Chapter 3

Thermal Maturation of Petroleum Source Rocks in the Anadarko Basin Province, Colorado, Kansas, Oklahoma, and Texas

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By Debra K. Higley

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Petroleum Systems and Assessment of Undiscovered Oil and Gas in the Anadarko Basin Province, Colorado, Kansas, Oklahoma, and Texas—USGS Province 58

Compiled by Debra K. Higley

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Thermal Maturation of Petroleum Source Rocks in the Anadarko Basin Province, Colorado, Kansas, Oklahoma, and Texas

By Debra K. Higley

Abstract

Petroleum source rocks are thermally mature for oil and gas generation across most of the Anadarko Basin in Oklahoma and Texas based on one-dimensional and four-dimensional petroleum system models. Three petroleum source rocks were defined in the four-dimensional model. They are the Oil Creek Formation of the Ordovician Simpson Group, the Devonian-Mississippian Woodford Shale, and the informal Thirteen Finger limestone of the Pennsylvanian Atoka Group. Modeled onset of oil generation in the basin was about 370 million years ago for the Oil Creek Formation, 330 million years ago for the Woodford Shale, and 300 million years ago for the Thirteen Finger limestone. The deep basin of Oklahoma and Texas is thermally mature for gas from Atokan and older source rocks. Deep basin areas that are overmature for gas generation are within the gas preservation window, as indicated by gas production from Woodford and older formations in this area, and on modeled levels of thermal maturation. Almost all of the Colorado and Kansas portions of the basin are thermally immature for petroleum generation. However, Mississippian and older source rocks may be marginally mature to mature for oil generation in the Las Animas arch of southeastern Colorado based on calculated vitrinite reflectance and transformation ratios from a four-dimensional petroleum system model.

Oil and gas migration pathways were mainly radially northward from the deep basin in Oklahoma and proximal Texas, and north and west from the Texas Panhandle. Petroleum was further funneled by local structures. The Nemaha uplift in central Oklahoma was a barrier that limited eastward migration. Northward flow was diverted toward the Pratt anticline and Central Kansas uplift in south-central Kansas, and to the northwest Hugoton embayment. Decrease in burial pressure associated with the Laramide uplift and erosion resulted in a probable volume increase of gas that displaced oil in reservoirs with subsequent renewed gas migration. Evidence for this includes Permian gas reservoirs of the southern Central Kansas uplift and Pratt anticline areas, and the Hugoton embayment gas fields.

Introduction

The U.S. Geological Survey (USGS) recently completed an assessment of the undiscovered oil and gas resource potential of the Anadarko Basin Province of western Oklahoma and Kansas, northern Texas, and southeastern Colorado (fig. 1). This is hereafter referred to as the 2011 assessment, which corresponds to the publication release date of the assessment results (Higley and others, 2011). This province area includes the Anadarko Basin, Las Animas arch, and a portion of the Palo Duro Basin. Stratigraphic units range in age from Precambrian to present, and petroleum is produced from Cambrian through Permian strata. Mesozoic strata are absent over most of the basin, being limited primarily to the Colorado and Kansas portions. The Cretaceous Niobrara Formation is productive near the northwestern boundary of the basin, but this biogenic methane resource was included in the Denver Basin assessment (Higley and Cox, 2007; Higley and others, 2007).

Figure 1 shows the province boundary and labeled total petroleum systems (TPS) and assessment units (AU). Total petroleum systems and included AUs are defined in Magoon and Dow (1994). The TPS concept basically incorporates hydrocarbon source rocks (source-rock maturation, hydrocarbon generation, migration, and accumulation), reservoir rocks (sequence stratigraphy and petrophysical properties), and hydrocarbon traps (trap formation, timing, and seals) whose provenance is a pod or closely related pods of active source rock. The TPS is basically a hydrocarbon fluid system that links petroleum source rocks, migration pathways, and real and (or) hypothetical oil and gas accumulations. An AU within a TPS is defined as a mappable volume of strata that incorporates petroleum accumulations (discovered and undiscovered) that have the same hydrocarbon source rock(s), and similar geologic and economic factors that control oil and (or) gas entrapment, exploration, and development. These accumulations should therefore be sufficiently homogeneous in terms of geology, exploration strategy, and risk so that the chosen method of resource assessment is applicable. A TPS might contain a single or multiple AUs, depending on whether differences are sufficient to warrant separation. Assigning AUs is

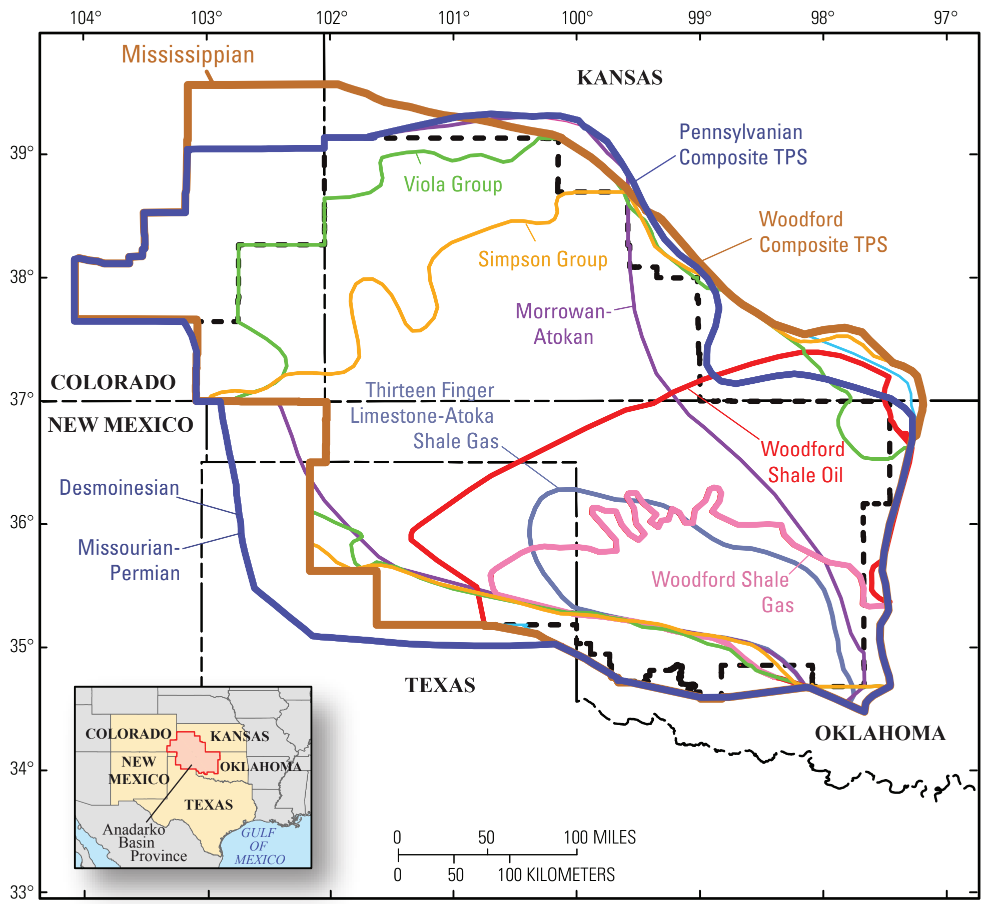


Figure 1. Map showing Anadarko Basin Province (dashed line) and boundaries of total petroleum systems (TPS) and assessment units (AU). Only AUs that contain source rocks are shown. The Woodford Shale is divided into the Woodford Shale Oil and Woodford Shale Gas AUs based mainly on levels of thermal maturation and formation thickness. The Desmoinesian and Missourian-Permian AUs share a common boundary with the Pennsylvanian Composite TPS, with the exception that the AUs exclude an area of the deep basin that is the Granite Wash Composite AU (not shown). There are common boundaries for most AUs.

also based on the quality and availability of petroleum source, reservoir, well history, and production data. Each AU can incorporate several exploration plays that are based on different reservoir formations, trap types, exploration strategies, and discovery histories.

The Anadarko Basin Province includes two TPSs that include nine conventional and three continuous AUs (Higley and others, 2011). The stratigraphic column in the basin (fig. 2) lists Ordovician through Pennsylvanian shales and limestones that are petroleum source and potential source rocks. The Woodford Composite TPS encompasses Ordovician through Mississippian petroleum source rocks and is named for the principal source rock. The Pennsylvanian Composite TPS includes the remaining petroleum source rocks. Reasoning behind this generalized TPS division is that geochemical research in the basin has been focused on the Woodford Shale, with lesser information on other possible petroleum source rocks. Continuous AUs are the Woodford Shale Gas and Woodford Shale Oil of the Woodford Composite TPS, and the Thirteen Finger Limestone–Atoka Shale of the Pennsylvanian Composite TPS. The AU assignments and associated codes are listed below; they are based primarily on (1) the lateral extent and thickness of associated reservoir and petroleum source formations, (2) timing and degree of thermal maturation of potential contributing petroleum source rocks, (3) oil and gas generation and migration pathways through time based on 4D petroleum system modeling of the basin, and (4) faults and other structures that would limit or enhance oil and gas accumulations. Results of the oil, gas, and natural gas liquids (NGL) assessment are listed in table 1.

System	Series	Lithostratigraphic Unit (HC Source Rocks in Red)		Relative HC Source Rock Potential (1-5)	Expected Hydrocarbons
Permian (part)	Leonardian	Sumner Gp; Enid Gp.; Hennessey Gp.			
	Wolfcampian	Chase Group Council Grove Group Admire Group	Pontotoc Group		
Pennsylvanian	Virgilian	Wabaunsee Group Shawnee Group	Ada Group		
		Douglas Group			
	Missourian	Lansing Group Kansas City Group	Hoxbar Group	1-2	Gas Oil
	Desmoinesian	Marmaton Group Cherokee Group	Deese Group	1-2	Gas Oil
	Atokan	Atoka Gp.; Thirteen Finger limestone		1-2	Gas Oil
	Morrowan	Morrow Gp./Fm.; lower Dornick Hills Gp.		2-3	Gas Oil
Mississippian	Chesterian	Springer Formation Chester Group	Mayes Group	1-2	Gas Oil
	Meramecian	Meramec lime			
	Osagean	Osage lime		2	Gas Oil
	Kinderhookian	Kinderhook Shale			
Devonian	Chautauquan	Woodford Shale, Chattanooga Shale		5 +	Gas Oil
	Senecan Erian Ulsterian	Misener sand			
Silurian	Cayugan Niagaran Alexandrian	Hunton Group			
Ordovician	Cincinnatian	Sylvan Shale; Maquoketa Shale			
		Viola Group/Formation		2	Gas Oil
	Champlainian	Simpson Group		1-2	Gas Oil
	Canadian	Arbuckle Group		?	??
Cambrian (part)	Trempealeauan				
	Franconian	Reagan Sandstone			

Figure 2. Generalized stratigraphic column for the Anadarko Basin Province with oil and gas source rocks (brown text). Increases in source rock potential are indicated by larger numbers. The expected hydrocarbons header indicates whether the source rock is more oil or gas prone. Hatch (oral commun., 2010), and modified from Burruss and Hatch (1989). Vertical lines show a generalized time range of unconformity from Bebout and others (1993, fig. 5). Gp., Group; Fm., Formation.

Table 1. Anadarko Basin Province assessment results are listed by name and code of total petroleum system (TPS) and assessment unit (AU).

[Resources are undiscovered oil, gas, and (or) natural gas liquids. MMBO, million barrels of oil; BCFG, billion cubic feet of gas; MMBNGL, million barrels of natural gas liquids. Type refers to mainly oil or gas accumulations in the AU. Fractiles are fully risked estimates. F95 denotes a 95-percent chance of at least the amount tabulated. F50 and F5 fractiles are defined similarly. Fractiles are additive only under the assumption of perfect positive correlation. Gray shading indicates not applicable]

Total Petroleum Systems (TPS) and Assessment Units (AU)	Field Type	Total Undiscovered Resources											
		Oil (MMBO)				Gas (BCFG)				NGL (MMBNGL)			
		F95	F50	F5	Mean	F95	F50	F5	Mean	F95	F50	F5	Mean
Woodford Composite TPS													
Arbuckle-Ellenburger AU	Oil	2	5	12	6	7	24	61	28	0	1	2	1
	Gas					43	164	371	181	0	1	2	1
Simpson Group AU	Oil	2	4	9	5	6	17	39	19	0	0	1	1
	Gas					33	114	252	125	2	9	21	10
Viola Group AU	Oil	2	5	10	5	3	9	20	10	0	1	2	1
	Gas					10	27	58	30	0	0	0	0
Hunton Group AU	Oil	2	8	21	9	8	32	87	38	0	1	3	1
	Gas					71	281	641	310	0	2	4	2
Mississippian AU	Oil	5	16	31	17	15	46	99	50	0	2	4	2
	Gas					125	350	663	367	3	8	17	9
Pennsylvanian Composite TPS													
Morrowan-Atokan AU	Oil	6	14	29	15	21	55	121	61	1	2	5	2
	Gas					101	261	469	271	2	5	10	5
Desmoinesian AU	Oil	2	6	12	6	8	23	52	26	0	1	2	1
	Gas					29	87	167	92	1	3	5	3
Missourian-Permian AU	Oil	10	22	38	23	49	114	223	122	2	4	8	4
	Gas					61	130	231	136	2	4	7	4
Greater Granite Wash Composite AU	Oil	4	14	34	16	22	78	198	90	1	2	7	3
	Gas					192	646	1,496	719	7	24	60	27
Total Conventional Resources		35	94	196	102	804	2,458	5,248	2,675	21	70	160	77
Woodford Composite TPS													
Woodford Shale Oil AU	Oil	175	357	730	393	795	1,750	3,851	1,963	22	51	121	59
Woodford Shale Gas AU	Gas					8,806	15,131	25,998	15,973	94	178	336	192
Pennsylvanian Composite TPS													
Thirteen Finger Limestone-Atoka Shale Gas AU	Oil												
	Gas					3,040	6,229	12,763	6,850	33	73	161	82
Total Continuous Resources		175	357	730	393	12,641	23,110	42,612	24,786	149	302	618	333
Total Resources		210	451	926	495	13,445	25,568	47,860	27,461	170	372	778	410

Woodford Composite TPS 505801:

1. Arbuckle-Ellenburger, AU 50580101
2. Simpson Group, AU 50580102
3. Viola Group, AU 50580103
4. Hunton Group, AU 50580104
5. Mississippian, AU 50580105
6. Woodford Shale Gas, AU 50580161
7. Woodford Shale Oil, AU 50580162

Pennsylvanian Composite TPS 505802:

1. Morrowan-Atokan, AU 50580201
2. Desmoinesian, AU 50580202
3. Missourian-Permian, AU 50580203
4. Greater Granite Wash Composite, AU 50580204
5. Thirteen Finger Limestone–Atoka Shale Gas, AU 50580261

Petroleum productive and potentially productive formations were divided into the two TPSs, with Ordovician through Mississippian source rocks mainly contributing to reservoirs of that age range, and Pennsylvanian source rocks to those of Pennsylvanian and Permian age reservoirs (fig. 2). The Hunton Group is not listed in figure 2 as containing petroleum source rocks. Also, there is only limited evidence for source potential from the Arbuckle-Ellenburger AU (Burruss and Hatch, 1989; J. Hatch, oral communication, 2010). The TPS and AU divisions were also influenced by the accuracy and existence of well history and production data. For example, much of the Atokan petroleum production is reported commingled with Morrowan production. The Thirteen Finger Limestone–Atokan Shale Gas continuous AU is based largely on source rock potential based on Carr and Hentz (2009) and on low permeability and source rock potential from well log analysis. Source rock research and data have been focused on the Woodford Shale in the Anadarko and adjacent basins. Most of the vitrinite reflectance data in the Anadarko Basin is from Woodford Shale cores, well cuttings, and outcrop samples. The one-dimensional (1D) and four-dimensional (4D) petroleum system models are preferentially calibrated to the Woodford Shale vitrinite reflectance data of Cardott (1989), Price (1997), and two wells in the Edmond West field (Chesapeake Energy [written communication, 2008] and Mark Pawlewicz [written communication, 2010] analyses). Source rock potential for other petroleum source rocks incorporate published research, vitrinite reflectance values from Pawlewicz (1989), and results of the 1D and 4D models of this study.

Petroleum System Modeling Methodology

Petroleum system modeling is designed to recreate, through time, oil and gas generation, expulsion, migration, saturation, accumulation, and loss for included petroleum source and reservoir rocks, and at well to basin scales. The timing and extent of petroleum generation from each source rock requires kinetic parameters that relate the geologic time required for generation reactions to the burial temperatures of source rocks. Development and assignment of kinetic algorithms for the Woodford Shale and other petroleum source rocks are discussed in Lewan (1983, 1985) and Lewan and Ruble (2002). Created models show levels of thermal maturation and generation of oil and gas through time based on kinetic factors such as transformation ratios (TR) and levels of thermal maturity for source organofacies based on calculated vitrinite reflectance, TR, and other factors. 1D, two-dimensional (2D), and 4D models commonly integrate influences through time of (a) basal heat flow, (b) water depth, (c) surface temperature, (d) time and extent of deposition and erosion, (e) vertical and lateral lithologic properties within each layer, (f) profiles of lithofacies decompaction through time, and (g) geochemical characteristics for each source organofacies, such as total organic carbon (TOC) content and hydrogen index (HI).

Maps and models were generated using Dynamic Graphics® Earthvision® (Dynamic Graphics® and Earthvision® are registered trademarks of Dynamic Graphics, Inc.) and PetroMod® software (Schlumberger, 2011). Schlumberger PetroMod® software was used for 1D and 4D petroleum system models. PetroMod® is pressure/volume/temperature (PVT) modeling software. The Anadarko 4D model incorporates flow path and Darcy flow migration that is referred to as hybrid-Darcy in PetroMod® documentation. Flow path migration of liquid and vapor components of petroleum and water is largely buoyancy-driven by hydrostatic pressure changes, whereas the Darcy flow is a multiphase process that uses gas diffusion and PVT to model migration. Structural relief on the top of the carrier (reservoir) layers is the primary control on migration pathways for oil and gas. Petroleum migration flow paths are vertical and lateral. When fluids and gases enter a reservoir or other permeable layer, the flow through the most permeable lithofacies is toward the top of the layer, and then laterally upward along the overlying seal layer. This seal layer can be breached by its thinning or lateral change to a permeable lithology, or the presence of an open fault system. Flow is then mostly vertical until the next seal is reached. These flow paths are more readily viewed than the more diffuse oil and gas Darcy flow within the reservoir layer. Oil and gas trapped as a result of accumulation or Darcy saturation in reservoirs does not further migration without a change in PVT conditions, such as uplift, erosion, open faults, or change in hydrodynamic flow. Modeling requirements, strengths, and weaknesses are discussed in Higley and others (2006).

Faults associated with the Wichita Mountain, Amarillo, Nemaha, and Central Kansas (CKU) uplifts are modeled as closed through time (see fig. 3 for locations). Main potential effects of this are to decrease petroleum migration east of the Nemaha uplift and south of the Wichita Mountain and Amarillo uplifts, and to channel migration in areas such as the Pratt anticline and CKU. Faults along the northern boundaries of the Wichita Mountain and Amarillo uplifts are modeled as vertical, with only minimal horizontal offset from Precambrian to ground surface. Also critical to migration and accumulation is the proximity of reservoir strata to vertical and lateral seals and to thermally mature source rock.

Petroleum system models were constructed using formation tops, lithologies, and ages of deposition and erosion from numerous sources. Data sources for the models include (1) formation top picks in more than 220 wells across the province, (2) IHS Energy (2009a, 2009b) and Kansas Geological Survey (2010, *http://www.kgs.ku.edu/PRS/petroDB.html*) formation tops, and (3) maps and data from Fay (1964), Rascoe and Hyne (1987), Robbins and Keller (1992), Cederstrand, and Becker (1998), Andrews (1999a, 1999b, 2001), and Rottmann (2000a, 2000b). Formation ages and lithologies are commonly generalized and include Denison and others (1984), Ludvigson and others (2009), and the National Geologic Map Database (2011, *http://ngmdb.usgs.gov/Geolex/*). Figures within this chapter of the report may have feet or meters as vertical scales. This is because the 1D, 2D, and 4D petroleum system models have meters as the vertical scale, largely because of ease in using the modeling software. Vertical scale of most contour maps and of well-log cross sections are in feet because that is traditionally used in the United States. Tilted three-dimensional (3D) images generally do not have map scales because edges would have different scales, with the associated clutter.

4D petroleum system models consist of stacked layers of formations and groups of formations. The Anadarko Basin model contains 30 layers. Below are names of modeled layers that correspond generally to associated formation, group, and period names.

1. Surface
2. OgallalaBase
3. Cretaceous
4. Permian
5. Blaine
6. StoneCorral
7. Wellington
8. Chase
9. CouncilGrove
10. Wabaunsee
11. HeebnerT
12. HeebnerB
13. Douglas
14. Desmoinesian
15. Cherokee
16. Atokan
17. Thirteen Finger
18. MorrowU
19. MorrowM
20. MorrowL
21. Springer
22. Woodford
23. Hunton
24. Sylvan
25. Viola
26. SimpsonT
27. Oil Creek
28. SimpsonB
29. Arbuckle
30. Precambrian

Formations that compose each layer were grouped based on common petroleum system elements of reservoir, source, seal, overburden, or underburden. Assigned petroleum source rocks in the model are the Oil Creek, Woodford, and Thirteen Finger layers; these correspond generally to the petroleum source rocks in figure 2. All model layers extend across the study area, even if the included formation(s) has limited lateral extent. This is because of a software requirement that all grid cells be populated with numbers representing the structural elevation relative to sea level, or isopach thickness of zero or greater. The structural surface of layers is somewhat like a geologic map in that the extent of the modeled formation is shown, as well as any lateral subcropping formations. Some layers consist of one formation, such as for the Sylvan Shale, Hunton Group, Woodford Shale, Chase Group, and Blaine Formation, and others are compound, such as the Desmoinesian and Missourian layers. Selection of layer intervals was based mainly on the quality of formation tops data and their relative importance as source, reservoir, and seal units.

X and Y axis grid spacing are 6 kilometers (km) for the 4D basin models, primarily because of computer processing and display limitations. File sizes of these “simplified” 4D models can exceed 170 gigabytes. The coarse gridding results in somewhat pixilated graphic images. Spacing is 1 kilometer (km) for published grids (Higley and others, 2014) and as initial “pre-filtered” input of the 4D models. Intervals with their associated lithologic properties are homogenized at this 6-km scale. A primary result of this homogenization is that most generated oil and gas is not trapped within but instead migrates outside the model; this lost petroleum is mainly along the northern extension of the model in Colorado and Kansas. Models for stratigraphic traps and those constrained by PVT history require more detailed lithologic assignments and closer grid spacing.

A heat flow map (fig. 3) was assigned as basement heat flow in the 4D model. Variation in measured heat flow is probably greater than that shown, as is indicated by “bull’s eye” contours in areas of closer data control. There are areas in western Kansas that display minor change in heat flow; these result from fewer data points, and perhaps less variation than other map areas. Data sources for downhole temperature include Carter and others (1998), Gallardo and Blackwell (1999), Price (1997), and drillstem test and corrected borehole temperatures. These well data were used to calibrate 1D models, and were also compared to 4D model temperatures for further calibration. Shown on figures 4 and 5 are present-day modeled and measured temperatures on the Devonian-Mississippian Woodford and the Virgilian Wabaunsee layers. Model layers and datasets show trends of increasing temperature with burial and similar temperature values. Woodford layer contours show the

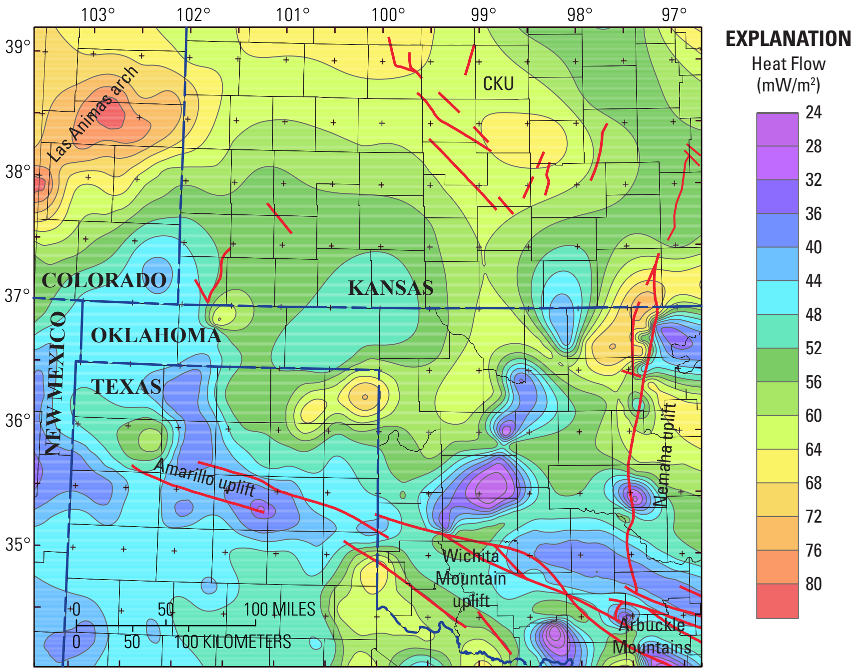


Figure 3. Map showing basement heat flow contours across the Anadarko Basin based on data from Carter and others (1998), Blackwell and Richards (2004), and data downloads from the Southern Methodist University Web site (*http://smu.edu/geothermal/*). Basin areas within and north of the Wichita Mountain and Amarillo uplifts exhibit generally lower heat flows than other basin areas. Highest measured heat flow is in the northwest, along the Las Animas arch. The northwest trending Central Kansas uplift (CKU) also exhibits elevated heat flow values. Contours are in milliwatts per square meter (mW/m^2). Red fault lines are from Adler and others (1971).

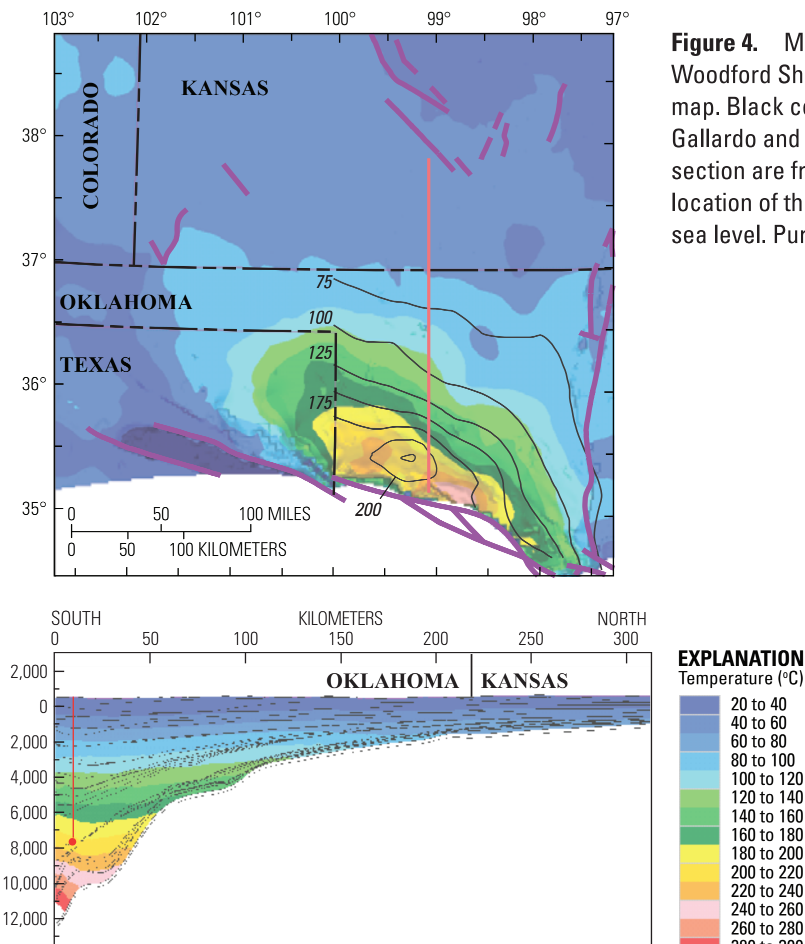


Figure 4. Map showing formation temperatures on the top of the Woodford Shale model layer. Cross section location is orange line on map. Black contour lines are temperature on the Woodford Shale from Gallardo and Blackwell (1999). Formation temperatures on the cross section are from ground surface to the Precambrian. The red dot is location of the Woodford Shale layer. Elevation in meters is relative to sea level. Purple fault lines are from Adler and others (1971).

