BPSM

Basin and Petroleum System Modeling Industrial Affiliates Program

3rd ANNUAL MEETING

NOVEMBER 5-6, 2010

Tressider Memorial Union, Stanford University

SCHOOL Of EARTH SCIENCES
DEPARTMENT OF GEOLOGICAL & ENVIRONMENTAL SCIENCES

BPSM Industrial Affiliates

for 2010

BP

Chevron

JOGMEC

Petrobras*

Schlumberger

* new for 2010

Meeting Attendees

From Industry and Academia

Jeffrey Allwardt, ConocoPhillips

Silvana Barbanti, IPEX

Wagner Bastos, Petrobras

Bonnie Bloeser, Aera Energy

Brad Cey, Chevron

Steven Crews, Hess

Jeremy Dahl, Stanford University

Hilario Camacho Fernandez, Occidental Oil and Gas Corporation

Changrui Gong, BP

Andrew Hanson, Univ. of Nevada Las Vegas

Zheng Hongju, PetroChina

Zehui (Tim) Huang, Marathon Oil

Olav Lindtjorn, Schlumberger

Tom Lorenson, U.S. Geological Survey

Marco Moraes, Petrobras

Ran Qigui, PetroChina

Mario Rangel, Petrobras

Tony Reid, Occidental of Elk Hills

Elin Rein, Statoil

Noelle Schoellkopf, Chevron

Vaughn Thompson, Oxy CA Exploration

Luiz Trindade, Petrobras

Kunihiro Tsuchida, JOGMEC

Wang Tongshan, PetroChina

Li Yongxin, PetroChina

Wang Zhaoyun, PetroChina

Stanford University BPSM Scientists and Graduate Students

Blair Burgreen, graduate student

Danica Dralus, graduate student

Keisha Durant, graduate student

Steve Graham, faculty

Meng He, graduate student

Bin Jia, graduate student

Carolyn Lampe, also at ucon Geoconsulting

Les Magoon

Tess Menotti, graduate student

Mike Moldowan, faculty

Tapan Mukerji, faculty

Ken Peters, also at Schlumberger

Allegra Hosford Scheirer

Bjorn Wygrala, also at Schlumberger

Meeting Announcement

The third annual Stanford University Basin and Petroleum System Modeling Industrial Affiliates Conference is scheduled for **Friday and Saturday, November 5 and 6, 2010.** The conference will be held in the Tressider Memorial Union Conference Facility, Stanford University. Six students will give talks and be available for questions on their basin and petroleum system modeling research, which may include work in the Salinas Basin, the Vallecitos Syncline of the San Joaquin Basin, the East Coast Basin of New Zealand, and the Sur Basin offshore of California, as well as geostatistical analysis of structural uncertainties in basin models, and lab experiments of the kinetics of the opal-CT to quartz transition as a function of temperature and pore fluid chemistry.

The following day (Saturday) will feature a field trip to the Salinas Basin near Monterey, where we have the opportunity in just one day to see outcrop sections and oil fields illustrating an entire petroleum system at work. For the source rock, we'll see bathyal, phosphatic organic-rich (type II, 4% TOC) mudstones of the basal Monterey Formation. This is a thermally mature source rock that has been inverted to the outcrop with a Ro of 0.6% frozen into it. For the overburden and seal rock, we'll see burial of the source rock by 2 to 3-km thick, organic-rich, biosiliceous upper Monterey Formation. As a proxy for the reservoir rocks, we'll see tar sand exposed in a roadcut near the San Ardo oil field. This outcrop also allows us to see migration pathways through fractured Monterey Formation, and the possibility of accumulations in fractured reservoir rocks. We'll see in two places the key elements of nature and timing of structures. Finally, we'll see all the elements and processes of the petroleum system come together in the giant San Ardo field and newly developed Lynch Canyon field. If there's time, we'll also visit Lynch Canyon field, which illustrates the rejuvenation of an old field with horizontal drilling technology and a new interpretation of the trap.

Registration information will appear on our website in mid-September: http://bpsm.stanford.edu

We look forward to sharing new developments in basin and petroleum system modeling research with you this fall.

