ES486 Petroleum Geology
Winter 2019
Student Case Study Presentations
Abstracts with Programs

ES486 Petroleum Geology
Peer-to-Peer Learning Model
Journal Article Summaries/Case Study Presentations *(Updated Winter 2019)*

Instructions:

Each student will be assigned a recent case-study journal article on a petroleum geology topic. The objective is to read the case study, digest the information, and create a 12-15-minute powerpoint oral presentation of the topic. The general organization of the presentation will be as follows:

I. Introduction to the topic, with outline of the main presentation headings (introduction should include figures with maps on location of the case study)
II. State of the problem or technique(s) addressed in the article.
III. Methodology
IV. Results
V. Conclusion and Summary

Project Deliverables will include:
-A 12-15-minute powerpoint slide show with images and text on topic, summary of take-home messages
-1-page handout / outline with key summary bullet points on topic
-Optional creative video-clip (youtube, etc.) illustrating the techniques or methods

Note: A general rule of thumb is to allow approximately 1 minute per slide of content in a scientific presentation. You presentation should be no more than 10-15 slides for a 12-15-minute presentation, depending on the complexity of the information you are trying to summarize. The presentations will be worth 20 points.

Presentation Schedule TENTATIVE
Download papers at following link:
http://www.wou.edu/las/physci/taylor/es486_petro/ES486_Case_Studies.htm

Week 10 / Tuesday March 12 [HAT PARTY – Wear a Festive Hat, prizes to be awarded for creativity]

2:00-2:10	Taylor Introduction
2:15-2:25	Okre et al., 2013, Hydrocarbon Potential in Kazakstan [WALTER]
2:30-2:40	Delpomdor et al., 2018, Precambrian Petroleum System in Congo, Africa [NICOLE]
2:45-2:55	Macgregor et al., 2012, Nile Basin System [BRIANNA]
3:00-3:10	Rateau et al., 2013, Igneous Intrusion and Hydrocarbon Accumulation, Shetland [NICK]
3:15-3:25	Holgate et al., 2013, Sedimentology and Stratigrphy of Troll Field, North Sea [MANDY]
3:30-3:40	TBD – Petroleum Geology in Brazil / Oman / Lebanon / Somalia – TBD [LANCE]
3:40-3:50	Taylor Conclusion

Week 10 / Thursday March 14 [TACO THURSDAY / POTLUCK]

2:00-2:10	Taylor Introduction
2:15-2:25	Gaswirth and Higley, 2013, Petroleum Analysis, West Edmond Field, OK [AUSTIN]
2:30-2:40	Baytok and Panter, 2013, Fracture Reservoirs Piceance Basin, CO [T-HO]
2:45-2:55	Hudec et al., 2013, Jurassic Salt Domes, Gulf of Mexico [SALVADOR]
3:00-3:10	Tozer et al., 2014, Athabasca Oil Sands [ANDY]
3:15-3:25	Shimer et al, 2014, Basin Analysis of Nanushuk Formation, Alaska [TIM]
3:30-3:50	Taylor Conclusion

Topics of Choice: Rank top 3 interest items / case-study journal article per student