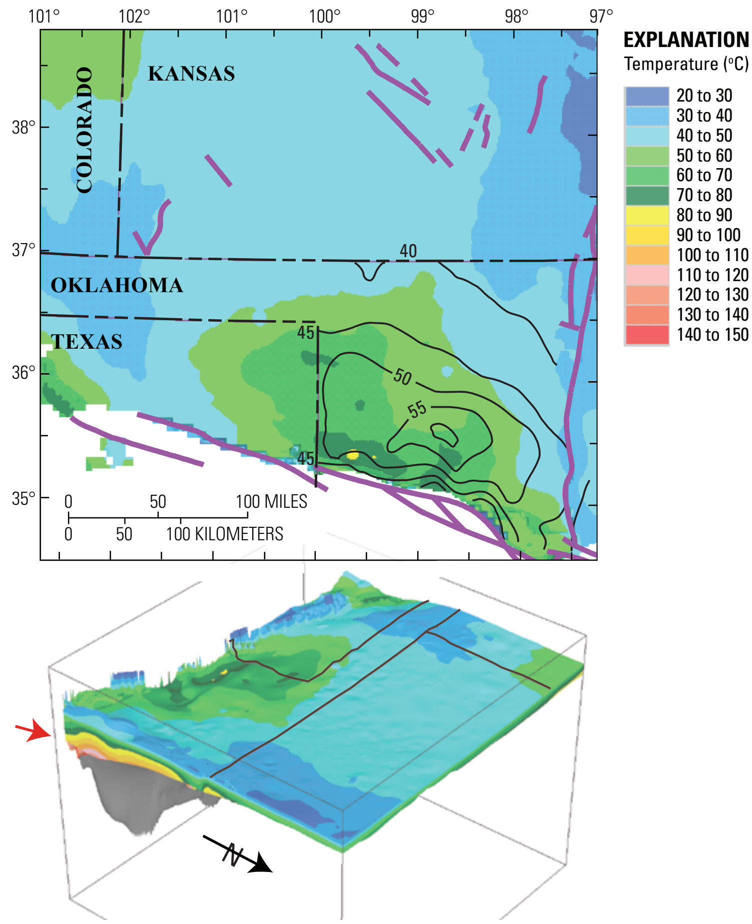


Figure 5. Map showing modeled Celsius (°C) temperatures on the top of the Wabaunsee layer. Oklahoma (black) contour lines from Gallardo and Blackwell (1999) are estimated temperatures on the top of the Pennsylvanian, which is roughly analogous to the Wabaunsee elevation. Both sets of contours show general increase in temperature with greater burial depth. Increasing depth with burial is shown by the underlying Precambrian through Morrowan layers (red arrow). 3D view is 10 times vertical exaggeration. Purple fault lines are from Adler and others (1971).

same northwest trend and similar values to those of Gallardo and Blackwell (1999). This indicates that temperatures for the 4D model compare generally with measured data. Subsurface temperatures are influenced by various factors. The Precambrian in the deep basin is primarily rhyolite, which is cooler than the mainly granitic rocks of the shallower basement and shelf regions. The rhyolite could influence thermal maturation by dampening thermal effects, essentially slowing onset of generation from overlying rocks. The Carter and others (1998) measured heat flow in the basin decreased from 55 to 64 milliwatts per square meter (mW/m^2) in the northern part, to 39 to 54 mW/m^2 in the southern part. Lee and Deming (1999) incorporated this information into their mean heat flows in the northern and southern basin of 39 mW/m^2 and 51 mW/m^2, respectively. They found no evidence that basement lithology influenced the increased heat flow from the south to north. Their work was based on thermal conductivity measurements of drill cuttings from nine wells in the basin. These and other heat flow data were contoured (fig. 3) and applied to the 4D model. Basement heat flow exhibits a heterogeneous distribution (fig. 3) with somewhat lower values in the southern part of the basin and greater heat flow across parts of the Las Animas arch, Central Kansas uplift, and parts of the Nemaha uplift. Lithofacies that overlie source intervals can also influence onset of maturation. For example, evaporites have good thermal conductivity that allows heat conduction away from kitchen areas, whereas thick shale and coal beds have the opposite effect, acting as thermal blankets that insulate underlying rocks. Minor differences in assigned lithofacies have no effect on modeling results.

Geologic Setting

Structural History

The Anadarko Basin is a south-dipping asymmetric basin in which the present configuration is controlled mainly by the late Paleozoic Wichita Mountain uplift and the Ouachita thrust plate (Amsden, 1975, 1989). Southern Oklahoma was initially described by Shatski (1946) as a failed Cambrian aulacogen. The deepest part of the basin is along and north of this rift zone and is proximal to its southern margin along the Wichita Mountain uplift (fig. 6). The tectonic history of the Anadarko Basin strongly influenced rate of sediment deposition, sediment sources, depositional environments, erosion, and especially burial depth of reservoir, seal, and source rocks. Depth of burial through time is the main control on thermal maturation of petroleum source rocks, although oil and gas generation is also influenced by factors such as basement heat flow and thermal conductivity of lithofacies. The focus of this is on oil and gas generation, migration and accumulation through time from source rocks in the basin.

The Wichita Mountain and Amarillo uplifts and adjacent basins were strongly influenced by structural, stratigraphic, and thermal evolution of the southern Oklahoma aulacogen (Rascoe and Adler, 1983) that was emplaced on the Precambrian craton (Ham and others, 1964). It is about 100 miles (mi) [160 kilometers (km)] wide and 300 mi (480 km) long with the southern boundary approximated by the Wichita Mountain uplift (fig. 6). The Wichita Mountain and Amarillo uplifts include a number of faults, such as Mountain View, Cordell, Cement, Meers, and Duncan-Criner (Luza, 1989) that are along and proximal to the northern boundary of the uplifts,

Early and Middle Cambrian rifting and igneous activity was the initial phase in basin development (Denison, 1976; Gallardo and Blackwell, 1999). Increased subsidence in the aulacogen during the Early Cambrian resulted in a greater rate of deposition near the present-day basin axis; the subsidence rate slowed by the beginning of the Silurian (Feinstein, 1981). This is indicated by the relatively thin Silurian and Devonian rocks (Johnson and others, 1988; Johnson, 1989) that are of limited lateral extent. Figure 7 shows generalized lateral extent of the Woodford Shale within the Woodford Shale model layer. Model layers are somewhat like geologic maps through time in that they display the extent of the named formation, and “subcropping” lateral formations. All formations on the surface of figure 7 are assigned to the Woodford layer. The Viola layer, for example, would show the same assigned lithofacies of the Viola Group and any underlying formations outside its extent.

The Ouachita-Marathon orogeny and related tectonism began in Mississippian (probably Chesterian) time (Burgess, 1976; Perry, 1989). Anadarko began to form as an independent structural basin in Late Mississippian time, when the Texas promontory of the southern continental margin of Paleozoic North America first reacted to early stages of plate collision with Gondwana or an intervening microplate (Perry, 1989). During Early to Late Pennsylvanian time the principal tectonic activity in the basin occurred in several pulses: (1) the Morrowan Wichita Mountain and Amarillo uplifts were accompanied by downwarping of the basin (Gallardo and Blackwell, 1999) with greater thickness of Morrowan strata in the deep basin relative to the shelf; and (2) Late Morrowan uplift along most of the Wichita Mountain and Amarillo blocks is evidenced by the upper Morrowan fan-delta chert conglomerate (Johnson, 1989). These were derived from Mississippian cherty limestones and dolomites that mantled the uplift (Johnson, 1989).

Climax of the Wichita orogeny during the Atokan was evidenced by Wichita Mountain and Amarillo uplift of thousands of feet relative to the proximal basin axis to north (Ball and others, 1991). Overthrusting associated with the uplift resulted in 15 ± 5 km (9 ± 3 mi) of crustal shortening (Brewer and others, 1983). The uplift supplied sediments to the informally named Granite Wash, which was deposited from Atokan through much of the Virgilian time. Transition from arkosic granite wash to felsic quartz grains extended some 30 miles northward from the mountain front during the Atokan (Ball and others, 1991). The Wichita Mountain and Amarillo uplifts persisted as major positive tectonic features during Missourian time (Johnson, 1989). The Anadarko Basin has

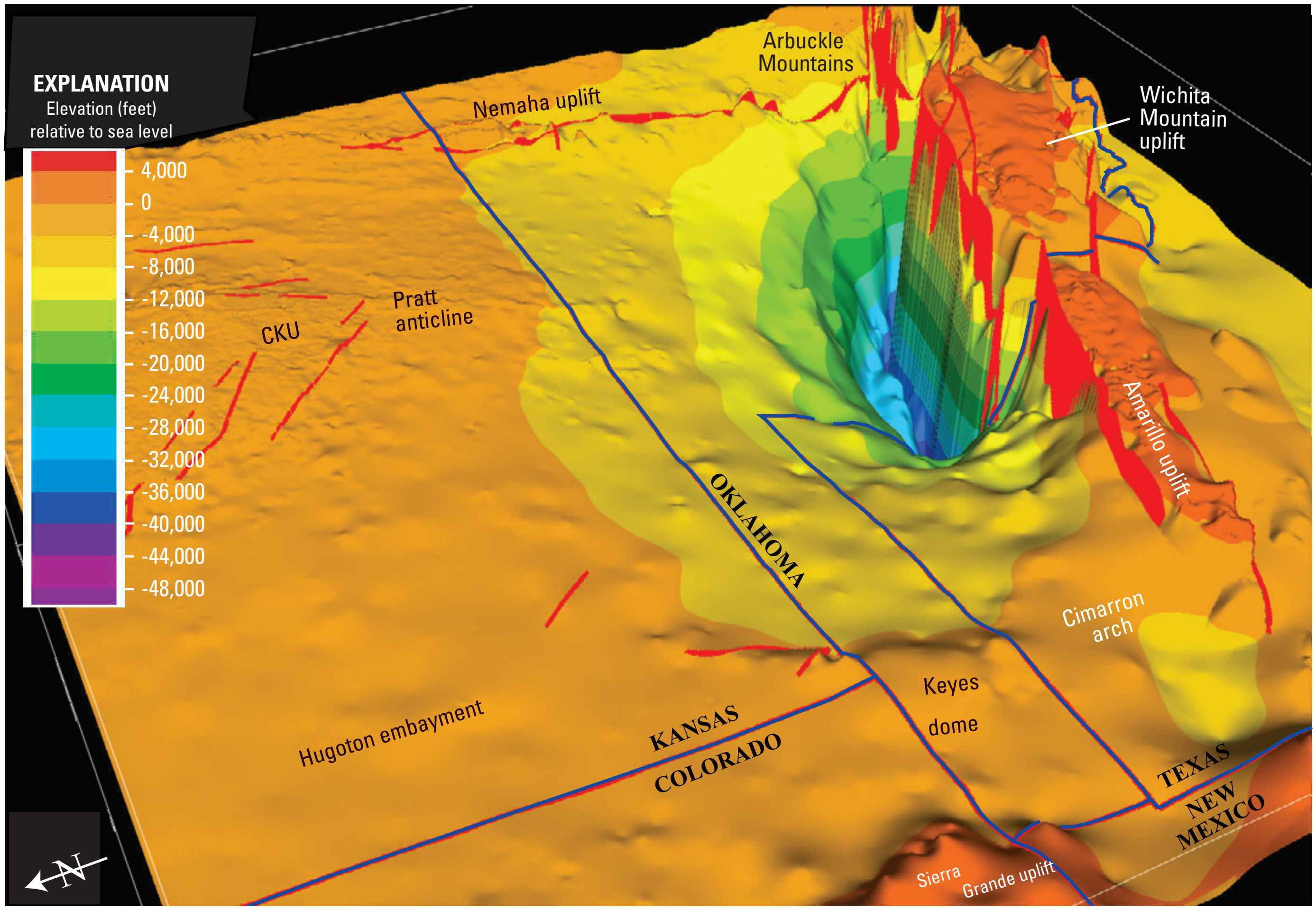


Figure 6. View to the southeast of elevation on the top of the Woodford Shale model layer is from the two-dimensional WoodfordTft.DAT grid file (Higley and others, 2014) that was created using Earthvision®. Vertical exaggeration is 18 times. Woodford extent is approximated by the -12,000-foot elevation contour, although Woodford is also present east of the Central Kansas uplift (CKU). Major structures are labeled. Precambrian faults (red) are from Adler and others (1971). Wichita Mountain uplift bounding faults are vertical for four-dimensional model purposes only, and the Woodford Shale surface in this area is unknown because of insufficient data. Data sources for this surface include Woodford picks from well logs, Rottmann (2000a, 2000b), and edited IHS Energy (2009a, 2009b) formation tops.

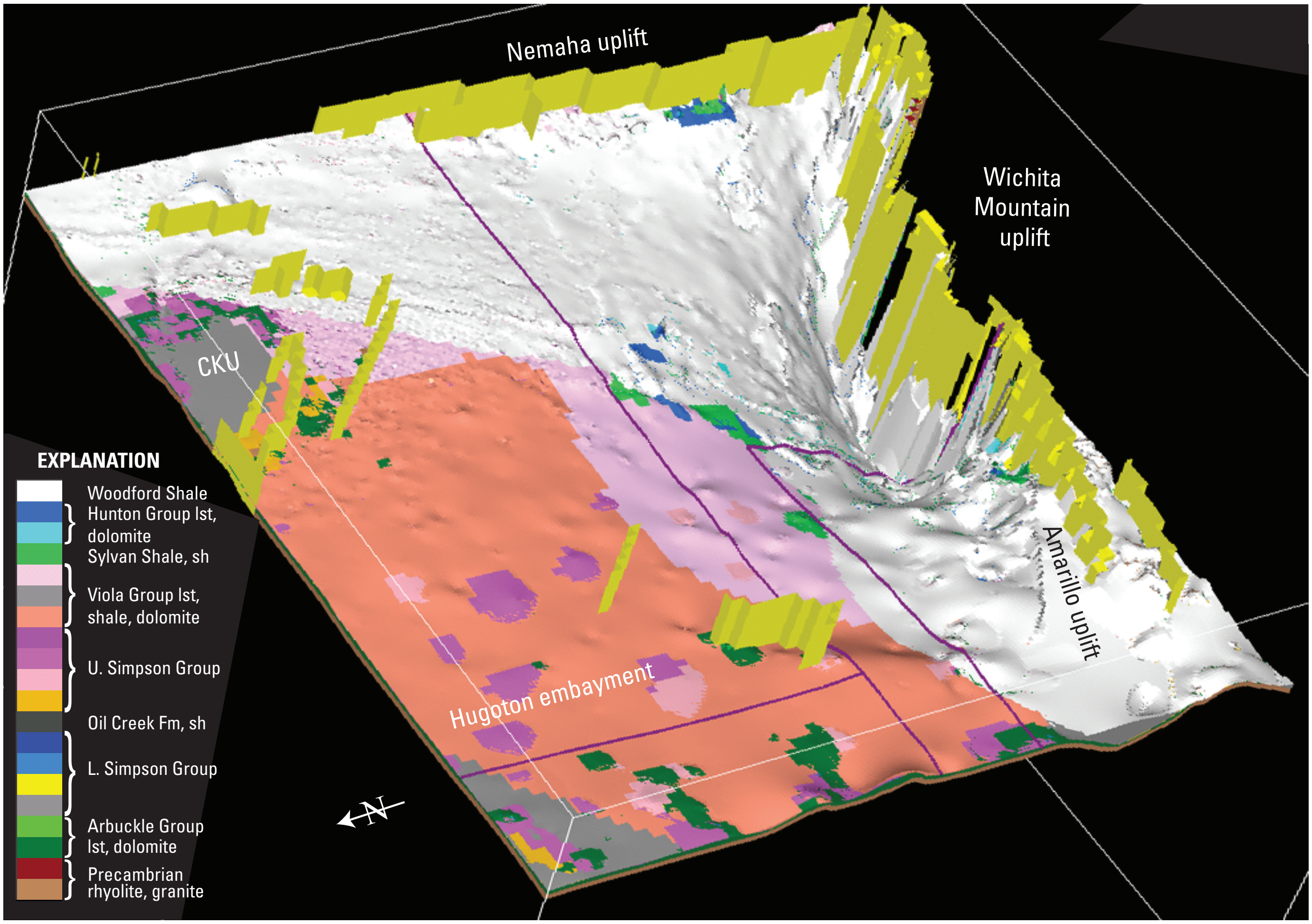


Figure 7. View to the southeast showing Woodford Shale layer lithofacies. Vertical exaggeration is 18 times. View orientation is similar to the 1-kilometer grid spacing Earthvision® image (fig. 6). This PetroMod® image shows underlying and lateral facies changes for the Woodford Shale layer, which is shown in white. Lateral lithofacies within the Woodford layer are primarily limestone and dolomite of the Viola Group. Because the purpose of this image is to show lateral changes in lithofacies assignments on a model layer, this information is generalized in the explanation and not all listed formations are visible. The southern half of the Kansas Woodford has almost 0 meter thickness and represents grid extrapolation between the northeast Kansas and Oklahoma extents. Vertical yellow bars are faults from Adler and others (1971). CKU, Central Kansas uplift; lst, limestone; sh, shale; U, upper; L, lower.

essentially been structurally dormant since Early Permian time (Perry, 1989), as indicated by relatively uniform thicknesses of Wolfcampian and Leonardian formations, and that Council Grove, Chase, and Hennessey Groups, and other strata can be fairly readily correlated across the basin. Guadalupian and younger units exhibit more irregular distribution because of nondeposition and uplift, tilting, and erosion associated with the Laramide orogeny. The Laramide orogeny in the southern Rocky Mountains began about 67.5 million years before present (Ma) and ended about 50 Ma (Tweto, 1975). Johnson and others (1988) indicated that southern Oklahoma has been structurally quiescent since the Permian, except for the Laramide orogeny causing slight eastward tilting. Subdued modest reactivation of older basin faults may have occurred during the Jurassic and Cretaceous, and minor Holocene movement has occurred on the Meers fault of the Wichita Mountain uplift (Crone and Luza, 1986), and possibly other faults in the basin (Perry, 1989).

Present-day surface expression of the Anadarko Basin is broad and low-relief with elevation decrease and drainage from west to east. This is in contrast to subsurface relief of Wolfcampian and older strata, which form a broad shelf over the Kansas and eastern Colorado portions of the basin that deepens gradually southward into Oklahoma and Texas. Northern Oklahoma and northeastern Texas evidence a marked increase in slope as the basin radially deepens southward to the Wichita Mountain uplift and its bounding high-angle reverse faults. Figures 6 and 7 are views to the southeast on the Woodford Shale layer. These and other three-dimensional (3D) structural images extend to the edges of the model, rather than terminating at the limits of contained formations. The slope of the Woodford surface increases gradually from the shelf southward to the basin axis; then slopes steeply upward toward the Wichita Mountain uplift and bounding faults. This slope increase is mirrored by increased thickness of most Pennsylvanian and older formations. The deep basin gradually filled with sediments through time. Figure 8 shows elevation on the Desmoinesian layer. Desmoinesian strata covered most of the Anadarko Basin, but is absent across most of the Wichita Mountain uplift, Central Kansas uplift, the Cimarron arch of northeastern New Mexico, and the Sierra Grande uplift of northeastern New Mexico and southeastern Colorado.

The figure 9 isopach of strata between the top of the Hunton Group and the Desmoinesian layers shows southward increase in thickness. The absence of contours just north of the Wichita Mountain uplift is because of variable thicknesses of layers next to the uplift and associated terminations of layers against fault segments. Greatest thickness of strata is along the basin axis, proximal and north of the Wichita Mountain uplift. Thickness changes in southeastern Colorado are associated with the Las Animas arch, primarily a Laramide feature that also experienced movement during the late Paleozoic (Rascoe, 1978). The pronounced thickening of strata in the deep basin is also shown by the cube slice of Precambrian through Desmoinesian layers from the 4D petroleum system model in figure 10. It shows the same break in slope southward that results in the wedge of sedimentation. The Atokan through Desmoinesian strata generalized lithofacies assignments were from Adler and others (1971) and are displayed as the gray, green and blue colors on the top slice of the model (fig. 10). Each color change across the vertical cut corresponds to a unique lithofacies assignment. Some of these extend across layers, such as for the Atokan through Desmoinesian layers. The result of this homogenization is a fairly leaky petroleum system model. For example, the Mississippian layer is about 900 meters (m) thick at the marked location, when corrected to vertical. The lithologic assignment (modified from Adler and others, 1971) for the light green bands in this layer is about 40 percent limestone, 30 percent sandstone, and 30 percent shale, and the intervening dark green band is 60 percent limestone, 20 percent sandstone, and 20 percent shale. Unless these assigned lithofacies truncate against or form a structure under a low-permeability seal layer, oil and gas is not trapped.

Model layers can be modified to better represent the vertical and lateral lithofacies variation in the basin, but this was beyond the scope of this project. Lithofacies for most layers were derived from the Adler and others (1971) generalized clastic and carbonate assignments. An overpressured zone in the basin that persisted through geologic time could not be modeled, at least partly because of the coarse 6 to 9 km grid sizes of the 4D model and the generalized lithofacies assignments. Most generated petroleum for the Pennsylvanian through Permian strata migrated outside the model edges. The Al-Shaieb and others (1994) megacompartment complex (MCC) is composed of Devonian, Mississippian, and Pennsylvanian stratigraphic intervals and is characterized by overpressured conditions in the Anadarko Basin that exceed the normal gradient of 10.515 kilopascal per meter (kPa/m) [0.465 pounds per square inch per foot (psi/ft)]. The isolation of the MCC is maintained through considerably long geologic times (early Missourian to present) via encasement by an intricately complex framework of top, basal, and lateral seals (Al-Shaieb and others, 1990).

Primary effect of the wedge of overburden is that thermal maturation of source rocks increases to the south. The primary kitchen area in the Anadarko Basin is in the Oklahoma and northeastern Texas portions (fig. 11). Thermal maturation ranges from onset to completion of oil generation from about 0.6 percent vitrinite reflectance (R_o) to 1.2 percent R_o, and overmature for gas generation at greater than 4 percent R_o. Increased slope of R_o contours is mirrored by depth of the Woodford Shale and thickness of overburden. The general northwest trend of R_o contours is similar to those of overburden thickness. The Cardott (1989) least squares regression correlation was 0.893 for 80 of the Woodford Shale R_o values compared to depth. Spread in R_o correlations can be influenced by (1) initial transformation of organic matter to vitrinite; (2) random experimental error; (3) interpretation of low-gray (low reflectance) vitrinite populations; (4) anisotropy of vitrinite-broadening reflectance histograms starting at 1.0 percent R_o, with a noticeable effect at greater than 2 percent R_o (Dow, 1977; Hunt, 1979); and (5) suppression of R_o in alginite-rich

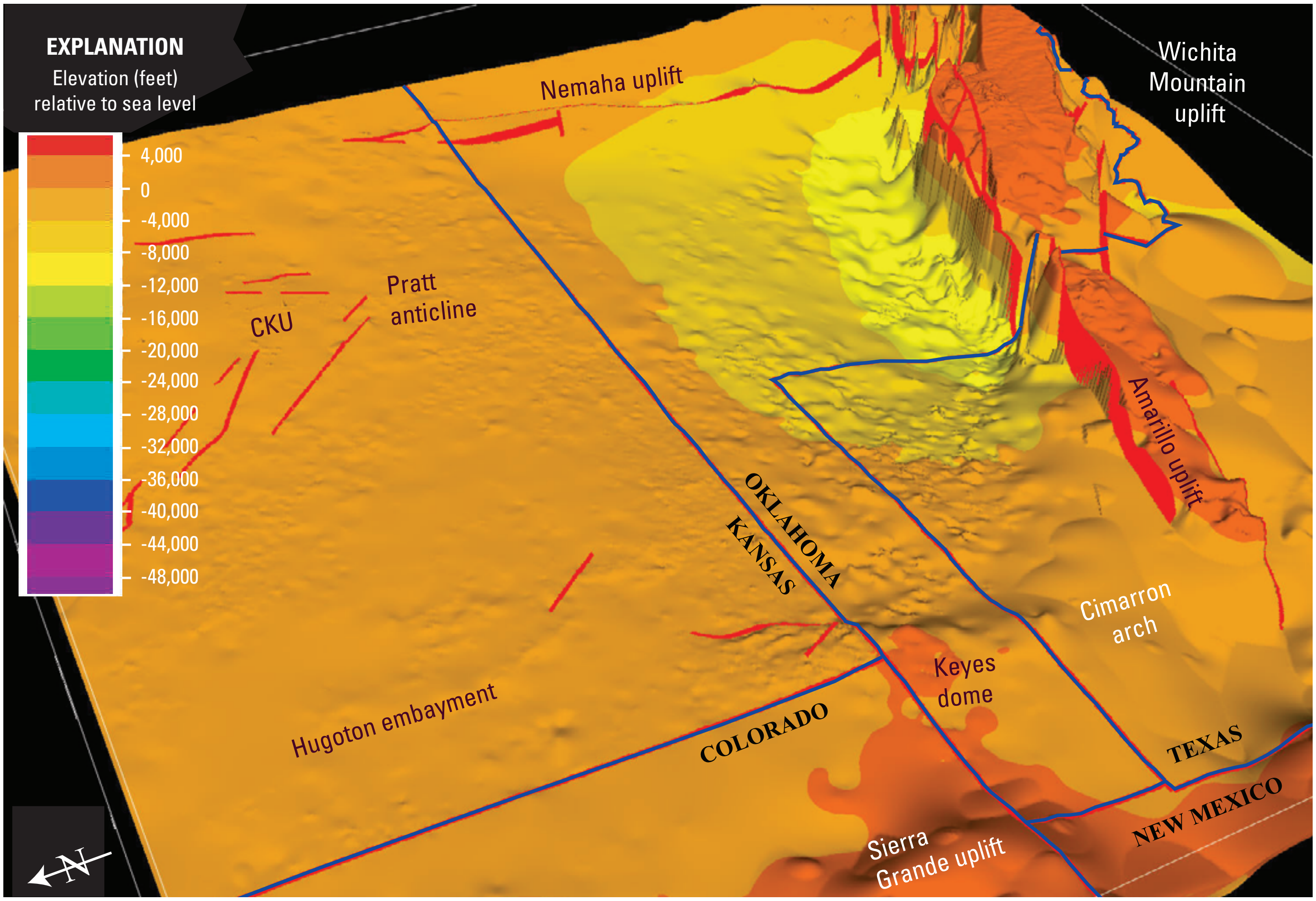


Figure 8. View to the southeast of elevation on the top of the Desmoinesian layer (Higley and others, 2014, DesmoinesianTft.DAT grid file). Vertical exaggeration is 18 times. Major structures are labeled. CKU is Central Kansas uplift. Precambrian faults (red) are from Adler and others (1971). Wichita Mountain and Amarillo uplift faults are vertical for three-dimensional Earthvision® model purposes only, and presence of the Desmoinesian in this area is unknown because of insufficient data. Data sources for this surface include picks from well logs and edited IHS Energy (2009a, 2009b) well formation tops. Elevation is relative to sea level.

rocks (Cardott, 1989; p. 41), which may be a factor in the Type II kerogen within the Woodford Shale.

