OWL) Program (*Directive 075: Oilfield Waste Liability (OWL) Program*).²⁸ 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.²⁹ A security deposit was required by the AER from companies with an LMR of less than 1.0, meaning the value of deemed assets was less than deemed liabilities.³⁰

The ERCB was later dissolved in 2013, upon the creation of the AER.³¹

1. THE ALBERTA ENERGY REGULATOR

A major turning point in liability management arose through the establishment of the AER with the introduction of the *REDA* in 2013.³² The AER has jurisdiction over all aspects of energy management and deals with competing priorities across a well's life cycle.³³ While previous government bodies (that is, 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.³⁴ 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.³⁵

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.³⁶ 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.³⁷ The *Oil and Gas Conservation Act* and the *Oil and Gas Conservation Rules* are prescriptive in stating that licence holders are responsible for the costs associated with the

²⁷ "100 Years of Service and Counting," online: *Alberta Utilities Commission* <www.auc.ab.ca/100-years-of-service-and-counting/>.

²⁸ "Liability Management Rating and Reporting," online: *Alberta Energy Regulator* <aer.ca/regulating-development/project-closure/liability-management-programs-and-processes/liability-management-rating-and-reporting>.

²⁹ Alberta Energy Regulator, *Directive 006: Licensee Liability Rating (LLR) Program* (Calgary: Alberta Energy Regulator, 1 December 2021) at 13–23, online: <static.aer.ca/prd/documents/directives/Directive006.pdf> [*Directive 006*].

³⁰ *Ibid* at 4.

³¹ *Responsible Energy Development Act*, SA 2012, c R-17.3, s 81 [*REDA*].

³² *Ibid*.

³³ *Ibid*, s 2.

³⁴ de Beer, *supra* note 5 at 13–14.

³⁵ Alberta Energy Regulator, News Release, PS2018-01, "Why We Are Fighting: AER President and CEO Jim Ellis" (15 February 2018) at 1, online: <static.aer.ca/prd/documents/news-releases/AERPS2018-01.pdf> [AER, "Why We Are Fighting"].

³⁶ "Liability Management," *supra* note 10.

³⁷ *REDA*, *supra* note 31, s 2(2)(g).

end-of-life obligations and explicitly mandate the licensee holder to comply with the AER's liability management directives.³⁸

2. 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 and 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 licensee'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 saw licensees with LMRs greater than 2.0 (and in one instance, a licensee with an LMR of 30) become insolvent. These insolvencies seriously brought into question the predictive value of the LMR in a licensee fulfilling its end-of-life obligations.³⁹

The AER attempted to address insolvency risk in *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals* by adding broad latitude to consider unreasonable risk factors and requiring financial statements.⁴⁰ 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,⁴¹ such reporting may not accurately reflect the true financial health and status of a licensee if well and pipeline lists are not accurate and AROs are underreported, making it difficult, if not impossible, for the AER to identify any discrepancies and update its own records.

³⁸ *Oil and Gas Conservation Act*, RSA 2000, c O-6, s 29 [OGCA]; *Oil and Gas Conservation Rules*, Alta Reg 151/1971, ss 3.013(2), 3.014 [OGCR]. See also Alberta Energy Regulator, *Directive 001: Requirements for Site-Specific Liability Assessments in Support of the ERCB's Liability Management Programs* (Calgary: Alberta Energy Regulator, 6 June 2012), online: <static.aer.ca/prd/documents/directives/Directive001.pdf> [Directive 001]; *Directive 006*, *supra* note 29 (creating the LLR program); Alberta Energy Regulator, *Directive 024: Large Facility Liability Management Program (LFP)* (Calgary: Alberta Energy Regulator, 24 February 2016), online: <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* (Calgary: Alberta Energy Regulator, 11 April 2016), online: <static.aer.ca/prd/documents/directives/Directive075.pdf> [Directive 075].

³⁹ "Liability Management," *supra* note 10.

⁴⁰ Alberta Energy Regulator, *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals* (Calgary: Alberta Energy Regulator, 7 April 2021), online: <static.aer.ca/prd/documents/directives/Directive067.pdf> [Directive 067].

⁴¹ 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>.

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 could be misleading as to the true financial health of the licensee.

3. THE ORPHAN FUND

The Orphan Fund was created pursuant to the *OGCA* and *OGCR* and is intended, *inter alia*, to pay for the suspension, abandonment, and reclamation costs of orphan wells, facilities, facility sites, and well sites where suspension, abandonment, or reclamation work is carried out by the AER.⁴²

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:

- [E]stimated 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 [non-budgeted] expenditures the AER deems necessary.⁴³

The Orphan Fund Levy is allocated among licensees included in the LLR and the OWL programs and payable to the AER by licence holders and approval holders of well, facility, or unreclaimed sites.⁴⁴ 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 licence or approval holder and not WIPs, so the immediate obligation remains with the licensee regardless of whether the WIPs contribute their working interest proportion.⁴⁵

The Orphan Fund Levy is calculated by the Government of Alberta in consultation with 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 Producers (CAPP), and the Explorers and Producers Association of Canada.⁴⁶ For the fiscal year of 2021–2022, the AER prescribed a \$70 million Orphan Fund Levy.⁴⁷ 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.⁴⁸ 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

⁴² *OGCA*, *supra* note 38, s 70(1); "Orphan Well Association," online: *Alberta Energy Regulator* <aer.ca/regulating-development/project-closure/liability-management-programs-and-processes/orphan-well-association>.

⁴³ "Orphan Well Association," *ibid*. See also *OGCA*, *ibid*, ss 73–74.

⁴⁴ *OGCA*, *ibid*; *OGCR*, *supra* note 38, ss 16.520–16.531; *Directive 006*, *supra* note 29 at 5–6.

⁴⁵ *OGCA*, *ibid*, s 74(1).

⁴⁶ "Orphan Well Association," *supra* note 42; *Directive 075*, *supra* note 38 at 6.

⁴⁷ Alberta Energy Regulator, *Bulletin 2021-09: 2021/22 Orphan Fund Levy – LLR and OWL Programs* (Calgary: Alberta Energy Regulator, 6 April 2021), online (pdf): <aer.ca/regulating-development/rules-and-directives/bulletins/bulletin-2021-09>.

