2011 ABERCB 028

Penn West Petroleum Ltd.
Application to Amend Approval No. 10947

Canadian Natural Resources Ltd.
Application for a Section 39 Review of
Approval No. 10947

Nipisi Gilwood A Pool

September 13, 2011

ENERGY RESOURCES CONSERVATION BOARD
Decision 2011 ABERCB 028: Penn West Petroleum Ltd., Application to Amend Approval No. 10947, Canadian Natural Resources Ltd., Application for a Section 39 Review of Approval No. 10947, Nipisi Gilwood A Pool

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Calgary Alberta

PENN WEST PETROLEUM LTD.
APPLICATION TO AMEND APPROVAL NO. 10947

CANADIAN NATURAL RESOURCES LTD.
APPLICATION FOR A SECTION 39 REVIEW
OF APPROVAL NO. 10947

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NIPISI GILWOOD A POOL **Applications No. 1624901 and 1675946**

DECISION

[1] Having carefully considered the evidence, the Energy Resources Conservation Board (ERCB/Board) hereby approves, in part, Application No. 1624901 for amending the cumulative and monthly voidage replacement ratios (VRR) and denies Application No. 1675946 for a review and variance of Approval No. 10947 for the addition of a minimum operating pressure (MOP) of 9000 kilopascals (kPa). The Board will amend Approval No. 10947 to require a monthly VRR target between 1.1 and 2.0 and a cumulative VRR of no more than 1.0 from the commencement of injection.

INTRODUCTION

Applications and Intervention

[2] Penn West Petroleum Ltd. (Penn West) applied (Application No. 1624901), pursuant to Section 39 of the *Oil and Gas Conservation Act*, to amend Approval No. 10947 for enhanced oil recovery (EOR) by water injection in the Nipisi Gilwood A Pool. Approval No. 10947 requires Penn West to maintain a cumulative VRR and a monthly VRR target of 1.0. Penn West requested that the cumulative VRR requirement be removed and that the monthly VRR target be revised to a value between 1.1 and 2.0. The boundaries of all the existing EOR approval areas and other defined areas referenced in this report are illustrated in Figure 1.

[3] Canadian Natural Resources Ltd. (CNRL) objected to Application No. 1624901 and applied (Application No. 1675946), pursuant to Section 39 of the *Energy Resources Conservation Act* for a review of Approval No. 10947. As the operator of the scheme subject to Approval No. 9956,[1] CNRL submitted that an MOP of 9000 kPa, as currently required in Approval No. 9956, should also be required in Approval No. 10947 in order to be consistent with the other schemes operating in the Nipisi Gilwood A Pool. CNRL contended that a monthly VRR target of between 1.1 and 2.0 should not be approved and that the Board should suspend production from Approval No. 10947 until continued water injection restores the reservoir pressure to 9000 kPa. CNRL said that the pressure imbalance between the two approval areas has caused fluid to migrate from the area of Approval No. 9956 to the area of Approval No. 10947.

[1] Approval No. 9956 pertains to a portion of the Nipisi Gilwood A Pool and is adjacent to the scheme subject to Approval No. 10947.

[4] The Board granted the review as CNRL demonstrated that new facts alleged by CNRL could lead the Board to materially vary Approval No. 10947.

Regulatory History of Approval No. 10947

[5] The ERCB approved an EOR scheme in a portion of the Nipisi Gilwood A Pool in March 1972 through Approval No. 1722. As part of the approval, Tenneco Oil & Minerals Ltd., the operator of the scheme, was required to inject sufficient volumes of water in order to maintain a suitable balance between water injected into and fluids withdrawn from the approval area. The ERCB transferred Approval No. 1722 to CDC Oil & Gas Limited in September 1976 before transferring it to Canterra Energy Limited in October 1986. The ERCB rescinded Approval No. 1722 with Approval No. 5619 in April 1988 and transferred it to Husky Oil Operations Limited (Husky) in September 1991.

[6] In 1998, Husky and Amoco Canada Petroleum Company Ltd. (Amoco) collaborated to add three injectors in the western area of the Nipisi Gilwood A Pool: two of which were dedicated to Approval No. 5619 (now Approval No. 10947) and one joint injector to support production in both Approval No. 5619 and Approval No. 6999 (now Approval No. 9956). The ERCB rescinded Approval No. 5619 with Approval No. 10947 in July 2007 when Penn West assumed operations. At that time, the ERCB amended the approval to clarify the ERCB's expectation with regard to "*a suitable balance between water injected to and fluids withdrawn from*" by specifying a cumulative and monthly VRR of 1.0 (see Figure 1 for the current approval area of Approval No. 10947).

Regulatory History of Approval No. 9956

[7] The ERCB approved an EOR scheme in a portion of the Nipisi Gilwood A Pool in September 1968 through Approval No. 1061. Pan American Petroleum Corporation operated the scheme which, as part of the approval, required the injection of water volumes sufficient enough to maintain a suitable balance between water injected to and fluids withdrawn from the approval area. The approval also required an MOP of 13 790 kPa.

