[PS]Unveiling the Reservoir Potential Near the Upslope Pinch-Out of Turbidite Systems: Examples from a Producing Oilfield

Fabio Berton[1], Luan de Oliveira[1], David Xavier[1], Vinicius de Lacerda[1], Manuela Silva[1], Nikolai Ojevan[1], Evelin Marquez[1], Gabriel Matos[1], and Jadison Alves[1]

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[1]Equinor Brazil

Abstract

Upslope stratigraphically-trapped turbidite reservoirs often combine high geological uncertainties and potentially good reservoir properties. Uncertainties derive from the influence of variable energy and autogenic controls on sediment accumulation or bypass, while reservoir potential result from the presence of voluminous channel-fill facies with high permeability and porosity. In the Peregrino Field, offshore Campos Basin, reservoir targets on the proximal domain of a multi-source upper slope turbidite system were detailed through the analysis of subsurface data, offering an opportunity to assess the reservoir potential of near-pinch-out deposits. The interval of interest comprises a depositional wedge that covers a regional unconformity and pinch out on an out-of-grade paleoslope. While the distal parts of the wedge have been intensively drilled in the past, the proximal termination below seismic resolution is still under development due to risks related to reservoir and seal presence and quality. The subsurface data includes a 3D seismic broadband volume, conventional well logs from 15 vertical wells and 80 horizontal wells and ultra-deep azimuthal resistivity data from horizontal wells. Two segments of the field were evaluated with the focus on near-pinch out potential. Indirect indicators of reservoir presence and quality were accounted to assess risks and opportunities, such as: (1) landward trends of onlap migration, favoring the preservation of upslope deposits; (2) presence of geomorphic elements attributable to channelized deposits in seismic attribute maps at the reservoir level; (3) identification of areas prone to sediment accumulation on the structure of the substrate, such as local depressions; (4) well correlation of reservoir properties and architecture, evaluating depositional trends towards the pinch-out; (5) modelling of geological scenarios and comparison with production performance in producing segments with the aim of assessing volume potential near the pinch-out; (6) planning and drilling of pilot wells.

The first segment evaluated is an area with production from several wells, four of which cross subparallel channel complexes. Seismic geomorphology suggested the extension of the channelized deposits upslope, and results from the horizontal wells indicated low changes in reservoir composition and dimensions from the most downdip to the most updip well. These conditions motivated the planning of three new producer wells in the area. Two of these wells proved the presence of up to 20m thick net reservoir sandbodies accommodated in local depressions on the slope. The third well crossed one sand-rich channel complex and one sand-poor bypass channel, reinforcing the relevance of

erosive processes near the pinch-out. The second tested segment is a currently non-producing area, where seismic amplitudes indicate the potential preservation of reservoir facies confined within a feeder canyon. A pilot well tested this potential, proving the presence of up to 10m thick net reservoir sandbodies. Such deposits are most likely discontinuous laterally but can be significantly continuous updip, motivating the revision of the pinch-out interpretation in the region. The results obtained so far through the maturation of near-pinch out reservoir targets reveal opportunities upslope, either as intra-canyon deposits, perched sediment accumulations, or sediment ponds, contributing to the reserves and life extension of the field.

Unveiling the reservoir potential near the upslope pinchout of turbidite systems: examples from a producing oilfield

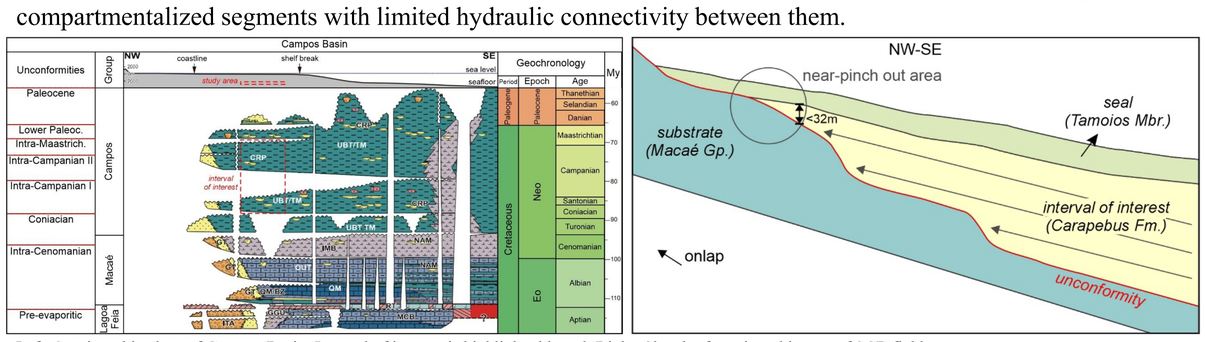
F Berton; **L de Oliveira**; D Xavier; V de Lacerda; M Silva; N Ojevan; E Marquez; G Matos; J Alves