Part of the area proximal to the Nemaha uplift (eastern part of fig. 11) is thermally immature for oil generation from the Woodford Shale based on Cardott (1989), but immature to mature based on R_o measurements for the West Edmond SWD 1-24 (0.55 percent mean R_o) and Streeter 1 (0.75 percent mean R_o) wells from Brian Cardott (written commun., 2011) and Mark Pawlewicz (written commun., 2010), respectively (fig. 11). The West Edmond SWD 1-24 sample was also analyzed by Chesapeake Energy (on January 10, 2008) with an estimated mean of 0.83 percent R_o and a range of 0.44 to 0.96 percent R_o based on Rock Eval Tmax values for 19 samples of the Woodford Shale interval. Gaswirth and Higley (2014) calibrated 1D petroleum system models of these wells using the measured R_o data. The Streeter 1 Woodford Shale sample was located just above the Hunton cored interval, and sample quality was marginal. It was analyzed using Rock Eval pyrolysis with associated TOC of 0.96 weight percent (wt%), Tmax of 550 °C, and low hydrocarbon and oxygen indices of 68 and 39, respectively. These wells may also record localized elevated thermal maturation. Possible increased thermal maturation along the Nemaha uplift could be associated with hydrothermal fluids along these deep faults, and increased erosion compared to wells to the west also contributed to greater thermal maturation.

Fractures are present within the Woodford Shale throughout its extent in Oklahoma and Arkansas, and province areas in which fractures are most commonly filled with bitumen include the Arbuckle Mountains and the southern part of the Anadarko Basin; these were areas of intense late Paleozoic orogenic activity (Comer and Hinch, 1987). Fractures filled with bitumen were located in Woodford samples along the Nemaha uplift in central Oklahoma, and in the southern Anadarko Basin

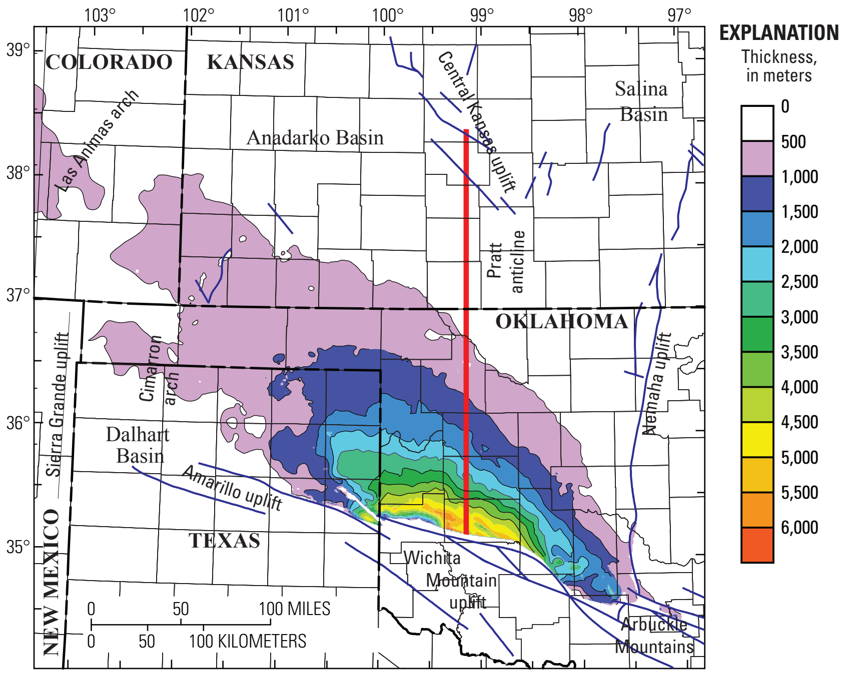


Figure 9. Map showing thickness of strata between the Hunton Group and Desmoinesian layers ranges from less than 500 meters over most of the Kansas shelf to more than 5,000 meters in the deep basin of Oklahoma. This wedge of units is oriented northwest-southeast. Precambrian faults (blue lines) and named structures are from Adler and others (1971). The north-south red line is the general location of the figure 10 image.

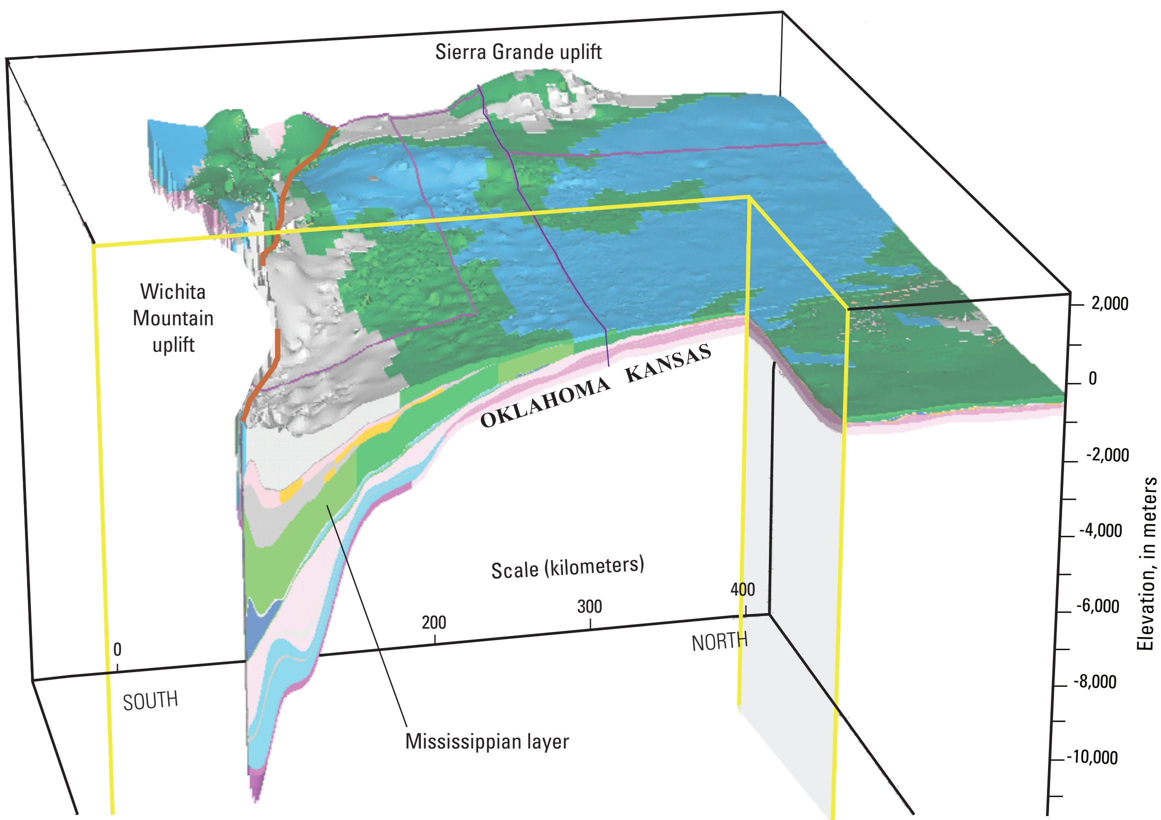


Figure 10. Cube dissection of the four-dimensional petroleum system model shows present-day elevation on the Desmoinesian layer surface; color variations on the Desmoinesian correspond to lithologies from Adler and others (1971). Vertical color bands represent lithofacies assignments for the Desmoinesian through Precambrian layers. For example, the labeled Mississippian layer is about 900 meters (2,900 feet) thick at the location. Location of the slice is in figure 9. Vertical exaggeration is 15 times.

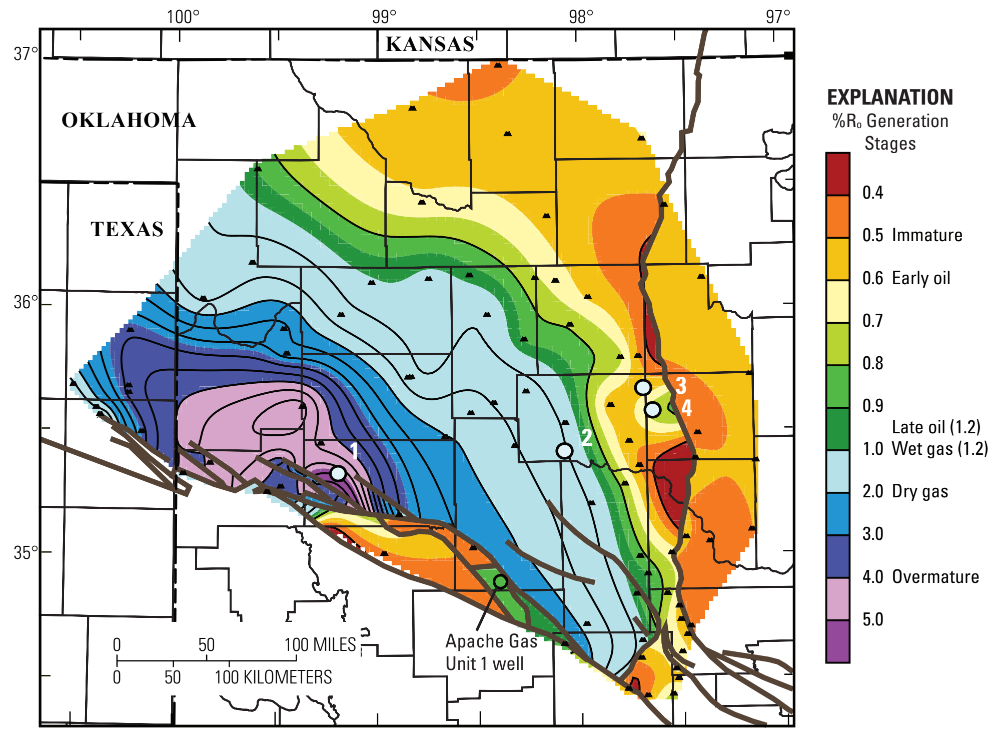


Figure 11. Map showing vitrinite reflectance (R_o) contours for the Woodford Shale; black line contours are in increments of 0.4% R_o. Generation stages on R_o legend are generalized, as gas generation also occurs within the oil generation range. Black triangles and white dots include R_o data from Cardott (1989; written commun., 2011), Price (1997), and Mark Pawlewicz (written commun., 2010). Labeled white dot well locations are (1) Bertha Rogers 1, (2) Petree Ranch 1, (3) West Edmond SWD 1-24, and (4) Streeter 1. Brown lines are faults in the underlying Hunton Group (Rottmann, 2000a, pl. 3).

and Arbuckle Mountains (Comer and Hinch, 1987). Bitumen is assumed to be sourced from the Woodford as generated oil migrated laterally and then vertically along the faults. Vitrinite reflectance was contoured relative to the Hunton faults of Rottmann (2000a), which also isolates samples from the Wichita Mountain uplift relative to those in the basin. That the uplifted samples exhibit lower levels of thermal maturation than samples located north of the fault system shows that uplift occurred prior to maximum burial in the basin. Thermal maturation in the Wichita Mountain uplift is extrapolated from several outcrop samples and does not reflect the actual conditions because of the complexity of faulting, timing of uplift, and distribution of the Woodford Shale. Uplift samples should be considered point sources because of extensive faulting. For example, the Woodford Shale is present at least 4 times within the 1,930- to 19,000-ft depth interval of the Apache Gas Unit 1 well (fig. 11); this well was not sampled, but it is likely that there would be a spread of R_o values.

Petroleum Source Rocks

Petroleum source rocks in the Anadarko Basin were depPetroleum source rocks in the Anadarko Basin were deposited in marine environments. Burruss and Hatch (1989) and Joseph Hatch (oral commun, 2010) identified shale intervals of the Simpson Group, Woodford Shale, and Middle and Upper Pennsylvanian strata as the main source rocks in the Anadarko Basin (fig. 2). Burruss and Hatch (1989, p. 57) identified the following Anadarko Basin source rocks as having moderate to good hydrocarbon potential based on oil and source rocks geochemical analyses: (1) Ordovician Simpson Group shale, (2) Devonian-Mississippian Woodford Shale, and (3) Pennsylvanian black shales. They indicated absent to moderate source potential for the Ordovician Sylvan Shale based on geochemical analysis of oil and rock samples in Kansas and Oklahoma. There is no evidence for source potential from the Sylvan (or equivalent Maquoketa) Shale in the Anadarko Basin based on studies by Hatch and others (1987) and Wang and Philp (1997), and the poor gamma response from examination of about 90 well logs across the basin. The primary and most studied petroleum source rock in the Anadarko Basin is the Devonian-Mississippian Woodford Shale; equivalent strata are termed the Chattanooga Shale in Kansas. Because of limited source rock information for many other formations, all but the Woodford will be grouped by system. The Woodford Composite TPS includes the Cambrian through Mississippian section, and the Pennsylvanian Composite TPS includes source and reservoir rocks of Pennsylvanian through Permian age.

Three layers in the 4D petroleum system model were assigned as petroleum source rocks based partly on the Burruss and Hatch (1989) determination of three oil types in the Anadarko Basin. They conducted geochemical analysis of 104 crude oils and 190 core samples of Cambrian through Pennsylvanian dark colored shales, and their sampled oils and source intervals are from (1) the Middle Ordovician Simpson Group, (2) Silurian to Mississippian reservoirs, and (3) Pennsylvanian strata. The modeled source intervals are the

Oil Creek Formation layer of the Simpson Group, the Woodford Shale layer, and the informal Thirteen Finger limestone layer (fig. 2). The Thirteen Finger limestone was chosen to represent Pennsylvanian source rocks because I mapped the thickness and extent of this high-gamma interval formation across the Anadarko Basin Province and therefore had a layer to assign source properties.

This definition of three petroleum source rock layers serves to model which source(s) contribute to which reservoir layers, and also if this contribution varies across the basin and through time. Three assigned source intervals in a basin that contains probable other source rocks further homogenizes the model, but can also be used to determine if all potential reservoir intervals are charged. For example, does the Oil Creek layer source charge underlying Arbuckle layer reservoirs? If not, is it because of the coarseness of the model and (or) would this indicate source intervals in the Arbuckle?

Middle Ordovician Simpson Group reservoirs contain "typical" Ordovician oils that are characterized by (1) strong odd-carbon predominance in the C_{13} to C_{19} n-alkanes, (2) few or no acyclic isoprenoids, and (3) $\delta^{13}C$ values of -33.9 parts per thousand (ppt) (saturates) and -33.7 ppt (aromatics) (Burruss and Hatch, 1989). Oils from Silurian to Mississippian reservoirs show little or no odd-carbon predominance in the n-alkanes, a regular decrease in abundance of n-alkanes with increasing carbon number, pristane/phytane ratios (pr/ph) of 1.1 to 1.5, and delta carbon-13 ($\delta^{13}C$) values of -30.6 ppt (saturates) and -30.1 ppt (aromatics). Oils in Pennsylvanian reservoirs have the greatest amounts of carbon 15+ (C_{15+}) hydrocarbons, are isotopically heavy (-27.5 ppt (saturates) and -26.4 ppt (aromatics), have methyl-cyclohexane as the most abundant hydrocarbon, and have pr/ph values from 2.0 to 0.9.

The Wavrek (1992) gas chromatography analysis of 385 Cambrian through Cretaceous crude oils from 83 fields across the Ardmore and Marietta Basins, south and east of the Anadarko Basin resulted in the assignment of 7 oil families. These A through G families were based largely on relative n-alkane distribution, cyclic isoprenoids, alkylated cyclic hydrocarbons, alkylated sulfur compounds, aryl-isoprenoids, hopanes, steranes, and carbon isotopes. Types A through E oils appear to correlate with respective source facies within the (A) Pennsylvanian (Atoka Group?), (B) Mississippian (Goddard Shale, Caney Shale, and Sycamore Limestone of the Mayes Group), (C) Devonian-Mississippian Woodford Shale, (D) upper Middle Ordovician Viola Group, and (E) Middle Ordovician Simpson Group (Wavrek, 1992). Type F oil was from Arbuckle Group reservoirs, but had uncertain parentage, and Type G oil had some characteristics of mixed oil types and possible effects of multiple sources because of proximity to the Ouachita thrust zone. Wavrek (1992) assigned greatest importance as a source rock to Type C, the Woodford Shale.

Ordovician Source Rocks

The Cambrian and Ordovician Arbuckle Group lithologies include limestones with algal mats and boundstones (Donovan, 1986), bedded and disseminated anhydrite (Latham, 1970; St. John and Eby, 1978; Ragland and Donovan, 1985; Donovan, 1986), and gray to dark gray limestone and some shale (Fay, 1989). The Arbuckle and Ellenburger Groups are partially equivalent and about 7,000 feet (ft) (2,150 m) thick in the deep basin; petroleum production is confined to the upper 200–300 ft (Cardwell, 1977a). Pyrolysis-gas chromatographic analysis reveals that, in most of Oklahoma, the Arbuckle section is thermally mature but is deficient in organic matter (Cardwell, 1977a, 1977b). The Arbuckle Group is unlikely to contain petroleum source rocks in the Anadarko Basin. If present, source rocks are most likely proximal to the subsiding southern Oklahoma aulacogen (Johnson and Cardott, 1992), an area that is currently mostly overmature for hydrocarbon generation. This generation would have resulted in depletion of TOC, so original TOC would have been greater. TOC from 21 Arbuckle and Ellenburger carbonate samples ranged from 0.03–0.24 wt %, with an average of 0.1% (Cardwell, 1977a), less than good quality source rock of greater than 1.0 wt % TOC (Hatch and others, 1987). The Trask and Panode (1942, table 94, p. 263) Arbuckle TOC values ranged from 0.3 to 0.8 wt % for 6 samples from 6 wells just east of the basin in Kansas and Oklahoma. Cardwell (1977a, p. 42) also observed that the composition of 9 Arbuckle oils from western Oklahoma were closely similar to those of 14 Desmoinesian oils from northeast Oklahoma and southeast Kansas.

The Ordovician Simpson and Viola Groups contain mainly oil-prone source intervals (fig. 2) of Types I and II kerogen based on Rock-Eval pyrolysis results (Rice and others, 1989; Burruss and Hatch, 1989). Wang and Philp (1997) indicated the Viola and Woodford petroleum source intervals are mostly Type II kerogen based on Rock-Eval pyrolysis. The Simpson Group reaches a maximum thickness of 2,300 ft (700 m), of which about 50 percent is shale (Schramm, 1964). Sparse sampling on the shelf indicated as much as 14 percent of these shales may contain more than the minimum 1.0 wt % TOC required for a petroleum source rock (Hatch and others, 1987). Burruss and Hatch (1989) state Ordovician rocks generally exhibit TOC less than 1.0 wt %, although several Kansas samples have TOC between 1.0 and 9.0 wt %. Joseph Hatch (oral commun., 2010) unpublished TOC data ranged from 0.02 to 18.2 wt % and averaged 1.54 wt % for 39 Ordovician core samples from 4 wells in Oklahoma and Kansas. The average was increased because of TOC values of 5.34, 8.81, and 18.2 wt % from a well located northeast of the province at about latitude 38.19 N. and longitude 97.66 W.; hydrocarbon index (HI) values for this well were 665 to 787 milligrams sulfur per gram of total organic carbon (mg S_2/g) TOC.

The Sylvan Shale is isolated to the deep basin in Oklahoma and Texas. It is light gray to grayish green and waxy (Johnson and others, 1988), with an average thickness of less than 250 ft (80 m) (Wang and Philp, 1997). Well log gamma ray signatures were subdued for the Sylvan Shale in 88 wells scattered across the Oklahoma and Texas portions of the basin. Signatures were distinct enough to correlate the formation, but the minor gamma response is characteristic of the generally low TOC for this formation in the province.

Devonian-Mississippian Woodford Shale

The Woodford Shale in the Anadarko Basin is a carbonaceous, siliceous, pyritic, dark-gray to black shale (Cardott, 1989), the general extent of which is outlined in figure 1 by the Woodford Shale Oil AU. Equivalent strata northeast of the province in Kansas are called the Chattanooga Shale. The Woodford Shale was deposited on a regional erosional surface of the Silurian-Devonian Hunton Group (fig. 2). This unconformity developed across a broad upwarping that was one of the most widespread in the entire Midcontinent (Amsden, 1975, 1989); it was accompanied by little, if any, folding or faulting except for faulting along the Nemaha uplift (Johnson, 1989). This upwarping partially isolated the epicontinental seaway. The organic-rich Woodford black shales were deposited under anoxic conditions during the early Kaskaskia transgression of this shallow epicontinental sea (von Almen, 1970; Walper, 1977; Sullivan, 1985; Johnson and Cardott, 1992; Lambert, 1993). Evidence of burrowing in exposed organic-rich rocks in the Arbuckle Mountains (fig. 3) suggests there were also periods of oxic depositional conditions (Neil Fishman, oral commun., March 2, 2011). Egenhoff and others (2011) indicated a basinward progression in the Woodford from siliciclastic mudstones to successively increasing downslope *Tasmanites* and then radiolarian cherts; short-term highstands completely shut off delivery of very fine-grained sediments to distal parts of the passive margin during Woodford deposition, enabling good preservation of Milankovitch cycles in the formation.

Elevation on the top of the Woodford Shale in the Anadarko Basin ranges from about -2,500 ft (-760 m) on the southern Kansas shelf, to -27,000 ft (-8,000 m) in southern Oklahoma (fig. 3). The formation is mostly absent because of erosion in the Wichita Mountain and Amarillo uplifts, although the Woodford Shale Gas AU includes an area of Woodford in the Wichita Mountain uplift proximal to the fault zone. The Woodford Shale is a fairly easy pick from well logs because of the large gamma kick and low permeability of this formation (fig. 12). Gamma-ray responses are commonly greater than 160 American Petroleum Institute (API) units (Amsden, 1975; Sullivan, 1985). The figure 12 cross section is located perpendicular to a thick interval of Woodford channel fill (fig. 13). The easternmost well in the cross section exhibits lateral thinning of the Mississippian section and absence of Morrow Formation and Thirteen Finger limestone.

Thickness of the Woodford Shale varies greatly across the province. It ranges up to 375 ft thick and averages 40 ft based on Rottmann (2000b), well-log picks from about 100 wells across the basin, and edited formation tops from IHS Energy (2009a, 2009b). Greatest thicknesses are in the southern part of the basin in Oklahoma and locally as fill within eroded channels of the underlying Hunton Group (figs. 12 and 13). This is also the basin area that is most thermally mature for gas generation. Areas within the Woodford Shale AUs boundaries (fig. 1) where the unit is absent or thin resulted from erosion or nondeposition. There are a few erosional remnants outside the Woodford Shale Oil AU boundary, and the unit is present northeast of the province in Kansas. Smooth contours near the southeastern corner of figure 13 reflect limited data and variable thicknesses because of extensive faulting. The Misener sand is a lower unit of the Woodford Shale that is located mainly in the northeastern basin in Oklahoma and Kansas. Petroleum resources of this unit were evaluated with the Hunton Group AU because the Misener sand reservoirs are conventional, and much of the petroleum production was reported as commingled with that of the Hunton Group.

The Woodford Shale comprises upper, middle, and lower informal members of carbonate- and silica-rich shales based on well-log signatures, palynomorphs, and geochemical differences (Urban, 1960; von Almen, 1970; Sullivan, 1983, 1985; Hester and others, 1990; Lambert, 1993). The middle shale member has the greatest areal extent and thickness, and is also the most organic rich (Lambert, 1993). The Woodford Shale exhibits two habits, fissile and nonfissile shale. Nonfissile contains phosphatic and siliceous shales, minor thin dolomite beds, phosphatic nodules, and rare chert; fissile shales are composed of laminations less than 1 centimeter (cm) thick and are more organic-rich than nonfissile shale (Krystyniak and Paxton, 2006). The Woodford has abundant Type A amorphous Type II kerogen [partially equivalent to the liptinite (exinite) maceral group] with the remaining primarily Type III kerogen (vitrinite) and Type I kerogen (*Tasmanite alginite*) (Lewan, 1983; Thompson and Dembicki, 1986; Crossey and others, 1986; Comer and Hinch, 1987; Burwood and others, 1988; Krystyniack and Paxton, 2006). Applied to the Woodford Shale layer within the 4D PetroMod® model were a generalized composition of the Woodford Shale is 37 percent quartz, 26 percent illite, 15 percent kerogen, 17 percent carbonate, and 5 percent kaolinite (Abousleiman, 2008), and a HI of 527 mg S_2/g TOC based on Lewan and Ruble (2002). HI data ranged from 3 to 1,127 mg S_2/g TOC and averaged 260 mg S_2/g TOC based on analyses of 97 core samples from 30 wells that were scattered across Oklahoma and Kansas (Burruss and Hatch, 1989; Joseph Hatch, oral commun., 2010). Kirkland and others (1992) indicated a HI range of 500 to 800 mg S_2/g TOC for their samples. The Oklahoma portion of the province is mostly mature to overmature for petroleum generation, whereas the Woodford (Chattanooga) in Kansas is immature. As such, the HI of 17 Kansas Woodford (Chattanooga) samples ranged from 89 to 600 and averaged 321 mg S_2/g TOC.

