

RESEARCH ARTICLE

Application of the Saturation Water Gradient (SWGRAD) Method to Well-Log Analysis for Gas-Bearing Zone Identification and Perforation Interval Recommendation in the Poseidon Field, Browse Basin, Western Australia

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Abstract

Accurate identification of gas-bearing intervals in heterogeneous sandstone reservoirs remains challenging when formation-water salinity is poorly constrained. This study evaluates the applicability of the Saturation Water Gradient (SWGRAD) method for identifying potential gas-bearing intervals in the Plover Formation of the Poseidon Field, Browse Basin, Western Australia. Well-log, mudlog, well-report, and available DST/MDT data from five wells, namely Torosa-1, Kronos-1, Boreas-1, Poseidon-1, and Poseidon-2, were analyzed. Gamma Ray, neutron-density porosity, and resistivity logs were integrated to characterize reservoir intervals prior to SWGRAD analysis. Water saturation was calculated using Archie's equation for formation-water salinities ranging from 1 to 25 kppm, and SWGRAD was determined from the slope of the least-squares linear regression between water saturation and salinity at each depth sample. The resulting SWGRAD profiles were interpreted using well-specific cutoff criteria and evaluated against available DST/MDT and production-test evidence. The results indicate that well-specific SWGRAD cutoffs ranging from ≤ 0.00002 to ≤ 0.000045 provide a more appropriate discrimination criterion than a universal threshold. Independent validation is strongest in Boreas-1, where SWGRAD intervals overlap approximately 61 m of the 70 m DST interval, corresponding to approximately 87.1% agreement, and in Kronos-1, where the interpreted intervals correspond to reported gas-show and production-test evidence. In Poseidon-2, the identified low-SWGRAD intervals are considered prospective rather than independently validated because the available DST results were inconclusive. For Poseidon-1, where direct well-test evidence is unavailable, the ≤ 0.00002 criterion was adopted as a working cutoff based on comparison with Boreas-1 and was used to identify prospective intervals and recommend perforation targets. The results demonstrate that SWGRAD can provide a quantitative supporting indicator for gas-zone screening under uncertain formation-water salinity, but its interpretation requires well-specific calibration and integration with conventional petrophysical, geological, and independent well-test information.

Keywords: SWGRAD; water saturation; formation-water salinity; gas reservoir; Plover Formation; Browse Basin; well-log analysis.

1. Introduction

Accurate evaluation of reservoir properties and fluid distribution is important in hydrocarbon exploration and production. Variations in lithology, pore structure and fluid characteristics may complicate well log interpretation in heterogeneous clastic reservoirs. Water saturation (S_w) is one of the most important petrophysical properties and is important, particularly since it is often utilized in the estimation of hydrocarbon saturation and in the differentiation between hydrocarbon-bearing zones and water-bearing formations (Archie, 1942; Pickett, 1966; Asquith and Krygowski, 2004; Tiab and Donaldson, 2004; Castillo Vincentelli and Caceres Contreras, 2016). However, the S_w estimation is highly reliant on the accuracy of formation water resistivity (R_w), porosity, formation resistivity and Archie variables. Then uncertainty in any one of these characteristics may propagate directly into the understanding of the distribution of reservoir fluids.

The Browse Basin, offshore northern Australia, is one of the major hydrocarbon bearing basins of the North West Shelf with considerable gas and condensate potential (Stephenson and Cadman, 1994; Symonds et al., 1994; Blevin et al., 1998a; Rollet et al., 2018). Its geologic history is characterized by alternating phases of Paleozoic sedimentation, Triassic–Jurassic extension and subsidence, and Jurassic continental

separation and subsequent passive-margin development (Stephenson and Cadman, 1994; Symonds et al., 1994; Struckmeyer et al., 1998). The basin has many important structural and depositional elements including the Caswell and Barcoo sub-basins, Scott Reef Trend and the Yampi Shelf. The Caswell Sub-basin is of unique importance as it contains several huge gas and condensate accumulations and is a critical component of the Browse Basin's petroleum system (Blevin et al., 1998a; Rollet et al., 2018).

The Plover Formation is a major Jurassic reservoir formation in the Browse Basin. This is an Early-Middle Jurassic succession accumulated in a fluvial to deltaic environment heavily affected by tidal processes (Tovaglieri & George, 2014). The thorough facies analysis showed channel-fill complexes, interchannel deposits, heterolithic mouthbars, sandflats, sandy mouthbars and offshore-transition deposits, pointing to a high degree of vertical and lateral heterogeneity in the reservoir architecture (Tovaglieri and George, 2014). Such depositional heterogeneity may result in significant variations in sandstone distribution, shale composition, pore connectivity, permeability and reservoir continuity.

The variability of the Plover Formation is a challenge for petrophysical interpretation. Sand-rich channel and mouthbar

deposits may be rather good in terms of pore connectivity whereas shale-rich and heterolithic intervals can reduce the effective pore volume and permeability and can act as vertical or lateral flow barriers. The thickness and distribution of sandstone may also be affected by other variables such as syn-depositional structural activity (Tovaglieri and George, 2014; Struckmeyer et al. 1998). Recent integrated petrophysical investigations of the Poseidon area have highlighted the substantial variation of reservoir quality and fluid distribution in the Plover Formation (Pardede et al., 2025; Yahia et al., 2025).

The fundamental relationship between formation resistivity, porosity, formation water resistivity and water saturation for reasonably clean formations is described by Archie's equation (Archie, 1942). However, the accuracy of S_w estimations obtained from Archie is strongly dependent on the right choice of R_w and the empirical parameters a , m and n (Pickett, 1966; Asquith and Krygowski, 2004). As demonstrated in previous studies, the variation of these parameters can significantly impact the computed water saturation, especially in the absence of representative core data or formation water samples (Kamel and Mabrouk, 2002; Castillo Vincentelli and Caceres Contreras, 2016; Jumaah, 2021). The sensitivity of S_w to Archie parameters is related to rock texture, pore structure, lithofacies, and wettability which means that the values derived in one reservoir environment should not be considered as universal (Jumaah, 2021).

The interpretation becomes more complicated in heterogeneous or shaly sandstone reservoirs. Clay minerals can contribute additional electrical conductivity to the formation, causing measured resistivity to differ from that predicted by the clean-sand Archie relationship. Waxman and Smits (1968) demonstrated the importance of shale-related electrical conductivity and cation-exchange effects in shaly sands, while Waxman and Thomas (1974) further examined the relationship between hydrocarbon saturation, resistivity index, and temperature. Alternative models, including the Simandoux and Indonesian approaches, have consequently been developed to account for shale effects in saturation calculations (Simandoux, 1963; Poupon and Leveaux, 1971; Peeters and Holmes, 2014). These studies demonstrate that low resistivity cannot always be interpreted as direct evidence of high water saturation.