Introduction

Turbidite systems rank among the most prolific hydrocarbon reservoir. Upslope segments, where sand-rich deposits thin and pinch out, often host stratigraphic traps with excellent reservoir properties. In a steeped-slope setting, erosional, bypass, and depositional interactions concentrate coarse-grained turbidites in topographic lows, yielding high NTG ratios near proximal pinch-outs. Despite their potential, these settings remain challenging. Reservoir compartimentalization, seal integrity, thief zones, and post-depositional modifications complicate prediction and development, and the proximal pinch-out zones therefore represent both opportunities and risks, with reservoir continuity and quality often uncertain.

Regional Context

The SCB field lies in the southern sector of Campos Basin, influenced by the Cabo Frio High. The basin's post-salt interval begins with the Macaé Group, a carbonate platform sucession truncated by a regional unconformity. Above it rests the Carapebus Formation, a Campanian-Maastrichtian siliciclastic wedge of gravity-flow deposits that thin and pinch out over the unconformity, where sandstone-rich turbidite channels and perched deposits within this wedge form the main reservoirs. The overlying mid-rich pelagic sediments of Ubatuba Formation act as an effective seal. Eocene canyon incisions partially eroded the Carapebus Formation and, locally, the Macaé Group. These canyons were later filled with fine-grained sediments, dividing the Carapebus wedge into 11 compartmentalized segments with limited hydraulic connectivity between them.



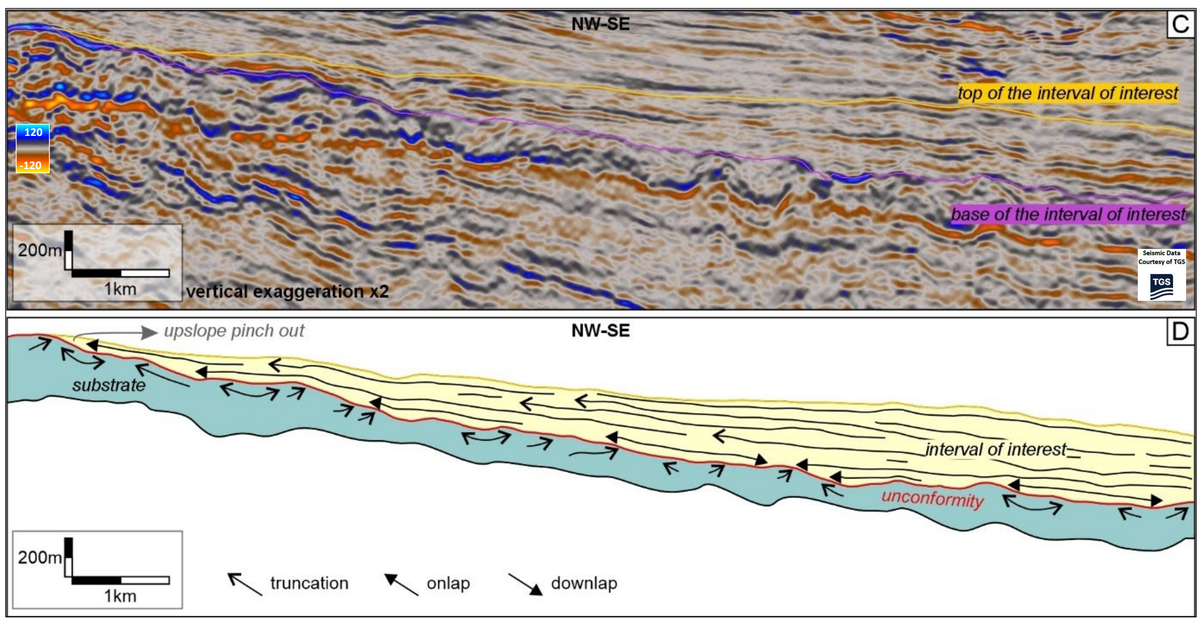
Left: Stratigraphic chart of Campos Basin. Interval of interest is highlighted in red; Right: Sketch of stratigraphic trap of SCB field.