Meeting Agenda

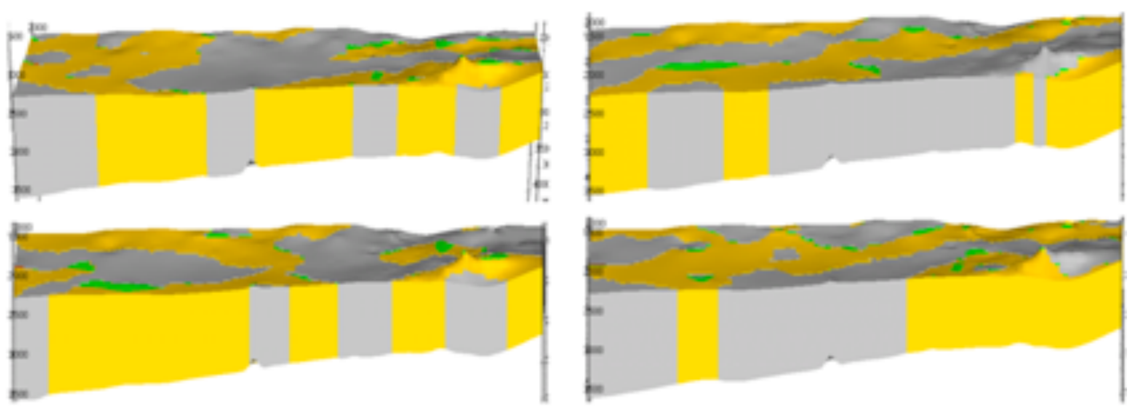
9:00 a.m.	Steve Graham	Introduction
9:20 a.m.	Tapan Mukerji	Basin modeling and spatial uncertainty: Links between BPSM & SCRF
9:40 a.m.	Bin Jia	Quantifying spatial uncertainty in basin and petroleum system modeling using geostatistics
10:15 a.m.	Tess Menotti	Modeling burial history and source rock maturation in the Salinas Basin, California
10:45 a.m.	Coffee break	
11:00 a.m.	Keisha Durant	Basin modeling study of the Sur Basin, California
11:20 a.m.	Allegra Hosford Scheirer	BPSM Research Group update
11:45 a.m.-1:30 p.m.	Lunch	
1:30 p.m.	Meng He	Geochemical and basin modeling study of the Vallecitos Syncline, California
2:00 p.m.	Danica Dralus	Kinetics of the opal-CT to quartz phase transition as a function of pore fluid chemistry
2:30 p.m.	Blair Burgreen	Basin and petroleum system modeling of offshore Hawke Bay, East Coast Basin, New Zealand
3:00 p.m.	Coffee break	
3:15 p.m.	Ken Peters	Timing of petroleum system events controls accumulations on the North Slope, Alaska
3:50 p.m.	Tess Menotti	Introduction to tomorrow's field trip to the Salinas Basin
4:00 p.m.	Steve Graham	Group Discussion

Presentation Abstracts

Linking Geostatistics with Basin and Petroleum System Modeling: Assessment of Spatial Uncertainties

Bin Jia

Basin and petroleum system modeling covers a large spatial and temporal interval. Many of the input parameters are highly uncertain. While probabilistic approaches based on Monte Carlo simulations have been used to address some uncertain parameters, the impact of spatial uncertainties remains unexplored. Maps of facies distribution are key inputs in basin models because all the rock properties are encompassed in facies definitions. Many techniques had been developed for facies modeling in reservoir characterization regime. These methods can be applied directly in basin modeling. In particular the "Multi-point Geostatistical Method" has been proven to be very effective in modeling categorical variables. Another important spatial parameter is the structure model. Present day structure model is the starting point for reconstruction of the deposition history. In this work we first conducted the traditional uncertainty analysis in basin modeling. Then the impact of facies distribution and structure uncertainty from time-to-depth conversion were studied. It is shown that facies distribution has great impact on the oil accumulation and different geological interpretations give quite different results. Structure uncertainty from seismic time-to-depth conversion has less impact in this case because the target area is quite homogeneous and it is expected that structure uncertainty is still the first order uncertainty sources in basin modeling.



