AAPG HEDBERG CONFERENCE
"Carbonate Characterization and Simulation: From Facies to Flow Units"
March 15-18, 2004 – El Paso, Texas

Characterization and Simulation of the Panoma Field (Wolfcampian); a Tight, Thin-Bedded Carbonate Reservoir System, Southwest Kansas

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The Panoma Field (Council Grove Group, Wolfcampian) in southwest Kansas (Figure 1) lies stratigraphically subjacent to the more prolific Hugoton Field (Chase Group), and has recovered 2.8 TCF of gas from approximately 2,600 wells across 1.7 million acres since its discovery in the early 1960's. Combined with the Hugoton Field (24 TCF) the area is the largest gas producing region in onshore North America, yet no comprehensive geologic model and field-wide reservoir study has been completed for the Panoma. This modeling and simulation project is an outgrowth of the Hugoton Project, a five-year industry, university and government funded consortium whose purpose was to develop technology and information to better understand the oil and gas resources of the Hugoton Embayment in southwest Kansas. The five-year consortium ended in July 2003, but the Panoma modeling project initiated in late 2002 is ongoing.

The immense volume modeled and simulated (200 cubic miles - 830 cubic kilometers over 5,200 square miles - 13,500 square kilometers), the need to represent fine scale vertical (0.5 to 2 meter scale) and lateral (1-5 kilometer scale) lithofacies heterogeneity, and problematic fluid saturations present challenges that are being managed by novel approaches and automation. The anticipated outcomes of the collaborative project are improved field management, evaluation of potential for "stranded" gas in low resistivity tight reservoirs, and characterization of possible communication of the Panoma with the overlying Hugoton. Reservoir management benefits include 1) exploitation of under-produced regions through infill and replacement wells; 2) identification of wells that are candidates for additional fracture stimulation; and 3) identifying and testing potentially productive intervals that have been bypassed. Methods employed for lithofacies prediction, management of upscaling from more than 300 layers to a more manageable number, and techniques used to develop lithofacies-based petrophysical property transform equations are departures from the more traditional work flow for simulations.

The Panoma Field produces gas from the upper seven sequences of the Permian Council Grove Group each containing 50% nonmarine siliciclastics, mostly eolian derived, and 50% thin-bedded marine carbonates and siliciclastics in a two hundred foot (60 meter) gross interval. Lithofacies controlled petrophysical properties dictate gas saturations and discrimination of lithofacies reduces standard error in permeability prediction in marine carbonate facies by a factor of twelve. Nonmarine siliciclastic facies error was reduced by a factor of three. Field-wide upscaling of lithofacies distribution for reservoir characterization in this large heterogeneous reservoir was facilitated by the use of a neural network, trained on core defined lithofacies, selected wireline log curves and geologic constraining variables, used in an automated process to predict lithofacies at 0.5 foot intervals in approximately 500 non-cored wells distributed across the field. These wells and their associated lithofacies and porosity were used to develop static cellular geologic and petrophysical models within a structural framework defined with tops data from 10,700 wells. Porosity was obtained from normalized wireline logs from the 500 wells. Lithofacies and porosity were upscaled at the 500 wells into layers scaled by proportional layering methods. Sequential indicator simulation, biased by facies distribution and geometry statistics, was employed to predict facies and porosity between the 500 wells.

Fundamental to construction of the reservoir geomodel was the population of cells with the basic lithofacies and their associated petrophysical properties - porosity, permeability, and fluid saturation. Directly measured fluid saturations by wireline logs are inaccurate and not correctable due to extreme and variable invasion, thus accurate property-based estimated saturations are required. Petrophysical properties vary between the eight major lithofacies classified. Equations were developed to predict permeability and water saturation using porosity and lithofacies as the independent variables because porosity data is readily available and is well correlated with the other variables for a given lithofacies. Each lithofacies exhibits a relatively unique *in situ* Klinkenberg (high-pressure gas or liquid-equivalent) gas permeability (k) power-law relationship with porosity, though the relationship changes in some facies at porosities below ~6%. Capillary pressures and corresponding water saturations (Sw) also vary between facies, and with porosity/permeability and gas column height. Threshold entry pressures and corresponding heights above free water level are well correlated with permeability and tied back to porosity.