This issue is particularly relevant to northwest Australian reservoirs. Johanna and Kusumah (2023) demonstrated that clay distribution in shaly sandstone reservoirs of the Vulcan Sub-basin can reduce measured resistivity and significantly influence calculated shale volume, porosity, water saturation, net-to-gross, and net-pay estimates. Similar concerns have been highlighted in low-resistivity reservoirs where conventional resistivity-based saturation estimates may disagree with independent formation or production evidence (Awolayo et al., 2017). Consequently, resistivity-derived fluid interpretation should be integrated with lithological, porosity, and independent formation-test information.

Formation-water salinity represents another major source of uncertainty. Salinity directly controls the electrical conductivity of formation water and therefore its resistivity, R_w . Increasing salinity generally increases water conductivity and decreases R_w , whereas lower salinity produces higher R_w (Asquith and Krygowski, 2004). Because R_w is explicitly incorporated into Archie's equation, uncertainty in formation-water salinity is transferred directly to calculated S_w . The importance of R_w uncertainty has long been recognized in conventional saturation interpretation (Pickett, 1966; Kamel and Mabrouk, 2002; Castillo Vincentelli and Caceres Contreras, 2016).

Formation-water properties may also vary spatially and temporally. Fluid-inclusion studies in the Caswell Sub-basin

provide evidence of multiple stages of formation-fluid evolution and hydrocarbon charging, suggesting that formation fluids did not necessarily remain chemically uniform throughout geological time (Brincat et al., 2004; Bourdet et al., 2019). Such fluid evolution provides a geological basis for considering uncertainty in formation-water salinity when interpreting resistivity-based saturation.

Several approaches have therefore been developed to improve fluid interpretation under uncertain or complex reservoir conditions. Conventional approaches generally require a representative R_w and calibrated petrophysical parameters, whereas shaly-sand models attempt to account explicitly for conductive clay effects (Simandoux, 1963; Waxman and Smits, 1968; Poupon and Leveaux, 1971; Peeters and Holmes, 2014). Other studies have emphasized the integration of multiple petrophysical indicators and independent formation information to reduce uncertainty in fluid identification (Awolayo et al., 2017; Ogbamikhumi and Ighodalo, 2021).

An alternative approach was introduced by Anwar and Hidayat (2018) through the Saturation Water Gradient (SWGRAD) method. Rather than relying on a single assumed formation-water salinity, SWGRAD evaluates the sensitivity of calculated S_w to systematic changes in formation-water salinity. The method therefore provides a diagnostic parameter describing how strongly the calculated water saturation responds to uncertainty in formation-water conditions (Anwar and Hidayat, 2018).

The conceptual advantage of SWGRAD is that it does not depend exclusively on the absolute value of S_w obtained at one selected R_w . Instead, it examines the behavior of S_w over a range of assumed salinity values. This approach is potentially useful where formation-water salinity is poorly constrained. However, the SWGRAD response may also be affected by porosity, lithology, shale content, Archie parameters, and resistivity. Therefore, SWGRAD should be regarded as a complementary diagnostic parameter rather than a replacement for conventional petrophysical analysis.

Although SWGRAD provides a useful framework for evaluating salinity-related uncertainty, its application remains limited compared with conventional water-saturation methods. In particular, the behavior and diagnostic value of SWGRAD in heterogeneous gas-bearing sandstone reservoirs with uncertain formation-water salinity have not been sufficiently evaluated. The original development of SWGRAD provides the methodological basis, but its interpretation criteria may depend on reservoir-specific characteristics such as lithological heterogeneity, porosity distribution, pore structure, and the investigated salinity range.

The Poseidon Field provides an appropriate setting to investigate this issue because its Plover Formation reservoir intervals exhibit substantial petrophysical heterogeneity and contain gas-bearing intervals that can be evaluated against available well-test information. Previous geological studies have established the importance of the Plover Formation as a Jurassic reservoir in the Browse Basin and documented its complex depositional architecture (Tovaglieri and George, 2014; Rollet et al., 2018). More recent petrophysical studies have also demonstrated substantial variability in reservoir properties in the Poseidon area (Pardede et al., 2025; Yahia et al., 2025).

Hence, the research requirement addressed in this study is not the development of a new SWGRAD equation, but the evaluation and refinement of the current reservoir-specific interpretation under different situations. Specifically, this study aims to determine whether SWGRAD can provide a consistent diagnostic response for gas-bearing intervals in the Plover Formation in the presence of uncertainty in formation-water salinity, whether meaningful SWGRAD cutoffs can be developed for individual wells rather than a universal

threshold, and whether integration with conventional petrophysical parameters and independent DST/MDT evidence may improve the reliability of gas-zone identification.

The aim of this study is thus to evaluate the viability of the SWGRAD approach to identify gas-bearing intervals from well-log data in the Plover Formation of the Poseidon Field, Browse Basin, under uncertain formation-water salinity conditions. The approach utilizes Gamma Ray derived shale volume, neutron-density porosity, Archie determined water saturation in a broad range of salinity, SWGRAD analysis and well-test data if available. The key contribution is the well-specific SWGRAD interpretative paradigm with empirically constrained cutoff values from existing DST/MDT evidence, supported by adjacent wells in the absence of direct test data.

2. Literature Review

2.1. Geology of Browse Basin

The Browse Basin is a major sedimentary basin located offshore northwestern Australia and forms part of the hydrocarbon-prospective North West Shelf. The basin developed through a prolonged tectonostratigraphic history involving Paleozoic sedimentation, Triassic back-rift subsidence, Jurassic continental breakup, and subsequent Cretaceous–Cenozoic passive-margin sedimentation (Stephenson and Cadman, 1994; Symonds et al., 1994; Struckmeyer et al., 1998). Regional geological investigations have established a complex structural framework involving several depocentres and structural highs that influenced sediment distribution and petroleum accumulation (Willis, 1988; Blevin et al., 1998a; Rollet et al., 2018).

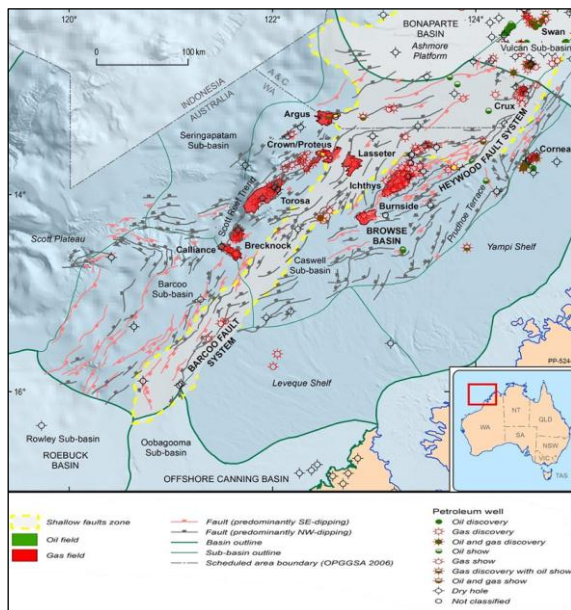


Fig. 1. Structural framework of the Browse Basin and locations of indicated hydrocarbon accumulations (Palu et al., 2017).