Materials and Methods

The SCB subsurface is imaged using two post-stack time- and depth-migrated seismic volumes, 17 vertical/deviated wells, and 82 horizontal wells. GRT and RTM datasets together with amplitude and frequency attributes supported structural-stratigraphic interpretations and reservoir analysis, with vertical seismic resolution at reservoir depth of approximately 32 m. The vertical/deviated wells include gamma-ray, resistivity, density, neutron, caliper and sonic logs, plus core data from 9 wells with poor recovery. Horizontal wells include the same standard logs (excluding sonic) and UDAR inversions, which, beyond geosteering, support monitoring of the reservoir dimensions, architecture, compartmentalization, and heterogeneity.

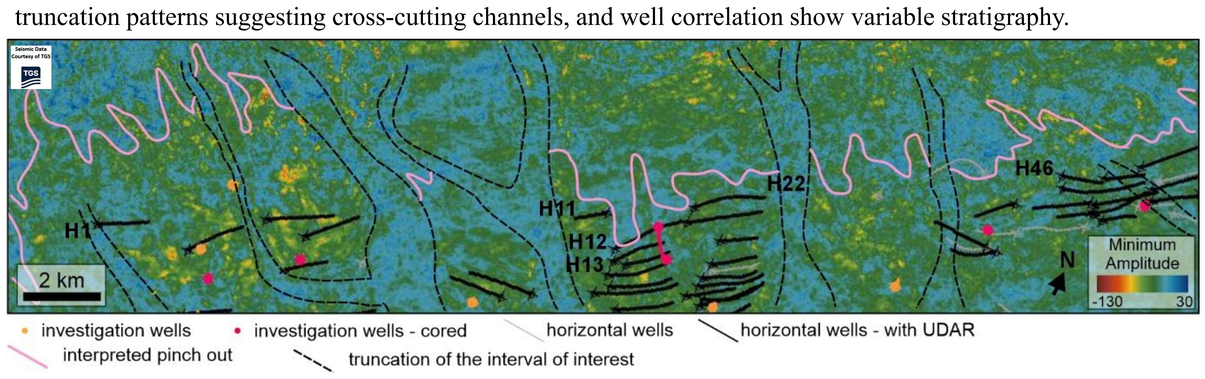
Results and Interpretation

The base of the reservoir is shallower and steeper in the northwest, and deeper, subhorizontal, and smoother in the southeast, and it exhibits irregular morphology with NE-SW lineaments, bathymetrical breaks and NW-SE alongated depresions. The overlying reservoir is a submarine siliciclastic wedge formed by subparallel reflectors, progessively thinning northwestward, where tuning effects and local truncations reduce confidence in pinchout interpretation. The top of the reservoir is poorly defined, reflecting the last sand-rich surface rather than the full extent of the Carapebus Formation, and truncated by late-incisions that segment the wedge laterally.

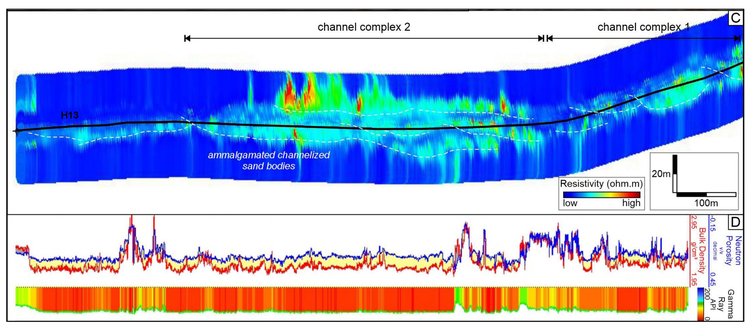


Top: Seismic dip section detailing the interval of interest of NE part of the field; Bottom: Geological interpretation of section C above.

The reservoir shows predominatly linear to slightly sinous features oriented NW-SE, with seismic amplitudes indicating sand-rich deposits. There features are discontinuous upslope and more continuous downslope, with truncation patterns suggesting cross-cutting channels, and well correlation show variable stratigraphy.