Ali et al., 2019, Petroleum Geology Northern Somalia
Al Saad, 2016, Paleozoic Petroleum Systems, Qatar
Al Ramadan et al., 2017, Reservoir Characterization, Nuayyim Field, Saudi Arabia
Amour et al, 2013, Carbonate Ramp Reservoirs
Baytok and Panter, 2013, Faulth and Fracture Reservoirs Piceance Basin, Colorado
Beglinger et al., 2013, Subsidence History and Thermal Maturation, Campos Basin, Brazil
Boro et al., 2014, Fracture Analysis of Reservoirs, Northern Italy
Burgess et al., 2013, Identification of Carbonate Build-ups with Seismic Reflection
Bust et al., 2013, Petrophysical Analysis of Shale Gas Reservoirs
Delpomdor et al., 2018, Precambrian Petroleum Systems of Congo
Fan et al, 2012, Reservoir Fracture Propagation During Oil to Gas Transformation
Gaswirth and Higley, 2013, Petroleum Analysis of West Edmond Field, Oklahoma
Ghalayani et al., 2018, Petroleum Systems of Lebanon
Grant et al., 2014, Porosity trends in the Skagerrak Formation, Central Graben, United Kingdom
Gross et al., 2018, Petroleum Systems North Alpine Foreland Basin, Austria
Grotzinger and Alrawai, 2014, Carbonate Reservoirs, Sultan of Oman
Haddad and Mancini, 2013, Reservoir characterization of Jurassic Smackover Formation, Southwest Alabama
Harouna et al., 2017, Subsidence History Termit Basin, Niger
Holgate et al., 2013, Sedimentology and stratigraphy of the Troll Field, North Sea
Hudec et al., 2013, Jurassic Salt Dome Systems, Gulf of Mexico
Hudec et al., 2013, Louann Salt Gulf of Mexico
Johansen, 2013, Seismic Facies Analysis Svalbard
Johnson, 1998, Petroleum Geology of Washington State
Karakitsios, 2013, Ionian Sea Petroleum Systems
Kohl et al., 2014, Gas Reservoirs in the Marcellus Shale, Appalachian Basin
Li et al., 2014, Resistivity as a Tool for Permeability Analysis
Li et al., 2017, Reservoir Potential in Deltaic Sandstones, Ordos Basin, China
Liu et al., 2017, Origin of Oils in Termit Basin, Niger
Macgregor et al., 2012, Nile Basin System
Max and Johnson, 2014, Gas Hydrates
Meng et al., 2019, Hydrocarbon Potential of Lacustrine Sendiments, NW China
Milliken et al., 2013, Gas Reservoirs in the Marcellus Shale, Pennsylvania
Moscardelli et al., 2013, Seismic Analysis of the Heidrun Field Norway
Neumaier et al., 2014, Seal Assessment of Venezuela
Nguyen et al., 2013, Diagenetic Effects on Reservoir Porosity in the North Sea
Okere et al., 2013, Hydrocarbon Potential in Kazakstan
Petersen et al., 2018, Source Rocks and Petroleum in Danish North Sea
Pimentel et al., 2016, Deep Offshore Petroleum Systems West Iberia
Rateau et al., 2013, Igneous Intrusion and Hydrocarbon Accumulation in Shetland
Roberts et al., 2013, Basin Modeling
Sen, 2013, Petroleum occurrence in the Black_Sea, Turkey
Shimer et al., 2014, Basin Analysis of the Nanushuk Formation, Alaska
Tozer et al., 2014, Athabasca Oil Sands
Yang et al., 2017, Hydrocarbon Potential Cretaceous Shales, Ecuador
Zeeb et al., 2013, Outcrop Fracture Analysis and Reservoir Permeability
Zhang et al., 2019, Calcite Content and Carbonate Reservoirs, E. Saudi Arabia

Walter

New insights into hydrocarbon plays in the Caspian Sea, Kazakhstan

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ABSTRACT: New exploration opportunities and improved imaging of already known prospects in the Caspian Sea, Kazakhstan, are presented, based on the acquisition, processing and interpretation of long-offset 2D seismic data acquired by CGGVeritas from 2006–2009. We have identified further examples of three already successful plays in the Caspian Sea and onshore, within open blocks in the North Caspian and North Ustyurt basins and a fourth, relatively unknown play, in the North Ustyurt basin. The already known plays include Devono-Carboniferous carbonate reefs and clastics, Triassic–Tertiary post-salt clastics and carbonates in the North Caspian basin and Jurassic–Cretaceous post-thrust clastics and carbonates in the North Ustyurt basin. The fourth play that we have identified comprises thrust faults, anticlinal structures with Late Palaeozoic–Early Mesozoic clastic and carbonate reservoirs in the North Ustyurt basin which, to our knowledge, has not been tested elsewhere in the region.

Nicole

AN INTRODUCTION TO THE PRECAMBRIAN PETROLEUM SYSTEM IN THE SANKURU-MBUJI-MAYI-LOMAMI-LOVOY BASIN, SOUTH-CENTRAL DEMOCRATIC REPUBLIC OF CONGO

F. Delpomdor[1,2*], S. Bonneville[2], K. Baert[3] and A. Préat[2]

This study presents a preliminary assessment of the petroleum potential of the Meso-Neoproterozoic Mbuji-Mayi Supergroup in the Sankuru-Mbuji-Mayi-Lomami-Lovoy Basin in the southern-central Democratic Republic of Congo. This basin is one of the least explored in Central Africa and is a valuable resource for the evaluation of the petroleum system in the greater Congo Basin area. Highly altered carbonates (potential reservoir rocks) and black shales (potential source rocks) are present in the Mbuji-Mayi Supergroup, which can be divided into the BI and overlying BII groups (Stenian and Tonian, respectively). For this study, samples of the BIe to BIIe subgroups from five boreholes and two outcrops were evaluated with petrographic, petrophysical and geochemical analyses.