The Browse Basin contains several petroleum systems and is strongly gas-prone. Organic-geochemical investigations have demonstrated the presence of source rocks capable of generating hydrocarbons within the basin, while regional petroleum-system studies have established the importance of Jurassic and Lower Cretaceous successions to hydrocarbon generation and accumulation (Boreham et al., 1997; Blevin et al., 1998a, 1998b). The structural evolution of the basin also influenced reservoir distribution, trap development, and migration pathways (Struckmeyer et al., 1998).

During the Early–Middle Jurassic, extensional tectonism and associated accommodation-space development facilitated the deposition of fluvial and deltaic systems represented in part by the Plover Formation. The interaction between tectonic subsidence, sediment supply, relative sea-level changes, and basin configuration produced substantial variability in depositional architecture (Stephenson and Cadman, 1994; Tovaglieri and George, 2014).

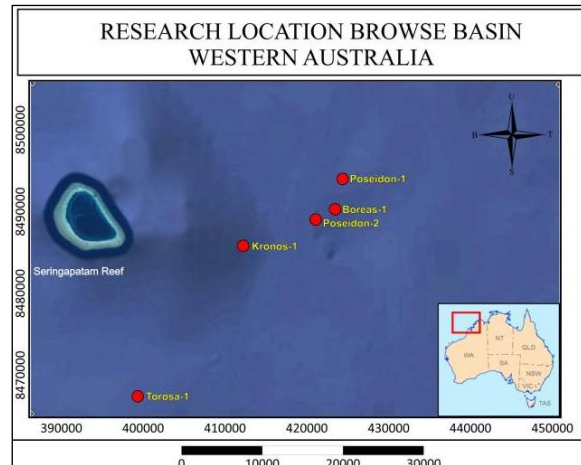


Fig. 2. Study area and locations of the investigated wells. Red dots indicate the wells used in this study (Google Earth, accessed November 23, 2025)

The Caswell Sub-basin is particularly relevant because it contains major gas and condensate accumulations and provides evidence for complex hydrocarbon and formation-fluid histories. Fluid-inclusion investigations have demonstrated the presence of multiple fluid stages associated with hydrocarbon charge and formation-water evolution (Brincat et al., 2004; Bourdet et al., 2019). Such evidence is relevant to the present study because changes in formation-fluid composition and salinity can influence R_w and consequently resistivity-based water-saturation calculations.

2.2. Plover Formation as the Target Reservoir

The Plover Formation is an Early to Middle Jurassic reservoir succession deposited by fluvial, deltaic and tidally affected processes. Sedimentological studies of the Calliance area revealed a range of facies associations including tidal channel fills, interchannel deposits, heterolithic mouthbars and sandflats, sandy mouthbars and offshore transition deposits (Tovaglieri and George, 2014). The resultant architecture is a series of sandstone bodies interbedded with heterolithic and shale-rich periods.

This depositional architecture controls the geometry and connectivity of the sandstone and reservoir quality from a reservoir viewpoint. Deposits of the channel and mouth bar may have very excellent reservoir properties but shaly and heterolithic intervals may represent permeability barriers or baffles. Hence, the vertical stacking of these facies directly influences fluid distribution and pressure communication between reservoir compartments.

The Plover Formation is quite diversified and this affects the interpretation of the well logs. The variations in the pore structure impact the porosity and the electrical responsiveness of the formation. Gamma ray, density, neutron and resistivity responses are affected by differences in shale composition. Therefore the low resistivity cannot be explained by water saturation alone. The distribution of clay may provide additional electrical conductivity and considerably impact the water saturation estimation as shown by the studies on shaly-sands (Waxman and Smits, 1968; Waxman and Thomas,

1974; Poupon and Leveaux, 1971; Johanna and Kusumah, 2023).

Hence, the identification of potential reservoir intervals is a crucial preparation for the present study. SWGRAD is calculated within perceived reservoir intervals, not blindly throughout the complete well. Prior to SWGRAD interpretation, the framework of the reservoir is constructed utilizing Gamma Ray, porosity, resistivity and supporting geological information.

2.2. Petroleum System and Hydrocarbon Distribution

The Browse Basin petroleum system developed through the interaction of source rocks, reservoirs, seals, structural elements, and migration pathways. Regional studies indicate that Jurassic and Lower Cretaceous source rocks contributed to hydrocarbon generation, with the Plover Formation representing one of the important Jurassic reservoir units (Boreham et al., 1997; Blevin et al., 1998a, 1998b; Rollet et al., 2018).

For this study, the petroleum-system framework is relevant primarily because it provides the geological context for gas occurrence within the Plover Formation. Hydrocarbon generation, migration, charge, trapping, and reservoir compartmentalization can result in different fluid saturations between individual reservoir intervals.

Fluid-inclusion studies provide additional evidence that hydrocarbon charging and formation-fluid evolution occurred through multiple stages. Brincat et al. (2004) and Bourdet et al. (2019) demonstrated that fluid inclusions can preserve evidence of palaeoformation-water conditions and hydrocarbon-related fluid evolution in the Browse Basin. These observations indicate that formation-water properties may have changed during reservoir evolution.

This fluid history provides a geological basis for considering formation-water salinity as an uncertain parameter rather than assuming a single immutable value throughout the reservoir.

2.3. Formation-Water Salinity and Its Effect on Water Saturation

Formation water salinity is an important parameter in resistivity-based petrophysical interpretation because it dictates the electrical conductivity of the aqueous phase in pore space. Generally, an increase in salinity causes the formation water resistivity, R_w , to rise and the resistivity to decrease. The uncertainty in formation-water salinity is thus directly propagated to the R_w uncertainty and eventually to the projected S_w (Asquith and Krygowski, 2004).

For a clean reservoir, Archie (1942) established the fundamental relationship:

$$S_w = \left(\frac{a \times R_w}{R_t \times \Phi^m} \right)^{\frac{1}{n}} \quad (1)$$

where S_w is water saturation, R_w is formation-water resistivity, R_t is true formation resistivity, Φ is porosity, and a , m , and n represent the tortuosity factor, cementation exponent, and saturation exponent, respectively.