[8] The ERCB transferred this approval to Amoco in August 1969. The ERCB then rescinded Approval No. 1061 with Approval No. 2061 in October 1974, reducing the MOP to 9650 kPa. The ERCB rescinded Approval No. 2061 with Approval No. 3822 in May 1983 to account for the inclusion of a solvent flood area within the waterflood area. The ERCB rescinded Approval No. 3822 with Approval No. 4106 in February 1984 to amend the approval to remove some injector locations. The ERCB rescinded Approval No. 4106 with Approval No. 4658 in October 1985 to establish solvent flood injection patterns and modify injector locations.

[9] The ERCB rescinded Approval No. 4658 with Approval No. 6999 in July 1994 to modify the solvent flood requirements. It amended this approval in August 1999 to reduce the MOP in the waterflood area to 9000 kPa. It transferred the approval to CNRL in March 2000. It rescinded Approval No. 9956 with Approval No. 6999 in July 2004 to modify injector locations. In June 2005, the ERCB amended the approval to clarify the ERCB's expectation with regard to "*a suitable balance between water injected to and fluids withdrawn from*" by specifying a cumulative and monthly VRR of 1.0 (see Figure 1 for the current approval area for Approval No. 9956).

Regulatory History of Lands Surrounding Approval No. 10947

[10] There are about 7.5 sections of land surrounding Approval No. 10947 that are not part of any waterflood scheme. These areas and their respective wells are referred to as primary areas, 19 of which have recovered oil from the Nipisi Gilwood A Pool. Wells in the primary areas produced under Maximum Rate Limitation administration until the ERCB granted good production practice in October 1989.

Regulatory Process to Support Resource Conservation Outcomes

[11] The ERCB requires companies holding mineral rights of productive pools to assess the feasibility of increasing recovery and, where technically and economically feasible, to implement EOR. Implementing an EOR scheme early minimizes solution gas production to optimize ultimate recovery. Where competitive schemes are necessary, the ERCB encourages companies to work together to ensure that independent operations do not detract from pool recovery. In 1998, the ERCB requested an assessment of potential options to improve voidage in the Nipisi Gilwood A Pool, to which Husky and Amoco responded by adding three injectors.

[12] As pools mature due to depletion, operators often make it a best practice to recover reserves at terminal stages and reduce ERCB surveillance. In all cases, the ERCB expects operators to comply with the terms of approval or amend the approval if operations change. The ERCB also responds to concerns from offset operators. In the Nipisi Gilwood A Pool, there is no record of ERCB staff seeking further optimization reviews after the Husky/Amoco addition of three new injectors or a concern being filed regarding Approval No. 10947, which has operated for 12 years.

Hearing

[13] The Board held a public hearing of the applications in Calgary, Alberta, which commenced on June 21, 2011 and concluded on June 23, 2011, before Board Members J. D. Dilay, P.Eng. (Presiding Member) and G. Eynon, P.Geol. and Acting Board Member R. J. Willard, P.Eng. Those who appeared at the hearing are listed in Appendix 1.

[14] As Penn West submitted undertakings on June 30, 2011, the Board closed the hearing record on that date.

ISSUES

[15] The Board considers the issues respecting the applications to be

- geological interpretation (depositional setting and existence of a permeability barrier),
- the depletion stage of Penn West’s waterflood scheme, and
- waterflood operating strategies.

[16] In reaching the determinations contained in this decision, the Board considered all relevant materials constituting the record of this proceeding, including the evidence and argument provided by each party. Accordingly, references in this decision to specific parts of the record

are intended to assist the reader in understanding the Board's reasoning relating to a particular matter and should not be taken as an indication that the Board did not consider all relevant portions of the record with respect to that matter.

GEOLOGICAL INTERPRETATION

Depositional Setting

Evidence

[17] Penn West submitted a geological interpretation for the West Nipisi Area[2] based on previous geological studies by others on the Gilwood Member in the Nipisi Area as well as its own interpretation. Penn West submitted that the Gilwood Sands in the West Nipisi Area were deposited as alluvial plain sediments that included isolated channel sand sequences in an area of limited accommodation space.[3] However, in the Main Nipisi Area, Penn West submitted that the Gilwood Sands were deposited as delta plain and delta front sediments in an area of greater accommodation space, resulting in multiple stacked sandstone and channel sequences with increased reservoir pay thickness and areal extent (see Figure 1). Penn West contended that the sandstones of the West Nipisi Area correlate locally but do not correlate directly to sandstones occurring in the Main Nipisi Area.

[18] CNRL submitted a similar model for the deposition of Gilwood Sands in the West Nipisi Area, an alluvial plain environment. CNRL stated that this geological interpretation was consistent with industry and academic interpretations, citing several published papers. However, CNRL submitted that the reservoir sands in the West Nipisi Area correlated to the Gilwood B sand unit in the Main Nipisi Area.

Analysis and Findings

[19] The Board notes the parties' agreement that the Gilwood sediments in the West Nipisi Area were deposited predominantly in an alluvial plain depositional system. The Board agrees with the parties and the academic and industry literature cited, acknowledging that the Gilwood Sands within the West Nipisi Area were deposited in an alluvial plain system, and that they grade eastward into the delta plain and delta front deposits of the Main Nipisi Area.