Based on analysis of 101 Woodford core samples from 30 wells that were scattered throughout its extent in Oklahoma and Kansas, Burruss and Hatch (1989) indicated the TOC ranged from greater than 2 wt % to 14 wt %. Joseph Hatch (oral commun., 2010) indicated that TOC data averaged 4 wt %. Estimated average TOC of a somewhat conservative 3.5 wt % was used for 1D models and was based on data from Hester and others (1990), Comer and Hinch

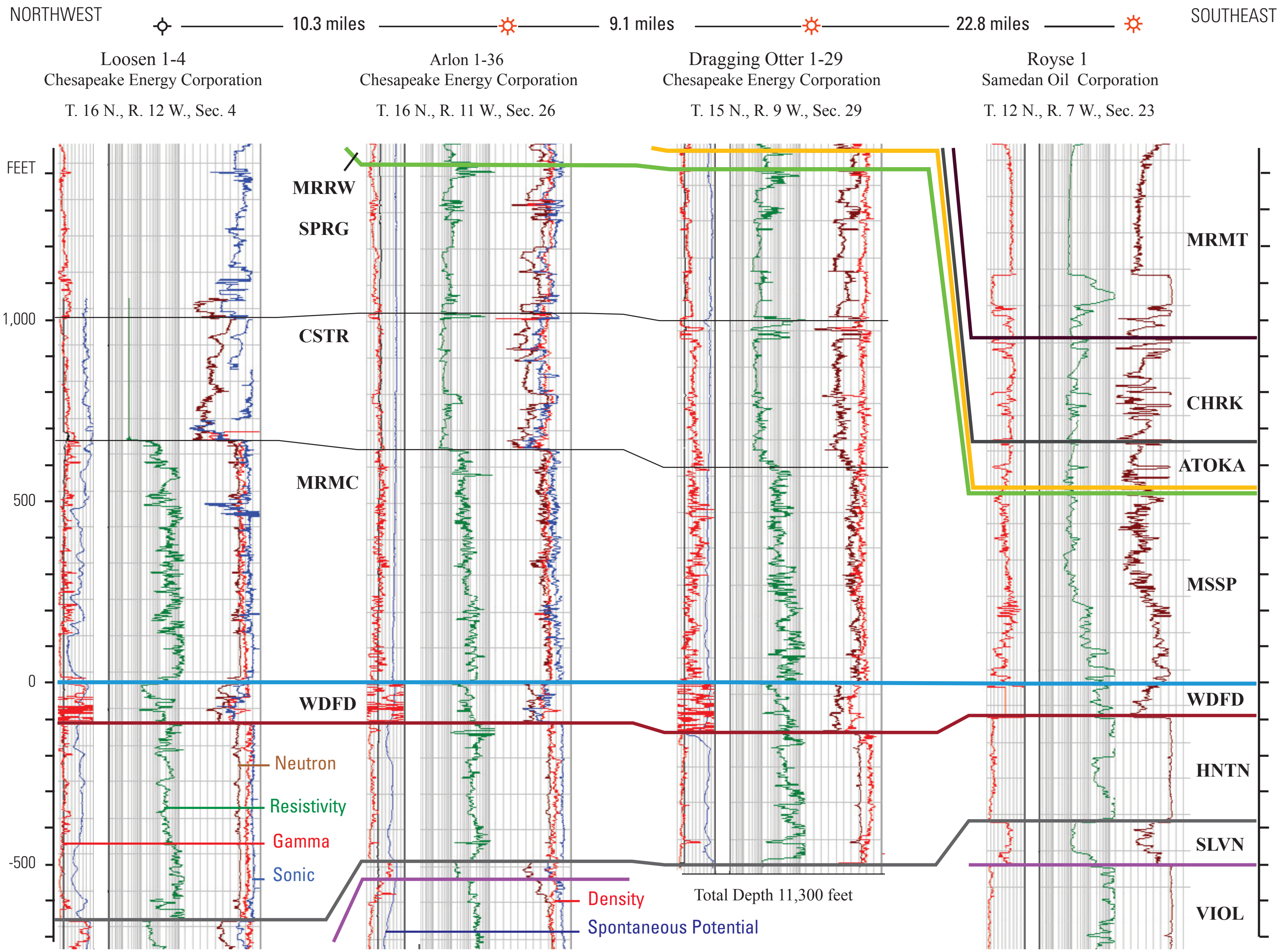


Figure 12. Cross section showing the Woodford Shale (WDFD, blue line) and terminus of the Morrow Group (MRRW) and overlying Thirteen Finger Limestone portion of the Atoka Group (ATOKA, gold line) in the deep Anadarko Basin. Line of section is shown in figure 13. Vertical scale is in feet relative to the top of the WDFD. MRMT is Marmaton Group, CHRK is Cherokee Group, MSSP is Mississippian, HNTN is Hunton Group, SLVN is Sylvan Shale, VIOL is Viola Group, and SPRG, CSTR, and MRMC are the respective Mississippian Springer Formation, Chester Group, and Meramec lime. Labeled well log traces are gamma (0 to 200 API), resistivity, sonic density, neutron density, spontaneous potential, and density.

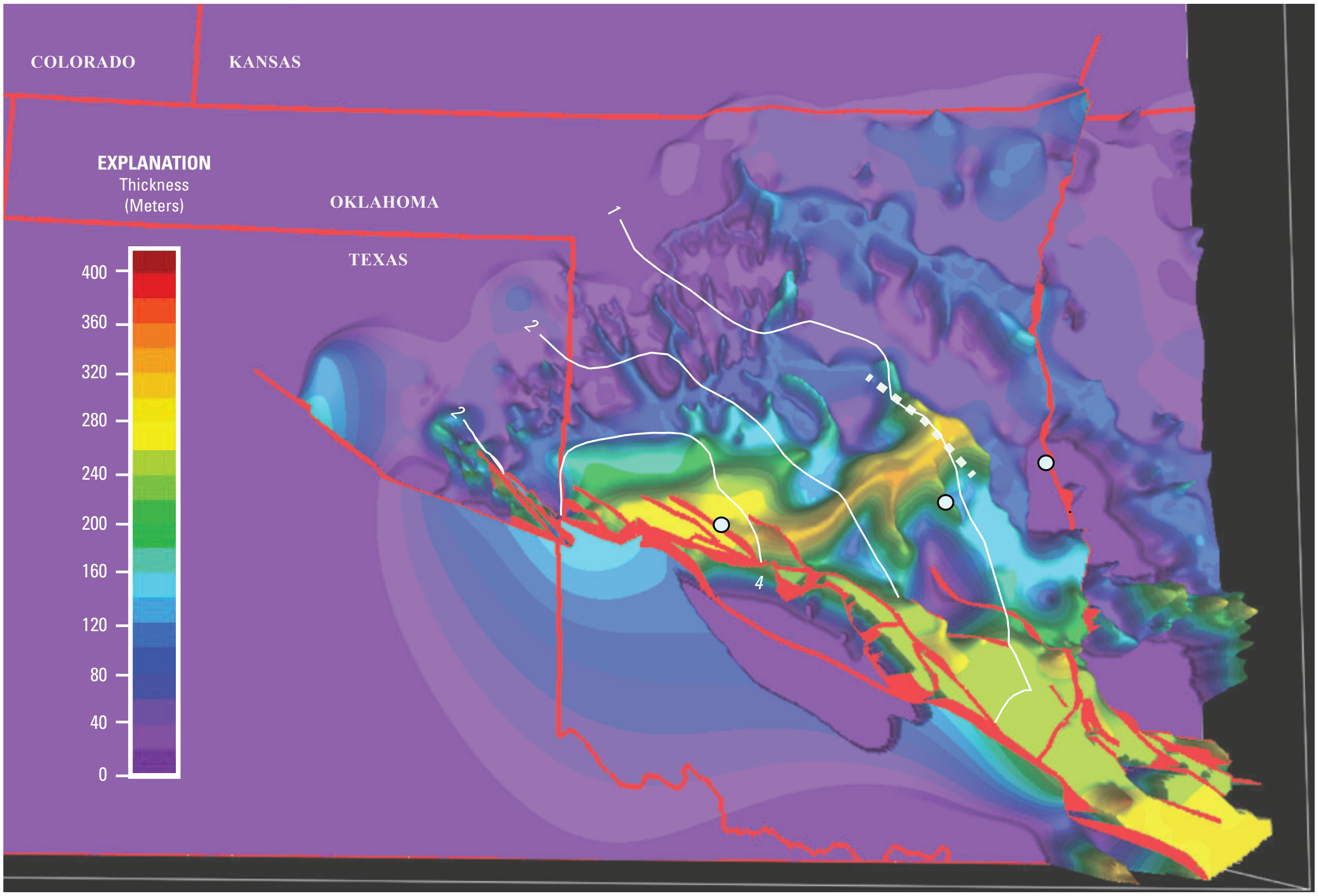


Figure 13. Three-dimensional isopach image of the Woodford Shale in the Anadarko Basin. Vitrinite reflectance (% R_o) contours (white lines) from figure 11 approximate end of oil generation at 1.2% R_o to overmature for petroleum generation (4% R_o). White dot well locations are, from left to right, Bertha Rogers 1, Petree 1, and Streeter 1. Dashed white line is location of figure 12 cross section. Woodford thickness is derived from Rottmann (2000b, pl. 2), analysis of more than 100 well logs, and edited formation tops from IHS Energy (2009a, 2009b). Faults (red) are from Rottmann (2000a, pl. 3). Image is tilted and 1,300 times vertical exaggeration.

(1987), Burruss and Hatch (1989), Price (1997), Joseph Hatch (oral commun., 2010), and the Energy Geochemistry Data Base (U.S. Geological Survey, 2010). 1D models are located in areas that are mature to overmature for petroleum generation from the Woodford Shale. As such, original TOC was greater. The 4D model incorporated a map generated from these TOC data (fig. 14), instead of assigning a value for the entire layer. The Comer and Hinch (1987) Woodford mean TOC content of 5.4 ± 6.9 percent by wt was based on analysis of 300 samples from 16 cores and 43 outcrops that were distributed across Oklahoma and Arkansas; uncertainty in TOC resulted from a range of less than 0.1 wt% in some chert beds to 26 wt% in highly compacted black shale. Their location A21 near the southeast corner of figure 14 averaged 5.5 ± 3.9 percent by weight TOC and this Type II kerogen was in early stage oil generation. Krystyniack and Paxton (2006) TOC values ranged from 0.8 to 17 wt% for upper Woodford outcrop samples of south-central Oklahoma. Comer and Hinch (1987) indicated that chert beds contained less TOC, but more total bitumen and hydrocarbons per gram. This may be indicative of greater fracturing and petroleum retention in chert beds.

Mississippian Source Rocks

Middle Ordovician through lowermost Mississippian sedimentary rocks in the basin are composed of fossiliferous shallow-water marine carbonates interbedded with fine-grained to moderately coarse-grained clastics that were derived from the northeast and east (Johnson and others, 1988). Probable Mississippian petroleum source rocks are within the informal Osage lime and Springer Formation (fig. 2) (Wang and Philp, 1997). Average thickness of the Springer Formation is about 500 ft (150 m) and more than 60 percent of it is shale and mudstone (Wang and Philp, 1997). Organic-carbon values for

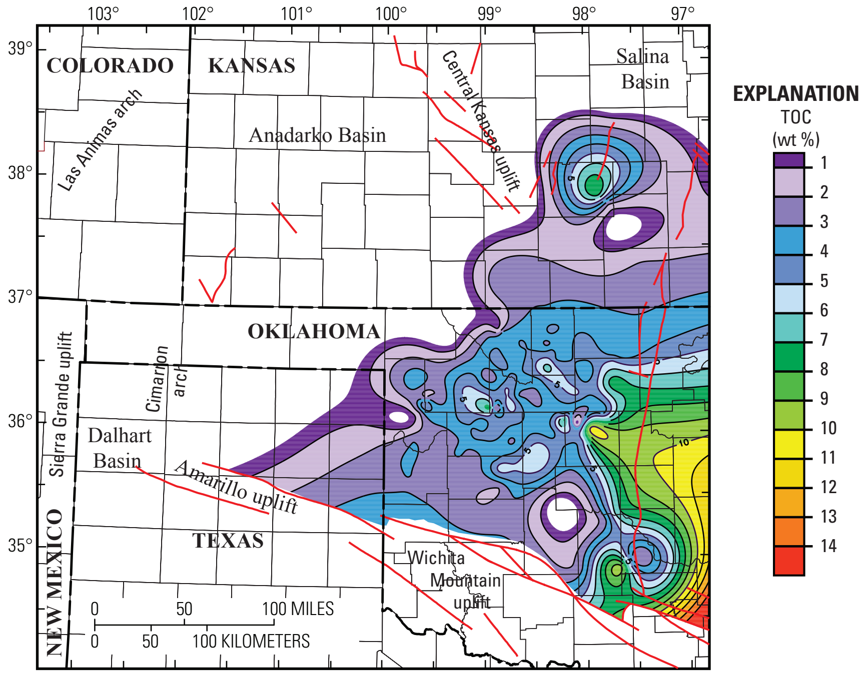


Figure 14. Map showing total organic carbon (TOC) content in weight percent (wt%) for the Woodford Shale based on TOC data from Burruss and Hatch (1989) and mean values from Hester and others (1990). TOC ranges from 0.08 to 14.05 wt% and averages 3.7 wt% for core and well log density calculations from 123 wells. There is considerable TOC variation, but almost the entire area that is thermally mature for petroleum generation contains greater than 2 wt% TOC. Oil and gas generation depletes TOC and HI (hydrogen index), the fuels for petroleum, so original TOC and HI values would have been greater. Red lines are faults from Adler and others (1971).

thick shales in the Springer and Pennsylvanian (Morrowan) producing intervals range from 0.5 to 3.4 wt%; however, the kerogen is mostly Type III, indicating that it is primarily gas-prone (Hatch and others, 1987; Rice and others, 1989; Wang and Philp, 1997) (fig. 2). Johnson and Cardott (1992, fig. 7) indicate that Mississippian shales and novaculite in the Ouachita trough, southeast of the Anadarko Basin, contain Types II and III kerogen with TOC values ranging from less than 1.0 to 1.9 wt %. The Mississippian ended with regional uplift and erosion that marked the onset of the Wichita orogeny, and resulted in erosion of Devonian and older strata, such as the Woodford Shale on structural highs around the margin of the basin (Ball and others, 1991).

Pennsylvanian Source Rocks

Morrowan, Atokan, Desmoinesian, and Missourian organic-rich shales are important petroleum source rocks in the Anadarko Basin (fig. 2) (Hatch and others, 1987; Burruss and Hatch, 1989). Absence of uppermost Morrowan through Atokan strata over most of the Cimarron arch indicates this structure formed toward the end of tectonic activity that gave rise to the Wichita Mountain and Amarillo uplifts (fig. 14) (Johnson, 1989). These strata are also absent over the Sierra Grande uplift (fig. 9), a broad regional feature that was active during the Precambrian and a positive feature since Paleozoic time (Speer, 1976). The Morrow Group averages 1,500 ft (460 m) in thickness in the Oklahoma portion of the Anadarko Basin, and comprises more than 60 percent shale and mudstone (Wang and Philp, 1997). As is the case with most other formations in the basin, the Morrow thins northward from the basin axis and across the shelf. Deposition across the province varied from shallow marine to shoreline and deltaic environments (Tsiris, 1983). Lower Morrow Group lithofacies are mainly black shale beds with interbedded sandstone and thin limestone layers; these probably represent deposition in a shallow transgressive sea (Wang and Philp, 1997). The middle Morrow is dominantly marine shales and carbonates, and the upper Morrow contains black shale, thin coal layers, and recycled organic matter (Wang and Philp, 1997). Unpublished data for Morrowan shales from core of 14 wells in the Oklahoma portion of the basin were from Joseph Hatch (oral commun., 2010); results ranged from 0.48 to 10.71 wt % TOC and averaged 1.72 wt %; HI ranged from 15 to 179 mg S_2/g TOC and averaged 46.

As is the case for Pennsylvanian and older rocks in the deep basin, sampled areas are thermally mature for petroleum generation and original TOC and HI values would have been greater. 4D model initial TOC and HI values are calculated by PetroMod® software based on present-day thermal maturation of source rocks and their burial through time.

Atokan Series source rocks include shales and limestones of the Atoka Group and underlying Thirteen Finger limestone. The Atokan Series averages 390 ft thick in Texas and the Oklahoma Panhandle and overlies a second-order unconformity at the top of the Morrow Group (Carr and Hentz, 2009). The Thirteen Finger limestone, also called the 13 Finger lime and Thirteen Finger lime, consists of fissile, organic-rich shale interbedded with fossiliferous wackestones that represents a third-order transgressive systems tract (Carr and Hentz, 2009; Carr and others, 2009). Depths range from about 4,000 to 18,500 ft across the mapped extent of the unit. Elevation of the Thirteen Finger limestone, based partly on examination of 125 wells across the basin, ranges from about -4,000 ft on the shelf areas of Colorado and Kansas, to -17,000 ft in the deep basin area of Oklahoma and Texas (fig. 15). There is limited change in elevation of the formation across the Colorado and Kansas shelf, aside from uplifts associated with the Las Animas arch in southeastern Colorado, and the Keyes dome. This dome (fig. 6) forms a trap for modeled Thirteen Finger limestone oil accumulations. The Cimarron arch and Sierra Grande uplift (fig. 6) were positive features during Morrowan and Atokan time, which prevented deposition of these strata. Thickness of the Thirteen Finger limestone is variable across its extent (fig. 16) and averages 95 ft based on examination of 125 well logs. Semicircular contours represent increased thickness along a curved axis of deposition, and data extrapolation in areas with sparse well coverage. Also shown in figure 16 is overall thinning of strata from the deep basin to shelf areas, although there is a northwest trend of increased thickness from the deep basin towards southeastern Colorado. The Perryton and Knowles Northwest oil fields (fig. 16) have cumulative production from the Thirteen Finger limestone of about 160,000 barrels of oil, 300 million cubic feet of gas, and 6,900 barrels of water (IHS Energy, 2010). These fields are considered to be conventional based on decline curves of petroleum and water production. Perryton and Knowles Northwest fields are also located in an area marginally mature to mature for oil generation from the Thirteen Finger limestone, based on modeled TR and R_o values.

The thickest, most organic-rich interval in the Atokan Series is in the uppermost part of the Thirteen Finger limestone and it probably represents a third-order marine condensed section (Carr and Hentz, 2009). Carr and Hentz (2009) estimated the average TOC ranged from about 4–6 wt % based on petrophysical examination of 28 wells. The Thirteen Finger limestone is characterized on well logs as stacked thin shale and carbonate beds with irregular high gamma kicks of 140 API and greater (fig. 17). This results in the “fingers” appearance. It is fairly readily correlated across the extent of the underlying Morrow Group in the province, except where proximal to the Wichita Mountain uplift. This is primarily because of tilting of strata and increased contribution of clastic sediments relative to organics. Gamma response for cross section *A-A’* is less pronounced than that of *B-B*’. This suggests that the Atokan section in *B-B*’ contains more organic matter. Source rocks in *A-A’* are also thermally mature for oil and (or) gas generation, which would deplete the TOC and HI values. Gamma response of the overlying Atoka Group is unremarkable in the *A-A’* cross section but the *B-B*’ response is similar to that of the Thirteen Finger limestone. The Atoka Group source interval differs in that it is primarily shale, rather than thin limestone and shale beds.

Desmoinesian and Missourian source rocks (fig. 2) are primarily organic-rich shales. Sixteen of the sample analyses results from Joseph Hatch (oral commun., 2010) were loosely categorized as Desmoinesian source rocks, 13 from Oklahoma, 1 from Texas, and 2 from western Kansas—TOC values ranged from 0.08 to 11.2 wt %, averaging 2.9 wt %, and HI values ranged from 7 to 442 mg S_2/g TOC, averaging 144 mg S_2/g TOC. Two samples from the Missourian section in Oklahoma and 4 from western Kansas ranged from 0.5 to 39.4 wt % TOC, averaging 11.4 wt %, and HI values ranged from 7 to 576 mg S_2/g TOC, averaging 296 mg S_2/g TOC (Joseph Hatch, oral commun., 2010).

Petroleum System Model of the Anadarko Basin

Petroleum Generation Kinetics

The 4D model of the Anadarko Basin was constructed of 30 layers of strata from Precambrian to ground surface. Incorporated in the model are maps of basal heat flow, water depth through time, periods and thicknesses of deposition and erosion, total organic carbon (TOC) and hydrogen indices (HI) for the Woodford Shale and other source rocks, and lithofacies for each layer. Ideally, once the 4D model is constructed, it can be readily calibrated to available temperature and thermal maturation data, but in actuality, numerous modifications and iterations are necessary to achieve “final” models. Changes are designed to fit the 4D model to generated 1D models and to measured temperature and thermal maturation indicators across the basin. 1D models and 1D extractions from the 4D model were calibrated using temperature and R_o data. 1D models were compared to 1D extractions from the 3D model as a further calibration step. Modeled R_o (Sweeney and Burnham, 1990) was preferentially calibrated on measured R_o from the Woodford Shale (Cardott, 1989; Price, 1997).

Onsets of petroleum generation and expulsion across the basin were determined primarily using modeled R_o and Woodford Shale hydrous pyrolysis (HP) kinetics (table 2) that were applied to potential source rocks of the Ordovician Simpson Group, Devonian-Mississippian Woodford Shale,

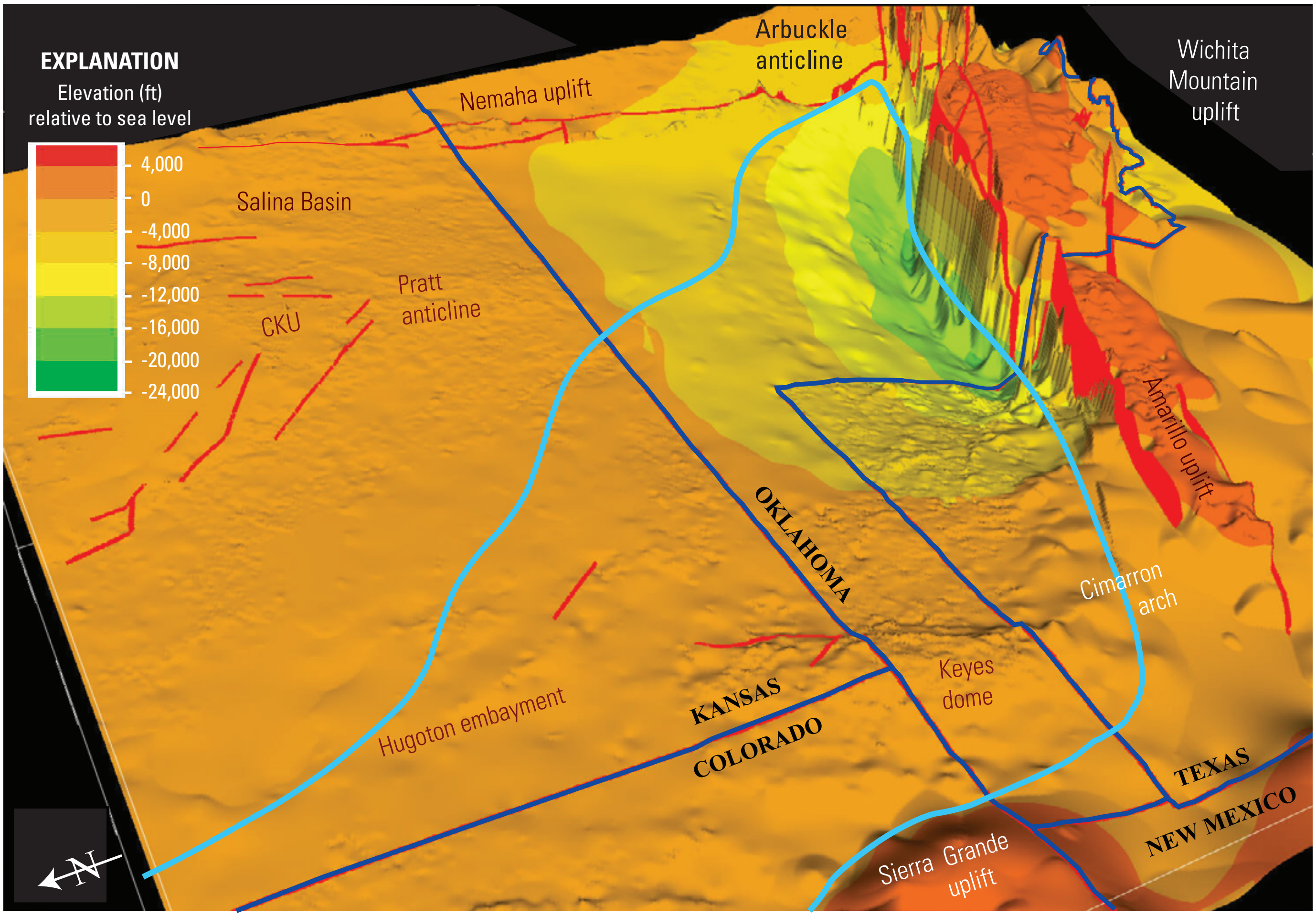


Figure 15. View to the southeast of elevation on the top of the Thirteen Finger limestone layer (Higley and others, 2014, ThirteenFingerTft.DAT grid file). Vertical exaggeration is 18 times. Thirteen Finger lime extent is approximated by the light blue line. Major structures are labeled. Precambrian faults (red) are from Adler and others (1971). Wichita Mountain uplift faults are vertical for four-dimensional model purposes only, and surface in this area is unknown because of insufficient data. Data sources for this surface include Thirteen Finger limestone picks from well logs and edited IHS Energy (2009a, 2009b) formation tops. Elevation is relative to sea level. CKU, Central Kansas uplift.

and Pennsylvanian Thirteen Finger limestone. Heat flow and erosional history, estimated depositional and thermal properties of assigned lithofacies, and choice of kinetic algorithms can significantly affect timing of generation. Petroleum modeling software can also affect results and associated conclusions (Higley and others, 2006). For these reasons I used several kinetic algorithms and heating histories. It is preferable to have kinetic algorithms calculated from and specific for each petroleum source rock, but those values were only available for the Woodford Shale.

Phosphoria Formation HP kinetics (Lewan and Ruble, 2002) was also applied to the models to investigate the effect of organic sulfur on timing of petroleum generation. Some wells in the Panhandle and Hugoton field area of the western basin produce sour oil and (or) gas from mostly Pennsylvanian reservoirs, but sour oil and (or) gas has also been reported from scattered Cambrian and Ordovician Arbuckle through Permian Chase reservoirs across the basin (Mason, 1968; Owen, 1975; Nehring and Associates, Inc., 2009). The Woodford Shale contains a fairly low ratio of organic-sulfur to carbon at 0.023 (S_{org}/C); the Phosphoria Formation is fairly high at 0.045023 S_{org}/C (Lewan and Ruble, 2002, table 1). HP kinetics depend partly on the organic-sulfur content of the original kerogen (Lewan and Ruble, 2002). Impact of the Type IIS kerogen organic sulfur on generation of oil is detailed in Lewan and Ruble (2002) and illustrated in Higley and others (2009). To simplify a complex process, essentially the organic sulfur results in sulfur-radical initiators that increase the associated reaction rates during thermal maturation of the source rock. A primary effect is that the onset-through-completion of oil generation and expulsion occurs at decreased levels of thermal maturation. The Tsuzuki and others' (1999) secondary and tertiary generation (cracking) of oil to gas kinetics were applied for each petroleum source rock in the model. Because of the coarse grid spacing and generalized lithologies, little secondary or tertiary gas

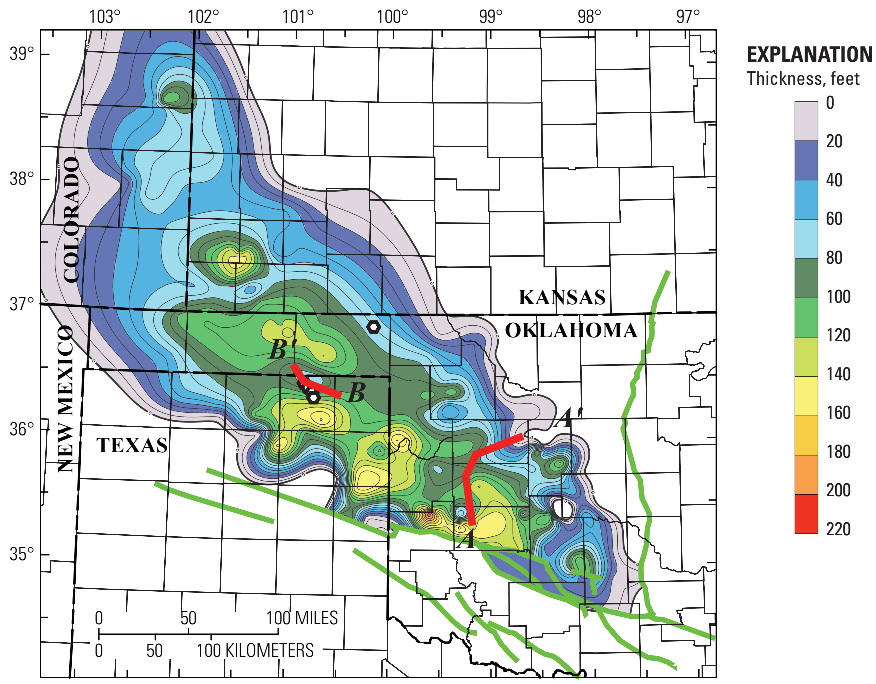


Figure 16. Isopach map of the top of the stratigraphic interval from the Thirteen Finger limestone to the Morrow Formation, based on Andrews (1999a, b), examination of more than 120 well logs, and edited tops from IHS Energy (2009a, 2009b). Morrow Formation faults (green) are modified from Andrews (1999b). Color contour interval is 20 feet and (black) line contours are 10-feet intervals. Figure 17 cross sections are labeled *A-A′* and *B-B′*. White polygons are Perryton (Texas) and Knowles Northwest (Oklahoma Panhandle) oil fields.

