CHAPTER 11. CONCLUSIONS

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The 108-million cell, 10,000 mi^2 (26,000 km^2), 3-D geologic and petrophysical property geomodel of the Hugoton presented in this study demonstrates application of a detailed reservoir characterization and modeling workflow for a giant field. Core-based calibration of neural-net prediction of lithofacies using wireline-log signatures, coupled with geologically constraining variables, provided accurate lithofacies models at well to field scales. Differences in petrophysical properties among lithofacies and within a lithofacies among different porosities illustrate the importance of integrated lithologic-petrophysical modeling and of the need for closely defining these properties and their relationships. Lithofacies models, coupled with lithofacies-dependent petrophysical properties, allowed the construction of a 3-D geomodel for the Hugoton that has been effective at the well, section (1mi^2, 2.6 km^2), and multi-section scales. Validity of the model workflow and model itself are supported by 1) pressure and production history-match simulations of multi-section extracts of the model, and 2) comparisons of the three-dimensional lithofacies patterns with earlier work at smaller scales and with depositional models that have been proposed for the area and for Upper Paleozoic cyclic depositional systems in general.

The model is a tool for predicting lithofacies and petrophysical properties distribution, water saturations, and OGIP that provides a quantitative basis for evaluating remaining-gas-in-place, particularly in low-permeability intervals. The model may prove instrumental in evaluating current practices and consideration of modified well-bore geometry and completion practices that will potentially enhance ultimate recovery. The reservoir characterization and modeling from pore-to-field scale discussed provides a comprehensive lithologic and petrophysical view of a mature giant Permian gas system. Both the knowledge gained and the techniques and workflow employed have implications for understanding and modeling similar reservoir systems worldwide. As the world's giant fields mature, high-resolution modeling at the full-field scale in data-rich environments will become increasingly important, and the Hugoton model is a large-scale example for developing such models.

Overall Key Observations and Findings:

1. The Kansas-Oklahoma portion of the field has yielded 35-tcf gas (963-billion m^3) over a 70-yr period from over 12,000 wells, and an estimated 65% of the original gas in place in the central portion of the field.
2. The Hugoton gas reservoir is a dry-gas, pressure-depletion reservoir with very little or no support from the underlying aquifer.
3. Most remaining gas is in lower permeability pay zones of the 170-m (500-ft) -thick, differentially depleted, layered reservoir system.
4. Despite being layered and differentially depleted, multiple lines of direct and indirect evidence suggest the Chase (Hugoton) and Council Grove (Panoma) behaved as a common reservoir system during the fill and production phases.

5. Main pay zones represent 13 shoaling-upward, fourth-order marine-continental cycles, comprising thin-bedded (2-10 m), marine carbonate mudstone to grainstone and continental siltstone to very fine sandstone.
6. Lithofacies bodies are laterally extensive and reservoir storage and flow units exhibit extensive lateral continuity.
7. Water saturations determined from wireline logs are problematic due to filtrate invasion during drilling, and saturations estimated using capillary pressure methods are believed to be more accurate.
8. Petrophysical properties vary among the 11 major lithofacies classes, and therefore an accurate lithofacies model is essential.
9. The Hugoton reservoir free-water level (FWL) is sloped and is estimated to occur at a subsea depth of +1000 ft (+300 m) at the western margin of the Hugoton and at approximately +50 ft (+15 m) at the east margin.
10. Rigorous model variogram analysis resulted in generally long ranges (30,000 ft) for both lithofacies and porosity; because horizontal ranges for estimated variograms are much greater than node-well spacing (often <10,000 ft), modeling cells between node wells was nearly deterministic.
11. The lithofacies model is sufficiently robust to represent fine-scale heterogeneity at well to field scales.
12. Automation for processing large volumes of data was crucial to the success of the modeling workflow.
13. Algorithms (tied to lithofacies) for assigning properties (permeability and water saturation) were effective at well to field scales.
14. Simulations validated static model properties, and therefore the techniques employed in the modeling workflow. Simulations achieved matches without modifying static model properties (mainly permeability) beyond the first standard deviation for the variable or beyond the anticipated adjustment range to handle model variability.
15. Production appears likely to be sustainable through 2050 (based on simulation work), provided the integrity of 40 to 70-yr-old wells can be maintained.
16. The project demonstrates the benefits of pooling proprietary geologic and engineering data in settings having multiple operators, typical of giant reservoir systems worldwide.

MODEL CONSTRUCTION

The goal to develop a model with sufficient detail to represent vertical and lateral heterogeneity at the well, multi-well, and field scale required that the model be finely layered (169 layers, 3-foot (1 m) average thickness) and have relatively small XY cell dimensions (660x660 ft, 200x200 m; 64 cells per mi^2). These criteria resulted in development of a 108-million cell model for the10,000-mi^2 (26,000 km^2) area modeled. Due to computational and software application constraints, the model was divided stratigraphically into six sub-models, three in the Chase and six in the Council Grove. The Hugoton static geomodel was constructed using Petrel™, Schlumberger's reservoir modeling software.

Model input data included the following:

1. Lithofacies and porosity at half-foot (0.15-m) intervals for 1600 node wells.
2. Well header information to relate porosity and lithofacies to XYZ space.
3. Formation-member level tops set for 8850 wells.
4. Grids representing seven structural framework horizons and the free water level constructed in Geoplus Petra™.

Proportional layering within the models used the following hierarchy:

1. Division between formation/members (24 zones).
2. Further subdivision into 169 layers based on minimum vertical thickness of the key lithofacies in the node wells. Layers averaged 2 ft thick in the marine intervals and 4 ft thick in the continental intervals.

Modeling lithofacies and porosity was accomplished with these steps:

1. Upscale lithofacies from 1/2-ft to layer *h* by "majority vote" at the node wells.
2. Upscale porosity from 1/2-ft to layer *h* by arithmetic averaging at the node wells, biased by upscaled lithofacies at the node wells.
3. Model lithofacies between node wells using Voxel-based sequential indicator simulation as implemented in Petrel™. Vertical proportion curves were generated in the application's data analysis tool and variograms were estimated from node well data outside of Petrel™, conditioned on the upscaled lithofacies values in the node well cells.
4. Model porosity values between node wells were generated using sequential Gaussian simulation as implemented in Petrel™, utilizing porosity transforms generated with the application's data analysis tool, variograms estimated from node well data outside of Petrel™, and conditioned by lithofacies.

