The Late Neoproterozoic Buah Formation of Oman: Regional Correlation and Reservoir Quality

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Extended Abstract

In 2009, some of the world's oldest sediment-hosted hydrocarbons were discovered in east central Oman in sub- Ara Huqf sediments. Their discovery and subsequent exploitation marked a significant addition to Oman's portfolio of petroleum prospects. Hydrocarbons are reservoired in dolomitic carbonates of the Buah and Khufai Formations and sealed by intraformational anhydrite/tight dolostones and Shuram mudstones respectively. The discoveries have focussed attention on these two formations, their regional correlations, depositional environments and petroleum systems. In this contribution we present new insights into the stratigraphic architecture and regional correlation of the Late Neoproterozoic Buah Formation. We then turn our attention to characteristics of the Buah reservoir focussing on the various forms in which hydrocarbons occur and developing a model for the timing and mechanism of porosity creation.

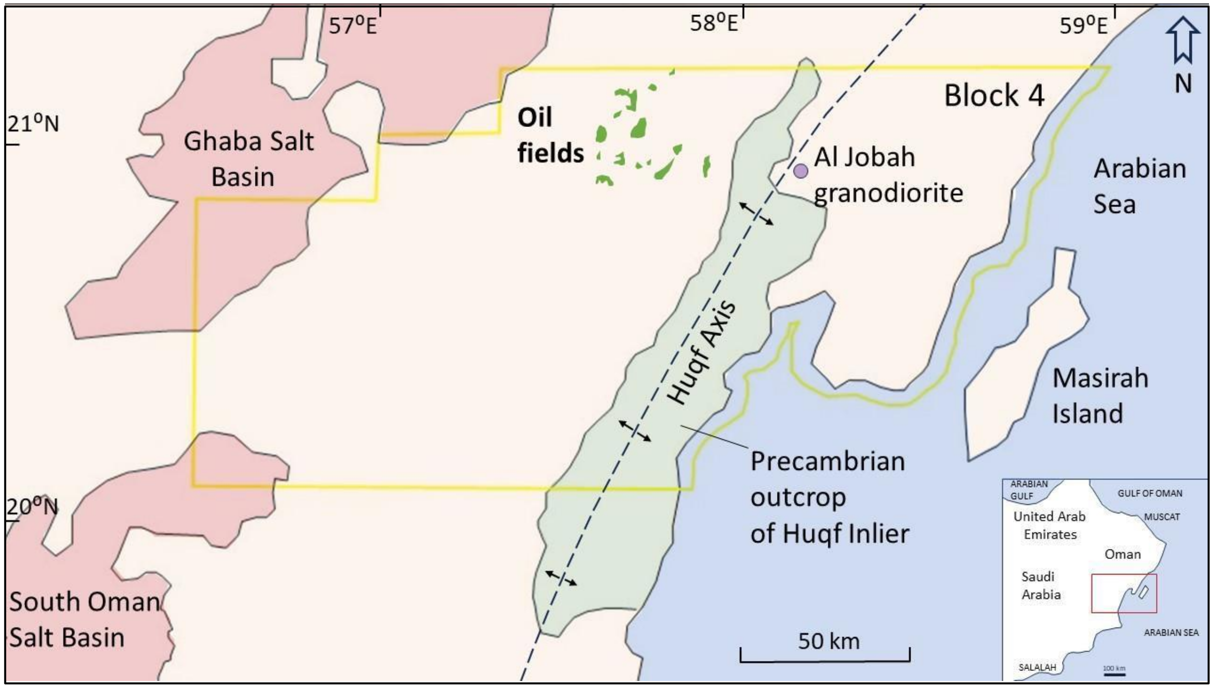
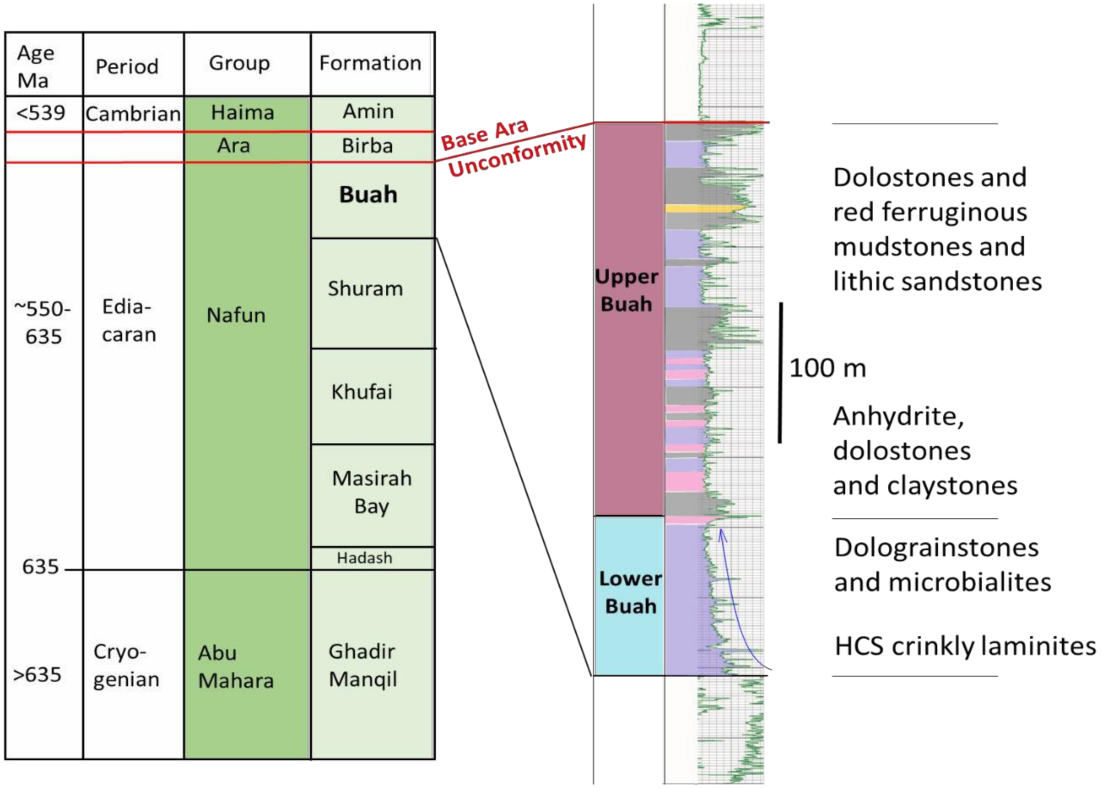