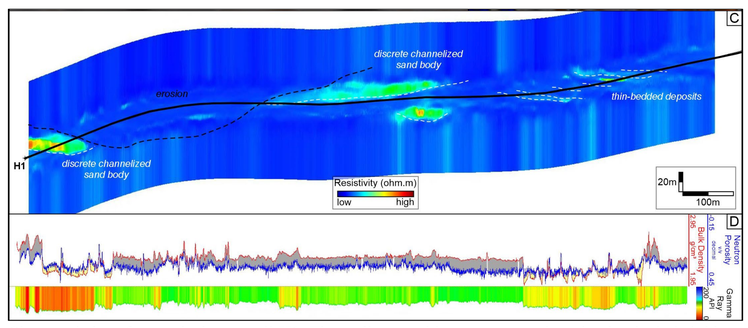
Interpretation of the pinch-out of the interval of interest in a Minimum Amplitude seismic attribute map of the top of the interval of interest



Characteristics of near-pinch out well H13. UDAR indicates it crossed amalgamated channelized sand bodies within at least two channel complexes.

Horizontal wells near the upslope pinchout revealed strong reservoir heterogeneity, ranging from thin or absent reservoir-quality sandstones to amalgamated channel complexes tens of meters thick. Some areas host wide, sands-rich channels (>30m thick) with high connectivity, while others are dominated by thin, discontinuous or eroded deposits interbedded with heterolithic or shally facies.

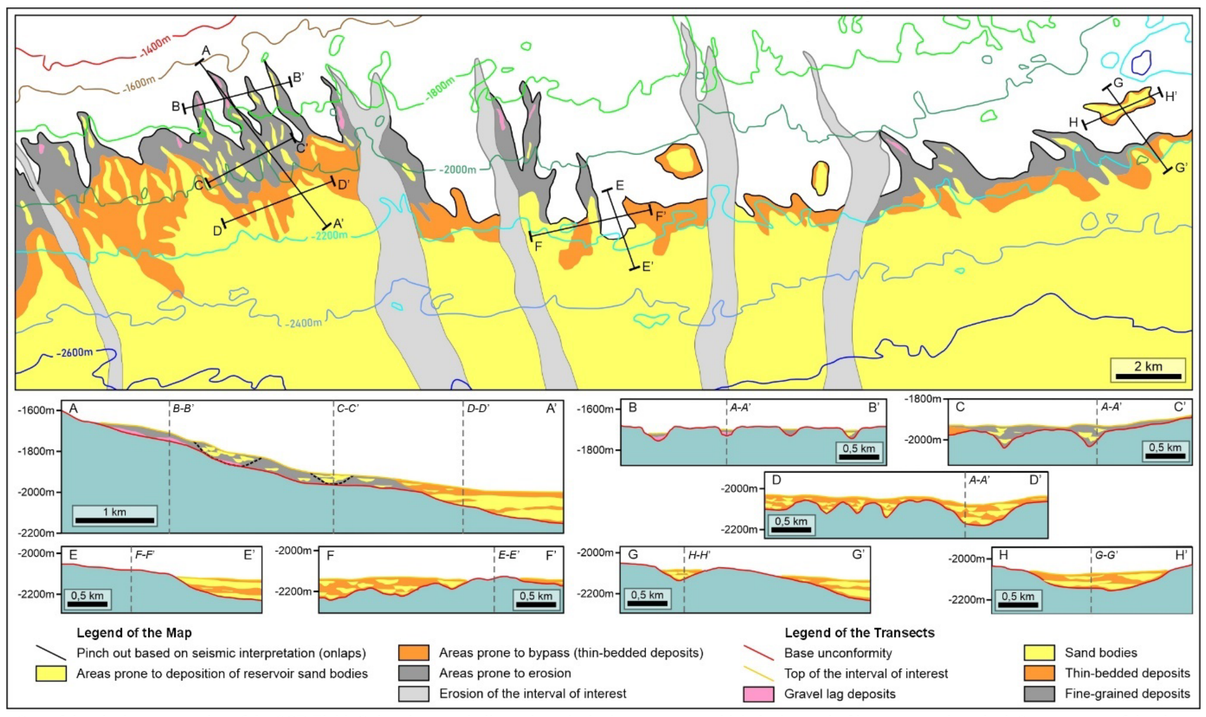
UDAR data highlights these contrasts between wide, amalgamated channel fills and narrow, isolated sand bodies. Local substrate depressions favored the accumulation of thick and wide (>400m) amalgamated sandbodies. Overall, the reservoir distribution is controlled by substrate geomor-phology and accomodation, channel stacking, and proximity to erosional features.