Caption. Snesim (Strebelle, 2002) is used to generate multiple facies realizations from the training image, conditioned to the well data. Four realizations are shown here from which we can see the facies distribution variations (Yellow: Sand, Gray: Shale, Green: Hydrocarbon). Using PetroMod simulator, we get P10 of 558, P50 of 965 and P90 of 1848 MMbbls.

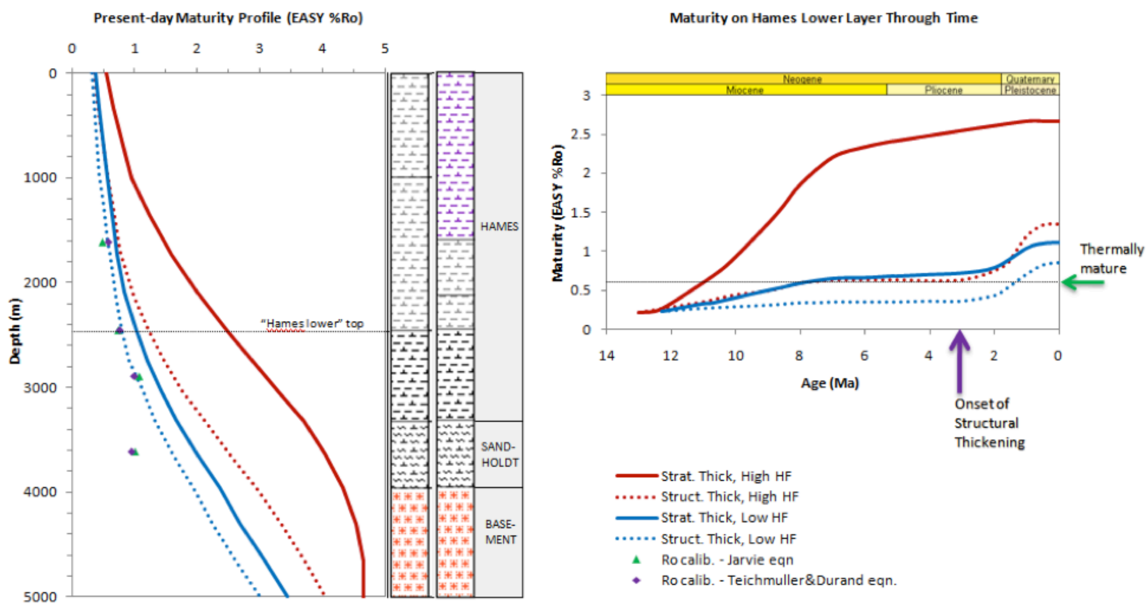
MODELING BURIAL HISTORY AND SOURCE ROCK MATURATION IN THE SALINAS BASIN, CALIFORNIA

Tess Menotti

The Salinas basin is a Cenozoic strike-slip basin in western central California, located east of the San Andreas Fault, and west of the Santa Lucia Range. This basin houses one of California's giant oil fields, San Ardo field, which has produced nearly half a billion barrels of oil since 1947. San Ardo is anomalously large in contrast to the six other oil fields in the basin, which collectively amount to 2% the size of San Ardo. Basin and petroleum system analysis can help provide an explanation for this skewed oil accumulation distribution. As the first step in developing more complicated models of the basin, one-dimensional (1D) burial history models were created in the Hames Valley syncline, the thickest depocenter of the basin, located 9 km southwest of the San Ardo oil field. The models were created for the Texaco Shell NCT-1 1 well which, at 3,000+ m (10,000+ ft) in depth, is the deepest well in the basin. This well penetrates the Hames and Sandholdt members of the Monterey Formation, but does not reach basement. A well located on the flank of the syncline, Shell Labarere 27X-21, does penetrate basement at 4,000 m (13,000 ft). Despite these significant depths, the Salinas basin is no longer at maximum burial depth: the shallowest thermally mature (0.6% R_o) source rock, which occurs within the Hames Member of the Miocene Monterey Formation, is currently at a burial depth of 2400 m (8000 ft); however, the present-day threshold for thermal maturation of the Monterey Formation in the neighboring San Joaquin basin occurs at 4000 m (13,000 ft) burial depth. Based on previously collected geochemical data, the 1D models use pyrolysis Tmax values for thermal calibration, and incorporate source rock properties of type II kerogen with 3 wt% TOC and 700 mgHC/gTOC hydrogen index.