Figure 1. *Location map*

The data for this talk comes primarily from core data from one of a cluster of oil fields in the northern part of Block 4 that produce from Late Precambrian carbonate reservoirs (Figure 1). The fields are located up dip from the salt edge of the Ghaba Salt Basin and down dip from the Huqf Axis along which Precambrian sediments including the Buah Formation are exposed providing an excellent lithological and diagenetic analogue for the adjacent fields. Also marked on the map is the location where crystalline basement comes to surface in the Al Jobah granodiorite. This location forms the locus of Ediacaran uplift which had a profound effect on the lithology of the Buah Formation.

Stratigraphic architecture and regional correlation

The Buah Formation forms the uppermost of five formations in the Ediacaran Nafun Group (Figure 2). Historically operators and partners in Blocks 3 and 4 have subdivided the Buah Formation into three members, upper, middle and lower, each appearing as distinct entities on the gamma ray profile.



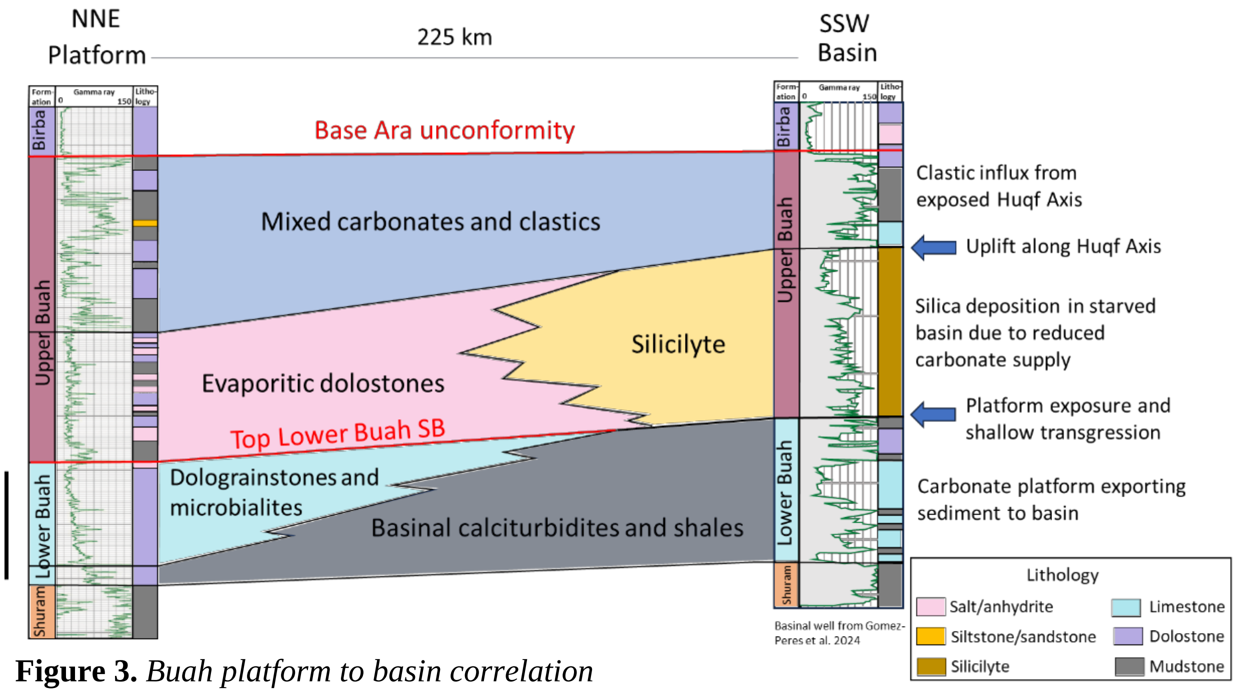
Age Ma	Period	Group	Formation
<539	Cambrian	Haima	Amin
		Ara	Birba
~550-635	Ediacaran	Nafun	**Buah**
			Shuram
			Khufai
			Masirah Bay
635			Hadash
>635	Cryogenian	Abu Mahara	Ghadir Manqil

Figure 2. *Buah lithostratigraphy*

However, recognition that the base of the Upper Buah corresponds to the Base Ara Unconformity has led to a reassignment of the Upper Buah to the Birba Formation at the base of the Ara Group and hence the Buah is reduced to two members which are referred to as simply upper and lower Buah, a nomenclature that aligns with current PDO terminology for the Nafun Group.

The Lower Buah shallows upwards from mid ramp HCS crinkly laminites to inner ramp dolograinstones and microbialites as part of a highstand systems tract that commenced above a maximum flooding surface in the upper part of the Shuram below. The Upper Buah on the other hand, above a lower anhydritic part, is a red bed sequence formed at a time of uplift and emergence of the adjacent Huqf Axis focussed on the Al Jobah location as shown on Figure 1. Lithoclastic sandstones bearing clasts derived from the Khufai and Masirah Bay formations testify to unroofing of the High at this time. A sequence boundary separates the Upper and Lower Buah.