Rigorous model variogram analysis resulted in generally long ranges (30,000 ft) for both lithofacies and porosity. Sequential indicator simulation (lithofacies) and sequential Gaussian simulation (porosity) were employed to estimate the value for cells between wells. Both are stochastic processes, however, because the horizontal ranges for the estimated variograms were much greater than node well spacing (often <10,000 ft); modeling cells between node wells was nearly deterministic.

Cells in the geomodel were populated with permeability and saturations by utilizing: 1) the petrophysical algorithms, discussed in Chapter 4, section 4.2, 2) the lithofacies model discussed above where lithofacies was assigned to each of the 108-million grid cells, 3) the porosity (ϕ) model discussed above, and 4) for water saturations and relative permeability, the capillary-pressure models discussed in Chapter 4, section 4.2, and the free-water level model discussed in Chapter 7, section 7.2. Finally, original-gas-in-place (OGIP) for each grid cell was calculated for an initial bottom-hole pressure = 465 psi and gas-compressibility factor (Z) = 0.92.

Multiple iterations of the model (four) rather than one as implied by the workflow diagram (Figure 6.1) proved very effective because: 1) adjustments could be made after discovery of new knowledge (e.g., Chase and Council Grove behave as a common reservoir rather than as separate reservoir systems), 2) it allowed critical tactical decisions to be made early in the process (e.g., lithofacies class boundaries and number of lithofacies), 3) it facilitated participation and technical review by industry partners, and 4) early results could be disseminated to industry partners for their immediate use.

DEPOSTIONAL MODEL

Typically, depositional models are used to help guide the construction of lithofacies models, particularly in object-based models, and to provide a model for validation of the lithofacies model by comparison. In this study, the lithofacies model was instrumental in helping to refine depositional models established by prior workers in this setting. Idealized depositional models for the Council Grove (Figure 3.4) and Chase (Figure 3.5) are similar, but differences exist due to gradual changes in climate, ambient sea level position, and sea level fluctuation rate. Differences may be related to a shift from more icehouse to more greenhouse conditions in the Permian (Parrish, 1995; Olszewski and Patzkowsky, 2003). For all studied Council Grove cycles, the entire Hugoton shelf was above sea level during maximum lowstand. Continental redbed siliciclastics accumulated, were stabilized by vegetation, and built relief preferentially near the field’s west updip margin (Dubois and Goldstein, 2005). Accommodation for the carbonate sediments of the overlying marine half-cycle was reduced, leading to non-deposition, or pinchouts, of several marine intervals in the Council Grove at that position. During Chase lowstand, the lateral extent of subaerial exposure on the shelf was generally more limited, and in some “continental” intervals, tidal-flat siltstone and very fine-grained sandstone is prevalent, particularly in positions lower on the shelf. Points significant to the model are given below:

1 Model intervals (zones) were defined within a simple cyclic rather than a sequence stratigraphic framework. Existing formation or member tops are half-cycle boundaries between marine and continental intervals and represent a sequence boundary and flooding surface, and little is gained by correlation of an additional surface (maximum flood) for sequence-stratigraphic classification.
2 Slope on the Hugoton shelf was approximately 1 ft/mi (0.2 m/km) during the deposition of the Council Grove Group and maximum water depth was approximately 100 ft (30 m).
3 Vertical succession of lithofacies in a shoaling-upward pattern in both the Council Grove and Chase Groups (Figure 3.6) resulted from depositional environments changing across the shelf in response to rapid sea level fluctuation.
4 Low relief and a rapidly fluctuating sea level (glacially forced) resulted in broad lithofacies belts that migrated across the shelf in response to absolute sea-level change rather than progradation resulting from the reduction of accommodation by sedimentation.

LITHOFACIES IN CORE, NODE WELL, AND MODEL SCALES

Because petrophysical properties vary among lithofacies, fundamental to reservoir characterization and the construction of a cellular-reservoir model is the population of cells with lithofacies. The primary goal for lithofacies modeling in this study was to develop a model with sufficient detail to represent vertical and lateral heterogeneity at the well, multi-well, and field scale. Results suggest that the goal was achieved:

1. Quantitative measures of lithofacies proportions (Table 6.5) in core, neural-network-predicted lithofacies at node wells, upscaled at the node wells and in the 108 million-cell model, show consistency at the different scales, suggesting that the sample rate for training and lithofacies prediction in each of the three steps was sufficient.
2. Direct comparison with known models cannot be made because none exists at this scale; however, the Hugoton model is consistent with earlier work at smaller scales (Garlough and Taylor, 1941; Hubbert, 1953; Pippin, 1970; Parham and Campbell, 1993; Fetkovitch, et al., 1994; Oberst et al., 1994, Seimers and Ahr, 1990; Olson et al., 1997; Heyer; 1999; Sorenson, 2005).
3. The core-to-model lithofacies workflow was sufficiently robust to characterize smaller important lithofacies bodies in the reservoir system (Krider bioclasts-ooid shoal, Figures 6.12-D, E, F, 6.18, and 6.19; phylloid algal-mound system, Figure 6.19).
4. The static model as a whole is validated by production and pressure matched simulation studies.
5. Estimation of OGIP at well, multi-well, and county scale is realistic (Chapter 10).

Lithofacies classification

Determining the number of lithofacies classes and the criteria for defining classes involved four objectives: (1) maximum number of lithofacies recognizable by neural networks using petrophysical wireline-log curves and other variables, (2) minimum number of lithofacies needed to accurately represent lithologic and petrophysical heterogeneity, (3) maximum distinction of core-petrophysical properties among classes, and 4) the relative contribution of a lithofacies class to storage and flow. An optimal solution using these criteria resulted in 11 lithofacies.