Through sensitivity testing, initial modeling has helped identify the controlling factors on thermal maturation at this location. This work is necessary to understand which boundary conditions must be refined in order to narrow the range of possible burial history scenarios. The controlling factors on thermal maturation calibration include 1) the temporal basal heat flow trend, 2) thermal conductivities of the Monterey sediments, 3) the amount of depositional overburden, of which much may have been eroded, 4) the amount of overburden due to structural thickening, and 5) the timing of overburden emplacement. The range of model results has implications for mapping the extent of active source rock in the Salinas basin, and the timing of hydrocarbon generation relative to trap formation. In addition to significance to the petroleum system, these models shed light on potential thermal evolution histories of the Salinas basin in the context of its complex tectonic setting. Model results indicate that a combination of late-stage (Plio-Pleistocene) structural thickening and a relatively low heat flow (30 mW/m^2) history is necessary for model calibration.

Caption. On the left is a thermal maturity-depth profile for four 1D model scenarios testing the impact of stratigraphically thick overburden on the source rock versus structurally thickened overburden, and high and low heat flow histories. The model that fits the calibration data best combines low heat flow with a late-stage structural thickening of the Monterey Formation. The figure on the right demonstrates the effect these models have on source rock maturation timing.



BASIN AND PETROLEUM SYSTEM MODELING OF THE SUR BASIN, OFFSHORE CENTRAL CALIFORNIA

Keisha Durant

The Sur Basin (informally called the Partington Basin) is an ~1800 km^2, asymmetric, structural basin offshore of the southern part of the central California margin, bounded to the south by the San Martin structural discontinuity, and to the northeast by a nearshore fault. The structural discontinuity separates the undeformed basement of the Sur Basin from the irregular basement of the offshore Santa Maria Basin. The Sur Basin has experienced down-to-basin vertical separation along the nearshore fault on the east, which has lowered the ~3 km thick upper Tertiary strata against the elevated basement of the late Mesozoic Franciscan Complex.

Sulfur-rich type IIS kerogen in the Miocene Monterey source rock in the nearby Santa Maria Basin has generated significant amounts of heavy, sulfur-rich crude oil. This study investigates whether the Monterey formation in the Sur Basin has also generated oil using 1D PetroMod models. There is no well data or outcrop samples available from the Sur Basin, therefore rock units, the age of unconformities and the timing of geologic events have been inferred indirectly from evidence in neighboring basins through correlation with seismic data available in the Sur Basin.

A pseudo-well for the model was created in the deepest part of the basin determined using isopach maps from a previous study (green star; figure). The pseudo-well penetrates the Upper Foxen, the Lower Foxen, Lower Sisquoc and the Monterey Formations, and penetrates basement at ~5200 meters. Based on geochemical data from the offshore Santa Maria Basin, the 1-D model incorporates source rock properties of a type IIS kerogen with 3 wt% TOC and 650 mgHC/gTOC hydrogen index. A relatively low-magnitude heat flow history was assumed, based on companion studies in the adjacent onshore Salinas Basin. Preliminary model results will be presented.

Caption. Map of the Sur Basin and the Offshore Santa Maria Basin. Green star denotes location of the 1D model.