Carbonates in the BIe to BIIe subgroups with reservoir potential include oolitic packstones and grainstones, stromatolitic packstones and boundstones, various dolostones, and brecciated and zoned limestones. Thin section studies showed that porosity in samples of these carbonates is mainly vuggy and mouldic with well-developed fractures, and secondary porosity is up to 12%. Black shales in the BIIc subgroup have TOC contents of 0.5-1%, and the organic matter is interpreted to have been derived from precursor Type I / II kerogen. The thermal maturity of asphaltite in carbonate samples is indicated by Raman spectroscopy-derived palaeo-temperatures which range from ~150 to ~260°C, which is typical of low-grade metamorphism. Raman reflectance ($R_{mc}R_o$%) values on asphaltite samples were between 1.0 and 2.7%, indicating mature organic matter corresponding to the oil and wet gas windows. Source rock maturation and primary oil migration are interpreted to have occurred during Lufilian deformation (650-530 Ma). The solid asphaltite present in fractures in the dolostones of the BIIc subgroup may represent biodegraded light oil from an as-yet unknown source which probably migrated during the Cambrian-Ordovician (~540-480 Ma). This migration event may have been related to the effects of the peak phase of Lufilian deformation in the Katanga Basin to the SE.

This study is intended to provide a starting

Brianna

The development of the Nile drainage system: integration of onshore and offshore evidence

Duncan S. Macgregor

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ABSTRACT: This paper reconstructs drainage systems with outlets close to the present-day Nile system, honouring both onshore and offshore evidence and attempts a source to sink quantification. A large river is evidenced to have extended the length of the Red Sea Hills from Eritrea to the current outlet since the Oligocene. The early route of the river is uncertain through Sudan but a more westerly course is proposed through Egypt. The largest contributor of clastic sediment was the Red Sea Hills, where average erosion of the order of 1200–1500 m is constrained by a combination of Apatite Fission Track Analysis, planation surface analysis, and Red Sea sink volumes. Nubia was a significant supplier of sand-rich sediment during wet periods. This sediment supply pattern contrasts with the present-day situation where the Ethiopian Highlands contribute the vast majority of sediments, this contrast being validated by available mineralogical data. This is a consequence of wetter climates in the past and of the younger Ethiopian topography. The interpretations presented here illustrate the importance of hinterland climate change on clastic supply and allow the reservoir fairways in the Nile Cone to be more precisely mapped out in time and space.

Nick

The potential role of igneous intrusions on hydrocarbon migration, West of Shetland

Rémi Rateau[1*], Nick Schofield[2] and Michael Smith[1]

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ABSTRACT: Numerous challenges for petroleum exploration exist within basins containing sequences of intrusive and extrusive rocks, ranging from seismic imaging to drilling. One poorly understood element in dealing with volcanic-affected basins is assessing the impact magmatism has on the elements of the petroleum system. Within this study we attempt to evaluate the potential impact that the extensive sequence of igneous intrusions of the Faroe–Shetland Basin may have on hydrocarbon migration. Using available well data combined with regional 3D seismic surveys, we show that geometrical relationships between sills location and overlying hydrocarbons shows, together with several cases of gas-charged open fractures in the sills, point toward the recognition of igneous intrusions as a factor in hydrocarbon migration through sill intrusions acting as both barriers or conduits to hydrocarbon migration. We also provide a series of general conceptual models dealing with hydrocarbon migration and igneous compartmentalization within sedimentary basins, which can be applied not just to the Faroe–Shetland Basin, but to other sedimentary basins worldwide if it is found (via well data or other methods) that the intrusions are interacting with a petroleum system.