Characteristics of near-pinch out well H1. The well crossed heterogeneous deposits that included thin-bedded deposits, discrete channelized features, and indications of truncation by erosive features. Sand exposure along the well was low, more relevant when discrete channelized features were crossed

5. Discussion

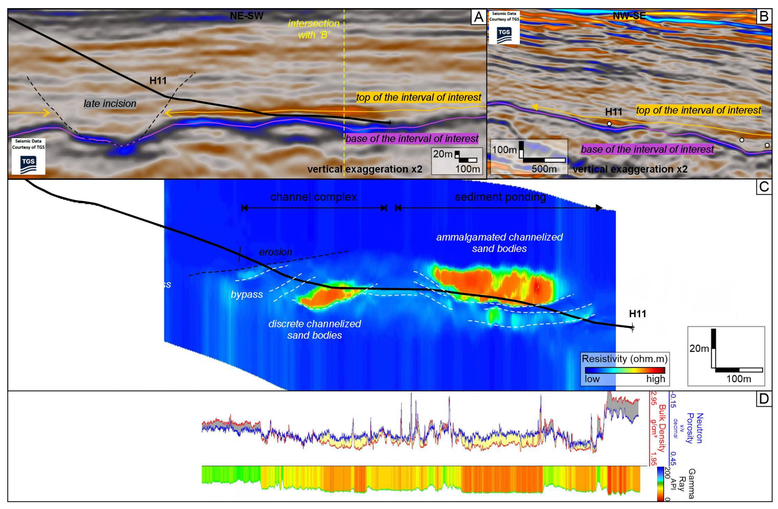
The upslope pinch-out is highly irregular, shaped by the interplay of depositional pinch-outs and erosive truncations along a complex carbonate paleoslope. Both deposition and erosional pinch-outs are present, forming a stratigraphic trap where facies distribution is highly variable and difficult to predict. Local pinch-outs align with substrate breaks, but structural control is passive, with no evidence of syn-depositional faulting.



One of the pinch out scenarios of the SCB Field. Colored curves indicate the paleobathymetry onto which the interval of interest was deposited. Steeper parts of the slope favor incision and prevalence of erosive processes, resulting in discontinuous sand bodies laterally and longitudinally (transects A-A', B-B', C-C' and D-D').

Sediment bypass dominates, creating zones that range from complete bypass to thin-bedded or sand-rich accumulations, while erosional incisions compartmentalize the reservoir. Local highs truncate sand bodies, whereas depressions preserve amalgamated channels and ponded sands, though often hydraulically isolated and prone to rapid production decline.

Paleoslope morphology is the main control: steep slopes show indented pinchouts with low predictability, while gentler slopes favor more linear geometries and clearer deposition limits. Subtle bathymetric variations strongly influence reservoir presence, continuity, and quality, underscoring the need for integrated seismic interpretation, geomorphology, and geological concepts to reduce uncertainty.



H11 near-pinch-out characteristics. This well was placed in a local depression of the substrate. (A) strike; (B) Dip cross section. UDAR data depicts discrete channelized features with thicknesses exceeding 15m (C). The features are sand-rich but laterally disconnected (D).

Conclusions

- The SCB field highlights the complexity of near-upslope pinch-out reservoirs, where stratigraphic trapping and wedge geometries create localized net-pay often below seismic resolution;
- Reservoir quality is controlled by channelized turbidite deposits, with coarse sandstones as main reservoir facies and heterolithic beds acting as baffles;
- Bathymetric irregularities on the paleoslope strongly dictated sediment routing:
  - Steep slopes favored erosive pinch-outs and sand accumulation in depressions;
  - Gentle slopes promoted depositional pinchouts and widespread bypass.
- Geomorphic controls produced reservoir units ranging from thin, low-pay bodies to thick, ponded sandstones with significant volumes;
- Reservoir potential is heterogeneous and unpredictable, demanding integration of seismic, geomorphology, well data, and geological scenarios, that reflect the influence of autogenic controls, to reduce risk and capture opportunities in near-pinchout settings.

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