Deep drilling results in the South Oman Salt Basin reveal that the platformal lithologies of east central Oman pass southwards into coeval basinal deposits. Events in this basin can be related to events on the platform (Figure 3). The Lower Buah carbonate platform sourced calciturbidites into the basin which were interbedded with shales. Exposure of the platform at the Top Lower Buah sequence boundary and subsequent shallow transgression caused a diminution in the volume of exported sediment leading to the development of a starved basin and the depositionof the highly siliceous sediments of the silicilyte facies under low energy anoxic conditions on the correlative conformity in the basin. Further uplift along the Huqf Axis led to increased clastic supply across the entire depositional profile.



Basinal well from Gomez-Peres et al. 2024

Figure 3. *Buah platform to basin correlation*

Buah reservoir characteristics

The top of the Upper Buah marks the economic ceiling for oil bearing horizons in the Buah Formation. Below this surface dolostones within the Upper Buah are productive but the main reservoir is in the upper part of the Lower Buah, top sealed by anhydrite at the base of the Upper Buah and sourced as with the Upper Buah reservoirs from maturing Khufai and Masirah Bay basinwards to the north west.

First impressions of the cores are the abundance of black reservoir bitumen. The bitumen occurs in two forms, firstly as a highly mature form that has proven resistant to solvent extraction and can therefore be referred to as a pyrobitumen. It has been called rock bitumen. The second type referred to as sticky bitumen is, as the name implies, a less mature form and occurs in fractures or partially to totally infilling vuggy dissolution pores. Cross cutting relationships show that the pores that host the sticky bitumen were superimposed upon an earlier rock bitumen fabric thereby establishing a temporal gap between the two phases of bitumen.