⁴⁸ "Orphan Well Association," *supra* note 42.

and government loans to the OWA, increased by 187 percent in 2021–2022 to \$392.2 million.⁴⁹ While this is a significant increase, the total remaining closure cost as of 31 March 2021 is estimated to range between \$650 million and \$700 million.⁵⁰

In 2020, the *Liabilities Management Statutes Amendment Act, 2020* (Bill 12) amended the *OGCA* to expand the types of expenses upon which the Orphan Fund could be applied.⁵¹ These amendments were made to allow for more effective management and accelerated clean-up of sites that do not have responsible owners.⁵² 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....
- 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 ... [reducing] 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.⁵³

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.⁵⁴ This means that compliant, low-risk, and responsible (in both the legal and colloquial sense) oil and gas producers and taxpayers end up funding the liabilities of irresponsible producers.

4. ADAPTING TO THE *REDWATER ENERGY CORPORATION (RE)* DECISION⁵⁵

In June 2016, the AER introduced *Bulletin 2016-16: Licensee Eligibility—Alberta Energy Regulator Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision*⁵⁶ in response to the *Redwater* ABQB decision of the Court of Queen’s Bench.⁵⁷ *Bulletin 2016-16*, along with the revision and clarification in *Bulletin 2016-21: Revision and Clarification on Alberta Energy Regulator’s Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision*,

⁴⁹ OWA Annual Report, *supra* note 1 at 7.

⁵⁰ *Ibid* at 5.

⁵¹ 2nd Sess, 30th Leg, Alberta, 2020 (assented to 2 April 2020), SA 2020, c 4.

⁵² Alberta, Legislative Assembly, “Bill 12, Liabilities Management Statutes Amendment Act, 2020,” 1st reading, *Alberta Hansard*, 30-2 (31 March 2020) at 297 (Hon Sonya Savage), online: <docs.assembly.ab.ca/LADDAR_files/docs/hansards/han/legislature_30/session_2/20200331_1330_01_han.pdf>.

⁵³ “Orphan Well Association,” *supra* note 42.

⁵⁴ *Ibid* (the levy on industry is proportionate to a licensee’s liabilities).

⁵⁵ 2016 ABQB 278 [*Redwater* ABQB].

⁵⁶ Alberta Energy Regulator, *Bulletin 2016-16: Licensee Eligibility—Alberta Energy Regulator Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision* (Calgary: Alberta Energy Regulator, 20 June 2016), online: <static.aer.ca/prd/documents/bulletins/Bulletin-2016-16.pdf> [*Bulletin 2016-16*].

⁵⁷ *Redwater* ABQB, *supra* note 55.

imposed a minimum post-transfer LMR of 2.0 on any licence transferee.⁵⁸ 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.⁵⁹

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 2016.⁶⁰ 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.⁶¹ 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.⁶²

Another insolvency that demonstrated the need for improvements to the LLR framework was Perpetual Energy Operating Corp., which was later renamed Sequoia Resources Corp. (PEOC/Sequoia). In 2016, the affiliated entities of Perpetual Operating Trust (POT), PEOC/Sequoia, and Perpetual Operating Corp. (POC) made a series of transactions in conjunction with a sale by their parent, Perpetual Energy Inc., of all shares in PEOC/Sequoia to a third party purchaser.⁶³ The following is a summary of the transactions (the Transactions) as described by the Alberta Court of Appeal in its 2021 decision. All Transactions occurred within minutes and essentially served as one simultaneous transaction:

- (1) Prior to the transaction, POT was the beneficial owner of various assets and PEOC/Sequoia was the legal owner, which assets are further described below.⁶⁴
- (2) POT transferred beneficial ownership in the "Goodyear Assets" to PEOC/Sequoia for \$10.⁶⁵ The Court described the Goodyear Assets as "mature legacy assets"

⁵⁸ *Bulletin 2016-16*, *supra* note 56 at 2; 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* (Calgary: Alberta Energy Regulator, 8 July 2016), online: <static.aer.ca/prd/documents/bulletins/Bulletin-2016-21.pdf> [*Bulletin 2016-21*].

⁵⁹ *Bulletin 2016-21*, *ibid*.

⁶⁰ 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>.

⁶¹ *Ibid*; "Agreed Statement of Facts and Undertaking" (12 June 2017) at 2, 4, online: *Alberta Energy Regulator* <static.aer.ca/prd/documents/news-releases/NR2017-09-StatementofFacts.pdf>.

⁶² Dan Healing, "Lexin Resources Bankruptcy Leads to Millions in Rising Costs for Orphan Well Association," *The Canadian Press* and *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-d668bae1ce6e>.

⁶³ *PricewaterhouseCoopers Inc v Perpetual Energy Inc*, 2021 ABCA 16 at para 7 [*Perpetual Energy* 2021].

⁶⁴ *Ibid* at para 4.

⁶⁵ *Ibid* at para 7.

which had been “operating with a negative cash flow for some time, were subject to high fixed operating costs, and were associated with significant future [AROs].”⁶⁶

- (3) POC was incorporated to be POT’s new trustee and hold legal title to other assets, which the Court referred to as “KeepCo Assets,” which were transferred from PEOC/Sequoia to POC and were to be retained by the Perpetual Energy group.⁶⁷
- (4) In addition to beneficial and legal title to the Goodyear Assets, PEOC/Sequoia momentarily held beneficial and legal title to, as the Court called them, the “Retained Interests” which were 1 percent working interests in certain producing wells that were a subset of the KeepCo Assets.⁶⁸
- (5) Perpetual Energy Inc. sold all shares of PEOC/Sequoia to an arm’s-length third party and Perpetual Energy Operating Corp. changed its name to Sequoia Resources Corp.⁶⁹
- (6) Once the sale of PEOC/Sequoia shares was complete, the Retained Interests were transferred from PEOC/Sequoia to POC.⁷⁰

PEOC/Sequoia declared bankruptcy within 18 months of the Transactions.⁷¹

The structure of the Transactions has generated commentary, including implications that Sequoia likely had a much higher LLR at material times during the Transactions than it should have had and that the AER effectively gave Sequoia credit for the value of the profitable well as if it held a 100 percent interest, even though it only held a 1 percent interest.⁷² The trustee in bankruptcy alleged that the Retained Interests were treated differently than the KeepCo Assets “as a method of artificially increasing the Licensee Liability Rating of [PEOC/Sequoia] until the transaction closed.”⁷³ The trustee in bankruptcy further alleged “that as a result of the [Transactions] [PEOC/Sequoia] obtained only \$5.67 million in assets, but assumed over \$223 million in obligations.”⁷⁴

The case is still ongoing as the Alberta Court of Appeal ruled that the PEOC/Sequoia bankruptcy will be returned to the Court of King’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.⁷⁵ The Alberta Court of Appeal stated that “end-of-life obligations could be loosely thought of as asbestos in the walls of a house. It will need to be rectified sooner or

⁶⁶ *Ibid* at para 5.