The equation demonstrates directly why uncertainty in R_w is important. If R_w is underestimated or overestimated, the resulting S_w will also be systematically affected. Pickett (1966) emphasized that conventional saturation calculations are susceptible to uncertainties in water resistivity, true resistivity, porosity, and cementation factor. Similar concerns have been discussed in subsequent studies of water-saturation estimation (Kamel and Mabrouk, 2002; Castillo Vincentelli and Caceres Contreras, 2016).

The influence of Archie parameters is also significant. The cementation and saturation exponents are related to pore structure, lithofacies, and wettability, and therefore may vary

between reservoir types and geological settings (Jumaah, 2021). Consequently, the use of representative default parameters should be treated as an approximation when direct core-derived parameters are unavailable.

The problem becomes more significant when formation-water salinity is spatially variable. Fluid mixing, water-rock interaction, hydrocarbon charging, and compartmentalization may produce different formation-fluid conditions between reservoir intervals. Evidence of changing fluid conditions in the Browse Basin further supports the need to consider formation-water uncertainty (Brincat et al., 2004; Bourdet et al., 2019).

2.4. Limitations of Conventional Water-Saturation Interpretation

Conventional Archie interpretation is most appropriate for relatively clean formations. In formations containing significant shale, clay minerals can provide additional conductive pathways and cause the formation resistivity to deviate from the clean-sand Archie relationship (Waxman and Smits, 1968; Waxman and Thomas, 1974).

Thus several saturation models have been developed for shaly-sands. Simandoux (1963) developed a method for evaluation of saturation of shaly formations. Poupon and Leveaux (1971) derived the Indonesian equation for shaly formations. Later studies have compared Archie, Simandoux, Indonesian, dual-water and Waxman–Smits approaches and shown that different assumptions on shale conductivity and clay distribution may lead to different water-saturation calculations (Peeters and Holmes, 2014).

These restrictions apply to the Plover Formation as sandstone interbeds with shale and siltstone. Hence a low-resistivity zone may be a water-bearing rock, a hydrocarbon-bearing rock affected by shale conductivity, or a combination of lithological and hydrodynamic variables.

Johanna and Kusumah (2023) highlighted this problem in the Vulcan Sub-basin, where the effects of laminated and dispersed shale were influential to the usual petrophysical calculations. Awolayo et al (2017) noted that low resistivity pay may show an apparent high water saturation in the presence of independent evidence of hydrocarbon.

The present study does not introduce a dedicated shaly-sand saturation model. Instead, Archie's equation is retained as the basis for calculating S_w , while shale volume and conventional log responses are used to constrain reservoir interpretation. SWGRAD is then applied as a sensitivity-based diagnostic parameter to evaluate how strongly the Archie-derived S_w responds to uncertainty in formation-water salinity.

2.5. Saturation Water Gradient (SWGRAD)

The Saturation Water Gradient (SWGRAD) method was introduced by Anwar and Hidayat (2018) as an approach for hydrocarbon identification under uncertainty in formation-water salinity. Rather than evaluating S_w at a single selected salinity, SWGRAD evaluates how calculated S_w changes as formation-water salinity is systematically varied. The method can be expressed as:

$$SWGRAD = \frac{\Delta S_w}{\Delta sal} = \frac{(S_{w2} - S_{w1})}{(sal_2 - sal_1)} \quad (2)$$

where sal represents formation-water salinity.

The principal advantage of SWGRAD is therefore that it provides a quantitative measure of the sensitivity of water-saturation interpretation to formation-water salinity. The original method proposed that hydrocarbon-bearing and water-bearing intervals may exhibit different sensitivities to changes in assumed salinity (Anwar and Hidayat, 2018).

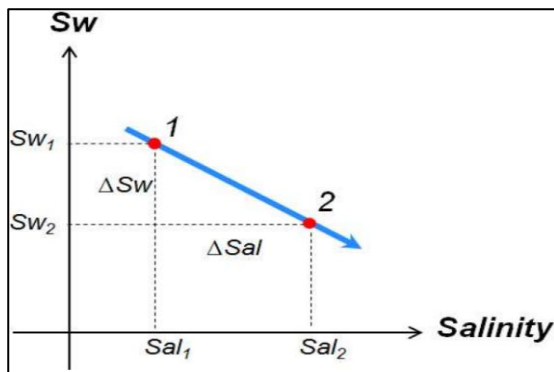


Fig. 3. Sw vs Sal Gradient (Anwar and Hidayat, 2018)

However, SWGRAD should not be interpreted as an independent replacement for conventional petrophysical analysis. The calculated gradient depends on the underlying Sw equation and is therefore influenced by porosity, resistivity, Archie parameters, and lithology. In heterogeneous reservoirs, these factors may produce variations in SWGRAD even when fluid saturation is similar.

For this reason, the present study treats SWGRAD as a diagnostic parameter complementary to Gamma Ray, porosity, resistivity, and independent formation-test information.

2.6. Application of SWGRAD to the Poseidon Field

The Poseidon Field provides a suitable geological setting for testing the effectiveness of SWGRAD, since the Plover Formation reservoir intervals are characterized by high lithological and petrophysical variability. Recent works (Pardede et al., 2025; Yahia et al., 2025) indicated that the Plover Formation has different reservoir quality, porosity, permeability, shale distribution, and water saturation.

The current research considers three primary uncertainties of SWGRAD application.

The Plover Formation is heterogeneous, with variations in sandstone and shale distribution that might affect porosity, pore connectivity and electrical reactivity.

Secondly, a single set quantity may not be reflective of formation water salinity. The complex fluid evolution in the Browse Basin shows that the formation-fluid properties vary regionally and temporally (Brincat et al., 2004; Bourdet et al., 2019).

Third, the target intervals include gas accumulations and it is necessary to distinguish between the hydrocarbon-induced resistivity responses and the resistivity changes caused by formation-water characteristics.

Thus, the approach allows the analysis of the Sw in the salinity range 1–25 kppm. The Sw values acquired are then used to generate SWGRAD for each depth sample. Intervals

with relatively low magnitudes of SWGRAD are interpreted as potential hydrocarbon-bearing intervals. Larger values are believed to be more consistent with water-dominated behavior.

The DST/MDT and production test data provide independent evidence to assess the interpretation. This is important since SWGRAD should be validated against direct or semi-direct fluid data, and not merely validated by correspondence with other log-derived metrics.

2.7. Research Gap and Conceptual Framework

Previous studies have established the geological complexity of the Browse Basin and the importance of the Plover Formation as a Jurassic reservoir (Stephenson and Cadman, 1994; Blevin et al., 1998a; Struckmeyer et al., 1998; Rollet et al., 2018). Sedimentological studies have documented the heterogeneous depositional architecture of the Plover Formation (Tovaglieri and George, 2014), while fluid-inclusion studies have demonstrated complex formation-fluid and hydrocarbon histories (Brincat et al., 2004; Bourdet et al., 2019).