Lithofacies predicted at node wells

A number of factors enabled the success of the neural networks in predicting lithofacies at 1600 node wells:

1. Lithofacies classes were chosen to maximize differences in the signature of wireline-log variables.

2. The training data set (28 continuous cores) provided an appropriate number of lithofacies examples in three dimensions (geographic (XY) and stratigraphic (Z)).
3. Wireline log-curves (gamma ray, neutron- and density-porosity, deep-resistivity and photoelectric-curves), coupled with geologic variables were effective predictor variables.
4. Geologic variables, relative position with respect to the base of half-cycles, and marine-nonmarine indicator, served to constrain the lithofacies predicted by adding geologic knowledge to the input variable set.
5. Neural-network models were trained for three separate stratigraphic intervals that included cycles with similar characteristics, the upper Chase, lower Chase except Wreford, and Council Grove plus the Wreford (lowermost half-cycle of the Chase).

<u>Distribution of lithofacies in the model</u>

The full-field geomodel presented reveals lithofacies and property patterns that could not be identified at smaller scales. General trends in thickness and lithofacies distribution are evident in the 3-D volume (Figures 6.10 to 6.19):

1. Continental rocks are thickest and marine carbonate intervals thin or pinch out at Hugoton's western updip margin and the relationship is nearly reciprocal basinward.
2. The important reservoir lithofacies (grain supported carbonate, dolomite, marine, and continental sandstone) are laterally extensive.
3. Marine carbonates, the primary pay zones, are separated by laterally continuous continental siltstone with poor vertical transmissibility.

Extensive lateral continuity of lithofacies, with typical lithofacies geobody size much larger than spacing between node wells, contributed to the success of the sequential indicator simulation of the lithofacies distribution in the full-field-scale model:

1. Large-scale sedimentation patterns, interpreted from lithofacies distribution, are striking when viewed at the scale made possible by the full-field-scale model.
    - Back-stepping of major marine lithofacies between cycles associated with changes in water depth and energy and position on the shelf.
    - Marine carbonates in the middle three of the seven Council Grove cycles (Figure 6.10C) pinch out at the western field margin.
    - Lateral continuity in the main reservoir lithofacies illustrated in Figures 6.12 through 6.19 where county-scale "connected volumes" are sub-parallel to depositional strike and the field margin but vary from cycle-to-cycle, most likely a function of changing hydrodynamics due to third order cyclicity and overall global climatic shift from icehouse to greenhouse during the Lower Permian.
2. Smaller important lithofacies bodies in the reservoir system are characterized by the core-to-model lithofacies workflow. Examples include dolomitized grainstone

and packstone of a relatively thick (30 ft, 10 m) carbonate ooid-bioclast-sand shoal system in the Krider (Figures 6.12-D, E, F, 6.18, and 6.19) and phylloid algal-mound system in the Cottonwood Limestone Member (B5_LM), Figure 6.19.

From a reservoir perspective, another important revelation in the model is the lateral continuity in the high-quality reservoir lithofacies illustrated in Figures 6.12 through 6.19. County-scale "connected volumes" of the more significant reservoir lithofacies (relatively high porosity and permeability) are sub-parallel to depositional strike and the field margin.

1. Grain-supported packstone-grainstone is found primarily in the eastern half of the field while muddier lithofacies are dominant in the western, more sheltered, and shoreward portion of the shelf.
2. The updip extent of rocks having grain-supported texture varies from cycle –to cycle, and the variability is most likely a function of changing hydrodynamics due to third-order cyclicity and overall global climatic shift from icehouse to greenhouse during the Lower Permian (Parrish and Peterson, 1988; Ross and Ross, 1988; Parrish, 1995; Rankey, 1997; Soreghan, 2002).
3. In the Council Grove, the main pay lithofacies are packstone-grainstone (L7) and very fine-crystalline dolomite (L6); however, the phylloid algal bafflestone lithofacies (L8) is important locally. Marine sandstone (L10) does not contribute to Council Grove production except in the Grenola (C_LM) in the very southwest corner of Texas County, Oklahoma (Figure 6.14), where the production is associated with a FWL that is different from that of the Hugoton-Panoma reservoir system (see Chapter 7). Continental sandstone (eolian), a significant reservoir where it occurs, is limited to the northwestern updip margin in the Council Grove (Figure 6.12B and 6.16)
4. Major contributing lithofacies are more variable in some Chase zones (Towanda, Krider, and Winfield) (Figure 6.15). The most prolific reservoir lithofacies is medium-crystalline moldic dolomite (L9), which is restricted to the Chase. Other high quality lithofacies are L7 and L10. L9, essentially dolomitized L7, is best developed in the middle to upper Chase (Towanda, Winfield, and Krider), while L7 dominates the grain-supported category in the Wreford and Fort Riley. Marine sandstone contributes significantly to reservoir volume in the Towanda, Winfield, and Herington. Where two major reservoir lithofacies coexist in the Towanda, Winfield, and Krider, they tend to be best developed in different areas of the shelf rather than overlap (Figure 6.15). Shallow marine and tidal-flat sandstone in the upper Chase is most abundant in the northwestern half of the field area (6.12C and Figure 6.17).
5. Distributions of lithofacies-dependent properties (porosity, permeability, and water saturation) reflect the lithofacies distribution (Figure 6.20), and the best porosity and permeability coincide with the main reservoir lithofacies (Figure 6.13). Laterally extensive low-permeability intervals separate the relatively high-permeability pay zones of the layered reservoir system. Water saturations are high in the confining intervals, and the "gas-water" contact crosses stratigraphic

boundaries at the east downdip margin as the pay intervals dip below the FWL and on the west where the free-water level is thought to rise more quickly than the rate of dip.

PETROPHYSICAL PROPERTIES

Fundamental to development of the geomodel for the Hugoton is the development of a suite of equations that predict petrophysical properties from widely available data. Data for routine porosity, permeability, and grain density were compiled for over 8,200 full-diameter and plug core samples from measurements performed by commercial laboratories and the Kansas Geological Survey. Data for these are presented in Table 4.2.1 (Appendix 4.2.1). Data are reported for cores from 34 wells geographically distributed across the Hugoton field area (Figure 4.2.1). For the 8,200 core samples, 3,700 (45%) are Chase Group and 4,500 (55%) are Council Grove Group samples. Of the 8,200 core samples, 5,300 (65%) are full-diameter and 2,900 (35%) are core plugs. Because a significant fraction of the rocks in the Hugoton have low porosity (ϕ<8%) and low permeability (k<1 md), core-analysis properties measured using routine laboratory methods do not necessarily reflect reservoir conditions. Petrophysical analysis of Hugoton and Panoma reservoir rocks indicates that accurate reservoir-properties prediction requires input of lithofacies, use of properties that represent reservoir (i.e., *in situ*) conditions, and filtering of permeability data for micro-fractured core. Principal conclusions for petrophysical properties follow.