⁶⁷ *Ibid* at para 7.

⁶⁸ *Ibid* at paras 4, 7, 9.

⁶⁹ *Ibid* at para 7.

⁷⁰ *Ibid*.

⁷¹ *Ibid* at para 12.

⁷² *Ibid* at paras 8–9; Drew Yewchuk, “The Sequoia Bankruptcy Part 1: The Motion to Strike and the Interveners” (18 January 2021), online (blog): <ablawg.ca/wp-content/uploads/2021/01/Blog_DY_Sequoia_Part_1.pdf>.

⁷³ *Perpetual Energy* 2021, *ibid* at para 9.

⁷⁴ *Ibid* at para 11.

⁷⁵ *PricewaterhouseCoopers Inc v Perpetual Energy Inc*, 2022 ABCA 111 at para 3.

later, and someone will have to pay for it. . . . Until then, however, the house is worth less than a similar asbestos-free house.”⁷⁶

5. THE IMPLICATIONS OF THE *REDWATER CA* DECISION

The orphan well problem was magnified in 2017 in *Redwater CA*.⁷⁷ With support from CAPP, the AER and OWA advocated that abandonment work should take priority over repaying creditors. The Alberta Court of Appeal 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.⁷⁸ 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 CA* 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.⁷⁹

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 incentivized to walk away from thousands of wells while the receivers of insolvent companies were selling off profitable assets, disclaiming unprofitable and liability-ridden assets, and making creditors whole at the expense of environmental liabilities.⁸⁰ The AER further cautioned that *Redwater CA* not only affected the industry as a whole, but also the AER’s ability to enforce its rules.⁸¹

6. *REDWATER SCC*

In 2019, the Supreme Court of Canada heard the appeal of the *Redwater CA* decision.⁸² The Supreme Court’s decision was highly anticipated by oil and gas stakeholders since the Supreme 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*.⁸³ While the Alberta Court of Appeal held that the federal bankruptcy law trumped the provincial laws, the Supreme Court disagreed.⁸⁴ The doctrine of federal paramountcy was not triggered because, in the view of the Supreme Court, 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.”⁸⁵ As a result, the Supreme Court held that “there is no operational conflict or frustration of purpose between the Alberta legislation and s. 14.06 of the *BIA*.”⁸⁶

⁷⁶ *Ibid* at para 54.

⁷⁷ *Supra* note 3.

⁷⁸ *Perpetual Energy* 2021, *supra* note 63 at para 91.

⁷⁹ “Orphan Inventory,” *supra* note 17 (as of 1 May 2022, there were 1,758 orphan wellbores for decommissioning).

⁸⁰ AER, “Why We Are Fighting,” *supra* note 35 at 1.

⁸¹ *Ibid*.

⁸² *Redwater SCC*, *supra* note 3.

⁸³ RSC 1985, c B-3 [*BIA*].

⁸⁴ *Redwater SCC*, *supra* note 3 at paras 129–31.

⁸⁵ *Ibid* at para 77.

⁸⁶ *Ibid*.

Having found that there is no conflict between the federal and provincial legislation, the Supreme Court turned to the assessment of whether the regulator was asserting claims provable in bankruptcy. In determining that regulatory claims are not provable claims, the Supreme Court applied a three-prong test that was first developed in *Newfoundland and Labrador v. AbitibiBowater Inc.*⁸⁷ For a claim to be a provable claim under the *BIA*:

- (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.⁸⁸

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.” As a result, such obligations cannot be stayed nor subject to a claims procedure order under the *BIA*.⁸⁹

The role of the trustee in bankruptcy evolved with respect to addressing end-of-life obligations, where the Supreme Court did not allow the trustee to ignore a licensee’s environmental liabilities.⁹⁰ The trustee in the *Redwater* SCC decision was directed to use the proceeds from the sale of Redwater’s assets to address Redwater’s end-of-life obligations.⁹¹

The decision made by the Supreme Court was significant, had implications for a multitude of stakeholders, and profoundly changed the functioning of the insolvency system.⁹² For practical purposes, the regulatory obligations following the Supreme Court decision were treated as priority claims before any distribution was made to creditors.⁹³ 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 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.⁹⁴ The finality of the Supreme Court decision paved the way for a new liability management system to be developed.

⁸⁷ 2012 SCC 67.

⁸⁸ *Ibid* at para 26, cited in *Redwater* SCC, *supra* note 3 at para 37.

⁸⁹ *Redwater* SCC, *ibid* at paras 135–36, 159.

⁹⁰ *Ibid* at para 160.

⁹¹ *Ibid* at para 163.

⁹² “Redwater Decision,” online: *Alberta Energy Regulator* <aer.ca/protecting-what-matters/holding-industry-accountable/redwater>.

⁹³ Frank Spizzirri & Sheldon Title, “SCC’s Final Word in the *Redwater Energy Corp.* Bankruptcy,” *American Bankruptcy Institute Journal* (April 2019) at 37, online: <abi-org-corp.s3.amazonaws.com/journals/international1_04-19.pdf>.

⁹⁴ *Redwater* SCC, *supra* note 3 at para 29.

III. THE CURRENT STATE OF *DIRECTIVE 088*

A. A NEW LIABILITY MANAGEMENT FRAMEWORK

On 30 July 2020, the Government of Alberta announced its new Liability Management Framework.⁹⁵ 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.⁹⁶ The amendments also allow landowners or First Nations to opt-in or nominate inactive or abandoned wells and facilities for closure.⁹⁷ The Liability Management Framework is part of a suite of policies designed to ensure the oil and gas industry is able to meet environmental obligations in a flexible and cost-effective manner.⁹⁸

On 17 December 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 and priority of the work, and request licensee financial and reserves information.⁹⁹ Concurrently, with the changes to the *OGCR* and *Pipeline Rules*, the AER released *Bulletin 2020-26*.¹⁰⁰

The AER released *Directive 088* on 1 December 2021, following consultation with stakeholders.¹⁰¹ 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.