Table 2. Summary of kinetic parameters derived for expelled-oil generation based on hydrous pyrolysis (HP) in isothermal experiments, and nonisothermal open-system pyrolysis (REV) that were derived from Lewan and Ruble (2002, tables 4 and 5) and cracking of oil to gas (Tsuzuki and others, 1999). The Woodford Shale analyses were on an unweathered, thermally immature sample that contained 12.7 percent total organic carbon (TOC), from section 25, T. 2 S., R. 1 E., Carter Co., Oklahoma (Lewan, 1983).

Formation-Name	SampleNumber	KerogenType	Activation energy, E_a (kcal/mol)	Frequency factor A_0 ($m.y^{-1}$)	HImgHC/gTOC
Phosphoria	P-64	Type II-S	42.71	4.31E x 10^{23}	276.0
Woodford	WD-5	Type II	52.16	5.706E x 10^{26}	246.2
Woodford	WD-5 (REV)	Type II	56.1 (Mean)	8.111E x 10^{26}	440.0
		(C_{15+} crude oil)[1]	76.00	3.419E x 10^{33}	

[1] Tsuzuki and others (1999) secondary gas generation kinetics was applied to all petroleum source rocks.

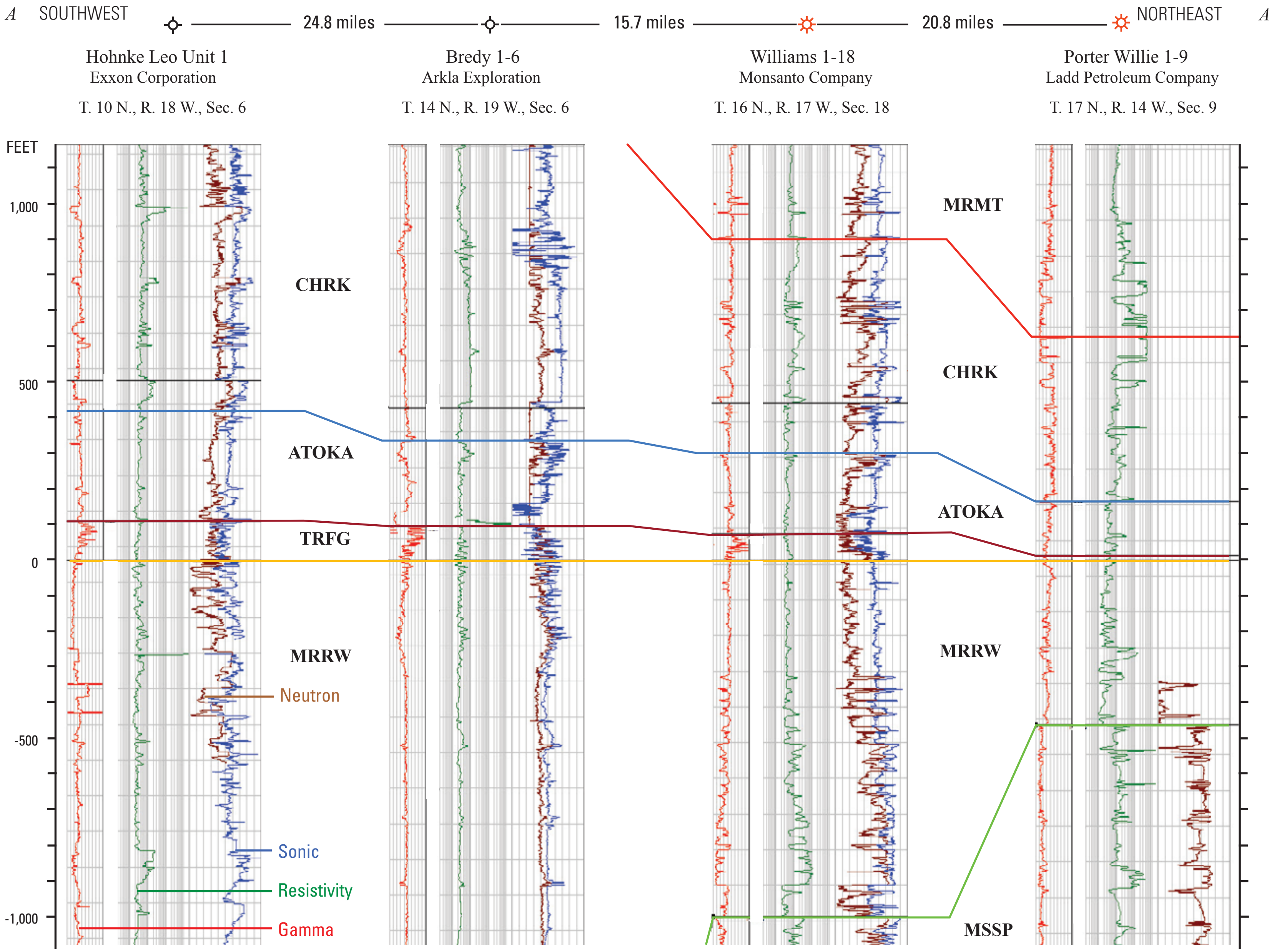


Figure 17. *A*, Southwest to northeast and *B*, southeast to northwest cross sections of the Thirteen Finger limestone (TRFG) of the Pennsylvanian Atoka Group (ATOKA) in the Anadarko Basin. Lines of section are shown in figure 16. Vertical scale is feet relative to the base of the Thirteen Finger. MRMT is Marmaton Group, CHRK is Cherokee Group, MRRW is Morrow Group, and MSSP is top of the Mississippian. Labeled well log traces are gamma (0 to 200 American Petroleum Institute [API] range), resistivity, sonic density, and neutron density.

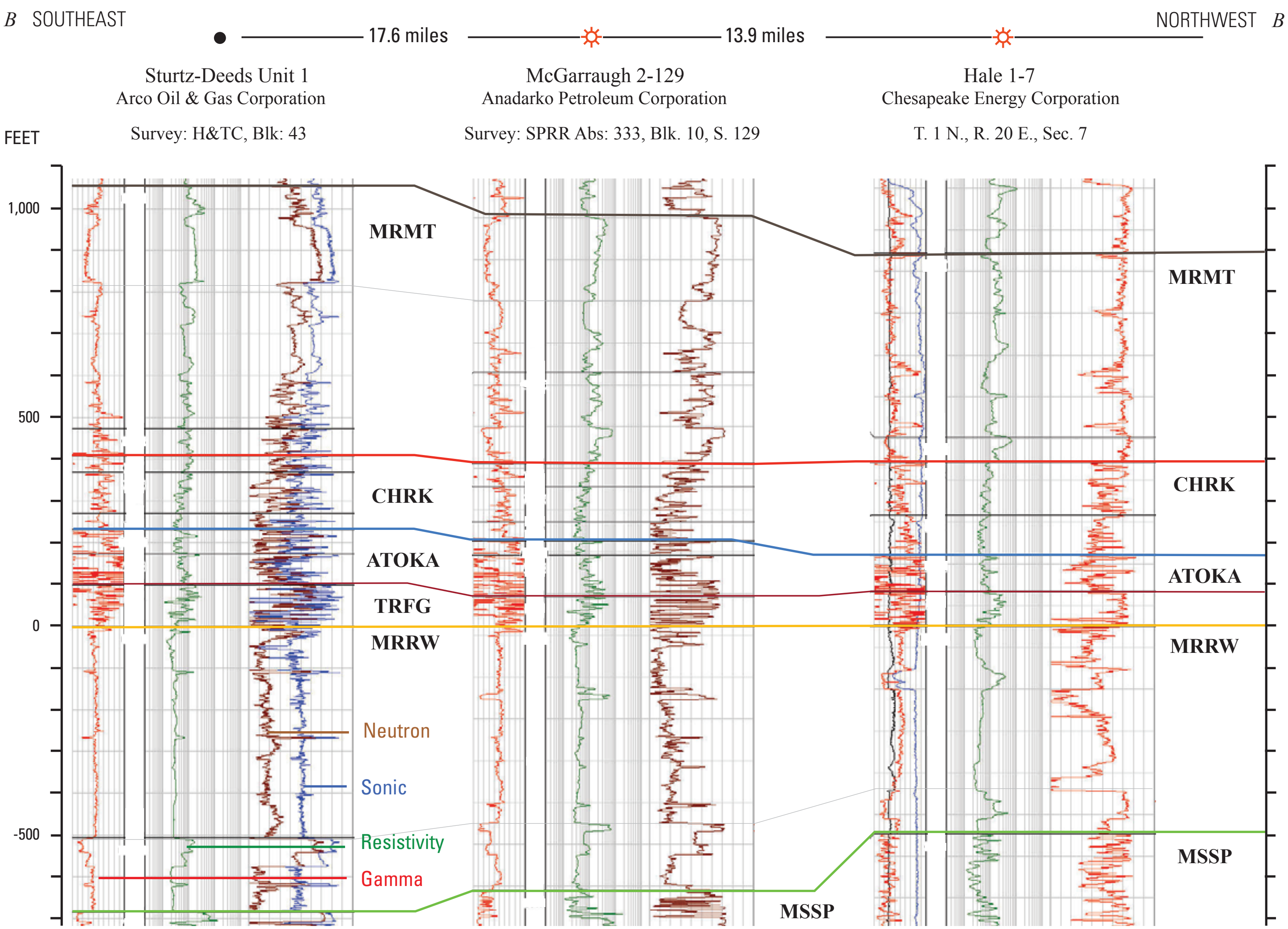


Figure 17. *A*, Southwest to northeast and *B*, southeast to northwest cross sections of the Thirteen Finger limestone (TRFG) of the Pennsylvanian Atoka Group (ATOKA) in the Anadarko Basin. Lines of section are shown in figure 16. Vertical scale is feet relative to the base of the Thirteen Finger. MRMT is Marmaton Group, CHRK is Cherokee Group, MRRW is Morrow Group, and MSSP is top of the Mississippian. Labeled well log traces are gamma (0 to 200 American Petroleum Institute [API] range), resistivity, sonic density, and neutron density.—Continued

was generated in the model. Basically, most generated oil migrated out of the deep basin instead of being trapped and subject to secondary or tertiary generation of gas. Future improvements in computer processing and display, and in software design, may allow for greater complexity of the basin-scale model and results.

The timing and extent of petroleum generation from a source rock requires determining kinetic parameters that relate to the length of geologic time responsible for generation reactions to burial temperatures. This process is detailed in Lewan and Ruble (2002) and briefly summarized here. Applying kinetic parameters is typically accomplished using the Arrhenius equation, which for first-order reactions can be expressed in terms of the transformation ratio (X) as

$$X = 1\text{-}exp\{\mathbf{t}A_o(exp[-E_a/R\mathbf{T}])\}$$

The transformation ratio (X) is the decimal fraction of the amount of petroleum product generated at a given time (**t**) and temperature (**T**) as determined by the kinetic parameters E_a and A_o. The activation energy (E_a) represents the energy barrier the reactants (kerogen or bitumen) must reach or exceed for the reaction to continue. The frequency factor (A_o) represents how often the reactants reach the energy barrier in a given amount of time for the reaction to proceed. R is the universal gas constant. HP kinetic parameters are used to determine narrow oil generation and expulsion windows that extend over a wide range of temperatures and depths. Timing of oil and gas generation is indicated on the petroleum system models by the following boundaries. Transformation ratios (TR) of oil generation and expulsion are onset (0.1 percent), peak (50 percent), and completion (99 percent). Vitrinite reflectance boundaries are presented graphically as onset of generation of oil (0.6% R_o), end of oil and start of wet gas generation (1.2% R_o), dry gas onset (2% R_o), and overmature for gas generation (4% R_o). Carter and others (1998) estimated the main intervals of oil generation at 0.7 to 0.9% R_o, and at depths in the deep Anadarko Basin of 2,800 to 3,800 m (eastern) and 2,200 to 3,000 m (western). The Cardott (1989) oil window is 0.6 to 1.3% R_o, and Cardott and Lambert (1985) estimated the limit of preservation of dry gas at 5% R_o.

Woodford, Phosphoria, and Tsuzuki HP, Rock Eval (REV), and R_o curves in figure 18 are modified from Lewan (written commun., 2011). Shown are R_o signatures for onset-through-completion of oil generation using Woodford Shale HP and REV kinetics, and Phosphoria Formation HP kinetics (Lewan and Ruble, 2002). The Pepper and Corvi (1995a, 1995b) kinetics for Type III kerogen is only to illustrate that gas generation can occur at low levels and over a broad range of thermal maturation; in this case, a range of 0.55 to 3.0% R_o. REV kinetics was not used for the 1D and 4D models because the broad window of oil generation extends from about 0.4 to 2.6% R_o, which appears to underestimate and overestimate the thermal maturity for oil generation. Phosphoria HP kinetics is specific to Type IIS kerogen, and shows the same early onset of generation at about 0.4% R_o with generation completed by 0.8% R_o. This would result in early generation of oil, and completion when the % R_o is in the oil generation window for source rocks that are low in Type IIS kerogen. However, source rocks that are believed to be thermally immature or marginally mature for oil may be in the oil generation window if they contain Type IIS kerogen. REV and Phosphoria TR maps of potential source rocks in the Colorado and Kansas portions of the province would be thermally mature for oil generation over almost the entire extent because of the onset at 0.4% R_o equivalent.

The Woodford TR completion of oil generation roughly outlines the 1.2% R_o contour of Cardott (1989). The HP TR onset and completion of oil generation are equivalent to about 0.6 and 1.2% R_o, respectively, which approximately brackets onset-to-completion of oil generation. Oil cracking to gas starts at about 1.7% R_o based on Tsuzuki (1999) HP kinetics (fig. 18). Cardott (1989) indicated that the 1.3–2.0% R_o window for the Woodford Shale brackets generation and preservation of condensate and wet gas, with 2.0% R_o marking the onset of thermal cracking of oil. The Woodford HP kinetics records onset-through-completion of oil generation and expulsion. However, gas generation and expulsion also occurs during oil generation. Instead of the abrupt onset-through-completion of oil and gas generation steps that are implied by R_o scales (fig. 20), oil and gas generation overlap. Significant volumes of thermogenic gas can be generated during oil generation, and this generated gas is not restricted to the high thermal maturities of greater than 1.2% R_o that represent post-oil generation (Lewan, 2002). Timing and volumes of oil and gas generation are dependent upon the kinetics specific to each petroleum source rock.

The figure 19 PetroMod® 1D wells use Sweeney and Burnham (1990) kinetics to model downhole R_o curves for the Bertha Rogers 1 and Petree Ranch 1 wells (fig. 20), which are compared to gas composition from the Energy geochemistry data base (U.S. Geological Survey, 2010). The calculated surface R_o of 0.4 percent represents depth of erosion relative to a thermally immature baseline of about 0.26% R_o. Distribution of wet and dry gas across the province is illustrated by the methane/(methane+ethane+propane) composition of gas and sample depth (fig. 19). Gas becomes isotopically heavier and chemically dryer with increasing thermal maturity and depth of burial. Pure methane is the 1.0 end member with progressively wetter gases shown by smaller fractions. The gas distribution shows extreme scatter vertically and laterally, probably because of long-distance migration in the province, contributions of gases from different petroleum source rocks, and composition of the contributing source rocks. Gas samples less than 1,000-m depth are almost exclusively from Permian strata in Kansas, and in the panhandle areas of Texas and Oklahoma. Permian gas fields are sourced from petroleum source rocks that are deeper in the basin, and based on the methane gas distribution scale from about 0.7 to 1.0, from ranges of thermal maturity. Pennsylvanian and Mississippian gases also show considerable scatter, but there is a general trend of increasing dryness with depth. Gas samples

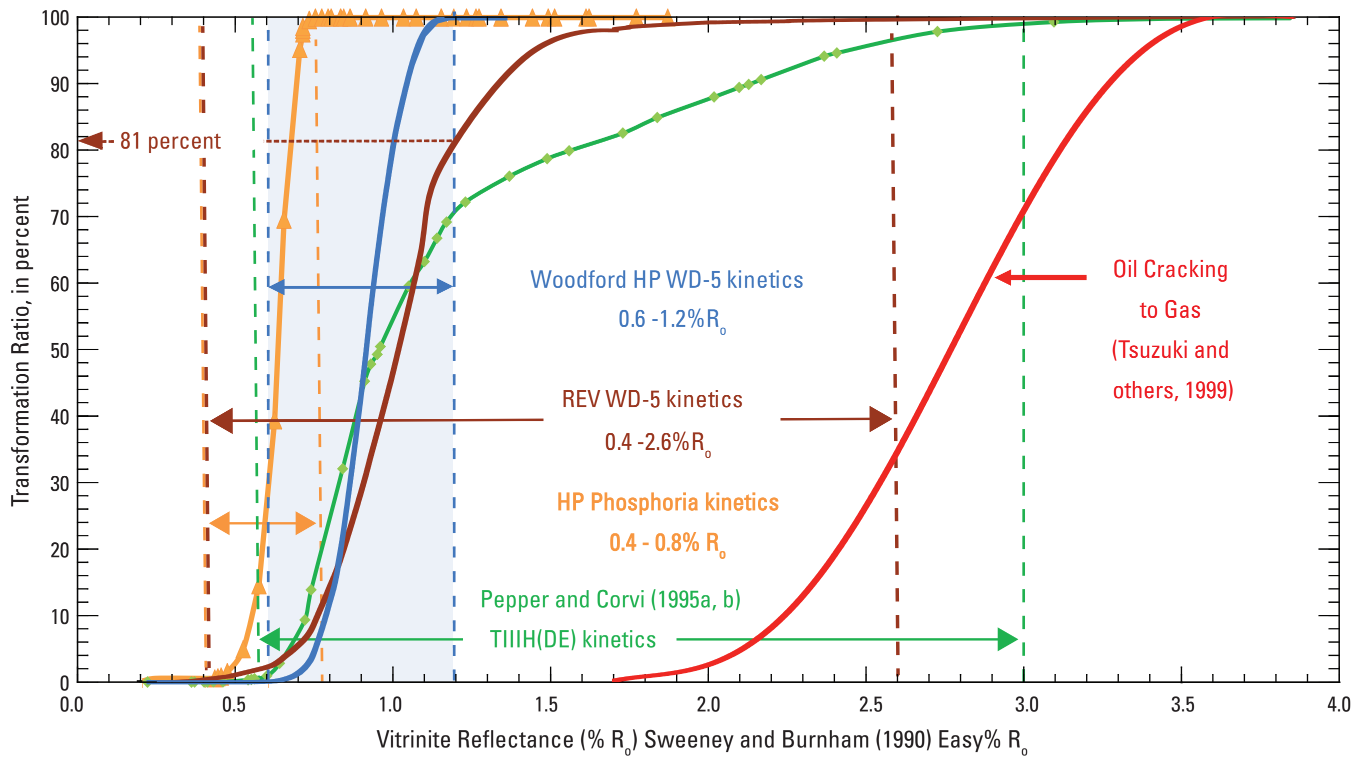


Figure 18. Graphic showing comparison of calculated vitrinite reflectance (% R_o) and transformation ratios (TR) using Woodford Shale and Phosphoria kinetic algorithms from Lewan and Ruble (2002), gas generation from coals based on Pepper and Corvi (1995a, 1995b), and dry gas generation using Tsuzuki and others (1999). Calculations are for the Bertha Rogers 1 and Petree Ranch 1 wells shown on figure 11. Woodford hydrous pyrolysis (HP) TR of onset- (0.1percent) to-completion of oil generation (99 percent) correlates to a range of about 0.6 to 1.2% R_o; Woodford Rock Eval pyrolysis (REV) TR range is much broader at approximately 0.4 to 2.6% R_o, and Phosphoria HP TR onset and completion are about 0.4 to 0.8% R_o. Woodford REV TR is at 81 percent when the HP TR has completed at 100 percent. Pepper and Corvi (1995a, 1995b) kinetics provides a range of gas generation from 0.55 to 3.0% R_o from the Type III kerogen in coals. Basin heating rate of 5 °C/m.y. was based on the Bertha Rogers 1 well; present-day geothermal gradient is 21.3 °C/km to the Woodford (19 °C surface and 200 °C Woodford temperature at 8,486.5-meter depth).

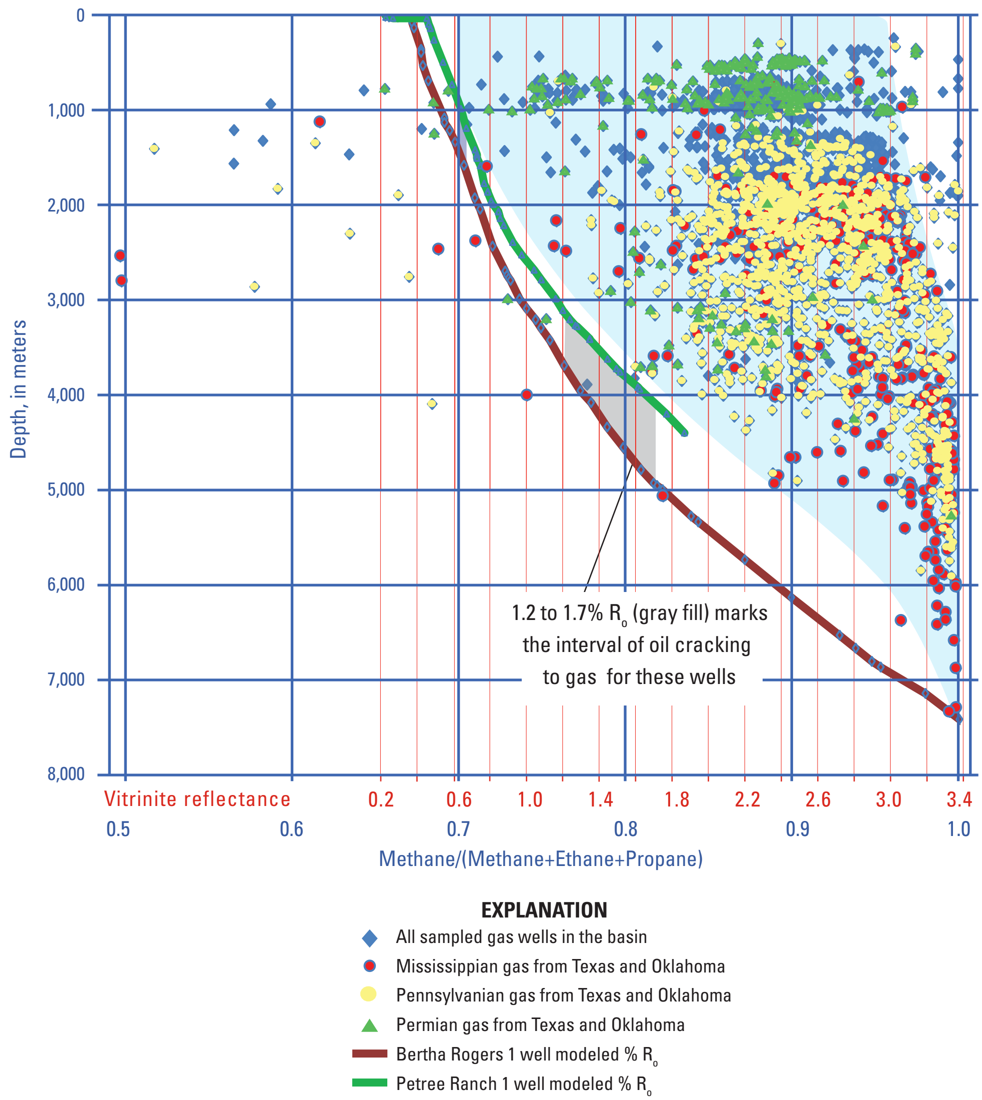


Figure 19. Graph showing depth distribution of wet and dry gas in the Anadarko Basin and of 1D vitrinite reflectance (% R_o) profiles for the Bertha Rogers 1 and Petree Ranch 1 wells (fig. 11). Depth range for end of oil generation to start of dry gas generation for the one-dimensional wells is about 3,200 to 5,000 meters. Increase in dry gas fraction and decrease in scatter below 5,000 meters indicates gas is becoming progressively dryer for these samples, with 1.0 being 100 percent methane. Gas data are from the Energy geochemistry data base (U.S. Geological Survey, 2010). The blue symbols are mostly Colorado and Kansas wells. Oklahoma and Texas wells were selected for detailed study because Colorado and Kansas portions of the province are thermally immature for gas generation. Light blue background is a generalized boundary for gas distribution.

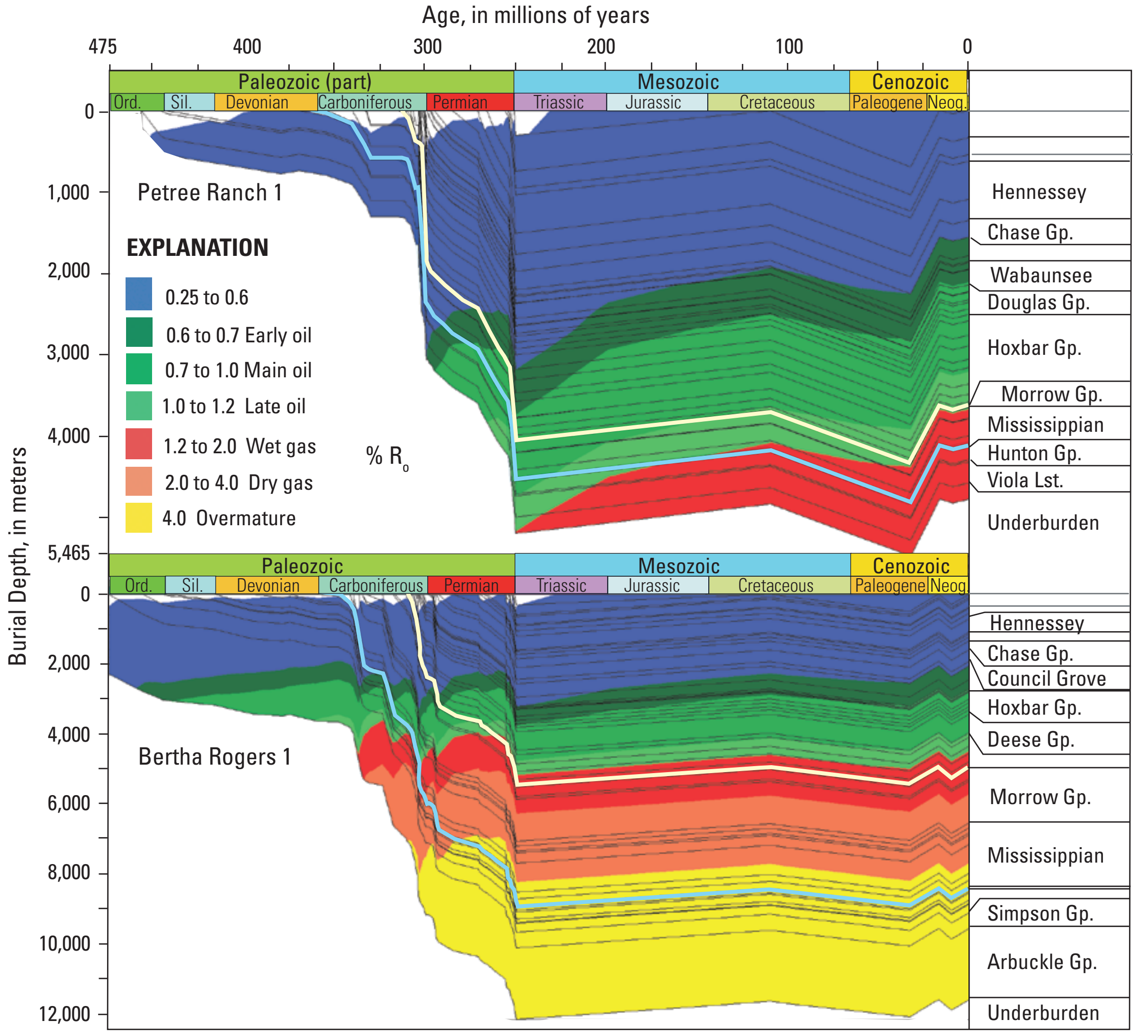


Figure 20. Burial history curves for the Bertha Rogers 1 and Petree Ranch 1 wells. Modeled vitrinite reflectance (percent Ro) through time includes heat flow of about 68 milliwatts per square meter (mW/m^2) to 260 million years ago (Ma) followed by 42 mW/m^2 for Bertha Rogers 1, and 68 mW/m^2 to 260 Ma followed by 52 mW/m^2 for Petree Ranch 1. Pale-yellow and blue lines follow the Thirteen Finger limestone and Woodford Shale, respectively. Gp., Group; Lst., Limestone; Ord., Ordovician; Sil., Silurian, Neog., Neogene.

greater than 5,000 m approach the methane composition. Any correlation of gas with modeled R_o is generalized, in that gas dryness increases with burial depth with associated increase in thermal maturation.