One-dimensional burial history model gives new insights into petroleum systems in the Vallecitos area and oil field, San Joaquin Basin, California

Meng He

The Vallecitos Syncline is a westerly structural extension of the western San Joaquin basin. By the end of 1959 the Vallecitos field, comprised of eight separate producing areas (Griswold Canyon, Franco, Cedar Flat, Ashurst, Silver Creek, Pimental Canyon, Central, and Los Pinos Canyon), produced approximately 2.2 MMBO and 1.5 BCF of gas from Cretaceous and Paleogene reservoirs. Cumulative oil and gas production through 2007 in the Vallecitos area reached 5.4 MMBO and 3.9 BCF, respectively. However, dispersed oil accumulations in the Vallecitos area make oil and gas exploration challenging. Further, prominent features of the Vallecitos Syncline in published works document complex subsurface geology and tectonic events. In order to better understand petroleum systems in the area and demonstrate oil generation locally, 1D burial histories were generated for the Vallecitos areas. These are important to understand the origin of the oils captured in the present-day traps in this syncline.

The 1D model is based on a pseudo-well located at the axis of Vallecitos Syncline where the overburden rock above the uppermost Cretaceous Moreno Formation is thickest. The pseudo-well was compiled from two nearby wells, Ne-Tex 1and Ortis 48-24. Using a cross-section through the pseudo-well and these two wells, there appears to be no basis for adding additional eroded stratigraphic section to the model, even though erosion removed significant overburden on the flank of the syncline. The thickness of the stratigraphic section and migration of the Mendocino triple junction were considered in terms of the heat flow for the model. Results suggest that in the Vallecitos Syncline the bottom and the top of the Cretaceous Moreno Formation reached thermal maturity at 19 Ma and 9 Ma, respectively. The synclinal Eocene Kreyenhagen Formation became thermally mature at 4 Ma. The 1D model results indicate that the Kreyenhagen Formation achieves a maximum transformation ratio (TR) of 18% present day while the Moreno Formation researched a TR of 100% in the Vallecitos Syncline. These results are supported by biomarker and diamondoid geochemistry, which indicate that the Kreyenhagen oils contain a high-maturity component that could originate from the Moreno Formation. The results differ from early interpretations that the Eocene Kreyenhagen Formation was the only source rock in the Vallecitos Syncline.

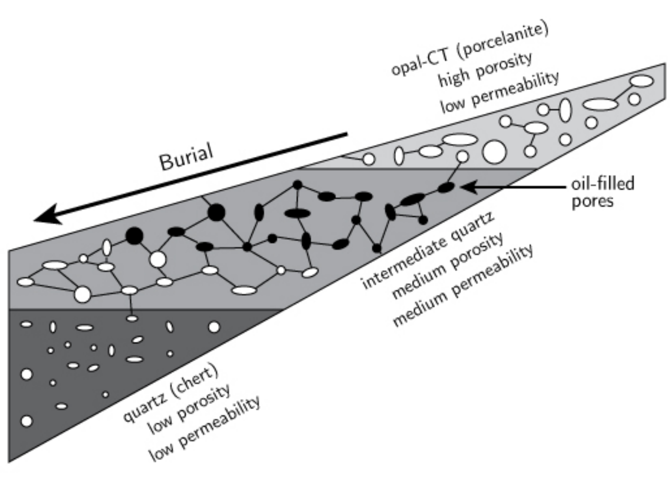
Kinetics of the opal-CT to quartz phase transition as a function of pore fluid chemistry

Danica Dralus

Chert and porcelanite originate from marine diatoms as diatomite, which undergoes diagenetic conversion from amorphous opal (opal-A) to cristobalite and tridymite (opal-CT) and finally quartz. Porosity generally decreases during this process. However, permeability can increase during the transformation from opal-CT to quartz. This intermediate period of higher permeability can result in stratigraphic traps for petroleum like those discovered in the Rose and North Shafter fields in the San Joaquin Basin. Subsurface changes in silica phase can be difficult to identify using seismic data, so the ability to accurately predict locations of these diagenetic traps would be a valuable exploration tool.