Petrophysical studies have further shown that shale distribution and low-resistivity effects can influence saturation interpretation in northwest Australian reservoirs (Johanna and Kusumah, 2023). Conventional saturation studies have also demonstrated the importance of Rw, Archie parameters, and independent validation (Pickett, 1966; Kamel and Mabrouk, 2002; Awolayo et al., 2017).

Nevertheless, existing studies do not directly establish whether SWGRAD can reliably distinguish gas-bearing and water-bearing intervals within the heterogeneous Plover Formation of the Poseidon Field. The present study therefore evaluates the applicability and diagnostic consistency of an existing SWGRAD approach under a specific geological setting characterized by heterogeneous Jurassic reservoir architecture and uncertain formation-water salinity.

The scientific contribution is consequently not the development of a new mathematical SWGRAD formulation. Instead, the contribution lies in evaluating the applicability of SWGRAD and establishing a reservoir-specific interpretation framework in which cutoff values are calibrated using independent well-test evidence and supported by geological and petrophysical characteristics.

3. Method

The study was conducted using well-log, mudlog, and well-report data from five wells: Torosa-1, Kronos-1, Boreas-1, Poseidon-1, and Poseidon-2. The wells are located within the Browse Basin and penetrate the Plover Formation and associated stratigraphic intervals. The data were obtained from the publicly available Tera Nubis database and associated well documentation

Table 1. Summary of well-log and well-test data used in this study.

Well	Depth	GR	Caliper	Resist	NPHI	RHOB	DT	Well test
Torosa 1	4683 m	v	v	v	v	v	v	v
Kronos 1	5322 m	v	v	v	v	v	v	v
Boreas 1	5205.5 m	v	v	v	v	v	v	v
Poseidon 1	5115.5 m	v	v	v	v	v	v	
Poseidon 2	5351 m	v	v	v	v	v	v	v

The available well-log data consisted of Gamma Ray (GR), caliper, resistivity, neutron porosity (NPHI), bulk density (RHOB), and sonic (DT) logs. Mudlog and well-report data were used to support lithological interpretation, formation identification, and fluid-zone validation. Available DST/MDT and production-test information was used as independent evidence for evaluating the SWGRAD interpretation.

Prior to petrophysical calculations, the logs were checked for data completeness, depth consistency, anomalous values, and null values. Invalid values were omitted from the computation. The caliper log was utilized to identify intervals likely to be influenced by borehole expansion, especially when analyzing density and neutron responses. The resistivity input is the actual formation resistivity (Rt) available.

The well-log interpretation is based on recognized concepts of formation appraisal and reservoir characterisation

(Dewan, 1983; Glover, 2000; Asquith and Krygowski, 2004). Integration of numerous logs was favored over interpretation based on a single log response because Gamma Ray, resistivity, density, neutron and acoustic responses give complimentary information on lithology, porosity and fluid effects.

3.1. Shale Volume Estimation

Shale volume (V_{sh}) was estimated from the Gamma Ray log. The Gamma Ray Index was calculated as:

$$I_{GR} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \quad (3)$$

and shale volume was determined using:

$$V_{sh} = I_{GR} \quad (4)$$

where GR is the measured Gamma Ray response, GR_{min} represents the clean-sandstone end member, and GR_{max} represents the shale end member.

This linear Gamma Ray approach provides a conventional first-order estimate of shale volume (Dewan, 1983; Glover, 2000; Asquith and Krygowski, 2004). The selected end-member values for each well are presented in Table 3.

The resulting V_{sh} values were primarily used to characterize lithological heterogeneity and constrain the interpretation of reservoir intervals. Because shale may influence resistivity, the V_{sh} response was also considered when evaluating anomalously low-resistivity intervals.

3.2. Porosity Estimation

Porosity was estimated from the neutron–density combination. Density-derived porosity was calculated using the bulk-density log and the assumed matrix and fluid densities, while neutron porosity was obtained from the NPHI log. The neutron–density combination is widely used in well-log interpretation because the two measurements respond differently to lithology and pore-fluid effects (Dewan, 1983; Glover, 2000; Asquith and Krygowski, 2004). The sonic log was retained for additional reservoir characterization and consistency checking but was not used as the primary porosity input.

The resulting porosity represents total formation porosity ($PHIT$) and was used as the porosity input in the Archie calculation.

3.3. Water Saturation Calculation

Water saturation was calculated using Archie's equation (eq.1). Archie's relation is still a major saturation model for clean formations (Archie, 1942). However, the uncertainties on R_w , a , m and n may propagate significantly on the anticipated saturation (Pickett, 1966; Castillo Vincentelli and Caceres Contreras, 2016; Jumaah, 2021).

The value of $a = 1$ was used throughout the whole investigation. Well reports were used for m and n values when accessible from core derived. If this information is not provided, the default representative values of $m = 2$ and $n = 2$ are utilized. Parameters of each well are shown in Table 2.

Table 2. Water saturation calculation parameters

Well	Formation	a	m	n
Torosa -1	Plover Reservoir	1	1.92	2
Kronos-1	Plover Reservoir	1	1.92	1.8
Boreas-1	Plover Reservoir	1	1.82	1.7
Poseidon-1	Plover Reservoir	1	2	2
	Nome	1	2	2
	Montara	1	2	2
Poseidon-2	Plover volcan	1	2	2
	Plover Reservoir	1	1.92	1.8

3.4. Formation-Water Salinity and R_w Calculation

Since it was not possible to evenly restrict formation water salinity throughout all periods, Sw was iteratively estimated assuming salinities from 1 to 25 kppm NaCl equivalent. The range chosen was to be reflective of situations below and above the salinity characteristic of the area.

The resistivity of formation water (R_w) corresponding to each salinity was estimated as a function of the salinity using the following salinity–resistivity relationship:

$$R_w = \left(0.0123 + \frac{3647.5}{Sal^{0.955}} \right) \times \left(\frac{T_s + 6.77}{T_{res} + 6.77} \right) \quad (5)$$

Then, consistently, the adjustment according to the formation temperature estimate acquired in the precalculation step was performed.

The obtained R_w values were then introduced into Archie's equation while keeping other petrophysical constants fixed. Thus, for each depth sample, a series of Sw values were associated for the salinity range studied.

The uncertainty of formation water salinity is transformed by this approach to a detectable change of the estimated water saturation, which is the foundation of the SWGRAD analysis.