Vitrinite reflectance history profiles for Petree Ranch 1 and Bertha Rogers 1 wells (fig. 20) show similar trends of increased burial and maturation that start about 350 Ma. The Woodford Shale is overmature for gas generation in Bertha Rogers 1, and is in the gas generation window for Petree Ranch 1. The Thirteen Finger limestone in Bertha Rogers 1 is in the wet gas window, and for Petree Ranch 1 is on the boundary between the 1.2% R_o end of oil generation and start of wet gas generation. The actual boundaries between oil and gas generation are more gradual, with wet gas generation within the oil generation window.

Burial History

Burial history trends through time across the province record (1) relatively slow rates of deposition until about 350 Ma that is associated with the Cambrian through Early Mississippian development of the southern Oklahoma trough, (2) more rapid rates of deposition in the deep basin from early Carboniferous through Leonardian (fig. 2) that is associated with late Paleozoic tectonism and formation of the basin, and (3) middle Permian to present periods of hiatus and (or) deposition and erosion in the deep basin, and slower rates of deposition on the shelf. Because most of the Permian (Guadalupian) through Mesozoic section is missing in the Oklahoma and Texas portions of the basin, reconstruction of this section is based largely on deposition and erosion of strata to the north and west.

Based on 4D model Woodford HP and vitrinite reflectance kinetics, thermal maturation of petroleum source rocks in the basin began as early as Devonian in the deep basin and was essentially completed by the end of the Permian. Woodford HP and R_o kinetics resulted in similar onset of oil generation. The Phosphoria HP kinetics is designed for Type IIS source rocks and had a narrow range of oil generation that corresponded to about 0.4 to 0.8% R_o; this information is provided here in case Type IIS source rocks are present in the basin. A period of Permian-Cretaceous deposition and erosion was modeled from about 250 to 110 Ma. This was included to evaluate effects on heating history, and because strata from all or most of this age range are absent across the province. Effects were minimal for this 500 m of eroded strata in Bertha Rogers 1 because it followed most petroleum generation in the basin. The second phase mainly followed onset of the Laramide orogeny, which began in the southern Rocky Mountains about 67.5 Ma and ended about 50 Ma (Tweto, 1975). The Laramide orogeny influenced uplift, tilting, and erosion such that Mesozoic strata and erosional remnants are present in the Kansas and Colorado portions of the basin, but absent from all but a few scattered places in the Texas and Oklahoma portions. Laramide uplift and erosion resulted in widespread deposition of Ogallala Formation sediments on the plains (Jorgensen, 1989), which was followed by the last phase of erosion about 10 Ma; the base of the eastward-thinning Ogallala aquifer wedge was derived from data in Cederstrand and Becker (1998). Ogallala Formation fluvial and eolian sediments were deposited upon an erosional surface of Permian strata and locally on Jurassic or Cretaceous formations; the Ogallala Formation probably mantled almost all the entire basin, but post-Tertiary erosion has removed much of it with only 200–600 ft remaining in the western part of the basin (Johnson, 1989).

1D burial histories for the Bertha Rogers 1 and Petree Ranch 1 wells (figs. 21–23) use Woodford and Phosphoria HP kinetics from Lewan and Ruble (2002). Bertha Rogers 1 is the deepest well in the onshore United States at 31,441 feet (9,583 m); it reaches total depth in the Arbuckle Group (fig. 2) and was productive of gas from the Atokan granite wash sequence (Rowland, 1974; Davis and Northcutt, 1989; IHS Energy, 2009a). A small show of high-sulfur gas was recorded at the surface, and sulfur crystals were circulated to the surface after this overpressured well was controlled [bottom hole pressure was 24,835 pounds per square inch (lb/in^2)] (Rowland, 1974; Davis and Northcutt, 1989). Arbuckle strata were the source of the sulfur, but the source of sour oil and gas in other areas of the basin is not known. Providing the Phosphoria kinetics gives timing of generation for potential Type IIS source rocks.

Burial history charts created for the Bertha Rogers 1 well were calibrated to R_o data from Price (1997), and to corrected bottom-hole temperatures (BHT) from Gallardo and Blackwell (1999, p. 348) which were based primarily on their discussion and table of predicted temperatures that were approximately 21°C greater than measured BHT. Respective TR oil generation percentages for onset, peak, and completion are 0.1, 50, and 99, and modeled R_o equivalent maximum values of 4.66 percent are shown on the R_o versus depth chart as the vertical line segment (fig. 21). Measured R_o from Price (1997) were about 5.3 percent, 4.9 percent and 6.0 percent for the Woodford Shale, Hunton Group, and Sylvan Shale (fig. 2), respectively. Strata older than the Hunton (Silurian) precede the existence of deciduous plants, which are the source of vitrinite, so Silurian and older strata more likely record pyrobitumen and are therefore suspect. I was not able to fit modeled Woodford R_o data to measured R_o or temperature using stable heat flow (HF) values through time. Lee and Deming (1999) indicated an absence of evidence that the thermal state of the Anadarko Basin has changed significantly since the late Paleozoic (250 Ma). Carter and others (1998) applied constant HF through the Paleozoic for their 1D models, although they indicated that the Arbuckle Group may have been subjected to a slightly higher HF because of decay of the Cambrian rifting. They ascribe a Late Pennsylvanian and Early Permian increase in measured thermal maturity on the models because of heating effects of shales that dominated the Pennsylvanian section. 1D models in the deep basin were best calibrated using variable heat flows (HF) through time. Modeled HF for Bertha Rogers 1 was 68 mW/m^2 from Cambrian to 260 Ma, then 42 mW/m^2 to the

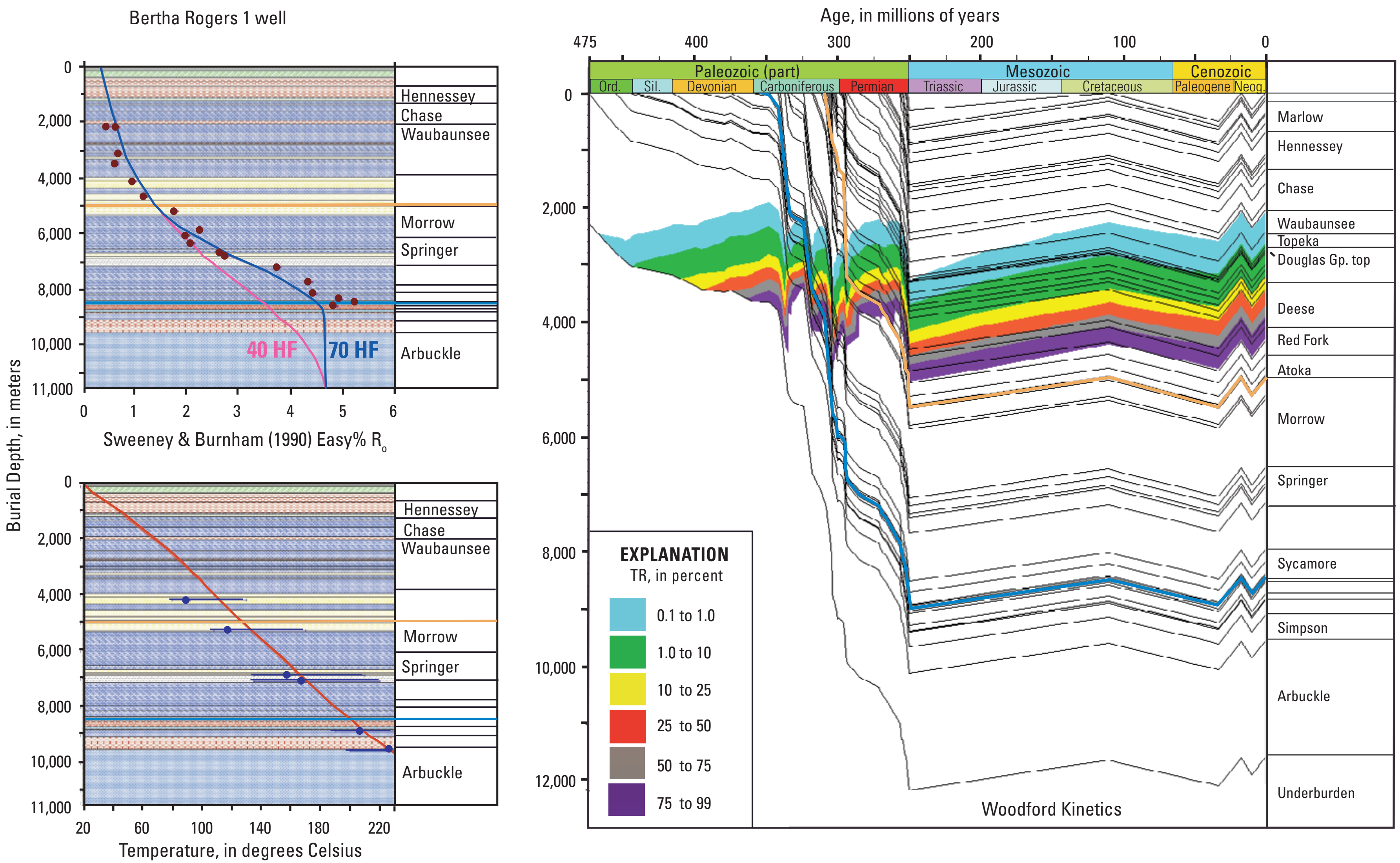


Figure 21. Burial history transformation ratios (TR) for the Bertha Rogers 1 well based on Woodford Shale hydrous pyrolysis (HP) kinetics (Lewan and Ruble, 2002). Depth compared to temperature and vitrinite reflectance profiles are calibrated at (1) 40 milliwatts per square meter (mW/m^2) heat flow (HF) through time, and (2) 70 mW/m^2 to 260 million years ago (Ma) followed by 42 mW/m^2 to present. Woodford Shale interval is marked with the blue line and the Thirteen Finger limestone by the gold line. Vitrinite reflectance (% R_o) calibration data are from Price (1997). Temperature dots are corrected bottom hole temperatures (BHT) from Gallardo and Blackwell (1999, fig. 8) and bars show range from measured to maximum estimated BHT. Gp., Group; Ord., Ordovician; Sil., Silurian, Neog., Neogene.

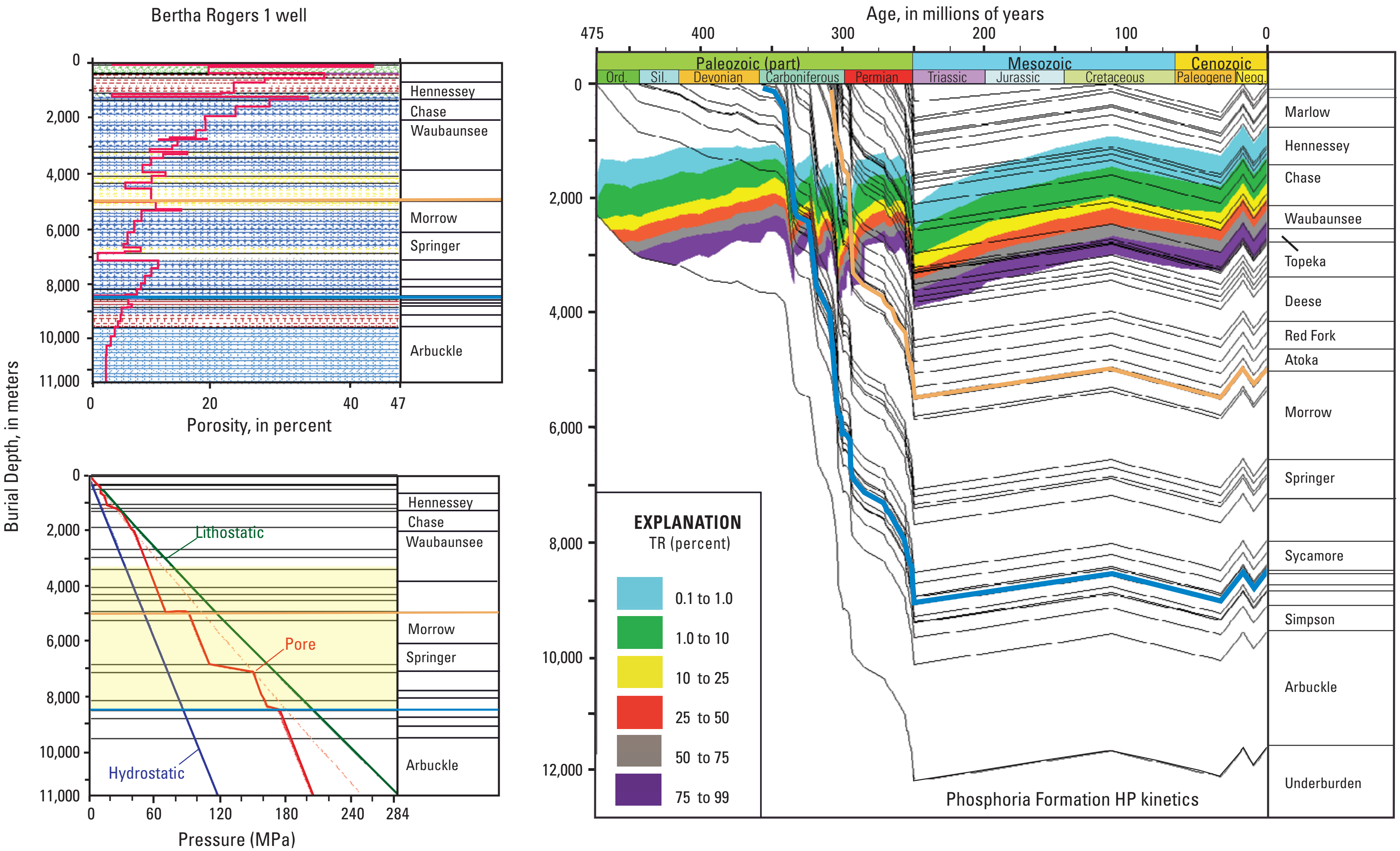


Figure 22. Burial history for the Bertha Rogers 1 well based on Phosphoria Formation hydrous pyrolysis (HP) kinetics (Lewan and Ruble, 2002). Depths are shown relative to calculated porosity, lithostatic, pore, and hydrostatic pressure; light blue line is hydrostatic pressure of 9,800 Pascals/meter (MPa/m) (0.465 psi/ft). Yellow band is probable zone of overpressure based on Al-Shaieb and others (1994). Woodford Shale interval is marked with the blue line and the Thirteen Finger limestone by the gold line. Ord., Ordovician; Sil., Silurian, Neog., Neogene.

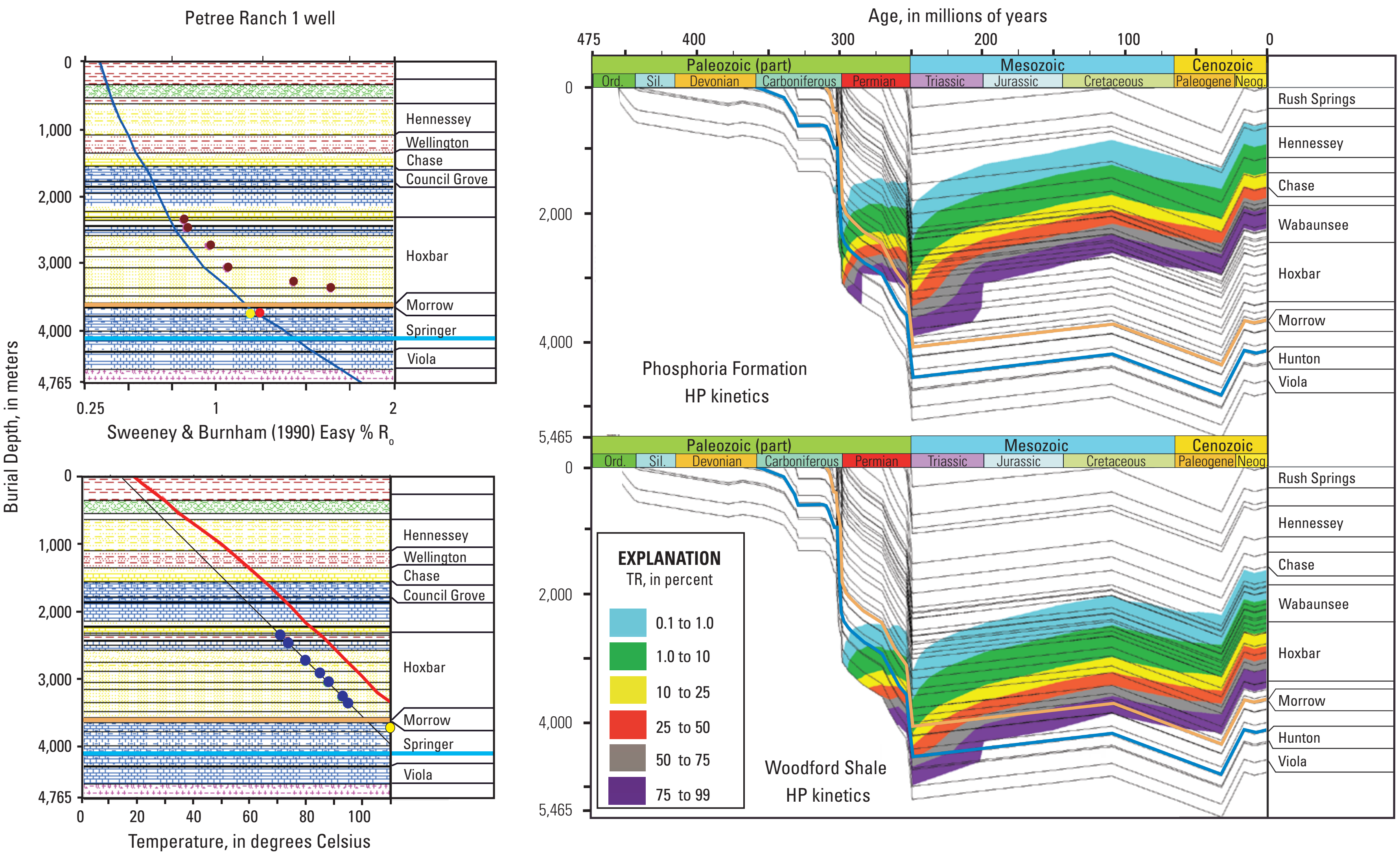


Figure 23. Burial history for the Petree Ranch 1 well based on Woodford Shale and Phosphoria Formation hydrous pyrolysis (HP) kinetics (Lewan and Ruble, 2002). Model is calibrated using 68 milliwatts per square meter (mW/m^2) heat flow to 260 million years before present (Ma), then 52 mW/m^2 to present. Woodford Shale interval is marked on the transformation ratio (TR) charts with the blue line, and the Thirteen Finger limestone by the gold line. Vitrinite reflectance (% R_o) calibration data are from Pawlewicz (1989) (brown dots) and Woodford Shale estimates from Cardott (1989) (yellow and red dots). Temperature data from Pawlewicz (1989, table 2) (blue dots and connecting line) were calculated based on 1.3 °F increase per 100 feet depth from a 15 °C (60 °F) surface temperature. The corrected bottom hole temperature (BHT) (yellow dot) was derived using Gallardo and Blackwell (1999, fig. 7). Ord., Ordovician; Sil., Silurian, Neog., Neogene.

present (figs. 21 and 22). Petree Ranch 1 was assigned an HF of 68 mW/m^2 to 260 Ma, then 52 mW/m^2 to present (fig. 23). Present-day HF in the area of the wells is about 54 ± 4 mW/m^2 based on Carter and others (1998) and 45–49 mW/m^2 based on Blackwell and Richards (2004); these sources were used to generate an HF map of the basin that was applied through time for the 4D model. The 4D model did not use variable heat flow through time, a possible effect of which could be a slight underestimation of the level of thermal maturation in the deep basin.

The Bertha Rogers 1 temperature-depth profile calibrates fairly well with measured temperature (fig. 21); however, measured R_o exhibits considerable spread. All R_o depth curves were preferentially calibrated to the Woodford Shale. The spread in R_o data for source rocks of the Anadarko Basin may have been influenced by various data quality and vitrinite suppression factors. Cardott (1989) indicated increased anisotropy of R_o histograms starting at 1.0% R_o, with a noticeable effect at greater than 2% R_o (Dow, 1977; Hunt, 1979). This suggests that the R_o/depth curve deflection that begins at about 2% R_o could be influenced by the “increasing anisotropy of the vitrinite and associated need to measure maximum reflectance; which cannot be done using random reflectance measurements” according to Brian Cardott (written commun., June 2011). Mixing of macerals such as the mainly marine Type II of the Woodford Shale with Type III vitrinite from recycled woody organic matter should not have increased R_o because there were few older source rocks that would have contained vitrinite (Cardott, 1989). Mixing should have minimal effect on increase in maturation in younger source rocks mainly because depositional processes predominated in the basin, and vitrinite macerals from sediment input from the north and west were probably less thermally mature. If mixing occurred, then the main effect could have been a decrease in measured maturation. However, mixing of macerals is generally detected during analysis of the vitrinite. Scatter in R_o data and calibration problems can also result from suppression of vitrinite from liptinite macerals; these “oily” particles could decrease the reflectance of vitrinite macerals. Cardott (1989) suspected that Woodford Shale R_o values less than 1.3% R_o were suppressed, but did not believe this continued past 1.3 percent because of the increase in reflectance of liptinite macerals above this level. In contrast, Price and Barker (1985, p. 80) believed potential suppression extended to at least 4.0% R_o.

Overpressure can retard organic matter maturation and associated R_o (Hao and others, 2007). That the Woodford Shale in the deep basin is overpressured (Al-Shaieb and others, 1994) could have decreased reflectance of vitrinite. The effect of suppressed vitrinite on the Petree Ranch 1 well would be to underestimate Woodford Shale R_o values. This could be a factor in increased reflectance of shallower formations, although measured reflectance in other wells from Pawlewicz (1989) show considerable scatter, including one well in which vitrinite reflectance decreases downhole. Pressure and temperature data are not available for most wells in the Oklahoma portion of the basin; estimated downhole temperatures for the Petree Ranch 1 well (fig. 23) are from Pawlewicz (1989) and Gallardo and Blackwell (1999). I was not able to fit the model to estimated downhole temperature for this well, possibly because of the quality of temperature data, and that Pawlewicz (1989) used a cooler surface temperature of 15 ^{o}C compared to the 19 ^{o}C assigned in this study. His geothermal gradient was 23.7 degrees Celsius per kilometer (^{o}C/km), compared to the modeled geothermal gradient of 24.57 ^{o}C/km; the curved line was also influenced by thermal conductivity of downhole lithofacies.

The onset and completion of oil generation shown on table 3 are based on 0.1% TR (0.6% R_o) and 0.99% TR (1.2% R_o), respectively. These boundaries were based on Woodford HP kinetics that was applied to petroleum system models. Onset of oil cracking to gas is at 1.7% R_o. Although the burial history plots show abrupt onset and completion for thermal maturity, the time ranges of petroleum generation are more gradual. Figure 24 shows oil generation through time for the Oil Creek Formation, Woodford Shale, and Thirteen Finger limestone petroleum source rocks. These are displayed as onset to completion, rather than volumes, partly because thickness of the Oil Creek layer is generalized and does not represent the actual thickness of the source interval. Oil generation and expulsion started about 370 Ma with the Oil Creek source rocks, reached peak generation about 290 Ma to 220 Ma with contributions from all three source rocks, and was relatively dormant until about 80 Ma when Laramide burial caused a brief increase in generation and expulsion (table 3, fig. 24). The primary factor causing increased thermal maturation is burial depth. For example, the Woodford Shale entered the oil generation window about 30 million years (m.y.) before the Thirteen Finger limestone because of deposition of thousands of feet of intervening Mississippian and Morrowan strata. Because Anadarko has a deep basin and shallow shelf, age ranges for hydrocarbon generation vary laterally as well, which allowed for longer periods of oil and gas generation, migration, and trapping. Carter and others (1998) indicated that Upper Pennsylvanian to Lower Permian source rocks in the deep basin moved into the hydrocarbon generation window during Cretaceous burial of the region. This is somewhat more recent than the Missourian onset of generation about 260 Ma for the 4D and 1D Bertha Rogers 1 models. The primary factor between the different onset times of Carter and others (1998) and my 1D models is that their maximum burial and erosion followed 110 Ma, and mine was about 250 Ma. Missourian source rocks in the Bertha Rogers 1 well are now in the oil generation window (0.9% R_o). If Virgilian and (or) Permian source rocks exist, their onset of generation would have been about 230 Ma using values of 0.1percent TR for the Bertha Rogers 1 and Petree Ranch 1 wells (figs. 21 and 23).

Calculations also include burial depth compared to measured and modeled downhole porosity and pressure. Because these data were not available for calibration, only the modeled values are shown in figure 22. Porosity and pressure are independent of the applied kinetics and are largely dependent upon burial depth and physical properties of assigned lithofacies. Jumps in pore pressure with depth are tied to effects of

Table 3. Onset of oil generation in the Anadarko Basin 4D model, and onset and completion dates in millions of years before present (Ma) for the Bertha Rogers 1 and Petree Ranch 1 one-dimensional models based on Woodford Shale hydrous pyrolysis (HP) kinetics (Lewan and Ruble, 2002). The Douglas Group overlies the youngest potential petroleum source rocks on figure 2. The (HP) kinetics-based onset of oil generation is 0.1 percent transformation ratio (TR) and completion is 99 percent TR. Oil generation histories in the four-dimensional model were recorded at 10 Ma increments, and the plus symbol indicates onset was before the listed age.