1. AN OVERVIEW OF *DIRECTIVE 088*

Directive 088, along with its companion *Manual 023: Licensee Life-Cycle Management*, provides a regulated management system throughout the energy resource development life cycle for Alberta oil and gas licence holders.¹⁰² The directive will apply to any licensee or approval holder of sites or infrastructure governed by the *OGCA* or the *Pipeline Act*.¹⁰³

⁹⁵ Government of Alberta, “Liability Management Framework” (July 2020), online: <alberta.ca/assets/documents/energy-liability-management-framework.pdf>.

⁹⁶ *Ibid.*

⁹⁷ “Landowner and Indigenous Community Site Nomination,” online: <alberta.ca/landowner-and-indigenous-community-site-nomination.aspx>; 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/>.

⁹⁸ Alberta, Legislative Assembly, “Bill 12, Liabilities Management Statutes Amendment Act, 2020,” 3rd reading, *Alberta Hansard*, 30-2, (2 April 2020) at 406 (Mike Ellis), online: <docs.assembly.ab.ca/LADDAR_files/docs/hansards/han/legislature_30/session_2/20200402_0900_01_han.pdf>.

⁹⁹ Alberta Energy Regulator, *Bulletin 2020-26: Changes to Oil and Gas Conservation Rules and Pipeline Rules* (Calgary: Alberta Energy Regulator, 17 December 2020), online: <static.aer.ca/prd/documents/bulletins/bulletin-2020-26.pdf> [*Bulletin 2020-26*]; *OGCR*, *supra* note 38; *Pipeline Rules*, Alta Reg 91/2005.

¹⁰⁰ *Bulletin 2020-26, ibid.*

¹⁰¹ *Directive 088, supra* note 2.

¹⁰² *Ibid.*; Alberta Energy Regulator, *Manual 023: Licensee Life-Cycle Management* (Calgary: Alberta Energy Regulator, May 2022), online: <static.aer.ca/prd/documents/manuals/Manual023.pdf> [*Manual 023*].

¹⁰³ *Directive 088, ibid* at 1; *OGCA, supra* note 38; *Pipeline Act*, RSA 2000, c P-15.

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 closure spend targets for closure activities and spends by licensees” (the Inventory Reduction Program);
- (4) updated “application requirements related to the licence transfer process”; and
- (5) the “first phase of improvements to security collection.”¹⁰⁴

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.¹⁰⁵ Additional changes are expected throughout the course of 2022.

2. 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.¹⁰⁶

Directive 088 details how the AER will holistically assess each licensee to determine whether to approve licence 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.¹⁰⁷ Any information provided to the AER by the licensee, whether in an application, amendment, or report, may be used in the Holistic Licensee Assessment.¹⁰⁸

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.¹⁰⁹ Statements of concern over the financial capability of proposed transferees may compel the AER to impose additional scrutiny on licence transfers in the public sphere.

¹⁰⁴ Alberta Energy Regulator, *Bulletin 2021-45: New Requirements and Guidance Related to Liability Management* (Calgary: Alberta Energy Regulator, 1 December 2021), online: <static.aer.ca/prd/documents/bulletins/Bulletin-2021-45.pdf>.

¹⁰⁵ “Liability Management Rating and Reporting,” *supra* note 28.

¹⁰⁶ Despite being no longer applicable to the soon-to-be rescinded *Directive 006*, LMRs will continue to be referenced in *Directives 001, 011, 024, and 075*.

¹⁰⁷ *Directive 088*, *supra* note 2 at 2.

¹⁰⁸ *Ibid.*

¹⁰⁹ *Manual 023*, *supra* note 102 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.¹¹⁰ It remains unclear as to what deliverable the licensee will receive from the AER supporting its assessment.

The AER must keep financial information confidential for five years and reserves information confidential for 15 years.¹¹¹ 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.

3. THE LICENSEE CAPABILITY ASSESSMENT

The Holistic Licensee Assessment includes some prescribed assessment factors; arguably the most important is the 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, and administrative and operational compliance history.¹¹²

Beyond the Holistic Licensee Assessment, the Licensee Capability Assessment will also guide licence eligibility under *Directive 067*, as well as regulatory decisions under *Directive 088*.¹¹³ 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.¹¹⁴

a. 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.¹¹⁵

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,

¹¹⁰ *Directive 088, supra* note 2 (“any other factors as appropriate in the circumstances” at 2).

¹¹¹ *OGCR, supra* note 38, s 12.152(2).

¹¹² *Manual 023, supra* note 102 at 1–9.

¹¹³ *Directive 088, supra* note 2 at 3.

¹¹⁴ *Ibid* at 7–8.

¹¹⁵ *Manual 023, supra* note 102 at 2–3.

and the impact of debt on operations.¹¹⁶ 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 zero and 100 based on the ranges identified in *Manual 023*.¹¹⁷ 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.¹¹⁸

The magnitude of liability factor is a relative assessment of the licensee’s total liabilities.¹¹⁹ The licensee’s magnitude of liability is estimated using their abandonment, remediation, and reclamation liability, as set forth in *Directive 011: Licensee Liability Rating (LLR) Program: Updated Industry Parameters and Liability Costs*, and site-specific liability as set forth in *Directive 001*.¹²⁰ 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).¹²¹ These groups are set so that 80 percent of the licensees hold only 10 percent of the total liabilities and represent the “low risk” group.¹²² The bulk of liabilities are thus held by the remaining 20 percent of licensees in the “medium” and “high” risk groups.

b. 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.¹²³ Performance is assessed by way of lifespan, closure, operations, and administration metrics, and is based on a three-calendar-year performance window.¹²⁴ Each performance parameter is weighted and the licensee is tiered, with tier 1 constituting the top 25 percent quartile, tier 2 constituting the middle 50 percent, and tier 3 constituting the bottom 25 percent quartile.¹²⁵

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 stone and will be modified or recalibrated with updates to *Manual 023* as the AER deems necessary.¹²⁶

¹¹⁶ *Ibid.*

¹¹⁷ *Ibid* at 3.

¹¹⁸ *Ibid.*

¹¹⁹ *Ibid.*

¹²⁰ *Ibid*; Alberta Energy Regulator, *Directive 011: Licensee Liability Rating (LLR) Program: Updated Industry Parameters and Liability Costs* (Calgary: Alberta Energy Regulator, 31 March 2015), online: <static.aer.ca/prd/documents/directives/Directive011_March2015.pdf> [*Directive 011*]; *Directive 001*, *supra* note 38.

¹²¹ *Manual 023, ibid.*

¹²² Alberta Energy Regulator, “Liability Management Framework – Licensee Capability Assessment” (8 June 2021) at 5m:49s, online (video): <youtu.be/mmaZGb2eQy0?t=349>.