[20] The Board finds that the depositional differences, as well as the major difference in accommodation space between the two areas, suggest that the Gilwood Sands of the West Nipisi Area are unlikely to correlate directly to the Gilwood Sands in the Main Nipisi Area. As a result, the Board finds that the differences in geological depositional setting and history have created a situation where there is likely to be limited connectivity between the sands of the alluvial plain and the delta plain and delta front depositional areas.

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2 West Nipisi Area encompasses those portions of the Nipisi Gilwood A Pool that are located primarily in Township 80, Range 9, West of the 5th Meridian (see Figure 2).

3 Accommodation space is the physical three-dimensional space in which sediment can be deposited. In this case, the contention is that there existed a finite alluvial plain area in which larger volumes of sediment passed through and were deposited as delta sediments in an area of much greater accommodation space.

[21] However, the Board notes that within the overall West Nipisi Area, the reservoir rocks should correlate from west to east, given that they are within the same alluvial plain system. The Board further notes, however, that stratigraphic correlation of the sediments within the same depositional environment does not indicate fluids and/or pressure communication across the area.

Existence of a Permeability Barrier

Evidence

[22] Penn West submitted a comprehensive examination of cores, well logs, and geological mapping in the West Nipisi Area of the Nipisi Gilwood A Pool. It also submitted isopach and structure maps to illustrate the significant differences between the thinner alluvial plain channel sands of the West Nipisi Area and the deltaic sediments deposited in the Main Nipisi Area, with its thicker, stacked, and laterally continuous and connected deltaic sediments.

[23] Penn West stated that faulting was likely an important factor contributing to the structural framework in the Main and West Nipisi areas. However, Penn West did not have seismic data to confirm the degree, amount, and orientation of faulting in the area. Penn West believed that basement faulting was related to ongoing reactivation of the Peace River Arch over geologic time. Penn West further submitted that such faulting was likely the major element controlling regional tilting, paleotopographic relief, depositional differences, and, ultimately, the development of an area of low permeability. Penn West further submitted that these elements all contributed to the separation of the Gilwood Sands in the area of Approval No. 10947—the area it had designated as the West Nipisi Gilwood Oil Accumulation (WNGOA)—from areas to the east (see Figure 2).

[24] In its original submission of Application No. 1624901, Penn West submitted structure, isopach, and porosity- and permeability-thickness maps, none of which indicated that the West Nipisi Area was separated from the Main Nipisi Area. However, in response to CNRL's concerns, Penn West conducted a detailed review and subsequently submitted an updated series of geological maps to demonstrate how the area in and around Approval No. 10947 is separated from the Main Nipisi Area.

[25] Based on its geological review, Penn West contended that Approval No. 10947 of the West Nipisi Area is separated from the eastern portion of the alluvial plain sediments and the Main Nipisi Area by a zone of very poor or nonexistent reservoir quality. Penn West designated this pool as the area of limited permeability, indicating in its submission its reasons why the West Nipisi Area should be treated separately as the WNGOA.

[26] Penn West submitted a series of porosity-thickness maps, with the most recent version indicating an area of limited permeability that effectively isolated the Gilwood Sands reservoir of Approval No. 10947 and some immediately adjacent portions of the area of Approval No. 9956 from the rest of the area of the approval. The map was based on porosity and permeability cutoffs of 5 per cent and 0.1 millidarcy (mD) respectively, illustrating an effective zero edge for porosity-thickness of less than 0.05 m. In addition, Penn West submitted a permeability-thickness map based on the same cutoffs, creating an effective zero edge for permeability-thickness of less than 0.5 mD*m. Penn West submitted that, together, these two maps define an effective low permeability area that separates the WNGOA from the rest of the Nipisi Gilwood accumulation.

[27] Penn West recognized that some of the westernmost parts of Approval No. 9956 adjacent to Approval No. 10947 are also alluvial plain sediments and part of the WNGOA. Penn West also identified an original oil/water contact in the general West Nipisi Area at -1074 metres subsea that extends east into the main Nipisi Gilwood reservoir delta plain sediments.

[28] CNRL relied heavily on past ERCB decisions that have included the West Nipisi Area in the Nipisi Gilwood A pool and submitted an interpretation of the West Nipisi Area as being in communication with the Main Nipisi Area via continuous reservoir sands. CNRL acknowledged the alluvial plain, delta plain, and delta front interpretation of the Gilwood Sands, as identified in the geological literature. However, CNRL maintained that the West Nipisi Area is a part of the Nipisi Gilwood A Pool and submitted structure, porosity-thickness, permeability, and net oil pay maps to support its position. These maps applied the same basic pool outline used by Penn West in its original submission to amend the VRR clause, having created them using available core and petrophysical well log data.

[29] In creating its net oil pay map, CNRL employed porosity and permeability cutoffs of 5 per cent and 1 mD respectively, but did not use a minimum thickness cutoff. Its mapping and interpretation, therefore, identified only three isolated areas of nonreservoir rock, each smaller than a single legal subdivision, (40 acres) in size, rather than a continuous area of limited permeability. CNRL contended that, as a result, there has been fluid flow between the reservoirs in the Main Nipisi and the West Nipisi Areas.