	Four Dimensional Model	Bertha Rogers 1		Petree Ranch 1	
	Onset	Onset	End	Onset	End
Virgilian (Douglas Group)	270	100			
Thirteen Finger limestone	+300	290	265	270	
Woodford Shale	330	330	310	290	200
Oil Creek Formation	+370	340	320		

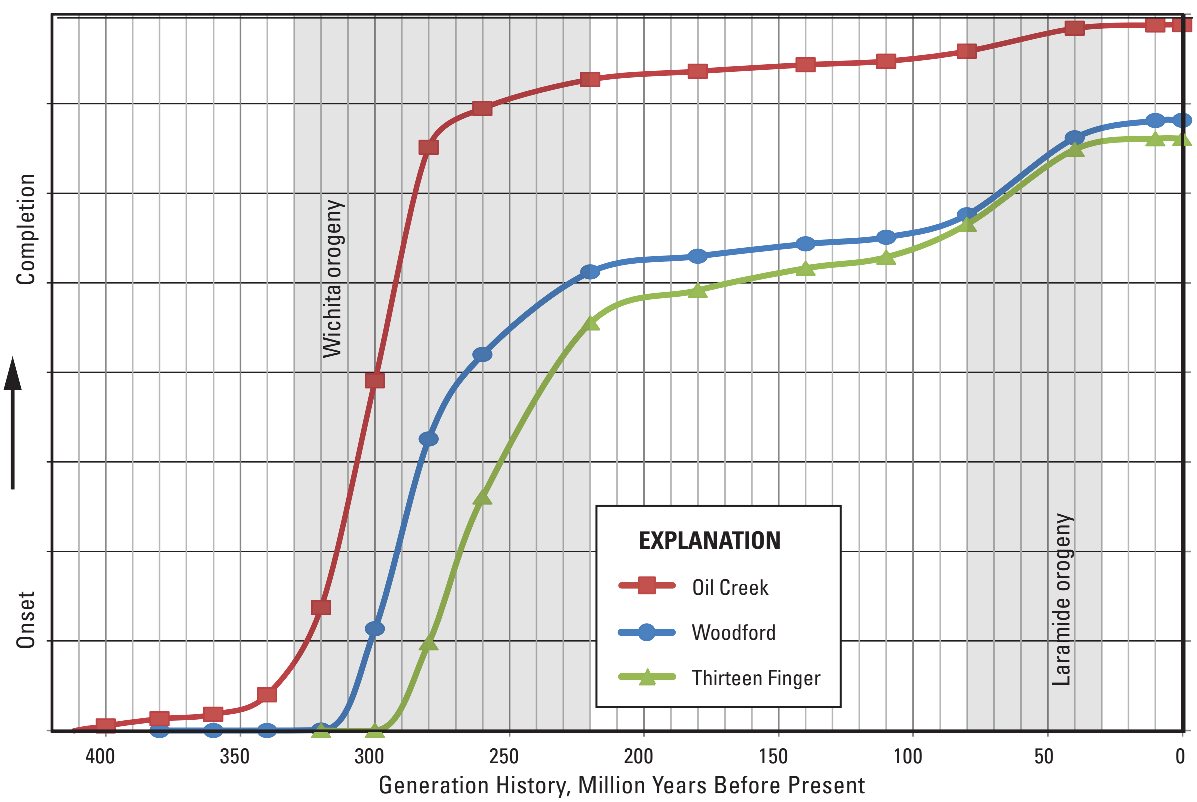


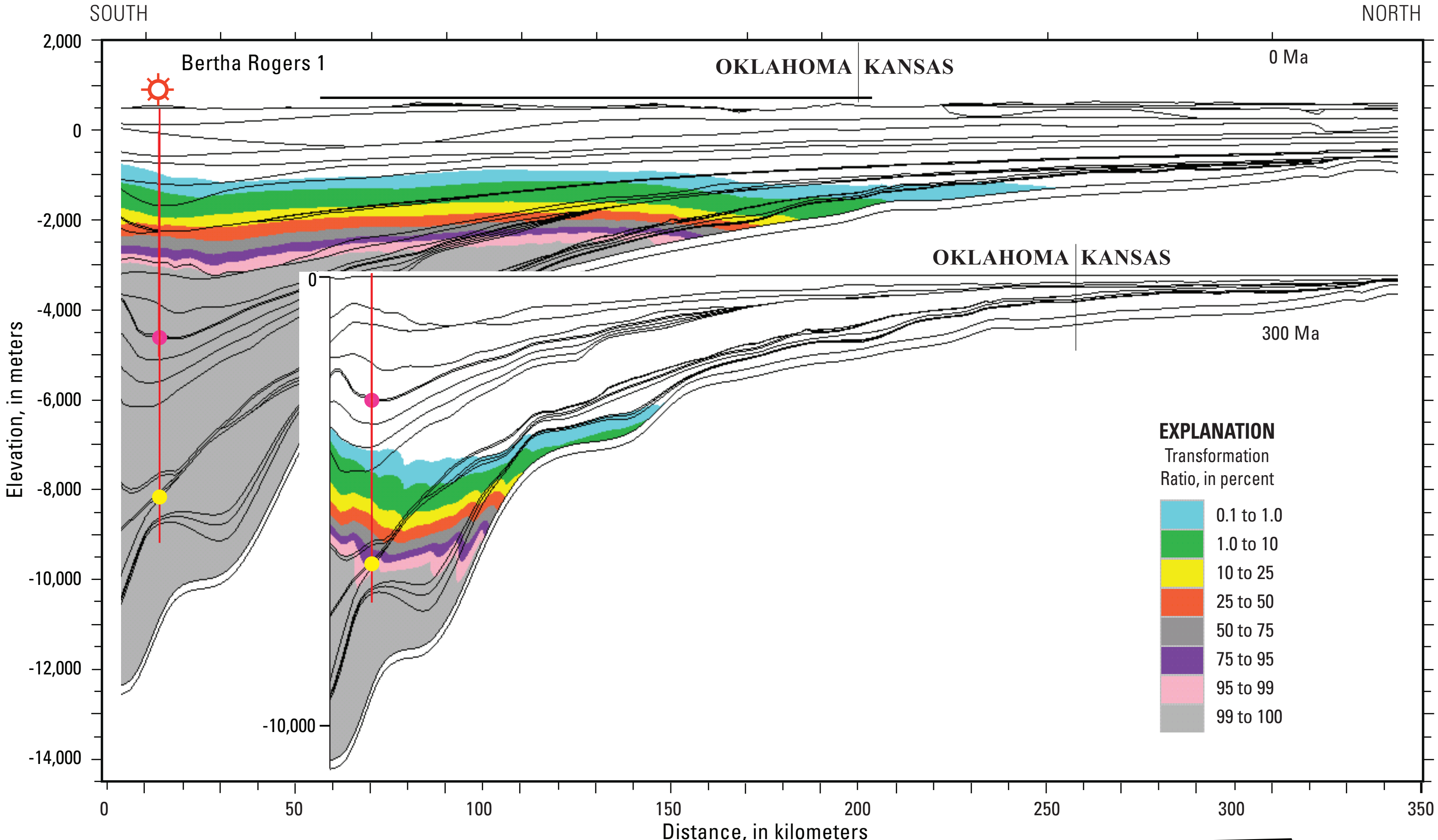
Figure 24. Graph showing history of generation of oil from the Oil Creek Formation, Woodford Shale, and Thirteen Finger limestone sources in the four-dimensional petroleum system model based on Woodford Shale HP kinetics. Gray bars delineate periods of peak oil generation. Early oil generation from the Oil Creek layer, prior to about 70 million years before present (Ma), is in a narrow band that is proximal to the Wichita Mountain uplift. This band exceeds maximum depth of the formation and is the result of poor data control in the area bordering the fault zone. The error could have been removed by clipping the four-dimensional model extent to the basin axis and northward, but less of the model would have been visible and usable.

near-surface evaporite seals and porosity of various lithologies, such as shale and low-permeability sandstone and limestone. The pressure/depth increases for the Woodford (blue line) and Thirteen Finger (gold line) strata are because of these and bounding low-permeability strata. The entire well is overpressured in this 1D model. The actual zone of overpressure is probably limited to Woodford through Desmoinesian strata (yellow zone, fig. 22) based on Al-Shaieb and others (1994). Because 1D models are points and are not influenced by 3D effects of PVT, pressure increase is tied to lithofacies and rate of burial depth.

Changes in thermal maturation laterally and through time are more easily viewed on the cross section extractions from the 4D model at 300 Ma and at present (fig. 25). The Woodford Shale yellow dot for the Bertha Rogers 1 location was mature for oil generation at 300 Ma, and is currently overmature. The 4D model and associated extractions are based on elevation relative to sea level and generated 1D models are depth from ground surface. Only the deep basin was thermally mature for oil and gas at 300 Ma (fig. 25) compared to the present generation range of mature for oil to overmature for gas. Southern Kansas is now only marginally mature for oil generation.

Modeled map views of present-day thermal maturation are shown for Arbuckle through Douglas Groups 4D layers in figure 26. Calculated R_o is displayed for each model layer. The red contours represent the 99% TR in the transformation ratio maps, and approximates the end of oil generation at 1.2% R_o. The Douglas layer overlies potential Missourian source rocks for which the deep basin is in the oil-to-gas generation window. There are no potential source rocks in the Sierra Grande uplift or Cimarron arch (fig. 8) and the lower levels of thermal maturity in those areas represent only shallower overburden and lower basement heat flow (fig. 3). The Colorado and Kansas portions of the province are almost exclusively immature to marginally mature for oil generation. Elevated thermal maturation in the Las Animas arch and CKU also have increased basement heat flow (fig. 3). Basinward increases in thermal maturation primarily reflect greater overburden thickness. This is why the Texas and Oklahoma portions of the province exhibit the most change from the Arbuckle to Douglas layers. Thermal conductivity of lithofacies also impacts the heat of underlying formations. The Oil Creek layer map image is not shown, but is only slightly less mature than that of the underlying Arbuckle layer. The Woodford Shale is located primarily in the Texas and Oklahoma portions of the Anadarko Basin Province (fig. 1), and this layer incorporates extents of underlying formations. This is why the oil generation window (yellow) in Colorado is almost identical for the Woodford, Viola, and Arbuckle; this area of the layer is primarily the top of the Arbuckle Group. Figure 16 shows the extent of the Thirteen Finger limestone. Almost the entire unit in the deep basin of Oklahoma and Texas is in the oil and gas generation window.

Map images of thermal maturation through time are displayed in figure 27 based on transformation ratios, and the trends are similar for R_o through time. Maturation started in the deep basin and expanded radially northward through time for each source rock. The largest increase in maturation corresponds to that of 1D models and is tied to basin downwarping and associated increased sediment deposition from about 350 to 250 Ma. Maturation continues past 240 Ma, but at a slower rate.



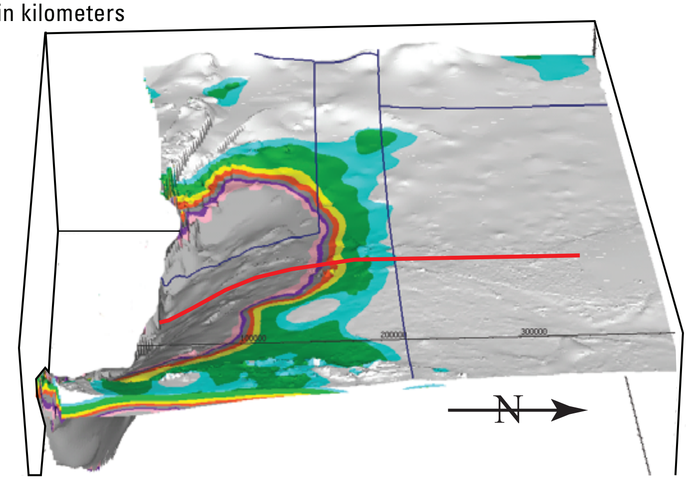
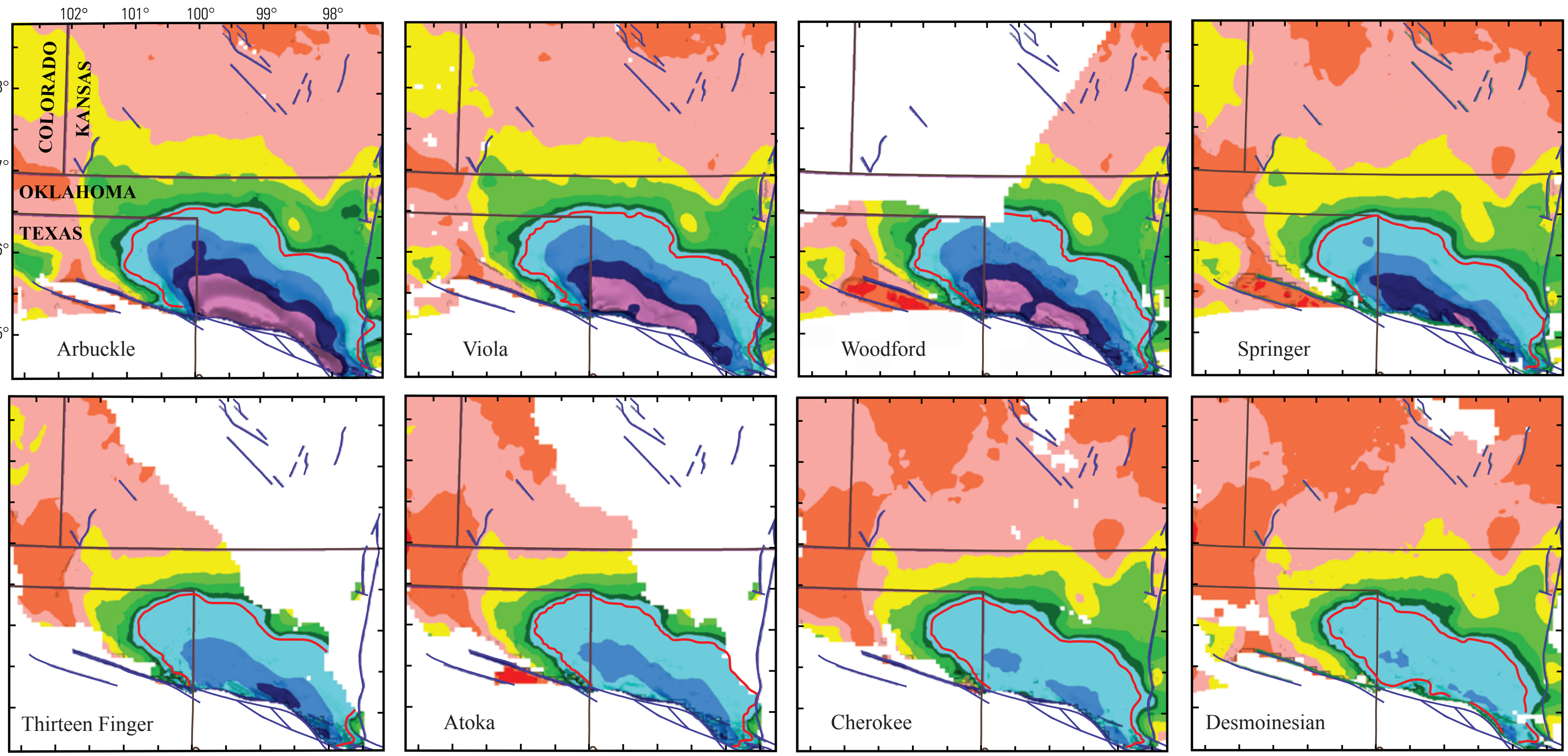


Figure 25. South to north cross sections of thermal maturation using Woodford transformation ratio (TR) at present (0 Ma) and at 300 million years before present (Ma). The inset shows the location of these extracts from the four-dimensional model. Yellow and pink dots are approximate locations of the Woodford Shale and Thirteen Finger limestone, respectively. Elevation is relative to sea level, and vertical and lateral scales are equivalent for the cross sections. Map image is TR on the Woodford Shale layer at 0 Ma and at 10 times vertical exaggeration. Red line is the approximate location of the cross section.



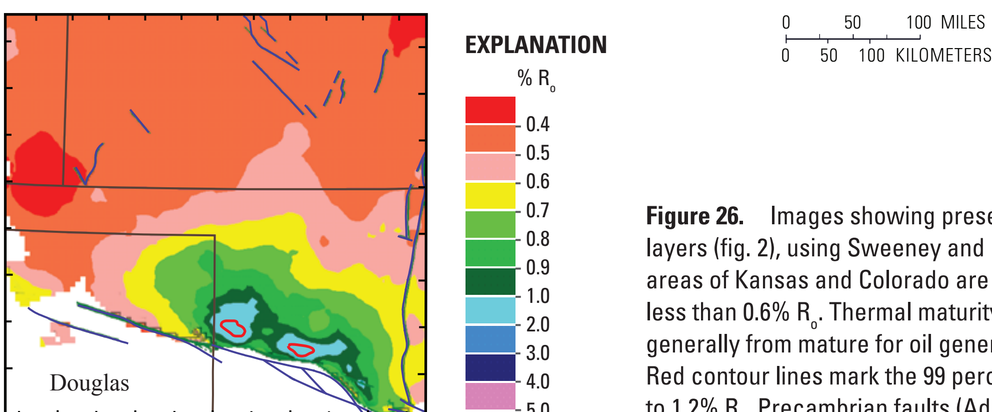
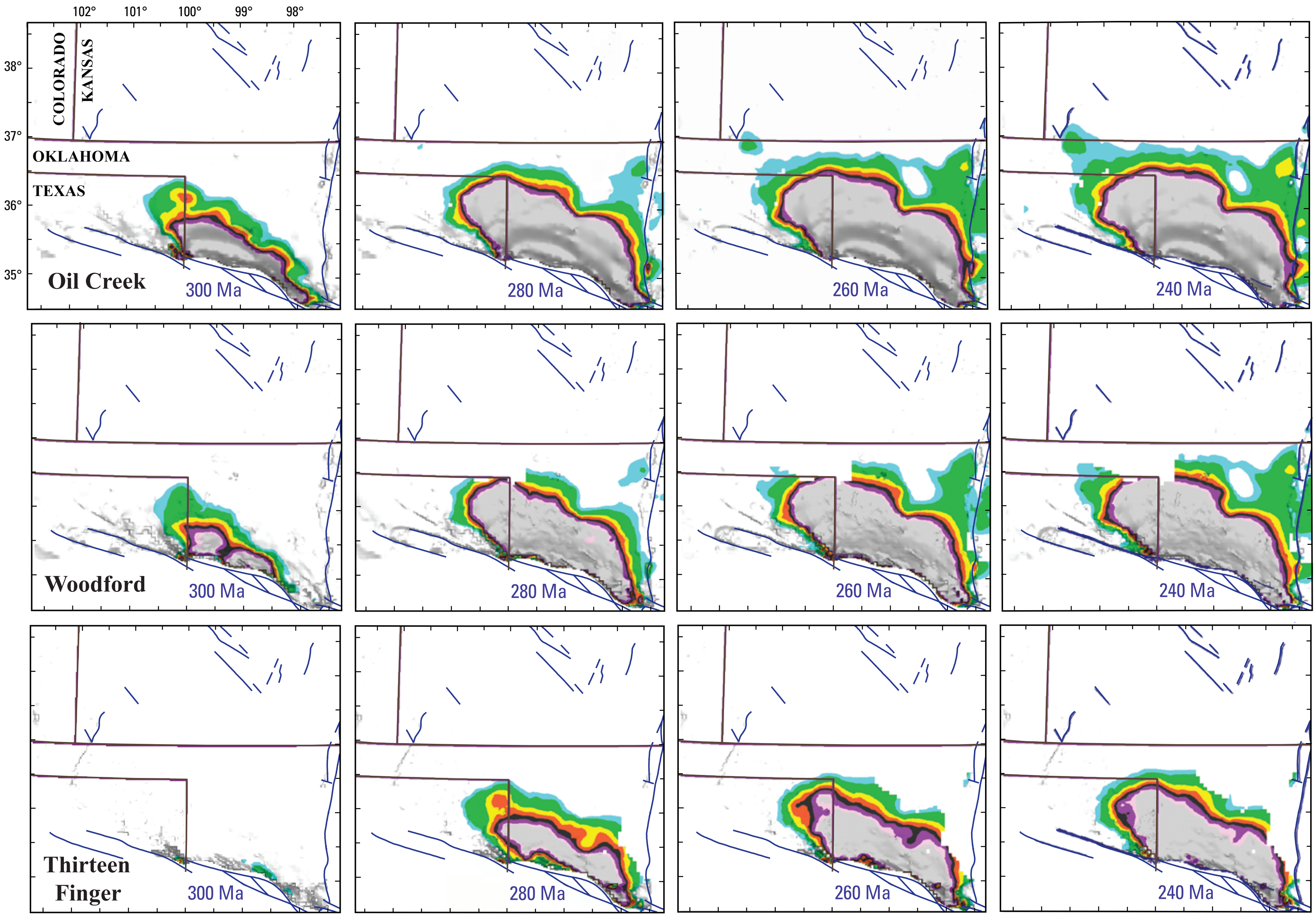


Figure 26. Images showing present-day vitrinite reflectance (% R_o) on Ordovician to Virgilian model layers (fig. 2), using Sweeney and Burnham (1990) kinetics. Changes in thermal maturity on the shelf areas of Kansas and Colorado are minor and source rocks are mostly immature for oil generation at less than 0.6% R_o. Thermal maturity for source rocks in the deep basin of Oklahoma and Texas ranges generally from mature for oil generation to overmature for gas generation at about 4% R_o and greater. Red contour lines mark the 99 percent transformation ratio for each layer; it is approximately equivalent to 1.2% R_o. Precambrian faults (Adler and others, 1971) are shown as blue lines.


102°
101°
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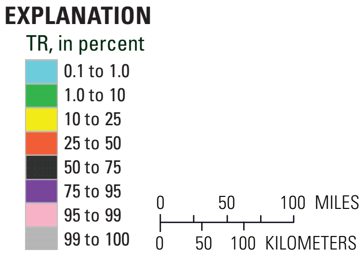

Figure 27 (previous page). Images showing transformation ratios (TR) through time on tops of the Oil Creek, Woodford Shale, and Thirteen Finger Limestone layers. Ten times vertical exaggeration results in variable shading within contours. Onset of oil generation was about 370 million years ago (Ma) (Oil Creek), 330 Ma (Woodford), and 300 Ma (Thirteen Finger) based on modeled vitrinite reflectance and 0.1 percent TR. Completion of oil generation is indicated by 99 percent TR. Source rocks are overmature for oil generation at greater than 99 percent TR (medium gray). Precambrian faults (Adler and others, 1971) are shown as blue lines.

Petroleum Migration and Accumulation

A general division of oil and gas migration is (1) primary, which is basically expulsion from the source rock(s), (2) secondary, or migration from the source rock through permeable carrier beds, and (3) tertiary migration that is remobilization of oil and (or) gas. Tertiary migration can result from tilting of the basin, development of structures such as the Wichita Mountain and Amarillo uplifts, or any hydrodynamic, erosional, or other process that changes the PVT conditions across or within the basin. Some of these PVT factors are discussed in the petroleum system modeling section of this report.

Secondary Migration of Hydrocarbons

The axis of the southern Oklahoma aulacogen is south of the present southern boundary of the Anadarko Basin (Perry, 1989), and the thickest, hottest, and most deeply buried lower Paleozoic section is probably hidden beneath the thrust plates of the Wichita Mountain uplift. Hydrocarbon generation and migration from contained source rocks were essentially synchronous with those to the north because of Morrowan onset of uplift, and would have included lateral migration along carrier beds and vertical migration along faults and fractures. Because the faults were modeled through time as closed (impermeable) faults, petroleum from source rocks located south of the faults did not migrate north in the 4D model. Lateral oil and gas migration pathways were mainly radially northward from the deep basin in Oklahoma and proximal Texas, and north and west from the Texas Panhandle. Petroleum was further funneled by local structures. The Nemaha uplift forms the eastern border of the province (fig. 6). It is the axis of the broad, gently raised central Oklahoma platform, and consists of a discontinuous series of block-faulted uplifts, each of which is in the general range of 5–20 mi long (north-south) and 3–5 mi wide (Johnson, 1989). This uplift was primarily a barrier to eastward migration from underlying source rocks because of termination of reservoir against nonreservoir facies, nondeposition of some source and reservoir formations, and decreased permeability because of fault gouge. Faults along the uplift would have been open or closed through time. They were modeled as closed through time, but leakage occurred between fault segments, such as for the CKU and Nemaha uplift. Lateral flow of petroleum is terminated or diverted by faults. Leakage is shown by modeled flow paths outside the basin margins. In actuality, vertical permeability of this and other fault systems in the basin probably varied through time. Michael and others (1989) indicated that biodegraded “tar-sand” bitumen deposits located in the southern Ardmore and Anadarko Basins and proximal to major fault systems were sourced from the Woodford Shale and Oil Creek Formations.

Migration pathways are more easily visualized as catchments, also known as drainage pathways. Figures 28 and 29 show modeled petroleum migration catchments and pathways for the Thirteen Finger limestone layer. Orientation of images is based on the best angle for viewing accumulations and flow. The Thirteen Finger limestone terminates north of the Adler and others’ (1971) Precambrian fault trace in the Wichita Mountain uplift in figures 28 and 29 because the layer was gridded using (Morrow Group) fault contacts modified from Andrews (1999a). Catchments and flow in east-central Oklahoma are mostly northward and are shown on the figures as wide catchments and smooth rays. Catchments are more complex in Texas, the Oklahoma Panhandle, western Kansas, and Colorado. This is reflected in figure 15 by the variable surface of the Thirteen Finger limestone layer. Catchments and flow paths could have been simplified by smoothing generated grid files, but doing so could remove subtle structures. One prominent feature is the oval maroon catchment shown at the intersection of Colorado, Kansas, and Oklahoma in figure 28 and is mirrored in figure 29 as an oil accumulation in the structural trap at Keys dome (fig. 15). Oil flow is directed to this and other accumulations in the western basin. Other accumulations are mostly updip pinchouts into low-permeability lithofacies of the overlying Atokan layer, particularly along the eastern terminus of the Thirteen Finger limestone. Whether these modeled accumulations correspond to actual Thirteen Finger limestone petroleum reservoirs is not known, but there is scattered production from Morrowan, Atokan, and Permian strata within Keyes dome (IHS Energy, 2009a, 2010). Again, the 4D model is coarse, so accumulations should be viewed more as terminations of flow rather than actual reservoirs. The gas migration pathways in figure 29 are partly obscured by overlying oil flow paths, but show radial outward flow from the deep basin. Absence of flow in the deep basin outlines the area that is thermally mature to overmature for gas generation.

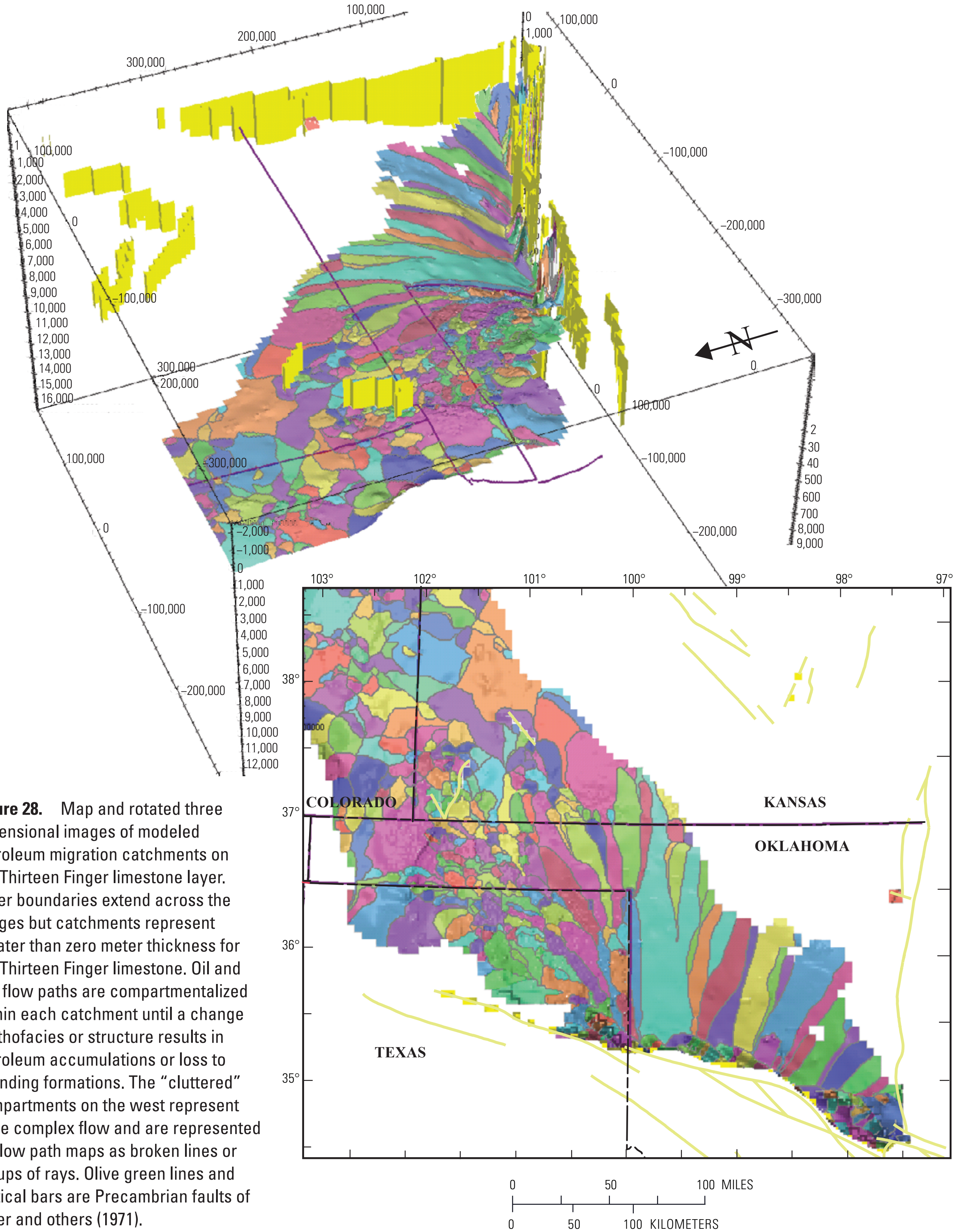

Figure 28. Map and rotated three dimensional images of modeled petroleum migration catchments on the Thirteen Finger limestone layer. Layer boundaries extend across the images but catchments represent greater than zero meter thickness for the Thirteen Finger limestone. Oil and gas flow paths are compartmentalized within each catchment until a change in lithofacies or structure results in petroleum accumulations or loss to bounding formations. The "cluttered" compartments on the west represent more complex flow and are represented on flow path maps as broken lines or groups of rays. Olive green lines and vertical bars are Precambrian faults of Adler and others (1971).