A previous study (Ernst and Calvert, 1969) determined zero-order kinetics for the opal-CT to quartz phase transition based on hydrothermal experiments using distilled water. However, this phase transition is a dissolution and re-precipitation process whose rate depends on a variety of rock and pore fluid properties including surface area, dissolution rate, and silica solubility. This study aims to determine kinetic parameters for the opal-CT to quartz transition based on hydrous pyrolysis of two natural samples: a weathered Monterey Formation porcelanite from Lompoc, California, which also contained dolomite; and a Wakkanai Formation porcelanite from Hokkaidō, Japan, which also contained quartz, albite, and some organic material. Unlike the previous study, temperatures were kept below the critical temperature of water, and the aqueous solution was buffered so that final fluid pH values measured between 7.0 and 8.2. Under these conditions, the samples showed a large variation in conversion rates, with the rates of the Monterey opal-CT the Wakkanai opal-CT conversions approximately five times faster and three times slower, respectively, than the rate predicted by Ernst and Calvert.

In addition to geochemical data, geophysical data will also be obtained for these samples, including porosity, hydraulic conductivity, and acoustic velocities. These data and the kinetics can be incorporated directly into petroleum system models of basins with siliceous layers.



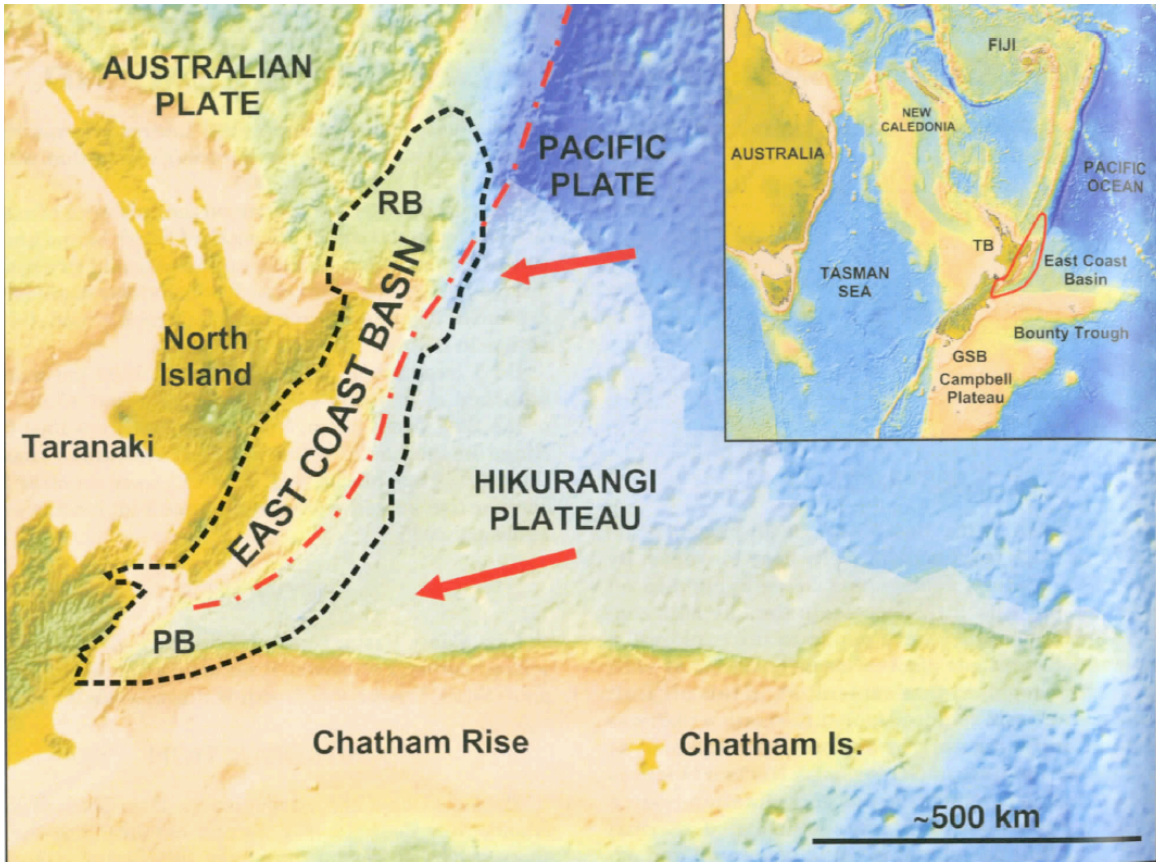
OFFSHORE BASIN AND PETREOLEUM SYSTEM MODELING IN A FOREARC SETTING: HAWKE BAY, EAST COAST BASIN, NORTH ISLAND, NEW ZEALAND