3.5. SWGRAD Calculation

The sensitivity of water saturation to formation-water salinity was quantified using the SWGRAD method proposed by Anwar and Hidayat (2018). For each depth sample, the calculated Sw values were evaluated against their corresponding formation-water salinity values using least-squares linear regression (Eq. 2).

The regression was performed independently for each depth sample, with salinity as the independent variable and Sw as the dependent variable. An intercept was included in the regression so that the slope represented the local rate of change in Sw with respect to formation-water salinity. Figure 3 illustrates the Sw –salinity relationships at 4949.5 m in the gas zone and 5020 m in the water zone of the Boreas-1 well.

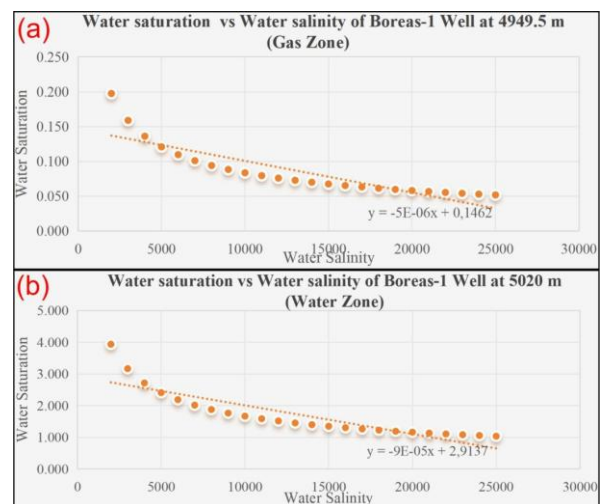


Fig. 3. Relationship between water saturation (Sw) and formation-water salinity at (a) 4949.5 m in the gas zone and (b) 5020 m in the water zone of the Boreas-1 well.

3.6. SWGRAD Cutoff Determination

The SWGRAD profiles were interpreted together with Sw , V_{sh} , porosity, resistivity, and available well-test information.

The sign of SWGRAD was not used as the sole discrimination criterion. Because the mathematical relationship between salinity, R_w , and Archie-derived Sw can produce negative or positive gradients depending on the formulation and parameterization, the magnitude and relative

contrast of SWGRAD were considered more important than its sign.

Intervals with relatively low SWGRAD magnitude were evaluated as potential hydrocarbon-bearing intervals, whereas higher values were considered more consistent with water-dominated behavior.

Cutoff values were calibrated separately for each well using available DST, MDT, production, or perforation information. This approach avoids assuming that a single numerical threshold is universally applicable to all wells.

For wells without direct formation-test information, the interpretation was supported by comparison with neighboring wells having similar geological and petrophysical characteristics. Such cutoffs are explicitly treated as working criteria rather than independent validation.

3.7. Integrated Interpretation

Finally, the interpreted intervals were evaluated by integrating SWGRAD with conventional petrophysical parameters and independent well-test information.

For wells with DST/MDT or production-test evidence, the spatial correspondence between low-SWGRAD intervals and tested fluid zones was used to evaluate the diagnostic performance of the method. For wells without direct confirmation, the interpretation was constrained using reservoir quality, lithological continuity, neighboring wells, and regional geological context.

This integrated workflow was used to identify potential gas-bearing intervals and, for Poseidon-1, to establish potential perforation targets.

4. Results and Discussion

4.1. Petrophysical Characteristics

The petrophysical evaluation indicates that the investigated reservoir intervals are characterized by considerable lithological and reservoir-quality heterogeneity. The shale volume (V_{sh}) within the Plover Formation ranges from approximately 27% to 54%, while the broader investigated stratigraphic intervals show values of up to 78%.

The highest-quality reservoir characteristics are observed in Boreas-1, which has a relatively low V_{sh} of approximately 29 % and the highest $PHIT$ and $PHIE$ values of approximately 15% and 9%, respectively. In contrast, Kronos-1 exhibits a relatively high V_{sh} of approximately 54% and low $PHIE$ of approximately 2%.

Across the investigated wells, $PHIT$ ranges from approximately 6% to 15%, whereas $PHIE$ ranges from approximately 2% to 9%. These variations indicate that the Plover Formation is a heterogeneous shaly-sand reservoir in which lithological variability, shale content, and pore characteristics influence reservoir quality. Such heterogeneity is important in interpreting SWGRAD because the calculated water saturation depends on porosity, formation resistivity, formation-water resistivity, and Archie parameters.

4.2. SWGRAD Analysis and Well-Test Comparison

SWGRAD was calculated by varying formation-water salinity from 1 to 25 kppm NaCl equivalent. For each depth sample, 25 corresponding S_w values were generated from the salinity-dependent R_w calculation and Archie's equation. The S_w -salinity relationship was then evaluated using least-squares linear regression with an intercept:

The regression was performed independently at each depth sample. Invalid or anomalous input values were excluded prior to calculation. Because increasing salinity generally produces decreasing R_w and consequently decreasing Archie-derived S_w , both gas-bearing and non-gas-bearing intervals may exhibit negative SWGRAD values. Therefore, the gradient direction was not used as the principal discriminator. Instead, the magnitude of SWGRAD and its contrast between independently constrained gas and non-gas intervals were used to establish the interpretation criterion.

The overall SWGRAD results and corresponding well-test evidence are summarized in Table 3. The cutoff values vary between wells, ranging from ≤ 0.00002 to ≤ 0.000045 . This variation indicates that a single universal SWGRAD threshold is not appropriate for the heterogeneous reservoir system investigated in this study.