Grain Density

Grain densities of Hugoton rocks are generally consistent with the mineralogy of constituent lithofacies. Accurate density porosity-log interpretation requires the input of matrix density. Matrix densities differ among lithofacies and within a given lithofacies differ among stratigraphic units, tending to decrease with increasing depth. Of particular note are the high grain densities of all marine and continental siliciclastic units and associated lithofacies. Important conclusions concerning matrix density are:

1. Mean density of all siltstone and shale intervals average 2.70$\pm$0.01 g/cc.
2. Mean density of most limestone is 2.71$\pm$0.01 g/cc
3. Mean density of most dolomite is 2.83$\pm$0.03 g/cc
4. Within a lithofacies class, grain density is 0.02 to 0.05 g/cc greater in the Chase than the Council Grove intervals, which is interpreted as resulting from greater fractions of anhydrite and dolomite.

Porosity

Routine (unconfined) helium porosity (ϕ_{He}) values range from 1% to 34%, averaging 9.2$\pm$5.1% (1 s.d.) but with a median of 8.7% and mode of 7.0%. Routine helium porosity data are important, but in lower-porosity rocks can differ from reservoir values sufficiently to affect reservoir characterization. Accurate reservoir porosity is especially important when other petrophysical properties are tied to porosity and to wireline-log porosity. Routine-helium porosity (ϕ_{He}) can be corrected to *in situ* reservoir porosity (ϕ_i) using

$$\phi_i = 1.02\phi_{He} – 0.68.$$

Comparing porosity among lithofacies and between stratigraphic intervals leads to the following conclusions:

1. In the continental siliciclastics, mean porosity decreases with decreasing grain size (i.e., very fine sandstone to siltstone).
2. In the limestones, porosity increases with increasing grain size and decreasing mud-fraction texture. Mean porosities increase with lithofacies class: L4-6.3$\pm$3.5%, L5-8.0$\pm$4.5%, L7-9.8$\pm$4.5%, and L8-10.4$\pm$4.4% (error 1 s.d). This porosity increase is both a function of increasing interparticle porosity and increasing moldic porosity development.
3. Although the medium-crystalline sucrosic moldic dolomite lithofacies (L9) represents a major reservoir lithofacies because of high permeability, in the cores sampled this lithofacies exhibits a mean porosity (11.7+5.4%) slightly lower than the fine-crystalline sucrosic dolomite lithofacies (L6; 12.5+6.3%).
4. Comparing the Chase and Council Grove, Chase very fine-grained sandstones (L0) and coarse siltstones (L1) exhibit greater porosity than the Council Grove. Chase limestones exhibit higher fractions of rocks with porosity greater than 8% than Council Grove.

Permeability

Full-diameter and core plug-measured routine-air permeabilities range from 0.0001 md to 2690 md (n = 7,650). Though the database of full-diameter air-permeability measurements is large (n = 5,300), a significant fraction (25%) are described or annotated as fractured and an unknown number of cores may contain unidentified hairline fractures that can significantly affect permeability in samples with matrix permeability less than 0.5 md. Important conclusions concerning permeability are

1. Comparison of full-diameter permeabilities and core-plug permeabilities as well as DST-measured permeabilities indicate that much routine full-diameter permeability data are influenced by coring-related or stress-release micro-fractures for permeabilities below approximately 0.5 md and may not be suitable for reservoir properties characterization.
2. Because of the low permeability of most rocks, it is important to correct for confining stress and Klinkenberg gas slippage effect. An empirical equation relating *in situ* Klinkenberg-gas permeability (k_{ik}) with routine-air permeability (k_{air}) is

$$\log_{10}k_{ik} = 0.059 (\log_{10}k_{air})^3 –0.187 (\log_{10}k_{air})^2 +1.154 \log_{10}k_{air} - 0.159.$$

3. Nearly 80% of Hugoton rocks exhibit an *in situ* Klinkenberg permeability less than 1 md, 56% less than 0.1 md, and 35% less than 0.01 md.
4. Comparing permeability among lithofacies, average permeability decreases with decreasing grain size (i.e., very fine sandstone to siltstone) in the continental and marine siliciclastics, from grainstone to mudstone in the limestones, and from medium-crystalline sucrosic moldic to very fine- to fine-grained sucrosic texture in dolomites.
5. Continental very fine-grained sandstones (L0) exhibit permeabilities ranging from 2 to 5 times those of coarse-grained siltstones, although coarse siltstones (L1) exhibit a similar permeability distribution to shaly siltstones (L2), and mean permeability of the L2 lithofacies (0.0025md) is half that of the L1 lithofacies (0.0052 md), though given the standard deviation of both lithofacies ($\pm$70X at 1 s.d.) the difference is not significant.
6. Marine siliciclastic sandstones (L10) exhibit significantly greater permeability than marine siltstones (L3).
7. Hugoton limestones exhibit increasing permeability with increasing grain size and decreasing mud-fraction texture. Mean permeabilities increase with lithofacies class: L4-0.00011 md, L5-0.0016 md, L7-0.091 md, and L8- 3.6 md. This permeability increase is both a function of increasing interparticle porosity and increasing moldic-porosity development.
8. The medium-crystalline sucrosic moldic-dolomite lithofacies (L9) represents a major reservoir lithofacies because a significant fraction of these rocks exhibit $k >$ 3 md. Though the fine-crystalline sucrosic dolomite lithofacies (L6) exhibits porosities slightly higher than the L9 lithofacies, permeabilities for this finer-grained facies are generally lower.
9. For the major lithofacies characterized in the Hugoton, each defined lithofacies exhibits a relatively unique k_{ik}-ϕ_i correlation that can be represented using a power-law equation of the form

   $$k_{ik} = A\ \phi_i^{\ B}$$

   where k_{ik} is in millidarcies (md), porosity is in percent (%), and values for A and B vary among lithofacies. Some lithofacies in some stratigraphic intervals exhibit k_{ik}-ϕ_i trends sufficiently different from the general lithofacies k_{ik}-ϕ_i trend that a unique k_{ik}-ϕ_i equation is warranted to improve permeability prediction.
10. Crossplots of *in situ* Klinkenberg permeability versus *in situ* porosity for each group of lithofacies display sub-parallel trends for the continental siliciclastics, marine siliciclastics, limestones, and dolomites. At $\phi_i > 6\%$, permeability in a phylloid algal bafflestone (L8) can be 60-100X greater than mudstone/mud-wackestone (L4) and >100X greater than marine siltstone (L3) of similar porosity. Within their principal range of porosity overlap (ϕ_i=2-10%), packstone/grainstones (L7) can exhibit 10-50X greater permeability than mudstone/mud-wackestones (L4). These differences illustrate the importance of identifying lithofacies to more accurately predict permeability from wireline-log porosity.