Mandy

Sedimentology and sequence stratigraphy of the Middle–Upper Jurassic Krossfjord and Fensfjord formations, Troll Field, northern North Sea

Nicholas E. Holgate[1,*], Christopher A.-L. Jackson[1], Gary J. Hampson[1] and Tom Dreyer[2]

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ABSTRACT: The Middle–Upper Jurassic Krossfjord and Fensfjord formations are secondary reservoir targets in the super-giant Troll oil and gas field, Horda Platform, offshore Norway. The formations comprise sandstones (*c.* 195 m thick) sourced from the Norwegian mainland to the east, that pinch out basinwards into offshore shales of the Heather Formation to the west. Sedimentological analysis of cores from the Troll Field has identified six facies associations, which represent wave- and tide-dominated deltaic, shoreline and shelf depositional environments. Resulting depositional models highlight the complex distribution of depositional environments, and reflect spatial and temporal variations in physical processes at the shoreline, rate of sediment supply and accommodation development. These models are further complicated by the absence of coastal plain facies, which implies that the Troll Field was fully subaqueous during deposition, that shoreline regression was forced by falling sea level or that coastal plain deposits were removed by transgression. Genetic sequences bounded by major flooding surfaces ('series') exhibit laterally uniform thicknesses, implying no major tectonic influence on sedimentation. The recognition of pronounced variability in facies character and stratigraphical architecture emphasize the need for a robust depositional model of the formations in order to drive future exploration in these, and coeval, reservoirs.

Lance

PETROLEUM GEOLOGY OF THE NOGAL BASIN AND SURROUNDING AREA, NORTHERN SOMALIA: PART 1, STRATIGRAPHY AND TECTONIC EVOLUTION

M.Y. Ali[1*] and J. Lee[1,2]

In this study, 92 closely-spaced reflection seismic profiles (~4000 line-km) were tied to biostratigraphic and lithological data from six deep exploration wells in the poorly-known Nogal rift basin, northern Somalia, and were integrated with outcrop and aeromagnetic data to investigate the basin stratigraphy and tectonic evolution. Aeromagnetic data show NW-SE trending magnetic anomalies which are interpreted as plutonic bodies intruded during the Early Cretaceous, probably contemporaneously with a pre-Cenomanian uplift phase. The aeromagnetic data also suggest a change of basement type from Inda Ad Series metasediments in the SE of the study area to igneous and high-grade metamorphic basement in the NW. Biostratigraphic data and seismic reflection profiles define the Nogal Basin as a WNW–ESE striking half-graben, approximately 250 km long and 40 km wide, which formed as a result of mainly Cenomanian–Maastrichtian and Oligocene–Miocene intracontinental rifting. The depocentre contains at least 7000 m of Mesozoic and Cenozoic sediments and is located in the centre of the basin (east of well Nogal-1), to the south of the Shileh Madu Range. To the north, the basin is bounded by a major border fault along which significant variations in the thickness of sedimentary units are observed, suggesting that the fault controlled basin architecture and patterns of sedimentation. Oligocene–Miocene normal faults which resulted in north-tilted fault blocks are widespread within the main basin; smaller-scale sub-basins oriented NW-SE to WNW-ESE are observed to the NW of the basin and probably developed contemporaneously.

The Late Jurassic rift phase which has been documented elsewhere in northern Somalia is either missing in the Nogal Basin or is preserved only in localised grabens in the western and central parts of the basin. This is probably due to the pre-Cenomanian uplift and erosion which removed almost the entire Jurassic and Lower Cretaceous successions over a wide area referred to as the Nogal-Erigavo Arch. A more pronounced rifting episode followed this erosional event in the Cenomanian–Maastrichtian and resulted in the deposition of well -sorted fluvio-deltaic sandstones (Gumburo and Jesomma Formations), more than 2000 m thick. In wells in the Nogal Basin, these formations are between two and three times thicker than in wells drilled in footwall locations, and include excellent reservoir rocks sealed by transgressive mudstones and carbonates. A final rifting event in the Oligocene–Miocene was related to the opening of the Gulf of Aden. A rift sag phase which accommodated the Early Oligocene continental sediments of the Nogal Group initially developed at the centre of the basin. This was followed by a period of strong rotational faulting and tilting, which reactivated the Cenomanian–Maastrichtian structures.