¹²³ Primary business activity is deemed to be one of the following: producers, pipelines, midstream, or waste management. Producer size is deemed to be one of the following: micro, junior, intermediate, or large/major. Primary production type is deemed to be one of the following: dry gas, liquid rich gas, light-medium oil, heavy oil/bitumen, or mixed: *Manual 023, supra* note 102 at 4–5.

¹²⁴ *Ibid* at 6–9.

¹²⁵ *Ibid* at 6.

¹²⁶ *Ibid* at 10.

4. 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.¹²⁷ 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.¹²⁸

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*.¹²⁹

5. THE INVENTORY REDUCTION PROGRAM

Closure means the permanent end of operations and includes the abandonment, remediation, and reclamation of wells, well sites, facilities, facility sites, and pipelines.¹³⁰ Previously, there was no regulatory requirement for the timing of closure obligations (although *Directive 013: Suspension Requirements for Wells* has included suspension requirements for quite some time).¹³¹ 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 under the *OGCR* and the *Pipeline Rules* to establish “closure quotas” setting forth a minimum amount of closure work and/or spend.¹³²

Closure quotas will be determined by the licensee’s proportion of inactive liabilities and level of financial distress.¹³³ 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.¹³⁴ Each licensee must report its closure activities and spends for the previous calendar year by March 31.¹³⁵

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.¹³⁶ Failure to either meet the mandatory annual target or provide a security deposit for that amount will trigger an automatic Holistic Licensee Assessment to

¹²⁷ *Directive 088*, *supra* note 2 at 4.

¹²⁸ *Directive 001*, *supra* note 38 at 3.

¹²⁹ *Directive 088*, *supra* note 2 at 4.

¹³⁰ *Ibid* at 2.

¹³¹ Alberta Energy Regulator, *Directive 013: Suspension Requirements for Wells* (Calgary: Alberta Energy Regulator, 1 December 2021), online: <static.aer.ca/prd/documents/directives/Directive013.pdf>.

¹³² *Directive 088*, *supra* note 2 at 4; *OGCR*, *supra* note 38, s 3.014; *Pipeline Rules*, *supra* note 99, s 82.1.

¹³³ *Manual 023*, *supra* note 102 at 10.

¹³⁴ “Onestop,” online: *Alberta Energy Regulator* <www.aer.ca/regulating-development/project-application/onestop>.

¹³⁵ *Directive 088*, *supra* note 2 at 5.

¹³⁶ *Ibid*.

determine whether the AER should demand security and in what amount.¹³⁷ 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.¹³⁸ Ultimately, the Inventory Reduction Program is designed to be flexible, allowing licensees to choose sites and activities to maximize efficiencies.

6. MANDATORY CLOSURE SPEND AND TARGETS

Starting on 1 January 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, and disclosed financial information, and are available in the OneStop closure report by July 31 of the following year. The historical spend analysis is based on the two-year average closure spends of the licensee.¹³⁹ The expected industry target increase is 5 percent annually, and licensees can use their current targets to estimate future targets.¹⁴⁰

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.¹⁴¹ 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 2024–2026.¹⁴²

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. However, well and facility suspensions, pipeline discontinuations as well as their associated installations, and remediation on active sites are not considered eligible spend activities.¹⁴³

7. 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 percent and participate in an

¹³⁷ *Ibid.*

¹³⁸ *Manual 023, supra* note 102 at 20–21.

¹³⁹ If a licensee does not participate in an Area-Based Closure Program, their estimated *Directive 011* spends will be used: *Directive 011, supra* note 120.

¹⁴⁰ Alberta Energy Regulator, "Liability Management Framework: Inventory Reduction Program" (Presentation delivered at the Focused Engagement Sessions on *Directive 088*, Calgary, 16 February 2022) [unpublished] at 9 [AER, "Focused Engagement"].

¹⁴¹ *Manual 023, supra* note 102 at 10; "Inventory Reduction Program," online: *Alberta Energy Regulator* <acr.ca/regulating-development/project-closure/liability-management-programs-and-processes/inventory-reduction-program>.

¹⁴² Alberta Energy Regulator, *Bulletin 2021-23: Mandatory Closure Spend Targets* (Calgary: Alberta Energy Regulator, 8 June 2021), online: <static.acr.ca/prd/documents/bulletins/bulletin-2021-23.pdf>.

¹⁴³ *Manual 023, supra* note 102 at 14.

Area-Based Closure Program project.¹⁴⁴ Incentives include deadline extensions for the removal of surface equipment and other specified materials associated with surface abandoned (cut and capped) well licences, and eligibility to apply to receive the maximum three-year extension for expired Crown mineral lease wells.¹⁴⁵ 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.¹⁴⁶

8. 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.¹⁴⁷ Licensees who do not meet their mandatory or voluntary spend targets are deemed to be non-compliant. Enforcement mechanisms include request for security and loss of incentive eligibility for licensees who fail to meet their voluntary targets.¹⁴⁸

9. LICENCE TRANSFERS

The new Liability Management Program will transition the licence transfer application (LTA) process from the LLR program to *Directive 088*. *Directive 006* was amended concurrently with *Directive 088*.¹⁴⁹ Subsequent phases of implementation will include additional changes to *Directive 006* and other AER directives related to liability management. Eventually, *Directive 006* will be rescinded in its entirety.¹⁵⁰

An LTA “can be submitted by the transferor, the transferee, or an authorized agent or consultant acting on behalf of either party.”¹⁵¹ Any LTA will trigger an immediate Holistic Licensee Assessment of both the transferor and transferee. The AER will consider the entire package of licences, including “abandoned, reclaimed, and reclamation-exempt sites to ensure they are held by a responsible party that can address, manage, and monitor current conditions or future issues related to public safety or the environment.”¹⁵² If inactive licences are included in the LTA, then the transferor must update their reported closure activities and spends prior to submitting the LTA.¹⁵³

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.¹⁵⁴ No estimated timeline is provided for the completion of this process and the AER will not provide

¹⁴⁴ AER, “Focused Engagement,” *supra* note 140. 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: *Manual 023*, *ibid* at 13.

¹⁴⁵ *Manual 023*, *ibid* at 11–12 (both incentives are subject to certain conditions imposed by the AER).

¹⁴⁶ *Ibid* at 12.

¹⁴⁷ *Ibid* at 14–15.

¹⁴⁸ *Ibid* at 16–17.