11. For the continental sandstones, vertical to horizontal permeability ratio (K_{vert}/ K_{havg}) averages 14%. Limited data for the very-fine to fine-grained sandstones indicate a higher average for the L0 lithofacies near 17%. Marine siltstones and sandstones exhibit an average of 18%. Within the limestone lithofacies the mudstone/mud-wackestone exhibits low K_{vert}/ K_{havg} (17%), with the remaining lithofacies exhibiting significantly higher K_{vert}/ K_{havg} L5-30%, L7-38%, and L8-25%. The dolomite lithofacies exhibit the highest K_{vert}/ K_{havg} with L6-37% and L9 – 33%. Average K_{vert}/ K_{havg} for the basic lithofacies groups are continental siliciclastics-14%, marine siliciclastics – 18%, limestones-32%, and dolomites-34%.

Water Saturation and Capillary Pressure

It is important to take into account the presence of water in the pore space of low-permeability reservoirs both for accurate volumetric calculations and because water occupies critical pore-throat space and can greatly diminish gas permeability, even in rocks at "irreducible" water saturation (S_{wi}). In the Hugoton, determination of formation water saturation from electric wireline-log response is problematic because of deep mud filtrate invasion with conventional mud programs due to the low reservoir pressure (Olsen et al., 1997; George et al., 2004). Because water saturations cannot be reliably determined for most wells using logs, saturations were estimated based on matrix capillary-pressure properties and determination of the free-water level (level at which gas-brine capillary pressure is zero). Air-mercury capillary pressure data were compiled and measured for 252 samples ranging in porosity, permeability, and lithofacies, and relationships were developed that allowed the prediction of a capillary-pressure curve for any given lithofacies and porosity. Capillary pressure conclusions:

1. A fractal-based method for predicting capillary-pressure curves for each lithofacies at any given porosity was used. This method allowed the input of equations into Petrel^{TM} that calculate a unique water saturation for each gridcell based on the cell porosity, lithofacies, and height above free-water level.
2. Capillary-pressure properties differ among lithofacies in the Hugoton and differ within lithofacies among rocks of different porosity/permeability. It is important to precisely model the exact capillary-pressure relationships to accurately model water saturation in the field.
3. Over 90% of all Hugoton rocks tested for capillary pressure exhibit a unimodal pore system or a significant fraction of the pore volume from $10\%<S_w<100\%$, which can be modeled using a single $\log H_{afwl}$-$\log S_w$ function. Regression coefficients of correlation between $\log H_{afwl}$ and $\log s_w$ for over 90% of all samples exceeded $r^2=0.94$, and 65% exhibited $r^2 = 0.98$-1.00. Using linear regression analysis the dimensionless height fractal slope, H_f, of all capillary pressure samples was determined and correlated with porosity. This correlation exhibits wide scatter for all lithofacies undifferentiated but gives improved correlation on a lithofacies-specific basis.

Relative Permeability

Limited work has been performed on the relative permeability of Hugoton rocks and even less has been published. To provide relative permeability models for the dynamic reservoir simulations, gas-water drainage relative permeability data were compiled for 32 samples representing a range of lithofacies. These data did not test the relative permeability for rocks with absolute permeability k_{ik}< 0.1 md and did not include an adequate population of continental fine- to coarse-grained siltstones. To model the continental and marine siliciclastics, equations developed for other low-permeability siliciclastics, and summarized recently (Byrnes, 2005), were adopted. In general

1. Gas and water drainage relative permeability curves for the Hugoton samples reveal several characteristics similar to other low-permeability rocks. Water permeability, even at 100% S_w, is less than Klinkenberg-gas permeability and decreases with decreasing permeability. Gas-relative permeability is less than the absolute-gas permeability at all water saturations greater than zero and gas-relative permeability decreases significantly as Sw increases above 50%.
2. Gas and water relative permeability was modeled in the carbonates and low-permeability siltstones and sandstones using the modified-Corey (1954) equations:
   $$k_{rg} = (1 - (S_w\text{-}S_{wc,g})/(1\text{-}S_{gc}\text{-}S_{wc,g}))^{\boldsymbol{p}} \, (1\text{-}((S_w\text{-}S_{wc,g})/(1\text{-}S_{wc,g}))^{\boldsymbol{q}})$$
   $$k_{rw} = ((S_w\text{-}S_{wc})/(1\text{-}S_{wc}))^{\boldsymbol{r}}$$
3. For the Hugoton rock samples studied with k_{ik}>0.1 md, the gas relative permeability curves could be modeled using exponents of $\boldsymbol{p} = 1.3 \pm 0.4$ (1 s.d.), $\boldsymbol{q}$ = 2, and $S_{wc,g} = 0$.

WATER SATURATION AND FREE-WATER LEVEL

It is well recognized by operators in the Hugoton that determination of formation water saturations from induction wireline-log response is problematic due to high mud filtrate invasion (George et al., 2004), and it was decided to estimate water saturations based on matrix capillary-pressure properties and determination of the free-water level (FWL, level at which gas-brine capillary pressure is zero).

Water saturations based on matrix capillary-pressure properties

1. Geomodel calculation of gridcell saturation is based on predicted gridcell lithofacies, predicted gridcell porosity, predicted free-water level, and the capillary pressure equation for the lithofacies and porosity at the gridcell height above free-water level.
2. Possible error in predicted water saturation was estimated by comparing probability-weighted saturations and the baseline-model saturations. Average error between the probability-weighted saturations and the baseline-model saturations is -1.0%. The region where error exceeds 5% is in the transition zone

unique to each lithofacies-porosity combination. Within the transition zone, water saturation errors can reach up to 15%.