[30] To support its position, CNRL submitted that the well located in the area Penn West contended was of limited permeability at Legal Subdivision (LSD) 12, Section, 26, Township 80, Range 9, West of the 5th Meridian (the 12-26 well) recorded a pressure response from two injectors located east of the alleged permeability barrier at LSD 12-28-80-8W5M (the 12-28 injector) and LSD 2-30-80-8W5M (the 2-30 injector).

[31] Penn West disagreed with CNRL's contention that the 12-26 well recorded a pressure response from two distant injectors. Penn West noted that the 12-28 and 2-30 injectors are located about 6.4 and 4.0 kilometres (km) respectively, from the 12-26 well. Penn West further noted that the well between the 12-26 well and the 12-28 and 2-30 injectors located at LSD 10-25-80-9W5M (the 10-25 well), was not influenced by water injection. The 10-25 well, being directly between the water injectors and the 12-26 well and, therefore, directly in the likely path of flow from the water injection, should have also seen a production response in order to conclude that communication occurred between these areas.

[32] CNRL further submitted that calendar day production rates from the well in Approval No. 10947 located at LSD 12-34-080-09W5M (the 12-34 well) and to the west of the area that Penn West contended had a permeability barrier, increased from August 1970 to January 1972, and interpreted the increase as being in response to water injection from the 12-28 and 2-30 injectors.

[33] However, Penn West disagreed with CNRL's contention that production rates from the 12-34 well increased in response to water injection from the 12-28 and 2-30 injectors, noting that the injectors are 6.2 km and 8.2 km respectively, from the 12-34 well. Penn West stated that the 12-34 well did not experience an increased oil production trend; analysis based on operating or producing day rates, instead of calendar day rates, did not show an increasing trend. Penn West further noted that the 10-25 well is located directly between the 12-34 well and the two injectors

and did not exhibit any production response, which should have been expected if water injection was affecting production in the 12-34 well.

[34] CNRL also submitted that the producer located in the area that Penn West contended had limited permeability at LSD 2-2-81-9W5M recorded a pressure response from the injector east of the permeability barrier at LSD 4-36-80-9W5M.

Analysis and Findings

[35] The Board acknowledges that the parties submitted somewhat different interpretations of data on the West and Main Nipisi areas, but recognizes that the two interpretations vary only in degree. The Board recognizes that the various reservoir maps created by Penn West and CNRL on structure, isopach, and porosity- and permeability-thickness differ in interpretation.

[36] The Board notes that, with respect to the porosity- and permeability-thickness maps used to indicate the presence or absence, respectively, of a permeability barrier isolating the area of Approval No. 10947 and some adjacent portions of Approval No. 9956 from the bulk of the area of Approval No. 9956, the most significant difference is the use of an effective zero edge value. The Board notes that, in not using any minimum value, CNRL's interpretation maximized the definition of reservoir rock. However, the Board notes that Penn West, on the other hand, contended that there needs to be a minimum thickness of porous rock for it to be an effective reservoir and applied a minimum porosity-thickness value of 0.1 m. The Board finds the latter approach more useful and persuasive. The Board would not expect that rock below a minimum cutoff to support fluid flow in amounts that would influence recovery performance or cause significant equity issues.

[37] In addition, the Board finds that CNRL did not substantiate its contention that large volumes of fluids have been transferred from the area of Approval No. 9956 to the area of Approval No. 10947. However, it accepts that there has been some transfer quite locally, adjacent to Approval No. 10947. The Board finds Penn West's arguments challenging pressure and production impacts from distant injectors more convincing than CNRL's position.

[38] For these reasons, the Board finds that, from the geological and petrophysical properties perspective, the WNGOA is separated by an area of limited permeability from the bulk of the Approval No. 9956 area. The Board notes that the WNGOA includes all of the Approval No. 10947 area, but that small portions of the Approval No. 9956 area are on the west side of the area of limited permeability.

[39] The Board agrees that the WNGOA proposed by Penn West is effectively separate from the Main Nipisi Area and should be treated as a separate reservoir unit. On the balance of evidence, the Board acknowledges that the area of limited permeability proposed by Penn West does, in fact, exist and that there is extremely limited connectivity between the WNGOA and the remainder of West Nipisi Area to the east of the low permeability area adjacent to the Main Nipisi Area.

[40] The Board understands from the literature cited that although neither Penn West nor CNRL provided seismic evidence, it is likely that a postdepositional structural imprint on the West Nipisi Area existed that could have supported local low permeability development and created the pool separation. The Board also finds that the difference in pressure between the Main Nipisi

Area and the WNGOA, noted in evidence as significantly different current operating pressures, supports the geological interpretation that the WNGOA is separate and should be treated as a separate entity.

[41] In summary, the Board finds that CNRL's evidence and argument on pressure and production regarding waterflood response between the West Nipisi Area and the Main Nipisi Area did not disprove the existence of an area of limited permeability. The Board agrees with Penn West's argument that the 10-25 well should have also seen a waterflood response to conclude communication between these areas since it is located between the 12-26 well and the 12-28 and 2-30 injectors. The Board further agrees that the pressure observed in the 12-26 well from 1970 to 1972 is levelling out, even with consistent injection from the 12-28 and 2-30 well. The Board acknowledges that the calendar and operating day rates from the middle of 1971 to the beginning of 1972 are significantly different and that the steep increase applied to the data on calendar day rates for the 12-34 well from mid-1971 to mid-1972, is not evidenced or apparent in the data on operating day rates. The Board finds CNRL's use of the pressure and production responses in the 12-26 and 12-34 wells as evidence of long distance fluid movement insufficient to establish the presence of communication through the alleged area of limited permeability.