Blair Burgreen and Stephan A. Graham

This study investigates the offshore forearc basin and petroleum system of the East Coast Basin in the Hawke Bay region of the North Island, New Zealand. The basin initiated in the early Miocene in association with the Hikurangi subduction zone, and is still an active margin. The forearc region is geologically complex consisting of numerous elongate sub-basins built through imbricate thrust faulting that have localized developmental histories. Hawke Bay is known to be charged with gas, but has been minimally explored. In 2005, Crown Minerals of New Zealand conducted a high quality offshore 2-D seismic reconnaissance survey of the basin, dramatically increasing and improving the data available for this region.

Previous 1-D modeling in Hawke Bay indicate that the main source of gas is not generated from the two main source rocks in the region, the Waipawa and Whangai Formations, but possibly from a deeper, lesser understood source rock. However, poorly constrained basal heat flow causes large uncertainties in timing and total maturation of the source rocks. Additionally, 1-D modeling does not adequately account for the tectonically driven structural and stratigraphic complexities that are characteristic of forearc systems.

The goal of this study is to better constrain and understand the nature and impact of thrusting on the system, particularly in terms of heat flow, burial, and timing. This will be accomplished through modeling of a palinspastically reconstructed 2-D line from the 2005 survey using Petromod TecLink. Modeling can also reveal additional insights on the impact of uplift and erosion, and constrain the timing of faults required to achieve basin connectivity. Other large uncertainties that will be addressed include the thickness and quality of source rock, and the impact of advective heat flow.



Caption. Map of the East Coast Basin. Black dashed line indicates approximate basin extent. Red dashed line indicates Hikurangi trench. RB = Raukumara Basin; PB = Pegasus Basin (Uruski et al., 2006).

Timing of Petroleum System Events Controls Accumulations on the North Slope, Alaska

Ken Peters[1], Oliver Schenk[2], Ken Bird[3]
[1]Schlumberger Information Solutions *and* Stanford University, kpeters2@slb.com, 18 Manzanita Place, Mill Valley, CA 94941
[2]Schlumberger, Ritterstrasse 23, 52072 Aachen, Germany
[3]U.S. Geological Survey, 345 Middlefield Road, Menlo Park, CA 94025