Seven cellular static models (rather than one), one for each sequence, were constructed during the lithofacies, porosity and permeability upscaling phase in order to efficiently manage the shear volume of cells required to maintain vertical and lateral heterogeneity. Layer rich models (one-two foot layers) with relatively small cell dimensions (1000 X 1000 feet) were required. Cell counts range from six to fifteen million per model depending upon thickness. In initial single well simulations the seven sequence models with 27-79 layers per model were each upscaled to as few as four layers per model prior to being combined into one 41-layer model for simulation, down from 327 layers total. Initial small-scale (single well) simulations using upscaled static model are favorable. Upscaling issues of larger scale dynamic models are the next challenges to be managed.

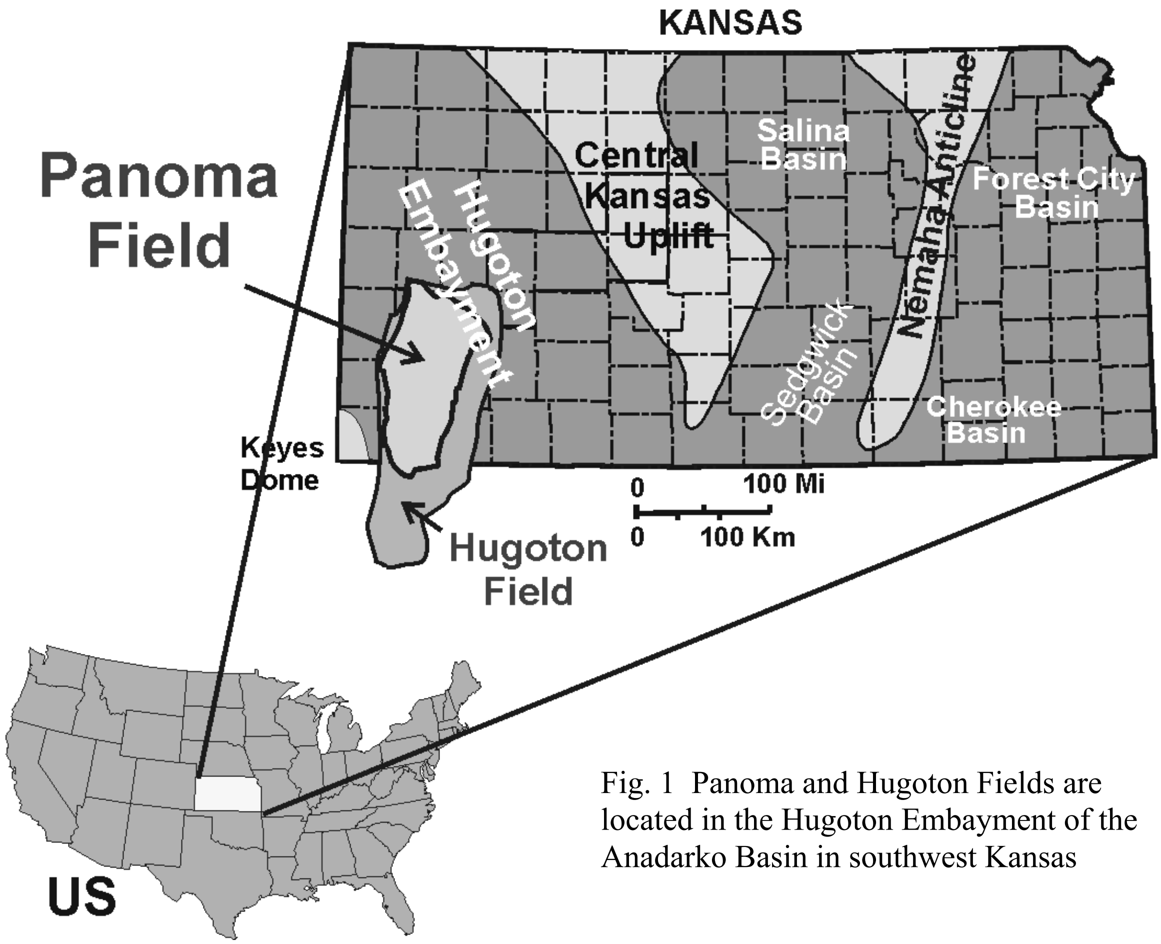

Fig. 1 Panoma and Hugoton Fields are located in the Hugoton Embayment of the Anadarko Basin in southwest Kansas