Light oil occurs in fractures and in discrete intervals where it is intimately associated with the sticky bitumen. Reservoired oil is now recognised as the feedstock for the sticky bitumen. The light oil preserved in core can be viewed as a low permeability remnant of a once more voluminous charge, retained in micropores with narrow pore throats but released from macropores on core uplift.

Channel ways for the corrosive fluids that effected dissolution were provided by either bedding plane discontinuities or along fractures. The dissolution pores occur indiscriminately across all dolostone lithotypes within the reservoir interval and it is concluded that primary depositional facies are not a major discriminant for porosity development. Whilst not denying the presence of some primary porosity in the Buah reservoirs it is our conclusion that most of the porosity has been created by deep burial dissolution. The main features of the Buah reservoir are summarized in Figure 4.

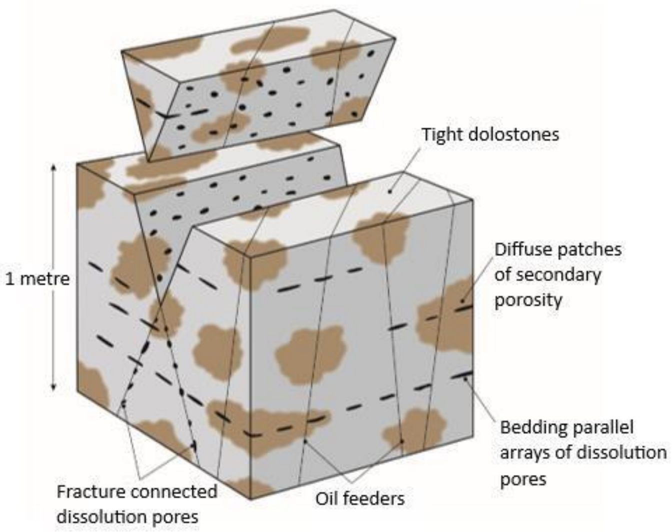


Figure 4. *Lower Buah reservoir metre cube*

In thin section, wherever the crystal size is large enough it is apparent that the dolomite mosaics contain saddle dolomite. This observation is critical as it provides direct evidence of the role of hydrothermal fluids in the development of the Buah reservoirs. Saddle dolomite requires a minimum temperature of 100^0C to form. Given the shallow depth of the Buah reservoir and every indication that its current depth is close to its maximum burial depth then the involvement of hydrothermal fluids in the development of the Buah reservoir appears to be an inescapable conclusion. Fi data indicate that the hydrothermal fluids from which the dolomite precipitated were also carrying hydrocarbons. Further support for a hydrothermal role is provided by the presence of heavy metal sulphides in the form of sphalerite and chalcopyrite in the Buah reservoirs.

The hydrothermal event is believed to be related to a short lived thermal pulse due to magmatic activity at the Cambrian- Precambrian boundary – ie soon after Buah deposition in the Ediacaran. The various diagenetic changes and oil emplacement and degradation effects can be related to the build-up, peak and waning phases of this thermal pulse. Rock bitumen is believed to have formed from in situ kerogens. Their maturation took place during the build-up phase of the thermal pulse, followed by thermal degradation at the peak at temperatures in excess of 150^0C.

With increasing depth of burial beneath the salt basins Nafun source rocks matured and expelled liquid hydrocarbons. Oil expelled migrated up beneath the salt to be trapped below the Lower Buah anhydrite in pores that were created during an earlier corrosive event. This oil charge took place during the waning phase of the hydrothermal system at a time when the reservoir had cooled enough for liquid hydrocarbons to enter but nevertheless warm enough for accompanying high temperature minerals such as saddle dolomite to form in the presence of hydrocarbons and for the incoming oil charge to undergo in reservoir bituminisation to sticky bitumen.

The implication of this model is that by the end of the Cambrian most if not all of the oil in the Buah reservoirs was in place. Oil emplacement and bitumen precipitation therefrom may well have continued after the thermal pulse had waned until the source regions were either exhausted or became overmature with burial. The reservoired oil may also have been subject to hydrous or bacterial alteration through its long period of residence in the reservoir.

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