DEPLETION STAGE OF PENN WEST'S WATERFLOOD SCHEME

Evidence

[42] Penn West estimated that, based on a volumetric analysis, the original oil in place (OOIP) for the area of Approval No. 10947 is 4289.2 thousand cubic meters (10^3 m^3).

[43] Penn West determined that, as of February 2011, the wells within Approval No. 10947 have recovered 48 per cent of their estimated OOIP based on the cumulative production of 2075.3 10^3 m^3. Penn West used an exponential production decline analysis with a scheme oil cut-off rate of 4.7 cubic meters per day (m^3/day) to estimate ultimate oil reserves of 2157.4 10^3 m^3. Cumulative production to date amounts to 96 per cent of its ultimate recoverable reserve estimate. The remaining 82.1 10^3 m^3 of reserves are 2 per cent of the OOIP, which Penn West determined would be recovered by September 2029.

[44] Penn West and CNRL agreed that the current average reservoir pressure in the area of Approval No. 10947 is 6500 kPa and that the bubble point pressure is 8384 kPa.

[45] CNRL estimated that, based on a volumetric analysis, the OOIP for the area of Approval No. 10947 is 3373.7 10^3 m^3.

[46] CNRL determined that, as of February 2011, the wells of Approval No. 10947 have recovered 50.7 per cent of their estimated OOIP, based on the cumulative production of 2075.3 10^3 m^3. CNRL used an exponential production decline analysis, with a scheme oil cut-off rate of 0.5 m^3/d, to estimate ultimate oil reserves of 2222.7 10^3 m^3. Cumulative production amounts to 93 per cent of its ultimate recoverable reserve value. The remaining reserves of 147.4 10^3 m^3 are 4 per cent of the OOIP, which CNRL determined would be recovered by September 2071.

[47] CNRL acknowledged that much of the solution gas in the area of Approval No. 10947 has already been produced.

Analysis and Findings

[48] The Board finds the Penn West waterflood scheme to be in a late stage of depletion for a number of reasons. First, at least 93 per cent of the ultimate recoverable oil reserves has been recovered. The Board notes that although there is a 20 per cent difference between CNRL and Penn West's estimates of OOIP, both parties agree that at least 48 per cent of the OOIP has been produced. This exceeds the ERCB's currently established average waterflood recovery estimate of 32.5 per cent for the Nipisi Gilwood A Pool.

[49] Second, within the area of Approval No. 10947, the majority of wells have either been suspended or abandoned and oil rates have declined by 87 per cent. The Board notes that, although 21 wells in this area produced oil as of May 2011, only 5 wells are currently operating—two of which produce 82 per cent of current production. As a result, the maximum scheme oil rate has declined from 230.0 m^3/d to 30.0 m^3/d.

[50] Third, the scheme pressure has remained below the bubble point for 30 years, significantly depleting solution gas. The Board notes that Penn West and CNRL agree that the average reservoir pressure of the scheme is 6500 kPa, which is below the bubble point pressure of 8384 kPa, the proposed MOP of 9000 kPa, and the initial pressure of 17 900 kPa. The Board also agrees with CNRL that much of the solution gas has been produced.

WATERFLOOD OPERATING STRATEGIES

Evidence

[51] Penn West requested that Clause 4(a) of Approval No. 10947 be removed. This clause states that, based on cumulative production and injection volumes, a VRR of 1.0 must be maintained. As of January 2011, the current cumulative VRR of 0.87 no longer complies with Clause 4 (a). Penn West proposed a VRR target between 1.1 and 2.0 on a monthly basis, stating that it was committed to optimizing oil recovery by water injection in the pool.

[52] Penn West contended that applying an MOP of 9000 kPa is not appropriate. It estimated that in order to restore the reservoir pressure to 9000 kPa, considering a 300 m^3/d injection rate, production would need to be shut in for four years. Penn West stated that this repressurization may not be successful because additional production from WNGOA would be occurring from primary wells around Penn West's approval area. Penn West was concerned that reserves would migrate outside of its approval area. Penn West was also concerned that with only two wells producing 82 per cent of the total production within the area of Approval No. 10947, these wells may not return to production after being shut in for four years during repressurization. Penn West contended that such a shut in would, at best, alter the timing of recovery, and that recovery could only be increased by altering the flood pattern, which was not economically feasible at this stage of depletion.

[53] Penn West indicated that a shut-in period lasting 2.5 years, as proposed by CNRL, would defer net operating income of $5.939 million for the West Nipisi Unit owners and an estimated loss, or deferral, of $3.778 million in royalties.

[54] Penn West analyzed CNRL's proposed repressurization scenario and stated that it was not as economic as continuing with the existing scheme. Penn West provided an economic analysis of four options. It calculated the base case and CNRL's higher VRR case on an unrisked basis, yielding net present values at 10 per cent (NPV_{10})of $6.641 million and $7.006 million, respectively. It also calculated the CNRL higher VRR case, risked at 75 and 50 per cent probability of success, as yielding NPV_{10} of $6.075 million and $4.728 million, respectively.