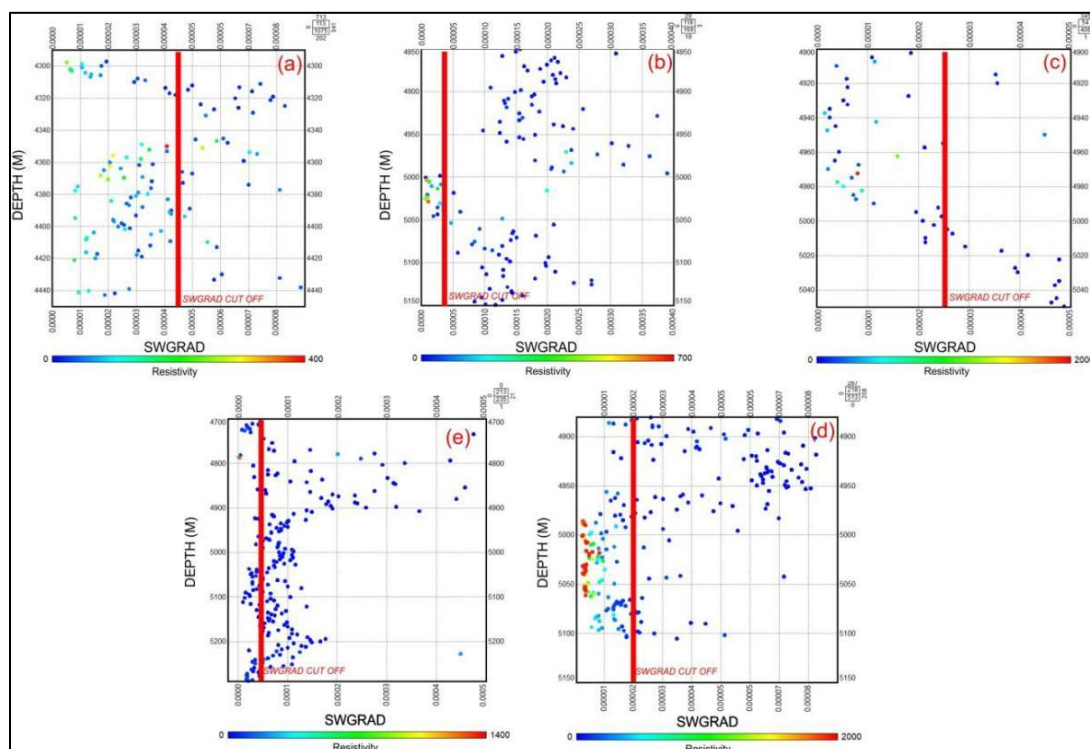


Fig 4. Depth versus SWGRAD plots for each study well: (a) Torosa-1, (b) Kronos-1, (c) Boreas-1, (d) Poseidon-2, and (e) Poseidon-1. The area to the left of the cutoff line (red) represents the gas zone.

Table 3 shows that smaller magnitudes of SWGRAD often correlate with periods where there is evidence of gas, especially in Torosa-1, Kronos-1 and Boreas-1. But the level of independent confirmation is different well to well. The interpretation in Poseidon-2 remains speculative since the available DST did not give clear flow evidence, whereas Poseidon-1 had no direct well-test data and hence depends on an analogue-based threshold.

The result of the Kronos-1 directly supports the correlation between the specified cut-off and the gas evidence. The criteria of ≤ 0.00004 indicates periods at 4999–5014.5 m and 5018–5031 m, which match to the stated gas-show and production-test intervals. The depth correspondence is shown in Table 3 as a clear foundation for judging the cutoff, not just as a claim that the conclusion is validated by production testing.

The Boreas-1 finding is the most robust quantitative comparison of SWGRAD with well test data from independent sources. The DST interval is 4904 to 4974 m, however the SWGRAD interpretation is 4907–4919 m and 4925–4990.5. In all, the SWGRAD intervals overlap with the DST period for roughly 61 m of the 70 m DST interval, which is approximately 87.1% agreement. The bottom limit of the SWGRAD interpretation is at roughly 4990.5 m, which is approx. 1.5 m lower than the stated GWC at approx. 4992 m MDRT. This change is modest compared to the thickness of the interpreted interval and is unlikely to alter the identification of the major gas-bearing zone in any significant manner. However, the discrepancy should be seen as a measurement and interpretation uncertainty rather than a perfect agreement as SWGRAD is calculated from the continuous wireline-log responses while the GWC is confined by formation-test information.

The data from Poseidon-2 need to be interpreted more cautiously. Several intervals met the requirement of ≤ 0.000045 , however definitive flow evidence was not obtained by the DST due to borehole washout, weak cement-bond conditions, and restricted reservoir deliverability. Therefore, these intervals are considered as possible gas bearing intervals and not confirmed gas bearing zones. The lack of quantifiable flow does not mean that there is no gas, but the given test results are not enough to independently corroborate the SWGRAD conclusion.

For Poseidon-1, we carried over the ≤ 0.00002 limit from Boreas-1, as there is no direct well-test information. Boreas-1 was chosen as the reference well because to its geographical closeness (~3.7 km), its penetration of the same major Plover reservoir system, and the availability of independent gas evidence that may be utilized to restrict the SWGRAD response. However, variations in lithology, porosity,

formation-water characteristics, and resistivity response may impact the amplitude of SWGRAD. Thus, the ≤ 0.00002 threshold is a working criteria for future interpretation, not a directly proven cut-off.

4.3. Cross-Well Interpretation

The cross-well comparison demonstrates that SWGRAD is sensitive to changes in formation-water salinity and that its magnitude provides a useful contrast between intervals associated with gas evidence and representative non-gas intervals. However, the observed variation in cutoff values indicates that SWGRAD interpretation is reservoir- and well-dependent.

The results therefore support the use of SWGRAD as a quantitative screening criterion rather than a standalone fluid-identification method. Its reliability is improved when the SWGRAD response is integrated with conventional petrophysical parameters, lithological interpretation, geological continuity, and independent well-test information.

The heterogeneous nature of the Plover Formation also explains why low-SWGRAD responses may occur over relatively thin and discontinuous intervals. Variations in shale content and reservoir quality can modify the resistivity–saturation relationship and consequently affect the calculated SWGRAD magnitude. This reinforces the need for well-specific calibration rather than application of a single threshold across the entire field.

4.4. Perforation Recommendation for Poseidon-1

The principal objective of the Poseidon-1 interpretation was to identify prospective gas-bearing intervals and establish perforation targets. Based on the ≤ 0.00002 working cutoff, the main prospective interval occurs between 4977 and 5097 m, with additional thin intervals at 4798–4805 m and 4873–4888 m.

The 4977–5097 m interval was evaluated using the integrated SWGRAD and petrophysical response. Because the interval contains internal lithological heterogeneity, it was subdivided into discrete perforation intervals rather than treated as a single continuous target.

The primary intervals were prioritized because they provide greater net thickness and a more consistent low-SWGRAD response, whereas the secondary intervals are thinner but remain prospective according to the adopted criterion. Because Poseidon-1 lacks direct formation-test or production-test confirmation, these intervals should be considered recommended prospective targets rather than confirmed productive intervals.