Free-water level geometry

Estimating the free-water level (FWL) position is critical for calculating water saturations using capillary pressures and the height above FWL. It has been recognized that the Hugoton field has a sloped gas-water contact (Garlough and Taylor, 1941; Hubbert, 1953, 1967; Pippin, 1970; Sorenson, 2005). Implicit in the assumption that there is a single FWL for the Council Grove and Chase is that they are part of a common reservoir and that there is a continuous gas column. The estimated model FWL subsea depth is approximately +50 ft (+15 m) at the east margin of the Hugoton, to +20 ft (+6 m) at the Panoma margin and, moving west, begins to rise at a rate of 15 ft/mi (2.85 m/km) to a datum of +250 ft (+80 m), where it then rises at 50 ft/mi (9.4 m/km) to a height of +1000 ft (+300m) at the western margin of the Hugoton (Figure 7.2.1).

The FWL was estimated using a combination of three indicators:

1. Base of lowest perforations in the Council Grove, beneath the Panoma.
2. Position where log-calculated water saturation equals 100% in Chase pay zones outside of the Panoma boundary in Kansas.
3. Calculation of the FWL required for an estimated original gas in place for Chase in parts of Texas County, Oklahoma.

RESERVOIR COMMUNICATION

Despite being layered and differentially depleted, multiple lines of direct and indirect evidence suggest the Chase (Hugoton) and Council Grove (Panoma) behaved as a common reservoir system during fill and production phases. Flow within and between layers is dominantly matrix flow, based on core-plug to DST permeability correlations and simulation studies. However, other mechanisms (natural and hydraulic fractures) in addition to matrix flow between 1/2-cycle zones is required to account for observations of pressure vs. production plots and to match production and pressure in simulation studies.

Communication from core, DST, and crossflow simulation

Fundamental to modeling Hugoton gas production is an understanding of the relative contribution of lithofacies/beds within defined productive intervals and of the nature of communication between intervals.

1. Matrix-scale arithmetically upscaled interval permeabilities and DST-measured permeabilities show good correlation. For the wells analyzed, this can be

interpreted to indicate that matrix properties dominate flow at the scale of full-diameter core.

2. It is important to note that although the wells examined here exhibit matrix-driven properties, fractures are present in Hugoton cores and in the Hugoton field.
3. Reservoir simulation modeling of simple layered-flow systems similar to those present in the Hugoton can be interpreted to indicate that a single, 1-ft-thick, high-permeability bed can effectively drain overlying and underlying beds and that the radius of influence is controlled principally by the thin-bed permeability and the vertical permeability.
4. Siltstones that separate marine carbonate 1/2-cycles are restrictions rather than barriers to flow. Vertical permeability changes with H_{afwl}. Siltstones with ϕ_i>12% exhibit k_v> 1x10^{-5} md over nearly the entire vertical section and are not a barrier to flow but can be a restriction at H_{afwl} < 200 ft. Siltstones with ϕ_i<8% are water saturated over much of the rock column and may initially present barriers to flow. However, with pressure depletion in overlying beds, it is possible that high-pressure underlying gas-charged beds may displace water from the overlying siltstones into the depleted overlying beds, and vertical communication may be established where there was none at the start.
5. Dewatering of the siltstones into overlying low-pressure carbonates may be occurring. The nature of possible dewatering is a complex function of the differences in capillary-pressure properties between the beds, the initial water saturations, and the pressures in the overlying, underlying, and siltstone beds. Pressure depletion of high-permeability beds would shift them lower on their capillary-pressure curve, which would increase the capillary force for them to imbibe water from adjacent saturated intervals. Under the condition that such dewatering of siltstones, or low-permeability carbonates, occurs, some gas will be moved from high-permeability intervals into low-permeability intervals.

Communication between Chase and Council Grove based on pressures

Though regulated as separate fields in Kansas, in most places the gas column is continuous between the Chase (Hugoton) and Council Grove (Panoma) inside the Panoma field boundary (Pippin, 1970; Parham and Campbell, 1993) and reaches a maximum thickness of 500 ft (150 m) in the west-central part of the study area. Pressure data are a very effective means of evaluating communication between reservoir volumes, however, because wellhead pressure tests in the Chase and Council grove are commingled multi-zone tests, and WHSIP does not accurately reflect BHP for all layers (Table 8.3.2) and more closely approximates the zone having the highest permeability, greatest depletion, and lowest pressure. Although it is certain that 72-hour WHSIP cannot be used to project remaining GIP, it remains a useful metric in evaluating communication and relative depletion and is available for practically all wells through time in the field. Three lines of 72-hour WHSIP evidence suggest the two reservoirs (Chase - Hugoton and Council Grove – Panoma) are in communication:

1. Hugoton and Panoma WHSIP generally track one another through time (Figure 8.3.4).
2. At <300 psi, Panoma initial WHSIP was significantly lower than original (435 psi) field pressure when most of the Panoma development occurred in the 1970's (Figure 8.3.3). Assuming that both reservoirs started at the same WHSIP (435 psi), the Panoma was partially depleted when most of the field was drilled.
3. Pressure (WHSIP) vs. cumulative production plots demonstrate interference among all vintages of wells (Panoma interfered with Hugoton parent, Hugoton infill interfered with both Hugoton parent and Panoma) at multiple scales (well, multi-well, and county) (Figures 8.3.5, 8.3.6 and 8.3.7).
4. Co-existence pressure anomalies through space and time for the Chase and Council Grove (separately) and of basement faults and/or fractures suggest that naturally occurring large-scale regional fractures or swarms of smaller fractures in Chase and Council Grove may contribute to communication (Figures 8.3.9 through 8.3.15).

Communication between zones and Chase and Council Grove based on simulation studies

Matching production and zone-pressure histories with minimal modifications to the static model guided the strategies for reservoir simulation on portions of the static models created (Chapter 9). Simulations suggested that there is communication between zones and between the two reservoir systems:

1. Where both Chase and Council Grove are productive but offset in starting date (Chase first), communication in addition to natural vertical permeability between the two reservoirs must be allowed for an adequate history match to be attained.
2. Naturally occurring vertical permeability in siltstone zones provided sufficient communication between zones to partially deplete zones that had not been perforated in one of the simulations (Hoobler).