[55] Penn West noted that, to pay out CNRL's proposed repressurization scenario on a risked basis, it would be required to add an incremental 18 433 m^3 (with a 50 per cent probability of success and a risked capital investment of $11 600 million) to 92 166 m^3 (with a 10 per cent probability of success and a risked capital investment of $2 320 million) of oil to proven recoverable reserves. Penn West stated that, from an exponential decline curve analysis, only 82 000 m^3 of remaining recoverable oil reserves will be achieved by September 2029 from Approval No. 10947.

[56] CNRL proposed applying an MOP of 9000 kPa for Approval No. 10947 to optimize oil recovery and to be consistent with Approvals No. 9956 and 9868. CNRL submitted that if a cumulative VRR from the start of injection of 1.0 was maintained for Approval No. 10947, the scheme's average reservoir pressure would have remained above 9000 kPa. CNRL proposed that in order to restore the cumulative VRR and repressurize the scheme, production would need to be shut in for 2.5 years and water injection increased to 600 m^3/d. For Approval No. 10947, CNRL calculated the cumulative VRR from the commencement of injection as of January 2011 to be 0.89.

[57] CNRL acknowledged that a minimum monthly VRR of 2.0 would be a satisfactory condition to repressurize the scheme provided that were to be achieved through increased injection rather than by limiting production.

[58] CNRL asserted that the standard industry operating practice for pools under waterflood is to operate them at or above the pool's bubble-point pressure. However, CNRL admitted that due to the late stage of depletion of wells within Approval No.10947, much of the evolved gas has been produced.

[59] CNRL submitted that incremental reserves produced under Approval No. 10947, should Penn West be mandated to maintain an MOP of 9000 kPa, are sufficient to justify the expenses incurred through the repressurization and temporary shut in of production wells under this approval.

[60] CNRL calculated that incremental production from repressurization would have to be at least 9164 m^3 to be economically feasible.

[61] CNRL acknowledged that it had not conducted a detailed economic feasibility analysis of repressurization. However, CNRL submitted that decline analysis for pre- and post-2005 data has shown incremental production of 120 10^3 m^3 as a result of the increasing reservoir pressure.

Analysis and Findings

[62] The Board finds that imposing an MOP of 9000 kPa is inappropriate for Approval No. 10947. The Board finds that operating at or above the bubble point pressure is no longer

necessary for this approval given its late stage of depletion. The practice of operating a waterflood at or above bubble point pressure is to prevent the release of solution gas and the detrimental impact on recovery that would result. However, in the case of Approval No. 10947, much of the initial solution gas in place has already been produced from the scheme area, depleting the solution gas drive. The Board notes that CNRL acknowledged that much of the evolved gas has been produced.

[63] The Board agrees that production from wells in areas surrounding Approval No. 10947 would hinder the repressurization of the scheme. The Board acknowledges the potential for migration from the approval area into the surrounding primary areas during prolonged periods of shut in. The Board further agrees that this fluid migration has the potential to cause reserves to be lost from the area of Approval No. 10947.

[64] The Board agrees that long-term injection in the area of Approval No. 10947 without continuing production would introduce risks to future operations, such as oil remaining trapped in the reservoir and wells watering out. As such, the Board finds that applying some form of risking is appropriate when considering long-term injection without production. With respect to CNRL’s repressurization proposal, the Board finds that sizable risks would be introduced and that investment in repressurization is not justified.

[65] The Board finds that consideration of a cumulative VRR is necessary to limit the total water injected into the scheme, monitor performance, and set criteria for surveillance. Given the Board’s conclusion that repressuring to 9000 kPa is not required, the Board will amend the cumulative VRR condition to state that it must not exceed 1.0 from the commencement of injection.

[66] The Board finds that a monthly target VRR is necessary to maximize the remaining recovery, and that a monthly VRR target of between 1.1 and 2.0, as proposed by Penn West, is appropriate.

[67] The Board notes evidence that the joint injection well located at LSD 14-16-080-09W5M, which injected only 5700 m^3, could be reworked based on CNRL’s experience with injectors in the main part of the Nipisi Gilwood A Pool. Notwithstanding differences between the west and main parts of the Nipisi Gilwood A Pool, the Board encourages the parties to examine this option.

OTHER CONSIDERATIONS

Evidence

[68] CNRL stated that Approval No. 10947 is seeing unusually large recoveries. CNRL stated that the only possible explanation for the high recovery is fluid migration from Approval No. 9956.

[69] Penn West stated that it was aware that other waterflood schemes in the Nipisi Gilwood A Pool require an MOP. Going forward, Penn West stated that it would not object to an application submitted by CNRL to amend Approval No. 9956 to remove the MOP requirement. CNRL

stated that it would consider this option should the Board decide to approve Penn West's application.

Analysis and Findings

[70] The Board finds that there is an area of limited permeability separating Approval No. 10947 from the large majority of Approval No. 9956. The Board is of the view that there is no fluid migration occurring across this area of limited permeability. The Board acknowledges that there is the potential for fluid migration within areas on the west side of the permeability barrier.