Austin

Petroleum system analysis of the Hunton Group in West Edmond field, Oklahoma

Stephanie B. Gaswirth and Debra K. Higley

ABSTRACT

West Edmond field, located in central Oklahoma, is one of the largest oil accumulations in the Silurian–Devonian Hunton Group in this part of the Anadarko Basin. Production from all stratigraphic units in the field exceeds 170 million barrels of oil (MMBO) and 400 billion cubic feet of gas (BCFG), of which approximately 60 MMBO and 100 BCFG have been produced from the Hunton Group. Oil and gas are stratigraphically trapped to the east against the Nemaha uplift, to the north by a regional wedge-out of Hunton strata, and by intraformational diagenetic traps. Hunton Group reservoirs are the Bois d'Arc and Frisco Limestones, with lesser production from the Chimneyhill subgroup, Haragan Shale, and Henryhouse Formation.

Hunton Group cores from three wells that were examined petrographically indicate that complex diagenetic relations influence permeability and reservoir quality. Greatest porosity and permeability are associated with secondary dissolution in packstones and grainstones, forming hydrocarbon reservoirs. The overlying Devonian–Mississippian Woodford Shale is the major petroleum source rock for the Hunton Group in the field, based on one-dimensional and four-dimensional petroleum system models that were calibrated to well temperature and Woodford Shale vitrinite reflectance data. The source rock is marginally mature to mature for oil generation in the area of the West Edmond field, and migration of Woodford oil and gas from deeper parts of the basin also contributed to hydrocarbon accumulation.

Taylor

Fault and fracture distribution within a tight-gas sandstone reservoir: Mesaverde Group, Mamm Creek Field, Piceance Basin, Colorado, USA

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ABSTRACT: The distribution and orientation of faults, fracture intensity and seismic-reflection characteristics of the Mesaverde Group (Williams Fork and Iles formations) at Mamm Creek Field vary stratigraphically, and with lithology and depositional setting. For the Mesaverde Group, the occurrence of faults and natural fractures is important as they provide conduits for gas migration, and enhance the permeability and productivity of the tight-gas sandstones. The Upper Cretaceous Mesaverde Group represents fluvial, alluvial-plain, coastal-plain and shallow-marine depositional environments.

Structural interpretations based on three-dimensional (3D) seismic-amplitude data, ant-track (algorithm that enhances seismic discontinuities) seismic attributes and curvature attributes are utilized jointly to understand the complex fault characteristics of the Williams Fork Formation. This study reveals that the lowermost lower Williams Fork Formation is characterized by NNW- and east–west-trending small-scale thrust and normal faults. Study suggests that the uppermost lower Williams Fork Formation, and the middle and upper Williams Fork formations, exhibit NNE- and east–west-trending arrays of fault splays that terminate upwards and do not appear to displace the upper Williams Fork Formation. In the uppermost Williams Fork Formation and Ohio Creek Member, NNE-trending discontinuities are displaced by east–west-trending events and the east–west-trending events dominate.

Fracture analysis, based on borehole-image logs, together with ant-track and attenuation-related seismic attributes, illustrates the spatial variability of fracture intensity and lithological controls on fracture distribution. In general, higher fracture intensity occurs within the southern, southwestern and western portions of the field, and fracture intensity is greater within the fluvial sandstone deposits of the middle and upper Williams Fork formations. More than 90% of natural fractures occur in sandstones and siltstones. *In situ* stress analysis, based on induced-tensile fractures and borehole breakouts, indicates a NNW orientation of present-day maximum horizontal stress (S_{Hmax}), an approximate 20° rotation (in a clockwise direction) in the orientation of S_{Hmax} with depth and an abrupt stress shift below the Williams Fork Formation within the Rollins Sandstone Member.

Salvador

Jurassic evolution of the Gulf of Mexico salt basin

Michael R. Hudec, Ian O. Norton, Martin P. A. Jackson, and Frank J. Peel

ABSTRACT

We present a new hypothesis for the Jurassic plate-tectonic evolution of the Gulf of Mexico basin and discuss how this evolution influenced Jurassic salt tectonics. Four interpretations, some based on new data, constrain the hypothesis. First, the limit of normal oceanic crust coincides with a landward-dipping basement ramp near the seaward end of the salt basin, which has been mapped on seismic data. Second, the deep salt in the deep-water Gulf of Mexico can be separated into provinces on the basis of position with respect to this ramp. Third, paleodepths in the postsalt sequence indicate that salt filled the Gulf of Mexico salt basin to near sea level. Fourth, seismic data show that postsalt sediments in the central Louann and the Yucatan salt basins exhibit large magnitudes of Late Jurassic salt-detached extension not balanced by equivalent salt-detached shortening.