¹⁴⁹ *Directive 006*, *supra* note 29.

¹⁵⁰ “Liability Management,” *supra* note 10.

¹⁵¹ *Directive 088*, *supra* note 2 at 6.

¹⁵² *Ibid* at 5.

¹⁵³ *Ibid* at 6.

¹⁵⁴ *Ibid* at 5.

preliminary determinations of expected security requirements or LTA approvals,¹⁵⁵ which creates considerable uncertainty of LTA success. Security may be required from either or both the transferor and transferee; the assessment of the amount of security considers the licences transferred and those remaining with the transferor.¹⁵⁶

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 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 and inactive wells, is a WIP in all wells and facilities, and accepts and assumes all obligations and responsibilities of a licensee at law.¹⁵⁷

The AER will consider the entire LTA package and may reject LTAs that do not "include licences that have received reclamation certification or that are abandoned and classified as 'reclamation exempt.'"¹⁵⁸ This is another deviation from the prior system, where reclamation-exempt licences could not be transferred. As part of *Directive 088*, such licences must be transferred.¹⁵⁹ 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.¹⁶⁰

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.¹⁶¹ Beginning on the date of the transfer, the transferee assumes liability for the wells, facilities, or pipelines to which the LTA pertains.¹⁶²

10. SECURITY DEPOSITS

The AER has broad and subjective authority to require a deposit.¹⁶³ In assessing whether to demand a security deposit as a condition to LTA approval or as part of the Inventory Reduction 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.¹⁶⁴ A request for refund of the security deposit will trigger another Holistic Licensee Assessment, using the same assessment criteria.¹⁶⁵

¹⁵⁵ *Ibid* at 7.

¹⁵⁶ *Manual 023, supra* note 102 at 21.

¹⁵⁷ *Directive 088, supra* note 2 at 9. For pipeline licences, 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 licence transfer.

¹⁵⁸ *Ibid* at 5.

¹⁵⁹ AER licences that are classified as Issued, Amended, Discontinued, Suspension, Abandoned, RecCertified, or RecExempt are all eligible to be transferred. Cancelled or Re-Entered licences are not eligible for transfer: *ibid*.

¹⁶⁰ *Ibid*.

¹⁶¹ *Manual 023, supra* note 102 at 20.

¹⁶² *Directive 088, supra* note 2 at 7.

¹⁶³ *OGCR, supra* note 38, s 1.100.

¹⁶⁴ *Directive 067, supra* note 40.

¹⁶⁵ *Directive 088, supra* note 2 at 8.

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 AER considers appropriate in the circumstance."¹⁶⁶ 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.¹⁶⁷

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.¹⁶⁸

11. 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.¹⁶⁹ Licensees who cease operations are expected to engage in an orderly wind-down of operations.¹⁷⁰

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 and pipelines, land or interests in land, including mines and minerals, equipment and petroleum substances."¹⁷¹ In addition, licensees remain responsible for adhering to AER regulations, including:

- initiating an immediate emergency response when called;
- maintaining insurance for all AER-licensed properties;
- either obtaining approval from the AER to transfer licences, approvals, and permits to an eligible party or completing abandonment and reclamation of all sites; and
- refraining from and ensuring creditors refrain from removing any equipment without the AER's consent.¹⁷²

12. STATEMENT OF CONCERN

Directive 088 does not specifically address any revisions to the process of submitting a statement of concern; however, applicants have chosen to withdraw applications under

¹⁶⁶ *Manual 023, supra* note 102 at 21.

¹⁶⁷ *Directive 088, supra* note 2 at 8.

¹⁶⁸ *Manual 023, supra* note 102 at 20.

¹⁶⁹ *Ibid* at 22.

¹⁷⁰ *Ibid* at 23.

¹⁷¹ *OGCA, supra* note 38, s 103(2).

¹⁷² *Manual 023, supra* note 102 at 22–23.

section 5(15) of *Directive 088* after reviewing *Directive 088*, and have accordingly notified statement-of-concern filers.¹⁷³

We expect the statement-of-concern filing process to remain the same under *REDA*, where the AER determines the standing of any statement-of-concern filer prior to approving the application, and accordingly proceeds to a hearing if any of the parties are granted standing.¹⁷⁴

B. INITIAL FEEDBACK, ISSUES, AND IMPACT OF *DIRECTIVE 088*

Directive 088 became effective on 1 December 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*.¹⁷⁵ The AER will continue to solicit feedback from stakeholders as *Directive 088* is executed in practice.¹⁷⁶ *Directive 088* will also impact the transactional markets, particularly from a due diligence and licence transfer perspective.

1. 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 their own AER reports which include the following:

- a Liability Assessment Report, which contains the inactive liability estimates used to calculate closure targets;
- a Licensee Capability Assessment, which outlines the License Capability Assessment profile and results, including the results for individual parameters within the risk and performance factors; and
- Closure Activity and Spend, which includes a summary of closure activity, closure targets, closure spend, and WIPs.¹⁷⁷

While oil and gas producers will likely still 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 licensee 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 listed above for due diligence purposes.

¹⁷³ *Shell Canada Limited and Pieridae Alberta Production Ltd: Caroline, Waterton, and Jumping Pound: Applications for Foothills Assets* (3 February 2022), 2022 ABAER 001, online: AER <static.aer.ca/prd/documents/decisions/2022/2022ABAER001.pdf>.

¹⁷⁴ *Ibid.*

¹⁷⁵ Alberta Energy Regulator, *Draft Directive: Licensee Life-Cycle Management: Stakeholder Feedback and AER Response* (Calgary: Alberta Energy Regulator, June 2021), online: <static.aer.ca/prd/documents/directives/Directive088_WWH.pdf>.

¹⁷⁶ “Liability Management,” *supra* note 10.

¹⁷⁷ *Manual 023*, *supra* note 102 at 1, 3, 14.

2. IMPACT ON MINERAL TRANSACTIONS

Directive 088 will undoubtedly impact the licence 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 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 percent/1 percent 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.¹⁷⁸ As part of the reconveyance, 1 percent 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 percent of the legal and beneficial title to the assets. The seller would hold the 1 percent interest in trust for the purchaser without incurring 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.¹⁷⁹ The parties would also typically enter into a contract operating agreement or rely on extended interim provisions, whereby the seller would operate the assets until such time as the LTA was approved, sometimes with a fee paid to the seller.¹⁸⁰

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

¹⁷⁸ The *OGCA* requires every licensee to hold a working interest in the well or facility: *OGCA*, *supra* note 38, ss 16–17.