Table 3. Potential gas intervals based on SWGRAD analysis and independent evidence

Well	SWGRAD range	Cutoff	Interpreted potential gas interval (m)	Independent evidence	Interpretation status
Torosa-1	0.00000532–0.01051623	≤ 0.000043	4297–4310; 4355–4420; 4438.5–4443.2	DST/MDT; gas at 4308.9–4309.9 m	Supported
Kronos-1	0.000006442–0.0006821543	≤ 0.00004	4999–5014.5; 5018–5031	Production test/gas shows at corresponding intervals	Supported
Boreas-1	0.00019812–0.01160338	≤ 0.000027	4907–4919; 4925–4990.5	DST 4904–4974 m; GWC $\approx$ 4992 m MDRT	Supported
Poseidon-2	0.0000078–0.0218471	≤ 0.000045	4707–4730; 4782–4787; 5035–5119; 5258–5292	DST inconclusive due to washout and poor cement bond	Potential
Poseidon-1	0.00000234–0.00240417	≤ 0.00002	4798–4805; 4873–4888; 4977–5097	No direct well test; cutoff referenced to Boreas-1	Potential

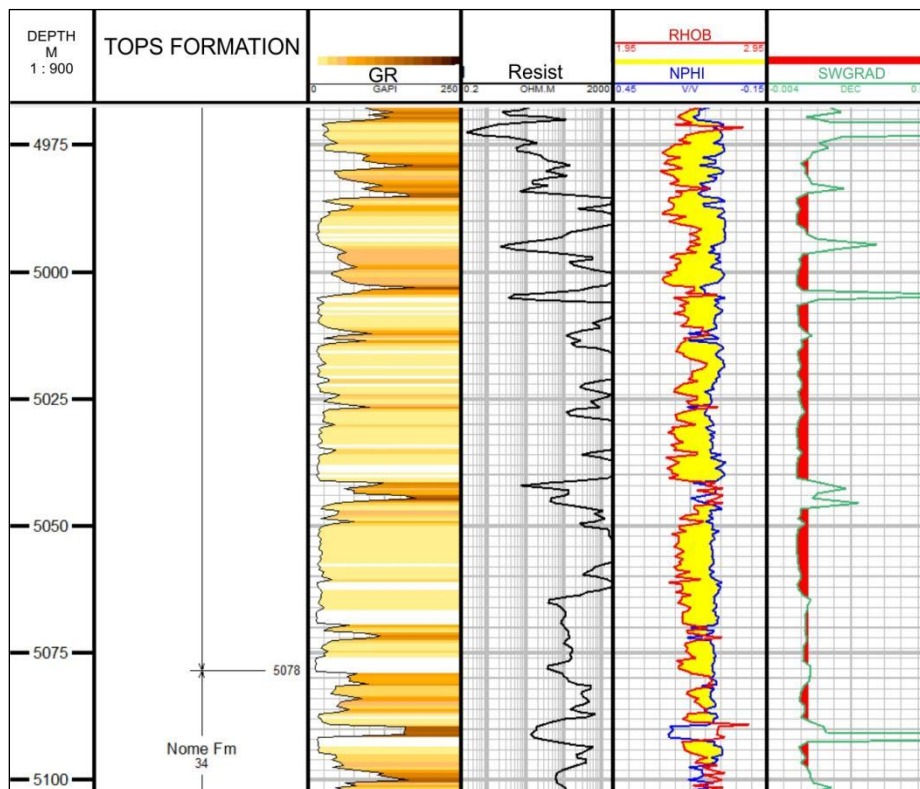


Fig 5. Well-log interpretation of Poseidon-1 showing intervals below the SWGRAD cutoff value. Red shading indicates intervals with SWGRAD values below the cutoff, representing potential gas-bearing zones.

Table 4. Recommended gas-bearing intervals in Poseidon-1 based on SWGRAD response and interval thickness.

Classification	Recommended interval (m)	Basis
Primary	5005–5040	Greater thickness and consistent low SWGRAD response
Primary	5046–5088	Greater thickness and consistent low SWGRAD response
Secondary	4977–4981	Greater thickness and consistent low SWGRAD response
Secondary	4984–4992	Thin interval satisfying SWGRAD criterion
Secondary	4996–5003	Thin interval satisfying SWGRAD criterion
Secondary	5092–5097	Thin interval satisfying SWGRAD criterion

4. Conclusion

Integrated petrophysical and SWGRAD research on five wells in the Browse Basin shows that the Plover Formation is highly lithologically and reservoir heterogeneous. The studied intervals include shale volume ranging from about 27% to 78%, total porosity ranging from about 6% to 15%, and effective porosity ranging from about 2% to 9%. Such variances affect the reservoir reaction and result in discrepancies in the amplitude of SWGRAD between the wells.

SWGRAD was calculated by varying formation-water salinity from 1 to 25 kppm and generating 25 Sw values at each depth sample. The Sw-salinity relationship was evaluated using least-squares linear regression with an intercept, and the regression slope was used as the SWGRAD value. The calculation was performed independently at each depth point, allowing the resulting SWGRAD profile to represent the local sensitivity of water saturation to formation-water salinity.

The results indicate that the sign of SWGRAD is not sufficient to discriminate gas-bearing from non-gas-bearing intervals because both types of intervals may exhibit the same gradient direction. Instead, the magnitude of SWGRAD provides the principal contrast used for interpretation. Well-specific cutoff values range from ≤ 0.00002 to ≤ 0.000045 , demonstrating that a universal threshold is not appropriate for the investigated heterogeneous reservoir.

Comparison with independent well-test information provides the strongest support in Torosa-1, Kronos-1, and Boreas-1. In Kronos-1, the ≤ 0.00004 cutoff identifies intervals at 4999–5014.5 m and 5018–5031 m, corresponding to the reported gas-show and production-test evidence. In Boreas-1, the interpreted SWGRAD intervals overlap approximately 61 m of the 70 m DST interval, corresponding to approximately 87.1% agreement. The difference of approximately 1.5 m between the SWGRAD lower boundary and the reported GWC at approximately 4992 m MDRT is small and does not materially alter the principal gas-zone interpretation, although it represents an inherent depth and measurement uncertainty.

Low-SWGRAD intervals are considered as candidate gas-bearing zones for Poseidon-2, while the current DST data are equivocal owing to drill wash-out and poor cement-bond conditions. These periods are therefore not recognized as distinct verified gas bearing zones. The ≤ 0.00002 cutoff for Poseidon-1 was borrowed from Boreas-1 because of the tight geographical link, similar Plover reservoir target, and independent gas evidence in Boreas-1. However, given the absence of direct well-test data in Poseidon-1 and the likelihood of reservoir property variations across wells, this threshold is regarded as a working criteria rather than a directly proven cutoff.

For Poseidon-1, the principal prospective interval is 4977–5097 m. Integration of SWGRAD, petrophysical properties, interval thickness, and lithological heterogeneity resulted in the recommendation of 5005–5040 m and 5046–

5088 m as primary perforation targets, while 4977–4981 m, 4984–4992 m, 4996–5003 m, and 5092–5097 m are considered secondary targets.

Overall, the findings indicate that SWGRAD can serve as a useful quantitative supporting method for screening potential gas-bearing intervals under uncertain formation-water salinity conditions. However, its interpretation should be calibrated on a well-specific basis and integrated with conventional petrophysical analysis, geological information, and independent well-test evidence rather than being used as a standalone fluid-identification method.

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