Communication by hydraulic fractures

Relatively large hydraulic fractures are applied in practically all (if not all) completions in both the Chase and Council Grove. Fracture treatments are generally applied to multiple zones simultaneously and are susceptible to extending beyond the zones being stimulated as suggested below:

1. Hecker and Downie (1996) reported on modification of fracture methods to reduce the downward growth of fractures in the Chase.
2. Our modeling of hydraulic fractures in the Flower area suggests that typical hydraulic fractures applied to the Chase stay in the Chase.
3. Our modeling also suggests that typical hydraulic fractures applied to the Council Grove extend vertically all the way to the Krider (upper Chase).

SIMULATION STUDIES

A principal goal for the Hugoton study was to build a single static geomodel for the entire Wolfcamp system that is sufficiently robust to be accurate on a local scale. Ideally, areas to be simulated could then be extracted from any location in the model, upscaled, and simulated, without significant modification in properties. Three multi-section (9-12) and multi-well (14, 28, and 39) reservoir simulations were conducted in three distinct reservoir settings:

- Flower – field center; thick (450’) gas column including complete Chase (7 zones) and upper 6 zones of Council Grove,
- Graskell - Panoma field margin, 300’ gas column, complete Chase (6 zones) and upper 1-2 zones in Council Grove, and
- Hoobler - outside of Panoma, thin gas column (150-200’), upper 4-5 zones in the Chase.

Simulations rigorously matched pressure and production in most wells in simulated areas and achieved their objectives:

1. Validated properties in the static model for the Chase and Council Grove reservoir system.
2. Characterized and quantified remaining gas in the simulation areas.
3. Projected future production.

Key points:

1. Simulations achieved matches without modifying static-model properties (mainly permeability) beyond the expected range resulting from algorithm uncertainty, validating the static model properties, and therefore, the techniques employed in the modeling workflow.
2. The Chase and Council Grove must be simulated together where there is Council Grove production because vertical communication, whether natural or induced by completion techniques, results in the Chase and Council Grove behaving as a common reservoir system.
3. The recovery factor (RF) from initial production to present (2005) ranges from 53 to 69% of the estimated static-model volumetric OGIP (Hoobler, 53%; Graskell, 64%; Flower, 69%), values that are consistent with that of the static model at well-, multi-well and county-scales.
4. The layered reservoir system is differentially depleted with zones having high permeability presently being 85-95% depleted (e.g., Flower model, Krider zone, p = 22 psi, 95% depleted). Zones with lower permeability are nominally depleted, at 56-61% depletion (e.g., Flower model, upper and lower Fort Riley zones, p = 201 and 178 psi).
5. The amount of depletion is correlated with reservoir properties (permeability), which are not very well correlated stratigraphically (by zone). However, there is a tendency for the upper Chase to be the most depleted and the lower Chase and upper Council Grove to contain the largest volumes of remaining gas due to their

lower permeability (<0.01 md). The Flower area exhibits this relationship; however, in the Graskell simulation area, the Fort Riley (lower Chase) is depleted while the Krider (upper Chase) is not.

6. Production forecasts suggest that future production rates will exhibit a hyperbolic decline rate. Flower rates decreased from 8% to 2% in the 45-year period tested (2005-2050).
7. Current wells are likely to remain economically productive with existing completion configurations for at least another 45 years (extended simulation period), if the Flower simulation model is correct and accurately represents the central portion of the field. Recovery increased from 69% to 80%, with the 38 wells averaging 21 mcfpd per well at the end of the simulation. Significant gas (16.3 BCF) remained in four zones in the lower Chase and upper Council Grove in the 9-section area at that time.
8. Natural matrix vertical permeability (Kz) can contribute to communication between zones; however, additional communication is required to obtain production and pressure matches in two of the three multi-section simulations. The Hoobler area is an example where matrix Kz was adequate to drain the Towanda even though it had not been perforated in the field or in the simulation model.

Technical aspects:

1. Dynamic model cell dimensions, 660' cell width and one layer per zone (24-25 formation/member zones), provide a good solution. Sensitivity tests for layering strategies in the Flower area indicate that nothing is gained by using layering that is finer than the formation/member level.
2. Upscaling portions of the finely layered static model for simulation, from 169 layers to 24, is an efficient way to derive a simulation model (volume-weighted arithmetic average for porosity and water saturation; tensor upscaling using PSK solver in Petrel^{TM} for permeability).
3. Portions of the static model can be efficiently extracted from the six submodels and combined for simulation (see appendix: *Geomod4_build*).
4. Modifying flow capacity by increasing the well productivity (ff) factor in the cells penetrated by the well bore is an effective proxy for modeling the influence of a hydraulic fracture on well production.
5. Permeability modifications that may be required to achieve adequate flow may be estimated by comparing model properties with permeability by zone from other sources (DST or core). For the Flower, permeability multipliers developed in this manner for the 6 of 25 zones that required multipliers averaged 5.2x.
6. Flowing wellhead-tubing pressure recorded bi-annually as part regulatory testing requirements provides a pressure to match in the absence of zone pressure data.

ORIGINAL AND REMAINING GAS IN PLACE

Based on the success of the flow simulations and comparison with production numbers, it can be characterized that a single set of rules, relationships, algorithms, and workflow can be applied on a giant gas field scale (6,000 square miles) and model area (10,000 square miles) and result in a realistic property-based volumetric OGIP at multiple scales. Volumes estimated, tabulated, and evaluated at the well, multi-well, county, and field scale are consistent with other volumetric methods and with anticipated field performance based on field properties, particularly in the portion of the field that accounts for most of the production. What may appear to be a discrepancy in the Council Grove recovery factor (i.e., too high) may instead be a function of Chase gas produced by "Council Grove" wells being attributed to the Council Grove (Chapter 7 and Chapter 9). It is tempting to categorically say that the OGIP must be too high because it is higher than others have suggested, and we would probably agree that it may be too high in some areas, as discussed. It should also be stated that much of the apparent "overage" is in the perimeter of the field where properties are poorer in general. These areas are also lower in the transition zone where small changes in FWL make a very large difference. Some of the difference is likely also to be in the gas attributed to some of the poorer reservoir facies (silts) that may account for 8% of the HCPV that other workers may not have considered in their GIP calculations.