¹⁷⁹ 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 percent beneficial interest with the remaining 99 percent of the beneficial interest conveyed to the purchaser.

¹⁸⁰ Well and facility operations may only be performed by the licensee: *OGCA*, *supra* note 38, ss 11–12.

immediately following the transfer.”¹⁸¹ One such strategy involved delivering a letter of credit to the AER in an amount sufficient to raise the transferee’s LMR to above 2.0. The licence transfers would be completed on this basis and the transferee 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 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.

3. 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.¹⁸² The AER previously had knowledge of the licensee, but would not normally have any insight into the other legal WIPs or beneficial WIPs.¹⁸³ However, under *Directive 088*, transacting parties will now update the AER on WIPs every time there is a licence transfer.¹⁸⁴ 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 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

¹⁸¹ *Bulletin 2016-21*, *supra* note 58 at 2.

¹⁸² *Directive 088*, *supra* note 2 at 6.

¹⁸³ 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* Schedule 1 filing due to a significant change to the working interest parties.

¹⁸⁴ *Directive 088*, *supra* note 2 at 6.

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.

4. 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.¹⁸⁵ 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 their competitors who have failed to use responsible business practices, such as setting aside 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 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.¹⁸⁶ 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, 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.¹⁸⁷ These funds were to

¹⁸⁵ "Orphan Well Association," *supra* note 42.

¹⁸⁶ *Ernst v Alberta Energy Regulator*, 2017 SCC 1 at paras 9, 51–57, citing *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*, *supra* note 31, s 27.

¹⁸⁷ Prime Minister of Canada, News Release, "Prime Minister Announces New Support to Protect Canadian Jobs" (17 April 2020), online: <pm.gc.ca/en/news/news-releases/2020/04/17/prime-minister-announces-new-support-protect-canadian-jobs>.

be distributed to oil and gas producers to assist them with their own ARO, paying between 25 percent and 100 percent of total cleanup costs (depending on the producer's ability to pay).¹⁸⁸

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 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.

IV. LIABILITY MANAGEMENT THROUGHOUT THE WORLD AND THE FUTURE OF LIABILITY MANAGEMENT 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; and Norway. There may be other successful liability regimes in other jurisdictions that we have not considered, but 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.¹⁸⁹ However, delaying decommissioning can increase costs, jeopardize safety, and create exposure for default risk.

A. 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 oil fields experienced malfunctions and corrosion as its facility neared end-of-life and the company could not demonstrate sufficient financial assurance to

¹⁸⁸ "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](https://www.cbc.ca/news/canada/calgary/kenney-wells-remediation-money-ottawa-alberta-1.5543935)>.

¹⁸⁹ Peter Milne, "Australia's Oil and Gas Industry Will Create a \$76B Clean-Up Bill" *Boiling Cold* (14 May 2020), online: <boilingcold.com.au/australias-oil-and-gas-industry-will-create-a-76b-clean-up-bill/>.

cover its liabilities in the event of an oil spill.¹⁹⁰ A subsequent review of the NOGA liquidation recommended changes to Australia's decommissioning framework.¹⁹¹

Decommissioning liabilities will cost AUD\$76 billion (approximately CDN\$76 billion) over the next 30-years to safely abandon oil and gas wells, pipelines, and platforms in Australia.¹⁹² Australian taxpayers "could bear up to 58% of the cost of offshore decommissioning as the expense is deductible against company income tax."¹⁹³

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.¹⁹⁴ Australia overhauled its liability regime effective 2 March 2022 with changes similar to the new Liability Management Framework such as information gathering power and increased control over changes in titleholders.¹⁹⁵ The changes include previous titleholders and their related parties retaining trailing liability where the current or immediate former titleholder fails to decommission, or if issues arise in relation to a previously decommissioned property.¹⁹⁶ The regulator in South Australia uses a financial security matrix similar to *Directive 088*.¹⁹⁷

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.¹⁹⁸ 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 likely to be passed from established major oil companies to smaller, less substantial titleholders."¹⁹⁹ 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 UK, where former titleholders have continuing liability but only as a backstop.²⁰⁰ Trailing

¹⁹⁰ Steve Walker, "Review of the Circumstances that Led to the Administration of the Northern Oil and Gas Australia (NOGA) Group of Companies" (June 2020) at 4–5, online: *Australian Department of Industry, Science and Resources* <industry.gov.au/sites/default/files/2020-08/review-of-circumstances-that-led-to-the-administration-of-noga-executive-summary-and-recommendations.pdf>.

¹⁹¹ *Ibid* at 9.

¹⁹² Milne, *supra* note 189.

¹⁹³ *Ibid*. Tax incentives include the ability to claim a refund from previously paid Petroleum Resource Rent Taxes.

¹⁹⁴ "Trailing Liability," online: *Australian Department of Industry, Science and Resources* <industry.gov.au/data-and-publications/trailing-liability-for-decommissioning-of-offshore-petroleum-property-guidelines/trailing-liability>.

¹⁹⁵ *Ibid*.

¹⁹⁶ *Ibid*.

¹⁹⁷ South Australia, Department of Energy and Mining, *Petroleum and Geothermal Energy Act 2000 Environmental Liability Management Policy* (24 August 2020) at 2, online: <petroleum.sa.gov.au/_data/assets/pdf_file/0008/305819/PGE-Act-Environ-ity-Management-Policy-APPROVED.pdf>.

¹⁹⁸ Walker, *supra* note 190 at 7.

¹⁹⁹ *Ibid*.

²⁰⁰ *Ibid*.

liability was subsequently included and then expanded in the March 2022 revisions to the Australian decommissioning framework.²⁰¹

B. THE UNITED KINGDOM

The UK has adopted a policy whereby “former owners can be made liable for decommissioning offshore installations or pipelines in which they had an economic interest at the time they sold their interest.”²⁰² 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.²⁰³

The UK government can issue a notice to certain persons (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.²⁰⁴ “Persons liable to receive a Section 29 Notice include the current licence 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).”²⁰⁵

However, unlike in Canada, the regulator can hold former owners liable for decommissioning 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.²⁰⁶ 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.²⁰⁷

1. *APACHE UK INVESTMENT LIMITED V. ESSO EXPLORATION AND PRODUCTION UK LIMITED*²⁰⁸

In *Apache v. Esso*, the English High Court recently clarified the extent to which prior owners could be liable and the security that purchasers are required to post in favour of sellers following the purchase of oil and gas wells.²⁰⁹ 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.²¹⁰ When Section 29 Notices were issued for new wells,

²⁰¹ “Amendments to Enhance Offshore Oil and Gas Decommissioning” (24 February 2022), online: *Australian Department of Industry, Science and Resources* <industry.gov.au/news/amendments-to-enhance-offshore-oil-and-gas-decommissioning>.