In our hypothesis, Callovian salt was deposited in preexisting crustal depressions on hyperextended continental and transitional crust. After salt deposition ended, rifting continued for another 7 to 12 m.y. before sea-floor spreading began. During this phase of postsalt crustal stretching, the salt and its overburden were extended by 100 to 250 km (62–155 mi), depending on location. Sea-floor spreading divided the northern Gulf of Mexico into two segments, separated by the northwest-trending Brazos transform. The eastern segment opened from east to west, leaving the Walker Ridge salient in the center of the basin as the final area to break apart. In some areas, salt flowed seaward onto new oceanic crust, first concordantly over the basement as a parautochthonous province, then climbing up over stratigraphically younger strata as an allochthonous province.

Andy

Athabasca oil sands: Megatrap restoration and charge timing

Richard S. J. Tozer, Albert P. Choi, Jeffrey T. Pietras, and Donald J. Tanasichuk

ABSTRACT

The petroleum trap for the Athabasca oil sands has remained elusive because it was destroyed by flexural loading of the Western Canada Sedimentary Basin during the Late Cretaceous and Paleocene. The original trap extent is preserved because the oil was biodegraded to immobile bitumen as the trap was being charged during the Late Cretaceous. Using well and outcrop data, it is possible to reconstruct the Cretaceous overburden horizons beyond the limit of present-day erosion. Sequential restoration of the reconstructed horizons reveals a megatrap at the top of the Wabiskaw-McMurray reservoir in the Athabasca area at 84 Ma (late Santonian). The megatrap is a four-way anticline with dimensions 285 × 125 km (177 × 78 mi) and maximum amplitude of 60 m (197 ft). The southeastern margin of the anticline shows good conformance to the bitumen edge for 140 km (87 mi). To the northeast of the anticline, bitumen is present in a shallower trap domain in what is interpreted to be an onlap trap onto the Canadian Shield; leakage along the onlap edge is indicated by tarry bitumen outliers preserved in basement rocks farther to the northeast. Peripheral trap domains that lie below the paleospillpoint, in northern, southern, and southwestern Athabasca, and Wabasca, are interpreted to represent a late charge of oil that was trapped by bitumen already emplaced in the anticline and the northeastern onlap trap. This is consistent with kimberlite intrusions containing live bitumen, which indicate that the northern trap domain was charged not before 78 Ma. The trap restoration has been tested using bitumen-water contact well picks. The restored picks fall into groups that are

consistent both with the trap domains determined from the top reservoir restoration and the conceptual charge model in which the four-way anticline was filled first, followed by the northeastern onlap trap, and then the peripheral trap domains.

Tim

Sedimentology, stratigraphy, and reservoir properties of an unconventional, shallow, frozen petroleum reservoir in the Cretaceous Nanushuk Formation at Umiat field, North Slope, Alaska

Grant T. Shimer, Paul J. McCarthy, and Catherine L. Hanks

ABSTRACT

Numerous oil and gas accumulations exist in the Brooks Range foothills of the National Petroleum Reserve in Alaska (NPRA). We use cores and well logs from 12 abandoned legacy wells at Umiat field, near the southeastern boundary of the NPRA, to characterize the sedimentology and stratigraphy of unconventional shallow frozen reservoirs in sandstones of the Cretaceous (Albian–Cenomanian) Nanushuk Formation. The Nanushuk Formation at Umiat has five facies associations: offshore and prodelta, lower shoreface, upper shoreface, delta front, and delta plain.

Three stratigraphically distinct, regionally extensive Nanushuk Formation depositional systems at Umiat contain several potential petroleum reservoirs. The lower Nanushuk Formation, including a reservoir interval known informally as the lower Grandstand, primarily consists of marine mudstone and shoreface sandstones. The middle Nanushuk Formation is dominantly deltaic and contains a second major reservoir interval in the informal upper Grandstand sandstone. Both the upper Grandstand and lower Grandstand are regressive. The transgressive upper Nanushuk Formation contains an additional potential reservoir interval in shoreface sandstones of the informal Ninuluk interval. The primary reservoir intervals at Umiat field are upper shoreface and delta-front sandstones in the upper Grandstand and lower Grandstand, where increased sorting and decreased bioturbation in high-energy depositional environments affect overall permeability and permeability anisotropy.