Key observations:

1. Wolfcamp (combined Chase and Council Grove) OGIP is likely to be most accurate in the center of the field where control is best on the cellular-model properties and the free-water level.
2. Cumulative-gas production for Grant and Stevens counties is 15.1 tcf or 65% of calculated OGIP (23.3 tcf).
3. Pressure- and production-matched simulation models in the two counties have similar recovery factors (Flower – 69%, Graskell – 64%).
4. Cumulative-gas production for the entire study area is 35 tcf or 52% of calculated OGIP (67.9 tcf).

<u>OGIP by lithofacies</u>

The main reservoir facies are marine carbonates, primarily those having grain-supported textures (lithofacies code 6-10, fine crystalline dolomite, packstone, grainstone, medium crystalline moldic dolomite and sandstone), and sandstones; the distribution of storage and flow capacity are largely controlled by the distribution of lithofacies and porosity. Table 10.1.5 illustrates pore volume (PV), hydrocarbon pore volume (HCPV), and OGIP by lithofacies for the entire Wolfcamp in version Geomod 4-3. It also shows the ratio of the volume by lithofacies and total volume for the three metrics, and the ratio of the HCPV to PV. Table 10.1.6 provides the same data for the Chase and Council Grove Groups, separately. All four statistics present a more meaningful view (in terms of reservoir) of the relative proportions of pore space and pore space occupied by gas for each lithofacies, than do lithofacies occurrence data alone. The most useful of the statistics in terms of understanding the control that lithofacies has on pore-throat diameter, permeability, and capillary pressure is the HCPV/PV ratio.

Key observations:

1. Lithofacies 1-4 (continental coarse and fine siltstone, marine siltstone, and mudstone) have very low HCPV/PV ratios due to small pore throats resulting in inability to desaturate except at very high elevations above FWL.
2. Lithofacies 5-9 (wackestone, fine crystalline dolomite, packstone-grainstone, and moldic dolomite) have ascending HCPV/PV ratios due to larger and larger pore throats with decreasing mud fraction.
3. L9 accounts for 11% of the pore space but 21% of GIP.
4. L10 (marine sandstone) and L0 (continental sandstone) are effective reservoirs and contribute significantly, L10 in the Chase and L0 in the Council Grove.
5. Continental coarse silts (L1) account for 20% of the pore space but only 6% of GIP.
6. Chase HCPV/PV ratios are higher than Council Grove ratios for the same lithofacies because they have greater height above the FWL.
7. Continental and marine sandstones have a high HCPV/PV ratio, to some degree, because of their geographic position and the corresponding height above FWL of these areas.
8. Continental siliciclastics (L0-2) contain 27% of PV and 9% of OGIP for the Wolfcamp (22%-8% in the Chase and 55%-36% in the Council Grove).

<u>Remaining gas in place</u>

Throughout this study a unifying theme appears to have been supported: the Hugoton and Panoma reservoir is a layered system that behaves as a single, extremely large reservoir system, although its layers are differentially depleted. Very limited historical pressure by zone tests and early simulations by Mobil (Fetkovich et al., 1994) and Phillips (Oberst et al., 1994) suggested differential depletion was occurring, and our four simulation studies (Figure 10.1.1) confirm, refine, and expand this concept. Through literature, searches of public records, and contributions of historic and recently collected data by participants in HAMP we have compiled a database of 375 zone tests from 38 wells scattered throughout the field (Figure 10.2.1), an accomplishment, but a very small sample considering that their are 12,000 wells in the field.

Key observations:

1. Zones with high permeability have current pressures (estimated by simulation) of approximately 25 psi, approximately equal to current WHSIP, and are 95% depleted.
2. Zones with moderately low permeability have relatively high current pressures, approximately 200 psi, are 45% depleted, and contain significantly more gas than the zones with high permeability.
3. The amount of depletion is a function of the rock properties and does not always correlate with stratigraphy (zone). However, there is a tendency for the upper

Chase to be depleted while the lower Chase and upper Council Grove are less depleted at present.

4. Production appears likely to be sustainable, provided the integrity of 40 to 70-yr old wells can be maintained. Production projected to 2050 in the 28 Flower model wells suggests that most of the additional gas recovered (21.3 BCF) is primarily from zones having lower permeability, average well production is estimated to be 21 mcfpd/well, decline rate is <2%, and the RF increases to 81% of OGIP.

Additional work for model improvement and topics deserving further investigation:

1. Investigate regions of the model where the cumulative gas production to OGIP ratio appears anomalous and establish compartments and modify properties or parameters where justified. It is suspected that the free-water level may need to be adjusted in a few regions
2. Explore the potential for adding a “current pressure” property to the cellular model. One approach would be to relate zone pressures to properties at the well (1/2 ft), model layer (3 ft) and multi-layer (2-4 layers) scales and to develop stratigraphically and/or geographically constrained algorithms that relate pressure to properties. If this could be accomplished, pressure could be an additional attribute for each cell in the model.
3. More thoroughly document wellhead shut-in pressure (WHSIP) evidence for Chase-Council Grove communication by 1) revisiting early Council Grove completions that were not fracture treated, and 2) undertaking a material balance study comparing gas produced by Council Grove wells with IWHSIP <270 psi (most wells) with those having IWHSIP > 400 psi.
4. Investigate further the potential for vertical communication through swarms of joints along basement-related structural flexures by quantifying fractures in core, refining basement fracture model, and relating them to pressure models.
5. Explore potential mechanisms or alternative interpretations for the apparently sloped free-water level.
6. Experiment with expanding the cell width from 660 ft to at least 1320 ft, considering that the breadth of lithofacies connected volumes generally exceeds township-scale. This would reduce the cell count by a factor of four and possibly permit the building of a single model rather than six sub-models.
7. Develop a software tool for modifying permeability values at wells based on cumulative production for the well (i.e., “tune” the permeability model to production history without a full reservoir simulation analysis) to both improve the static model and identify areas of anomalous productivity.

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