²⁰² Jameela Bond, Alistair Calvert & 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.com/legalnews/decommissioning-oil-and-gas-wells-in-2466612/>.

²⁰³ *Ibid.*

²⁰⁴ *Ibid.*, citing *Petroleum Act 1998* (UK), s 29.

²⁰⁵ Bond, Calvert & Young, *ibid.*

²⁰⁶ *Ibid.* 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” (*ibid.*).

²⁰⁷ *Ibid.*

²⁰⁸ [2021] EWHC 1283 (Comm) [*Apache v Esso*].

²⁰⁹ *Ibid.*

²¹⁰ Bond, Calvert & Young, *supra* note 202.

ExxonMobil argued that they could be held liable for those wells and demanded additional security.²¹¹

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. As such, Apache was not required to provide ExxonMobil with any additional security for the new wells.²¹²

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.²¹³

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 consideration.²¹⁴ 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.²¹⁵ 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 sellers 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.

²¹¹ *Ibid.*

²¹² *Ibid.*

²¹³ Ron Bousso & 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)>.

²¹⁴ Rita Brown, "Enquest Strikes \$50m North Sea Decom Deal with BP," *Energy Voice* (31 January 2018), online: <[energyvoice.com/oilandgas/north-sea/162411/enquest-strikes-50m-north-sea-decom-deal-bp/](https://www.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](https://www.shell.com/media/news-and-media-releases/2017/shell-to-sell-package-of-uk-north-sea-assets-to-chrysaor.html)>.

²¹⁵ United Kingdom, Comptroller and Auditor General, *Oil and Gas in the UK – Offshore Decommissioning* (London: National Audit Office, 22 January 2019) at para 2.11, online: <[nao.org.uk/wp-content/uploads/2019/01/Oil-and-gas-in-the-UK-offshore-decommissioning.pdf](https://www.nao.org.uk/wp-content/uploads/2019/01/Oil-and-gas-in-the-UK-offshore-decommissioning.pdf)>.

C. NORWAY

In Norway, the Ministry of Petroleum and Energy (the Ministry) has broad rights to require security from production licensees.²¹⁶ In practice, “the Ministry requires licensees to provide an unlimited parent company guarantee (PCG) for the benefit of the Norwegian State to secure all obligations in relation to the petroleum activities.”²¹⁷ The licensee must also “submit a decommissioning plan to the Ministry two to five years before the license expires or is relinquished, or before the use of a facility ceases.”²¹⁸

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.²¹⁹ All inter-company petroleum operations must be conducted through a single legal entity so that special-purpose entities cannot be created and then default.²²⁰

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.²²¹ However, the parent company guarantee is returned if the parent ceases to hold more than 50 percent of shares in the target.²²² 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.²²³ 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.²²⁴

D. 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

²¹⁶ *Act 29 November 1996 No 72 relating to petroleum activities* (Norway), s 10-7.

²¹⁷ Advokatfirmaet BAHR AS, “Oil and Gas in Norway: An Introduction” (January 2019) at 6, online: <ba hr.no/wp-content/uploads/2018/04/Oil-and-gas-in-Norway-introduction-2018.pdf>.

²¹⁸ *Ibid.*

²¹⁹ *Ibid.*

²²⁰ *Ibid.* at 8.

²²¹ Penelope Warne, “Inside Track to Decommission Off Norway,” *Energy Voice* (28 August 2018), online: <energyvoice.com/oilandgas/north-sea/180094/inside-track-to-decommission-off-norway/>.

²²² *Ibid.*

²²³ *Ibid.*

²²⁴ *Ibid.*

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.²²⁵ Providing security for such liabilities has, in recent years, become a significant negotiating point in mineral transactions.²²⁶

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. 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 trailing liability, even if it is not enforced by the AER. The *OGCA* states the following:

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.²²⁷

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 WIP 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

²²⁵ Bond, Calvert & Young, *supra* note 202.

²²⁶ “Australia’s New Offshore Oil and Gas Decommissioning Framework” (6 September 2021), online: *Gilbert + Tobin* <gtlaw.com.au/knowledge/australias-new-offshore-oil-gas-decommissioning-framework>.

²²⁷ *OGCA*, *supra* note 38, s 31.

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 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*.²²⁸
- (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.”²²⁹
- (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.”²³⁰
- (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*.”²³¹
- (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, on a joint and several basis, to address releases and other environmental non-compliance events.²³²

Licensees can submit a working interest claim (WIC) to the AER for a defaulting WIP’s proportionate share of incurred costs.²³³ 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.²³⁴

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 WIPs could end up jointly and severally liable for the

²²⁸ Heather Elaine Lilles, *The Statutory Liabilities of Joint Operators and Non-Participating Parties* (LLM Thesis, University of Calgary, 2017) [unpublished] at 168, online: <prism.ucalgary.ca/bitstream/handle/11023/3577/ucalgary_2017_lilles_heather.pdf>.

²²⁹ *Ibid.* We are not aware of any instances where the AER has pursued this course of action.

²³⁰ *Ibid.*

²³¹ *Ibid.* We are not aware of any instances where the AER has pursued this course of action.

²³² *Ibid.* at 214.

²³³ “Working Interest Claims (WICs),” online: *Orphan Well Association* <www.orphanwell.ca/producers/working-interest-claims/>, citing *OGCA*, *supra* note 38, s 70(2)(b).

²³⁴ “Working Interest Claims (WICs),” *ibid.*

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 percent 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.

E. 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, 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 its 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, the Orphan Fund Levy would no longer be necessary. The liability would be linked to the asset as opposed to a company or a licence.

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.

F. 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 its position on this will remain unchanged, and oil and gas producers should be aware that the AER has numerous legislative options 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 approximate 90,000 inactive wells or provide absolute prevention against future ARO defaults.²³⁵ Only through co-operation and a commitment from the AER and oil and gas producers to uphold the “polluter pays” principle, will the Province of Alberta overcome its crisis of inactive and orphan wells.

²³⁵ “Well Status,” *supra* note 12 (as of 1 May 2022).

[this page is intentionally blank]