[71] The Board acknowledges that there are portions of CNRL's Approval No. 9956 that are located west of the area of limited permeability. The Board notes that CNRL could apply to amend Approval No. 9956 with respect to these areas and the MOP.

CONCLUSIONS

[72] The Board finds that there is an area of limited permeability separating the Gilwood Sands in the WNGOA from the Gilwood Sands in the West Nipisi and Main Nipisi areas.

[73] The Board finds Penn West's waterflood scheme to be in a late depletion stage.

[74] The Board finds that there is no migration occurring between areas east and west of the permeability barrier. However, there is the potential for migration within the WNGOA west of the permeability barrier.

[75] The Board finds that application of an MOP to Approval No. 10947 would be inappropriate for the scheme.

[76] The Board finds that a cumulative VRR requirement not exceeding 1.0 is appropriate for Approval No. 10947.

[77] The Board finds that a monthly VRR target of between 1.1 and 2.0 is appropriate for Approval No. 10947.

[78] The Board acknowledges that there are portions of Approval No. 9956 located on the west side of the area of limited permeability. The Board notes that CNRL may apply to amend this approval with respect to these areas and the MOP requirement.

Dated in Calgary, Alberta, on September 13, 2011.

ENERGY RESOURCES CONSERVATION BOARD

<original signed by>

J. D. Dilay, P.Eng.
Presiding Member

<original signed by>

G. Eynon, P.Geol.
Board Member

<original signed by>

R. J. Willard, P.Eng.
Acting Board Member

APPENDIX 1 HEARING PARTICIPANTS

Principals and Representatives (Abbreviations used in report)	Witnesses
Penn West Petroleum Ltd. (Penn West) M. McCachen K. McGlone	M. M. Stewart T. W. Stasiuk, P.Eng. J. L. D'Eath, M. B. Blair, P.Eng. D. J. Staples, P.Geol., of Grandview Energy Inc.
Canadian Natural Resources Ltd. (CNRL) P. McGovern	J. Urdaneta D. A. Payne, P.Eng. J. G. McEwen, P.Eng. G. Daly, P.Geol. G. Lackner, Ph.D. M. S. Chalmers, P.Geol. B. Paulssen V. Simin, P.Geoph.
Energy Resources Conservation Board staff R. J. Mueller, Board Counsel R. Parkyn B. Lee K. Jors M. Fierro A. Koper	