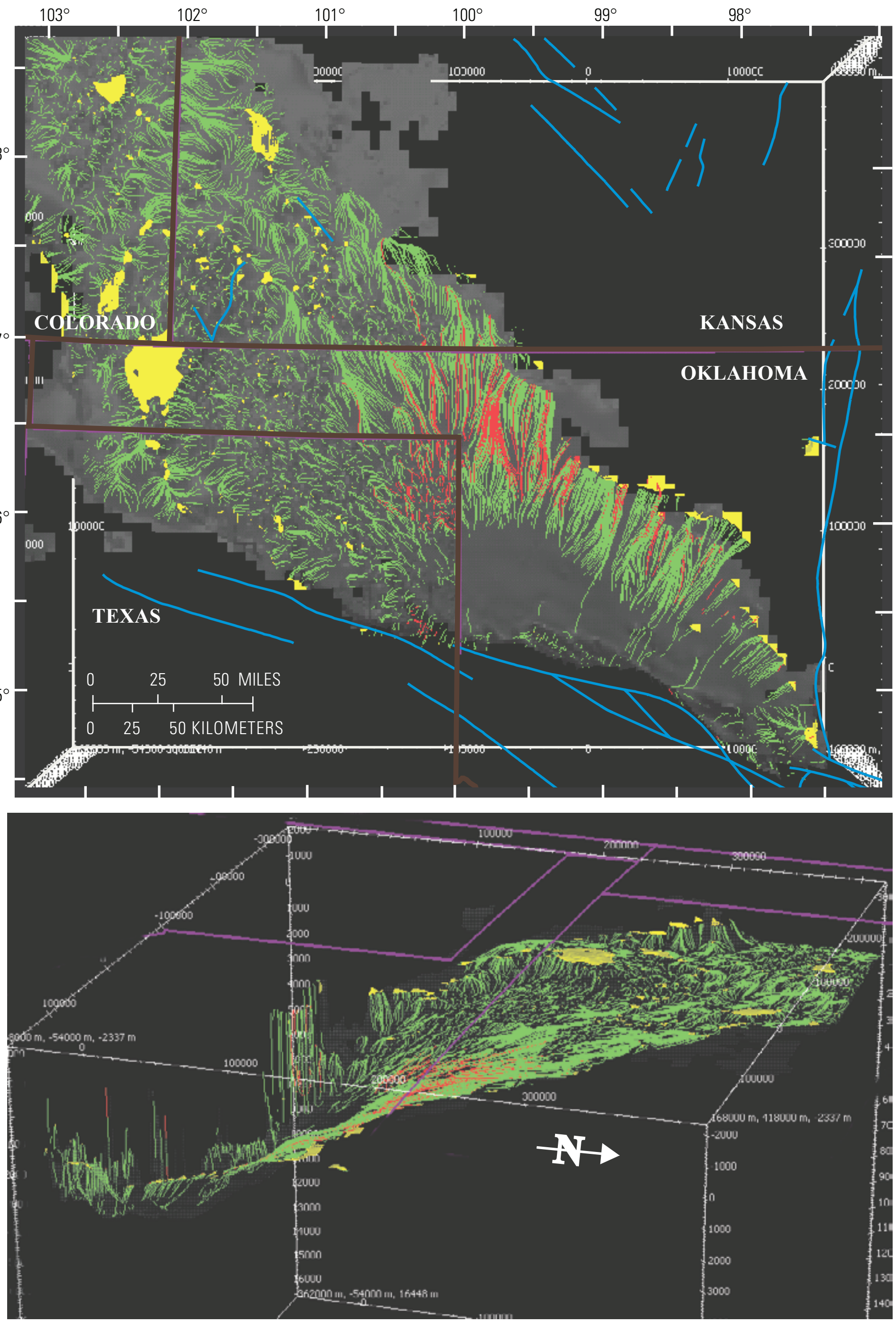

Figure 29. Two views of modeled oil (green) and gas (red) flow path lines, and oil (yellow) accumulations for the Thirteen Finger limestone. Layer shown in dark gray on three dimensional map view is the top of the Morrow Group layer. The gray space in the deep basin that is devoid of oil flow paths is the area that is mature for gas generation from the Thirteen Finger limestone. Inset image is a rotated view at 10 times vertical exaggeration.

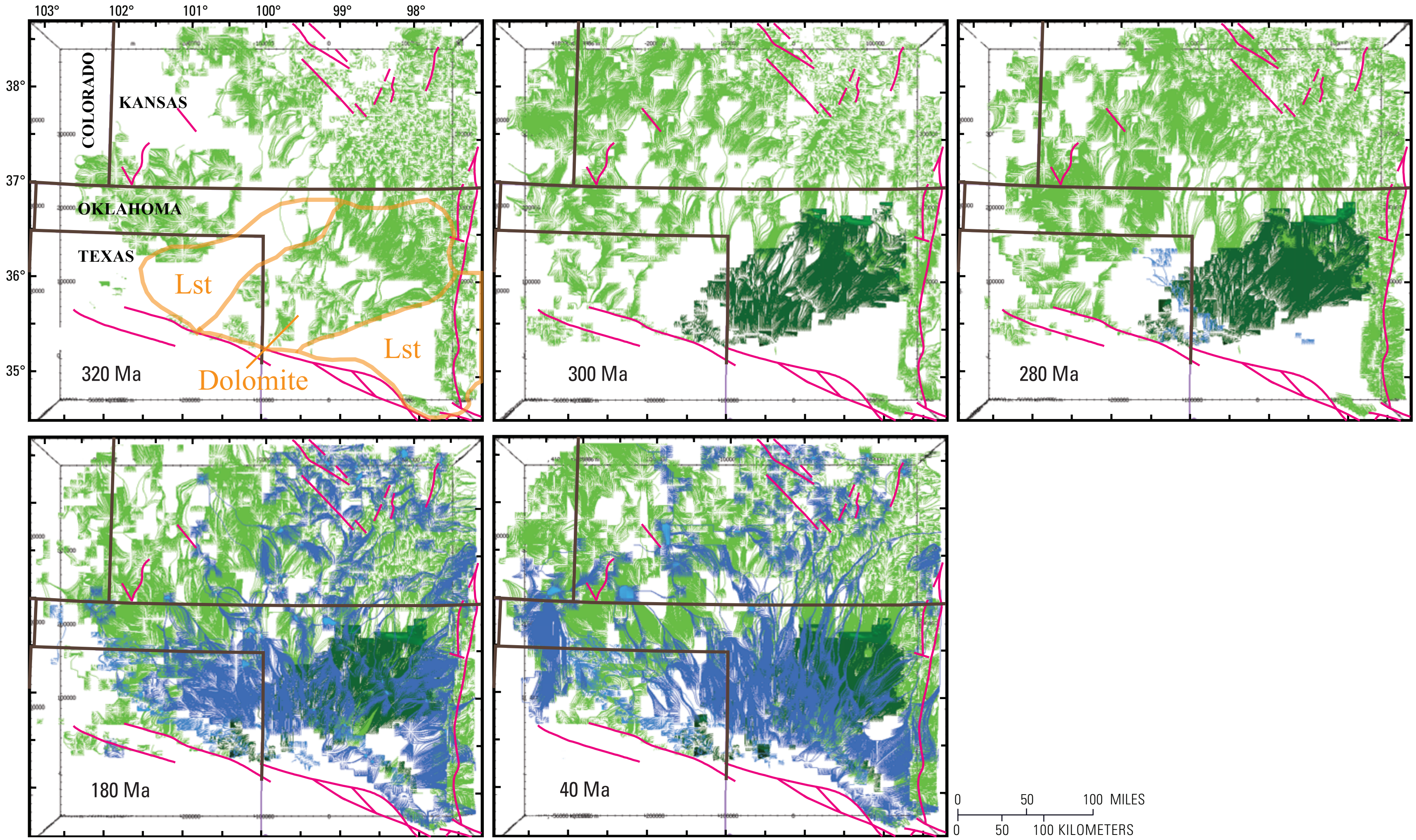

Figure 30. Images showing oil migration flow paths from 320 to 40 million years ago (Ma). Blank migration areas can indicate no migration, (invisible) Darcy flow through lithofacies, or overmaturity for petroleum generation. Hunton Group facies from Howery (1993) are delineated by orange lines for limestone (Darcy flow area) and dolomite (flow path migration). Onset of oil generation preceded migration from the Oil Creek Formation layer source rocks (light green), which started about 340 Ma. This was followed by Woodford Shale oil generation about 335 Ma, then the Thirteen Finger limestone (blue) about 300 Ma. Lst, limestone. Maroon lines are Precambrian faults of Adler and others (1971).

The isolated square of flow and accumulation east of where the formation exists is a gridding artifact.

Flow from the deep basin in Oklahoma and eastern Texas was northward toward the Pratt anticline and Central Kansas uplift (CKU) and northwest toward the Hugoton embayment (locations are on fig. 15). Figure 30 shows oil flow paths and accumulations for petroleum source rocks through time. Light green corresponds to Oil Creek as the primary source for flow path accumulations, dark green is for a primarily Woodford Shale source, and dark blue flow paths mark the Thirteen Finger limestone as the main source for oil accumulations. Change of primary-contributing-source through time is marked by change in ray colors. These ray colors do not reflect the volumes of migrating oil because flow paths are visual rather than volumetric. Modeled Darcy flow is invisible and through low-permeability lithofacies. It is "present" as the two blank flow areas north of the Wichita Mountain uplift in the 320 Ma through 280 Ma images in figure 30. These correspond to the Hunton Group limestone lithofacies from Howery (1993), which have lower permeability than the dolomite facies that form the (dark green) Hunton fairway of production from 300 through 40 Ma. The Woodford Shale is also the primary source rock for Hunton accumulations in the 4D model. The blue vertical flow paths in western Oklahoma and Texas begin in an area with no Woodford or Thirteen Finger limestone source rocks. These particular flow paths originate from the underlying Oil Creek source rock, and they merge updip with Oil Creek, Woodford, and Thirteen Finger flow paths from the deep basin.

Long distance migration of oil and gas in the Anadarko Basin is indicated by the progressive depletion of toluene in oils with increased distance from the kitchen area (Burruss and Hatch, 1989, p. 61), and that most of the Kansas and Colorado portions of the province are thermally immature for oil or gas generation but contain abundant oil and gas resources. Lateral migration can exceed 200 km (124 mi), which is the distance between the extent of thermally mature source rocks for the Oil Creek layer and the northern limit of the model. Maximum migration is probably considerably greater as evidenced by the abundance of oil and gas resources in the Central Kansas uplift and the Cambridge arch to the north, areas that are thermally immature for petroleum generation.

Tertiary Migration of Hydrocarbons

Impact of the Laramide orogeny included withdrawal of the Cretaceous epicontinental seaway and regional uplift that caused an eastward and southeastward tilt to the Anadarko Basin (Johnson, 1989). Primary modeled effect of this tilting is remobilization of some trapped oil and gas with subsequent remigration, perhaps resulting in the red flow paths of gas migration in the northern basin (fig. 31). Uplift and erosion can also influence pressure in formations across the basin, resulting in the release of pressure by removal of overburden, particularly if they are seals, and associated modification of hydrologic flow. The Permian layers provide an example of gas remigration and diffusion during the Laramide uplift and erosion in gas reservoirs of the southern Central Kansas uplift and Pratt anticline, and the Hugoton embayment (fig. 32). The Laramide orogeny redistributed Panhandle field fluid columns, possibly spilling gas northward into the Hugoton embayment (Sorenson, 2005). Regional uplift, erosion, and associated drop in pressure in the Hugoton embayment and CKU areas resulted in a volume increase in the gas within the Chase and underlying layers. Gas flow paths are primarily in the Douglas Group through Permian layers. The mostly northern flow of Oil Creek- and Thirteen Finger-sourced petroleum from the Panhandle field area and northwesterly curving Thirteen Finger flow in Kansas suggests these are primary sources for the Hugoton field area of southwest Kansas. Oil Creek is the primary modeled source for petroleum in the panhandle area; however, north of this field there are numerous and variable source rocks that contribute to accumulations.

The modeled source rock contributions to petroleum accumulations in the Anadarko Basin correspond generally to the Burruss and Hatch (1989) determination of three petroleum systems; divisions were based on carbon stable-isotopic compositions and gasoline-range hydrocarbon compositions of oil that correlated with extracts of Ordovician, Devonian, and Pennsylvanian source rocks. These divisions correspond generally to our Ordovician Oil Creek, Devonian-Mississippian Woodford, and Pennsylvanian Thirteen Finger limestone source rock layers.

Within the 4D model, the Oil Creek primarily sources Arbuckle through Viola petroleum accumulations, the Woodford Shale is the major source for Hunton, Springer, and lower Morrow accumulations, and the Thirteen Finger limestone is the main source for middle Morrow through Permian accumulations. Each color bar in figure 32 shows petroleum accumulations specific to the corresponding named layer, and each of these layers can have contributions from one or more source rocks. Contributions from sources can change through time as shallower source rocks enter the oil and gas generation and expulsion windows. I will only list generalized source rock contributions for modeled accumulations at 0 Ma.

The Oil Creek Formation of the Simpson Group was the only petroleum source layer that contributed to the Arbuckle layer accumulations (fig. 32). These minor accumulations are located primarily in uplifted and exposed areas of the Central Kansas uplift and Panhandle field. The Oil Creek source layer is the only contributor to lower Simpson petroleum accumulations, but minor upper (overlying) Simpson accumulations include about 25 percent contribution from Woodford sources. The Viola layer petroleum sources include Oil Creek (71 percent) and Woodford (29 percent) layers. Hunton accumulations have the Woodford Shale as the primary source at about 77 percent of the oil and wet gas; the remainder is sourced from the Oil Creek layer. Most of the modeled Hunton petroleum accumulated along the northern boundary of the Sooner trend (fig. 32), which is along the northern terminus of the formation against the sealing Woodford Shale layer. Sooner-trend oil and associated gases are produced from

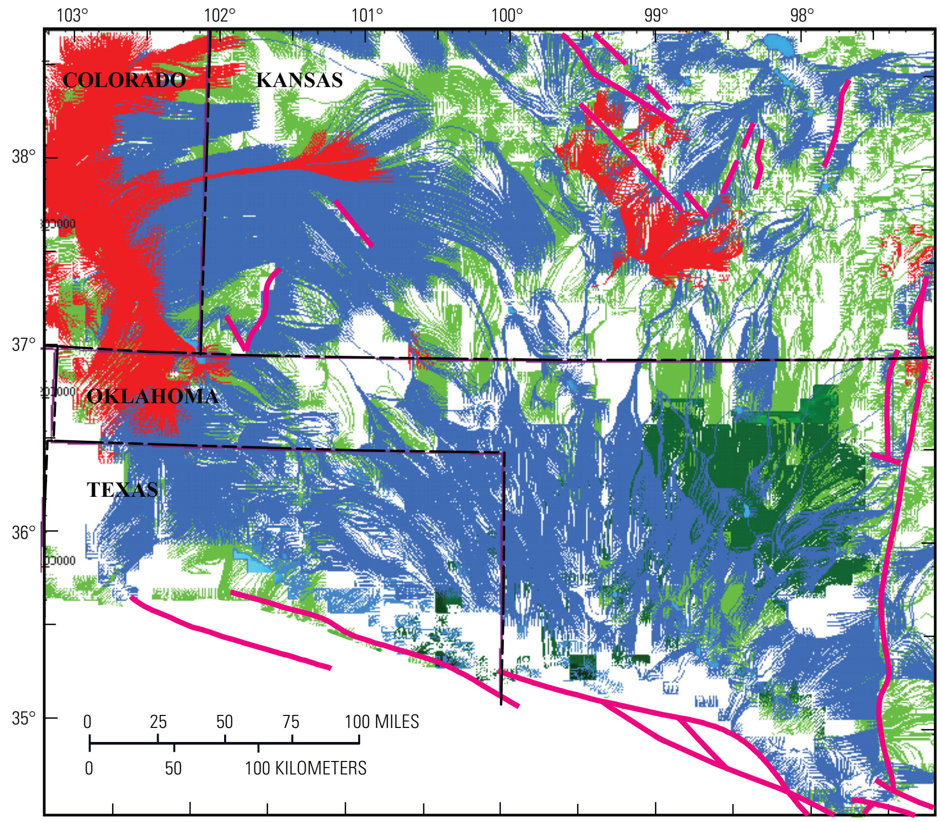

Figure 31. Image showing present-day oil and gas migration flow paths. Blank migration areas indicate no migration, (invisible) Darcy flow through lithofacies, or overmaturity for petroleum generation. Oil migration flow paths from mostly Oil Creek layer source rocks (light green) are overlain by mostly Woodford Shale (dark green), and then Thirteen Finger limestone (blue) flow paths. Gas (red) flow paths are not differentiated by source rocks. Maroon lines are the fault system from Adler and others (1971).

Silurian, Devonian, and Mississippian carbonates at depths as great as 9,600 ft, including Hunton Group carbonates, and were generated from Type-II kerogen during the mature stage; associated oil correlates with extracts of the Woodford Shale (Rice and others, 1989). Gases are isotopically light ($\delta^{13}C$ values of -47.3 to -40.6 ppt) and chemically wetter (C_1/C_{1-5} values of 0.67 to 0.99) than those derived from Type-III kerogen at an equivalent level of thermal maturity (Rice and others, 1989). Hunton petroleum in the Cement field (fig. 32) is sourced partly from the Oil Creek and primarily from the Woodford. A number of modeled source rocks contribute to Springer layer production across the study area, but the primary source is Woodford at 49 percent, followed by Oil Creek at 31 percent, and Thirteen Finger limestone at 20 percent. The Morrow was divided into three layers with assigned lithofacies boundaries based on Andrews (1999b). Lower Morrow is primarily sourced from the Woodford (76 percent) with secondary Oil Creek (23 percent). The middle Morrow layer has 98 percent Woodford and 2 percent Oil Creek layer contributions; if were there were additional petroleum source rocks, these percentages would change. The upper Morrow layer is sourced 74 percent from the Thirteen Finger and 26 percent from the Woodford layer; Woodford contributions are focused along the updip limit of the Morrow layers.

Model results include petroleum volumes remaining within source rocks. This is primarily because the low permeability of the Oil Creek, Woodford, and deep-basin Thirteen Finger layers resulted in saturation rather than discrete accumulations. Technically, these layers would be mostly or completely self-sourced. Although saturation/accumulation seems a subtle difference, the saturation results do not include petroleum migration, accumulation, or reported volumes. Unlike for the Oil Creek Formation and Woodford Shale source rocks, PetroMod® calculated oil reservoir accumulations for the Thirteen Finger limestone north of the deep basin (figs. 28 and 29). This layer is defined as a source rock with the general lithofacies assignment of shaley limestone. The area of the deep basin that is mature for Thirteen Finger limestone gas generation contains some peripheral oil and wet gas accumulations with the Woodford Shale as a contributing source, but

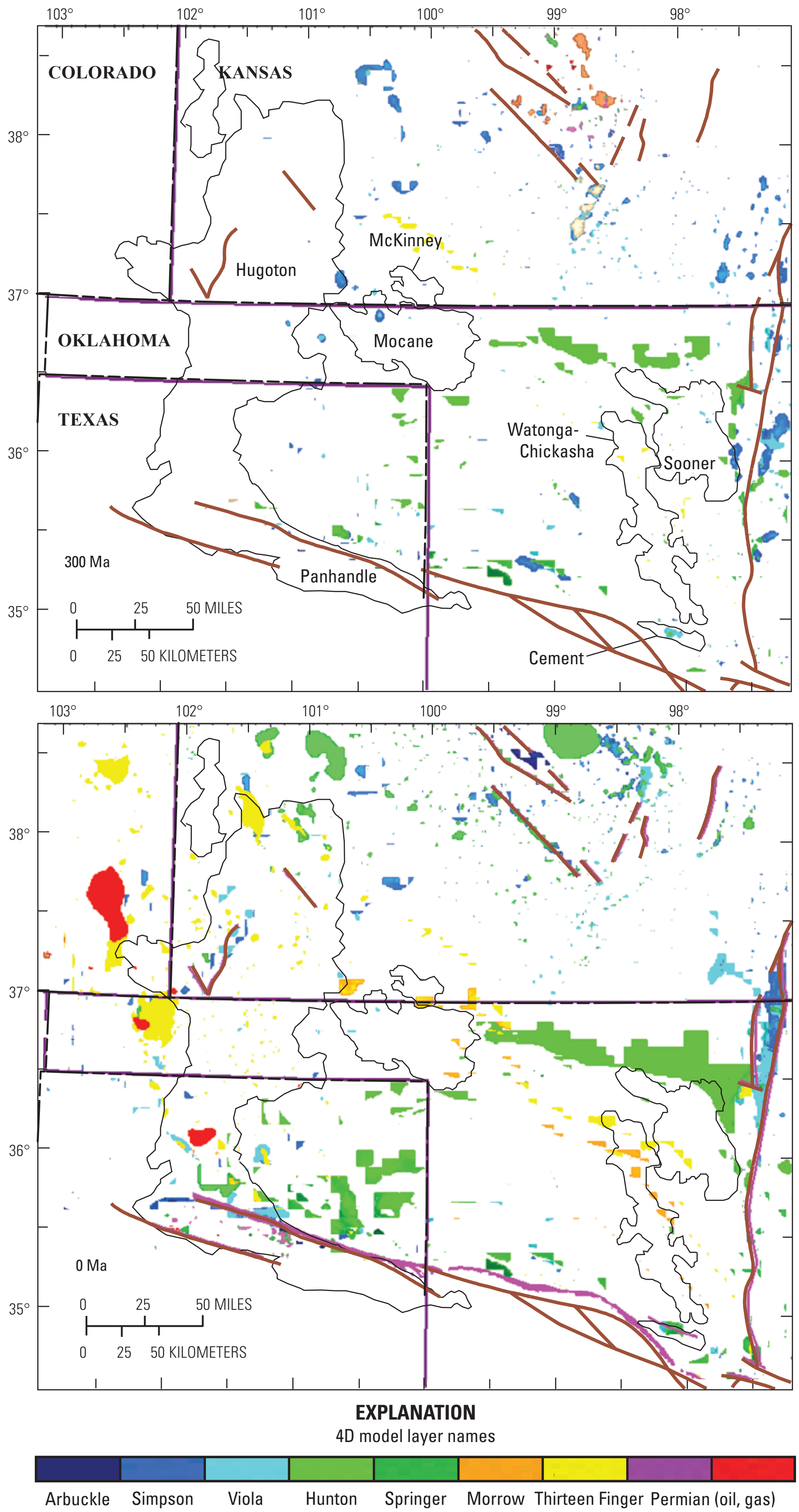

Figure 32. Images showing modeled gas (red) and oil accumulations at 300 million years before present (Ma) and present day for above named layers. Some major oil and gas fields are outlined and labeled. Brown lines are the Precambrian fault system from Adler and others (1971); the purple lines north of this fault system are modeled locations of the Wichita Mountain uplift at 200 Ma and at present. Accumulations preferentially form on large structures, such as the Cement field, and updip pinchout of reservoir layers against seal layers, such as for the Hunton Group accumulations in northeast Oklahoma. Stratigraphic traps are commonly not filled in this leaky four-dimensional model because of the coarse grid size and lithologic assignments.

98 percent of the oil in this layer is sourced from the Thirteen Finger limestone, with about 2 percent Woodford Shale. Permian oil and gas is sourced 56 percent from the Thirteen Finger limestone, 26 percent from the Oil Creek layer, and 18 percent from the Woodford Shale; most of the Permian gas accumulations are in the panhandle through western Hugoton field areas (fig. 32). Probable reasons for this mix are (1) Woodford Shale and Thirteen Finger limestone source rocks are absent in most of the Amarillo uplift area, so the Permian blue "rectangle" southwest of Colorado in figure 30 at 40 Ma was mostly migration of Oil Creek hydrocarbons updip along the flanks of the basin; (2) the isopach of Woodford through Desmoinesian strata is thin in the Texas panhandle (fig. 9), which could allow for greater contributions from deeper source rocks, which could also be a factor in sour oil and gas in parts of the Panhandle field; and (3) this leaky 4D model allows for more vertical and lateral migration than a more complex model would. Isolating the model to smaller areas of the basin and running it with closer grid spacing and more complex vertical and lateral lithofacies would provide additional information.

Conclusions

The Anadarko Basin is an important petroleum province in the United States. The richness of oil and gas production is reflected by petroleum source rocks that range in age from Ordovician through Pennsylvanian. These source rocks are most thermally mature in the deep basin of southwestern Oklahoma and northern Texas. Oil and gas generation, migration, and accumulation were strongly influenced by the history of deposition, uplift, and erosion. A 4D petroleum system model of the Anadarko Basin Province was built using 30 layers of Precambrian to present-day stratigraphic units with assigned lithofacies and ages of deposition and erosion. 1D models were constructed and calibrated using vitrinite reflectance and temperature data. These were used to calibrate the 4D model, and 1D extractions from the model were used for further calibration.

Three source intervals were incorporated in these models, mainly to derive timing of oil and gas generation and migration, and to evaluate total petroleum systems based on source contributions to petroleum accumulations. Petroleum source rocks are the Oil Creek Formation of the Ordovician Simpson Group, the Devonian-Mississippian Woodford Shale, and the Thirteen Finger limestone of the Pennsylvanian Atoka Group. These modeled source rock contributions to petroleum accumulations correspond generally to the determination of three petroleum systems in the basin. Within the 4D model, the Oil Creek primarily sources Arbuckle through Viola petroleum accumulations; the Woodford Shale is the major source for Hunton, Springer, and lower Morrow accumulations; and the Thirteen Finger limestone is the main source for upper Morrow through Permian accumulations.

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