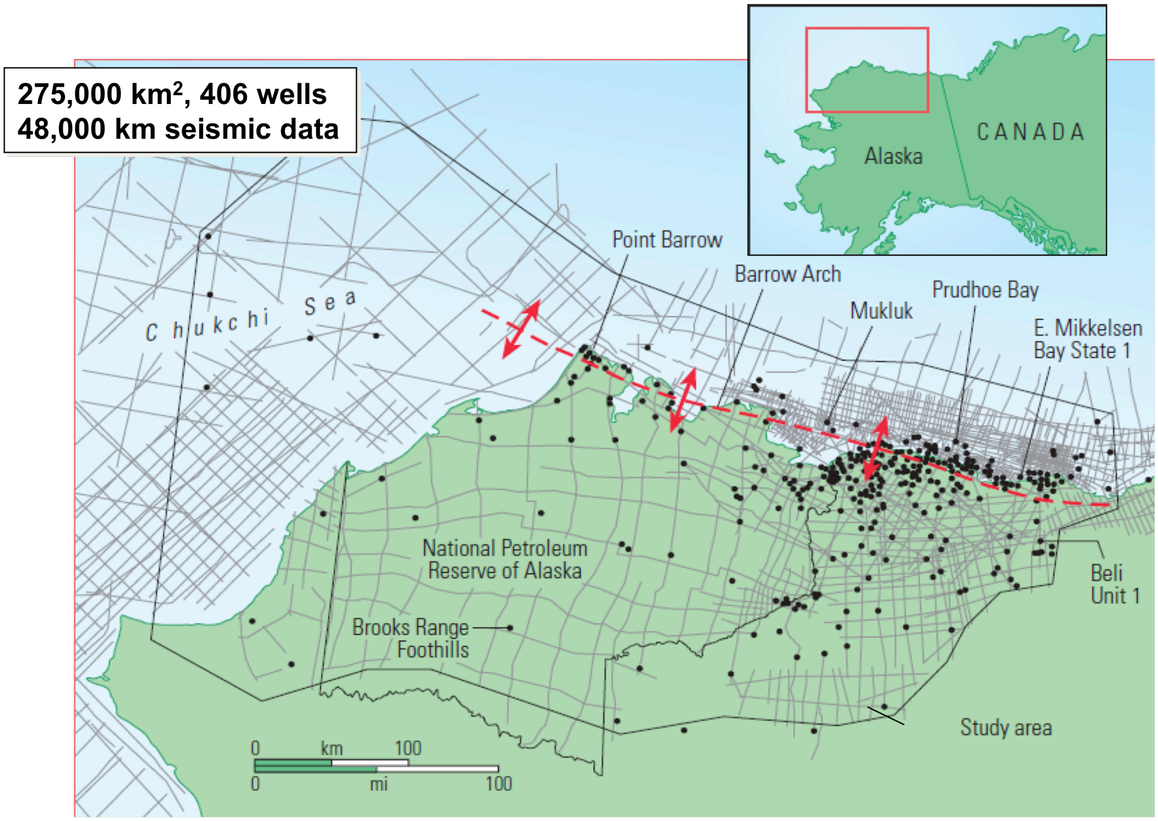
The Alaska North Slope (Figure) is estimated to contain most of the undiscovered oil and gas in the circum-Arctic. Results from a calibrated 3D basin and petroleum system model for this region demonstrate the importance of the relative timing of trap formation and expulsion from the source rock. Petroleum system event charts for four examples from the model in the foothills of the Brooks Range, Prudhoe Bay, Mukluk, and the Barrow Peninsula show how the relative timing of these events impacts risk.

The event chart for a location in the foothills of the Brooks Range shows significant risk for accumulation because stratigraphic traps formed at about the same time as expulsion from the Triassic Shublik Formation source rock. Risk is also high for accumulations in structural traps formed after expulsion, because they can fill only by remigration from older stratigraphic traps.

At Prudhoe Bay, trap formation preceded expulsion, resulting in a major accumulation. Biomarkers show that Prudhoe Bay field contains mixed oil from the Triassic Shublik Formation and Cretaceous Hue-gamma ray zone (Hue-GRZ) with lesser input from the basal Jurassic Kingak Shale. These results are consistent with the 3D model, where Shublik and Kingak source rocks started to expel petroleum during the Cretaceous, while the Hue-GRZ contributed later.

Debate persists over the reasons for failure of the Mukluk wildcat well. At the time of drilling, the Mukluk structure was estimated to contain 1.5 billion bbl of recoverable oil in a structural-stratigraphic trap, although subsurface imaging was uncertain due to difficulty in assessing seismic velocities. Drill cuttings showed extensive oil stain in the target formation. The 3D model shows that petroleum accumulated, but spilled from the structure to the southeast through the Kuparuk C-D interval toward the Kuparuk River field during Tertiary tilting.

Preliminary 3D simulations predicted a large petroleum accumulation on the Barrow Peninsula, although only a few small gas fields are known (S. Barrow, E. Barrow, Sikulik) near the Avak structure, which resulted from a middle-late Turonian meteor impact. Our revised 3D model accounts for the effects of the meteor impact on temperature and permeability of the target rocks. The model predicts a large accumulation prior to impact, but predicted present-day accumulations occur only to the west, south, and east of the Avak structure, in agreement with known accumulations.



Caption. The three-dimensional basin and petroleum system model of Alaska North Slope covers an area of 275,000 km^2 and is based on 48,000 km of seismic data and stratigraphic or geochemical information from more than 400 wells. Four locations were selected to demonstrate the importance of the relative timing of petroleum system events: Brooks Range foothills, Prudhoe Bay, Mukluk, and Point Barrow.