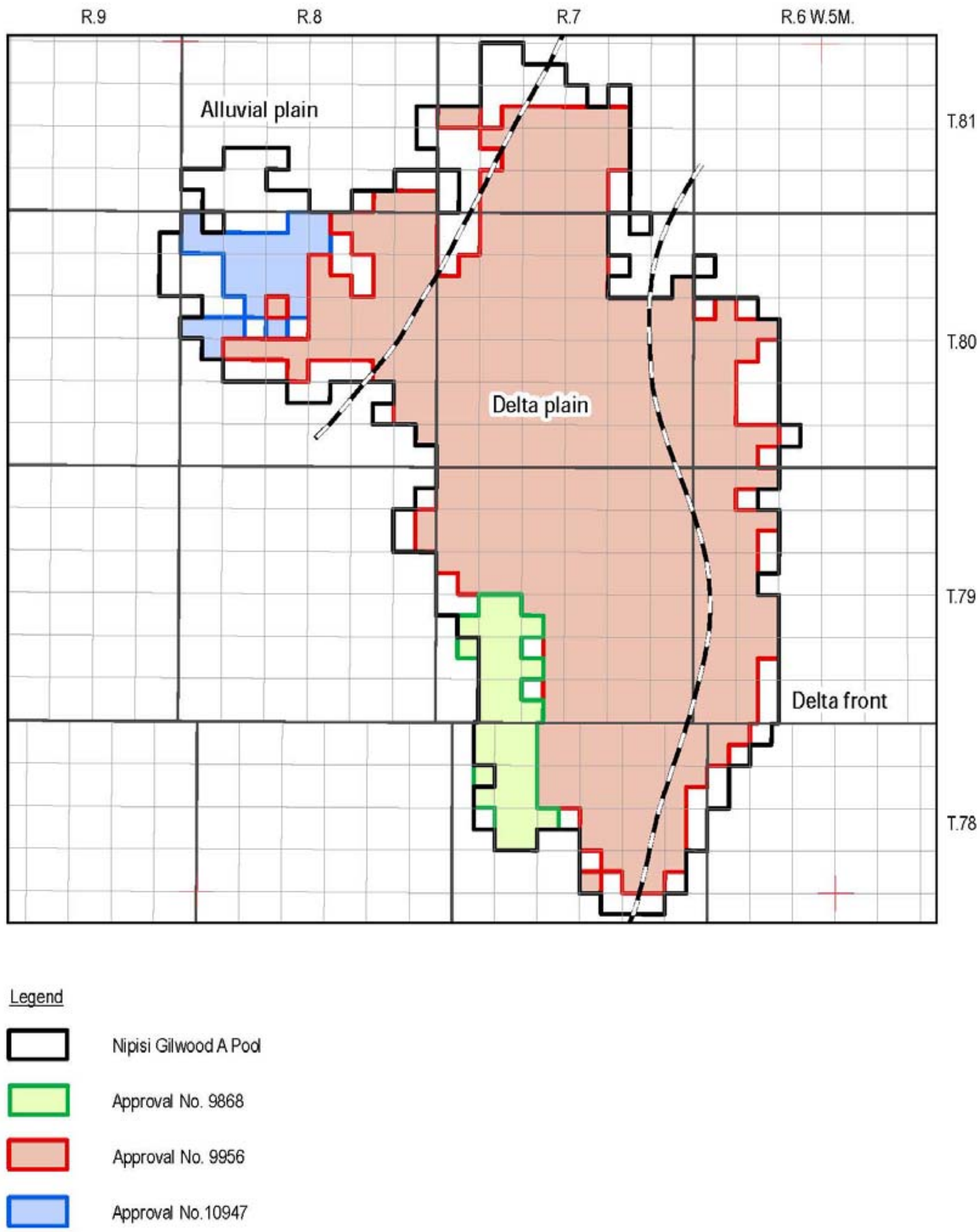

Figure 1. Nipisi Gilwood A Pool and approval area boundaries

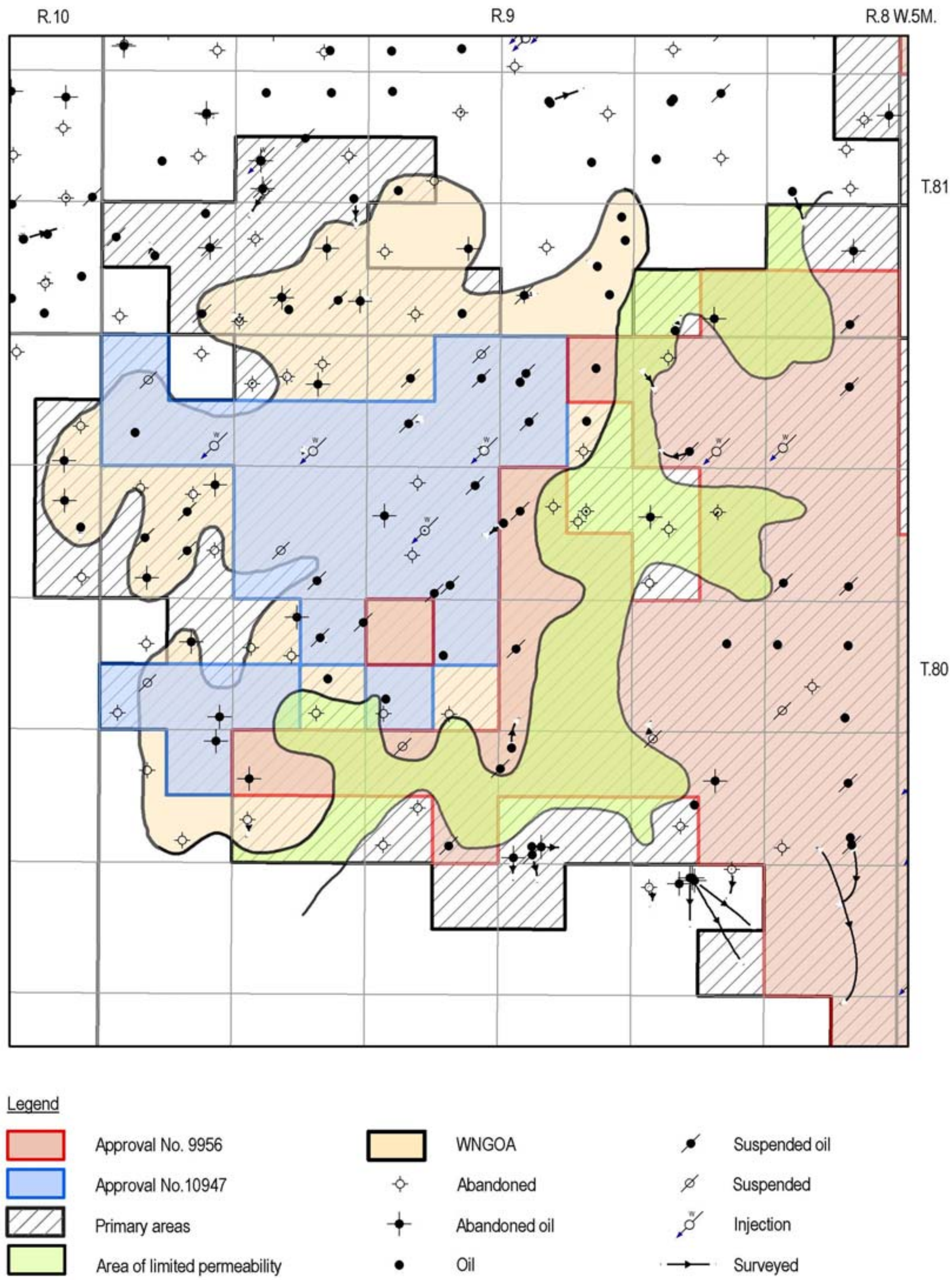

Figure 2. West Nipisi Area and permeability barrier boundaries